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Integrated Infrastructure Planning and 2050 Climate Neutrality:

Deriving Future-Proof European Energy Infrastructures

Imprint

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Project Management

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The modelling approach in this study is based on PyPSA-Eur, which requires a mathematical solver for the underlying optimization problems. We acknowledge the support of Gurobi Optimization (https://www.gurobi.com) for providing a scientific license for the Gurobi Optimizer. Due to the high complexity of the energy system model, the resulting linear optimization problem involves a large number of variables and constraints, requiring a robust and fast solver to find an optimal solution within a reasonable timeframe. We are very grateful to Gurobi for this support.

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Abbreviations

AC	Alternative Current
ACER	European Union Agency for the Cooperation of Energy Regulators
BioSNG	Synthetic Natural Gas from biomass
CBCA	cross-border cost allocation
CCGT	Combined cycle gas turbine
CCS	Carbon Capture and Storage
CCU	Carbon Capture and Use
CE	Scenario "CE" (Cross-sectoral and European view)
CEF-E	Connecting Europe Facility – Energy
CHP	Combined Heat and Power
CN	Scenario "CN" (Cross-sectoral and National view)
CO_2	Carbon dioxide
COP	Coefficient of Performance
DC	Direct Current
ENTSO-E	European Network of Transmission System Operators for Electricity
ENTSO-G	European Network of Transmission System Operators for Gas
EV	Electric Vehicle
H2	Hydrogen
NRAs	National Regulatory Agencies
OCGT	Open-cycle gas turbines
PEIs	Projects of European Interest
PHS	Pumped Hydro Storage
PtX	Power-to-X
PV	Photovoltaics
PyPSA-Eur	Open-source energy system model
RES-E	Renewable Energy Sources (Electricity)
RFNBO	Renewable Fuels of Non-Biological Origin
RRF	Recovery and Resilience Facility
SAF	Sustainable Air Fuel
SE	Scenario "SE" (Sectoral and European view)
SMR	Steam Methane Reforming
SN	Scenario "SN" (Sectoral and National view)
TEN-E	Trans-European Energy Networks
TransHyDE	German National Flagship Project on Hydrogen Infrastructures (https://www.wasserstoff-leitprojekte.de/projects/transhyde)
TSO	Transmission System Operator
TYNDP	Ten-Year Network Development Plan

Summary

Objective of the Study

The report analyses **the role that integrated infrastructure planning plays in the transformation of the European energy system into a climate-neutral energy system by 2050**. The focus is on energy infrastructures and their role in the transformation process, notably:

- Electricity infrastructure
- Gas infrastructure (including both natural gas and future hydrogen infrastructures)
- Infrastructure related to CO_2 from carbon capture, transport, storage and use.
- Heat infrastructure and its contribution to sector coupling[1].

The **main objective** of this study is to quantitatively develop **an integrated infrastructure planning procedure in Europe that considers the different energy vectors of electricity, natural gas, hydrogen and CO_2, their dynamic interaction and the geographical dimension across the EU**. Instead of deriving individual cost-optimal infrastructure for one energy vector or country, the system derived using this integrated approach results from an overall optimisation based on common framework conditions across all Member States and energy vectors. In this approach, the endogenous optimisation concentrates on energy infrastructures including storage and flexibility options, while implicitly considering distribution infrastructures for electricity and heat.

The study's starting point is the **hypothesis that deeper levels of integrated planning of energy infrastructures, both geographically across Europe and between the different infrastructure sectors, are required to put Europe on track to net-zero emissions by 2050**.

Electricity infrastructures are highly developed but face new requirements concerning changing energy generation and storage technologies and the need to cope with high shares of fluctuating energy sources and rising electricity demand. Gas infrastructures are also highly developed, but fossil gas demand is expected to decrease substantially. This decrease will only be partially offset by a shift from fossil-based natural gas to hydrogen. Finally, CO_2-related infrastructures are new and will be driven by the contribution they can make to climate neutrality through Carbon Capture, Use and Storage. In our analysis, these infrastructures are characterized **as sectors** and fully modelled on the transmission level. As these infrastructures are closely interrelated, the question is **whether coherent planning and development processes across all infrastructures could be beneficial to the transformation process, which already requires substantial investments in new technologies**.

The study covers a large part of the European continent (33 countries in total, including EU27, Norway, UK, Switzerland, and Energy Community Parties on the Balkans), considering countries at **national** level and Europe as a whole.

Benefits of Integrated Infrastructures and Present State

The **integrated planning** of **energy infrastructures** is expected to lead to **multiple benefits**. These include lower capital expenditures on generation and backup capacity in the energy system due to better cooperation between Member States and more efficient use of different energy vectors in the energy system. Furthermore, it might be possible to avoid capital expenditures on energy infrastructures and sector-coupling technologies through improved coordination and integration of infrastructures. Other potential benefits include the reduction of operational expenditures in the overall energy system also due to a more efficient combination of energy vectors and better use of renewable energy potentials. Ultimately this can help to increase the acceptance of infrastructure projects and the energy transition in general and reduce challenges with respect to skills and the shortage of rare materials. In sum, these effects are expected to reduce total energy system costs. This study aims to assess the

[1] i.e. integrating the energy consuming sectors - buildings (heating and cooling), transport, and industry - with the power producing sector.

impact of differing degrees of sectoral and geographic integration on system costs and physical investment needs for energy supply, storage, and transmission.

Although current planning approaches in the Ten-Year Network Development Plans (TYNDPs) have evolved to include some cross-sectoral and European elements, they are still based on national energy strategies, e.g. on national renewable energy plans, national definitions of generation adequacy, and national grid development plans. The inputs and assumptions in the TYNDP therefore stem from a national perspective. This reliance on national plans also limits the cross-sectoral integration of system development strategies as integrated grid planning is only in its infancy at the Member State level. In short, the current cross-border grid planning regime can be characterised as considering only limited integration of sectoral and geographic dimensions.

Approach of the Study and Main Scenarios

Based on the infrastructures (sectors) and the geographic dimension introduced above, we consider **two main policy dimensions** for the scenario analysis of integrated infrastructures, which is performed using the PyPSA-Eur open-source energy system model in line with climate neutrality ambitions:

a. **Cross-sectoral view** ◄——► **Sectoral view**

Infrastructure planning in sectoral silos does not consider the interaction of electricity, gas, hydrogen and CO_2 infrastructures in a consistent or harmonized way and therefore involves the risk of unnecessarily high energy system costs due to grid bottlenecks and/or overcapacities (both in generation and storage technologies and infrastructures). *Implementation: To account for the sectoral policy dimension in the energy system modelling, we go beyond current infrastructures to include future electricity transmission lines and natural gas and hydrogen pipelines that have been proposed in frameworks like the TYNDP 2022, the H2 Infrastructure Map and the German Hydrogen "Core Network"[2]. Based on the existing grid and these projects, we set limitations for endogenous model-based transmission-capacity expansion until 2040 in the scenarios with a strong sectoral view while allowing for fully model-based transmission capacity expansion in the scenarios with a strong integrated view.*

b. **European view** ◄——► **National view**

The second policy dimension builds on the observation that many EU member states aim to minimize significant energy import dependencies (from within the EU as well) by implementing policies that strive to establish sufficient domestic generation and storage capacities to largely meet domestic electricity demand, at least on an annual basis. This approach could lead to unnecessarily high system costs of the overall European energy supply. *Implementation: In our model, we impose a maximum share of hydrogen and electricity imported on an annual basis compared to national generation. A strong focus of policy making on national self-sufficiency can be modelled by requiring a higher share of national generation. This is contrasted with scenarios where national policies do not aim to meet any self-sufficiency thresholds.*

[2] *Detailed explanation of the scenario design and the TYNDP process are given in chapters 3 and 4.*

These two policy dimensions yield a matrix of four scenarios, which form the core of our analysis of European infrastructure:

	EUROPEAN VIEW	**NATIONAL VIEW**
CROSS-SECTOR PLANNING	**(1) CE:** **Cross-Sectoral, European View**	**(2) CN :** **Cross-Sectoral, National view**
SECTORAL GRID PLANNING	**(3) SE:** **Sectoral, European View**	**(4) SN :** **Sectoral, National view**

1) **Scenario "CE"** (**C**ross-sectoral and **E**uropean view): Model-based generation, storage and integrated grid expansion across Europe for achieving a climate-neutral energy system by 2050.
2) **Scenario "CN"** (**C**ross-sectoral and **N**ational view): Cross-sector integrated grid expansion with limited coordination and expansion of interconnection capacities across Europe by constraining the model with maximum levels of annual imports (including those from within Europe).
3) **Scenario "SE"** (**S**ectoral and **E**uropean view): Sectoral grid planning in silos with simultaneous European-wide optimisation of capacity expansion for energy supply.
4) **Scenario "SN"** (**S**ectoral and **N**ational view): Sectoral grid planning in silos with limited expansion of interconnection capacities across Europe by constraining the model with maximum levels of annual imports.

Infrastructure Model for the Analysis and Main Data Inputs

The PyPSA-Eur model is used for the analysis of European energy infrastructures. As a compromise between calculation time and precision, the regional resolution was set to 62 regional cluster points, which cover all the European countries considered (larger countries and case study regions with a higher geographical resolution). Similarly, the temporal resolution focuses on seven milestone years between 2020 and 2050 in steps of five years and divides the year into 2190 increments with a flexible time segmentation. The width of these increments is determined by an algorithm that considers exogenous time series like renewable energy supply and demand profiles and groups adjacent time steps that do not significantly differ from each other. As a result, time periods with high fluctuation can have an hourly resolution, compensated by larger intervals for times with little fluctuation. A test on a smaller model showed that discrepancies compared to a full hourly resolution are kept to a minimum with this method. By doing so, we can incorporate important features in the time series of supply and demand throughout the day while drastically cutting down the run-time.

The main scenarios are built on modelling assumptions within the PyPSA-Eur framework. The detailed input parameters can be found in the repository and additional information published with this report. Two overarching remarks on the input data and scenario assumptions:

- *Energy demand* is modelled based on the structure already provided by PyPSA-Eur-Sec [1]. A key source to build the demand in PyPSA-Eur-Sec is JRC-IDEES [2], see the PyPSA-Eur-Sec license documentation [3] for a full list of input data. The exogenously set energy demand developments in Europe are then configured and validated based on recently published data [4] from the TransHyDE study [5].
- In addition, our approach ensures that the transformation of the energy system towards climate neutrality can be optimised freely, considering innovative technologies and the modelling assumptions stated above. Notably, the model provides a novel and useful approach to handling adaptable Power-to-X technologies, hydrogen and its derivatives, and flexible optimisation of grid infrastructure.

Quantification of the Benefits of Integrated Infrastructures

The analysis of the four main scenarios revealed the following **benefits of strengthening the European and cross-sectoral infrastructure planning processes**:

1. **Reduction in the energy supply and sector-coupling capacity required**, notably:
    - Reduction in the European-wide renewables generation capacity required (e.g. 15% less onshore wind capacity required in the CE scenario than in the SN scenario)
    - Reduction in the back-up capacity[3] required (e.g. 505 GW less in the CE and SE scenarios than in the SN scenario)
    - Reduction in the H_2-electrolyser-capacity required (e.g. 9% less capacity in the SE scenario than in the SN scenario)
2. **Reduction in overall infrastructure investments,** but a **mixed picture regarding infrastructure capacity needs**:
    - Sectoral integration leads to an important decrease of hydrogen transport capacity and to some decrease of national electricity transmission capacity, some increase of electricity interconnection capacity and enhanced capacity use of hydrogen infrastructure.
    - European integration leads to some increase of electricity interconnection and of hydrogen transport capacity.
    - In terms of storage infrastructure, European integration leads to a substantial decrease of hydrogen storage needs and an increase of electric batteries, whereas sectoral integration leads to an important increase of hydrogen storage and a decrease of electric batteries.
    - In combination, sectoral and European integration leads in most cases to a reduction in infrastructure needs and enhanced capacity use of hydrogen infrastructure, but definitely to substantial increases in battery and hydrogen storage capacities, as well as some increase in electricity interconnection capacities.
3. **Reduction in (annual and cumulative) investments/energy system costs**, composed of:
    - Reduction in technology-related investments
    - Reduction in infrastructure-related investments
    - Overall reduction in energy system costs.

Note that the categories 1 and 2 above contribute in combination to the benefits in category 3, but may not show immediately benefits in 1 and 2. For example, European integration leads to a reduction of investments in renewable energy capacity but to increased investments in electricity interconnection capacities. However, overall total system costs, which are the sum of the annuities of all capital and operational expenditures of the energy system, are reduced by European and cross-sectoral integration.

Compared to the SN scenario (Sector and National view), i.e. the scenario with the least degree of European and sector integration, the main findings in qualitative terms from the scenarios with partial integration (SE, CN) and the fully integrated scenario CE include the following observations.

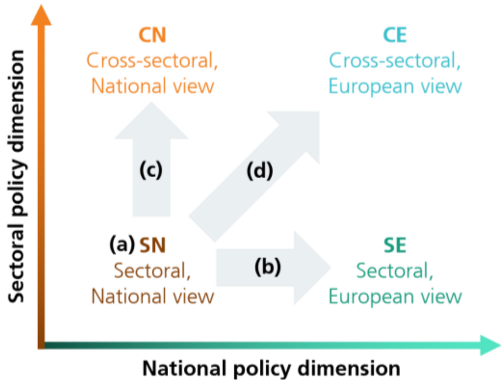
1. **Reduction in the energy supply and sector-coupling capacity required**:
    - All three integrated approaches (CE, CN and SE) have benefits (reduction in technology capacity required) in most cases. Benefits are limited in the shorter term (2030), except for back-up capacities, but increase thereafter.

[3] These capacities refer to dispatchable peaking plants that allow a country to meet its domestic demand in every situation. In a functioning European market and based on a European definition of generation adequacy substantially lower capacities are needed.

- Towards 2050, CN and CE yield the highest reductions in PV technology required, while CE has the largest reductions for onshore wind. In the case of cross-sectoral integration only (without European integrated planning processes), the reduction of PV capacity is strongly linked to a reduced need for hydrogen electrolysers, while the reduced need for wind-onshore capacity in the scenario CE is a result of the least cost installations at best locations in Europe due to the fact that self-sufficiency constraints are lifted.
- Back-up power generation capacities are strongly reduced in the European scenarios (SE and CE), as Member States rely on each other for the security of power supply.
- There are no major differences between the scenarios for offshore wind.
- The integrated scenarios lead to a reduction in the H_2 electrolyser capacities required. The highest reductions of 9% are reached by European and cross-sectoral integration (CE scenario) due to more efficient regional allocation of electrolyser capacities and larger imports from outside of Europe.

2. **Reduction in infrastructure required** (including transmission/transport, and storage capacities), notably hydrogen and CO_2-related infrastructures, and **enhanced utilisation of infrastructure**.
    - Cross-sectoral and European integration have a limited impact on the overall size of electricity infrastructure needed. While there is a reduction in internal transmission infrastructure (between clusters defined in the national context), interconnection capacities (between countries) are increased under both sectoral and European integration. Furthermore, European integration leads to an expansion of renewable energy capacity in countries with low-cost renewables and increased storage capacity in these countries.
    - Our cross-sector integrated scenarios (CE and CN) have a significantly reduced need for H_2 infrastructure (H_2 transport capacities and their utilisation). This is due to the fact that current sectoral planning approaches lead to overcapacities of H_2-infrastructure. European integration results in a reduced need for H_2 storage capacity (SE vs SN and CE vs CN).
    - For CO_2 infrastructure, the benefits of European and cross-sectorally integrated planning processes are linked to a reduction in sequestration capacities. This is driven by a lower primary energy demand for natural gas due to infrastructure integration at European and cross-sectoral level.
3. **Reduction in (annual and cumulative) investments/energy system costs**: cumulative for the period 2030-2050 (see overview table below):
    - Overall, all three scenarios with sectoral and European integration lead to a reduction in investments/energy system costs compared to the scenario SN (which in itself is already a partially optimised approach compared to a pure bottom-up approach to energy infrastructure development). The largest benefits from European integration are the reduction in energy supply investments, but cross-sector integration substantially reduces infrastructure-related costs.
    - The largest benefits in terms of the cumulative overall system costs are from scenario CE (cross-sector and European), **amounting to over 560 billion euros for the period 2030-2050**.
    - This result is affected by integrating both the cross-sectoral and the Europe-wide perspective into the planning processes. Integrating a European perspective reduces the total system costs by 1%, while integrating a cross-sectoral perspective reduces the costs by 2% in 2050. If both effects are combined, the total cost reduction amounts to 3% in 2050.

Benefits of integrating European and sectoral perspectives - reduction in cumulative investments/energy system costs (compared to the SN Scenario – Sector/National view).



	(a) SN	(b) SE	(c) CN	(d) CE
	Reference	(compared to SN)		
(bn Euro)	2030-2050	2030-2050	2030-2050	2030-2050
Cumulative investments/energy system costs (2030-2050) [EU27[4], Norway, UK, Switzerland, Balkan-EnC[5]]				
Technology-related investments[6]	11773	**-230**	**-145**	**-506**
Infrastructure-related investments[7]	1465	-14	**-191**	**-169**
Operational & fuel costs	4115	**124**	**-70**	**114**
Overall-energy system costs[8]	17353	**-120**	**-406**	**-561**

Note: A negative value (in green) means a reduction in investments/energy system costs compared to the SN Scenario, i.e. a benefit from the integration. A positive value (in red) means more investments/energy system costs than in the SN scenario.

All results are stated compared to the fragmented SN scenario (but which can already be considered more optimised than a less co-ordinated bottom-up planning and development process, and which dominates the early stages of this scenario). The stated cost savings could therefore be even higher than evaluated compared to the SN scenario.

Based on the optimisation approach applied in this study, the electricity and hydrogen infrastructures on the transmission/transport level are planned and operated in strong coordination with flexibility technologies on the transmission and distribution grid level, and the heat sector. Strong-cross border coordination with electricity imports and exports provide the majority of flexibility resources of the energy system. If this coordination can be achieved in practice, only moderate additional storage capacity of battery storages and hydrogen at the transmission level are required. If this cannot be achieved, higher storage capacity would be needed.

The scenarios that focus on meeting domestic demand with domestic supply (SN and CN) increased the technology costs for energy supply and storage but had little impact on transmission infrastructure costs. This is because countries achieve higher self-sufficiency in these scenarios as an annual average

[4] EU27: European Union excluding Cyprus and Malta

[5] Balkan-EnC: Energy Community Parties on the Balkans (Albania, Bosnia and Herzegovina, Montenegro, North Macedonia, and Serbia, excluding Kosovo).

[6] Power generation, heat generation and transformation technologies (e.g. H2 electrolysis)

[7] Electricity, hydrogen, methane and CO_2 network

[8] Capital, operational and fuel costs

but still rely heavily on international trade in many hours of the year, which makes strong transmission infrastructure necessary.

The scenarios with differing degrees of cross-sector integration showed large differences in the costs for infrastructure.

The largest differences appear in the hydrogen sector. Current grid plans developed at Member State-level overestimate the overall need for H_2 pipelines but lead to incomplete hydrogen infrastructure in certain regions at the same time. The hydrogen grid in the CE scenario features more diverse connectivity with lower capacities. This means that, in total, a higher interconnectivity with less overcapacity results from the cross-sector scenarios.

Natural gas infrastructures are partly repurposed for hydrogen uses but otherwise follow the large reduction in natural gas uses for heat and electricity generation purposes. Notably decentral uses of natural gas to heat buildings is reduced to less than 4% of today's uses of natural gas for these purposes. Modelling options to reduce to zero the - already largely decreased - remaining (fossil) methane uses in the scenarios show that fossil fuels still find a way into net-zero energy systems (through blue hydrogen coupled with CCS or supported by carbon removal technologies) as long as the deployment of cheap renewables, especially wind power and solar PV, is constrained by limits to those technologies currently implemented in the model, unless they could be overcome by adequate measures.

In short, the transformation to a climate-neutral energy system without an integrated planning approach is associated with higher costs and material use. These costs are mainly due to the higher demand for renewable energy generation, backup capacities, electrolysers, and hydrogen infrastructure. An integrated approach makes it possible to operate a system that uses and combines the properties and strengths of the different energy carriers and infrastructures. For example, the capacity factors of electrolysers are higher in the case of cross-sector integration because electricity and hydrogen infrastructures are better aligned. A system planned in an integrated manner can link sinks and sources cost-effectively.

In addition to the importance of integrated approaches within the EU27, the connections to non-EU countries will be essential for an efficient transition. In particular, the UK will be very important for the stronger integration of electricity and hydrogen infrastructures. The EU27 stand to benefit from the wind energy potentials in the UK enabling a low-cost transition.

While integrating the national and sectoral perspectives in planning processes (CE scenario) leads to substantial savings at the level of overall system costs, the allocation of costs and benefits varies compared to the more fragmented national and sector scenario SN. This variance is illustrated by **two regional case studies** (on the larger Polish-Baltic region and the larger North-West Germany/Benelux region) performed in this study, which show that the countries develop more specialised technology and infrastructure portfolios in the CE scenario. For example, in the fully integrated scenario CE, low-cost decarbonisation options like offshore wind play a stronger role in the Polish-Baltic region, whereas hydrogen imports are more important in the North-West Germany/Benelux region. While the interplay of different solutions yields overall Europe-wide benefits, **it does raise the question of how the costs and benefits can best be distributed among countries (including non-EU countries, such as the UK, Norway, Switzerland and Western Balkans)**. Policy could be designed to compensate those countries that would be better off in the SN scenario, so that the benefits of the integrated approach are shared by all.

In two sensitivity studies we investigate uncertainties with respect to several assumptions entering the modelling analysis:

- The industrial sector could transition in such a way that either large parts of the industrial value chain related to and building on the hydrogen economy are located in Europe or are partly relocated to other regions with low-cost renewable energy potentials. To understand the impact of such a development of the industry sector in Europe, we introduce a sensitivity analysis to the cross-sectoral, European scenario. The additional demand for hydrogen in the sensitivity analysis (mainly for larger amounts of sponge iron, methanol and ammonia produced in Europe than in the main scenarios) is covered first by steam-methane reforming as blue hydrogen and from 2040 onwards by green hydrogen from imports from outside of Europe. In 2050, 46% of the additional industrial hydrogen demand in the sensitivity is supplied by European production via electrolysis. The increase in the hydrogen demand in some regions due to more local industrial activity along with the increased usage of electrolysis and imports to provide the hydrogen affects the grid architecture in the EU – yet more in the longer run only. The additional electrolyser capacity is directly installed in regions with high renewable potential and coincides with additional renewable capacities. Therefore, there is no need to transmit the electricity between clusters to electrolysers. Not surprisingly, for the hydrogen network capacity, however, we see a strong increase in needed pipeline capacity with higher industrial hydrogen demand. As a result, the total EU's hydrogen network is 30% larger in 2050 compared to the network resulting from lower industrial hydrogen demand as per the CE scenario. When incentivising industrial energy-intensive processes to convert fully to a hydrogen economy in Europe, certain regions might become more reliant on hydrogen imports, and planners also must account for the increase in need for more hydrogen infrastructure. Such a shift in the energy system would increase system costs.

- Another area of interest is the usage of flexibility options to handle the large renewable capacities in the system. Here, local distribution grids might play an essential role with the use of electric vehicles and the electrification of the heating sector. To analyse the effect of less availability of flexibility options in the local grid, we compared the main scenario assumptions for a high level of flexibility with a lower flexibility case for the cross-sectoral, European (CE) scenario. Specifically, we halved the share of district heating and the ability of electric vehicles to participate in demand-side management and vehicle-to-grid activities and increased investment costs for flexibility options like water tanks and heat pumps in the heating sector. As a result, the heating sector remains more reliant on gas and oil boilers than in the main scenarios that feature high local grid flexibility. The reduced availability of vehicle-to-grid results in a shift in storage technologies from the distribution grid to the transmission grid but also in a shift from electricity to hydrogen storage. This implies increased need for an electricity infrastructure (additional 7.7 TWkm installed in 2050 compared to the main scenario with high flexibility). Conversely, due to the shift from electricity to hydrogen storage, less infrastructure is needed for hydrogen transport. As such, the hydrogen network would be 5% smaller in 2050 compared to the main scenario with high flexibility in the local grids.

1 Introduction and Objective of this Study

The EU's greenhouse gas emission reduction targets that are enshrined in the European Climate Law (-55 % by 2030, net-zero by 2050 at the latest) as well as the intermediate target proposed for 2040 (-90% by 2040) imply a fundamental shift of the EU's energy mix away from fossil fuels towards renewables, clean electricity, and increased energy efficiency. At the same time, the Russian war against Ukraine has revealed the severe effects that a high dependence on energy imports can have in terms of energy security. A climate-neutral Europe is no longer seen as only vital to ensuring a liveable environment in the future but is also understood as essential for a sustainable, secure and affordable energy system and economy. Achieving a climate-neutral Europe by 2050 requires a fundamentally different energy infrastructure:

- Unprecedented expansion of electricity transmission is required to match renewable energy generation sites with load centres and smooth output across national borders. A major share of new renewables will be connected to the distribution grids, which poses investment and operational challenges for the power system (grid investments, flexibility provision, reverse power flows, advanced system management needs), while expansion plans for offshore wind require the development of a European offshore grid.
- With a view to the need for gas networks, the role of natural gas will shrink with the reduction in demand (notably in buildings and industry), while electricity and hydrogen (and derivatives) will partly replace the current uses of natural gas.
- Parts of the current natural gas network will be repurposed to transport hydrogen, linking domestic generation, storage sites, import terminals and demand centres.
- Expanding current heat networks is an important option for decarbonizing buildings and industrial heat demand.
- As part of an effective carbon management strategy, it will become necessary to construct European CO_2 infrastructure and develop rules on access to CO_2 transport and storage sites.

While there is growing consensus on the options and obstacles involved, the planning processes for the associated transport infrastructures of electricity, methane, hydrogen, and carbon dioxide are not yet up to the challenges ahead. Planning procedures for carbon dioxide and hydrogen are not established or are in their infancy. The regulatory framework for Europe's currently unbundled energy infrastructures (gas and electricity) was constructed for incremental adaptation of fully developed networks and not for the radical changes required by the transformation of infrastructures to support climate neutrality.

Electricity and natural gas are still planned and developed in national silos to a large extent, notwithstanding efforts and steps to link the processes involved. Within the power system, planning procedures for electricity distribution grids are still relatively detached from transmission-level planning with respect to the challenges raised by climate neutrality. There is insufficient consideration of the potential interplay between heat networks with their potential for storing energy and the electricity system. Furthermore, national approaches to energy policy and regulation only partially account for the potential of an integrated European infrastructure. Infrastructure planning and energy strategy remain largely national, while European energy and climate policy is becoming increasingly relevant.

Any approach to infrastructure planning must deal with uncertainties. Infrastructures typically have long lifetimes and cannot be built reactively in the face of the structural changes ahead. Due to the chicken or the egg problem, waiting for certain energy demand or supplies to arise would either mean that they will not emerge due to the lack of infrastructure, or that network expansion will be extremely expensive due to stepwise, short-sighted expansion.

Failing to address these uncertainties could prevent the emergence of a future-proof resilient energy infrastructure in Europe that, in turn, would limit widespread deployment of RES-E and hinder investments in storage and energy-intensive industries. Accordingly, there is a need to prioritise energy infrastructure and its governance, planning, and regulation on the political agenda, increase transparency and promote a more integrated approach.

This study aims to estimate the benefits of a more integrated, forward-looking and long-term planning of energy infrastructure to meet the 2050 climate neutrality targets. It creates a set of scenarios with varying degrees of European integration in energy infrastructure planning and compares the results and costs of the approaches.

Chapter 2 discusses the benefits of integrated infrastructure planning and the risks and costs of fragmented approaches.

Chapter 3 describes infrastructure development procedures and scenarios in Europe, with a particular emphasis on cross-border projects. National best practices are also reviewed where possible to offer additional insights.

The approach to our study and the main scenario philosophy are laid out in Chapter 4.

To perform the scenario analysis and model calculations, a comprehensive input dataset has been created and is summarised in Chapter 5. This dataset incorporates key variables such as technology costs and energy demand projections up to 2050. This was designed for publication, ensuring that the code and data can be shared upon the study's completion.

The project further establishes an analytical foundation for integrated European infrastructure planning. In Chapter 6, quantitative assessments are conducted focusing on the transmission and transport levels and employing a geographically disaggregated approach. This is complemented by two regional case studies in Chapter 7. All PyPSA optimization runs for this project were performed with the Gurobi Optimizer. We thank Gurobi for supporting the research of this project by providing an academic license.

The two sensitivity analyses in Chapter 8 explore the impact of a strong industrial value chain linked to the hydrogen economy in Europe, and the impact of forfeiting flexibility in the energy system.

Finally, Chapter 9 provides a quantified summary of the benefits of integrated infrastructures in terms of the technologies and infrastructures required, as well as imports. It also includes an outlook to a future-proof European energy infrastructure, identifies potential risks associated with stranded assets, and highlights the implications of infrastructure planning that is not in line with long-term sustainability goals.

2 Benefits of Integration on Infrastructure Planning and the Risks and Costs of Fragmentation

2.1 Why New Challenges Require an Update of Infrastructure Planning Approaches

Energy infrastructure is the foundation for a secure, affordable, and sustainable energy system. There are very detailed planning procedures for the unbundled and regulated energy transport infrastructures in place. In the past, the rules and procedures have arguably served us well, as security of supply remained high, the cost for infrastructure manageable and the clean energy supply grew substantially.

Nonetheless, the new challenges on the horizon raise the question of whether the established practices for infrastructure planning are suited for what lies ahead. The rapid transformation of the energy system creates significant **uncertainties** in terms of its design and infrastructure. Several factors have contributed to these uncertainties:

Changing International Dynamics and Security Threats

Geopolitical shifts and changing energy import routes create new dependencies. The security of supply threats, which started in 2022 with the Ukraine war, underline the need for Europe to have flexible, resilient and efficient infrastructures. This applies to electricity grids, gaseous energy carrier infrastructure, and energy storage. Only with robust infrastructures in place can we make use of the strengths of the internal energy market. Furthermore, the efficient use of infrastructures also impacts on technology and material needs in the transformation processes: the present dominance of imported PV modules highlights the need for an efficient use of such technologies and a rational utilisation of often scarce input materials such as copper or steel needed to build infrastructure. Infrastructures may also be subject to security threats (as illustrated by recent damage to infrastructure in the Baltic Sea) which raises questions regarding the robustness and resilience of the infrastructures to be developed for the future.

Economic and Industrial Changes

The transformations required to meet climate targets may lead to shifts in industrial activity, such as relocating energy-intensive production (e.g., green ammonia or green methanol) abroad if comparative advantages exist. Similarly, major process changes like replacing blast furnaces with hydrogen-based direct reduction steelmaking may affect the choice of location, according to the availability of renewable energy. Conversely, new industries producing energy transition technologies, such as batteries, hydrogen electrolysers and transport/storage systems for hydrogen may emerge domestically, though this depends on infrastructure availability (for hydrogen in this case) and remains uncertain. All in all, it raises the questions of where Europe can position itself in the changing or nascent industrial value chains by capitalising on its competitive advantages in those fields.

Increasing shares of renewable energy

The accelerated growth and contribution of renewable energy sources will provide the basis for the most cost-effective transition to a climate neutral energy system. As the majority of the renewable energy generation will be based on variable sources like wind and solar, Europe will need reliable and integrated infrastructures in order to incorporate and transport the generated energy to the final customers. The fluctuating nature of these energy sources can be accommodated for, but this requires further adjustments to the market rules and regulations, as well as to the infrastructures and their planning procedures.

Technological Innovations

Decarbonisation relies on both existing and established technologies but will also require the ramp-up of options not yet widely implemented or commercially viable. Examples include advancements in electrolysis, hydrogen power plants, and batteries for heavy transport. Technological progress in areas like chemical recycling of plastics or alternatives for cement and lime production is crucial for reducing energy demand. Seasonal hydrogen storage is another cornerstone for decarbonization, but large-scale solutions, such as repurposing natural gas storage, have yet to be implemented. Solutions related to carbon capture, use, transport and storage will need to be developed for certain applications. Artificial Intelligence (AI) and digitalisation will be central building clocks in the development of flexible power grids and virtual power plants, as well as for new business models. On the other hand, they will lead to a strong increase in energy demand for IT data centres.

Political Decisions and Private Sector Behaviour, Competitiveness and Affordability

Political strategies and private sector actions play pivotal roles. Policy outcomes influence market actors, while private investments, such as in home battery systems, may diverge from systemic optimisation models. This unpredictability complicates infrastructure planning, as it – to some extent – needs to include not only a prediction of market decisions, but also a forecast about the regulatory framework and support policies. For example, building a hydrogen network needs to implicitly assume a continuing and growing financial support for hydrogen production and usage; the support policies of the future will determine where hydrogen will be needed, and are consequentially vital for the development of hydrogen infrastructures.

Aside from the increasing uncertainty, planning infrastructures becomes increasingly challenging in the face of **growing interdependencies**, as decarbonization increases the integration of the energy system. One could argue that there has always been some degree of connection between the infrastructures, as for example gas power plants had to be connected to both the electrical grid and the gas pipeline network. Still, the interdependencies are bound to increase many times over due to small and large-scale heat pumps, electrolysers, and H2-ready gas power plants switching to hydrogen at some point in the future. These interdependencies will make it increasingly difficult to plan networks for electricity, gas, hydrogen and heat without having a reliable forecast about the future of the other energy carriers. It also means that the uncertainties in one subsystem can ripple across others, magnifying their effects. For example, misjudging the demand for hydrogen or heat could put a strain on the electrical system and vice versa.

Finally, the need for transformation of our infrastructures in parallel with the overall transformation necessary to achieve climate neutrality will challenge the competitiveness of industries and the affordability of energy through their growing impact on energy prices (notably from increasing network charges, taxes and levies).

All of these challenges are being faced and tackled in every Member State. **However, there is a wider, European component to this dilemma. For many, if not all of these questions, it becomes increasingly difficult to give appropriate answers from a solely national viewpoint**. The challenges, but especially the opportunities for integrating renewables change when viewed from a European-wide perspective. When planning procurement of hydrogen or green fuels on the emerging international markets, a strategy in which each country pursues its own goals without a unified strategy might be both costly as well as unnecessarily risky. A European hydrogen network will require a substantial amount of alignment as well as a strategy for sharing costs and benefits. There has been remarkable success in the past decades in aligning European energy strategies. Nonetheless, energy policy remains the responsibility of each Member State, and **infrastructure planning is still rather a "bottom-up" process, in which strategies are developed first and foremost within the Member States and afterwards compared and – where possible – aligned**. This situation raises questions about the risks this approach bears, and what benefits alternative, more holistic approaches could achieve if implemented.

2.2 Benefits from European Infrastructure Integration Policies

As discussed in the previous section, several new developments mean that the suitability of the infrastructure planning procedures in Europe in their current state, must be reconsidered with regard to the challenges ahead. To dissect this complex question, we could start by imagining an abstract, fully integrated planning of energy infrastructure for the European Union covering all energy forms and their interdependencies. In this state, the infrastructure would be cost-efficient; building more or different infrastructure would increase the overall costs of the energy system, as would building less infrastructure than needed. The internal market can fully operate in this (theoretical) situation and deliver energy at the lowest cost.

The question now is: What real-life bottlenecks, challenges and obstacles hinder fully integrated planning, and what are the consequences? The consequences of lacking integration – or looking at it from the other side – the benefits of successfully integrated approaches, can be **categorized in three dimensions:**

1. **Integrated assessment of uncertainties (Dimension 1)**
2. **Spatially integrated planning (Dimension 2)**
3. **Sector integrated planning (Dimension 3)**

2.2.1 Integrated Assessment of Uncertainties (Dimension 1)

As discussed in the previous section, many of the new challenges arise from new or increasing uncertainties. This is especially challenging for regulated, unbundled energy infrastructures. Under both national and EU regulations, infrastructure operators cannot simply build infrastructure at their own discretion but have to acquire permits in procedures in which the necessity of the new infrastructures must be demonstrated. The question in the face of the new uncertainties is: What makes infrastructure necessary? There is a spectrum of necessity, ranging from the need for a new industrial site with building permits and a finalized investment decision, to more uncertain infrastructure needs. Those uncertain needs include regions with good renewable energy conditions that are likely to be used in the future, or a hydrogen network that enables the production and usage of hydrogen despite these infrastructure demands remaining unfulfilled. It might be useful or even necessary to shift the perspective from "necessity" to "utility" when planning and authorising infrastructure. Probabilistic cost-benefit analyses could be the basis to decide if the potential utility of an infrastructure justifies its costs even in the face of uncertainty.

The integrated assessment of uncertainties, despite being very important, is only briefly mentioned here because the modelling approach is not capable of quantifying the impact of failures in this dimension. The opportunity costs of failure to invest in infrastructure, depend heavily on the specific infrastructure decision and the scenario.

2.2.2 Spatially Integrated Planning (Dimension 2)

The next deviation from a fully integrated EU-wide planning procedure is that – as discussed – planning procedures remain largely "bottom-up" because they are developed at Member State level. Planning a larger area in sub-regions has advantages but can cause very substantial and costly inefficiencies. One example would be an attempt to develop a decarbonization plan for a small, isolated island system without infrastructure connection to the outside. While this is possible, a solution will require extensive renewable energy capacities (which have to rely on the weather conditions at this location alone) and large storage systems. Adding demand for hydrogen or synthetic fuels at this location would further complicate the solution.

The consequences of this type of planning for electricity infrastructures are discussed in Zachmann et al. (2024) [6], the authors conclude that significant techno-economic benefits can be secured from optimizing the design and operation of several national electricity systems jointly, rather than individually. The authors emphasize that the value of these benefits will increase with higher shares of renewables. Benefits detailed in [6] include less fossil-fuel combustion and less volatile short-term prices, cost savings through harnessing the advantages of regional renewables, reduced need for expensive back-up capacity and flexibility, enhanced resilience to shocks and lower grid investments. **These observations apply even more when several interlinked infrastructures (a system of infrastructures) are developing dynamically, which is the heart of the present study (see Dimension 3)**.

In essence, the optimal solution for a larger system is almost always substantially less expensive than providing a solution for all the subsystems. Larger energy systems can benefit from renewable energy potentials and complementary weather patterns, lower simultaneity (meaning not all consumers will demand energy at the same time) and to some extent sharing certain assets, e.g. back-up power plants.

Therefore, one key downside of insufficiently integrated planning is (unnecessarily) high cost. Furthermore, unaligned solutions might in some instances also lead to conflicts or even technical problems and a less then optimal security of supply.

A central obstacle to more integrated infrastructure planning lies in the fact that costs and benefits of energy infrastructure are often distributed unevenly. To some extent, this already occurs with any cross-border activity that takes place between two countries, for which the cost might be higher in one country, while the other country benefits more. The problem becomes even more pronounced in the meshed network of European infrastructure. Here, several countries might reap some fruits of a strengthened transport infrastructure, while the costs and effort occur only in isolated cases. In an extreme example, two non-neighbouring countries might want to transport hydrogen or CO_2, but the pipelines would need to cross the territory of a third state, which does not profit directly from the infrastructure.

Consequently, a better and more systematic linking of costs and benefits could be an important part of a strategy that paves the way towards a more integrated approach to European infrastructure.

This goal could be aligned with the current ACER recommendations on Cross Border Cost Allocation. These changes to cost and benefit allocations should be integrated into the first steps of the infrastructure planning process and be based on energy system modelling as conducted in the present project. This would allow the assessment of the cost-benefit-allocation of individual infrastructures on the common European energy system.

Box: Proposed methodology for evaluation of the costs and benefits of energy infrastructure based on the ACER recommendations on Cross Border Cost Allocation

Effective methodologies for sharing costs and benefits for European energy infrastructure projects exist. Examples can be found in the ENTSO-E Guideline for Cost Benefit Analysis of Grid Development Projects [7] and the ACER cross-border cost allocation (CBCA) methodology based on the regulation on guidelines for trans-European energy infrastructure (TEN-E Regulation) [8].

Both contain current approaches to assess the benefits of infrastructure projects and to allocate the cost based on the calculation of national net impacts for all the affected countries. Thereby the allocation of cross-border costs is typically based on case-by-case agreements between National Regulatory Agencies (NRAs).

For each country concerned the calculation of the net impacts is based on the following formulae:

$$\sum_{t=f}^{c+x-1} \frac{B_t + F_t - C_t}{(1+r)^{t-y}}$$

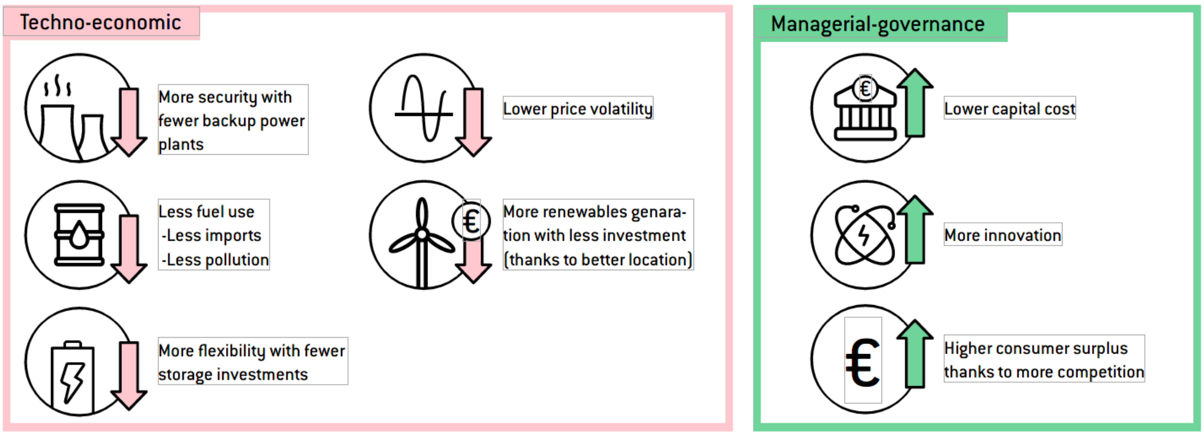
Where,

- f is the first year where costs are incurred
- c is the first full year of operation of the project (or project cluster)
- x is the year considered for the assessment time horizon
- y is the year of the analysis (i.e. the year of the submission of the investment request)
- r is the discount rate used to discount benefits and costs
- B are all the benefits assessed by the project-specific CBA
- F are all the benefits assessed in the analysis of other cross-border monetary flows
- C is the sum of costs.

When building on the modelling framework presented in this study, the approach to analyse the possible cross-border distribution of costs and benefits of individual infrastructure projects could be as follows:

- The optimal target infrastructure for the years 2040/2050 is derived in a similar fashion to the scenario which assumes the cross-sectoral European-view of this study.
- Based on a reference-infrastructure, which can be defined similarly to the TYNDP process, individual infrastructure components of the target infrastructure are added, and a new cross-sectoral optimisation run is conducted for each new topology.
- The benefits and expenses of each infrastructure project are calculated for each country affected.
- Because the result also depends on the sequence of adding new infrastructure, the sequence needs to be varied for different realistic infrastructure development options and the distribution of the impacts evaluated.

Figure 1: Benefits of market integration of European electricity infrastructures. [6]



2.2.3 Sector Integrated Planning (Dimension 3)

The third dimension of benefits from integrated planning approaches concerns the integration **of the different sectoral infrastructures**, notably electricity, natural gas, hydrogen, heat and carbon dioxide infrastructures. Historically, the planning of the European infrastructures was mostly done on a sector-by-sector basis, with a few exceptions, such as gas power plants, which were based on scenarios developed by private actors from a bottom-up perspective (i.e. arising from the Member States) and enhanced by some European sectoral characteristics (see the TYNDP process described in chapter 3.2). Common scenarios can be a good starting point but might fall short of tackling the complex interdependencies that will arise from ongoing sector coupling. In the next years, for example, different options with respect to deployment dynamics and location choices have to be weighed up for H_2-ready gas power plants and electrolysers. The role of carbon management will need to be formulated, with wide-ranging implications for many other options and infrastructures. Ultimately, energy and/or carbon will have to be transported over increasing distances. Failure to plan the infrastructures for this task in an integrated manner can either lead to costly over-investment, or to underinvestment. Either outcome can slow the energy and industry transitions down or cause high costs when second or third best options have to be used due to insufficient infrastructure. In some cases, different infrastructure options exist for the same or similar task, and we need planning procedures that carefully weigh the costs and benefits, while at the same time being manageable and pragmatic.

Focussing on electricity, natural gas and hydrogen infrastructures, the infrastructure of each of the three sectors interacts with the infrastructure of the other sector typically in the following manner:

- Competition between carriers to serve demand; hence, demand-side assumptions (per vector per sector) must be defined in a consistent way and determined based on technical and economic considerations (e.g. regarding the role of hydrogen for cars or in low-temperature-heating). Some of these decisions will be based on purely economic considerations and will be taken endogenously in the model; others will be based on complex techno-economic considerations and will be taken exogenously to the model (see chapter 5).
- Optimisation of the location of "coupling points", i.e. gas and hydrogen power plants and electrolysers using electricity to produce hydrogen.
- Competition for flexibility provision between battery storage and hydrogen power plants. The more batteries, the less hydrogen power plants are needed.

In summary, the first of the three dimensions (uncertainty) related to integrated infrastructure planning cannot be dealt with in this study, despite its importance, as the approach does not allow for it. The two other dimensions (geographical and sectoral integration) are the focus of this study.

3 Current Status of the Integration of European Energy Infrastructures

3.1 Overview of Ongoing European Infrastructure Integration Policies

The integration of European energy infrastructure is a process with a long history. In Europe, energy infrastructures started to become transnational in the early 20th century when the first national electricity grids became interconnected between countries. In 1951, the *Union pour la coordination de la production et du transport de l'électricité* (UCPTE) was established, which later became the *Union for the Co-ordination of Transmission of Electricity* (UCTE).

The EU began planning its energy infrastructure in a coordinated way in the 1990s. In 1993, the Maastricht Treaty created the legal basis for energy cooperation and introduced Trans-European Networks (TENs) as EU policy. In 1996, the EU launched the Trans-European Energy Networks (TEN-E) to support cross-border electricity and gas networks and already established Projects of European Interest (PEIs). In parallel, the First Energy Package (1996 and 1998) started opening electricity and gas markets to competition. The creation of ENTSO-E in 2009 and ENTSO-G in 2010 aimed at facilitating more coordinated planning by electricity and gas transmission operators across Europe. The European Union Agency for the Cooperation of Energy Regulators (ACER) was established in 2011 to improve coordination between national energy regulators and support the implementation of a unified EU energy market.

In 2013, the new TEN-E Regulation accelerated the integration of infrastructure planning. Interestingly, one can see its stronger focus on long-term strategy and security of supply as a reaction to the 2009 gas crisis, which started after Russia cut off gas deliveries to Ukraine. In 2015, the Energy Union Strategy aimed at better electricity connection to isolated markets, diversification of gas supply, and more regional cooperation. The Fourth Energy Package of 2019 contained a minimum interconnection target of 15% by 2030, ensuring better cross-border electricity flow. The European Green Deal of 2019 and the Fit for 55 package shifted TEN-E priorities from fossil fuels to clean energy. REPowerEU, a reaction to Russia's attack on Ukraine, continued this path, especially by focusing on strengthening electricity and hydrogen projects. In the revised TEN-E Regulation of 2022, natural gas projects are no longer eligible as PCI projects, while hydrogen and CO_2 networks are.

Considering all these policies together a clear tendency is revealed: The EU gradually strengthens its cooperation in infrastructure planning and energy policy alignment. However, the EU only has competence in the common energy policy areas, setting the framework for cross-border coordination, market integration, and climate goals. Member States retain sovereignty over national energy decisions, like the energy mix (as long as it is in line with climate goals) and national infrastructure. These distributed competences create certain tensions:

- **National Priorities vs. EU Priorities in the Energy Mix:** The EU promotes a swift transition to renewables and decarbonization, along with the strengthened transport infrastructures this transition requires. There are national differences in both energy mix strategies and the speed of transitions.
- **Strong Interconnections vs. National Energy Independence:** The EU's push towards strong cross-border interconnections, e.g. the 15% electricity interconnection target by 2030, is met with reluctance from some stakeholders, as each strengthened interconnection can create disadvantages for some national players that benefit from bottlenecks. Furthermore, electricity infrastructures in particular are regularly faced with opposition from people in the affected regions.
- **Planning inconsistencies:** Lastly, the existing approach to energy infrastructure planning can be described as bottom-up, being rooted mostly in planning at the Member State level, which then has to be reconciled at the EU level. While it is important to align cross-border projects,

harmonizing the different puzzle pieces of national energy and infrastructure policies only at the borders has substantial limitations.

The following sections describe the key regulations and instruments that drive forward the coordination of infrastructure planning in the EU.

3.2 Ten-Year Network Development Plans

The Ten-Year Network Development Plans (TYNDPs) were introduced under the Third Energy Package in 2009 as part of the EU's effort to create a coordinated, long-term infrastructure planning framework for electricity and gas networks. The TYNDP process requires a pan-European energy infrastructure plan every two years. ENTSO-E, the European Network of Transmission System Operators for Electricity, prepares the TYNDP for electricity, while ENTSOG, the European Network of Transmission System Operators for Gas, prepares the one for gas, which since 2020 also includes hydrogen. The TYNDP processes are extensive and complex; they are summarized and discussed here only at the level of detail relevant to the scope of this study.

The processes begin with scenario development, modelling future energy supply and demand. The data is rooted in bottom-up data collected from gas and electricity TSOs, especially for the first scenario years up to 2040. It also includes the NECPs of EU Member States, as well as further nationally determined ambitions, e.g., the hydrogen strategies. Different scenarios are developed in the process:

- A central scenario in the TYNDP 2024 is the **National Trends+ (NT+)** scenario, which serves as a baseline scenario. It builds upon existing national policies and strategies, reflecting the perceived current trajectory of energy transition efforts.
- The **Distributed Energy (DE)** scenario focuses on a decentralized approach to energy generation and consumption.
- The **Global Ambition (GA)** scenario emphasizes large-scale, centralized solutions to achieve climate goals.

The scenarios are developed by ENTSO-E and ENTSOG with input from national TSOs, the European Commission, ACER, industry representatives, and NGOs. The draft scenarios are published and consulted.

The TSOs then submit infrastructure projects for evaluation based on their own scenario modelling. These proposed projects undergo a cost-benefit analysis (CBA) assessing market integration, security of supply, and climate impact. After public consultation and regulatory review by ACER and the European Commission, the final TYNDP is published, and the Commission selects Projects of Common Interest (PCIs) for EU funding and streamlined permitting.

Assessment of the Role of the TYNDP Process for Linking Infrastructure Planning in the EU

The TYNDP is the central and most important process planning for cross-border infrastructure and linking electricity, gas, and hydrogen. It also has to be noted that the process has evolved substantially, and many points of critique to previous iterations have been addressed. Nonetheless, the process still has aspects in which it could be improved:

- **Electricity and gas infrastructure planning are still too siloed.** Despite joint scenario development, ENTSO-E and ENTSO-G still publish separate TYNDPs based on separate modelling exercises. The scenarios, while being described as harmonized, seem to differ between electricity and gas modelling. This has been addressed by ACER, alongside other aspects, like a certain lack of transparency. It has to be acknowledged that harmonization of the TYNDP processes is very challenging.
- **Limited scenario diversity.** While the current scenario set analyses the future along the centralization vs. decentralization axis, other key uncertainties are not fully explored, such as:
    - The level of electrification vs. the use of energy carriers like hydrogen.
    - The extent to which the "efficiency first principle" reduces energy demand.

  - The degree to which energy-intensive pre-products are imported.

- **Room for improvement in Cost-Benefit Analyses (CBA).** The European energy system is complex, making CBAs for individual infrastructure projects inherently challenging. ACER has addressed this issue to ensure a more integrated treatment of electricity and gas infrastructure as well as transparency and fairness.
- **Lacking consistency of the TYPDP scenarios with national trajectories.** ACER has criticized that the TYNDP scenarios are not fully in line with national data and scenarios.

The evolution of the TNYDP processes towards better integration is clearly visible and successful. Still, it is not a top-down process analysing what infrastructure necessities arise from strategic goals of the EU, but a bottom-up process trying to align national energy and infrastructure strategies to EU goals. Like with any highly complex process, there is room for improvement in the TYNDP process. Nonetheless, there is a natural limit on the level of integration and cohesion that can be reached when the process remains anchored to this degree in bottom-up methods. As long as the overall strategy and targets of the EU are mostly a benchmark and not the starting point for infrastructure planning, achieving the required level of cohesion by cross-border projects alone does not seem realistic.

3.3 EU Projects of Common Interest (PCI)

Projects of Common Interest (PCIs) are key cross-border energy infrastructure projects selected by the EU to achieve its energy policy and climate goals. PCI projects aim to facilitate market integration, security of supply, and the transition to a low-carbon economy by improving interconnections between Member States. A project must first be submitted and assessed in the TYNDP process. The European Commission then, in consultation with ACER and Member States, selects projects from the pool of TYNDP projects based on their strategic importance. The criteria for PCI are defined in the TEN-E regulation. Among other aspects, the projects must have a significant cross-border impact, must contribute to EU Energy policy goals and must be compatible with EU climate policy. Furthermore, the benefits must outweigh the costs.

PCI projects receive faster permitting, regulatory support, and access to EU funding under the Connecting Europe Facility (CEF). The CEF supports the development of trans-European infrastructure in energy, transport, and digital sectors. The CEF 2021–2027 has a total budget of 33.7 bn. EUR, with 5.8 bn. EUR allocated to energy [9]. The CEF covers up to 50% of eligible costs of PCI, but in cases of projects with exceptional benefits (e.g. high-impact security of supply projects), funding can be as high as 75%. However, national governments also support PCI, through direct subsidies, the approval of higher transmission tariffs, or the of use state-owned TSOs to invest. It should be noted that since the 2022 revision of the TEN-E Regulation, fossil gas projects are no longer eligible as PCI.

Assessment of the Role of PCI Projects for Linking EU Energy Infrastructure

PCI are a crucial tool for improving EU's cross-border energy infrastructure, integrating energy markets, and enhancing security of supply. Nonetheless, the process is not without challenges. Projects often delayed due to permit procedures at the national level, in particular for electricity projects. ACER has also identified room for improvement regarding the transparency of the evaluation and selection process [10].

However, like in the case of the TYPND, PCI specifically addresses cross-border connections. The process cannot adequately address mismatches of the national energy and infrastructure strategies and policies.

3.4 Electricity Interconnection targets of the EU

The EU has set an interconnection target of at least 15% by 2030 to encourage Member States to integrate their electricity production capacity across borders [11]. This means that each country should have electricity transmission capacity allowing at least 15% of its generated electricity to be transported to neighbouring countries.

As of 2021, 16 countries reported being on track to meet this target by 2030 or had already achieved it. However, further interconnections are still needed in certain regions to ensure a more integrated and resilient European electricity market. The 15% target is defined as the import capacity over a country's installed electricity generation capacity.

Due to the significant expansion of renewable energy—particularly wind and solar, which have lower load factors than traditional generation sources—the installed capacity in the EU has increased considerably, while new interconnection capacities have not grown at the same pace. To account for these changes, the 15% interconnection target has been supplemented with additional urgency indicators, including:

- Wholesale market price differentials, reflecting bottlenecks in cross-border electricity flows.
- Nominal transmission capacity of interconnectors in relation to peak electricity demand.
- Interconnection capacity relative to the renewable generation installed, ensuring that electricity surpluses from renewables can be exported efficiently.

Additionally, under EU regulations, each new interconnector must undergo a socio-economic and environmental cost-benefit analysis to ensure that the potential benefits outweigh the costs before implementation.

3.5 European Commission's Grid Action Plan

The EU Grid Action Plan ([12]), introduced in November 2023, brings concrete changes to electricity infrastructure planning and development by accelerating permitting, improving cross-border coordination, mobilizing funding, and modernizing grids. It streamlines approval processes to speed up permit approval for new projects, reducing bureaucratic delays that often stall infrastructure expansion. By requiring better coordination between EU Member States, the plan ensures that grid investments align with an integrated European strategy, rather than being planned in isolation. To address the €600 billion investment gap by 2030, the plan enhances access to EU funding mechanisms and private financing, making it easier to secure capital for large-scale grid expansions. Additionally, it mandates the modernization of aging infrastructure, integrating smart grid technologies that improve energy flow management, reduce congestion, and support the growing share of renewables.

The Grid Action Plan primarily serves as a strategic framework to enhance and expedite the development of Europe's electricity infrastructure. While it outlines several key actions and recommendations, it does not, in itself, enact immediate regulatory or legislative changes. The plan also does not introduce additional funding. It instead aims to optimize the use of existing financial instruments; among these are the Connecting Europe Facility – Energy (CEF-E), which allocates €5.8 billion for cross-border energy projects between 2021 and 2027, and the Recovery and Resilience Facility (RRF), which provides approximately €13 billion for grid upgrades and digitization. The plan also aims at improving the regulatory frameworks to attract both public and private investments necessary for modernizing and expanding the EU's electricity grid.

3.6 Indirect Incentives for Infrastructure Integration through Market Integration

The integration of EU energy infrastructure is also driven indirectly through measures that increase market integration; a well-functioning internal energy market requires seamless cross-border electricity and gas flows. By removing regulatory barriers, harmonizing market rules, and increasing competition, the EU creates a natural incentive for infrastructure expansion. As energy markets become more interconnected, the need for cross-border transmission capacity, storage facilities, and network upgrades grows to ensure efficient price signals, energy security, and grid stability. Policies that liberalize and integrate markets indirectly push for greater infrastructure development, as market forces demand more interconnectors, hydrogen corridors and storage solutions to balance supply and demand across regions.

The Electricity Market Regulation (EU 2019/943) and Electricity Market Directive (EU 2019/944) enhance EU energy infrastructure integration by ensuring a harmonized and competitive electricity market. They mandate regional coordination of grid operations, set the above-mentioned minimum 70% cross-border capacity rule to facilitate electricity trade and establish market-based congestion management. The Gas Market Reform (2023) and the Hydrogen and Decarbonized Gas Market Package drive infrastructure integration by creating a regulatory framework for cross-border hydrogen networks, enabling the development of European Hydrogen Backbone corridors and improving gas market interconnections to support decarbonization. Meanwhile, the Gas Security of Supply Regulation (EU 2017/1938) strengthens regional energy security by requiring emergency gas storage levels, implementing joint gas purchasing and introducing solidarity mechanisms for gas-sharing among Member States. Together, these policies create a more interconnected, secure and decarbonized EU energy system by facilitating seamless electricity and gas flows, stronger market integration and resilience to supply disruptions.

3.7 Overall Assessment

While EU policies have significantly advanced cross-border energy infrastructure integration, they often do not adequately address the internal challenges within Member States, which can limit the full potential of interconnectivity. As energy strategy and infrastructure remains largely in the domain of the Member States, EU policies focus on inter-country links, such as interconnectors and cross-border capacity rules. While this is crucial for market integration, bottlenecks, grid constraints and inconsistent national regulatory frameworks continue to impede progress. According to Bruegel [13], ensuring effective electricity interconnections requires more than just financial investment—national grid upgrades and streamlined permitting processes must be addressed to avoid underutilized cross-border links. Similarly, the International Monetary Fund (IMF) highlights that national interests often take precedence, as countries with low electricity prices may resist integration to avoid price increases, while high-cost countries may fear competition from cheaper imports, creating structural barriers to full market integration [14]. The IMF calls for a "blueprint" for the evolution of the EU energy system.

Focusing on cross-border energy infrastructure while national strategies remain misaligned is like forcing together and glueing mismatched puzzle pieces. While the pieces may interconnect, the overall picture still remains fragmented and incoherent. There is no doubt that a sufficient number of cross-border connections are necessary, however, this alone is not sufficient. Without stronger coordination between European-wide and national infrastructure (and energy) planning, cross-border links risk remaining underutilized, and internal market inefficiencies may hinder the EU's broader energy security and decarbonization goals.

4 Definition of the Main Scenarios

This section presents our approach to planning energy-related infrastructures, which integrates European and sectoral perspectives to achieve European climate-neutrality objectives by 2050. By concisely mapping and reviewing the current procedures and scenarios for infrastructure development, we derive a robust outline of a future-proof European energy infrastructure and identify risks of stranded assets when planning infrastructure.

For this purpose, the European energy system is analysed as a whole. Changes in energy demand and supply required to achieve climate neutrality and the influence that different infrastructure solutions have on the development of the energy system are modelled. We investigate futures for the following infrastructures[9] in Europe:

- Electricity infrastructure
- Gas infrastructure (including both natural gas infrastructure – which will have to be re-dimensioned and re-purposed - and future hydrogen infrastructure)
- Infrastructure related to CO_2 from carbon capture, transport, storage, and use.

In the following, these infrastructures are characterised **as sectors**, which will be considered in the context of the evolving energy system. Simultaneously, this study covers the entire European continent (countries at **national** level and Europe as a whole[10]). The resulting high complexity leads to two major modelling challenges. First, the model's run-time is substantial, and second, there are a multitude of scenarios that can achieve climate neutrality. The combination of these two challenges makes it apparent that a narrower focus is required in the scenarios investigated in this study. We therefore considered **two main policy dimensions** in line with climate neutrality ambitions:

Cross-sectoral view ◄────────► **Sectoral view**

The first dimension represents infrastructure planning approaches ranging from a cross-sectoral view to a view in sectoral silos. Infrastructure planning in sectoral silos does not consider the interaction between sectors in a consistent, harmonised way as electricity, natural gas and hydrogen networks are planned largely independently of each other. The sectoral view, therefore, involves the risk of unnecessarily high energy system costs due to grid bottlenecks and/or overcapacities (in terms of technologies for climate neutrality and infrastructures) compared to integrated, cost-optimal grid expansion. Despite these drawbacks, the sectoral silo approach to infrastructure planning is currently applied in the TYNDP as discussed in Chapter 3.2. Investments in gas and electricity networks are investigated (mostly) separately and thereby enforce this sectoral view on the energy system [15].

Implementation:

To account for the sectoral policy dimension in the energy system modelling, we go beyond current infrastructures to include future transmission lines, and natural gas and hydrogen pipelines that have been proposed in frameworks like the TYNDP, the H_2 Infrastructure Map and the German Hydrogen "Core Network". For a more detailed list of the projects considered in the different scenarios, we refer to Annex 2: Implementation of Current Infrastructure Planning.

Cross-sector view: The existing grid and already advanced TYNDP projects (i.e. with the status "in construction" for electricity, "FID" for gas, see Annex 2: Implementation of Current Infrastructure Planning*) form the lower boundary for endogenous transmission capacity expansions. In the scenarios with a cross-sector view (CE and CN), the optimisation model can freely expand the transmission capacities in addition to the existing grid and already advanced TYNDP projects.*

9 Note: Infrastructure for heat supply is implicitly included: heat demand for buildings is modelled as a demand for utilised heat in PyPSA-Eur. The structure of the heat supply is endogenously set by the optimisation (see section 5.2)

10 Modelling includes the Member States of the European Union excluding Cyprus and Malta, as well as the United Kingdom, Norway, Switzerland, Albania, Bosnia and Herzegovina, Montenegro, North Macedonia, and Serbia.

Sectoral view: In the SE and SN scenarios, the existing grid and all projects mentioned above (TYNDP, H_2 Infrastructure Map and Hydrogen Core Network) are the only capacity expansion permitted in the system until the end of the planning period in 2040. Therefore, up until 2040, the only expansion in grid capacity is implemented through sectoral grid plans such as the TYNDP. The optimisation model can freely expand the transmission capacities only after 2040. In the case of TYNDP projects that feature a maturity status, we also include less advanced projects such as "in permitting" and "under consideration" for the electricity network (for details see Annex 2: Implementation of Current Infrastructure Planning*). This approach reflects the network capacity expansion as envisioned by grid planners.*

European view ←——————————————————→ National view

The second dimension represents infrastructure planning approaches ranging from a cross-border, European view to a national view. While the EU's internal market supports the European view, protectionist tendencies can lead to minimising significant energy import dependencies (also from within the EU) by expanding domestic generation and storage capacities. Countries with large energy generation potentials could refrain from expanding low-cost generation and infrastructure capacities for exports to ensure low domestic electricity prices.[11] These national tendencies could lead to unnecessarily high system costs of European energy supply (e.g. by building excess regional capacities despite sub-optimal generation conditions) [15].

Implementation:

Self-sufficiency constraints can be activated in the model to account for the national policy dimension. If these constraints are activated, they restrict the imports of individual countries by imposing a maximum annual share of hydrogen and electricity imported compared to national generation. There is no restriction to energy imports and exports on an hourly basis. More details on the self-sufficiency constraints can be found in Annex 1: A Short Description of the PyPSA Model.

European view: The self-sufficiency constraints are not activated. The system can freely optimise the share of imported versus domestically generated electricity and hydrogen.

National view: To model a strong focus of policy making on the national energy system, the self-sufficiency constraints are activated and set to require a high share of domestic generation for each country considered in the modelling. For example, in 2030, the minimum share of national (domestic) generation is set to 80% for electricity and to 70% for hydrogen in each country. For hydrogen, the share remains constant while in the electricity, countries must produce 100% of their electricity demand annually by 2050. Also, countries will build capacities to enable them to export 10% of their electricity/hydrogen demand. Details on the parameterisation can also be found in Annex 1: A Short Description of the PyPSA Model.

[11] These views of a nationally dominated energy system are exemplified by recent discussions on transmission lines from Norway during a phase of very high electricity prices that sparked debates in Norway [73].

These two policy dimensions yield a matrix of four scenarios characterised in the following table:

Table 1: Mapping of four main scenarios on two policy dimensions.

	EUROPEAN VIEW	NATIONAL VIEW
CROSS-SECTORAL VIEW	**CE:** **Cross-Sectoral, European View**	**CN:** **Cross-Sectoral, National view**
SECTORAL VIEW	**SE:** **Sectoral, European View**	**SN:** **Sectoral, National view**

The four scenarios abbreviated as "CE", "SE", "CN" and "SN", respectively, represent the central focus of the analysis of European infrastructures. Each scenario is described in the following.

"CE" Scenario (**C**ross-sectoral, **E**uropean view): In this scenario, the model can freely expand the transmission capacities for the different sectors (electricity, gas, hydrogen, CO_2). The existing grid and advanced TYNDP projects form the lower bound. The model can also freely set the share of imported versus domestically generated hydrogen and electricity, i.e. the self-sufficiency constraints are not activated. This scenario is expected to yield cost-optimal generation, storage and sectorally-integrated grid expansion across Europe to achieve a climate-neutral energy system by 2050.

"CN" Scenario (**C**ross-sectoral, **N**ational view): This scenario also represents sectorally-integrated grid expansion by allowing free further expansion of transmission capacities. However, it also assumes a focus on national self-sufficiency. In contrast to the previous CE scenario, the self-sufficiency constraints are activated. This is expected to manifest as a trend towards a high level of national supply and a low level of import dependence (including from within Europe).

"SE" Scenario (**S**ectoral, **E**uropean view): This scenario assumes sectoral grid planning in silos. Up until 2040, transmission capacity expansion is fixed based on TYNDP, the H_2 infrastructure map and the German Hydrogen Core Network. However, the self-sufficiency constraints are not activated, allowing the model to freely determine the annual national shares of imports. This is expected to achieve good EU-wide coordination but fail to integrate sector-coupling approaches in the planning processes.

"SN" Scenario (**S**ectoral, **N**ational view): This scenario assumes sectoral grid planning in silos by fixing the transmission capacity expansion as in the previous scenario. However, it further assumes a focus on national self-sufficiency, i.e. the self-sufficiency constraints are activated. As a result, uncoordinated expansion of generation and grid infrastructure is expected.

These four scenarios should generate findings that can be used to inform policies in the context of policy and regulatory frameworks.

Box: The National View: Self-sufficiency and autonomy

The distinction between **self-sufficiency** and **autonomy** in national electricity systems is determined by the role of **net imports** versus domestic **generation capacity**. A country is considered self-sufficient when it has a low share of net energy imports; it relies primarily on domestic generation but may still engage in trading electricity, importing and exporting as needed to optimize costs and grid stability. Autonomy, on the other hand, which could also be referred to as energy independence, means that a country has enough domestic power plant capacity to always meet its electricity demand, even in the absence of imports. While self-sufficiency reflects a balanced energy trade position, autonomy ensures that a country is **structurally independent** of external electricity supply under any circumstance, including crises or geopolitical disruptions. However, an autonomous system does not necessarily imply optimal efficiency or cost-effectiveness, as maintaining surplus capacity without utilizing imports can lead to higher infrastructure and operational costs. Many EU countries aim for a mix of self-sufficiency and strategic interconnections, leveraging imports for flexibility while ensuring they have sufficient domestic backup capacity for emergencies.

Both **self-sufficiency** and **autonomy** are addressed in the scenarios with a national view:

- **Self-sufficiency** is implemented as a boundary limiting each country's maximum net imports over the year.
- **Autonomy** is implemented by constructing additional power plants that allow a country to meet its domestic electricity demand in every situation, even if these capacities are not fully used in a functioning market. In our scenarios, these are referred to as "back-up capacities". This means that the demand in each country can be covered by domestic power plants in every hour of the year without reliance on other countries.

5 Main Input Parameters for the Scenarios

This section presents the main modelling assumptions that are common to each of the four scenarios. The modelling is based on the PyPSA-Eur framework [3] with the version 0.10 (adapted to the present project through a number of stakeholder interactions). While detailed input parameters can be found in the repository and additional information published with this report, here we summarise some of the key assumptions. First, the regional and temporal resolution of the model is presented. The following section discusses the energy demand, distinguishing between demand for industry, transport and heating. Thirdly, we discuss parameters significant to this study such as the CO_2 reduction pathway, technology parameters, exogenous capacity expansion limits and hydrogen import parametrisation.

5.1 Regional and temporal resolution

Regional resolution

To be able to review the current state of infrastructure planning in Europe, our model needs to reflect the main transport and transmission pathways in the electricity grid and gas network. However, modelling at full spatial resolution is unfeasible, since the run-time scales with the number of regional points that are considered. Therefore, in the model, we cluster the energy system to a limited number of points. While the minimum number of clusters is given by the number of countries[12] considered in this study, we identified a maximum of 80 cluster points in terms of run-time concerns. Still, a lower number is advisable to reduce computational complexity. Thus, we decided on a clustering comprising 62 points, which were distributed based on the following strategies:

- Each country must have at least one cluster.
- Automatic clustering based on the regional electricity demand gives the number of clusters per country.
- Countries relevant for the regional case studies (see Chapter 7) receive a higher spatial resolution.
- Expansion pathways must be included in the clustering.

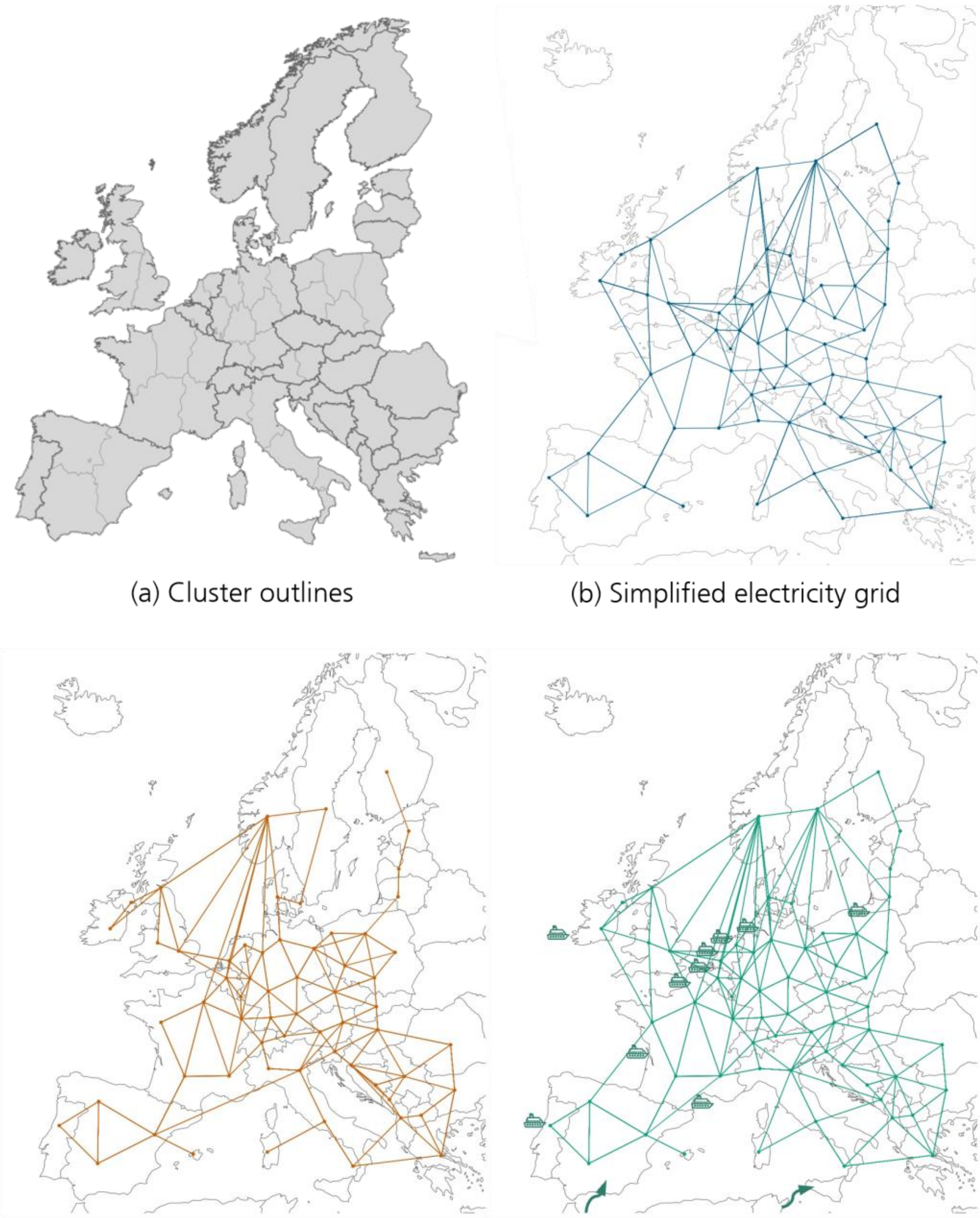
In Annex 1: A Short Description of the PyPSA Model, we elaborate in more detail about which criteria led to each country's number of clusters. Figure 2a shows the resulting clustering used in this study. A higher resolution clustering is set for central Europe. The centres of the clusters are then connected by the transmission lines and the transport pipelines of the electricity and gas infrastructure. Therefore, we map the existing electricity grid according to ENTSO-E, as well as future projects from the TYNDP 2022, to the clustering, resulting in the model for the electricity grid in Europe depicted in Figure 2b. Each of the 62 nodes has also an offshore-wind power generator assigned to it. The costs of this generator include connection costs, while the grid connection to these offshore regions is not explicitly modelled.

Similar to the electricity grid, we implement existing gas pipelines from the database SciGrid Gas [16] by assigning them to the corresponding cluster and add transmission projects from the TYNDP 2022, resulting in the gas network in Figure 2c. The existing gas infrastructure can also be used for repurposing to hydrogen pipelines as required by endogenous optimisation or by exogenous constraints depending on the scenario assumptions. This hydrogen network is still in the planning phase. Therefore, in our model it is first initialised without transport capacity. In addition, we add the hydrogen pipeline projects as summarised in the H_2 Infrastructure Map and the German Hydrogen core network [17, 18]. Altogether, the routes available for hydrogen pipelines are shown in Figure 2d. Depending on the scenarios described above, we then allow the model to optimise the hydrogen network freely or restrict it to existing infrastructure plans. Additionally, Figure 2d also indicates entry points for hydrogen imports from outside the modelling region via ship or pipeline. A more detailed description on the modelling of hydrogen imports can be found in Chapter 5.3.

[12] The modelling includes the countries of the European Union excluding Cyprus and Malta as well as the United Kingdom, Norway, Switzerland, Albania, Bosnia and Herzegovina, Montenegro, North Macedonia, and Serbia.

Lastly, CO_2 infrastructure is also optimised within the model. As plans for a CO_2 pipeline network are not yet mature, we do not set exogenous constraints here but instead allow the fully endogenous expansion of CO_2 pipelines along the routes depicted in Figure 2d.

Figure 2: Clustering used for infrastructure modelling.



(a) Cluster outlines

(b) Simplified electricity grid

(c) Simplified CH_4 network

(d) Possible H_2 or CO_2 network with H_2-import entry points

Temporal resolution

For the analysis of future scenarios, it would of course be most favourable to model multiple milestone years with an hourly resolution. Yet again, such a high resolution is unfeasible in terms of run-time. Instead, we focus on seven milestone years, from 2020 to 2050 in five-year steps, and then subdivide the year into 2190 increments **with a flexible time-segmentation**. The width of these increments is determined by an algorithm in the tsam package [19]. It considers most exogenous time series, like the profiles for renewable energy and demand, and groups adjacent time steps with the least difference. Thereby, time periods with a high fluctuation can have an hourly or two-hourly resolution, compensated by larger intervals in times with little fluctuations. A test case on a smaller model has shown that discrepancies are kept to a minimum with this method with a full hourly resolution (see Annex 1: A Short Description of the PyPSA Model). Thereby, we are still able to incorporate important features in the time series of supply and demand throughout the day while drastically cutting down the run time.

5.2 Energy Demand Development

The overview of the energy demand detailed in this section distinguishes between demand for industry, transport and buildings (households and tertiary sector).

The energy demand is modelled using the structure already provided by PyPSA-Eur-Sec [1]. A key source for the energy demand in PyPSA-Eur-Sec is JRC-IDEES [2], see the PyPSA-Eur-Sec license documentation [3] for a full list of input data. The energy demand developments in Europe which are exogenously determined are then configured and validated based on recently published data [4] from the TransHyDE study [5].

The resulting exogenous energy demand figures are detailed and discussed below for each sector, as well as the selected TransHyDE scenarios and corresponding assumptions. The demand discussed in this section refers to the entire modelling region[12].

Industry

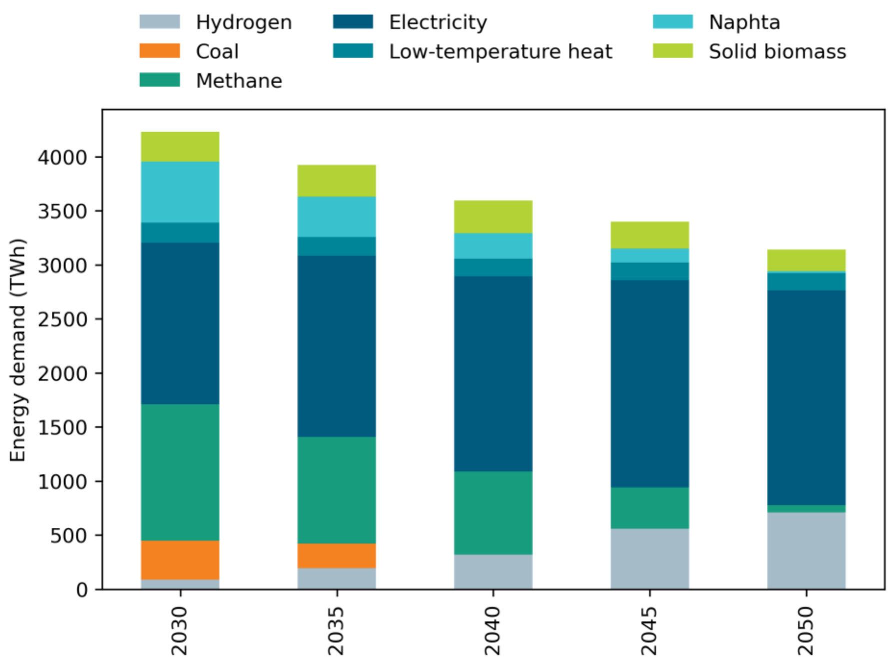
A key source for industrial demand assumptions in our study is the TransHyDE study. Compared to other sources, TransHyDE builds on a very recent assessment of hydrogen demand in industry, transport and the building sector and makes it possible to consider the different sub-sectors of hydrogen demand individually. Based on a detailed energy system analysis it focuses on developing a better understanding of future hydrogen demand in the EU by assessing different scenarios ranging from low to high hydrogen demand using a bottom-up energy demand model. The following key assumptions are common to all scenarios in TransHyDE: A climate neutral European energy system is reached in 2050. The supply and use of biomass is limited and there is no migration of energy-intensive industries. In the industry sector, a switch to hydrogen-based processes is modelled, which are all located within the EU. The only exception is the TransHyDE Scenario with the lowest hydrogen demand (S1) in which parts of the value chain take place outside of the EU. Here, H_2-derivatives such as methanol and ammonia as well as iron sponge are imported.

Additionally, the TransHyDE scenarios differ in their usage of hydrogen in various industry processes, resulting in differing industry demand for hydrogen. An in-depth description of the scenarios can be found in Fleiter et al. [5]. As the basis of the industry demand in our study, we choose an intermediate between scenario S2 and S1. Both assume a switch to hydrogen for high temperature process heating in furnaces with temperatures above 500°C. Similarly, they assume a high demand for hydrogen as a feedstock since there is little or no competition from other technologies. This shift includes the hydrogen-based direct reduction of iron ore in steel production, the production of ammonia, and the production of High Value Chemicals (HVC) where synthetic naphtha is produced from green hydrogen or via the Methanol-to-Olefins (MTO)/Methanol-to-aromatics route. In the TransHyDE demand scenario S2, it is assumed that these materials are produced within the EU rather than being imported. In contrast, the TransHyDE demand scenario S1 assumes significant imports of those materials, in particular of ammonia and 50% of the sponge iron. In our intermediate demand scenario S1.5 in this study assumes that 60% of methanol and ammonia will be imported as green naphtha derivatives and further processed using an electric steam cracker in the EU. The remaining 40% will be produced using the MTO route. For steel production based on hydrogen, similar to S1, it is assumed that only a partial relocation of production outside of the EU will occur. This is based on the assumption that a significant part of the industrial value chain based on green hydrogen and derivatives will arise outside of Europe, while partly attracting such industries in the EU, notably where there is a strong grey industrial value chain (e.g. for steel production) assuming that future industrial value chains will take advantage of currently existing structures within the EU. The logic behind these decisions is that the industrial value chain will be partly rebuilt or expanded when switching to hydrogen and derivatives, with a redistribution of production both within and outside the EU, taking advantage of better conditions for renewables production outside the European Union. This production is not industrial leakage (industries relocating) but the reconstruction of a new value chain which takes into account energy partnerships with partner countries to develop common interests.

The energy demand, including feedstocks, for industry processes is summarised in Figure 3. Here, we see an increase in the demand for electricity and hydrogen. At the same time, the demand for fossil fuels is decreasing, especially the demand for methane. Due to TransHyDE's system boundaries, this gas demand also includes the methane that is needed for steam-methane reforming plants at specific industrial sites. Therefore, the hydrogen demand for industry here only includes hydrogen that is not produced onsite but rather can be viewed as part of the overall energy system. The remaining hydrogen demand from onsite production is reflected in the figures for methane gas in Figure 3. Note that the demand for hydrogen is irrespective of the hydrogen colour since the model is free to decide endogenously how to produce (or import) hydrogen to satisfy the demand.

For more detail on the implementation of the TransHyDE demand scenario into our PyPSA model, we refer to the Annex 1.

Figure 3: Industry energy demand, incl. feedstocks, according to carrier in Europe.



Transport

Overall transport demand [20] is modelled in PyPSA-Eur-Sec by determining the annual energy demand for land transport, aviation and shipping for the different countries sourced from the JRC-IDEES dataset. The evolution of transport demand is configured as follows:

For land transport, both road and rail transport are combined. The mix of propulsion technologies is adjustable, allowing for battery electric vehicles (BEV), hydrogen fuel cell vehicles (FCEV), and internal combustion engine vehicles (ICE). BEVs and FCEVs consume electricity and hydrogen respectively. Vehicles running on ICEs demand oil-based fuel. Until 2050, nearly complete electrification of all vehicles in road and rail transport is assumed. However, in the long term, hydrogen-based propulsion technologies are expected to become more widespread, particularly to some degree in heavy-duty transport, to achieve complete defossilization of the sector. It is assumed that hydrogen will cover about 10% of land transport in 2050 due to heavy-duty vehicles fuelled by hydrogen. The direct hydrogen demand in transport in 2050 corresponds to 184 TWh. This amount corresponds to about half the hydrogen demand in land transport in TransHyDE Scenario S4 and is in line with the Transport&Environment [21] study.

Note that oil-based fuels can be either obtained from fossil reserves or are of synthetic origin. The latter case requires the model-endogenous construction of Fischer-Tropsch plants, while emissions from fossil fuels need to be compensated or captured to achieve CO_2 neutrality. The use of fossil or synthetic fuel is determined endogenously.

Table 2: Changes in shares of propulsion technologies and fuels in transport sector.

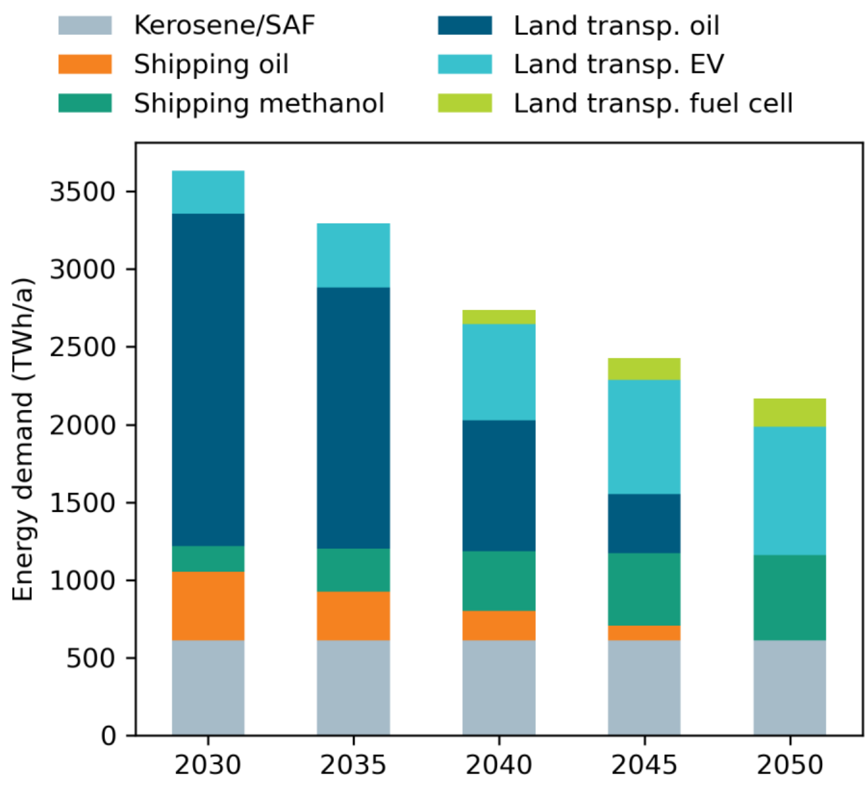
Year	Propulsion technology shares in land transport [%]			Fuel shares for shipping [%]	
	BEV	FCEV	ICE	Oil	Green methanol
2020	0	0	100	100	0
2025	15	0	85	85	15
2030	30	0	70	70	30
2035	45	0	55	50	50
2040	67.5	5	27.5	30	70
2045	80	7.5	12.5	15	15
2050	90	10	0	0	100

The maritime transport mode (shipping) accounts for domestic demand and consumption of international bunker fuels. The exogenously determined fuel mix comprises oil and methanol. The latter can be produced in dedicated methanol production plants based on hydrogen and carbon dioxide from carbon capture or direct air capture. In 2050, all maritime transport uses this green methanol.

The fuel demand of aviation is modelled as oil demand due to kerosene consumption for both international and domestic European flights. Similar to overland transport and shipping, the mix of fossil and synthetic kerosene is determined by optimisation.

Thanks to the efficiency gains for the modalities of the land and maritime transport, the switch to alternative fuels results in large savings in final energy demand of the transportation sector. As presented in Figure 4, the energy demand in transportation amounts to 2133 TWh in 2050, compared to around 3600 TWh expected in 2030.

Figure 4: Final energy demand in transportation sector in Europe.



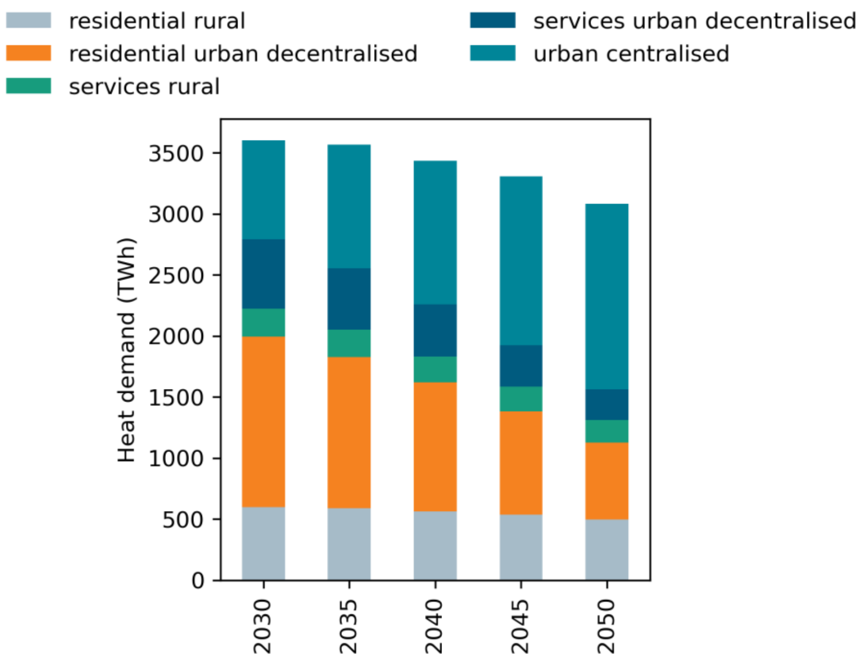
Heating Demand for Residential and Service Buildings

The heat demand for buildings is modelled in PyPSA-Eur-Sec as a demand for utilised heat. One benefit is the independence from pre-defined energy sources to cover the demand for space and water heating, i.e. the structure of the heat supply is endogenously by the optimisation. The installed capacity of heat generation technologies, taking into account the technology stock, the expansion of heat storage facilities, and the operation of generation and storage technologies are optimised to satisfy the demand for utilised heat. The approach differentiates between decentralised and centralised heat supply and can select from a range of technologies (boiler, heat pumps, CHPs, solar thermal, waste heat).

The exogenously set demand for utilized heat is based on the annual heat demand from JRC IDEES per country. The heat demand is distributed among the clusters, considering the population per cluster and subsector. Seasonal and daily variations in heat demand are driven by the temperature (see PyPSA-Eur-Sec [1]). The evolution of total heat demand is configurable and modelled based on the LTS CN scenario for buildings in the EU CALC Tool [22], resulting in a demand reduction by 14% in 2050 with respect to 2030 due to improved building insulation.

The evolution of heat demand over the planning horizons for Europe is shown in Figure 5, where a distinction is made between centralised and decentralised heat demand. Here, centralised heating covers the district heating demand both from the residential and service sectors in urban areas.

Figure 5: Evolution of heat demand in the residential and service buildings sector in Europe.



5.3 Main Scenario Assumptions

In addition to the scenario-specific assumptions in Chapter 4 and the exogenous demand modelling in Chapter 5.2, the scenarios are defined by the basic, overarching configuration of the model. The model configuration thus forms the foundation of the scenario analysis. The main assumptions are closely linked to the general functionality of the PyPSA-Eur model. Detailed information on the model that goes beyond what is presented in this report can be found in the documentation [23] and various publications [24, 25, 26]. Several different types of configurations can be distinguished:

General Configuration of Model Topology and System Boundaries

The general configuration of the model determines the topology of the energy systems to be analysed. This configuration is based on the definition of the geographical boundaries of the model introduced in Chapter 4 and the spatial resolution of the countries depicted.

For these regions, we first define the technologies available for electricity and heat generation (RE generation plants, conventional power plants, CHPs, etc.), for energy storage (battery and pumped storage, gas and hydrogen storage, short-term and seasonal heat storage, etc.), for energy conversion (H_2 electrolysis, methanation, steam reforming, etc.) and for supra-regional energy and material transport (electricity, gas, hydrogen, CO_2 networks). Subsequently, the technologies for which CO_2 capture is permitted and the potential for CO_2 storage, are specified.

In addition to the technologies, the basic model configuration also includes all relevant energy sources that are important in today's energy system: fossil fuels (coal, gas, oil), renewable fuels (biomass, biomethane), renewable primary energy sources (wind, solar, hydropower) and nuclear energy. Synthetic energy sources will be of great importance for the decarbonisation of the energy system, in particular hydrogen and its derivatives (methanol, ammonia). The model also includes synthetic oils and synthetic methane.

In addition to modelling the energy carriers, it is also relevant which energy carriers can be imported from outside the model boundaries and to what extent. For the current energy system, imports include hard coal and oil products as well as natural gas via pipeline or liquefied via LNG terminals. In the future, the import of hydrogen (pipeline, LH2) and its derivatives will also have a significant influence on the energy system.

Our setup has been designed to fully cover the current energy system. In addition, our selection of technologies ensures that the development of the energy system towards climate neutrality can be optimised freely, taking into account innovative technologies and reliable assumptions. Especially relevant for this optimisation are adaptable Power-to-X technologies, import, generation and the distribution of hydrogen and its derivatives as well as the flexible optimisation of the grid infrastructure.

The transition of the European energy system from its current status to greenhouse gas neutrality is largely driven by the CO_2 reduction pathway. In the model used, a maximum CO_2 budget is set that may be emitted into the atmosphere for each milestone year. This budget is based on a CO_2 reduction pathway, which covers significant milestones defined by the European Commission to reach CO_2 neutrality by 2050. More specifically, targets from the 'Fit For 55' package are met, with its 55% reduction by 2030 and the proposed target of 10% remaining annual emissions by 2040. [27] This CO_2 reduction pathway is equivalent to a CO_2 budget of 40.3 Gt for our entire modelling region.

Meeting this CO_2 budget is defined as a binding constraint in the model. The energy system is optimised to ensure that the energy supply for all sectors is guaranteed, while complying with the maximum CO_2 budget at minimum overall system costs. The model offers three different options for reducing CO_2 emissions:

1. Reduction of emissions into the atmosphere through the expansion and use of low-carbon or CO_2-neutral technologies and energy sources: The model can invest in technologies to reduce emissions into the atmosphere by increasing energy efficiency or using less CO_2-intensive energy sources. The exogenous capacity corridors for the technologies, described later, have to be adhered to.
2. The model can invest in technologies that capture emissions from industrial or power plant processes from exhaust streams and make them available for synthesis of synthetic hydrocarbons or sequestration.
3. Carbon capture from the atmosphere: The model can extract CO_2 from the atmosphere by direct air capture or nature-based removal from the atmosphere and make it available for further use or sequestration.

Each country has individual potentials for the permanent storage of CO_2. Additionally, the model is bound by a pan-European restriction for CO_2 sequestration, limiting the annual storage to 500 Mt per year, which is well within the assumptions of other studies [28].

Capacity Limits and Expansion Potential

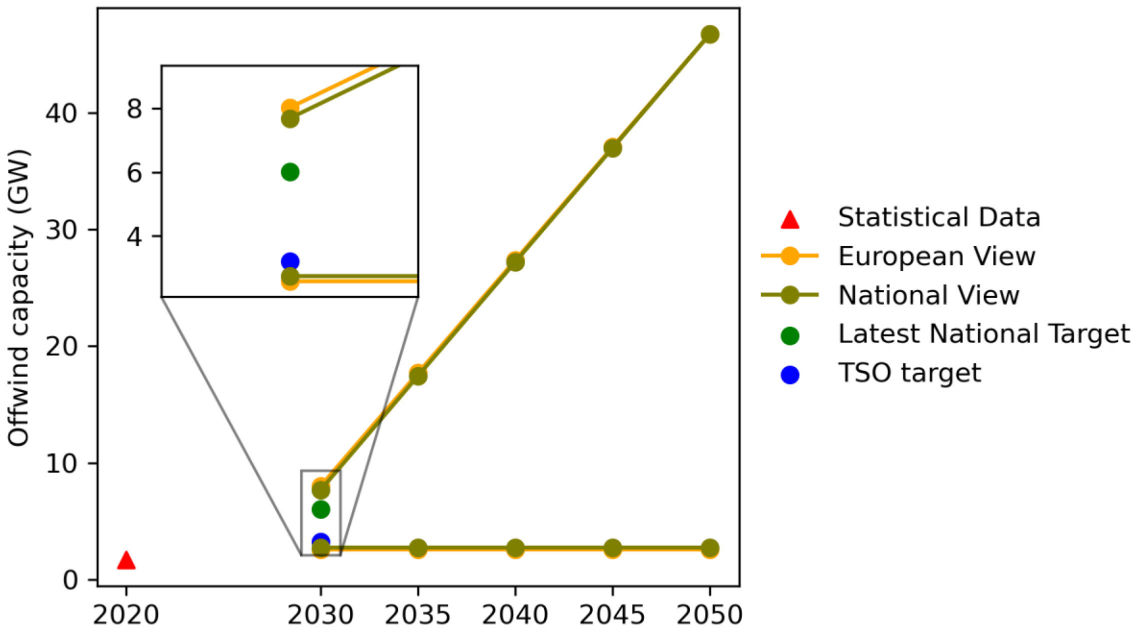
The optimisation of technology expansion in the model is constrained by exogenous configurable capacity limits and capacity limits determined by endogenous methods.

The overall capacity limits for renewables, in particular solar and wind, are determined by the Atlite software package [29] for the individual regions based on technology-specific space requirements and land-use restrictions. These capacity limits are independent of the optimisation year. Which capacities are then actually installed is part of the model simulation and can be optimally determined within the limits. The methodology can be found in the Atlite documentation [29] and in the Reference [30].

In addition to the endogenous capacity limits, exogenous limits are set to represent scenario-based assumptions as well as political and regulatory specifications. In this way, corridors can be specified for the expansion of the generation, conversion, storage and infrastructure technologies optimized by the model. These include technical framework conditions, such as upper limits for the expansion of electrolysers and heat pumps, which incorporate factors such as the evolution of the technologies and the practicable installation of the systems. In addition, the corridors can contain assumptions from national grid development plans and the TYNDPs for electricity and gas. Furthermore, political targets and regulatory requirements are set as additional constraints. These targets are supplementary to the scenario assumptions on grid expansion and national self-sufficiency discussed in Chapter 4.

For renewable energy carriers in particular, we implemented country-specific capacity expansion pathways to avoid countries exploiting their renewable potential at an unrealistic rate. An example of such an expansion corridor is provided in Figure 6.

Figure 6: Capacity expansion corridor for offshore wind power in Denmark based on Reference [31] and Atlite [29].



The plants actually installed in 2020 [32] are marked with a red triangle. For 2030, we select data from the Ember study [31], which summarises expansion targets according to national policy makers and transmission system operators (TSOs). These targets are used to define an upper and lower limit for the capacity in 2030 with an additional 10% for the data of the national scenarios (CN, SN) and 15% for the European scenarios (CE, SE).

The 2050 data represent the total available potential according to Atlite's calculations, whereby some data were adjusted after expert consultation, as they did not appear to be achievable for geological and/or political reasons. The corridor for the years 2035 to 2045 was determined by linear interpolation of 2020 and 2050.

Timed Load and Generation profiles

In addition to static constraints, time-variable profiles are specified for the optimisation of the model, differentiating between time-variable, exogenous energy demand profiles and time-variable maximum generation profiles.

A time-variable demand profile is applied to the exogenous electricity demand and the demand for space heating and hot water.

The exogenous electricity demand is determined from historical consumption time series in combination with assumptions on efficiency gains and is given as an hourly profile for each model region. These are taken from the Open Power System Data (OPSD) based on ENTSO-E Transparency [33].

The heating demand described in Chapter 5.2 is characterised by an hourly profile in a routine that depends on the weather data used (base year 2013). For space heating, the heating degree days are first determined for each model region depending on the temperature profile. On these days only, there is a demand for space heating. In a subsequent step, the hourly heat demand is determined for the identified heating degree days on the basis of the intraday temperature profile. Hot water demand, on the other hand, is much more constant and is especially affected by user-dependent intraday fluctuations.

The renewable electricity generation technologies and solar thermal energy are attributed a time-varying maximum generation profile. An individual profile is determined for each technology in each model region based on the weather databases ECMWF ERA5 [34] and CMSAF SARAH-3 [35]. As for the maximum technology expansion potentials, this is computed in the tool atlite [36]. Details on the method can be found in the documentation linked above.

Technology Parameter

The technology parameters of all model components are specified exogenously for each of the (modelling) milestone years considered in the optimisation and can be adjusted individually. The initial data set originates from the public input data repository [37], in which the primary data sources and the computation of the individual technology parameters are transparently described. For our modelling, version 0.9 of the technology data was used. The model input data contains details on all modelled technologies, as well as additional technologies that are not included in the model used. This latter data is therefore not relevant for the calculations in this project.

The data set contains the key assumptions on costs for the technologies, represented by investment costs as well as fixed and variable operating costs. The lifetime and conversion efficiencies are also included for each technology. The data also includes the prices of importable energy sources such as oil or hard coal. Figure 7 show exemplary cost trends for wind and PV systems. Also, the development of investment costs for heat pumps and the development of the coefficient of performance (COP) of heat pumps is displayed in Figure 8. Along with the data on heat pumps, it also shows investment costs of H_2 electrolysers, which differ from the PyPSA technology data in consultation with experts from the TransHyDE research project [38] to avoid too optimistic cost assumptions in this important technology. The full set of technology parameters that was used in this study is available as an additional file.

Figure 7: Exemplary cost trends for wind and photovoltaic systems.

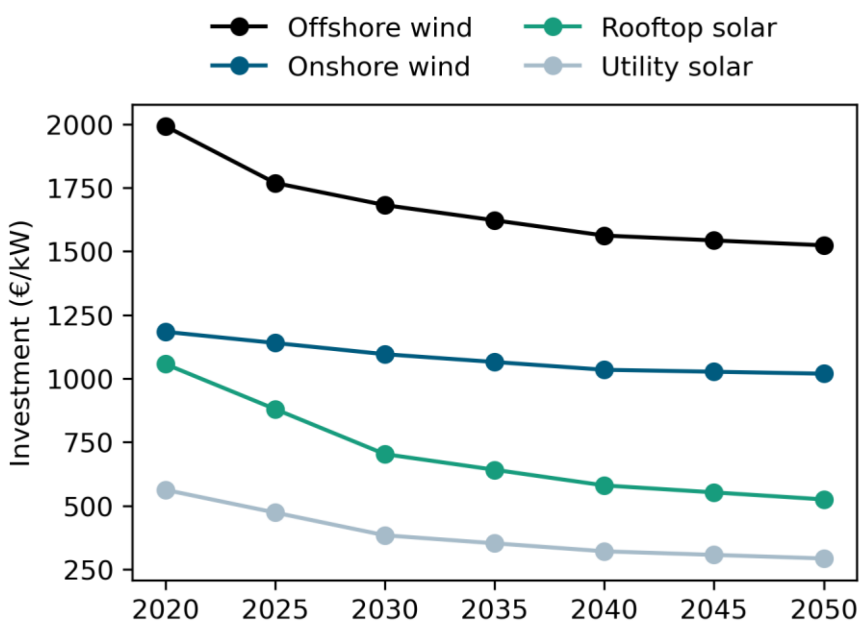
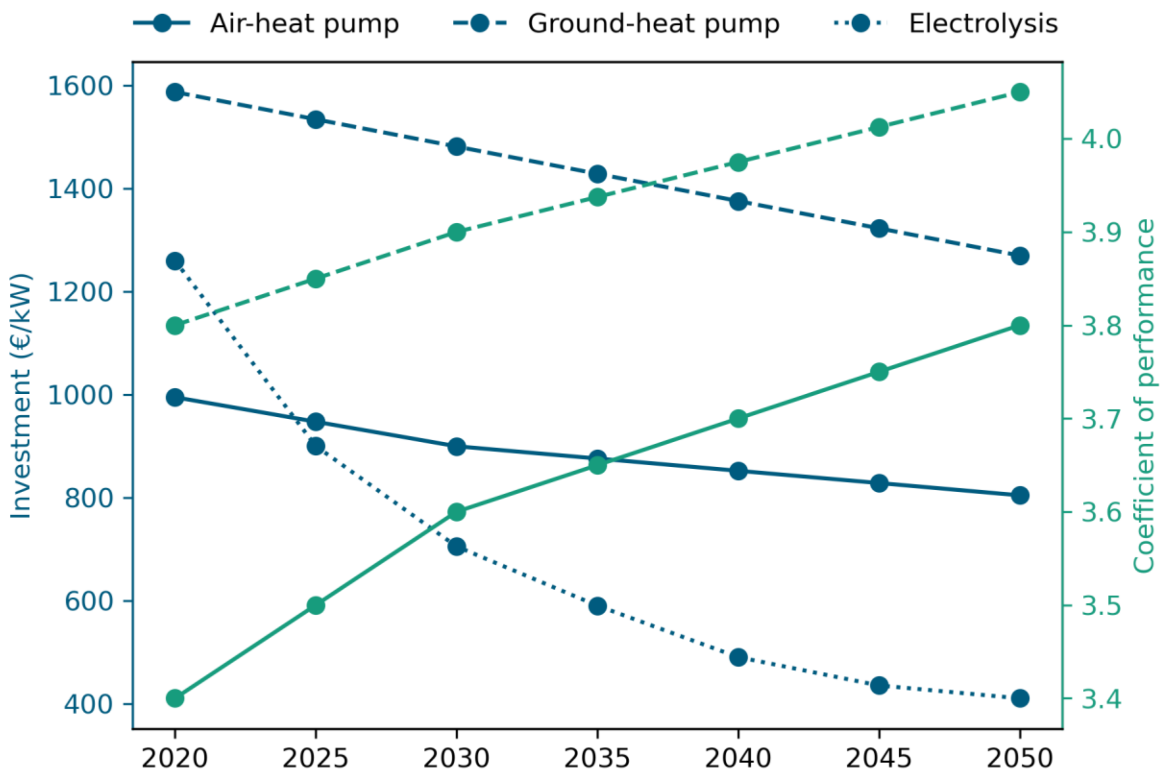


Figure 8: Exemplary cost trends for the development of investment costs for heat pumps and electrolysers and the development of the COP of heat pumps.

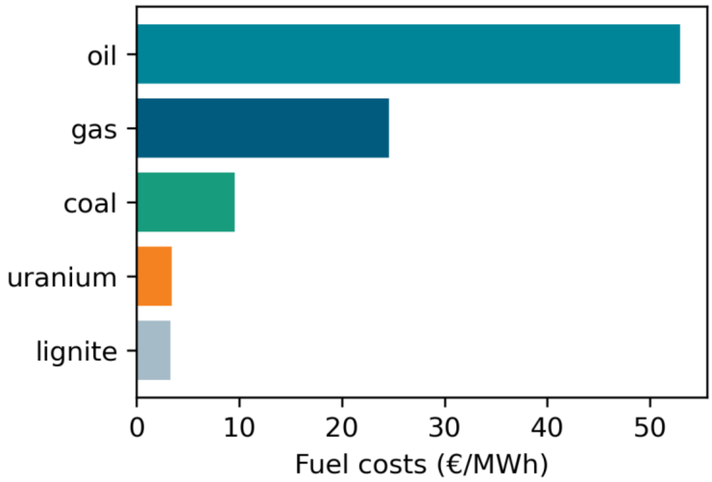


Import of Energy Carriers from Outside Europe

Apart from producing the energy to cover Europe’s energy demand locally, energy carriers can also be imported from outside Europe, including fossil fuels, uranium, hydrogen, synthetic methane and liquid hydrocarbons.

Uranium, oil and synthetic liquid hydrocarbons are imported to the European zone as a whole and not with specific import locations in the PyPSA-Eur framework. This is based on the assumption that their distribution is lossless and that the cost of their distribution is assumed to be negligible. For the import of natural gas, on the contrary, different import locations via pipeline and LNG terminals are modelled. This import infrastructure can also be used for the import of synthetic methane. In Figure 9, the costs for the import of these conventional energy carriers are displayed.

Figure 9: Fuel costs for the import of conventional carriers.



From 2030, the model also has the option to retrofit the LNG terminals to liquid hydrogen terminals with underlying costs estimated by Neumann et al. [24]. Similarly, the gas import pipelines entering Spain and Italy can also be repurposed. In addition to the usage of existing gas import infrastructure, new import terminals are built according to the H_2 infrastructure map [17].

The model considers the import of hydrogen via terminals in different states (liquid, LOHC) as well as derivates. Only the gaseous state of hydrogen is considered within the model, therefore the different import methods are only distinguished by the cost of the terminals and the price of the hydrogen. The import costs for liquid hydrogen, hydrogen derivates, synthetic methane and liquid hydrocarbons are taken from the meta study of Genge et al. [39], whereas the cost assumptions for hydrogen pipeline import are given by Fleiter et al. [5].

An overview of the cost assumptions for hydrogen imports and import infrastructure is given in Table 17 in the Annex 3: Supplementary Figures.

To do this, the model allows various options to import energy carriers from outside the model regions if it is cost optimal.

Options of hydrogen supply

Generally, PyPSA allows for hydrogen production in Europe based on electrolysis of the mix of renewable, nuclear and fossil based electricity or steam methane reforming with or without carbon capture or the import of green hydrogen. Thereby, the costs of hydrogen imports are given exogenously (see above). The optimal combination of these production options is result of the optimisation within the study. Hydrogen based on pyrolysis or gasification of coal is not considered.

Repurposing of CH_4 Pipelines

Besides repurposing existing natural gas import infrastructure to hydrogen needs, retrofitting the methane network within Europe to hydrogen pipelines can also be an option. While challenges such as material strain may arise, the repurposing of existing CH_4 pipelines is assumed to be more cost effective than building new pipelines in many cases [40]. In our model, repurposing takes place both endogenously and exogenously. In the case of the sectoral silo scenarios, where pipeline capacities are taken from the German hydrogen core network and the H_2 infrastructure map, exogenous retrofitting takes place according to the capacities given in these grid plans. When the model allows for endogenous optimisation of the hydrogen network, it can also choose to repurpose parts of the methane network.

Due to the geographical resolution, most routes reflected in our model actually combine multiple pipelines. Therefore, the model is also allowed to repurpose only parts of the pipeline capacity connecting two clusters. In terms of costs, repurposing is 57% less expensive than installing a new hydrogen pipeline at a cost of 129 €/MW/km. To take into account technical constraints, a hydrogen pipeline can only use 60% of the original CH_4-pipeline capacity.

6 Overview of Scenario Results

This section presents the analysis of the four scenarios. The results focus on energy system infrastructures, including electricity, hydrogen, and CO_2 infrastructure:

- As a starting point, section 6.1 presents the results of planning infrastructure from a sectoral, national perspective, i.e. with a low degree of integration ("SN" Scenario - Sectoral, National view). This identifies the major drawbacks of non-integrated planning and development.
- We then analyse the benefits of European integration in the SE Scenario (Sectoral, European view) in section 6.2 and the benefits of sectoral integration in the CN Scenario – (Cross-sectoral, National view) in section 6.3.
- Finally, section 6.4 presents the results of the CE Scenario (Cross-sectoral, European view), and shows the advantages of infrastructure planning that integrates both a European and a sectoral perspective.

Methane uses were not constraint while modelling the scenarios, considering the strongly decreasing role of methane gas demand. There could, however, be arguments to reduce the use of methane further to zero. In section 6.5, we deal with an approach where the remaining (fossil) methane uses in the scenarios are explicitly reduced to zero and analyse in detail the question of why the unconstrained main scenarios in our modelling analysis still have a gas network in 2050.

6.1 Sectoral & National View

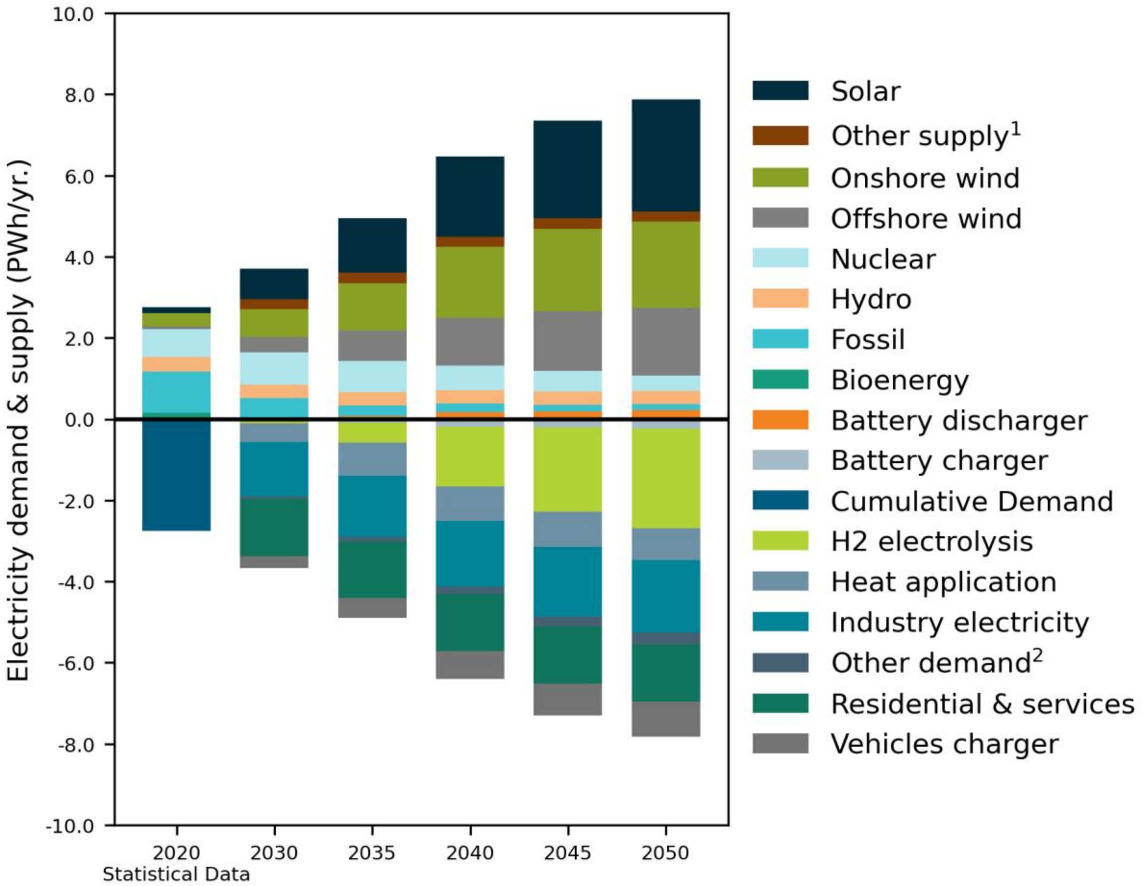
This section presents the results of the **"SN" Scenario** (**S**ectoral, **N**ational view), which assumes sectoral grid planning in silos with a focus on national resilience, i.e. limited interconnection capacities across Europe (trend towards a high level of national supply/low levels of import dependence).

6.1.1 Electricity Generation, Infrastructure and Consumption

With the phase-out of fossil energy carriers, the role of electricity for energy supply becomes increasingly relevant with electrification taking place in many sectors, such as industry, transport and heat.

This trend is also observable in our model runs. Figure 10 shows the electricity demand and supply in the EU for each of the years modelled together with the statistical data in 2020. Energy demand increases due to the electrification of industry and other demand sectors in addition to the need for hydrogen production via electrolysis. As a result, the demand for electricity triples between 2020 and 2050. To meet rising electricity demand, the renewable electricity produced in the EU also increases. While fossil electricity production still accounted for 37% of total electricity generation in 2020 [41], this drops to only 14% of the electricity produced in 2030, as many countries within the EU intend to phase out their coal power plants by 2030 [42], and CO_2 reduction targets need to be met. In contrast, the amount of electricity from nuclear power plants increases up to 2030, as countries like France and Poland commission new reactors, while aging reactors have not yet been phased out [43, 44]. In later years, the nuclear electricity produced in the EU decreases as old reactors reach their end-of-life and are decommissioned. In terms of renewable energy, wind energy increases from 398 TWh in 2020 to 3787 TWh in 2050 in the EU. Aside from this strong increase, solar energy is established as an important source of electricity in a CO_2-neutral energy system with a share of 35% in total electricity supply. Taken together, the electrification of demand sectors and the increased demand for hydrogen require the electricity supply to more than triple and renewable energy to increase ninefold.

Figure 10: Electricity demand and supply in the EU27 for the sectoral, national view (SN scenario).

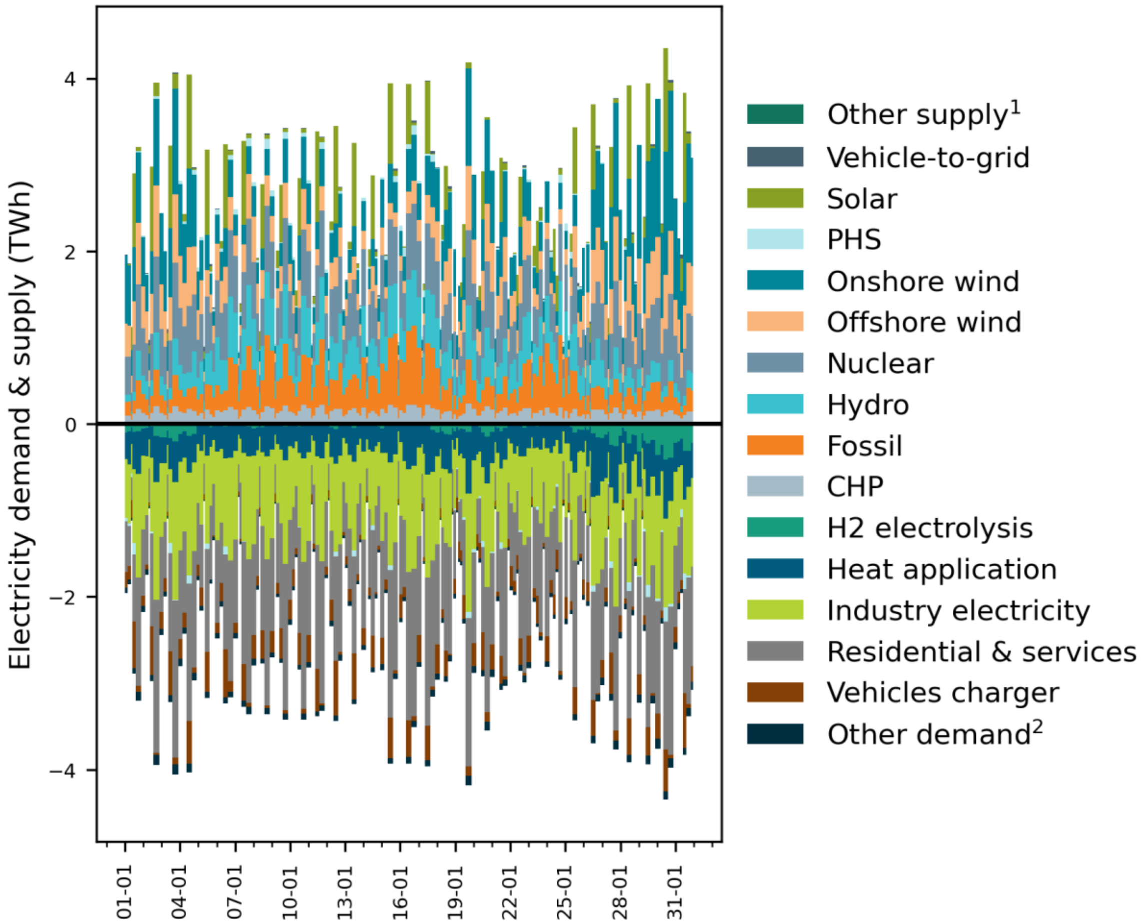


[1] Other supply: Import, CHP, H2 fuel cell, H2 turbine, Home battery discharger, Vehicle-to-grid

[2] Other demand: Export, Agriculture electricity, DAC, Home battery charger, Methanol production, PHS

A heavy reliance on renewable energy sources also requires the energy system to react to their intermittency. In terms of flexibility options, Figure 10 identifies stationary batteries and fossil gas turbines as the most widely used flexibility options. Amongst the technologies summarised under "Other supply", vehicle-to-grid and CHPs (including gas and biomass) make the largest contribution with 83 TWh and 167 TWh, respectively, in the EU in 2050. More detailed analysis is required to understand this low need for flexible technologies. In particular, longer periods with low solar irradiation and little wind need to be examined as they will be challenging for the energy system. The energy system model will only build the minimum capacities required for electricity supply based on its weather data and needs to find the cost-optimal solution for these periods of low renewable generation in this weather data.

Figure 11: Electricity demand and supply of the entire modelling region during a period of low renewable generation in 2050.

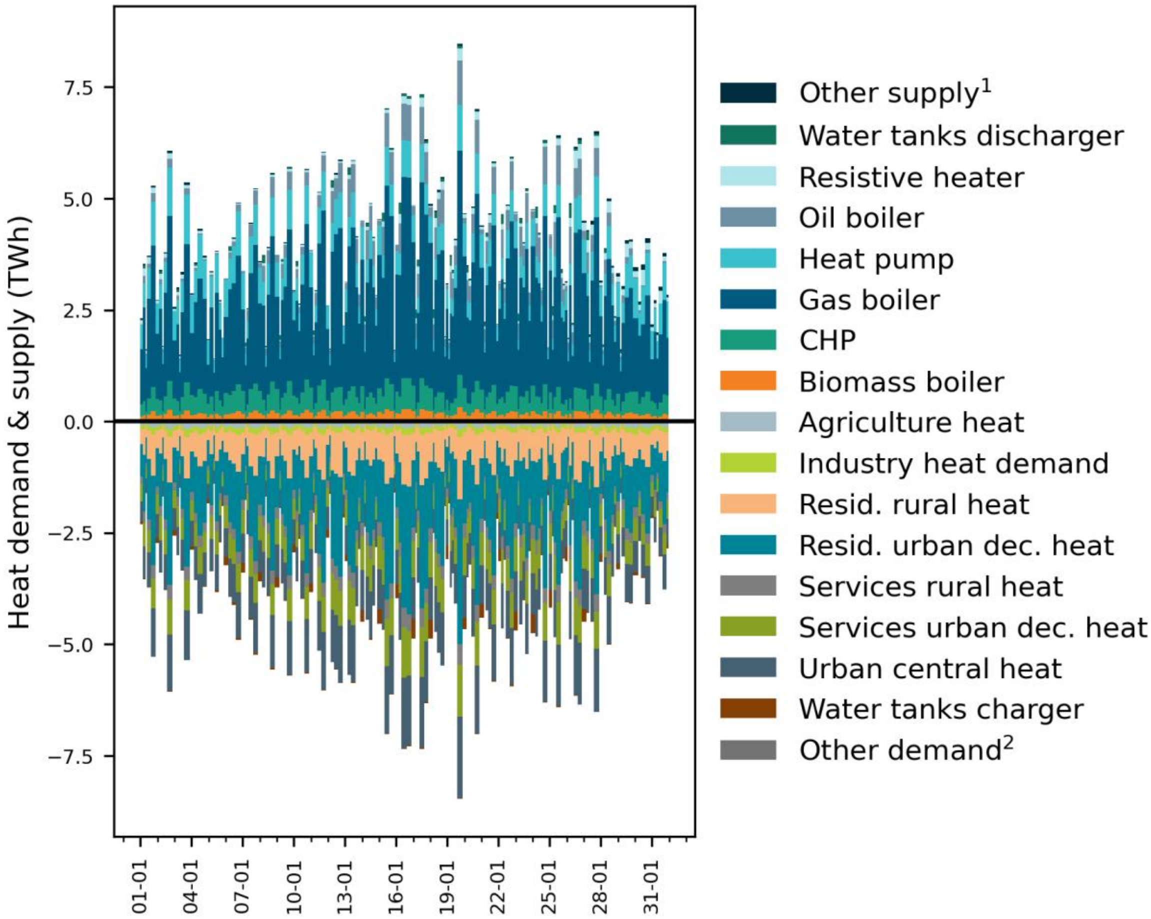


[1] Other supply: Battery discharger, H2 fuel cell, H2 turbine, Home battery discharger

[2] Other demand: Export, Agriculture electricity, Battery charger, DAC, Home battery charger, Methanol production

For example, the weather data feature several weeks of relatively low renewable electricity supply in January all over Europe, which are displayed in Figure 11. As this figure shows the electricity supply and demand over the entire modelling region in 2050, the drops in electricity supply are not as drastic as they would be for single countries. Still, there is a period of low supply, which is most significant between the 22nd and 25th of January, with very little production from renewables. Instead, there is an increase in electricity generation from fossil sources, namely gas turbines. In contrast to some other studies [45, 46, 47], there is no electricity produced from hydrogen in the form of backup fuel cells or turbines. The low level of backup power generation capacities is partly attributed to the reaction on the demand side. In Figure 11, there is an exogenous demand from industry and the residential and services sectors. Flexible demands such as H_2 electrolysis, though, are drastically reduced throughout January. Electrolysis is kept to a minimum with hydrogen supplied from hydrogen storage during this period. Demand from the heating sector is also reduced.

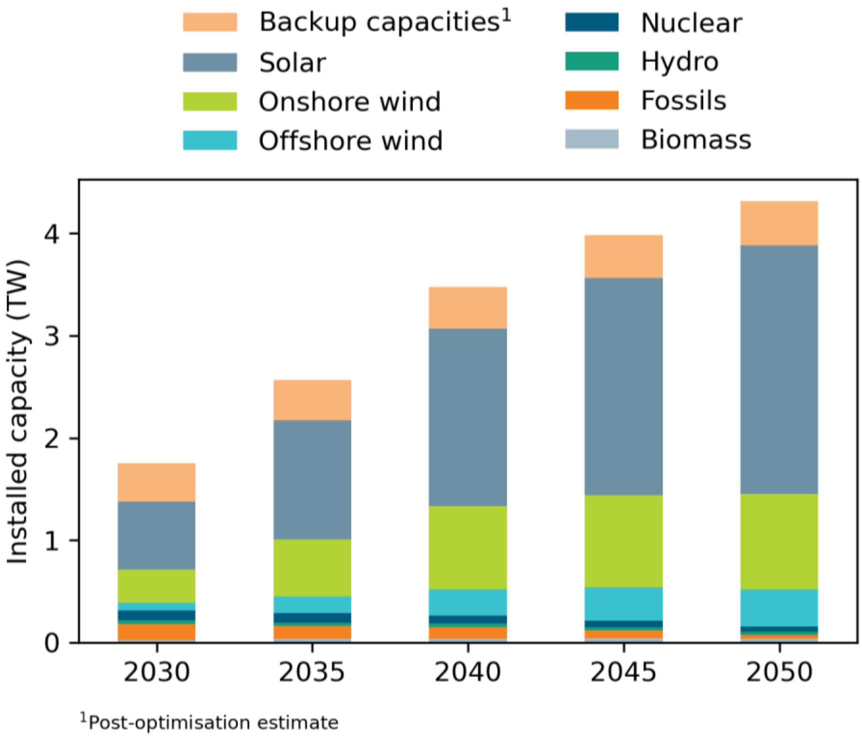
Figure 12: Heat demand and supply for Europe in a period with low renewable electricity in 2050.



[1] Other supply: Methanol production, Residual heat, Solar thermal
[2] Other demand: DAC

The behaviour of the heating sector can be better understood by looking at Figure 12, which shows the heat supply and demand during the period of low renewable electricity generation in 2050. The demand side shows that in addition to the lack of solar irradiation and wind, this is also a colder period with increased heat demand. During this period, hot water storage tanks are emptied, and heat is generated using fossil fuels. This fossil heat generation concerns oil boilers, but more importantly gas boilers (running on a mix of natural gas and biomethane). As these technologies do not capture the CO_2 emissions, they have to be compensated by negative emissions most importantly from biomass used in processes with carbon capture. Despite this, the model considers this route to be more cost-effective than using hydrogen backup capacities. Therefore, the modelling results include backup generation in the heating sector in addition to gas turbines in the electricity sector. This outcome could change if more extreme weather events were introduced into the weather data underlying the model. Periods of low renewable electricity generation are naturally more extreme at national level than for the entire European region. We included the electricity supply and demand for Germany in Figure 49 in the Annex as an example. At national level, besides demand reductions, electricity imports play a major role in handling such a shortage in renewable energy. Even though the analysis covers the sectoral, national scenario, in which countries generate as much electricity as they consume on an annual basis, imports and exports are still essential for national supply security. This finding also underlines the need for cross-border transmission infrastructure to facilitate this exchange.

Figure 13: Installed capacity for electricity generation in the EU in the sectoral, national view (SN scenario).

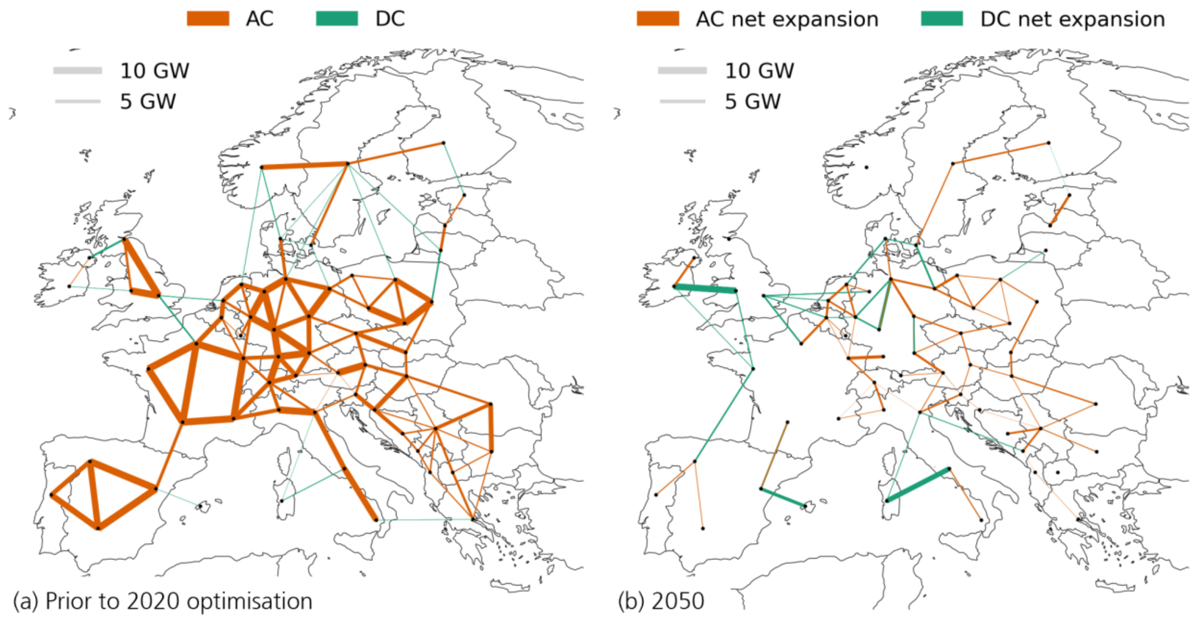


As these short-term imports and exports of electricity are permitted in our national policy dimension, the model still optimises the reaction to such weather events at European level. Uncoordinated planning procedures that might occur when countries individually plan their backup capacities to supply demand peaks are not reflected in the modelling results. To estimate the impact of fully uncoordinated planning on backup capacities, we calculated the capacities needed in each country to supply its exogenous, inflexible electricity loads. This post-optimisation estimate can be interpreted as strategic reserves being implemented in all countries. Figure 13 shows the resulting need for these capacity reserves and the theoretical backup capacity required in the EU to allow each country to cover its inflexible electricity demand. The estimated need in 2030 is 377 GW, and potentially 428 GW could be installed by 2050 in the EU due to uncoordinated, national planning. This estimate amounts to 11% of the endogenously optimised electricity generation capacities, which are also shown in Figure 13.

It should be noted that the technological choice for back-up capacities or peak power plants with a relatively low utilization is – with the chosen parameters – a flat optimum. This means that while the model must make a choice, small changes in the assumptions can lead to very different results. This is especially important in the face of high uncertainties. For the mentioned power plants, a wide range of options is discussed: Hydrogen power plants (with and without hydrogen network access), methanol or ammonia power plants, CCS power plants or even conventional gas power plants the emissions of which are compensated with negative emissions. Depending on the assumptions, all these options can be part of an economic solution, but the uncertainty regarding their costs and technical characteristics is high. With the closeness of the utility of the options, understanding the given solution means acknowledging that in real life, the best combination of back-up power plants is still to be researched and discussed and will depend on future developments as well as local conditions.

The capacities resulting from endogenous optimisation indicate that the EU would have to significantly expand its renewable energy capacities to supply such large amounts of renewable energy. Whereas the installed capacity of onshore wind turbines almost triples between 2030 and 2050, investments in offshore wind lead to 4.7 times more installed capacity. Solar emerges as an important energy carrier in 2050 with the installed capacity increasing from 658 to 2432 GW within the EU. Even though renewable energy sources already supply most of the EU's electricity demand in 2040, as seen in Figure 10, there are still fossil generation capacities in the model that remain unused until their decommissioning or act as backup capacities with very few running hours. Their decommissioning then decreases the installed fossil capacity until 2050 in Figure 13. To counteract this trend but most importantly to meet full CO_2 neutrality by 2050, the model sees a need for 3.5 times the renewable capacity of 2030.

Figure 14: Electricity grid (a) prior to the optimisation of 2020 and (b) its expansion between 2020 and 2050 in the sectoral, national view (SN scenario).

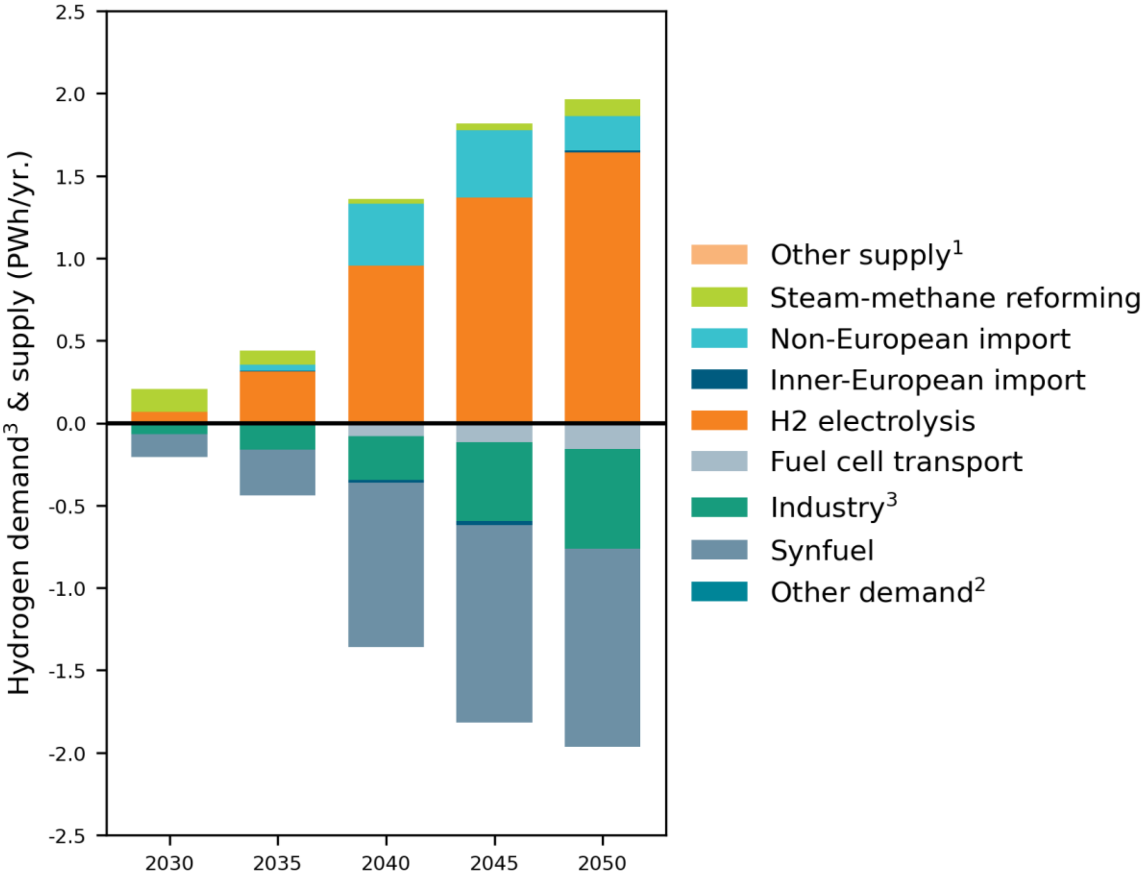


This massive deployment of renewable capacities also requires a corresponding grid expansion. The status of the electricity grid prior to optimisation is displayed in Figure 14a with the line width indicating transmission line capacity. It shows a strong network of AC transmission lines with a few DC lines, most of which are submarine interconnectors. In the sectoral silo scenarios, grid expansion until 2040 is limited to TYNDP projects as described in detail in Annex 2: Implementation of Current Infrastructure Planning. Therefore, grid expansion up to 2040 (compare Figure 55) can be fully attributed to the exogenous grid expansion in the TYNDP project catalogue. Most expansion of the electricity grid occurs in Western Europe, for instance across the Channel to England, or the establishment of a strong connection between mainland Spain and the Baleares. As the TYNDP planning process does not extend beyond 2040, the model is allowed to endogenously build electricity transmission lines in the decade 2040-2050. The resulting grid expansion up to 2050 is shown in Figure 14b, which illustrates grid expansion in Central and Eastern Europe that the model identifies as necessary in addition to the TYNDP projects. Therefore, the sectoral, national scenario focuses on DC transmission line projects in Western Europe, whereas endogenous optimisation identifies the need for AC network expansion in Central and Eastern Europe.

6.1.2 Hydrogen Demand, Supply and Infrastructure

While the electricity network is already quite mature, hydrogen infrastructure is still in a planning stage. Hydrogen will play an important role in future industrial production, replacing processes that rely on fossil fuels. It also has some relevance in the transport sector, where it can either be used directly in fuel cells or in Fischer-Tropsch synthesis to provide liquid hydrocarbons, notably for ship and air transport.

Figure 15: Hydrogen demand for different sectors and the production of synthetic fuels and hydrogen supply in the EU27 for the sectoral, national view (SN scenario).



[1] Other supply: Hydrogen storage

[2] Other demand: H2 fuel cell, H2 turbine, Hydrogen storage

[3] Excluding grey hydrogen demand for industrial processes, which is included as methane demand in the model.

The resulting hydrogen demand is visualised in Figure 15 together with the supply for the planning horizons 2030 to 2050 in the EU for the sectoral, national scenario. In the industry sector modelled in the TransHyDE study, which was used as the main input for the demand set exogenously for this sector [5], hydrogen demand increases over time reaching 608 TWh in the EU in 2050. This hydrogen, however, only includes hydrogen sourced from the larger energy system as explained in Chapter 5.2. Steam-methane reforming at local site is included as methane gas demand for industry in our model. On the other hand, the industrial hydrogen demand covers European production of methanol and ammonia to cover 40% of the industry's demand whereas the rest is imported. This import share is chosen as an intermediate level. For more details on industrial hydrogen demand, we refer to the sensitivity analysis in Chapter 8.1.Outside of the industry sector, most hydrogen is used for the production of synthetic fuels. These are needed to meet the exogenously set demand for kerosene for aviation and methanol for shipping fuel. The steepest increase in hydrogen demand for these liquid hydrocarbons appears in 2040, as the ambitious CO_2-reduction target enforces more carbon-neutral technologies. In 2030, while hydrogen production is still low, a significant share is produced by steam methane reforming, mostly with carbon capture, introducing 20 TWh of grey and 120 TWh of blue hydrogen to the EU's energy system. In 2050, only 99 TWh of blue hydrogen production remain in the EU. These shares of blue and grey hydrogen result from the endogenous optimisation within our study. In all the years after 2030, most of this hydrogen demand is supplied by hydrogen produced within the EU using electrolysis. This hydrogen cannot necessarily be considered green hydrogen

as it is produced using the current electricity mix, which may not be all renewable. So, the higher the share of renewable energy in the electricity supply, the greener the hydrogen is produced. In some regions in 2050, this production becomes more cost-competitive than importing green hydrogen from outside the modelling region. Therefore, our modelling suggests that Europe could be largely self-sufficient in producing hydrogen despite high demand from industry and Power-to-Liquid processes.

Due to the fact that large shares of hydrogen demand are set exogenously based on the TransHyDE study for industrial demand, a set share of fuel cell transport, and exogenous liquid fuel demand, overall demand and supply do not differ greatly between scenarios. However, regionally, there can be large differences in infrastructure build-up due to the scenario assumptions. In the sectoral, national scenario presented here, the pipeline build-up until 2040 is limited to the H_2-infrastructure map [17] and the German hydrogen core network [18].

Figure 16: Hydrogen network and nodal supply mix in (a) 2030 and (b) 2050 in the sectoral, national view (SN scenario).

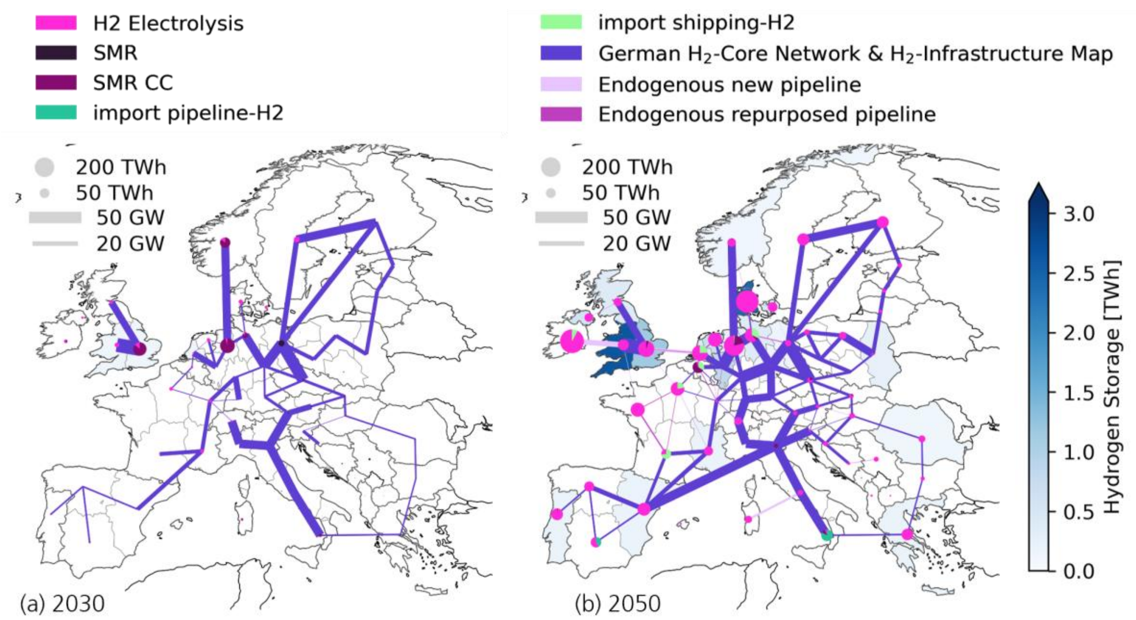


Figure 16 shows the resulting infrastructure, including production, storage, and transport in (a) 2030 and (b) 2050. The circle size indicates the hydrogen produced. This can be produced either through electrolysis or through steam methane reforming without carbon capture (grey hydrogen) or with carbon capture (blue hydrogen). Imports can reach Europe via pipeline or ship. The colour-code of the cluster area indicates the amount of hydrogen stored in that region in the specific planning year (for a more detailed view of the hydrogen storage, see Figure 50). The pipelines' installed capacity is indicating by their line thickness, with Figure 16a showing large capacities already in 2030, as many of the pipeline projects included here are planned to be finished within the next decade. However, hydrogen production is still low (see pie charts), meaning the pipeline infrastructure depicted here has a very low average utilisation of 16% for the year 2030. Additionally, there is a very inhomogeneous distribution of pipelines across Europe. Large pipeline capacities are, for example, planned for North-South corridor connecting Italy, Central and Northern Europe, whereas parts of France and the Balkans have no hydrogen pipeline connections at all. When the model is allowed to endogenously build pipelines after 2040, these blind spots in the current hydrogen infrastructure planning are filled, as displayed in Figure 16b for the year 2050. However, these pipeline capacities are still smaller than those introduced by the H_2-infrastructure map and the German hydrogen core network. Even though the resulting hydrogen network can transport hydrogen from regions with high renewable generation and storage potential like the countries bordering the North Sea to the rest of Europe, the pipelines only have an average utilisation of 30%. In contrast, the model's endogenously built pipelines have 80% utilisation on average. The modelling indicates how the current hydrogen grid planning overestimates the need for H_2 pipelines, while also resulting in an incomplete network in certain regions. This observation underlines the finding that recognising the importance of infrastructure does not mean that this will be developed efficiently and effectively.

6.1.3 The Decreasing Role of CH_4 Infrastructure

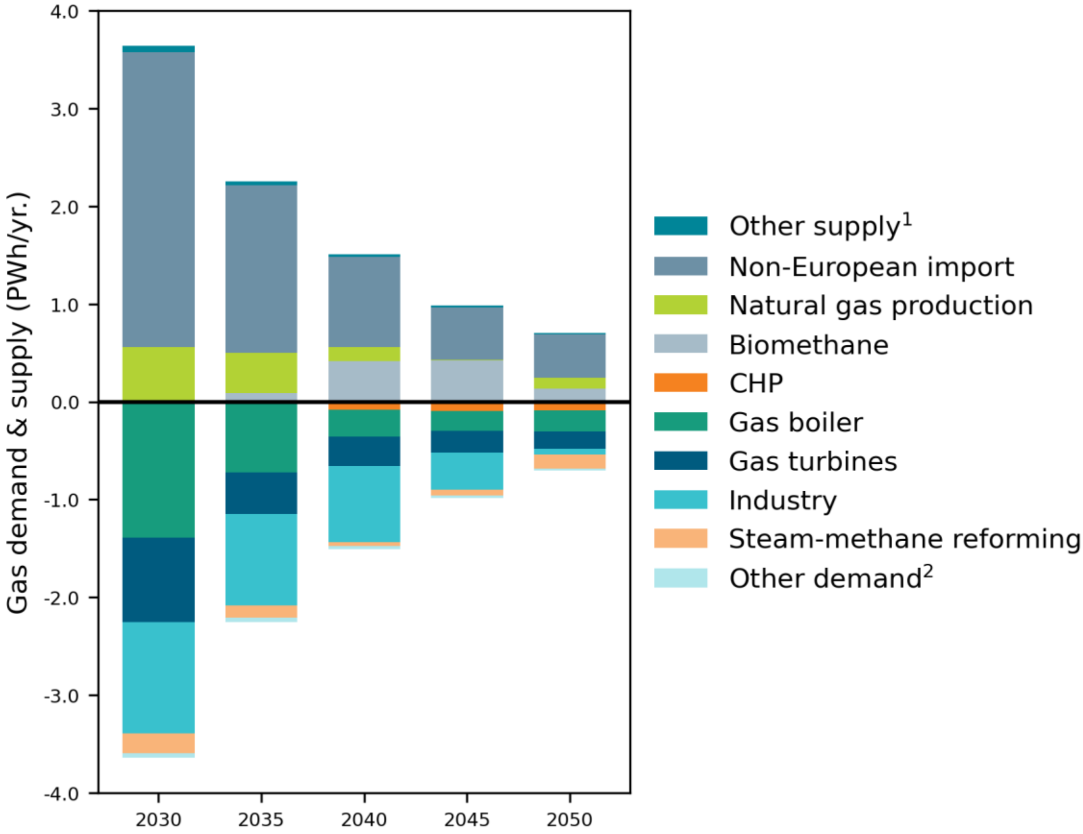
With the increasing use of electricity and hydrogen in the industry and heating sector, the role of natural gas is strongly decreasing over the decades. Figure 17 shows the demand and supply of methane gas within the EU in the years 2030 to 2050. In 2030, still 3592 TWh of methane are needed to supply the energy demand in the heating, industry, and electricity production. This demand is mostly covered by natural gas imports (84%) and local production. Over the two decades until 2050, the gas demand and supply decrease to 10% (as compared to 2020 numbers). The small remaining gas demand is covered mainly by natural gas, with biomethane playing a role as a transitional supplier, and is used for heating and electricity production in the sectoral, national (SN) scenario. As discussed previously, these remnants are parts of endogenous optimisation, where the model chooses either:

- methane based technologies in combination with carbon capture; or
- gas-based technologies where emissions are compensated by negative emissions arising from biomass combined with CCS.

However, it is important to keep in mind that the modelling result, which includes a small remaining role of fossil gas, is subject to high uncertainties. Under slightly different input assumptions, the optimisation could opt for a solution with no endogenous methane gas demand. Also, the use of negative emission potentials bears the risk that such potentials are in practice not available for an increased demand for negative emissions from the industry sector or there is a higher need to compensate for additional emissions from the land use sector as a result of climate change.

The role of remaining smaller amounts of natural gas in our modelling is more generally discussed in Section 6.5.

Figure 17: Methane gas demand and supply in the EU in the sectoral, national (SN) scenario.



[1] Other supply: Methanation, Storage

[2] Other demand: Inner-European import/export, Storage

As noted, the decarbonisation of the energy system results in a strongly decreasing role of methane in the energy supply. This strong reduction in methane use leads to the need to adapt the size of present gas infrastructures and offers the opportunity to use the existing methane gas network for the emerging hydrogen backbone as described in Section 5.3. Thus, due to both repurposing and significant decline in the demand for gas, the methane infrastructure will become considerably smaller over the next decades (see the more detailed discussion in section 6.5).

Figure 18: Methane gas pipeline network in (a) 2025 before major repurposing to H_2 pipelines and (b) in 2050, where most remaining pipelines are not utilised.

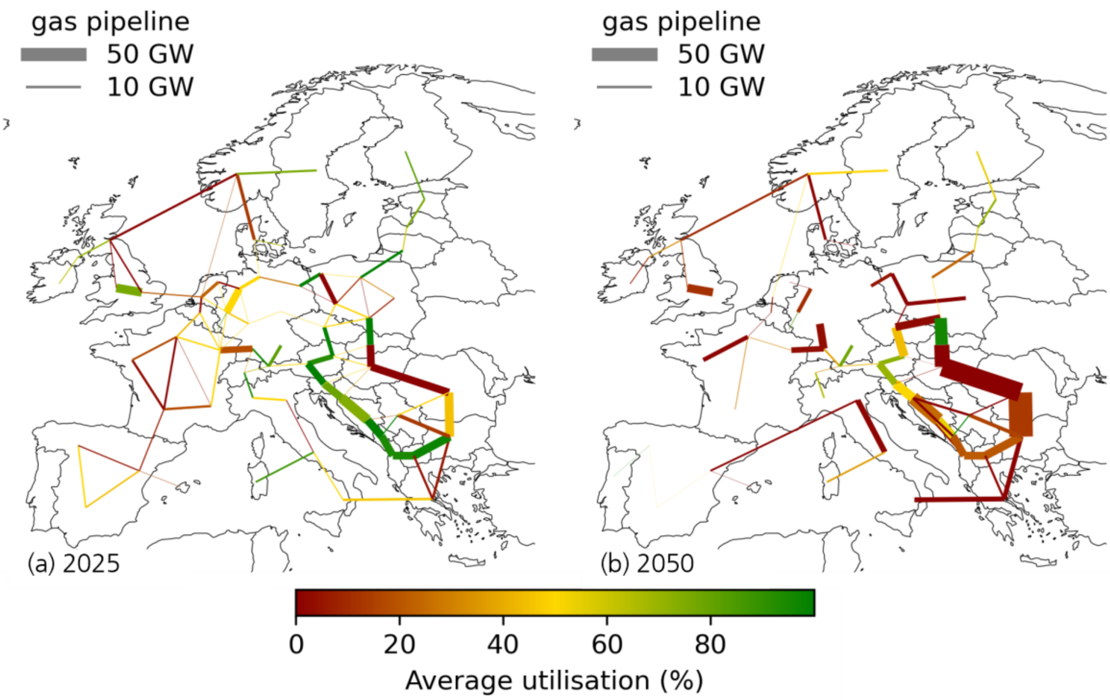


Figure 18 compares the European methane gas pipeline network for the years 2025 and 2050. The thickness of the lines indicates the installed capacities of the individual pipeline segments, and the colour indicates their utilisation - green for higher and red for lower utilisation. Two main observations can be derived from this figure. Firstly, there is a general decrease in methane gas pipeline capacity from 2025 to 2050. A significant capacity reduction can be seen in South-West Europe, which is mainly due to the retrofitting of methane pipelines to transport hydrogen. On the other hand, there is a slight increase in pipeline capacity in Eastern Europe, which is primarily caused by network expansion based on the Ten-Year Network Development Plan (TYNDP) in South-East Europe that is exogenous to the modelling. Nevertheless, the endogenous reduction in capacity due to retrofitting by far exceeds the capacity increase in Eastern Europe – declining utilisation of the pipeline system can be observed until 2050 due to decreasing gas demand: In Western Europe, both pipeline capacity and utilisation decrease, indicating a significant decline in methane gas transport. Although pipeline capacity in Eastern Europe increases due to TYNDP expansion plans, the exceptionally low utilisation of the larger pipeline system indicates that such expansion will not be cost-effective when set against the general development of the European energy system. Such low utilisation rates raise the question of who bears the operational costs for these pipelines. While the model cannot endogenously decide to decommission pipelines, in reality, pipeline capacities will likely be even lower in 2050 than shown here as unused pipelines would be decommissioned, given the significant decline in the demand for methane gas transport by 2050.,

6.1.4 CO_2 Usage, Storage and Transport

Similar to hydrogen, the construction of CO_2 infrastructure has not yet commenced. However, as there is no planning framework in place, the model can endogenously build the necessary CO_2 pipelines even in the sectoral silo scenarios. Figure 19 shows the CO_2 infrastructure for all CO_2 captured and utilised resulting from optimisation in the SN scenario. The upper semi-circles for each cluster show the source of CO_2 captured, identifying industrial processes, steam methane reforming, and biomass CHPs as the main emitters in 2050. To achieve a net-zero CO_2 balance, each cluster processes most of its CO_2 emissions, either using them to produce methanol or kerosene or sequestering them (permanently storing CO_2). Mainly clusters with access to the sea have the relevant CO_2 sequestration potential. Italy, Poland and Germany therefore become the countries with the highest volumes of stored CO_2 per year as they have high emissions and a high natural availability of sequestration sites.

Figure 19: CO_2 stored, transported and consumed in 2050 in sectoral silo, national view (SN scenario).

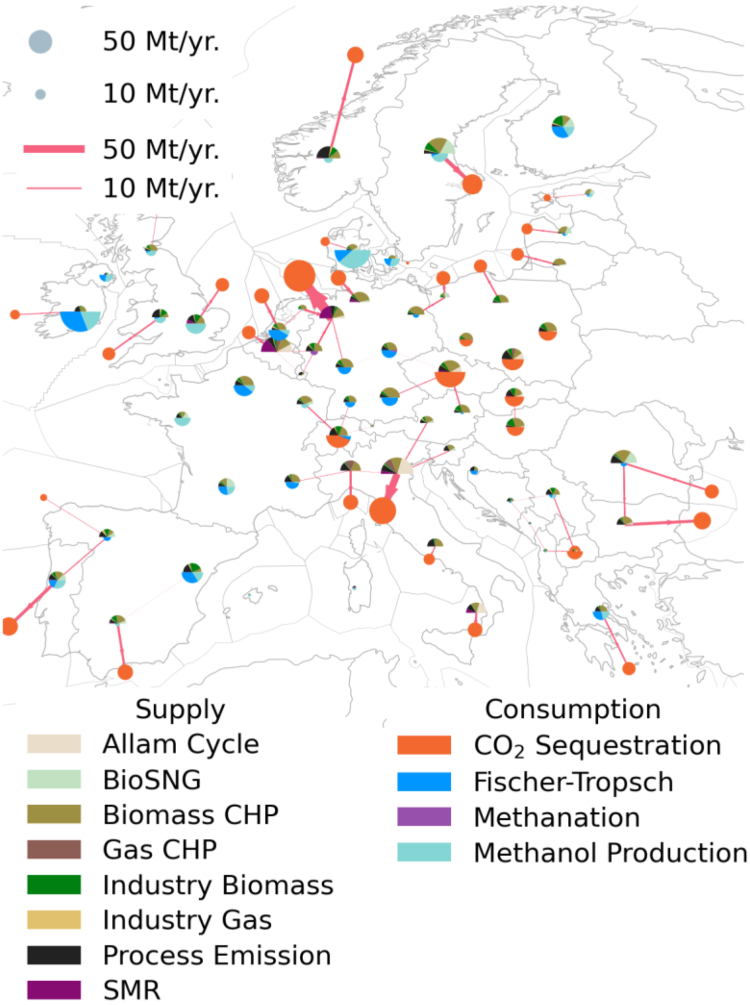


Figure 19 shows only limited transport of CO_2 between clusters as it is expensive to install CO_2-pipelines. One example of cross-border CO_2 transport is Austria, which has no potential for long-term storage. Instead, some of the CO_2 captured in Austria is transported via pipelines to Italy and the Czech Republic. However, there are still few remaining pipelines overall, as by 2050 pipeline capacities are endogenously built to transport a maximum of 21 kt of CO_2 per hour between clusters. As a result, the model does not deem an extensive CO_2 pipeline network to be necessary and instead favours regional carbon management via green methanol production and Fischer-Tropsch synthesis.

6.2 Benefits of European Integration

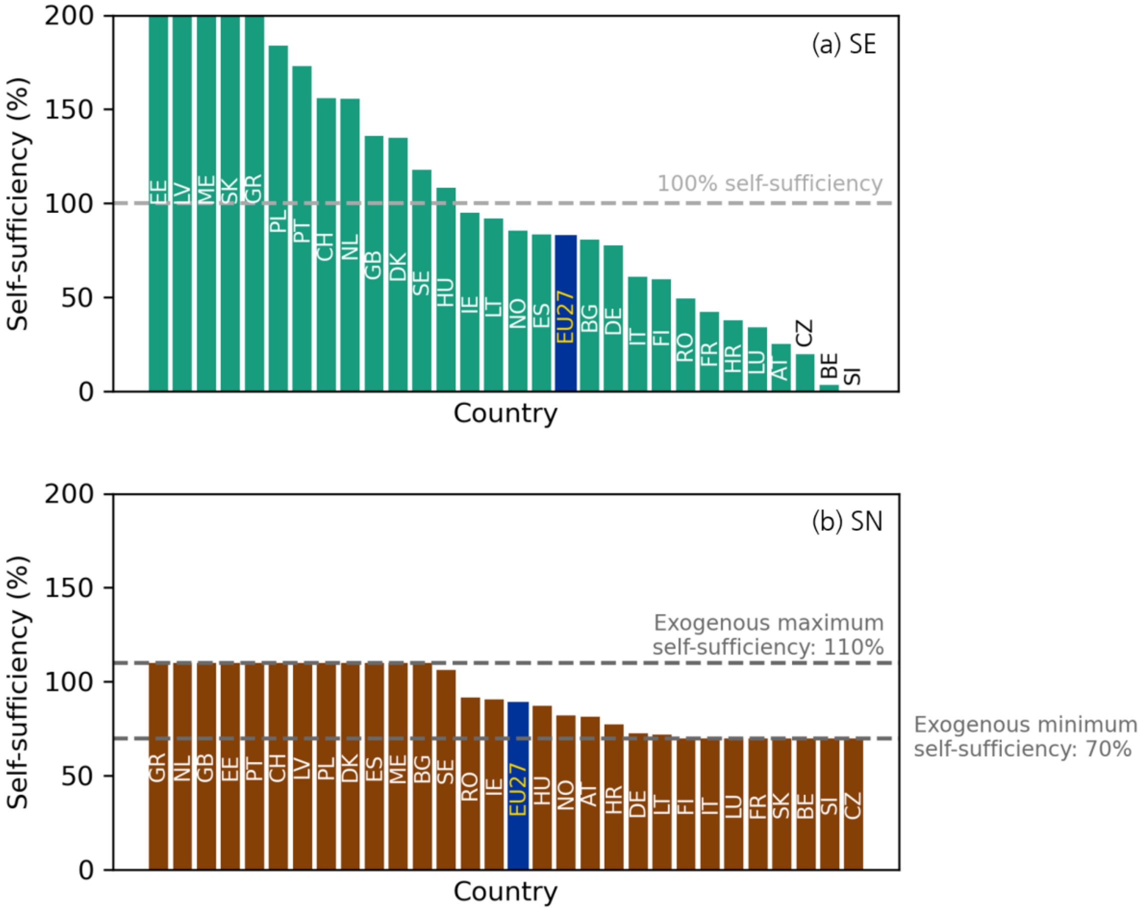
This section discusses the results for the **"SE" Scenario** (**S**ectoral, **E**uropean view), which assumes sectoral grid planning in silos with simultaneous European harmonisation of capacity expansion for energy supply, i.e. relaxing the constraint on the maximum annual import shares for electricity and hydrogen as described in section 4. This relaxation means that, although EU-wide optimisation of meeting national demand is achieved, does not consider sector-coupling technologies in the planning processes.

6.2.1 Optimal Imports and Exports of Electricity and Hydrogen

When looking at today's power systems, most countries are largely self-sufficient in terms of their annual electricity production. While electricity is still imported and exported throughout the year on an hourly basis, the annual balance indicates that the majority of countries cover most of their electricity demand as shown in Figure 53 in the Annex 3: Supplementary Figures for the year 2022. When looking at the SN scenario, the self-sufficiency target has an impact on smaller countries like Estonia. It is an exporter with 117% self-sufficiency in the sectoral, European scenario (SE) and will need to decrease its exports to reach an annual self-sufficiency of 100% in the SN scenario. On the other hand, Luxembourg and Belgium, which are importers in the SE scenario with 77% and 75%, have to produce more electricity in the SN scenario to achieve the exogenous target of 100%. Larger countries in Europe like France, Spain and the UK, but also the EU itself, all have a self-sufficiency degree between 96 and 103% in 2050, even in the SE scenario. Therefore, enforcing 100% self-sufficiency in 2050 in the electricity sector does not significantly affect many countries.

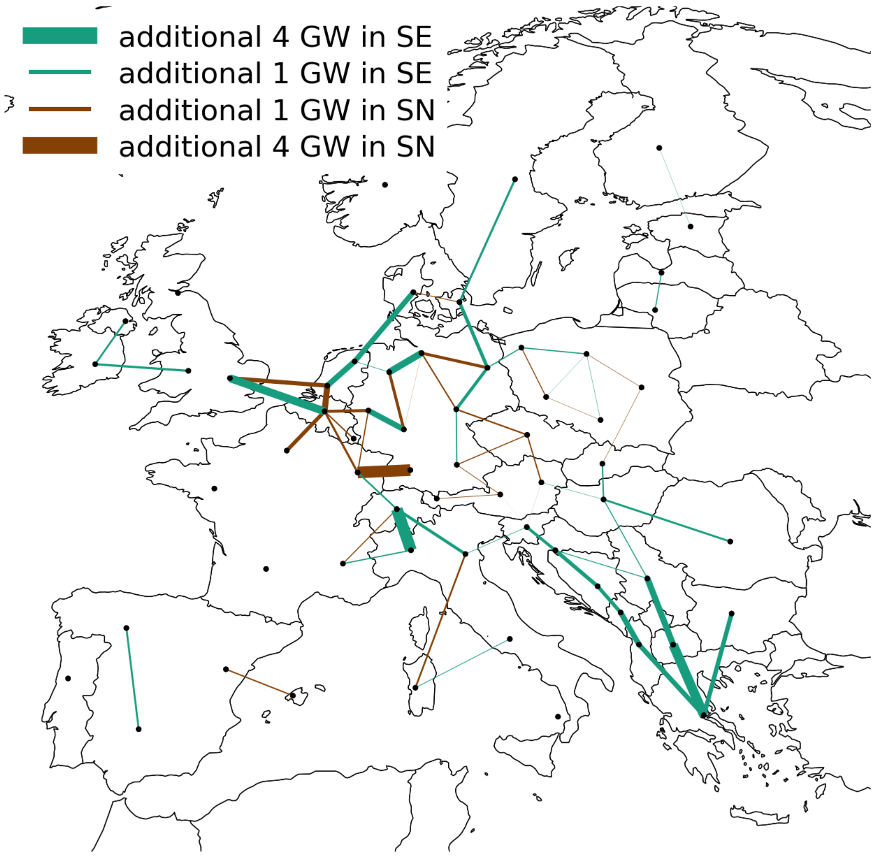
The hydrogen system, by contrast, is has yet to be developed. Thus, scenarios with European optimisation can freely allocate hydrogen production in countries with high potential for the production of cheap, renewable energy. Figure 20a shows the resulting self-sufficiency levels for hydrogen in 2050 of countries in such a European optimisation, more specifically the SE scenario. A large discrepancy can be observed, with some countries exporting more than their national consumption in hydrogen and others like Belgium and Slovenia relying almost entirely on imports. A high degree of self-sufficiency can either indicate that a country has very low national hydrogen demand, like Estonia or Latvia, or that it has very high renewable potentials, and is supplying a large proportion of European hydrogen demand, like Poland, Denmark or the UK. The recipients of the exported hydrogen are countries with a large consumption of hydrogen like Germany, France, and Belgium. This wide range of self-sufficiency levels is drastically constrained when moving from European to national planning in the SN scenario in Figure 20b. When countries decide to rely less on hydrogen imports, 13 of the total 33 countries modelled in this study have to increase their national production of hydrogen from electrolysis or steam methane reforming. Therefore, national tendencies when planning hydrogen infrastructure will lead to a significant redistribution of hydrogen production capacities away from the best regions in Europe with cheap, renewable energy.

Figure 20: Levels of annual self-sufficiency for hydrogen (a) without any national targets (SE scenario) and (b) with exogenously set national targets (SN scenario) in 2050.



In terms of hydrogen pipeline infrastructure, the sectoral silo scenarios (SN and SE) are dominated by large overcapacities due to using the H_2-infrastructure map as an exogenous input until 2040, irrespective of a European or a national approach. As such, the two silo scenarios assessed in this project, SN and SE, do not reveal significant differences in terms of hydrogen infrastructure. The same holds for the electricity network, which is determined by the TYNDP projects until 2040.

Figure 21: Comparing electricity transmission capacity in the SN scenario with the SE scenario in 2050.



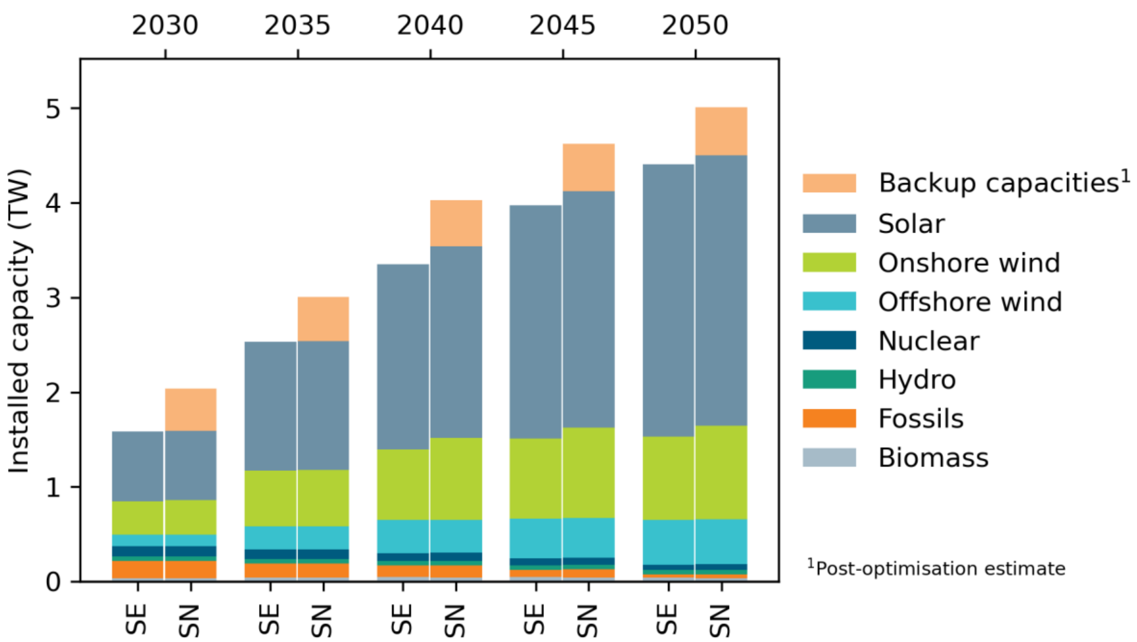
Nevertheless, Figure 21 shows some differences in the need for electricity infrastructure between the sectoral silo scenarios SN and SE because of the influence of self-sufficiency targets. The colour and thickness of the lines show how much more transmission capacity is installed in 2050 in one scenario compared to the other. In the SE scenario (green), larger interconnector capacities are installed all over Europe compared to the national counterpart. In particular, the routes in the Balkan countries are much more noticeable. However, some interconnector capacities are larger in the SN scenario than in the SE scenario. In total, European optimisation results in 5 TWkm of additional capacity in cross-border electricity interconnectors. These differences in installed capacity are relatively small in the context of the total electricity network with 315 TWkm in the SN scenario. However, these differences are much more pronounced in the cross-sectoral scenarios, with 18 TWkm of additional interconnector capacities in the CE scenario compared to the CN scenario. These 18 TWkm are equivalent to 10% of the interconnector capacities in the CE scenario. Figure 54 in the Annex shows the differences at regional level and highlights the greater need for interconnection in the North Sea region and the Balkans. These differences illustrate how national targets for increased generation capacity within countries also lead to a less interconnected Europe.

6.2.2 European Coordination of Generation Capacities

One essential aspect of imposing minimum annual production targets for hydrogen and electricity in the national scenarios is the need for additional renewable capacity in countries with less favourable renewable energy potential.

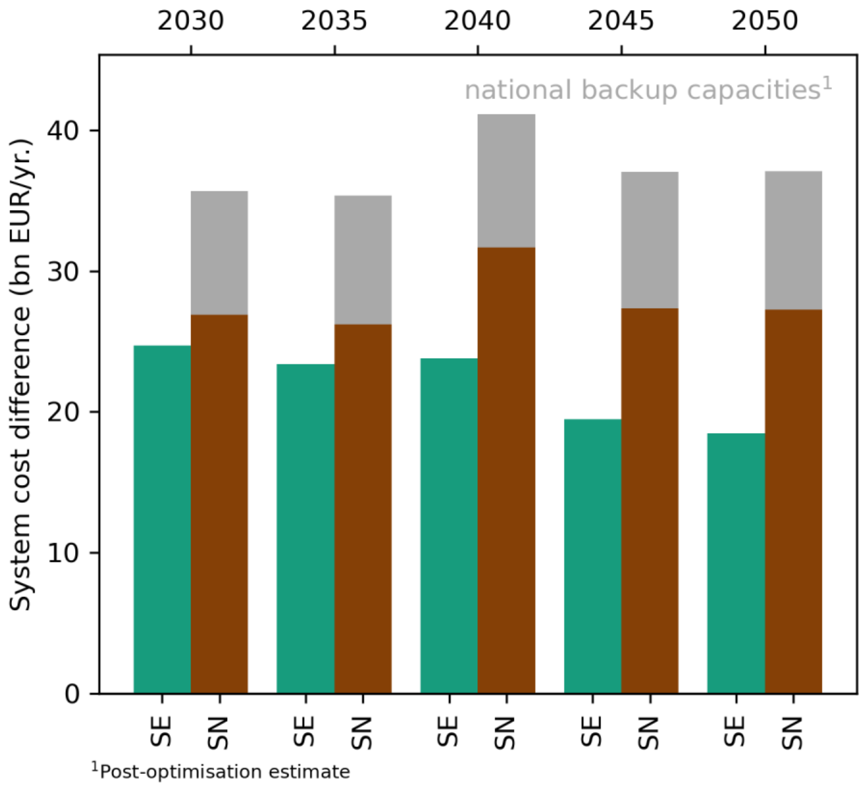
The consequence of this increased need for renewable capacity is illustrated in Figure 22, which shows the total capacity installed in the energy system between 2030 and 2050 to produce electricity in Europe. The SN scenario features higher wind and solar energy capacities than the SE scenario. These capacities amount to an additional 118 GW of renewable capacity installed system-wide. This increase is relatively low compared to the total installed capacity because the national constraint also causes a redistribution of generation capacities. For example, this shift can lead to reducing PV capacity in Greece by 47 GW and increasing PV in Belgium by 23 GW. However, these capacities are still installed in coordination among countries as the model always optimises the energy system as a whole. As discussed in Chapter 6.1.1, in addition to these endogenously optimised generation capacities, we estimated the backup capacity that would be needed for each country to cover its maximum residual exogenous load. This national planning of backup capacities is only attributed to the scenarios incorporating the national view (SN, CN). Therefore, in Figure 22, an additional 505 GW can be seen in the SN scenario compared to the SE scenario that results from this post-optimisation analysis. Thus, our study indicates that integrating the European view reduces the renewable and backup capacity needed by 623 GW.

Figure 22: Installed capacities for electricity generation in Europe for the sectoral, European scenario (SE) and the sectoral, national scenario (SN).



If implemented, these backup capacities would not be used as they are not required by the endogenous optimisation. Even if they were used, their full-load hours would be negligible, allowing investment in the cheapest available and also flexible technology – gas turbines. These gas turbines would require an additional annuity of 8.8 to 9.9 billion Euros per year. These costs, along with the residual costs compared to the cost-optimal solution (CE scenario) are illustrated in Figure 23. It shows the annual system costs including investments, fuel and operation costs caused by non-integrated planning in the SE and SN scenarios and highlights the impact of a nationally focused policy dimension. The coloured bars show the additional annual costs resulting from non-integrated planning of 26 to 32 billion euros in the SN scenario, and 18 to 25 billion euros in the SE scenario. The discrepancy between the two scenarios can be largely attributed to the increasing need for electricity generation capacity. If we also consider the 8.8 to 9.9 billion Euros per year from national tendencies when handling peak loads (shown as grey bars) in the SN scenario, total additional costs of up to 17 billion euros per year can result compared to European optimisation (SE scenario). These results underline the importance of coordinated planning, not only of transmission infrastructure but also of power-generation capacities across national borders.

Figure 23: Additional annual energy system costs compared to the cost-optimal energy system in the sectoral, European (SE) and national (SN) scenarios.



6.3 Benefits of cross-sectoral Integration

In the following, we compare the SN scenario with the cross-sectoral, national (CN) scenario. In the CN scenario, infrastructure development is optimised endogenously in each country, as described in Chapter 4. We therefore assess the benefits of integrated infrastructure planning compared to planning in sectoral silos. The effects and benefits of this integrated planning approach are outlined in the following sections.

6.3.1 Mitigating Overinvestments due to Sectoral Grid Planning

The sectoral policy dimension contrasts endogenous optimisation with more fragmented sectoral grid planning like the TYNDP. Up to 2040, the electricity and hydrogen networks in the SN scenario are determined by and limited to projects in the TYNDP, the H_2 infrastructure map and the German hydrogen core grid. Only after 2040 is the model allowed to optimise the electricity and hydrogen networks endogenously.

Figure 24: Annualised investments in infrastructure in different sectors in the cross-sectoral, national (CN) and the sectoral, national (SN) scenarios.

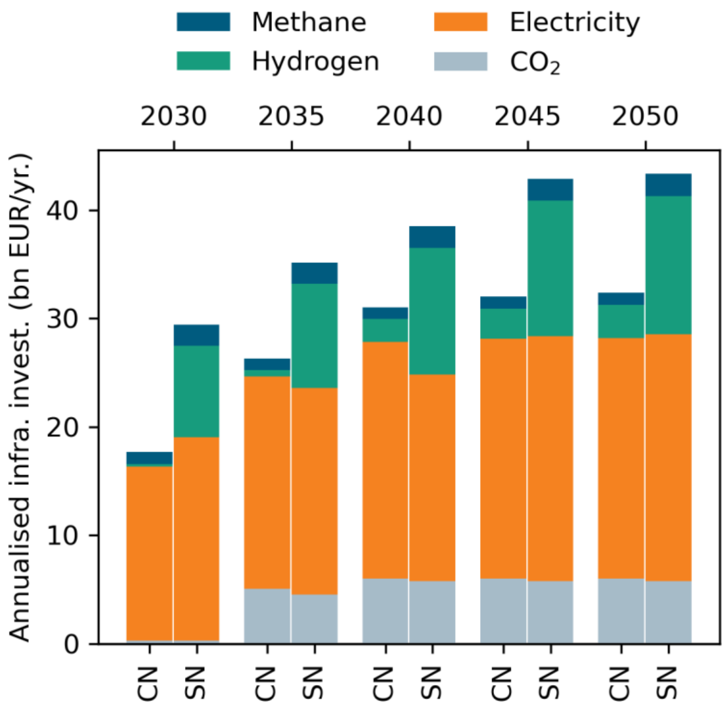


Figure 24 compares the annualised investments in the CN scenario with the SN scenario. These include the costs for all networks optimised in the model: CO_2, electricity, hydrogen, and methane (transporting natural, synthetic and biomethane). The investments in the CO_2 network are relatively similar in both scenarios as there are no exogenous plans for developing this network in the SN scenario. Concerning investments in electricity networks, they are lacking behind up to 2040 in the sectoral silo scenario SN which is driven by the TYNDP 2022 projects compared to the endogenous optimisation in the cross-sectoral scenario CN. As soon as endogenous expansion is allowed in the last decade of the SN scenario, the annualised investments in electricity transmission infrastructure are similar to the CN scenario. For the methane network, the investments for the last optimisation years are due to the annualization of older pipelines. The additional projects stemming from TYNDP results in an average overinvestment of 0.9 billion euros for electricity and methane infrastructure, each. The largest cost difference, however, can be seen in the hydrogen network. In 2030, the endogenous optimisation in the CN scenario does not yet invest in hydrogen pipelines, while Europe's hydrogen grid planners already foresee significant investments in earlier years as discussed in section 6.1.2. Even when the model builds more pipelines in later years, the investments in the CN scenario are only 24% of those in the SN scenario in 2050. Figure 24 illustrates how the existing plans for network expansion lead to additional investments and highlights that cross-sectoral planning could save up to 11 billion euros annually in infrastructure investments.

Figure 25: Methane gas infrastructure capacity installed in Europe according to TYNDP and from existing or endogenously built pipelines in the sectoral, national (SN) and the cross-sectoral, national (CN) scenarios.

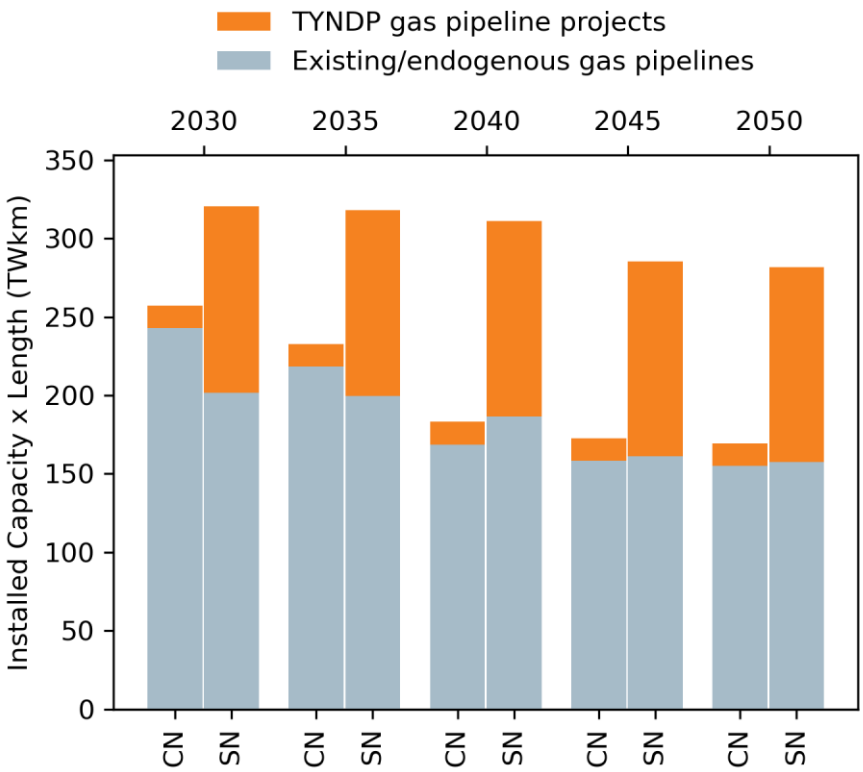
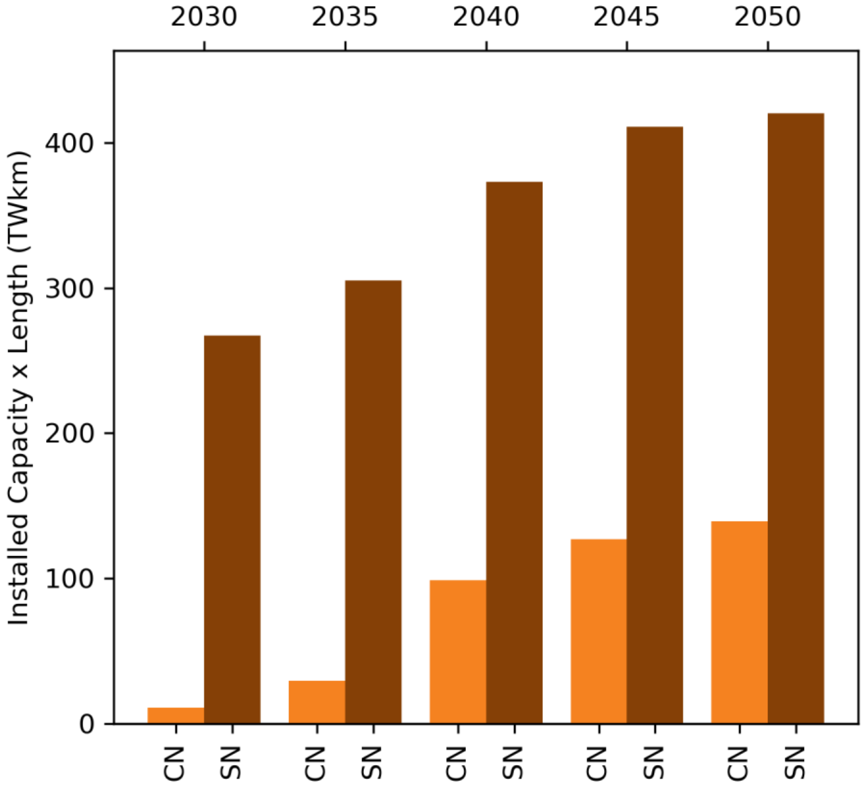


Figure 25 compares the aggregated European methane pipeline network in the CN and SN scenarios. Its size is quantified as the product of capacity multiplied by the length of each individual pipeline segment, aggregated over the entire network. The graph distinguishes existing or endogenously built pipelines, shown in grey, and expansion based on TYNDP plans, shown in orange. The endogenous expansion of the methane network is only of minor importance; the differences between scenarios are negligible. Both scenarios show a general trend towards a decrease in methane pipeline capacity by 2050. One notable observation is that the pipeline system in the CN scenario is consistently smaller than that in the SN scenario throughout the observation period. The orange-coloured bars indicate that the capacity expansion in the TYNDP is the main reason for the differences between the two scenarios. In the SN scenario, extensive and early retrofitting of natural gas pipelines to transport hydrogen leads to a reduction in existing pipeline capacity compared to the CN scenario, although this reduction is compensated for by a significant increase in capacity based on the TYNDP. An anomaly occurs in 2040, when the existing capacity in the SN scenario (grey bar) exceeds that of the CN scenario. The endogenous retrofitting of natural gas pipelines to transport hydrogen provides a logical explanation for this counterintuitive event. In the SN scenario, the development of the hydrogen network begins earlier and is based on both retrofits and newly built pipelines. In the CN scenario, on the other hand, the expansion of the hydrogen network starts later and is primarily achieved by retrofitting existing natural gas pipelines. In combination with the decreasing demand for gas, this leads to a stronger reduction of the existing capacities in the CN scenario, which increases the overall difference in the total capacity of the pipelines. An overarching conclusion is that the sectoral strategy in the SN scenario results in a larger gas pipeline system than in the CN scenario, which does not appear to be cost-optimal given the general trends in the European energy system.

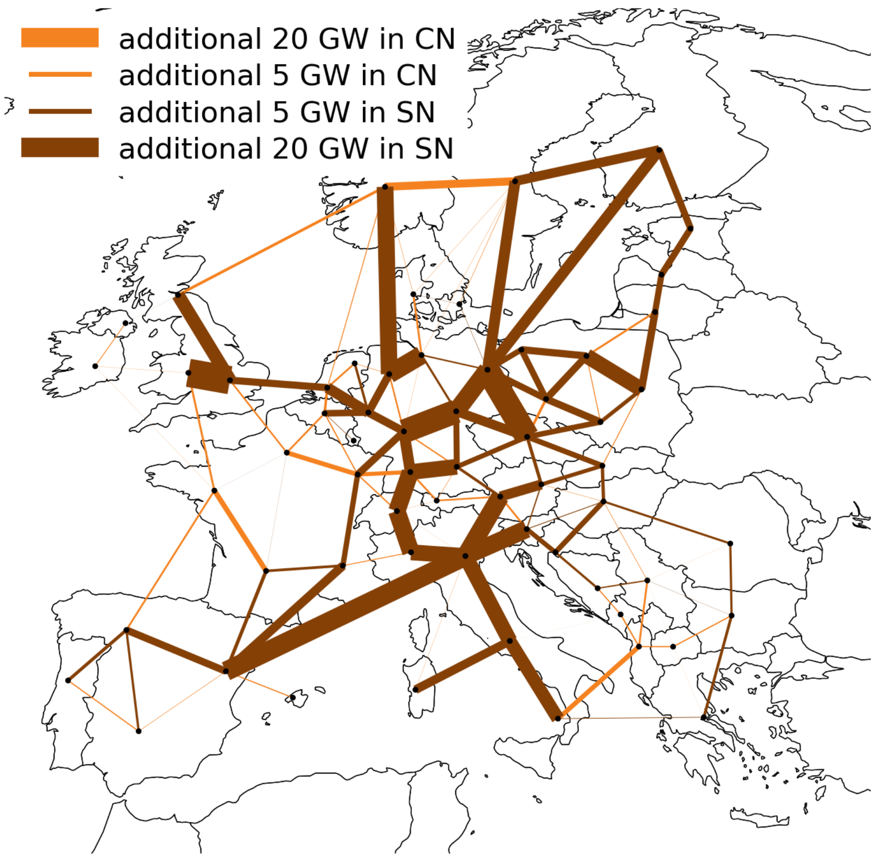
Figure 26: Total installed capacity of the hydrogen network in Europe scaled by length to compare the expansion in the cross-sectoral, national (CN) scenario and the sectoral, national (SN) scenario.



As the largest differences in the sectoral policy dimension appear in the hydrogen sector, we discuss this in more detail here by comparing the installed capacity in TWkm of the hydrogen network in the cross-sectoral, national (CN) scenario and the sectoral, national (SN) scenario. Under endogenous optimisation in the CN scenario, the hydrogen network increases gradually over time with the highest expansion of 69 TWkm in 2040, as hydrogen demand for synthetic fuels rises significantly in this year to comply with the exogenous CO_2 reduction pathway. Despite the strong endogenous expansion in the CN scenario in 2040, the hydrogen pipeline capacities in the SN scenario, which are based on the exogenous inputs of the H2-infrastructure map and the German hydrogen core network, are 3.8 times higher than in the CN scenario. Even after the SN scenario is allowed to expand the hydrogen network endogenously, in 2045 and 2050, additional capacity is still needed to cover the areas that are underrepresented in the infrastructure network plans. Finally, in 2050, the hydrogen network planned with sector integration (scenario CN) could be three times smaller than the network planned in sectoral silos based on the H_2-infrastructure map and the German hydrogen core network (scenario SN) and would avoid unnecessary overinvestment in infrastructure.

6.3.2 Developing Consistent Infrastructure Throughout Europe

Figure 27: Difference in the hydrogen pipeline capacities installed in the cross-sectoral, national (CN) and the sectoral, national (SN) scenarios in 2050.

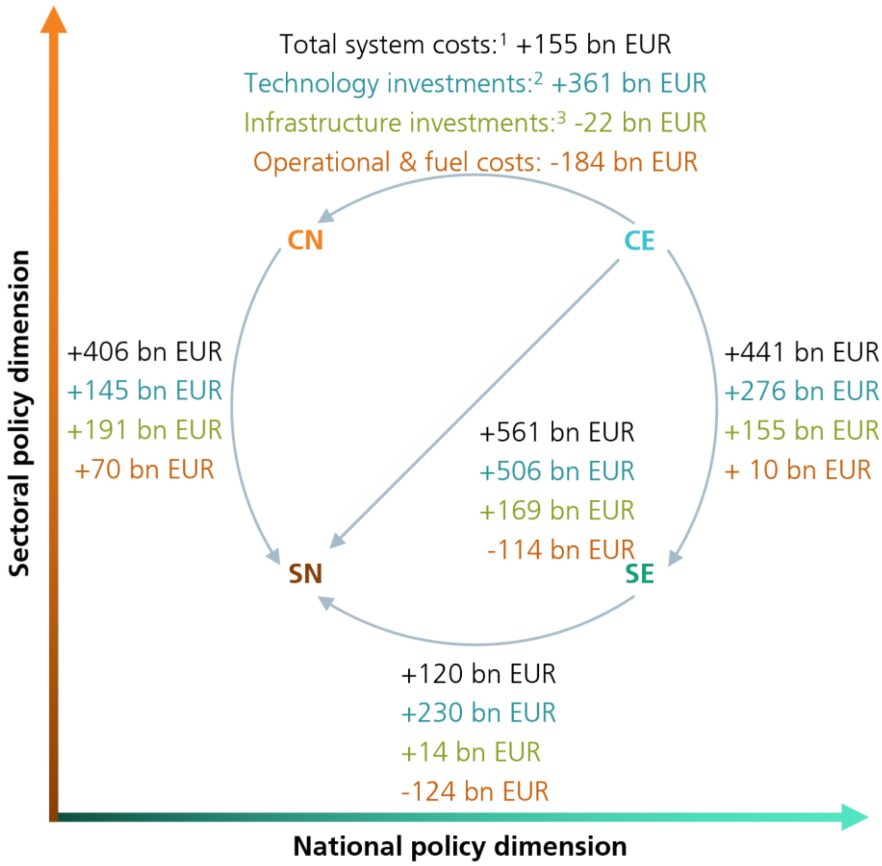


Looking at the geographical distribution of the hydrogen transport network (see Figure 27) reveals marked differences between sectoral and cross-sectoral planning. Figure 27 shows any additionally installed capacity in a scenario-specific colour. The SN scenario's pipelines are shown in brown, those of the CN scenario in orange. The thick brown lines once again highlight the overcapacities resulting from the hydrogen network plans in the SN scenario. However, there are also higher pipeline capacities in the cross-sectoral, fully endogenous hydrogen network of the CN scenario. Most prominently, France plays a larger role in the system resulting under the CN scenario. In addition, the CN scenario sees hydrogen from Norway not only exported to Germany but also to Sweden and the UK. A similar trend can be observed in Southeast Europe. While the H_2-infrastructure map foresees hydrogen supply to Central and Northern Europe mainly from mainland Italy, endogenous expansion puts more emphasis on submarine pipelines through the Adriatic Sea. These examples highlight a general trend: The existing hydrogen infrastructure plans focus on fewer transport routes with much higher capacity, whereas the construction of a hydrogen network based on sector-integrated optimisation features more diverse connectivity with lower overall capacities.

6.4 Benefits of Integrated Infrastructure Planning

The two previous sections showed how the integration of different sectors when planning infrastructure, and the coordination of efforts on a European level can avoid overcapacities in transmission infrastructure and generation capacities. These overcapacities would cause additional costs for the energy system of up to 32 billion euros per year (mainly stemming from annualised investments in generation, transformation, and transmission technology). When cumulated over the whole transformation period, the much higher cost of non-integrated planning becomes very obvious.

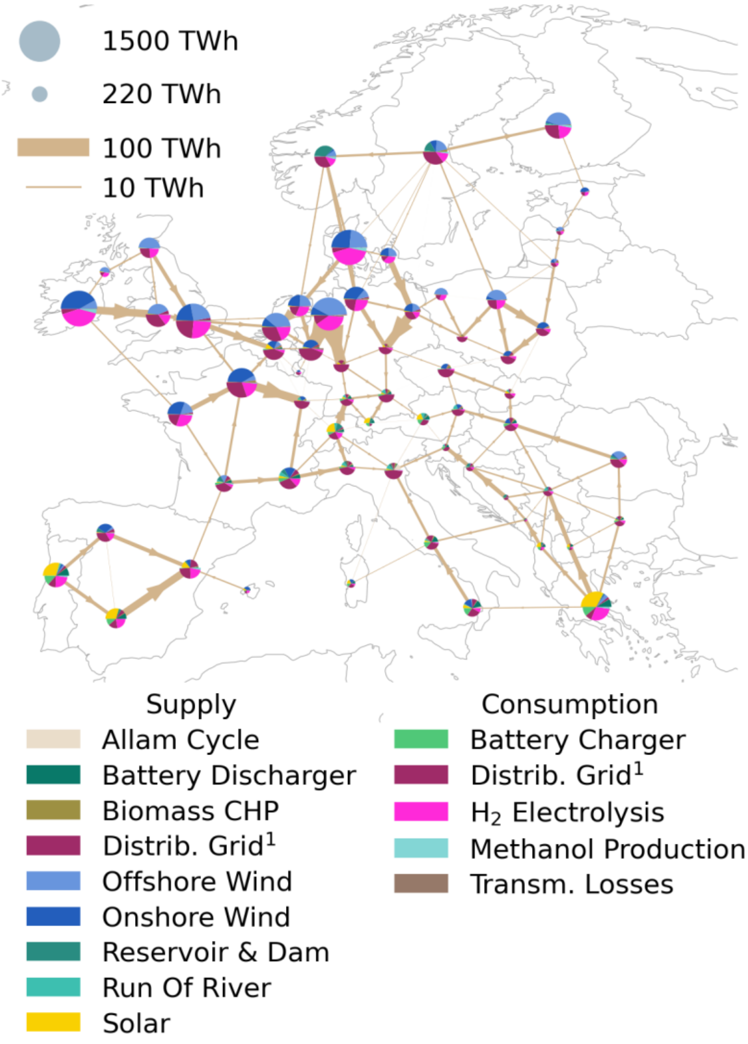
Figure 28: Total system costs due to non-integration, including capital and operational costs, cumulated over the timespan between 2030 and 2050.



[1]Capital, operational and fuel costs
[2]Power generation, heat generation, storage and transformation technologies (e.g. H_2 electrolysis)
[3]Electricity, hydrogen, methane and CO_2 network

Figure 28 compares the energy system costs from optimisation (excluding back-up capacities) that are accumulated over the timespan between 2030 and 2050 between the four scenarios. The figure shows the total system costs, including capital costs, operational costs, and fuel costs, and cumulated investments in infrastructure and technology, including electricity and heat generation as well as transformation processes such as H_2 electrolysis. For example, when comparing the cross-sectoral, European (CE) scenario with the sectoral, national (SN) one, **we see maximum cost savings of 561 billion euros from geographical and cross-sectoral integration**. Technology savings make the largest contribution here. Note that the sum of the technology and infrastructure costs are larger than the total savings, as in the SN scenario (to which the other three scenarios are compared), less fuels are imported and hence less fuel costs occur compared to the CE scenario. Figure 28 also indicates that national tendencies are most detrimental in an energy system that also operates in a sector-integrated manner, and that cross-sectoral integration is most beneficial with a European view. When considering the investment costs in unused backup gas turbines, which are not included in Figure 28, an additional 188 billion euros of overinvestments would be added to the national dimension. This suggests that infrastructure planning that integrates the different sectors and a European perspective could achieve energy system cost savings of up to 749 billion euros in the period between 2030 and 2050 including optimisation results and post-optimisation estimates.

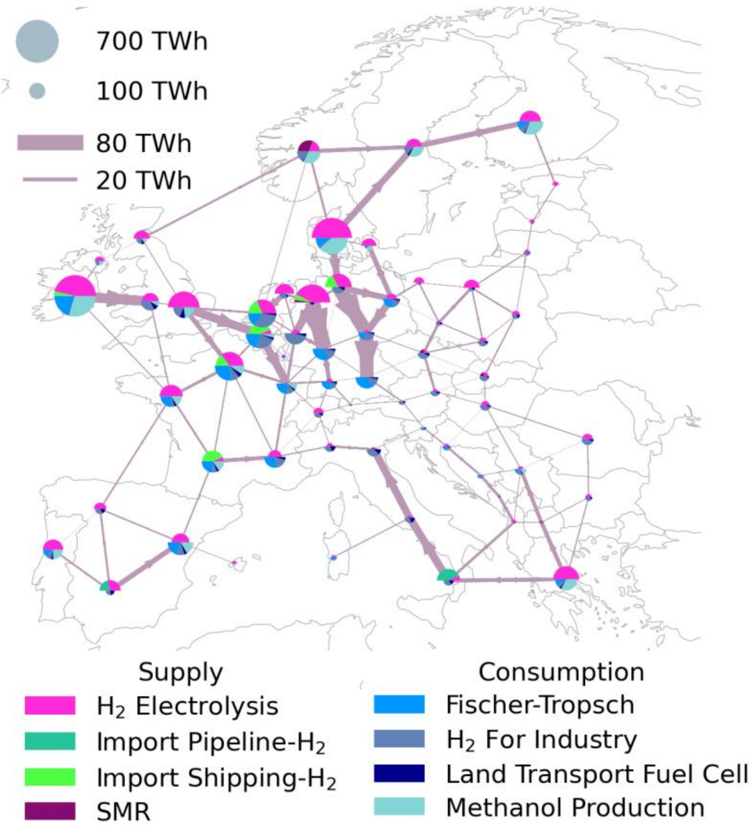
Figure 29: Optimised annual electricity production, transport & consumption in the CE scenario's grid planning in 2050 [48].



[1]End consumers and suppliers from distribution-grid level.

The electricity system plays a critical role in such a cost-optimal energy system. Even though the model can build transmission lines endogenously as needed, most clusters produce the electricity they consume, aggregated over the year. This observation can be drawn from Figure 29, which illustrates the electricity produced, transported, and consumed on a regional level in the cross-sectoral, European (CE) scenario in 2050. For each cluster, the upper semi-circle in the pie chart shows the electricity produced by different energy sources, while the lower semi-circle provides an overview of the consumers. For the transmission grid, the distribution grid can be both a supplier and a consumer by generating electricity via rooftop photovoltaic and vehicle-to-grid and using electricity to meet household demand and charge electric vehicles. Pie charts featuring semi-circles of the same size indicate equal production and consumption in the annual balance. However, there can still be significant transmission of electricity between clusters during certain periods. This is illustrated by the connecting lines, which show the annual average transmission and the main direction of its flow. These transmission lines show that clusters with higher imports are mainly supplied by their direct neighbours, like in Central Germany or South Poland. It becomes clear when comparing transmission in 2050 with transmission in 2030 in Figure 50 that there has been an increase in the need for electricity exchange between certain clusters, for example, in Spain, Poland, or the Balkan countries. Additionally, longer, pan-European electricity transmission corridors can be observed transporting solar power from Greece and wind power from Denmark. Therefore, cross-sectoral, European optimisation results in significant exchanges of electricity between clusters and longer transmission routes.

Figure 30: Optimised annual hydrogen production, transport & consumption in the CE scenario's grid planning in 2050 [48].



Hydrogen production in the CE scenario is more concentrated in regions with high renewable energy potential. In Figure 30, the upper semi-circles in the pie charts that represent hydrogen production are largest around the North Sea, where wind potentials are high and in the Southern clusters of Spain, Italy, and Greece that have high solar generation potentials. Additionally, in some clusters like South Italy and along the North Sea coast, hydrogen is also imported via pipelines or by ship. The latter also includes ports with import infrastructure for hydrogen derivatives, which then enter our model as hydrogen. Unlike the electricity sector, many clusters have large differences between hydrogen production and consumption. Clusters with high hydrogen consumption either have to meet high industrial demand, such as Western Germany, or need hydrogen for Fischer-Tropsch synthesis or methanation to avoid CO_2 emissions or expensive CO_2 pipelines. The latter can be observed in Finland or in Southern Germany, which have no potential for long-term storage of their CO_2 emissions. Here, longer pipeline transport of hydrogen produced from inexpensive renewable energy is favoured in the model over local hydrogen generation. Such longer supply routes are established from Denmark to Finland and as a North-South connection in Germany or Italy. Even over shorter distances, high volumes of hydrogen are traded across borders. This suggests that transporting hydrogen remains significant even though the overall pipeline capacity in the hydrogen network is lower in the CE scenario (see for the full resulting hydrogen infrastructure). Fully integrated planning of hydrogen infrastructure enables sensible scaling of H_2 pipelines, allowing for large transport volumes in order to profit from low electricity prices in regions with favourable renewable energy potential. It makes it possible to use and combine the properties and strengths of the different energy carriers and infrastructures and to link sinks and sources cost-effectively.

The role of CCS in relation to fossil fuels, is a very limited one: In the CE scenario 486 Mt CO_2 are captured in 2050, of this only around 20% are linked to remaining fossil fuels, mainly natural gas. Overall, CCS has its most important role in the biogenic carbon cycle (negative emissions).

6.5 Phasing out Methane from the Energy Mix

The remaining natural gas consumption in 2050 in the different scenarios was not a major focus of the present study. For this reason, methane uses were not constrained in the scenario modelling -, but – as discussed in section 6.1.3 – there is a strong decrease in methane gas demand (**including natural gas, bio-methane or synthetic methane**) happening in all modelled scenarios. There is, however, a rational to fully phase-out fossil methane, in particular:

- Concerns about supply security, although, already in the modelled scenarios the amount of imports from outside the European area is much smaller compared to current imports,
- Risk of increasing energy cost, as evidenced during the period 2022-2024,
- Resource considerations (which remain even for domestic production),
- Concerns about the necessary compensation of direct emissions from natural gas with CCS,
- Concerns about upstream emissions of natural gas (e.g. from upstream methane leakage and upstream CO_2 emissions)[13].

In this section, we therefore outline results from a sensitivity where the remaining methane uses are reduced to zero. **It is important, however, to emphasise that this sensitivity reduces also bio-methane and synthetic methane uses and represents therefore a conservative approach**.

We first discuss the remaining methane supply and demand in the cross-sectoral, European (CE) scenario – which represents the most efficient infrastructure scenario in the modelling exercise – and compare it with present methane uses. We then present the sensitivity where methane is excluded from the model solution space. Finally, we carry out an in-depth discussion of the results and address the question of why the main scenarios in our modelling analysis still have a gas network in 2050.

Remaining methane supply and demand in the CE scenario

Figure 17 shows that 3592 TWh of methane[14] are still needed in 2030 for the EU27 in the SN scenario, to supply the energy demand for heating in industry, as well as for buildings, and for electricity production (mostly covered by natural gas imports and local production) in the EU. Over the two decades until 2050, the gas demand and supply then decreases to 19% of 2030's numbers. Figure 31 presents the same view of methane demand and supply of the EU for the CE scenario. In that case, the methane demand in 2050 is reduced even further **to 13.7% of the methane demand in 2030**. This remaining gas demand is covered mainly by natural gas with biomethane playing a role as a transitional supply.

As discussed in section 6.1.3, despite this drastic decrease in demand for methane gas, even in 2050, some natural gas demand for heating and electricity production remains in the system. The demand part of Figure 31 (lower half) shows that the remaining users of methane (including natural gas, bio-methane and synthetic methane) are mainly:

[13] Upstream emissions of fossil fuels are not considered by PyPSA (especially when occurring outside Europe). Only downstream, direct combustion-related emissions within the modelling region are compensated, not impacts outside the modelling region. Upstream emissions can vary strongly across the different origins of fossil fuels.

[14] Compared to 4026 TWh natural gas for the period 2020-2023, and 3580 TWh natural gas in the first year after the start of the Ukraine war in 2022.

- remaining gas boilers in buildings and central heat-only supply, partly converted to synthetic methane or biomethane (48% of the methane demand in 2050);
- gas turbines for electricity generation (substantially reduced compared to 2030) (20% of the demand), as well as CHP units (14%);
- industrial processes (11%);
- steam-methane reforming for the production of synthetic methane from blue hydrogen (or grey hydrogen in early years) (6%).

Some more detailed analysis of the figures for methane uses in buildings (decentral and central heat), as well as for electricity production:

- *Methane uses in buildings (decentral and central heat, the latter from central heat-only schemes and CHP):*
  - Compared to the consumption of natural gas-based heating today the absolute reduction in natural gas use is massive: In the EU (CE Scenario) 304 TWh of methane is remaining for heating purposes in buildings (which includes methane for small scale heating in residential and service sector buildings, as well as large scale heating of buildings through heat only and CHP plants), compared to 1700-1800 TWh in the period 2020-2023 for those purposes[15]. This represents a 83% reduction compared to the present. It must be emphasized that only part of the remaining methane is natural gas; it further includes biomethane and synthetic methane: Though these different methane sources cannot be separated with the present model settings, the largest part is nevertheless linked to natural gas (we estimate the share to around 90%). With respect to **decentral heat supply to buildings**, only 54 TWh methane remain in the system in the CE scenario, **representing less than 4% of today's decentral heat supply to buildings based on natural gas.** The same holds for a large EU Member State such as Germany, with 80 TWh of methane remaining in 2050 (CE scenario) for the small- and large-scale heat supplies to buildings, while today around 492 TWh are consumed for those purposes in the period 2020-2023. This corresponds to a similar reduction as in the case of the EU27 as a whole. Also there, remaining decentral methane uses for heat in buildings represent only slightly more than 4% of today's natural gas demand.
  - From the modelling perspective, it must further be considered that the model does not analyze the changed grid charges with lower load, nor decision making processes of natural gas customers in a dynamic perspective, while the gas demand is shrinking. **Hence, potentially higher natural gas prices resulting from low natural gas grid uses, could enhance decision making of natural gas users to switch to cheaper options.**
- *Methane uses for electricity generation:*
  - Table 3 illustrates that in the CE scenario, only around 40.6 GW of new gas turbines (GT) are built in Europe until 2030, and no further increase is seen up to 2050. More than half of this investment happens in Eastern Europe. Italy also requires a large part of this investment for backup power when solar irradiation is low. In Germany, only 3-4 GW are built in the CE Scenario (again up to 2030). These gas turbines are powered by a mix of biomethane and natural gas. The emissions from natural gas combustion that are not directly captured on-site (by CCUS) must be compensated by negative emissions elsewhere (Carbon Dioxide Removal CDR Technologies). These negative emissions largely arise from the production of biomethane from biomass and from the use of biomethane and biomass in processes that include carbon capture.

[15] Eurostat: Supply, transformation and consumption of gas [nrg_cb_gas__custom_18076088]

Figure 31: Methane gas demand and supply in the EU in the cross-sectoral, European (CE) scenario.

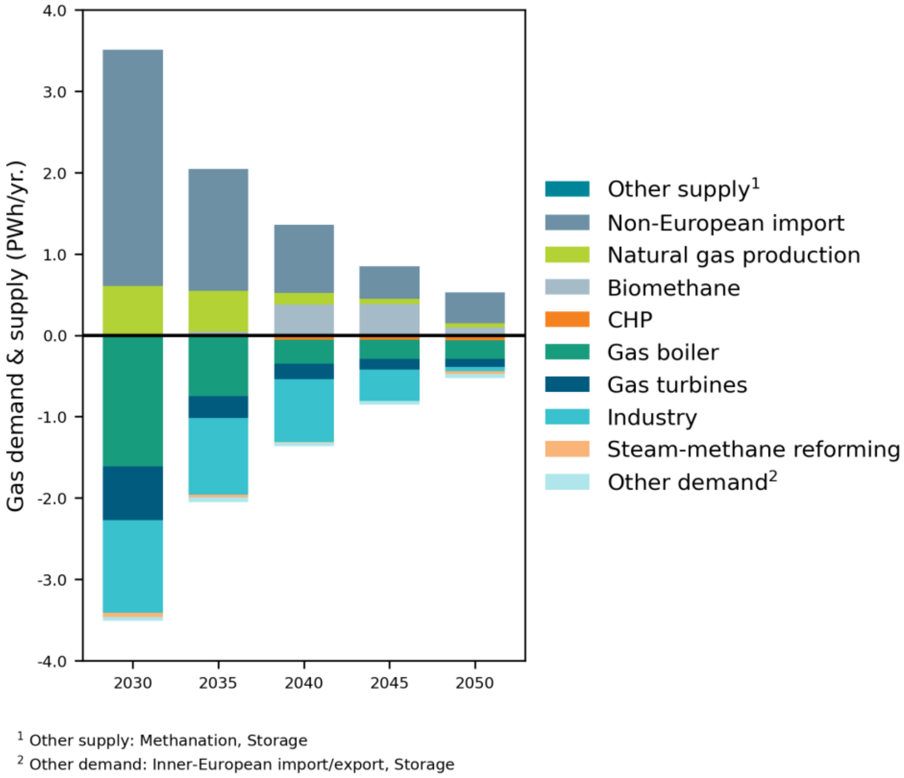


Table 3: Newly built gas turbines (GT) in GW in the CE Scenario by country.

Country	2030
Bulgaria	3.82
Germany	3.58
Estonia	0.15
Finland	0.00
Greece	0.60
Hungary	1.51
Italy	14.36
Lithuania	0.09
North-Macedonia	2.10
Poland	3.33
Romania	4.64
Slovakia	6.40
Total	**40.58**
Eastern/South-Eastern countries	*22.04*

Note: European countries not in the list have no new gas turbines in the CE scenario. No new gas turbines are built after 2030 (except one small increase in Finland in 2050, but which is within the error margins)

The very moderate expansion of gas turbines until 2030 is also reflected in the evolution of the methane pipeline network. The capacity of a few pipeline routes is expanded until 2030. As illustrated in Table 4, this additional capacity is mainly needed in Eastern and South-Eastern Europe. Here, 9.54 of the 24.46 TWkm are set exogenously in accordance with the TYNDP project database (see Annex 2: Implementation of Current Infrastructure Planning), while the remaining 14.92 TWkm are built based on endogenous optimisation. As explained above, the CE scenario includes only TYNDP projects in a comparatively advanced stage. Similarly, 43% of the German pipeline expansion are exogenous TYNDP pipelines. For the full European modelling region, 37% of expansion of methane pipeline capacity is set according to TYNDP. Of these 14.46 TWkm from TYNDP pipeline projects, most remain unused as 9.75 TWkm feature an average utilisation below 5% in 2050, even in the CE scenario where the smallest amount of exogenous pipelines is set in the model. Therefore, most exogenous capacity expansion in the methane network is not required in an energy system, for which integrated, co-optimised and cross-sectoral analysis of energy infrastructures follow - as much as possible - the most efficient pathway to the expansion of energy infrastructures.

In addition, for the large majority of the already existing methane gas network, the size of the network does not match the need for methane transport in future decades: thus, the decreasing role of methane in energy supply offers the opportunity to use the existing methane gas network as well as small short-term additions to the gas grid until 2030 as the basis for some emerging hydrogen backbone as described in Section 5.3 (although the backbone may be realised to a smaller degree as currently envisaged). Table 4 also shows the strong decrease in the overall pipeline capacity due to the repurposing to hydrogen pipelines. In 2050, 156 TWkm of methane pipeline network remain in the energy system, most of which are remaining pipelines from today's network. As discussed before, the model cannot decommission unused gas pipelines, even though 105 TWkm of the pipelines remaining in the system in 2050 show an average utilisation below 30%. This observation, together with the major retrofitting in our model, underlines the finding that, overall, natural gas plays a subordinate role in the future of the energy system.

Table 4: Newly built methane pipelines in TWkm in the CE Scenario (major countries/regions).

	until 2030	2030-2035	2035-2040	2040-2045	2045-2050
Total methane pipeline network (TWkm)	**250.73**	**215.8**	**176.26**	**165.99**	**156.49**
Total new methane pipelines built in the respective periods (TWkm)	**38.83**	**0.42**	**0.00**	**0.05**	**0.15**
Exogenous TYNDP projects included in the CE scenario	*14.46*	-	-	-	-
Eastern/South-Eastern Europe	24.46	-	-	-	-
Germany	9.12	-	-	-	-
Italy	2.05	-	-	-	-

Sensitivity with remaining methane uses reduced to zero

The main scenario runs discussed so far included the use of natural gas-based technology in combination with negative emissions and carbon capture. This result is subject to high uncertainties: under slightly different conditions, the optimisation could opt for a solution with no or substantially reduced endogenous methane gas demand while total system costs increase only by a small amount ("flat optimum"). We therefore explore in this section sensitivities where natural case is excluded from the solution space of the model.

In a first step (Figure 32), both natural gas and fossil oil were excluded from the power mix and from heating.

Figure 32: Sensitivity run (year 2050) for the CE Scenario "No Fossil Gas & No Oil" (assumptions and results) for the full European modelling region.

Assumptions

- Electricity from natural gas: no expansion
- Heat from natural gas: no expansion
- Heat from fossil oil: no expansion
- No oil imports in 2050

- Increasing demand for synthetic fuels
- Increasing hydrogen demand covered by SMR
- Natural gas remains part of energy system through blue hydrogen

Results for 2050

	CE main scenario	Sensitivity (no gas, no oil)
Electricity generation capacity from methane	73.9 GW	0 GW
Electricity generation capacity from hydrogen	0 GW	82.2 GW
Hydrogen generation SMR	61 TWh	550 TWh
Hydrogen generation electrolysis	1764.3 TWh	1682.1 TWh
Primary energy demand methane	500.5 TWh	802.9 TWh
Synthetic fuel generation (Fischer-Tropsch synthesis)	512.7 TWh	710.5 TWh
Primary energy demand oil	232.9 TWh	0 TWh
Annualized total system costs	807 bn €	838 bn €

Main results:

- Phasing out gas yields the use of hydrogen in the electricity sector where hydrogen-fired power plants are then used as a flexibility option in the power sector and an ever larger deployment of heat pumps provide space heating in the buildings sector.
- There is an increasing demand for synthetic fuels (given that fossil oil is fully removed from the system) as well as an increasing hydrogen demand met by steam methane reforming (SMR).
- Consequently, natural gas remains in the system in the form of blue hydrogen and requires compensation through CCS even though it is fully phased out in the conversion and end-use sectors.
- This outcome highlights the impact of the uncertainties in some of the parameters:
    - There is a large amount of methane which will be used for steam reforming in 2050. This methane is needed to meet the increased demand for hydrogen for Fischer-Tropsch synthesis (in order to produce the necessary liquid fuels which compensate the phasing out of fossil oil).
    - In this step of the sensitivity, steam methane reforming with CCS will have to come into the modelling results, as the potentials for expanding electrolysis for hydrogen production further, is limited. In Spain and Italy, for example, the exogenous PV expansion corridors are being fully utilized, which limits the expansion of further electrolysis plants. Thus, if more renewable energy expansion were possible for the model, one would expect more electrolysis instead of blue hydrogen. This would imply, for example, the revision of trade-offs between competing land-uses.
- The annualised total system costs rise from 807 to 838 billion Euro by excluding natural gas and fossil oil from the system.

In a second step (Figure 33), carbon dioxide removal (CDR) technologies were assumed to be more expensive to impede the model from picking solutions that rely too strongly on negative emissions.

Figure 33: Sensitivity (year 2050) for the CE Scenario "Expensive Carbon Dioxide Removal (CDR) technologies" (assumptions and results) for the full European modelling region.

Assumptions

- +50% capital costs for technologies enabling negative emissions

- Natural gas gains importance through technologies with carbon capture
- Negative emissions remain essential even when more expensive

Results for 2050

	CE main scenario	Sensitivity (no gas, no oil)
Electricity generation capacity from methane	75.2 GW	73.3 GW
Electricity generation capacity from hydrogen	0 GW	0 GW
Hydrogen generation SMR	88.1 TWh	113 TWh
Hydrogen generation electrolysis	1773.2 TWh	1531.2 TWh
Primary energy demand methane	495.5 TWh	682.5 TWh
Synthetic fuel generation (Fischer-Tropsch synthesis)	509.1 TWh	225.2 TWh
Primary energy demand oil	236.7 TWh	521.9 TWh
Annualized total system costs	804 bn €	886 bn €

Main results:

- Negative emissions still remain essential, even when more expensive.
- However, increasing the cost of Carbon Removal Technologies (negative emissions) by 50% leads to a similar amount of natural gas and oil as in the main scenarios, but by replacing natural gas in combination with CDR by Gas Turbines (GT) combined with CCS. This further reinforces the message of the main scenarios.
- Hydrogen conversion back into electricity will still not be part of the system. In addition, large quantities of synthetic fuels will be imported from outside the system boundaries.
- The annualised total system costs rise from 807 to 886 billion Euro as the costs for negative emission technologies were raised.

A major conclusion from the three sensitivities is **that fossil fuels still find a way into net-zero energy systems as long as the deployment of cheap renewables, especially wind power and solar PV, is constrained by the limits currently implemented in the model.** More deployment of renewables can be realised through steps such as:

- increasing the capacity corridors for RES to ensure availability of cheap hydrogen (for this purpose competing land-uses will have to be re-evaluated);
- increasing the cost for gas & oil import;
- decreasing the cost for hydrogen imports/ increase import capacities.

Discussion: Why do the main scenarios in the modelling analysis still have a gas network in 2050?

In this section, we shed more light on the question of why the main scenarios in this modelling approach still have gas networks in 2050. This result is at first counterintuitive, and therefore needs to be explained, and should not be overinterpreted. As explained above, most pipelines remain unused and simply are not decommissioned, as the model is not programmed to do so. But for the remaining few pipelines that still transport methane in 2050, the short explanation for the result is: Flat optimum and uncertainties, i.e. the costs of solutions including natural gas in electricity and heat generation, are very similar to those solutions which exclude natural gas in these sectors. **Also, the contribution of methane the energy system in 2050 is far from having the same importance as today**.

Methane use, including biomethane and synthetic methane, is **six times smaller than today**. Furthermore, the model creates an emission budget for a small amount of fossil fuels due to the negative emissions resulting from the production of biomethane from biomass and from the use of biomethane and biomass in processes that include carbon capture.

The flat optimum within the space of solutions means that several options are so close to each other in terms of key economic parameters in the model, at the same time that the uncertainty of these parameters is relatively high. The flat optimum concerns the last remaining hard-to-abate applications, for which climate-neutral options are not currently used and/or are likely to be rather expensive.

An example of this outcome can be seen in the technological choice for back-up capacities for peak power plants. Several options for power supply in times of low renewable generation exist:

- hydrogen power plants with access to hydrogen network,
- hydrogen storage power plants, without network access but with electrolysers and a cavern storage on site
- biogas or biomethane power plants, (currently used in the model, although the opportunity cost of the energy carriers will increase because the model must use its climate neutral hydrocarbons wisely)
- methanol or ammonia power plants,
- gas power plants with CCS with access to the gas network and access to the CO_2 network
- unabated gas power plants, the emissions of which are compensated with negative emissions elsewhere in the modelled European region, for example by sequestering atmospheric CO_2

Depending on the techno-economic assumptions, all of these options can be part of an economic solution, but the uncertainty regarding their costs, technical characteristics and the public acceptance of the CCS technology is high. Thus, while the model must make a choice, small changes in the assumptions can lead to very different results. With the parameters chosen for our main scenarios (e.g. available renewables deployment potentials, industrial demand), the model finds that a cost-efficient option for supplying residual demand includes natural gas, partly without CCS, but with compensation of the emissions in Europe primarily through the use of biomass and biomethane in combination with carbon capture. This result is again somewhat counterintuitive ("Why not capture the emissions at the power plant?"), but the peak power plants have a very low utilisation, and therefore the high investment into the capturing process cannot be justified –it is simply cheaper to capture emissions for example from biomethane production, in a process that runs almost continuously, to offset the emission in the few running hours of the peak power plants fired with natural gas.

Given the closeness of the utility of the options, understanding the flat optimum means acknowledging that in real life, the best combination of back-up power plants still needs to be researched and discussed, and ultimately will depend on future developments of the technology options as well as local conditions. The complex questions regarding whether, or to what extent, CCS could or should be part of Europe's decarbonisation strategy need to be addressed, as well as the strong ramifications these decisions will have on the gas infrastructure. The present study simply focuses on a different question (the integration of energy infrastructures), rather than exploring in detail the flat optimum of a residual amount of natural gas and consequent uncertainties.

The question of gas versus hydrogen power plants will also have implications on the extent to which the remaining natural gas network will be further repurposed to hydrogen and to what extent a natural gas network will be utilized. In our current model results, large parts of the natural gas network will be repurposed to hydrogen and the remaining gas network will run on an average utilization rate of well below 50% (depending on the scenario). A stronger use of hydrogen in peak power plants would accelerate this process of decommissioning or repurposing of transport networks for natural gas. Most parts of the distribution networks for natural gas will be decommissioned in any case as the remaining applications for natural gas are dominantly central and therefore do not need natural gas in distribution networks.

7 Regional Case Studies

When analysing the transition towards a climate-neutral energy system in Europe and its evolving energy infrastructure, we see different regions taking up different roles in the transition. Looking at regional examples helps to illustrate the interplay between countries and sectors. While many regions deserve a more in-depth analysis, in this study we focus on the wider regions of Poland and the Baltics in Chapter 7.1, as well as the Benelux Countries / North-West Germany in Chapter 7.2. These cases enable insights into a disaggregated manner, inter alia with a view to the role of wind energy and industrial energy demand.

7.1 Poland and the Baltics

Poland and the Baltic countries Latvia, Lithuania and Estonia will play a central role in 2050's energy system for Central and Eastern Europe. Thanks to their location at the Baltic Sea, the four countries each have offshore territories that can be used to produce wind energy.

Figure 34: Installed capacity in offshore wind turbines in Poland, Lithuania, Latvia and Estonia.

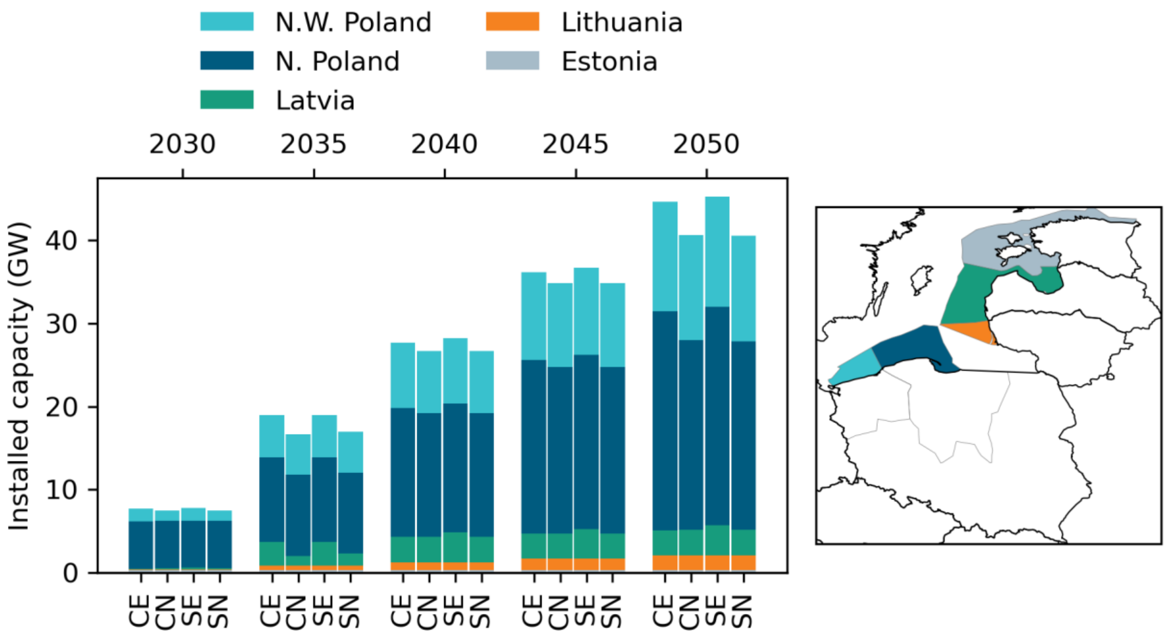
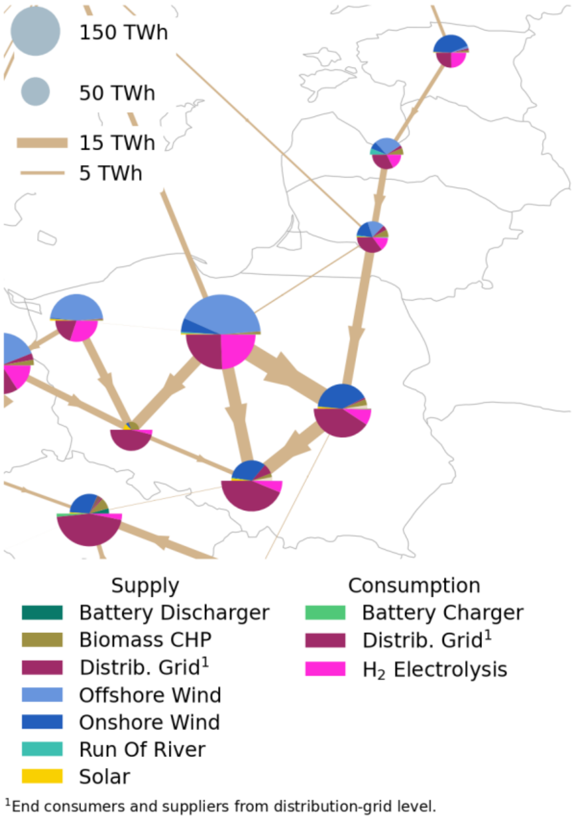


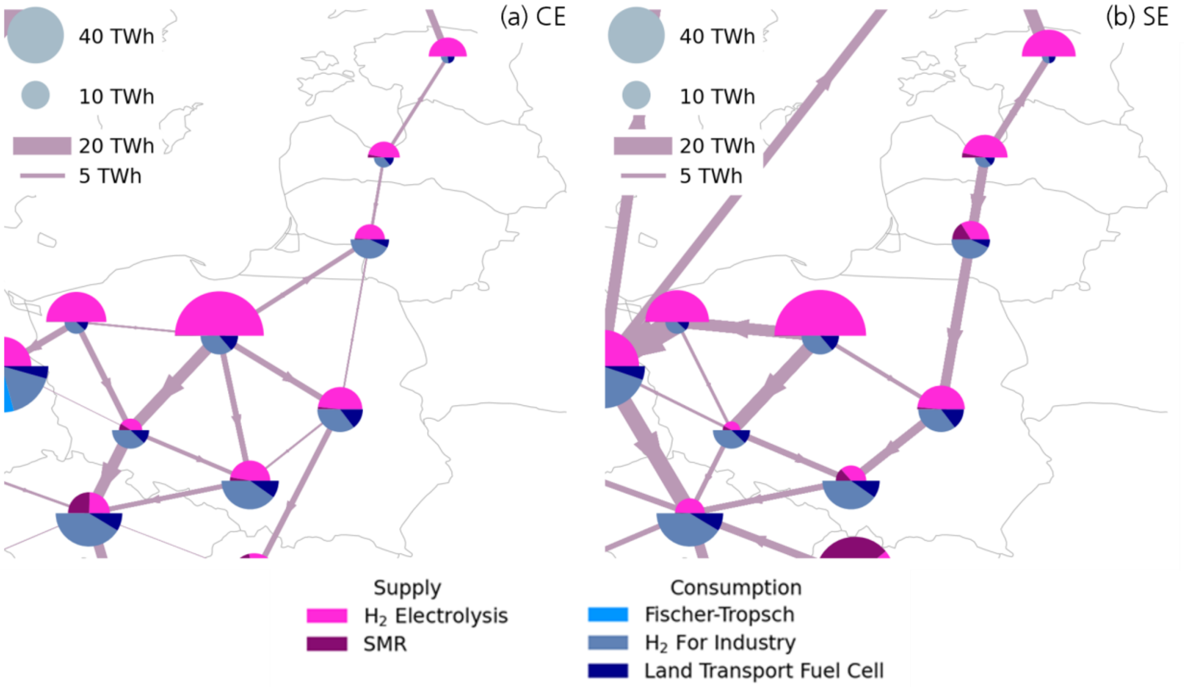
Figure 34 shows the installed offshore wind capacity on a cluster level for each year and scenario. While in 2030, the offshore wind capacities still reflect the exogenous Polish expansion target, the following years offshore wind power even exceeds policy targets. Thereby, we see a strong increase in PL from 0 GW today to 36-40 GW in 2050. The capacities are predominately located in Poland while 1.8 GW of offshore wind power are installed in Lithuania and 3 to 3.6 GW in Latvia. In the case study region, we see the largest deployment of offshore wind power in our two European scenarios, most significantly in the cross-sectoral, European (CE) scenario.

Figure 35: Electricity production, consumption and transport resulting from cross-sectoral, European (CE) optimisation in 2050 [48].



If we look at electricity produced by these offshore wind capacities (Figure 35), we see that the majority of offshore wind in 2050 stems from the Eastern Polish offshore regions with 114 TWh, while the Western territories produce 57 TWh. This overview of the electricity system under cross-sectoral, European optimisation (CE) in 2050 in Figure 35 showcases not only the electricity produced from offshore wind power plants but the total electricity produced in each cluster in the upper semi-circle. The lower semi-circle visualises the electricity consumption. In the coastal clusters of Poland and Estonia, around half of the electricity demand comes from H_2 electrolysis, while the other part is accumulated electricity demand from the electricity distribution system, serving the industry and the residential sector. The latter poses a large exogenous electricity demand in the South and East of Poland, where renewable potentials are comparatively low, causing it to be supplied by wind energy from Northern Poland and Lithuania. These transport pathways are visualised by the connecting lines, with their width indicating the amount of transported energy and the arrow pointing in the direction of transport. These transmission flows also show that the clusters in Southern Poland are not only supplied by Polish electricity but also from the West via Germany and the other Baltic countries.

Figure 36: Hydrogen production, consumption, and transport in 2050 in the European scenarios with (a) cross-sectoral (CE) and (b) sectoral grid planning (SE) [48].



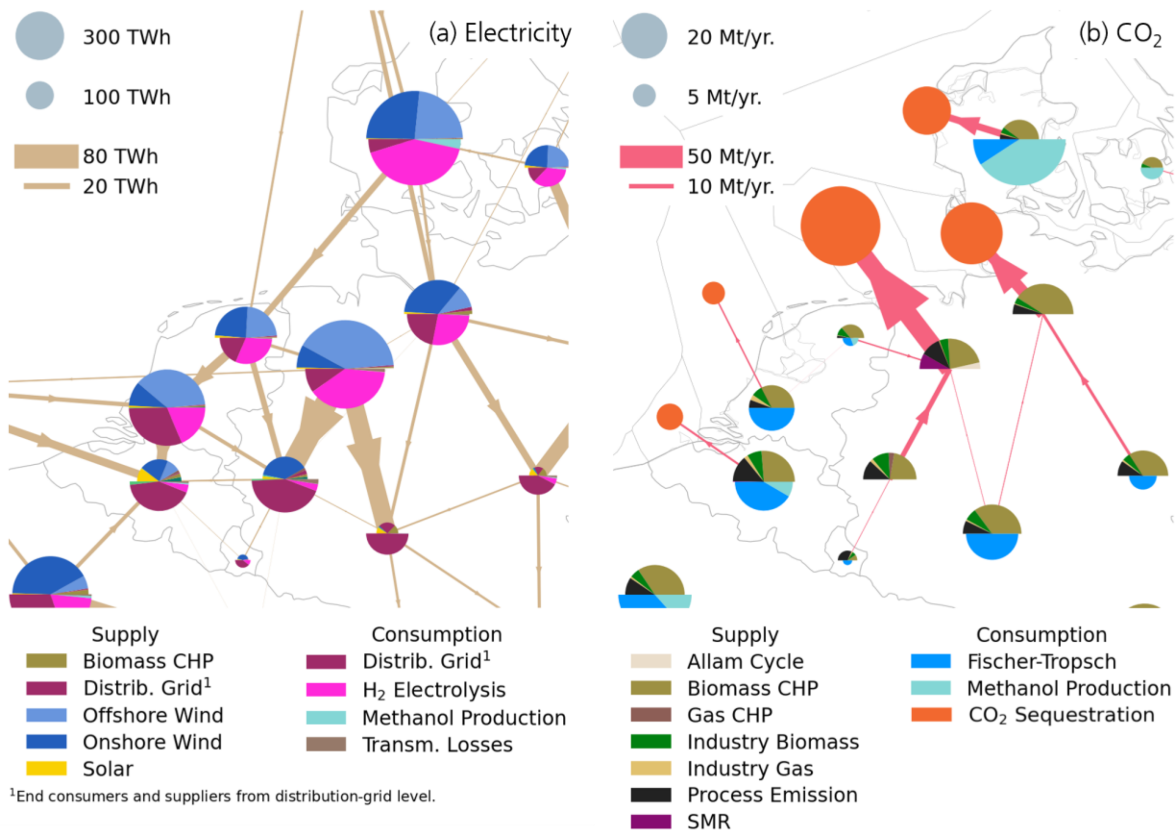
A significant part of the electricity consumed in Poland is used to produce hydrogen beyond its own demand. Figure 36a shows the hydrogen sector in terms of production, transport and consumption in 2050 resulting from fully integrated optimisation (CE scenario). The hydrogen that is mostly produced using electricity from wind power in Poland and the Baltic countries is needed to support the industrial transition to hydrogen-based processes, and to a certain extent for the use of fuel-cell transport in each cluster. In the CE scenario, there is no hydrogen demand to produce synthetic fuels.

Aside from meeting their own hydrogen demand, the countries in the Baltic regional case study also export hydrogen to neighbouring countries. Estonia exports to Finland, where it is needed for CCU in the production of methanol and for Fischer-Tropsch synthesis. Poland exports hydrogen to the Czech Republic as illustrated by the arrows in Figure 36a, when the hydrogen grid is endogenously built. These transport corridors change, though, once the hydrogen network is mostly restricted to the existing infrastructure plans from the H_2 infrastructure map in the sectoral, European (SE) scenario in Figure 36b. The Nordic-Baltic hydrogen corridor is used to transport hydrogen from Latvia via Poland to Central Europe and hydrogen from Estonia and Latvia is exported to Finland. Since Poland an Germany are also very interconnected in the exogenous hydrogen projects, Poland uses these connections to export its hydrogen, which is then further distributed to Scandinavia, the Czech Republic and the rest of Germany. Therefore, implementing current plans for the hydrogen infrastructure might even solidify the role of the Baltic offshore wind energy for hydrogen supply in the region.

7.2 Benelux Countries and North-West Germany

Western Germany, Belgium and the Netherlands are one of the centres of European industry. [49] At the same time, the region is one of the most densely populated areas in Europe. [50] These two factors can lead to challenges in the energy supply unique to this region. At the same time, these countries are all located at the North Sea, which has gained a lot of attention for its potential of offshore wind for energy supply. [51] For these reasons, we take a closer look at the Benelux region and North-Western Germany to lay out their potential role in the future energy system.

Figure 37: Production, transport and consumption of (a) electricity and (b) CO_2 in the cross-sectoral, European (CE) scenario in 2050 [48].

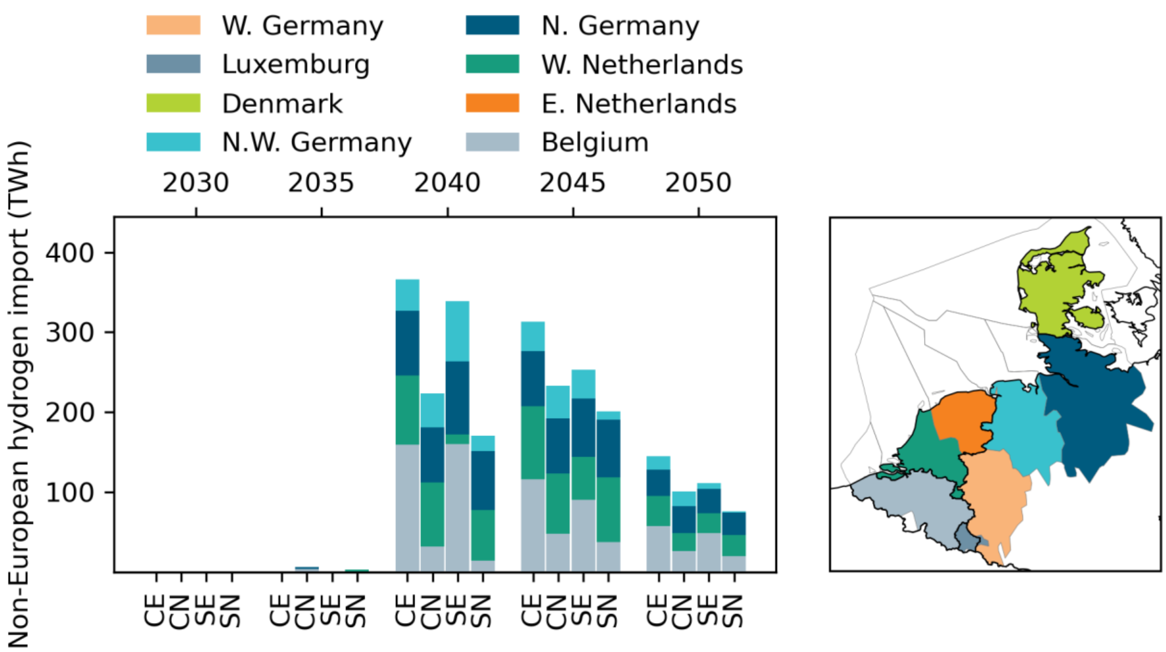


The regional differences already become apparent when looking at the electricity system in Figure 37a. Here we see electricity production (upper semi-circles), consumption (lower semi-circle) and transmission-level transport directions (arrows) in the year 2050 that result from optimisation in the cross-sectoral, European (CE) scenario. Figure 37a shows the significance of both onshore- and offshore wind energy for the region, while specifically offshore wind is most relevant in the Western Netherlands and the North-West of Germany. Large amounts of this wind energy are not used to supply exogenous electricity demand but instead produce hydrogen via electrolysis in these clusters with cheap electricity. In North-West Germany alone, 146 TWh of hydrogen are produced in 2050. In addition, Denmark does not play a large role in the electricity supply of the region as its large wind potentials are mainly used for hydrogen production. Apart from their role in the hydrogen production, the clusters neighbouring the North Sea are also supplying electricity to clusters with shorter or no coastline. Most prominently Belgium and Western Germany only cover 66 and 60 % of their electricity demand by "within cluster" generation. As far as Belgium is concerned, the country also imports electricity from the UK and France.

These regions with high population density and industry not only feature large energy demands but also related high CO_2 emissions. The modelled CO_2 capture sources are shown in Figure 37b in the upper semi-circles, illustrating that most of the CO_2 in 2050 is produced by biomass-based technologies (to facilitate negative emission) and in industrial processes. It also highlights another important role of the offshore regions for the Benelux countries and Germany as storage sites for captured CO_2. Especially German North Sea regions have large sequestration potentials, fully storing their own emissions. In addition, CO_2 pipelines are built from neighbouring clusters to transport CO_2 to its final storage. The remaining clusters in this region require CCU for carbon management as further transport to storage sites is not deemed cost-optimal by the model. This decision by the optimiser can be based on the combination of synthetic fuels being produced under the least expensive conditions and the exogenous Europe-wide limit for sequestration making other regions more urgent candidates for CO_2 storage. Thus, even Belgium and the Netherlands, which have some offshore sequestration potential, utilise CCU. In sum, the North Sea territories of Germany, the Netherlands and Belgium are relevant for supplying the region including the clusters without a coastline with electricity and providing storage capacities for CO_2.

With the large relevance of Fischer-Tropsch synthesis and green methanol production for the usage of CO_2 in the Netherlands, Belgium and Western Germany, hydrogen demand also increases substantially. Belgian, Dutch and German harbours at the North Sea coast could thus become relevant for the import of liquid hydrogen or hydrogen derivatives from outside of Europe in the future to benefit from "co-location" of CO_2 and H_2 supply.

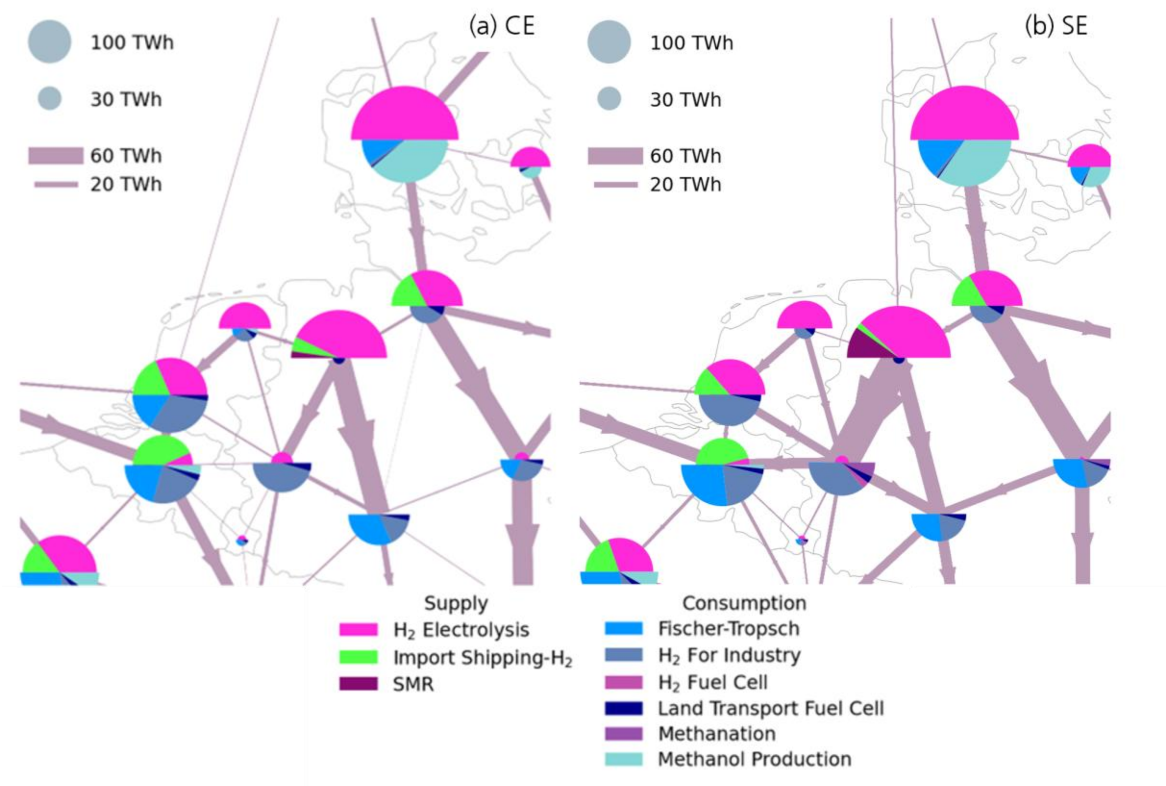
Figure 38: Hydrogen (also in form of derivatives) imports from outside Europe to the clusters in the case study regions between 2030 and 2050 in all scenarios.



Accordingly, Figure 38 shows the import of green hydrogen in form of liquid hydrogen or hydrogen derivates into the model region between 2030 and 2050 that was produced outside of Europe, as described in Section 5.3. The colours distinguish the different clusters in the Benelux region, and Germany. Significant import of hydrogen and derivates via ship transport is used in 2040 with a maximum of 366 TWh. Germany and the Netherlands both import some hydrogen, but under European-wide geographic optimisation (scenarios CE, SE), Belgium is the largest importer. However, once countries select policies that support a more national hydrogen production, the import of shipped hydrogen shifts. Belgium produces more hydrogen nationally through electrolysis and steam-methane reforming.

On the contrary, the Netherlands are a large producer of hydrogen which reduces its annual production under the national constraint. In order to still ensure reliable hydrogen supply, it therefore imports larger amounts of hydrogen from outside of Europe. Finally, in 2050, the amount of hydrogen imports decreases again to around 145-76 TWh, indicating that local production has mostly become cheaper than the import. Therefore, the import of green hydrogen from countries outside of Europe plays an important role in the supply of the high hydrogen demand in the Benelux and Western German region in transition years until the local production becomes more cost-effective.

Figure 39: Hydrogen supply, transport and consumption in 2050 comparing the (a) cross-sectoral (CE) and (b) the sectoral, European (SE) scenarios [48].



As shown, the coastal regions play an important role in the production and import of green hydrogen while hydrogen still needs to be further distributed from the import clusters according to the other clusters' hydrogen demand. An overview of demand, supply and transport in 2050 under cross-sectoral, European optimisation is shown in Figure 39a. The lower semi-circles indicate large hydrogen demand for industrial processes in Belgium, the Western Netherlands and Western Germany. These clusters additionally feature hydrogen demand to produce synthetic fuels, requiring them to import hydrogen from other clusters. In the cross-sectoral, European scenario, North-Western Germany supplies with Western Germany directly neighbouring clusters. However, there are also longer supply routes from the Western Dutch cluster to Belgium and a strong North-South corridor from Denmark to Southern Germany.

When switching from cross-sectoral grid planning (scenario CE) to sectoral silos (scenario SE) as shown in Figure 39b, the role of Northern Germany as a supplier of hydrogen for Central and Southern Germany is more pronounced. Additionally, the exchange of hydrogen between North-Western Germany, Belgium and the Netherlands becomes more significant. Here, like the Baltic countries, the introduction of the pipeline system according to the H_2 infrastructure map and the German hydrogen core network is responsible for larger amounts of hydrogen transported, since the North-Sea clusters export even more hydrogen than in the CE scenario. Especially the German hydrogen core network plans on a high connectivity within this region, facilitating the Netherlands to be a supplier of German hydrogen demand. Plus, Germany acts as a net exporter of hydrogen to Belgium. Therefore, the grid plans establish more exchange of hydrogen across German borders than a cost-optimal scenario.

8 Sensitivity Analyses

In the previous chapters, we have analysed possible scenarios of European and sectoral integration and their impact on the energy systems. However, there are of course numerous other developments that could drastically shape the future of the European energy system. For example, the industrial sector could transition in such a way that either large parts of the industrial value chain related to and building on the hydrogen economy are located in Europe or are relocated to other regions with low-cost renewable energy potentials. To understand the impact of such a development of the industry sector in Europe, we introduce a sensitivity analysis to the cross-sectoral, European scenario in Chapter 8.1.

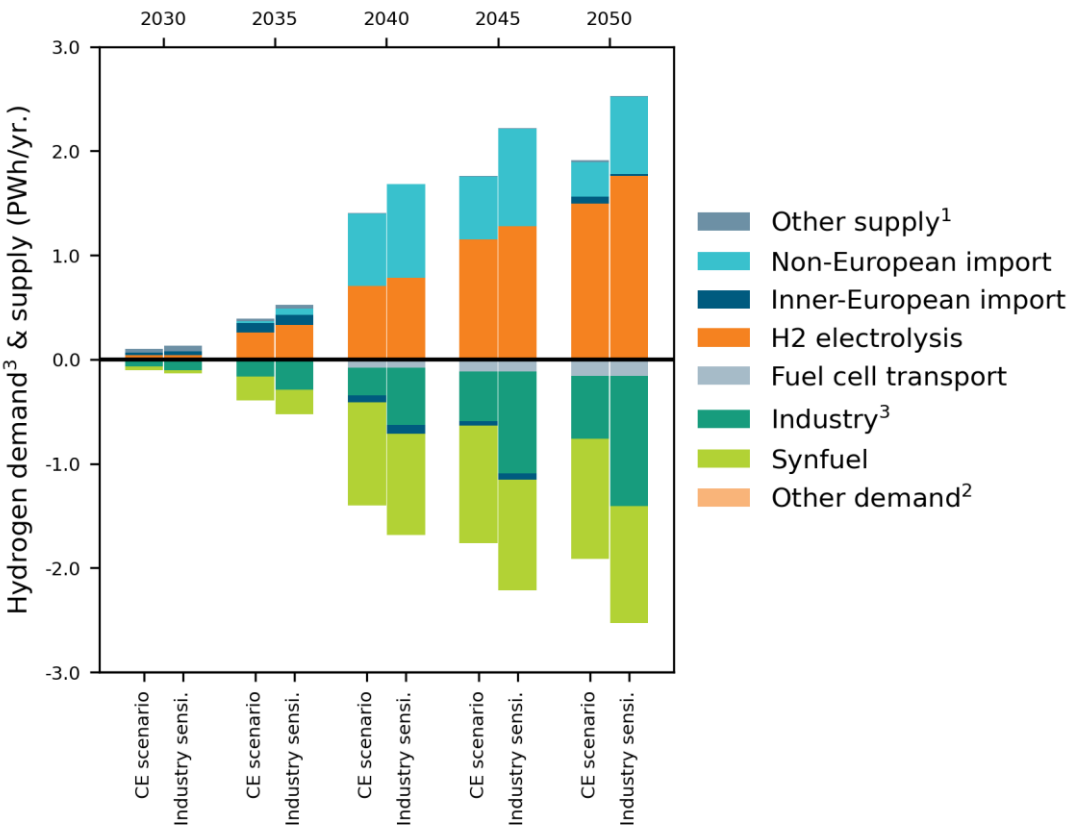
Another area of interest is the usage of flexibility options to handle the large renewable capacities in the system. Here, local distribution grids might play an essential role with the use of electric vehicles and the electrification of the heating sector. Thus, Chapter 8.2 contains the discussion on a second variation of the cross-sector, European scenario, where we specifically focus on the influence of flexibility in local grids.

8.1 Strong European Industrial Value Chain in the Hydrogen Economy

An important question regarding the future of the European energy system is how much of the industrial value chain, notably around the hydrogen economy, will unfold in Europe. For economic reasons, it could be profitable to outsource major parts of the current European industrial production capacities (which are largely based on fossil fuels) to countries, where electricity and hydrogen prices are lower [52]. However, to secure jobs inside Europe and to facilitate a degree of independence on imports, industrial policies are already in place to support European industry [53]. In our main scenarios, we assume that some of the production of energy-intensive intermediate products, based on a future hydrogen economy like sponge iron, ammonia and methanol, is developing both within and outside Europe in the next decades (see Section 5.2), reflecting a balance between potentially lower production costs outside Europe, the efforts of Energy Partnerships to develop economic links around the hydrogen economy, as well as security of supply with respects to such European production. If there is a stronger emphasis on keeping or developing larger parts of the value chain within Europe, these imports would be lower. To analyse the impact of a stronger value chain around the hydrogen economy within Europe, we apply a sensitivity to our cross-sectoral, European (CE) scenario in which there are no imports of sponge iron, methanol, and ammonia for industrial purposes. The corresponding industrial energy demand for this sensitivity is taken from scenario S2 of the TransHyDE project [5]. This scenario focuses on the use of hydrogen in chemical and steel production. Analogous to the main scenarios, it is implemented as an inflexible, exogenous demand.

We do not include in the scenario analysis the differentiated options to define Renewable Fuels of Non-Biological Origin (RFNBO). First, these options are still largely under discussion in the European Union. Second, differentiating such options in the modelling frame would require additional modelling power compared to what is anyhow already necessary for the main purposes of this study. Qualitatively, the inclusion of RFNBO criteria would – depending on their strictness - potentially yield some decrease in cross-European H_2-transport infrastructures as considered here.

Figure 40: Hydrogen generation and consumption in the EU in the CE scenario (TransHyDE S 1.5) and in sensitivity analysis around a stronger industrial value chain (TransHyDE S2).



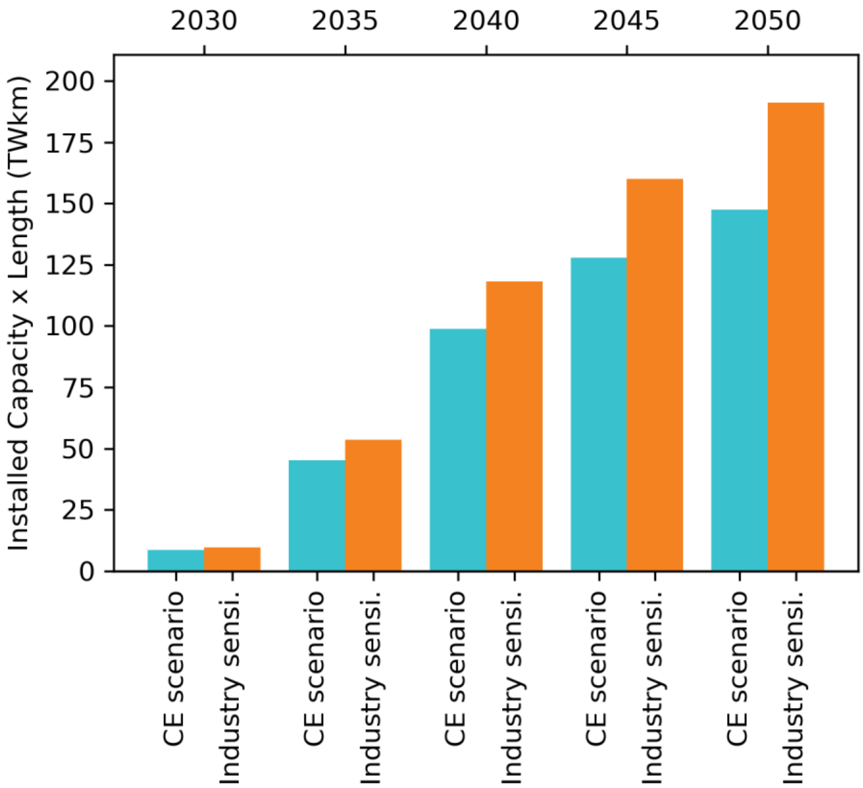
[1] Other supply: Hydrogen storage, Steam-methane reforming

[2] Other demand: H2 fuel cell, H2 turbine, Hydrogen storage

[3] Excluding grey hydrogen demand for industrial processes, which is included as methane demand in the model.

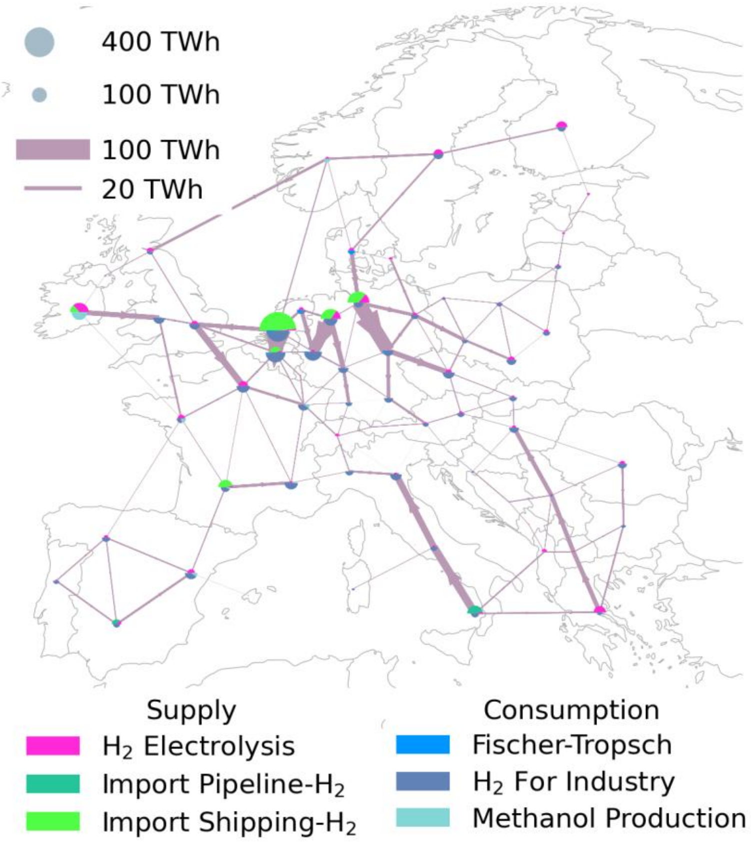
This increase in industrial hydrogen demand is depicted in Figure 40, which shows the hydrogen demand and supply for our CE scenario and the sensitivity analysis on a stronger industrial value chain for the EU. The hydrogen demand of the industry sector only includes hydrogen sourced from the larger energy system as explained in Chapter 5.2. Steam-methane reforming at local site is included as methane gas demand for industry in our model. The additional demand for hydrogen in the sensitivity analysis is used to produce sponge iron, methanol and ammonia amounts to 641 TWh in the EU in 2050. Other hydrogen demand sectors remain unaffected by effects from the change in industry demand. Also, Figure 40 visualises that supply of this additional hydrogen demand in the sensitivity analysis is covered first by steam-methane reforming as blue hydrogen and from 2040 onwards by green hydrogen from imports from outside of Europe. In 2050, 46% of the additional industrial hydrogen demand in the sensitivity is supplied by European production via electrolysis. For this purpose 118 GW of additional electrolyser capacity and 188 GW of renewable capacity are needed. Thereby, the additional hydrogen demand does not introduce significantly more CO_2 into the system, allowing a similar CO_2 infrastructure as in the main scenario.

Figure 41: Installed hydrogen pipeline capacity in EU under varying energy demand from industry.



On the contrary, the increase in the hydrogen demand in some regions due to more local industrial activity along with the increased usage of electrolysis and imports to provide the hydrogen affects the grid architecture in the EU – yet more in the longer run only. When comparing the installed capacity of electricity transmission infrastructure in TWkm between the CE scenario and the sensitivity with more European production of hydrogen-related products, the capacity in the electricity grid does not significantly change with the demand scenarios (see Figure 52). Therefore, the increase in the electricity demand from electrolysis does not require additional transmission lines. The additional electrolyser capacity is directly installed in the regions with high renewable potential and coincides with additional renewable capacities. Therefore, there is no need to transmit the electricity between clusters to electrolysers. For the hydrogen network capacity (Figure 41), however, we see a strong increase in needed pipeline capacity with higher industrial hydrogen demand. As a result, the total EU's hydrogen network is 30% larger in 2050 compared to the network resulting from lower industrial hydrogen demand as per the CE scenario.

Figure 42: Additional hydrogen generation, consumption and transport under increased industry demand in the sensitivity analysis compared to the main CE scenario in 2050 [48].



The increase in the need for hydrogen pipelines manifests itself on a regional level as industry-heavy regions face a steep increase in hydrogen demand in the sensitivity analyses compared to the main scenarios while other regions remain unaffected. To analyse these regional effects, Figure 42 shows the hydrogen generation, consumption and transport that is caused by the increase in industry demand in the sensitivity analysis compared to the main scenarios. For each modelled cluster, we visualise the increase in demand by the lower semi-circle. For example, in Western Germany, Belgium and the Netherlands, we see a significant additional demand for hydrogen in the industry. The size of the upper semi-circle corresponds to the hydrogen that is additionally produced or imported in the sensitivity compared to the main scenario. The increase in hydrogen to supply the increase in demand often does not come from the industrial regions but instead from electrolysis with wind power in the North Sea and Baltic Sea countries or from access points for imports into Europe. From these regions, hydrogen is transported to the demand centres allowing for a good overview of the effects of more local industry demand on the European hydrogen system. We see how imports from outside of Europe to Northern Germany supply German and Czech industry demand, Dutch harbours are relevant for the Netherlands and Belgium and pipeline imports in Italy from Africa supply Northern Italian industry.

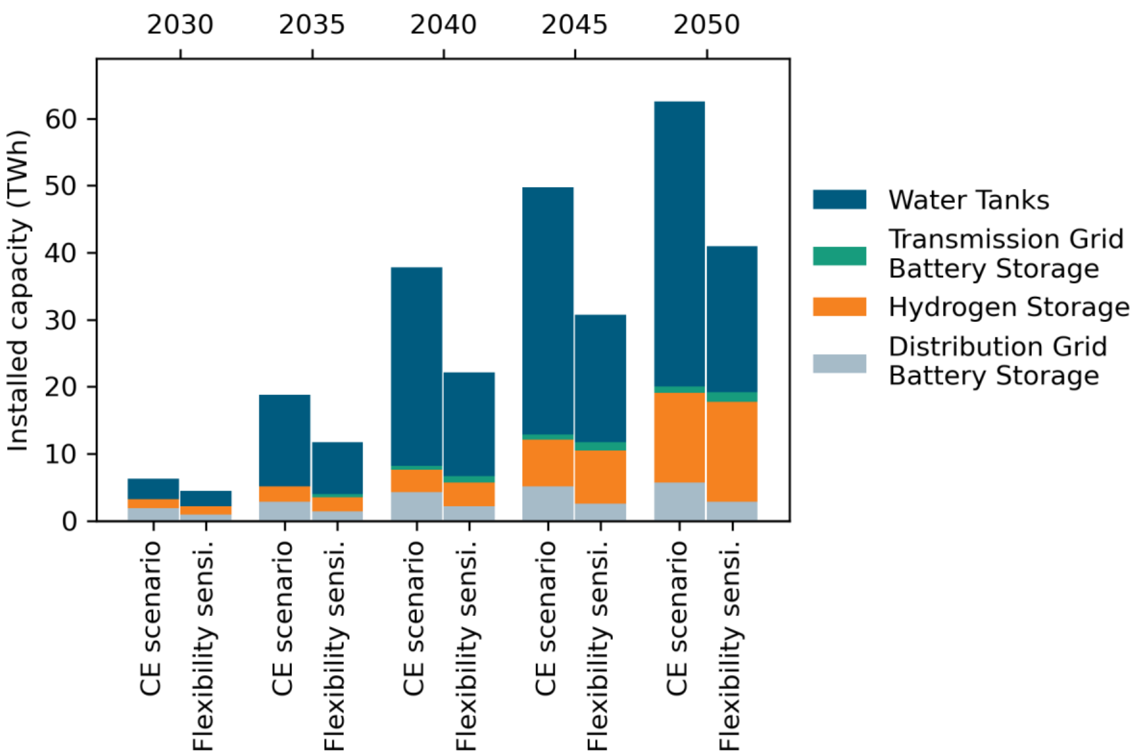
Therefore, when incentivising industrial energy-intensive processes to convert fully to a hydrogen economy in Europe, certain regions might become more reliant on hydrogen imports, and planners also must account for the increase in need for more hydrogen infrastructure. Such a shift in the energy system could lead to up to 67 billion Euros of additional system costs per year.

8.2 Flexibility Potential in Local Grids

With the increasing share of renewable energy sources in the European energy supply, technologies that can react flexibly to fluctuations in wind and solar energy are gaining in importance. These flexibility options can be situated on the transmission levels, with large battery storage, gas turbines or hydrogen electrolysis, but also on a distributed level, for example with electric vehicles and heat storage. A high level of flexibility in the distribution grid will potentially alleviate some stress from the transmission network and therefore require less transmission infrastructure. For our main scenarios, we chose such a high level of local grid flexibility in our main scenarios with a high share of district heating in urban areas and high technical availability of vehicle-to-grid. However, effects on the transmission grid observed in the main scenario analysis may become even more significant if the flexibility options lag behind these ambitious assumptions. This can be caused, for example, by a lack of market or policy incentives, insufficient regulation (e.g. grid tariffs that hinder system-friendly behaviour of electricity consumers) or public acceptance.

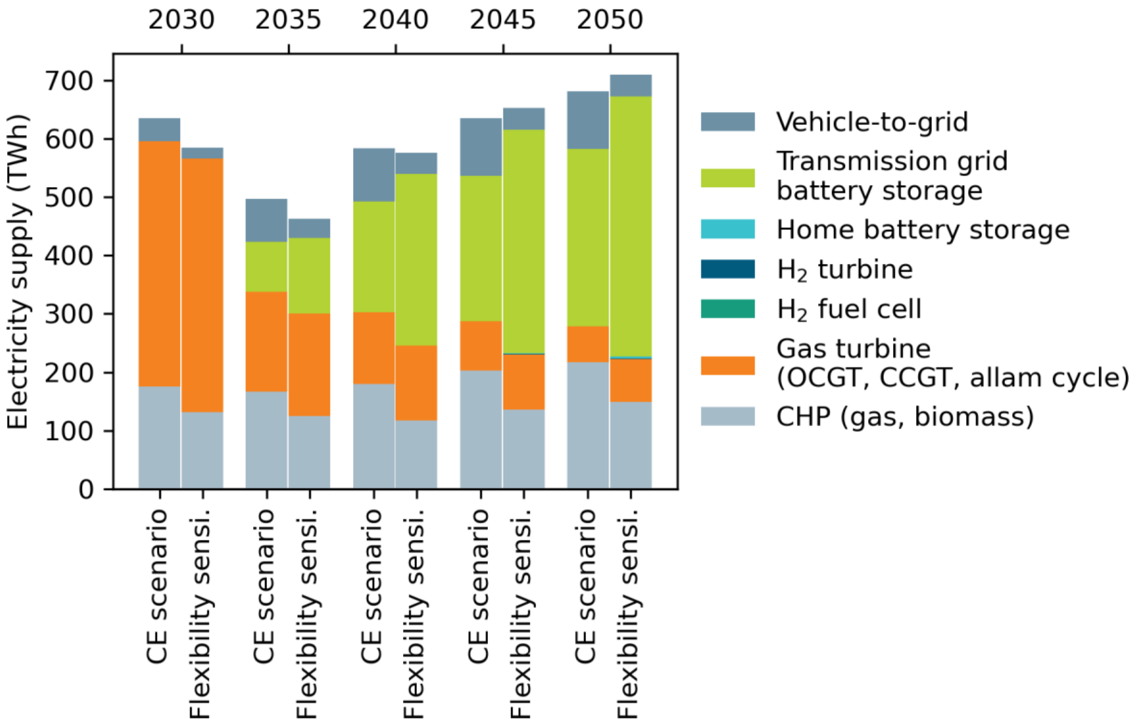
To analyse the effect of less availability of flexibility options in the local grid, we herein compare the main scenario assumptions for a high level of flexibility with a lower flexibility case for the cross-sectoral, European (CE) scenario. Specifically, we halve the share of district heating and the ability of electric vehicles to participate in demand-side management and vehicle-to-grid activities. Additionally, we increase the investment costs for flexibility options like water tanks and heat pumps in the heating sector. For details on the input assumptions, we refer to Annex 1: A Short Description of the PyPSA Model.

Figure 43: Installed capacities of selected storage technologies in the cross-sectoral, European scenario under the assumption of high flexibility (CE) and low flexibility (sensitivity) in the local grids.



The impact of the adjusted input assumptions can be directly seen in the choice of storage technologies in the system as these are essential when handling the intermittence of renewable energy sources. Figure 43 shows the installed capacity of selected storage technologies and their development between 2030 and 2050 in case of high flexibility (CE scenarios) and low flexibility (sensitivity). With increasing costs for water tanks and technologies in the heating sector that can transform excess electricity to heat, the installed capacity in water tanks reduces by 49% in 2050. Instead, the heating sector remains more reliant on gas and oil boilers than in the main scenarios that feature high local grid flexibility. Thereby, an additional 137 TWh in 2030 and 87 TWh in 2050 of heat are supplied by gas and oil boilers in the sensitivity compared to the CE scenario. The reduced availability of vehicle-to-grid can be directly seen in the reduction of battery storage capacity in the distribution grid which also includes home batteries. To some degree, it is compensated for by more centralised battery storage on the transmission grid level, but most importantly, we see a higher capacity of hydrogen storage in the low flexibility sensitivity. Thus, we do not only see a shift in storage technologies from the distribution grid to the transmission grid but also a shift from electricity to hydrogen storage.

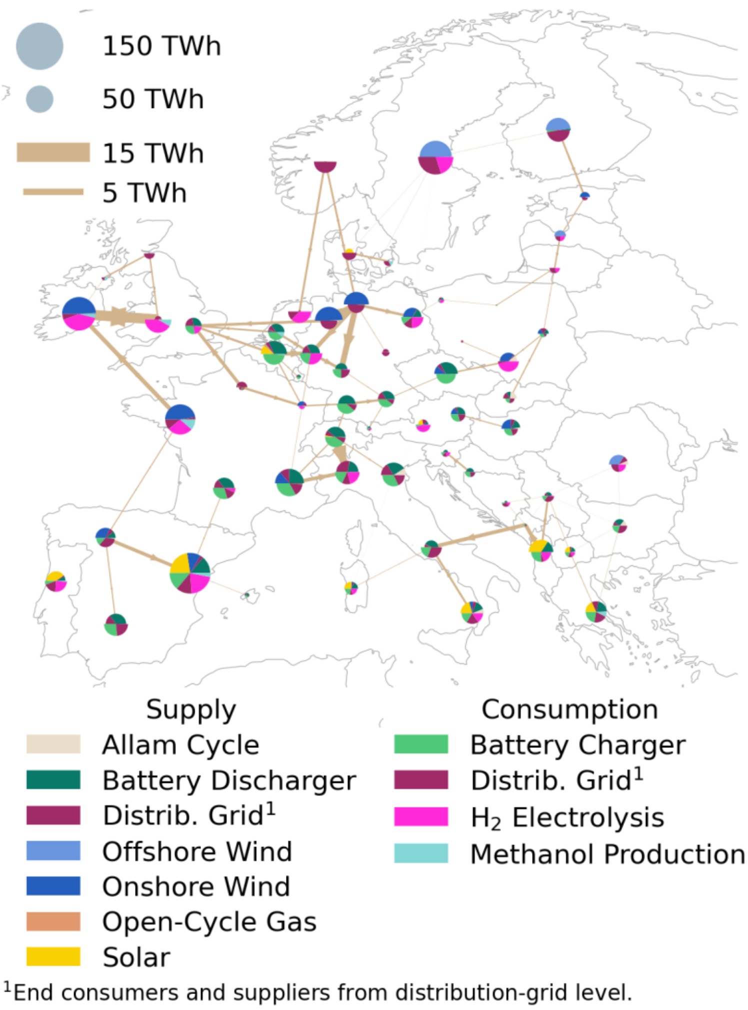
Figure 44: Annual dispatch of flexible technologies in the European electricity generation from optimisation with high flexibility in the local grids (CE scenario) and low flexibility (sensitivity).



When diving more into detail on the technologies providing flexible electricity supply, Figure 44 shows their annual dispatch. Note that in this focus on electricity supply, the total annual dispatch between the main scenario and the sensitivity with low local grid flexibility may differ as the heating sector and hydrogen storage also play a relevant role. When analysing the evolution of flexibility utilisation, it is notable that in 2030, gas turbines still dominate both scenarios. With decreasing dispatch of gas turbines, batteries on the transmission grid level gain in significance. When comparing the CE scenario with the sensitivity results, we see drops in the dispatch of vehicle-to-grid and CHPs caused by exogenous assumptions for the sensitivity. In 2030, this drop is compensated by the usage of gas turbines, requiring 23 TWh more of gas for electricity production via CCGT, OCGT and Allam cycle. Together with the gas used in the heating sector, this amounts to an additional primary energy demand of gas of 148 TWh. As discussed in the Chapter on the example of a dispatch-time series, the usage of hydrogen turbines is not deemed cost optimal by the model compared to gas turbines and transmission grid batteries. The latter are clearly favoured in 2050 with 141 TWh more electricity from discharging in the sensitivity with low local grid flexibility than in the main scenario.

This dispatch of transmission grid batteries only stems from certain regions in Europe as depicted in Figure 45, which shows the electricity that is additionally produced, transported and consumed in 2050 in the case of low flexibility compared to the main scenario with high flexibility. Here, we see that clusters either additionally utilise battery charging in the lower semi-circles and discharging in the upper semicircles or more electrolysis in the lower semi-circle. In contrast to battery utilisation, hydrogen production from electrolysis remains on a similar level in the sensitivity as in the main scenarios but is shifted to regions which have the potential for salt cavern storage such as the UK, Germany and Poland. The electricity for this electrolysis is produced onshore and offshore tapping into strong winds as they occur in Ireland or the North of Germany, where we see more wind energy produced in the upper semi-circles of Figure 45. Thereby, electrolysis is used as a flexibility option for the intermitted wind power supply. However, the hydrogen is not used for re-electrification in hydrogen turbines or fuel cells, but instead directly supplies the exogenous demand and the production of synthetic fuels. In clusters without cheap hydrogen storage potential, we see an increase in the use of batteries for electricity supply. Also, to cover large residual loads in the electricity system of certain clusters, electricity is imported from neighbouring clusters instead of utilising a flexible technology locally. Thereby, we see an increase in electricity transmission in Figure 45 in North-Western Europe that is additionally needed in the case of low local grid flexibility. As a result, there is also an increased need for an electricity infrastructure with an additional 7.7 TWkm installed in 2050 compared to the main scenario with high flexibility. Conversely, due to the shift from electricity to hydrogen storage, less infrastructure is needed for hydrogen transport. As such, the hydrogen network would be 5% smaller in 2050 compared to the main scenario with high flexibility in the local grids.

Figure 45: Electricity production, transport and consumption in the sensitivity analysis with lower flexibility in the local grids is available, compared to the high flexibility case in the CE scenario, 2050 [48].



9 Conclusions

In this study, we analysed the role that integrated infrastructure planning could play in transforming the European energy system to a climate-neutral one by 2050. The focus was on energy infrastructures and their role in the transformation process, notably:

- Electricity infrastructure
- Gas infrastructure (including both natural gas and future hydrogen infrastructures)
- Infrastructure related to CO_2 from carbon capture, transport, storage and use.

The study's starting point is the hypothesis that the transition to net-zero will require better integrated planning in terms of both the **geographic dimension** and the **cross-sectoral** dimension.

Although current planning approaches based on TYNDPs increasingly include more cross-sectoral and European elements, they are still largely "bottom-up" processes based on national energy and infrastructure strategies, e.g. on national renewable energy plans, national definitions of generation adequacy, and national grid development plans. This limits the cross-sectoral integration of system development strategies, as integrated grid planning is still in its infancy at Member State level. Therefore, the current regime can be described as a sectoral approach with a limited European perspective.

Europe's electricity grid is highly developed but faces new requirements concerning changing electricity generation technologies, the need to cope with high shares of fluctuating energy sources and rising electricity demand. Gas infrastructures are also highly developed, but demand is expected to decline significantly, which will only be partially compensated by a shift from fossil natural gas to a hydrogen-based supply. Finally, CO_2-related infrastructures are new and driven by the contribution they can make to climate neutrality through Carbon Capture, Use and Storage. In the analysis, these infrastructures are characterized **as sectors** and considered in the context of the evolving energy system. As these infrastructures are closely interrelated, the question is whether coherent planning and development processes across all infrastructures could be beneficial to the transformation process, which already requires substantial investments in new technologies.

This study covered the entire European continent (33 countries in total, including EU27, Norway, UK, Switzerland, Energy Community Parties EnC on the Balkans), considering countries at **national** level and Europe as a whole, thereby adding another level of complexity to the analysis. Here, too, the question is whether coherent planning and joint development of infrastructures on the European continent could bring benefits that enable a more efficient transformation process.

These two policy dimensions yielded a matrix of four scenarios, which is shown in Table 5.

Table 5: Mapping of four main scenarios on the two policy dimensions.

	EUROPEAN VIEW	NATIONAL VIEW
CROSS-SECTORAL PLANNING	**(1) CE:** **Cross-Sectoral, European View**	**(2) CN:** **Cross-Sectoral, National view**
SECTORAL GRID PLANNING	**(3) SE:** **Sectoral View, European View**	**(4) SN:** **Sectoral View, National view**

1) **Scenario "CE"** (**C**ross-sectoral, **E**uropean view): Cost-optimal generation, storage and grid expansion across Europe that integrates sectors to achieve a climate-neutral energy system by 2050.

2) Scenario "CN" (**C**ross-sectoral, **N**ational view): Cross-sectoral grid expansion but with a policy focus on meeting national demand mainly by national generation, i.e. limited coordination and expansion of interconnection capacities across Europe. This manifests as a trend towards a higher level of national supply and a lower level of imports.

3) Scenario "SE" (**S**ectoral, **E**uropean view): Sectoral grid planning in silos with simultaneous Europe-wide optimisation of generation capacity expansion for energy supply.

4) Scenario "SN" (**S**ectoral, **N**ational view): Sectoral grid planning in silos with a policy focus on meeting national demand mainly by national generation.

The analysis of these four scenarios revealed the following **benefits of strengthening European and cross-sectoral integration**:

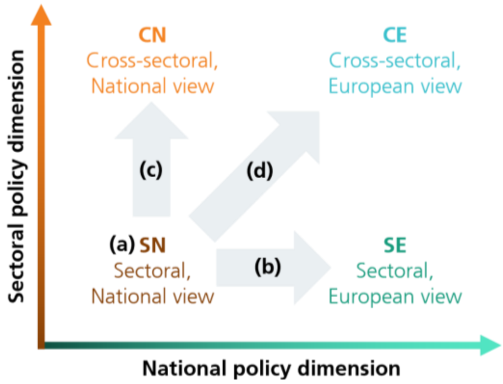
1. **Reduction in capacity needs**, notably:
   - Reduction in the European-wide renewables generation capacity required (e.g. 15% less onshore wind capacity required in the CE scenario than in the SN scenario)
   - Reduction in the back-up power plant capacity required (e.g. 505 GW less in the CE and SE scenario than in the SN scenario)
   - Reduction in the H_2 electrolyser capacity required (e.g. 9% less in the SE scenario than in the SN scenario)
2. **Reduction in overall infrastructure investments,** but a **mixed picture regarding infrastructure capacity needs**:
   - Sectoral integration leads to an important decrease of hydrogen transport capacity and to some decrease of national electricity transmission capacity, some increase of electricity interconnection capacity and enhanced capacity use of hydrogen infrastructure.
   - European integration leads to some increase of electricity interconnection and of hydrogen transport capacity.
   - In terms of storage infrastructure, European integration leads to a substantial decrease of hydrogen storage needs and an increase of electric batteries, whereas sectoral integration leads to an important increase of hydrogen storage and a decrease of electric batteries.
   - In combination, sectoral and European integration leads in most cases to a reduction in infrastructure needs and enhanced capacity use of hydrogen infrastructure, but definitely to substantial increases in battery and hydrogen storage capacities, as well as some increase in electricity interconnection capacities.
3. **Reduction in (annual and cumulative) investments/energy system costs** in 2030 and 2050, and cumulative for the period 2030-2050, composed of:
   - Reduction in technology-related investments/energy system costs
   - Reduction in infrastructure-related investments/energy system costs
   - Overall reduction in energy system costs.

While some aspects of the first two benefit categories, "capacity and infrastructure needs," may not consistently result in reductions due to sectoral or European integration, the benefit category "Reduction in (annual and cumulative) investments/energy system costs" clearly demonstrates the overall advantages of integration within the system.

Table 6 to Table 8 present the findings from the scenarios in quantitative terms compared to the "SN" Scenario (Sectoral, National view), i.e. the scenario with least European integration and least sector integration. A negative value in the tables means less technology/infrastructure needs than in the SN Scenario, i.e. a benefit from the integration; a positive value means more technology/infrastructure needs than in the SN scenario. The same holds for the cost perspective.

It should be noted that the more integrated scenarios could also lead to a greater need for certain technologies or infrastructures, especially in the shorter-term perspective of 2030.

Table 6: Benefits of European and cross-sectoral infrastructure integration - Reduction in technology capacity needs (compared to the SN Scenario – Sectoral/National View).



	(a) SN	(b) SE	(c) CN	(d) CE
	Reference	(compared to SN)		
	2030 2050	2030 2050	2030 2050	2030 2050
1. Reduction in <u>technology needs</u> due to integration [EU27[16], Norway, UK, Switzerland, Balkan-EnC[17]]				
Solar PV (GW)	727 2859	10 15	7 **-38**	-1 **-37**
Wind-onshore (GW)	366 987	**-17** **-107**	-2 -24	-11 **-133**
Wind-offshore (GW)	122 473	0 -3	0 10	1 -3
Back-up capacity (GW)[18]	449 505	**-449** **-505**	0 0	**-449** **-505**
H_2 Electrolyser capacity (GW)	76 770	0 **-42**	0 **-18**	0 **-69**

Note: A negative value (in green) means less technology/infrastructure required than in the SN Scenario, i.e. a benefit due to the integration; a positive value (in red) means more technology/infrastructure required than in the SN scenario.

- All three integrated approaches lead to benefits in most cases (reduction in technology capacity needs) compared to the SN scenario as evidenced by the negative values shown in green. Except for back-up capacities, benefits are limited in the shorter term (2030), but increase thereafter.
- The cross-sectoral scenarios (CN and CE) achieve the highest reductions in technology needs for PV, while European integration has the highest reductions for onshore wind. This is due to the fact that European integration leads to a shift of wind generation to countries with better wind potentials because self-sufficiency constraints are lifted. Cross-sectoral integration in the CN and CE scenarios reduces the need for PV and onshore wind capacity due to more efficient RE integration, lower curtailment and lower hydrogen production in Europe.

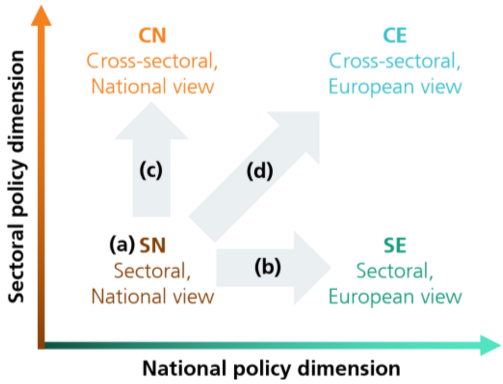
[16] EU27: European Union excluding Cyprus and Malta

[17] Balkan-EnC: Energy Community Parties on the Balkans (Albania, Bosnia and Herzegovina, Montenegro, North Macedonia, and Serbia, excluding Kosovo).

[18] Capacities needed in each country to supply its exogenous, inflexible electricity loads. This post-optimisation estimate can be interpreted as a strategic reserve.

- Back-up capacities that are national capacity reserves are not needed in the SE and CE scenarios that integrate the European perspective.
- No clear picture results for offshore wind. For H_2 electrolyser capacities, the SE and CE scenarios reduce the need, as capacities are concentrated on regions with cheap renewable energy.

Table 7: Benefits of European and cross-sectoral infrastructure integration - Reduction in infrastructure needs (compared to the SN Scenario – Sectoral/National View).



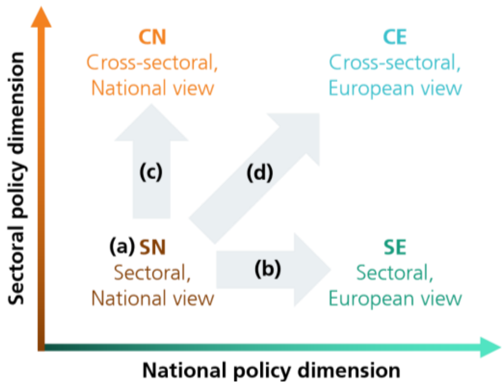
	(a) SN	(b) SE	(c) CN	(d) CE	Comments
	Reference	(compared to SN)			
	2030 2050	2030 2050	2030 2050	2030 2050	
2. Reduction in <u>infrastructure required due to</u> integration [EU27, Norway, UK, Switzerland, Balkan-EnC]					
Electricity interconnection capacities (TWkm)	115 144	0 5	-4 8	-1 **26**	Between countries
National electricity transmission capacities (TWkm)	179 194	0 0	**-13** -7	**-14** -6	Connecting the national clusters
Battery storage (GWh)[19]	1920 6605	0 **168**	0 **-19**	0 **119**	
H_2 transport capacities (TWkm)	267 420	0 11	**-256** **-281**	**-258** **-262**	
H_2 transport capacity use (difference to SN in %-points)	16 54	2 2	**66** **24**	**72** **25**	Exception: positive value = benefit
H_2 storage capacities (GWh)	992 12202	14 **-761**	**98** **1759**	**309** **1117**	
CO_2 transport capacities (Mt/h km)	0 5	0 -1	0 0	0 -1	
CO_2 capture and storage capacities (Mt)	345 577	-1 8	**-27** -5	**-39** -8	

Note: A negative value (in green) means less infrastructure required than in the SN Scenario, i.e. a benefit due to the integration; a positive value (in red) means more infrastructure required than in the SN scenario. Exception: higher capacity use compared to the SN scenario is a benefit.

[19] Battery storage includes batteries, home batteries and electric vehicle batteries.

- In terms of the infrastructure required, sectoral integration in the CE and CN scenario leads to the largest benefits in the capacity of the hydrogen network, whereas European integration in the CE and SE scenarios leads to a larger need for electricity storage.
- When moving from the SN scenario to any of the integrated scenario, it becomes apparent that sectoral and European integration have limited impact on electricity infrastructure. While domestic transmission infrastructures (between clusters in the same country) are reduced, interconnection capacities (between countries) and storage capacities need to be enhanced.
- Based on the optimisation approach applied in this study, the electricity and hydrogen infrastructures on the transmission/transport level are planned and operated in strong coordination with flexibility technologies on the transmission and distribution grid level as well as in the heat sector. The latter provide the majority of the energy system's flexibility resources of the energy system. If this coordination can be achieved, only moderate additional storage capacity of battery storages and hydrogen is required at the transmission level. If strong coordination between the transmission and distribution level cannot be achieved in practice, higher storage capacity would be needed. In the longer term, European integration also leads to benefits in H_2 storage capacities. This is because hydrogen storage is a flexibility option that can be substituted by direct imports and exports without intermediate storage in the European integration scenarios (SE & CE). The implications for electricity storage are very small, i.e. less than 3% of the capacity.
- For CO_2 infrastructure, the benefits are linked to reducing sequestration capacities in earlier years. This is possible by harnessing potential within the framework of sectoral integration, which decreases the reliance on CO_2-emitting technologies.

Table 8: Benefits of European and cross-sectoral infrastructure integration - Reduction in cumulative investments/energy system costs (compared to the SN Scenario – Sectoral/National View).



	(a) SN	(b) SE	(c) CN	(d) CE
	Reference		(compared to SN)	
(bn Euro)	2030-2050	2030-2050	2030-2050	2030-2050
3. Cumulative investments/energy system costs (2030-2050) [EU27, Norway, UK, Switzerland, Balkan-EnC]				
Technology-related investments[20]	11773	**-230**	**-145**	**-506**
Infrastructure-related investments[21]	1465	-14	**-191**	**-169**
Operational & fuel costs	4115	**124**	-70	**114**
Overall-energy system costs[22]	17353	**-120**	**-406**	**-561**

[20] Power generation, heat generation and transformation technologies (e.g. H2 electrolysis)

[21] Electricity, hydrogen, methane and CO_2 network

[22] Capital, operational and fuel costs

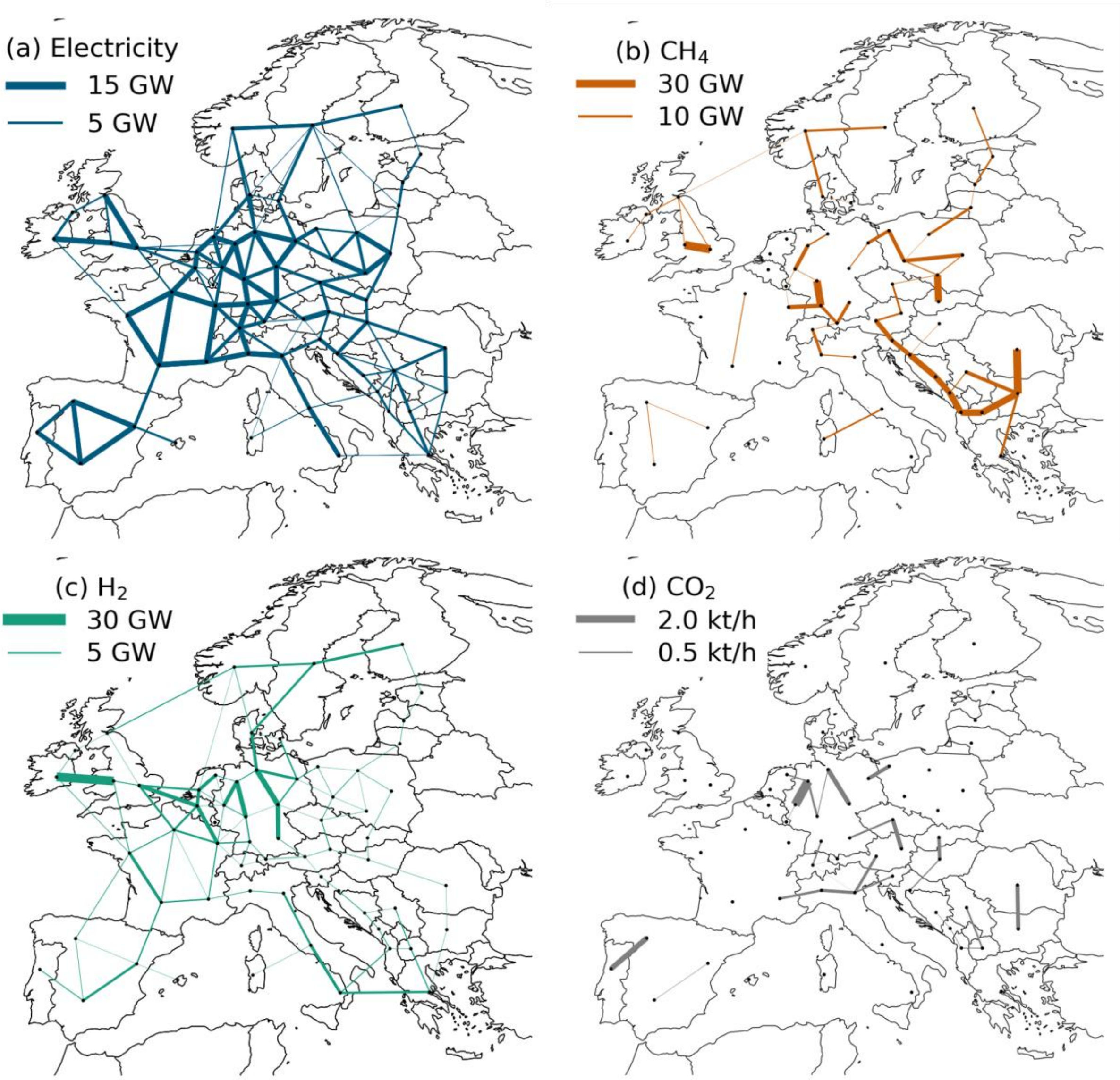
Note: A negative value (in green) means lower investments/energy system costs than in the SN Scenario, i.e. a benefit due to integration; a positive value (in red) means higher investments/energy system costs than in the SN scenario.

- Overall, all three scenarios with sectoral and European integration lead to a reduction in investments/energy system costs. The largest benefits come from the reduction in technology-related investments, but the reduction in infrastructure-related investments also make a significant contribution to decreasing costs.
- The largest benefits in cumulative overall system costs result from the CE scenario, which integrates the cross-sectoral and European view, amounting to over 560 billion euros for the period 2030-2050.
- This result is strongly affected by both the cross-sectoral and European integration.

All results are stated compared to the fragmented SN scenario (but which can already be considered more optimised than a less co-ordinated bottom-up planning and development process, which dominates the early stages of this scenario). The stated cost savings could therefore be even higher than evaluated compared to the SN scenario.

Further general observations and cross-cutting issues:
In order to benefit from an integrated energy system as described above, appropriate build-up of transmission infrastructure is required. Figure 46 shows the cost-optimal (a) electricity, (b) methane, (c) hydrogen and (d) CO_2 infrastructure in 2050 from the cross-sectoral, European integration and therein illustrates that the electricity transmission system remains a strong component of the future energy system. The methane gas pipeline capacity is heavily reduced up to 2050 due to repurposing hydrogen pipelines. The hydrogen backbone in Figure 46c is relatively small, focusing mainly on North-South connections, and no large-scale system is established for CO_2 and only a limited number of pipeline connections are built instead.

Figure 46: Integrated energy infrastructure in 2050 resulting from optimisation in the cross-sectoral, European (CE) scenario.



A key observation is that integrated infrastructures need to be planned and operated in strong coordination with flexibility technologies on the transmission and distribution grid level as well as in the heat sector. If this coordination can be achieved, only moderate additional storage capacities of battery storages and hydrogen are required at the transmission level.

The SN and CN scenarios that focus on national demand predominantly being met by domestic generation mainly resulted in increased technology costs but had relatively little impact on transmission infrastructure costs. The SN and SE scenarios with limited cross-sectoral integration had a major impact on absolute infrastructure costs.

The largest differences when comparing the sectoral silo scenarios (SN and SE) with the cross-sectoral scenarios (CN and CE) are in the hydrogen sector. The current grid plans developed at Member State level overestimate the need for H_2 pipelines while also resulting in incomplete hydrogen infrastructure in certain regions. The hydrogen grid in the CE scenario with integrated cross-sectoral planning at EU-level features more diverse connectivity with overall lower capacities.

If the transformation to a climate-neutral energy system does not integrate the European and cross-sectoral view, substantial cost increases can be expected. These mainly result from inefficiently high capacities of renewable energy generators, backup power, electrolysers, and hydrogen infrastructures.

An integrated approach allows the system to utilise and combine the properties and strengths of the different energy carriers and infrastructures. A system planned in this way can link sinks and sources cost-effectively. Although this study did not quantify the reduction in material requirements, particularly for critical materials, its findings for the technology and infrastructure required clearly indicate that integrated infrastructure planning leads to a considerable reduction in the material requirements for the transformation of our energy system as well.

In addition to the importance of integrated approaches within the EU27, the connections to non-EU countries will be essential for an efficient transition. In particular, the UK will be very important for the stronger integration of electricity and hydrogen infrastructures.

While European and sectoral integration leads to substantial overall cost savings at the system cost level, the allocation of costs varies compared to the more fragmented national and sectoral silo SN scenario. This outcome is illustrated by the two regional case studies (on the larger Polish-Baltic region and the larger North-West Germany/Benelux region), which show that the countries develop specialised technology and infrastructure processes to transform their own energy systems. For example, in the fully integrated scenario CE, low-cost decarbonisation options like offshore wind for the Polish-Baltic region and hydrogen imports for the North-West Germany/Benelux region play a stronger role. While integration offers overall Europe-wide benefits, it does raise the question of how these benefits can best be distributed among countries (including other countries in Europe, such as UK, Norway, Switzerland and the Western Balkans). Appropriate policy approaches are needed to reward the additional efforts made by countries that would be better off in the SN scenario.

Annex 1: A Short Description of the PyPSA Model

PyPSA-Eur is an open-source energy-system-model that covers the European energy system across all relevant sectors. The model optimizes both the investment and the operation of the generation, storage, conversion and transmission infrastructure with regard to the minimum total system costs for the energy supply. The model covers the European Union excluding Cyprus and Malta as well as the United Kingdom, Norway, Switzerland, Albania, Bosnia and Herzegovina, Montenegro, North Macedonia, and Serbia. The final energy demands of the electricity sector, industry and agriculture, the building sector and the transportation sector provide a holistic view of the energy system. Wind, solar, biomass, hydropower as well as fossil and nuclear fuels serve as primary energy sources to cover the demand. For the optimisation of the energy supply, the main relevant conversion technologies (including heat pumps, combined heat and power plants CHP, thermal storage, electric vehicles, batteries, power-to-X processes and hydrogen fuel cells) are modelled. Their expansion and operation are optimized with consideration of individual constraints. Alongside the conversion technologies, the transport infrastructure is included. Based on the existing electricity and gas transmission infrastructure, the grid expansion and new construction needs are determined by the optimisation. Additionally, gas pipelines can be repurposed to transport hydrogen and new hydrogen pipelines can be built. Carbon flows are also mapped in detail, taking into account capture, utilization, transport, sequestration, removal and emissions into the atmosphere, whereby atmospheric emissions are limited and can serve as a driving force for the transformation of the energy system. Detailed information on the model can be found in the documentation and various publications [25, 26, 54].

For this report, we have built upon the open-source code of PyPSA-Eur, version 0.10. In the following chapter, we will supply some detailed information on implementations specific to our model for this study.

Clustering

In the current model, there is a regional aggregation to a total of 62 clusters as shown in Chapter 4. More specifically the countries are assigned the number of clusters as shown in Table 9. First, certain countries are represented by at least two clusters to account for the island regions. These are Denmark, Italy, Spain and the UK. Second, countries with a high energy demand and supply have a higher resolution. Lastly, the clustering supports the focus of our study and the country cases, providing a higher resolution to those regions that are investigated in the case studies. Within each country, the borders of the clusters are determined automatically in the PyPSA framework based on the regional electricity load. The only exception is Poland, where in order to reflect the relevant transmission corridors, the Western cluster is split into a North and South component.

Table 9: Distribution of clusters amongst the countries modelled.

Number of Clusters	Countries
8	DE
5	FR, IT, PL
4	ES, GB
3	AT
2	NL, DK
1	AL, BA, BE, BG, CH, CZ, EE, FI, GR, HR, HU, IE, LT, LU, LV, ME, MK, NO, PT, RO, RS, SE, SI, SK

Self-Sufficiency Constraint

The self-sufficiency constraint establishes a minimum share of domestic electricity and hydrogen generation relative to gross consumption. Therefore, a country's self-sufficiency in electricity is calculated by the ratio of all electricity generated in the country over the entire year and the country's gross electricity consumption. The latter is given by the some of the domestic electricity generation and the net electricity imports. The self-sufficiency level for hydrogen is calculated analogously. On the other side, the model applies a country's self-sufficiency by restricting the annual net export of electricity and hydrogen. Each country can have a unique self-sufficiency level for both electricity and hydrogen each planning year. The specific self-sufficiency levels designated for each year are detailed in Table 10. These are applied to all countries in the scenarios subject to the national view (CN, SN).

Table 10: Exogenous self-sufficiency level applied to all countries per carrier and year.

Energy carrier	2030	2035	2040	2045	2050
Electricity					
• Minimum	80%	85%	90%	95%	100%
• Maximum	110%	110%	110%	110%	110%
Hydrogen					
• Minimum	70%	70%	70%	70%	70%
• Maximum	110%	110%	110%	110%	110%

Retrofitting of Methane Pipelines

With the trend towards decarbonization, the existing gas network will lose its relevance in transporting natural gas. However, the infrastructure can be repurposed for other uses in the future energy system.

Our model allows the retrofitting of methane pipelines for hydrogen transport as described by Neumann et al. [54]. Here, the costs of 129 €/MW/km [55] to switch to hydrogen pipelines account for changes in compressors, valves and protection of the pipelines against the corrosive properties of hydrogen. Due to the aggregation of all gas pipelines between two clusters in the model, retrofitting does not occur with the level of detail of every pipe. Instead, the model can decide each optimisation year to repurpose a certain share of the connection between two clusters. If a certain pipeline capacity is decommissioned, 60% of this capacity can be used for hydrogen transport [55]. Therefore, between two clusters, there can be a pipeline retrofitted for hydrogen and a natural gas pipeline as long as their capacity in sum matches the initial methane connection between these clusters.

With the need for transport of CO_2, the option of retrofitting the methane network to a CO_2 network also arises. However, research on the technical constraints and cost implications is still at an early stage not allowing a reliable parametrization of retrofitting in our energy system model. We therefore opt for greenfield optimisation in regard of the CO_2 network instead of retrofitting methane pipelines.

Industry Modelling Details

The original PyPSA industry demand is overwritten with TransHyDE industry demand.

For some countries, the industry demand from TransHyDE is not available, e.g. Switzerland, Norway, Albania, Bosnia and Herzegovina, North Macedonia, Montenegro, Serbia. In these cases, the demand is modelled as provided by PyPSA.

Due to the regional clustering provided by PyPSA, the TransHyDE demand is grouped at country level and then distributed across the regions within a country, proportionally to the PyPSA distribution of demand. The PyPSA assumptions regarding use of hydrogen in future industry processes have been adapted to reflect the TransHyDE assumption, resulting in a fitting distribution of hydrogen demand across Europe.

Sensitivity Parameterisation: Flexibility of Local Grids

Flexibility in the local grids can be found either in the use of electric vehicles with demand-side management (DSM) and vehicle-to-grid (V2G) or in the heating sector with water tanks and electricity-based technologies. For the sensitivity of low flexibility, we reduced the technical availability as shown in Table 11. This percentage can be understood as the share of cars that is the percentage of cars that have the technical ability to discharge for electricity supply. But on these cars, there are still further restrictions. For example, they follow an hourly availability profile in which a maximum of 95% and an average of 80% of cars are currently standing in their garages ready for V2G. Additionally, all cars need to have a minimum state of charge of 75% at 7am on weekdays. Therefore, it is never 50% of the combined capacity of BEVs being available all at once.

Furthermore, in the model, district heating is available for heating supply in urban areas. The share of district heating in this urban heat demand is reduced in our sensitivity analysis. To further reduce flexibility in the heating sector, we increased costs for heat supply from electricity and heat storage in water tanks by 20%.

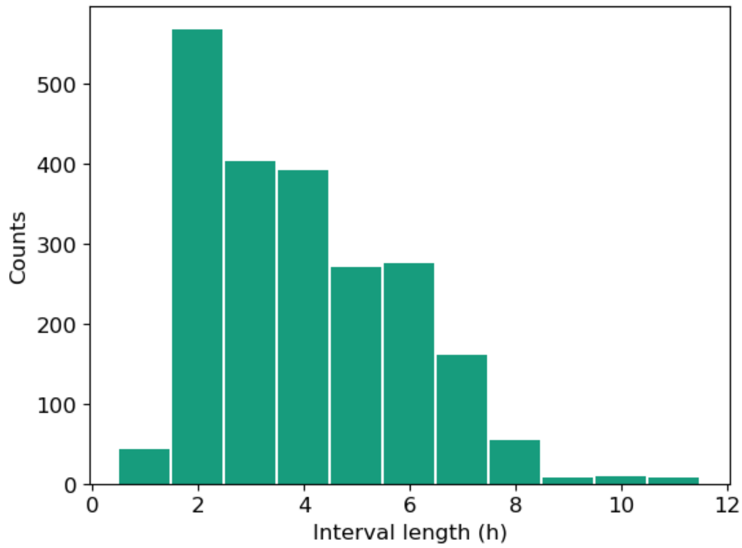
Table 11: Parameter choice for the sensitivity analysis of the flexibility in local grids.

	High Flexibility (Main Scenarios)	Low Flexibility
DSM/V2G availability	50%	25%
Share of district heating	60%	30%
Investment costs - Heat pumps - Water tanks - CHP - Resistive heater	PyPSA standard (see input parameter file)	20% increased

Temporal Resolution: Time Segmentation vs. Hourly Resolution

To be able to assess the impact of the temporal resolution that was chosen for this study, we tested it in comparison to an hourly resolution and examined the differences. As our model is very memory intensive (above 512GB for 2h resolution), we were unable to test an hourly resolution on the main model for this study. Instead, we used the PyPSA-Eur open-source version [23] with the same technologies and grids like in our model, but a reduced spatial resolution. Here, we modelled only Germany and its neighbours with 20 clusters in total. Additionally, to reduce the size of the model, we only optimised 2050 instead of using myopic optimisation. With this model, we performed two runs, one with an hourly resolution and one using the time segmentation of the tsam package [19] to separate the year into 2190 flexible intervals. The resulting distribution of interval sizes can be seen in Figure 47. It shows, how the majority of intervals has a length of two hours, while the average is at four hours.

Figure 47: Distribution of time interval length using time segmentation.



For comparing the results on the European level, we have summarised some of the most impacted key indicators in Table 12. While we see that the hydrogen and electricity gird are barely affected, it also shows the largest difference between the hourly resolution and the lower temporal resolution of 2190 segments in the curtailed energy of renewable carriers. While these have a high relative difference, the significance to the energy system in total is low as the share of energy curtailed is 5% or lower in all cases. Besides the curtailment, we see a difference in the installed capacity of centralised battery storage on the transmission grid level. Here, 8% are additionally needed on an hourly resolution to react to larger fluctuations in the time series.

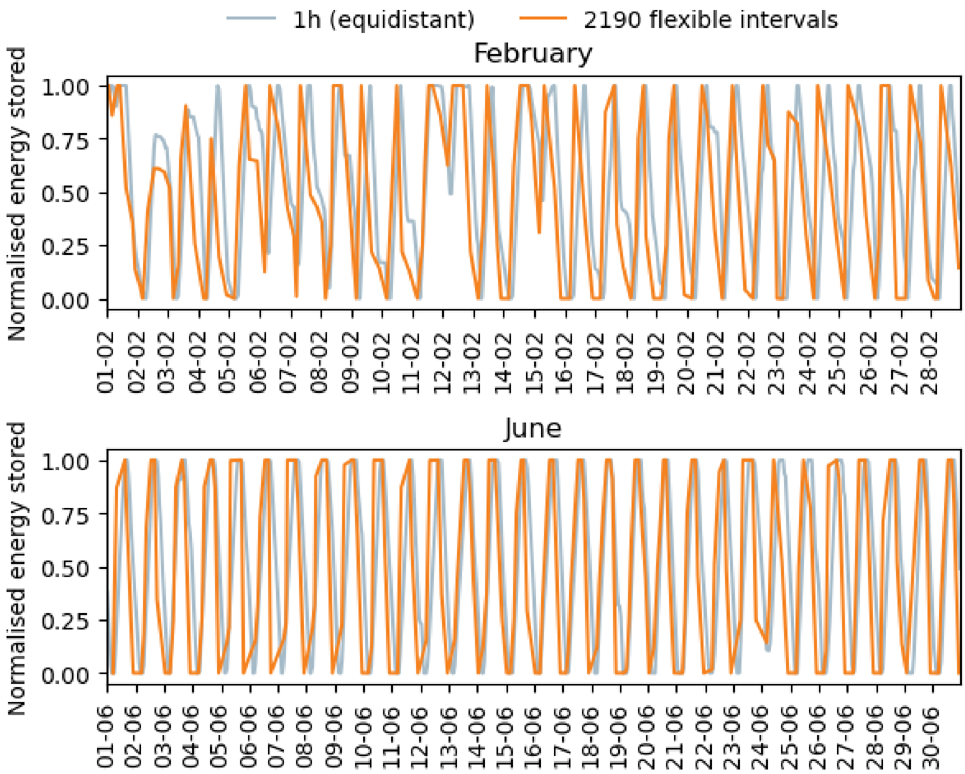
Table 12: Key indicators on the European energy system when comparing the equidistant hourly resolution to time segmentation with 2190 flexible intervals.

KPI	Carrier	Unit	1h	Time seg.	Difference (%)
Ratio of curtailed energy	Solar	%	0.3	0.1	63
Ratio of curtailed energy	Offshore wind	%	3.9	5.1	28.8
Installed capacity	Electricity storage (transmission grid)	[GWh_{el}]	142.1	130.9	7.9
Ratio of curtailed energy	Onshore wind	%	2.4	2.3	4.1
		…			
Installed capacity	Hydrogen grid	[TWkm]	30.8	30.6	0.6
Installed capacity	Electricity grid	[TWkm]	191.5	191.5	10^{-5}

However, when looking at the dispatch of such battery storage, we see in Figure 48 at the example of the largest battery storage in the system that the lower temporal resolution is able to follow the profile of the hourly resolution relatively well. We here display two exemplary months, the month of June with a very periodic dispatch and February with more irregular patterns.

We thereby see that using a lower temporal resolution with flexible intervals yields results that are close to an hourly resolution while drastically saving memory and computation time.

Figure 48: Normalised dispatch of an exemplary battery storage unit in February and June to compare the accuracy of time segmentation with 2190 flexible intervals to the hourly resolution.



Annex 2: Implementation of Current Infrastructure Planning

An integral part of our modelling efforts is the review of current infrastructure planning like the Ten-Year Network Development Plans (TYNDP) of ENTSO-E and ENTSO-G which are described in detail in Chapter 3.2. Therefore, we implemented projects from infrastructure plans into our model in the electricity grid, methane network and future hydrogen network. To support the sectoral policy dimension from our scenario development, these future transmission projects are implemented to a different extend comparing the sector-integrated scenarios (CE, CN) and the scenarios reflecting a sectoral view (SE, SN). The strategy for this implementation is summarized in Table 13 and in the following, we will explain the reasoning behind it for each of the sectors.

Table 13: Limitations on network expansion for each scenario implemented in the model.

Scenario	Electricity grid	Methane network	Hydrogen network
(1) CE	Endogenous optimisation in all years TYNDP projects as lower bounds with status 'under construction'	Endogenous optimisation in all years TYNDP projects as lower bounds with status 'FID'	Endogenous optimisation
(2) CN	Endogenous optimisation in all years TYNDP projects as lower bounds with status 'under construction'	Endogenous optimisation in all years TYNDP projects as lower bounds with status 'FID'	Endogenous optimisation
(3) SE	Fixed grid capacities up to 2040. Only expansion by TYNDP projects with status 'in planning' 'in permitting' 'under construction' Endogenous expansion after 2040	Endogenous optimisation in all years TYNDP projects as lower bounds with status 'FID' 'Advanced' 'Less-Advanced'	Fixed grid capacities up to 2040. Only expansion by Hydrogen core network and H_2 Infrastructure Map Endogenous expansion after 2040
(4) SN	Fixed grid capacities up to 2040. Only expansion by TYNDP projects with status 'in planning' 'in permitting' 'under construction' Endogenous expansion after 2040	Endogenous optimisation in all years TYNDP projects as lower bounds with status 'FID' 'Advanced' 'Less-Advanced'	Fixed grid capacities up to 2040. Only expansion by Hydrogen core network and H_2 Infrastructure Map Endogenous expansion after 2040

TYNDP projects for electricity grid expansion

For the electricity grid, we consider transmission projects that appear in the database of TYNDP 2022 [56]. These projects are assigned to a planning status, 'under consideration', 'in planning', 'in permitting' and 'under construction'.

In our sectoral silo scenarios, we aim to model an electricity grid as envisioned by grid planner. Therefore, we consider all projects that are rated likely to be implemented by TYNDP, more specifically the projects with a status of 'in planning', 'in permitting' or 'under construction'. These projects are listed in Table 14. In a data processing routine, we then map the projects onto our current clustering. In the sectoral view (scenario SE & SN), these transmission line projects are the only ones built up to 2040. There is no endogenous optimisation. However, since the grid plans do not reach until 2050, we allow endogenous optimisation of the electricity grid after 2040, once there are no TYNDP projects left to be built.

In contrary, in the cross-sectoral view (scenario CE & CN), we allow endogenous optimisation of the electricity grid in all years. Thereby, we can evaluate, what would be the cost-optimal solution. Yet, we also consider the TYNDP in these scenario as it also projects that are already under construction. To be able to propose a plausible grid for the future planning years, we need to consider these projects also in our cross-sectoral scenarios. Thereby, the projects with the status 'under construction' act as lower bounds to the endogenous optimisation of the electricity system.

TYNDP projects for the methane network

Similar to the case of the electricity grid, the TYNDP projects provided by ENTSO-G [57] are grouped into different planning statuses. Here, they are called 'Final investment decision (FID)', 'Advanced' and 'Less-Advanced'. The pipeline projects from TYNDP 2022 are listed in Table 15.

Within the same logic as discussed above, we implement projects of all the three statuses into the scenarios with a sectoral grid planning. For the cross-sectoral grid planning, we only enforce the pipelines with a status 'FID' to be built. As there is little endogenous expansion to be expected in the methane network, we set these projects as lower bounds and allow further optimisation in all four scenarios.

Hydrogen backbone plans for the future hydrogen network

Since the hydrogen network needs to be built from ground up in our model, the approach to implementing it in the sectoral policy dimension is slightly different to the other infrastructure. On the one hand, we allow full greenfield optimisation in the scenarios reflecting cross-sectoral infrastructure planning. In the sectoral view, on the other hand, there are multiple frameworks outlining the future hydrogen networks like the European Hydrogen Backbone [58], but few are detailed enough in their planning stage for model implementation. For this study, we implemented pipelines described in the H_2 infrastructure map [17] and the German core network [18] as these provide relatively complete datasets on their project portfolio. Both datasets were retrieved in March 2024. The code implementation is based on the implementation of the German hydrogen core network in the Kopernikus-Project Ariadne [59]. Wherever a pipeline's capacity is still missing, we assume the capacity of its nearest neighbour to facilitate sensible transport pathways.

All the hydrogen pipeline projects considered in this study are detailed in Table 16. These pipelines represent the only hydrogen network that is built in the scenarios with sectoral view (SE, SN) up until 2040. As the grid planning does not involve projects after 2040, we allow endogenous optimisation after 2040 to fulfil the needs for the hydrogen network in the later planning years.

Table 14: Projects from TYNDP 2022 considered for electricity grid capacity expansion.

ID	Project Name	Country	Year	Status
1	RES in north of Portugal	PT	2023	under constr.
26	Reschenpass Interconnector Project	AT, IT	2023	under constr.
28	Italy-Montenegro	IT, ME	2026	under constr.
33	Central Northern Italy	IT	2026	under constr.
94	GerPol Improvements	DE, PL	2025	under constr.
103	Reinforcements Ring NL phase I	NL	2025	under constr.
123	LitPol Link Stage 2	LT, PL	2023	under constr.
138	Black Sea Corridor	BG, RO	2024	under constr.
142	CSEunder construction	BG, GR	2022	under constr.
186	East of Austria	AT	2022	under constr.
230	GerPol Power Bridge I	PL	2024	under constr.
286	Greenlink	GB, IE	2024	under constr.
297	BRABO II + III	BE	2025	under constr.
312	St. Peter (AT) - Tauern (AT)	AT	2025	under constr.
350	South Balkan Corridor	AL, MK	2023	under constr.
1055	Interconnection of Crete to the Mainland System of Greece	GR	2024	under constr.
4	Interconnection Portugal-Spain	ES, PT	2024	in permitting
16	Biscay Gulf	ES, FR	2027	in permitting
29	Italy-Tunisia	IT, TN	2028	in permitting
35	CZ Southwest-east corridor	CZ	2028	in permitting
81	North South Interconnector	GB, IE	2025	in permitting
85	Integration of RES in Alentejo	PT	2022	in permitting
107	Celtic Interconnector	FR, IE	2027	in permitting
111	Aurora line (3rd AC Finland-Sweden north)	FI, SE	2025	in permitting
124	NordBalt phase 2	LT, LV, SE	2027	in permitting
127	Central Southern Italy	IT	2027	in permitting
130	HVDC SuedOstLink Wolmirstedt to area Isar	DE	2025	in permitting
132	HVDC Line A-North	DE	2027	in permitting
144	Mid Continental East corridor	RO, RS	2029	in permitting
153	France-Alderney-Britain	FR, GB	2030	in permitting
174	Greenconnector	CH, IT	2026	in permitting
176	Hansa PowerBridge I	DE, SE	2026	in permitting

ID	Project Name	Country	Year	Status
183	DKW-DE, Westcoast	DE, DK	2023	in permitting
187	St. Peter (AT) - Pleinting (DE)	AT, DE	2030	in permitting
200	CZ Northwest-South corridor	CZ	2024	in permitting
210	Würmlach (AT) - Somplago (IT) interconnection	AT, IT	2026	in permitting
219	EuroAsia Interconnector	CY, GR, IL	2026	in permitting
227	Transbalkan Corridor	BA, IT, ME, RS	2026	in permitting
235	HVDC SuedLink Brunsbüttel/Wilster to Großgartach/Bergrheinfeld West	DE	2026	in permitting
247	AQUIND Interconnector	FR, GB	2026	in permitting
250	Merchant line Castasegna (CH) - Mese (IT)	CH, IT	2025	in permitting
254	HVDC Ultranet Osterath to Philippsburg	DE	2026	in permitting
285	GridLink	FR, GB	2025	in permitting
299	SACOI3	FR, IT	2027	in permitting
309	NeuConnect	DE, GB	2027	in permitting
313	Isar/Altheim/Ottenhofen (DE) - St.Peter (AT)	AT, DE	2026	in permitting
323	Dekani (SI) - Zaule (IT) interconnection	IT, SI	2025	in permitting
324	Redipuglia (IT) - Vrtojba (SI) interconnection	IT, SI	2024	in permitting
329	Stevin-Izegem/Avelgem (Ventilus): new corridor	BE	2028	in permitting
339	Tyrrhenian link	IT	2028	in permitting
340	Avelgem-Courcelles (Boucle du Hainaut): new corridor	BE	2029	in permitting
346	ZuidWest380 NL Oost	BE, NL	2029	in permitting
1059	Southern Italy	IT	2028	in permitting
1096	Beznau - Mettlen	CH	2028	in permitting
1100	Reinforcement of the existing CZ-DE interconnector (Hradec - Röhrsdorf) on the CZ side	CZ, DE	2028	in permitting
1102	Mettlen - Ulrichen	CH	2035	in permitting
1103	Bickigen - Chippis	CH	2028	in permitting
1107	EuroAfrica Interconnector	CY, EG	2026	in permitting
47	Westtirol (AT) - Vöhringen (DE)	AT, DE	2030	in planning
120	Belgian Modular Offshore Grid II (MOG II)	BE	2028	in planning
121	Nautilus: multi-purpose interconnector Belgium - UK	BE, GB	2029	in planning
126	SE North-south short-term reinforcements	SE	2035	in planning
228	Muhlbach - Eichstetten	DE, FR	2026	in planning

ID	Project Name	Country	Year	Status
244	Vigy - Uchtelfangen area	DE, FR	2029	in planning
252	Internal Belgian Backbone Center-East: HTLS upgrade Massenhoven-VanEyck-Gramme-Courcelles-Bruegel-Mercator	BE	2038	in planning
259	HU-RO	HU, RO	2030	in planning
270	FR-ES project -Aragón-Atlantic Pyrenees	ES, FR	2030	in planning
276	FR-ES project -Navarra-Landes	ES, FR	2030	in planning
328	Interconnector DE-LUX	DE, LU	2026	in planning
338	Adriatic HVDC link	IT	2028	in planning
341	North CSE Corridor	RO, RS	2029	in planning
342	Central Balkan Corridor	BA, BG, ME, RS	2034	in planning
343	CSE1 New	BA, HR	2033	in planning
375	Lienz (AT) - Veneto region (IT) 220 kV	AT, IT	2035	in planning
378	Transformer Gatica	ES	2027	in planning
379	Uprate Gatica lines	ES	2026	in planning
1034	HVDC corridor from Northern Germany to Western Germany	DE	2031	in planning
1042	Offshore Wind LT 1	LT	2028	in planning
1046	Finnish North-South reinforcement	FI	2030	in planning
1052	Lienz (AT) - Obersielach (AT)	AT	2032	in planning
1054	Westtirol (AT) - Zell/Ziller (AT)	AT	2029	in planning
1086	Estonia internal grid reinforcement to increase RES connection capability (RRF project)	EE	2026	in planning
1104	Niederstedem - Roost	DE, LU	2030	in planning
1109	Basilicata - Campania reinforcements	IT	2030	in planning
1110	Sicily - Calabria	IT	2026	in planning
1121	Hessenberg (AT) - Weißenbach (AT)	AT	2029	in planning
1129	New RES at Minho region	PT	2029	in planning

Table 15: Projects from TYNDP 2022 gas considered for gas grid capacity expansion.

ID	Project Name	Country	Year	Status
TRA-N-7	Development for new import from the South (Adriatica Line)	IT	2028	Advanced
TRA-A-10	Poseidon Pipeline (Phase 1)	GR, IT	2025	Advanced
TRA-A-10	Poseidon Pipeline (Phase 1)	IT, GR	2025	Advanced
TRA-A-10	Poseidon Pipeline (Phase 2)	GR, IT	2025	Advanced
TRA-A-66	Interconnection Croatia -Bosnia and Herzegovina (Slobodnica- Bosanski Brod)	HR, BA	2026	Advanced
TRA-A-66	Interconnection Croatia -Bosnia and Herzegovina (Slobodnica- Bosanski Brod)	BA, HR	2026	Advanced
TRA-A-68	Ionian Adriatic Pipeline	HR, BA	2024	Advanced
TRA-A-70	Interconnection Croatia/Serbia (Slobodnica-Sotin-Bačko Novo Selo)	HR, RS	2030	Advanced
TRA-A-70	Interconnection Croatia/Serbia (Slobodnica-Sotin-Bačko Novo Selo)	RS, HR	2030	Advanced
TRA-A-86	Interconnection Croatia/Slovenia (Lučko - Zabok - Jezerišće - Sotla)	HR, SI	2025	Advanced
TRA-A-86	Interconnection Croatia/Slovenia (Lučko - Zabok - Jezerišće - Sotla)	SI, HR	2025	Advanced
TRA-A-302	Interconnection Croatia-Bosnia and Herzegovina (South)	HR, BA	2024	Advanced
TRA-A-628	Eastring - Slovakia (Phase 1)	SK, HU	2025	Advanced
TRA-A-628	Eastring - Slovakia (Phase 1)	HU, SK	2025	Advanced
TRA-A-628	Eastring - Slovakia (Phase 2)	HU, SK	2030	Advanced
TRA-A-628	Eastring - Slovakia (Phase 2)	SK, HU	2030	Advanced
TRA-A-655	Eastring - Romania (Phase 1)	HU, RO	2025	Advanced
TRA-A-655	Eastring - Romania (Phase 1)	RO, HU	2025	Advanced
TRA-A-655	Eastring - Romania (Phase 2)	BG, RO	2026	Advanced
TRA-A-655	Eastring - Romania (Phase 2)	RO, BG	2026	Advanced
TRA-A-655	Eastring - Romania (Phase 3)	BG, RO	2029	Advanced
TRA-A-655	Eastring - Romania (Phase 3)	RO, BG	2029	Advanced
TRA-A-655	Eastring - Romania (Phase 4)	HU, RO	2030	Advanced
TRA-A-655	Eastring - Romania (Phase 4)	RO, HU	2030	Advanced
TRA-A-656	Eastring - Hungary (Phase 1)	RO, HU	2025	Advanced
TRA-A-656	Eastring - Hungary (Phase 1)	HU, RO	2025	Advanced
TRA-A-656	Eastring - Hungary (Phase 1)	SK, HU	2025	Advanced
TRA-A-656	Eastring - Hungary (Phase 1)	HU, SK	2025	Advanced

ID	Project Name	Country	Year	Status
TRA-A-656	Eastring - Hungary (Phase 2)	RO, HU	2030	Advanced
TRA-A-656	Eastring - Hungary (Phase 2)	HU, RO	2030	Advanced
TRA-A-656	Eastring - Hungary (Phase 2)	SK, HU	2030	Advanced
TRA-A-656	Eastring - Hungary (Phase 2)	HU, SK	2030	Advanced
TRA-A-851	Southern Interconnection pipeline BiH/CRO	HR, BA	2024	Advanced
TRA-A-851	Southern Interconnection pipeline BiH/CRO	BA, HR	2024	Advanced
TRA-A-967	Nea-Messimvria to Evzoni/Gevgelija pipeline (IGNM) and BMS	GR, MK	2024	Advanced
TRA-N-1009	Czech-Polish Bidirectional Interconnection	PL, CZ	2026	Advanced
TRA-N-1009	Czech-Polish Bidirectional Interconnection	CZ, PL	2026	Advanced
TRA-N-1141	Czech-Polish Gas Interconnection - PL section (Czechia to Poland)	CZ, PL	2026	Advanced
TRA-N-1141	Czech-Polish Gas Interconnection - PL section (Poland to Czechia)	PL, CZ	2026	Advanced
TRA-A-1268	Romania-Serbia Interconnection	RO, RS	2023	Advanced
TRA-A-1268	Romania-Serbia Interconnection	RS, RO	2023	Advanced
TRA-A-258	Developments for Montoir LNG terminal 2.5 bcm expansion	FR	2027	Advanced
TRA-F-137	Interconnection Bulgaria - Serbia	BG, RS	2022	FID
TRA-F-245	North - South Gas Corridor in Eastern Poland	PL	2028	FID
TRA-F-298	Modernization and rehabilitation of the Bulgarian GTS	RS, BG	2024	FID
TRA-F-298	Modernization and rehabilitation of the Bulgarian GTS	BG, RS	2024	FID
TRA-F-329	ZEELINK	DE	2023	FID
TRA-F-378	Interconnector Greece-Bulgaria (IGB Project)	GR, BG	2022	FID
TRA-F-378	Interconnector Greece-Bulgaria (IGB Project)	GR, BG	2024	FID
TRA-F-378	Interconnector Greece-Bulgaria (IGB Project)	GR, BG	2027	FID
TRA-F-394	Norwegian tie-in to Danish upstream system	NO, DK	2022	FID
TRA-F-1095	TENP Security of Supply plus (Pipeline Schwanheim-Au am Rhein)	DE	2026	FID
TRA-F-1095	TENP Security of Supply plus (Pipeline Schwarzach-Eckartsweier)	DE	2026	FID
TRA-F-1173	Poland - Denmark interconnection (Baltic Pipe) - onshore section in Poland	PL	2022	FID
TRA-A-68	Ionian Adriatic Pipeline	AL, HR	2028	Less-Advanced

ID	Project Name	Country	Year	Status
TRA-A-68	Ionian Adriatic Pipeline	HR, AL	2028	Less-Advanced
TRA-A-68	Ionian Adriatic Pipeline	HR, ME	2028	Less-Advanced
TRA-N-112	R15/1 Pince - Lendava - Kidričevo (Phase 1)	SI, HU	2025	Less-Advanced
TRA-N-112	R15/1 Pince - Lendava - Kidričevo (Phase 1)	HU, SI	2025	Less-Advanced
TRA-N-112	R15/1 Pince - Lendava - Kidričevo (Phase 2)	SI, HU	2035	Less-Advanced
TRA-N-112	R15/1 Pince - Lendava - Kidričevo (Phase 2)	HU, SI	2035	Less-Advanced
TRA-N-224	Gaspipeline Brod - Zenica	HR, BA	2027	Less-Advanced
TRA-N-224	Gaspipeline Brod - Zenica	BA, HR	2027	Less-Advanced
TRA-N-303	Interconnection Croatia-Bosnia and Herzegovina (west)	HR, BA	2027	Less-Advanced
TRA-N-303	Interconnection Croatia-Bosnia and Herzegovina (west)	BA, HR	2027	Less-Advanced
TRA-N-377	Romanian-Hungarian reverse flow Hungarian section 2nd stage	RO, HU	2027	Less-Advanced
TRA-N-377	Romanian-Hungarian reverse flow Hungarian section 2nd stage	HU, RO	2027	Less-Advanced
TRA-N-390	Upgrade of Rogatec interconnection (M1A/1 Interconnection Rogatec)	SI, HR	2026	Less-Advanced
TRA-N-390	Upgrade of Rogatec interconnection (M1A/1 Interconnection Rogatec)	HR, SI	2026	Less-Advanced
TRA-N-600	Czech-Austrian Interconnection (AT)	AT, CZ	2028	Less-Advanced
TRA-N-600	Czech-Austrian Interconnection (AT)	CZ, AT	2028	Less-Advanced
TRA-N-612	ES-IT Offshore-Interconnector_	IT, ES	2040	Less-Advanced
TRA-N-612	ES-IT Offshore-Interconnector_	ES, IT	2040	Less-Advanced
TRA-N-910	West Interconnection BiH/CRO	BA, HR	2027	Less-Advanced
TRA-N-910	West Interconnection BiH/CRO	HR, BA	2027	Less-Advanced
TRA-N-1059	Czech-Austrian Interconnection (CZ)	CZ, AT	2028	Less-Advanced
TRA-N-1059	Czech-Austrian Interconnection (CZ)	AT, CZ	2028	Less-Advanced
TRA-N-1124	Capacity increase from Bulgaria to Romania (Rupcha-Vetrino Looping)	BG, RO	2024	Less-Advanced

ID	Project Name	Country	Year	Status
TRA-N-1131	Reinforcement of NNGTS-South section	GR, BG	2027	Less-Advanced
TRA-N-1140	Technical capacity increase of gas transmission from GR to BG and BG to NM	GR, BG	2024	Less-Advanced
TRA-N-1140	Technical capacity increase of gas transmission from GR to BG and BG to NM	BG, MK	2024	Less-Advanced

Table 16: Projects from H_2 Infrastructure Map and German Hydrogen core network considered for hydrogen network.

Project Name	Country	Year
H2 Readiness of the TAG pipeline system	AT	2029
H2 Backbone WAG + Penta West (part 1)	AT	2030
Route Breclav - CZ/AT border	AT, CZ	2040
H2 Backbone Murfeld	AT, SI	2035
Central European Hydrogen Corridor (SK part)	AT, SK	2029
HyPipe Bavaria - The Hydrogen Hub	AT, DE	2030
Italian H2 Backbone (part 6)	AT, IT	2029
H2 supply system Croatia - South H2 supply system Croatia - South H2 supply system Croatia – South	BA, HR	2045
H2ercules Belgien	BE, DE	2031
WHHYN : Wallonie Hainaut Hydrogen Network (Franco-Belgian H2 corridor)	BE, FR	2026
DHUNE (Dunkirk Hydrogen Universal NEtwork)	BE, FR	2027
Franco-Belgian H2 corridor Franco-Belgian H2 corridor	BE, FR	2030
Interconnected hydrogen network	BE, LU	2040
National H2 Backbone National H2 Backbone National H2 Backbone National H2 Backbone National H2 Backbone Interconnected hydrogen network	BE, NL	2026
Dedicated H2 Pipeline (part 3)	BG, GR	2029
Giurgiu - Nodlac corridor modernization for hydrogen transmission	BG, RO	2029
Transitgas H2 pipeline project (part 1)	CH, DE	2035
RHYn (part 2)	CH, FR	2028
Waidhaus-Arzberg Arzberg-Niederhohndorf/ Zwickau	CZ, DE	2030
Arzberg-Niederhohndorf/ Zwickau	CZ, DE	2030
EUGAL	CZ, DE	2030
Route Breclav - CZ/PL Border (part 2)	CZ, PL	2040
Central European Hydrogen Corridor, Czech part (CEHC, CZ part)	CZ, SK	2029
Kötz-Hittistetten Altbach-Bissingen	DE	2032
Löchgau-Altbach Flow2H2ercules Ludwigshafen-Karlsruhe	DE	2030
Fessenheim-Bad Krozingen	DE, FR	2028
Folmhusen-Achim Ganderkesee-Bremen H2ercules Nordsee-Ruhr-Link (NRL III) H2ercules Nordsee-Ruhr-Link (NRL III)	DE	2027
Voigtei-Weser AQD SEN-1-Helgoland AQD Helgoland-Schillig	DE	2030
Ganderkesee-Achim	DE	2031
Wefensleben-Wedringen	DE	2027

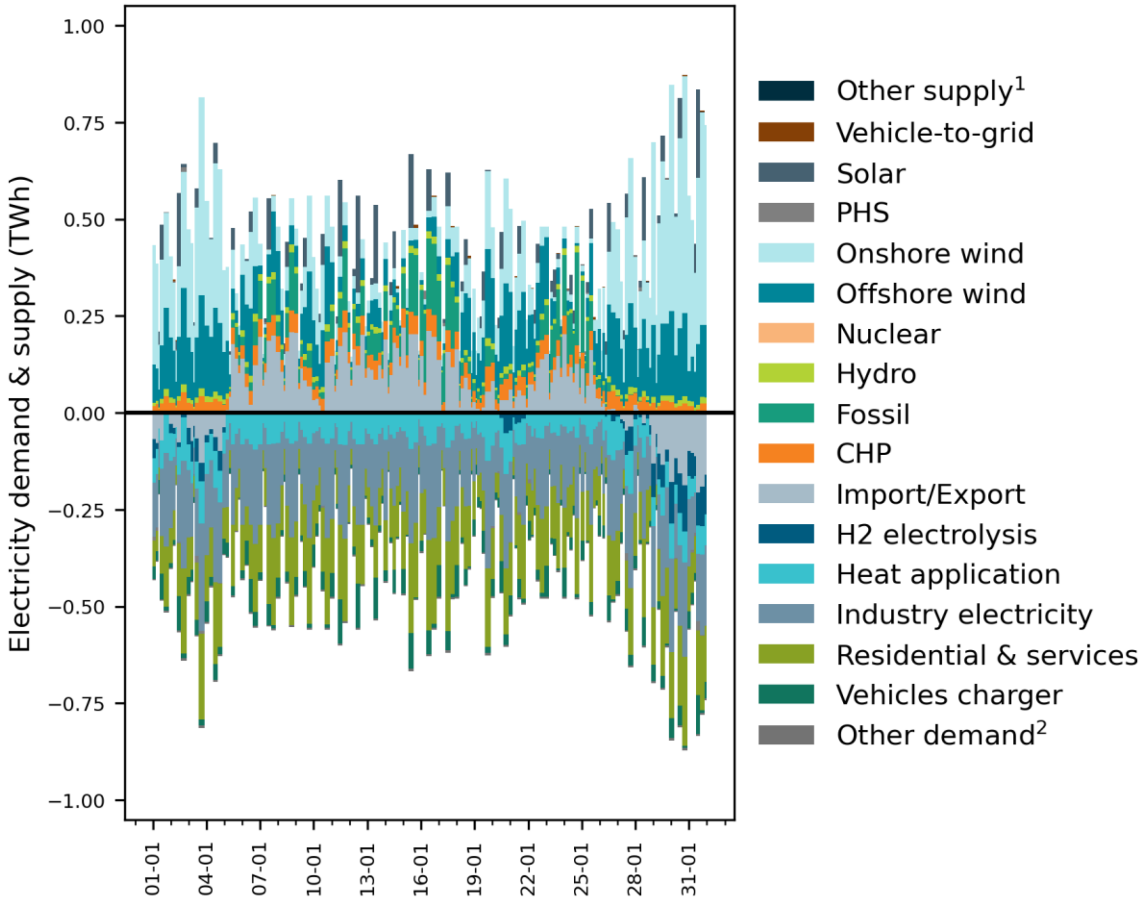
Project Name	Country	Year
Edesbüttel-Bobbau	DE	2029
Werne-Eisenach	DE	2032
Danish-German Hydrogen Network; German Part - HyPerLink Phase III	DE, DK	2028
17-Legden-Chemiepark Marl	DE	2025
GetH2 Legden-Dorsten Gescher Süd-Amelsbüren	DE	2027
H2ercules Gescher-Werne H2ercules Gescher-Werne H2ercules Gescher-Dorsten	DE	2030
H2ercules Werne-Paffrath	DE	2031
H2ercules Neumühl-Werne	DE	2032
388-Seyweiler-Dillingen H2ercules Birlinghoven-Rüsselsheim Delta-Rhine-Corridor (DRC)	DE	2032
MosaHYc (Mosel Saar Hydrogen Conversion) - Germany (part 1) MosaHYc (Mosel Saar Hydrogen Conversion) - Germany (part 7)	DE, FR	2027
Thyssengas NDP 2022	DE, NL	2027
RiBs Rotterdam, Amsterdam, Zeeland, Limburg and North Netherlands	DE, NL	2026
Delta Rhine Corridor H2 (part 2) Delta Rhine Corridor H2 Delta Rhine Corridor H2	DE, NL	2027
Werne-Eisenach	DE	2032
NOGAT offshore H2 backbone project	DE, DK	2028
AquaDuctus (part 1)	DE, DK	2029
CHE Pipeline HyONE-DE (part 1) HyONE-DE (part 1)	DE, DK	2030
Vlieghuis-Kalle	DE, NL	2027
H2ercules Rimpar-Rothenstadt	DE	2032
STEGAL West	DE	2028
H2ercules Rimpar-Rothenstadt	DE	2032
JAGAL	DE	2025
Buchholz-Apollensdorf Lüptitz-Cavertitz	DE	2027
HY-FEN H2 Corridor Spain France Germany connection	DE, FR	2030
H2 Interconnector Bornholm-Lubmin (IBL)	DE, DK	2027
Eisenhüttenstadt-Gosda	DE, PL	2030
Baltic Sea Hydrogen Collector - Offshore Pipeline [BHC] (part 1)	DE, PL	2030
Polish Hydrogen Backbone Infrastructure	DE, PL	2039
CHE Pipeline	DK, NO	2030
Baltic Connector	EE, FI	2029
Spanish hydrogen backbone 2030 (part 1)	ES	2027
Spanish hydrogen backbone 2030	ES	2026

Project Name	Country	Year
Spanish hydrogen backbone 2040 (part 5) Spanish hydrogen backbone 2040 (part 5) Spanish hydrogen backbone 2040 (part 7)	ES	2039
H2Med-CelZa (Enagas) (part 1)	ES, PT	2029
Spanish hydrogen backbone 2040 (part 1) Spanish hydrogen backbone 2040 (part 6) Spanish hydrogen backbone 2040 (part 6)	ES	2039
Spanish hydrogen backbone 2040 (part 5) Spanish hydrogen backbone 2040 (part 7)	ES, FR	2039
H2Med-BarMar	ES, FR	2029
ES-IT Offshore- Interconnector	ES, FR	2040
Nordic-Baltic Hydrogen Corridor - FI section	FI, SE	2028
Baltic Sea Hydrogen Collector - Offshore Pipeline [BHC] (part 2) Baltic Sea Hydro-gen Collector - Offshore Pipeline [BHC] (part 4)	FI, SE	2030
HY-FEN H2 Corridor Spain France Germany connection	FR	2030
HY-FEN H2 Corridor Spain France Germany connection	FR	2030
ES-IT Offshore- Interconnector	FR, IT	2040
Franco-Belgian H2 corridor	FR	2030
Project Union and the UK Hydrogen Backbone (part 1) Project Union and the UK Hydrogen Backbone (part 2)	GB	2028
Project Union and the UK Hydrogen Backbone (part 3)	GB	2028
NGT offshore H2 backbone project	GB, NL	2028
Levante Pipeline Project	GR, IT	2028
H2 repurposing interconnection HR-HU	HR, HU	2040
H2 interconnection Croatia/Slovenia (Luko-Zabok-Rogatec)	HR, SI	2026
Italy-Slovenia-Hungary H2 corridor	HU, SI	2029
HU hydrogen corridor IV HU/SK (part 2)	HU, SK	2029
Italian H2 Backbone Italian H2 Backbone Italian H2 Backbone (part 8) Italian H2 Backbone (part 8) Italian H2 Backbone (part 8)	IT	2029
Italian H2 Backbone (part 3)	IT	2029
Italian H2 Backbone (part 1)	IT	2029
ES-IT Offshore- Interconnector ES-IT Offshore- Interconnector ES-IT Offshore- In-terconnector	IT	2040
Italian H2 Backbone	IT, SI	2040
Nordic-Baltic Hydrogen Corridor - LT section	LT, LV	2029
Nordic-Baltic Hydrogen Corridor - PL section	LT, PL	2029
National H2 Backbone National H2 Backbone	NL	2026
NOGAT offshore H2 backbone project NGT offshore H2 backbone project	NL	2028
HyONE Network NL (part 1)	NL	2030

Project Name	Country	Year
Nordic-Baltic Hydrogen Corridor - PL section	PL	2029
Polish Hydrogen Backbone Infrastructure Polish Hydrogen Backbone Infrastructure	PL	2039
Polish Hydrogen Backbone Infrastructure	PL	2039
Nordic-Baltic Hydrogen Corridor - PL section	PL	2029
Polish Hydrogen Backbone Infrastructure	PL	2039
Polish Hydrogen Backbone Infrastructure	PL	2039
Polish Hydrogen Backbone Infrastructure Polish Hydrogen Backbone Infrastructure Polish Hydrogen Backbone Infrastructure	PL	2039
Baltic Sea Hydrogen Collector - Offshore Pipeline [BHC] (part 1)	PL	2030
Polish Hydrogen Backbone Infrastructure	PL	2039
Baltic Sea Hydrogen Collector - Offshore Pipeline [BHC] (part 1)	PL, SE	2030

Annex 3: Supplementary Figures and Tables

Figure 49: Electricity demand and supply in Germany in 2050 during a period of low renewable electricity generation in the sectoral, national (SN) scenario.



[1] Other supply: Battery discharger, H2 fuel cell, H2 turbine, Home battery discharger

[2] Other demand: Agriculture electricity, Battery charger, DAC, Home battery charger, Methanol production

Figure 50: Hydrogen storage capacity per cluster in the sectoral, national (SN) scenario in 2050.

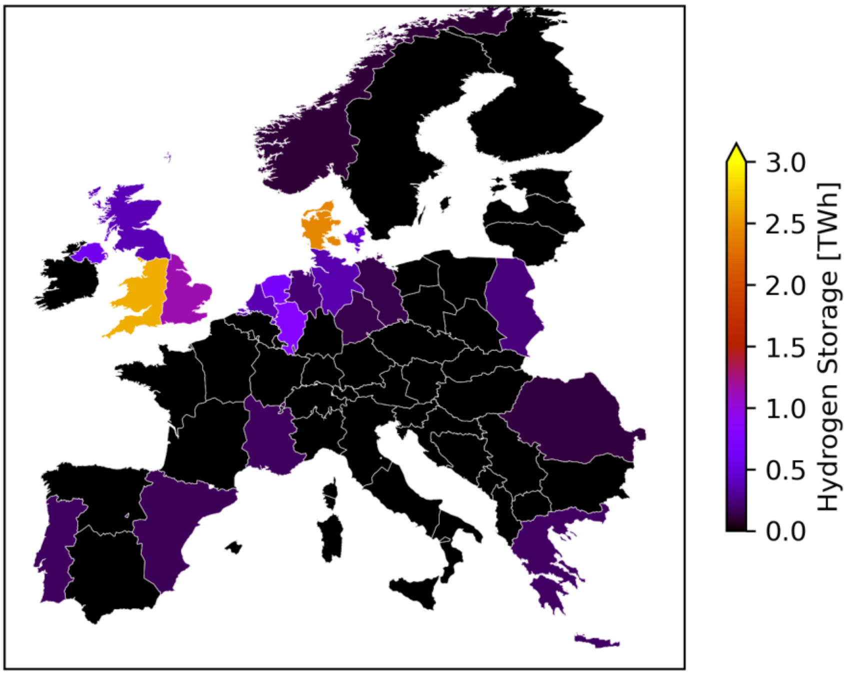
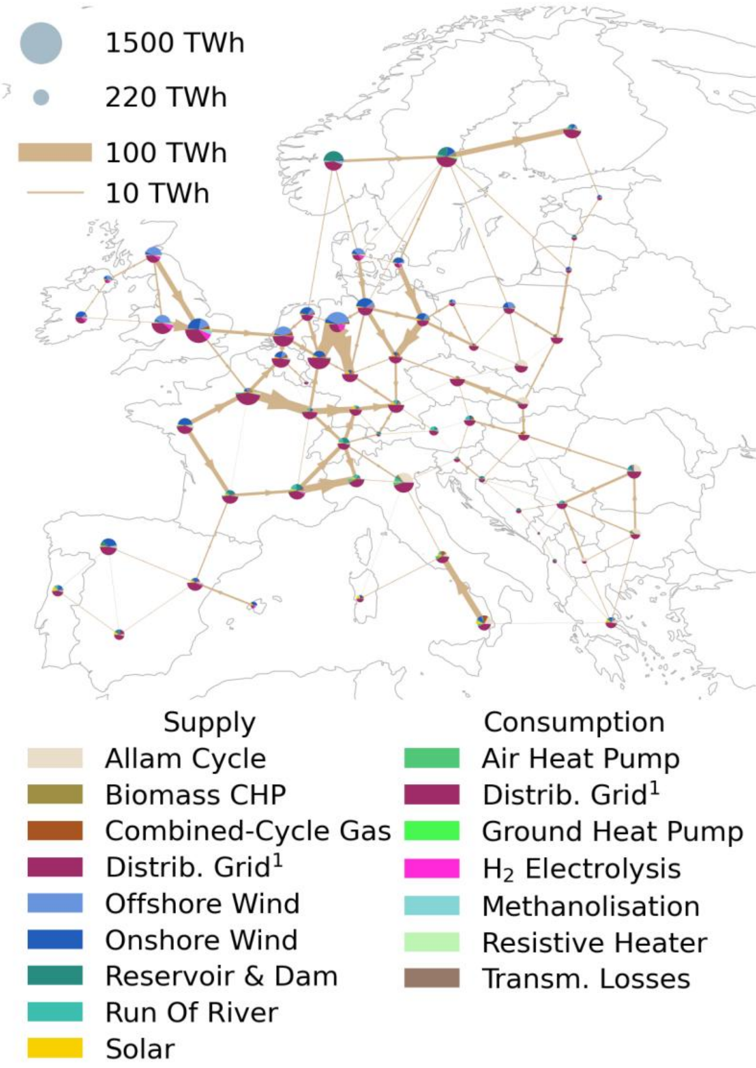


Figure 51: **Optimised annual electricity production, transport & consumption under European, cross-sector integrated grid planning in 2030.**



[1]End consumers and suppliers from distribution-grid level.

Figure 52: Capacity of the electricity grid under variation of the industrial energy demand in the sensitivity discussed in section 8.1.

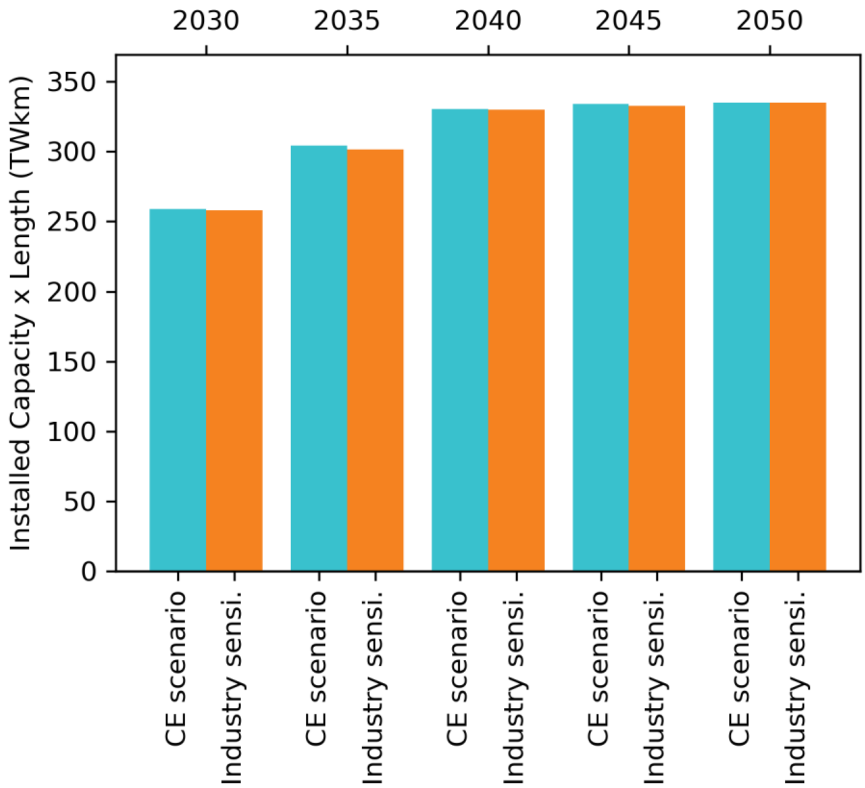


Figure 53: Level of self-sufficiency in the electricity from statistical data in 2022.

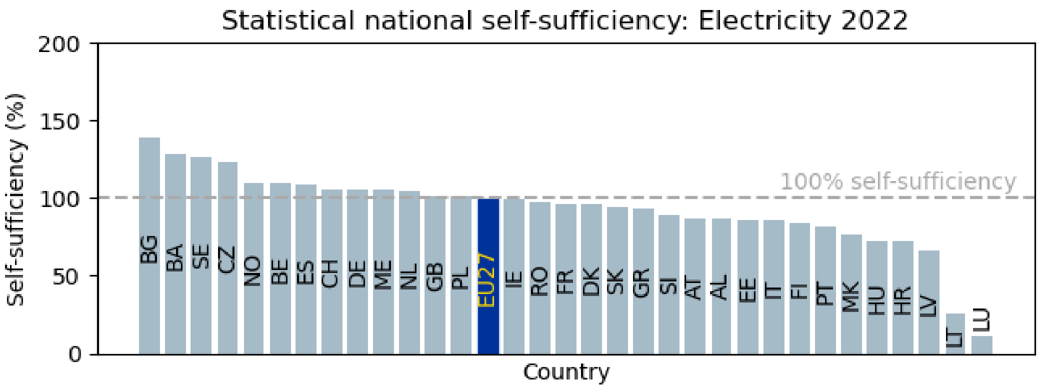


Figure 54: Difference between the electricity networks of the cross-sectoral, European (CE) scenario and the cross-sectoral, national (CN) scenario in 2050.

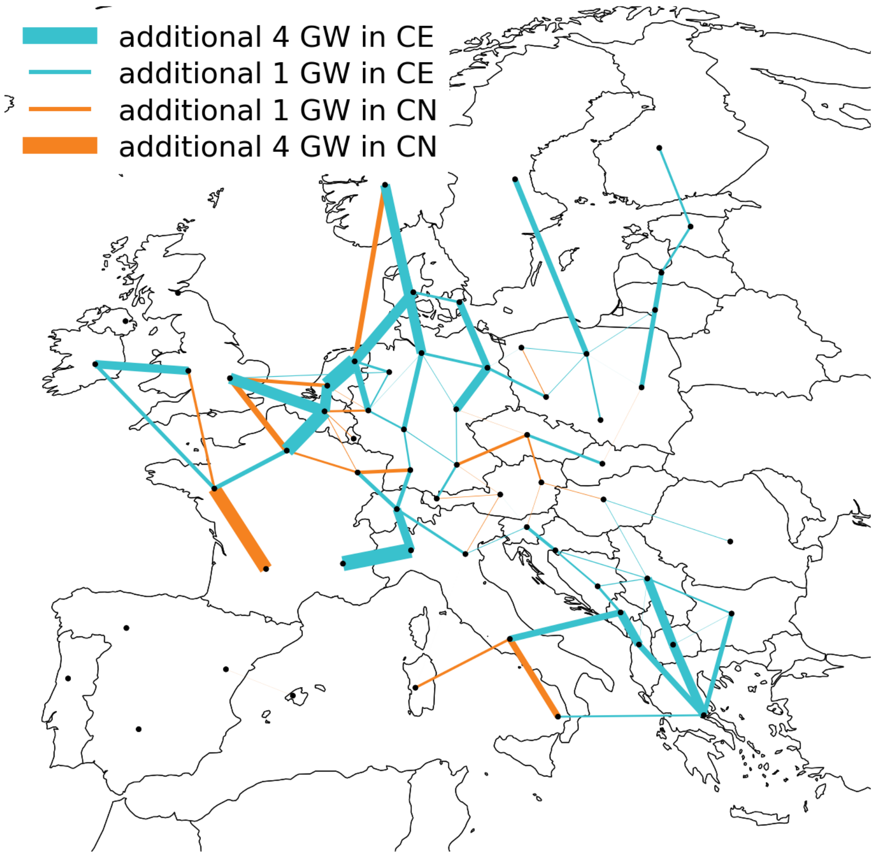


Figure 55: Exogenous electricity grid expansion up until 2040 in the sectoral, national view (SN scenario) according to TYNDP.

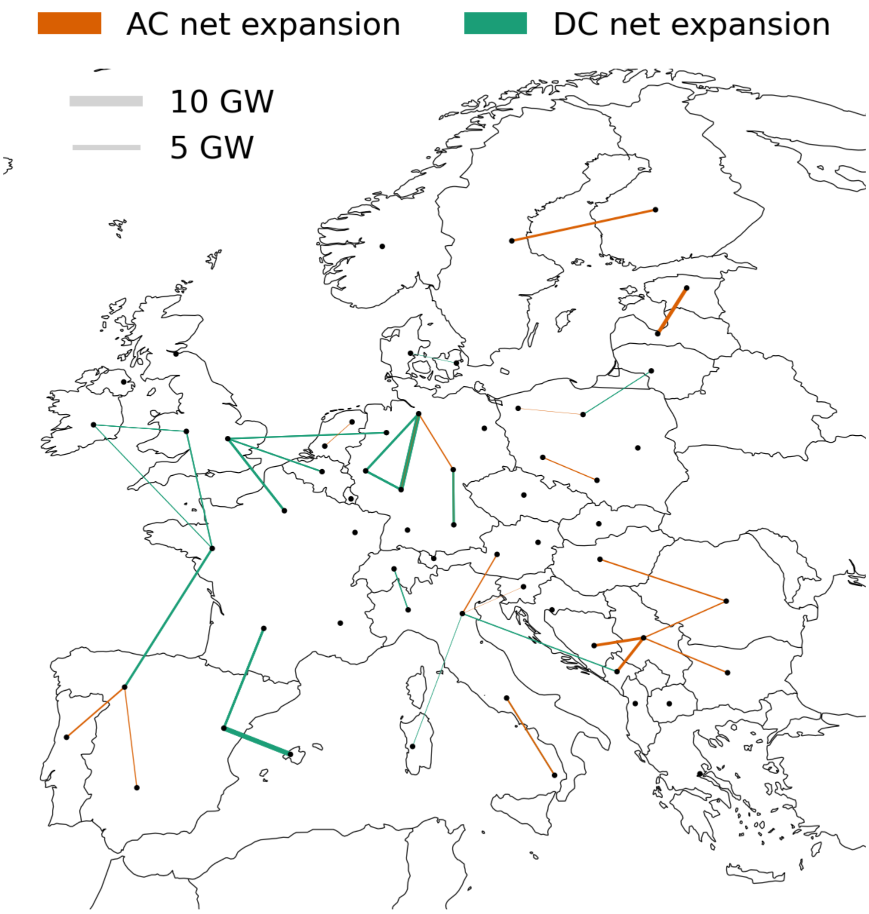


Figure 56: Hydrogen pipeline and storage capacity in 2050 in the cross-sectoral, European (CE) scenario. Pie charts illustrate the hydrogen supply.

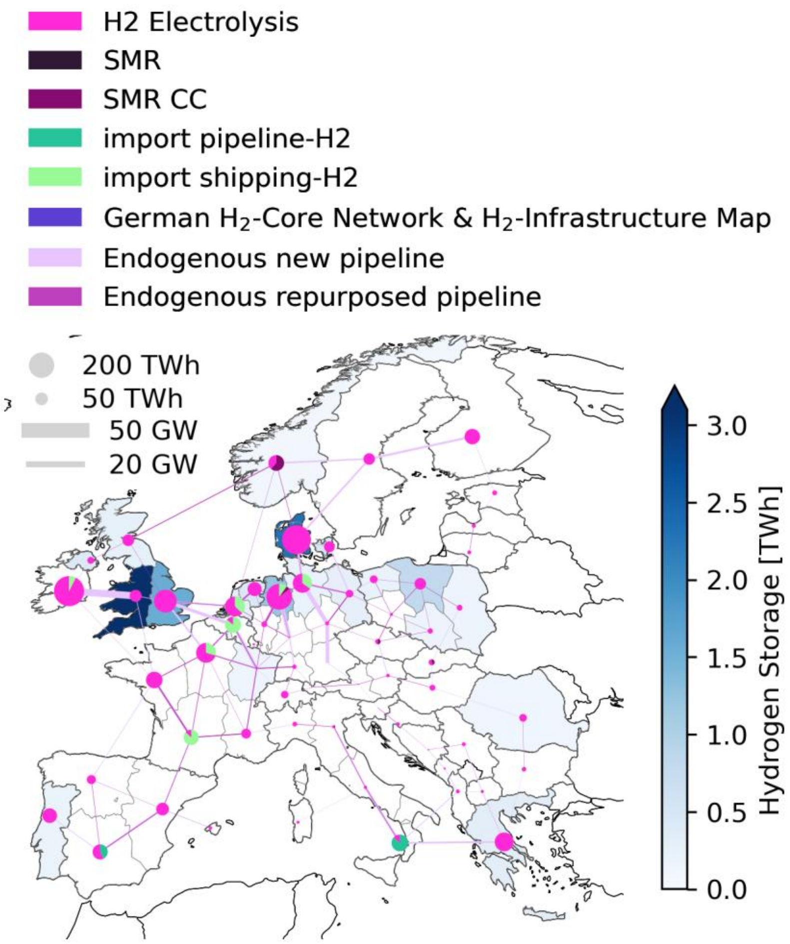


Table 17: Costs for hydrogen import and import infrastructure.

	Component	2030	2035	2040	2045	2050	Reference
Marginal cost (€/MWh)	H_2 (pipeline)	97	87	76	74	71	Fleiter et al. [5]
	LH2	143	138[23]	132[23]	127[23]	121	Genge et al. [39]
	Syngas	163	154[23]	144[23]	134[23]	124	Genge et al. [39]
	Synfuel	161	152[23]	143[23]	134[23]	124	Genge et al. [39]
	LOHC	96	91[23]	86[23]	81[23]	76	Genge et al. [39]
	Ammonia	99	87[23]	75[23]	74[23]	73	Genge et al. [39]
Annualised capital cost (€/MW)	Pipeline retrofit-ting	2688					PyPSA cost assumptions on 100 km pipeline
	LH2 Terminals	8422					Neumann et al. [24]

[23] This value results from interpolation between 2030 and 2050.

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