STUDY

Requested by the ITRE committee

Energy system infrastructures and investments in hydrogen

Including an impact analysis of Ukraine's connection to the EU power grid

Policy Department for Economic, Scientific and Quality of Life Policies
Directorate-General for Internal Policies
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PE 754.207- April 2024

EN

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Abstract

This study analyses the present and future of the European electricity and gas infrastructure, exploring production capacity scenarios and their impact on the electricity system (including the role of interconnections, transmission and distribution grids, prosumers, and storage). It also assesses the potential impact of renewable hydrogen development in terms of production and transport. Furthermore, it discusses Ukraine's synchronisation with the EU power grid and its potential impact on the EU energy system.

This document was provided by the Policy Department for Economic, Scientific and Quality of Life Policies at the request of the Committee on Industry, Research and Energy (ITRE).

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Manuscript completed: March 2024
Date of publication: April 2024

This document is available on the internet at:
http://www.europarl.europa.eu/supporting-analyses

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ACER	European Union Agency for the Cooperation of Energy Regulators
APS	Announced Pledges Scenario
CAGR	Compound Annual Growth Rate
CAPEX	Capital Expenditure
CCS	Carbon Capture and Storage
DSO	Distribution System Operator
EASE	European Association for Storage of Energy
EED	Energy Efficiency Directive
EHB	European Hydrogen Backbone
ENTSO-E	European Network of Transmission System Operators for Electricity
EU	European Union
FID	Final Investment Decision
GHG	Greenhouse Gases
GWel	Electrical Gigawatt (used to describe the electrical consumption of an electrolyser)
HV	High-Voltage
IPS/UPS	Integrated Power System / Unified Power System
JRC	Joint Research Centre
Mt	Million tonnes
Mtoe	Million tonnes of Oil Equivalent
NDC	Nationally Determined Contribution
NDC-LTS	Nationally Determined Contributions and Long-Term Strategies
NECP	National Energy and Climate Plan
OPEX	Operational Expenditure

pp	Percentage Points
PPA	Power Purchase Agreement
PV	Photovoltaics
TSO	Transmission System Operator
TYNDP	Ten-Year Network Development Plan
VRE	Variable Renewable Energies

EXECUTIVE SUMMARY

Background

The EU's energy mix is expected to dramatically change by 2030 and even further by 2050 due to mounting political momentum for energy system decarbonisation. Europe is amid a geopolitical, environmental, and economic transformation that was accelerated by the Covid-19 pandemic and Russia's war of aggression against Ukraine. Europe's heavy reliance on Russian oil and gas imports rendered it vulnerable to significant political pressure. While this situation resulted in serious economic and social implications, it also heightened the need to collectively advance the energy transformation across the European Union.

Decarbonising Europe's energy system rests on three key pillars: first, the mitigation of greenhouse gas (GHG) emissions from the energy sector, mainly through decreases in energy demand, electrification of end-uses, and development of renewable and low-carbon energies; second, reducing external dependency risks, including reliance of fossil-fuels coming from outside of the EU (e.g., Russia) and on infrastructure development by foreign competitors (e.g., China); third, the facilitation of this transition borne by citizens must be at a reasonable cost, mainly by ensuring affordable prices for retail energy.

However, the existing infrastructures for energy production, import, and transmission were built for a centralised energy system that is largely dependent on fossil fuel. Decarbonising the energy system will require much more renewable energy, particularly wind and solar, which will have large impacts on both the electricity system and gas infrastructure and will require the progressive phase-out of fossil fuels and their infrastructure while developing new energy carriers, particularly hydrogen.

Since the REPowerEU communication in 2022, the EU has instituted ambitious reforms and action plans to match these objectives, including institutionalisation of the Fit for 55 package into directives and regulations (e.g., energy efficiency, renewable energies) but also into new strategies, including the EU Solar Energy Strategy, the Wind Power Action Plan, the Grid Action Plan, and more recently the Net-Zero Industry Act.

Aim

The aim of this study is to provide a comprehensive analysis of the current and future European energy system in relation to these strategies. It focuses on the role the EU's energy infrastructure can play in sustaining increasing electrification. It also compares recent achievements and the current development pace to the most recently formulated EU-objectives and associated strategies.

Chapter 1 looks at the current status of the energy system, its evolution during the last decade, and the impacts of that evolution on the decentralisation of energy assets, on the EU's energy dependency and on wholesale and retail energy prices. Chapter 2 explores the changes in production infrastructure that are needed to meet the climate objectives for 2030 and 2050, and puts these into perspective by comparing them to current growth rates of various power production assets including solar, wind, and nuclear power. Chapter 3 focuses on the electricity grid and on the role that flexibility assets could play in mitigating the impact of high penetration rates of renewables. Chapter 4 analyses the role hydrogen could play in the future energy system and the associated infrastructure that would be required to facilitate its development, both by building new assets (electrolysers, renewables, pipelines) and by repurposing existing assets, namely the gas network. Finally, Chapter 5 analyses the impacts of Ukraine's 2022 synchronisation to the European power grid, while Chapter 6 presents the conclusion and recommendations.

Key Findings

The European energy system has undergone profound changes over the last three decades, marked by a reduction in energy demand and a shift from coal, oil and nuclear to renewables and natural gas.

The European Union's energy transition has been in line with objectives set forth for 2020, both in terms of energy demand reduction (Energy Efficiency Directive) and penetration of renewable energies (Renewable Energy Directive). The progress in energy efficiency in industry has contributed most to demand reductions, but is slowing down and will need to be complemented with demand reductions in other sectors, in particular through the electrification of end-uses.

Sources of renewable electricity have contributed the largest share towards the EU's renewables target, mainly driven by solar and wind power. At the same time there has been a progressive replacement of coal, oil, and nuclear power plants with gas-fired units that has made the EU more reliant on natural gas. Nuclear power, though undergoing a decline, has consistently been the largest contributor to the EU's power generation since 1997. A stabilisation of the decline in nuclear is predicted from 2030 in some scenarios, propelled by the emergence and advancement of new nuclear reactors, while others estimate that new capacity additions may prove inadequate to offset the closure of current power plants.

During the past decade, increased development of the electricity infrastructure facilitated a gradual growth in cross border electricity exchanges while electricity production remained stable. At the same time, developments of the gas network have slowed down and are now focused on maintenance of existing assets.

This has had multiple impacts on the EU's energy infrastructure. First, there has been a decentralisation of power production, which has enlarged the role of distribution system operators and created challenges for the efficient integration of distributed energy sources into the grid. Second, a modest reduction in reliance on energy imports has occurred, resulting in part from a large increase in locally produced biomass. Third, there have been impacts on intraday wholesale electricity prices, including increased volatility, especially in countries with high shares of renewables. However, the impact of this transition on long-term and retail energy prices is less obvious. The surge in energy prices in 2022 was mainly a consequence of Russia's war of aggression against Ukraine, and was exacerbated by the EU's increased reliance on imported Russian gas.

Achieving Fit for 55 objectives by 2030 and the net-zero target by 2050 will require a rapid acceleration in the electrification of end-uses and of wind power development.

Meeting the European Union's 2030 GHG reduction objectives and the net-zero target by 2050 poses considerable challenges. While all existing scenarios analysed in this study are conservative and are not sufficient to achieve the most recent renewables' and energy demand targets, they all involve an evolution in energy production and demand at four levels.

First, it requires increased electrification of end-uses as a strong driver of energy efficiency progress in all sectors, particularly in transport. Second, while growth in solar power aligns with the achievement of Fit for 55 objectives and the EU solar strategy, there are development challenges for wind power related to its cost, auction mechanisms, and grid connection queues. Third, a large drop in fossil fuel consumption is anticipated that can only partially be compensated for by the development of biomethane, hydrogen as an energy carrier, and carbon capture and storage. However, this development might also result in an increase in fossil power plant capacities to compensate for the unpredictability of variable renewable energies (wind and solar). Such plants will need to be built with lower capacity factors and at increased costs (Carbon Capture projects, penetration of biomethane in the gas mix). Finally, in this transition, total plant capacity is expected to significantly grow compared to electricity production, meaning that capacity factors will be overall lower, and production costs per kWh higher.

As the EU's energy system electrifies, optimising the penetration of variable renewable energies through holistic planning of flexibility portfolios becomes pivotal for a successful energy transition.

In order to reduce the need for fossil fuel power plants, there will be an increased need for flexibility services directly proportional to variable renewable energy penetration. The potential overdevelopment of solar, and lower-than-expected development of wind may increase this need.

Grid flexibility will be provided by an extensive portfolio of technologies at various levels. Substantial investments in grid infrastructure are anticipated, including the doubling of cross border interconnections by 2040, ambitious investments in national transmission networks, particularly in Germany, and the expansion of distribution networks to accommodate the growing share of decentralised production assets, thereby reducing mounting connection queues. Reducing connection queues will require adaptation by Distribution System Operators, particularly of their remuneration models to new practices favouring less-capital intensive, but more flexible approaches.

Meeting flexibility requirements calls for additional storage resources, with batteries playing a significant role in short-term flexibility. Batteries should complement longer-duration storage solutions, such as hydropower, to collectively provide up to 40% of required flexibility. Lastly, influencing the demand-side by increasing shares of self-consumed energy and fostering a market for demand response are crucial complementary drivers steering this transition.

The development of low-carbon hydrogen is a strong lever for decarbonisation of the energy system that can benefit from the existing gas infrastructure.

Renewable and low-carbon hydrogen produced by electrolysis, directly or indirectly powered by renewable electricity and nuclear, has the potential to solve three key issues related to the EU's energy transition. In the short term, it can help decarbonise the currently gas-intensive production of hydrogen, which represents up to a third of natural gas consumption in the industrial sector. Additionally, it can partly replace other fossil fuel-intensive end-uses, particularly industrial heat and heavy transport. Finally, in the long-term it could be used as a fuel for existing natural gas power plants, and thus provide long-term energy storage to a decarbonised electricity grid, complementing hydropower, which has a limited growth potential.

Today, hydrogen is mostly produced locally. To achieve a sufficient scale to meet the EU's goals for green hydrogen production, a cost-efficient solution would be to centralise electrolysis production in large, GW scale projects (in the EU or in neighbouring countries). To this end, the development of a hydrogen transmission network would be an economic solution that would avoid unnecessary development of expensive power lines. This network could benefit from the existing natural gas network, which could be partially retrofitted for this purpose.

The EU, through the European Strategy on Hydrogen and the REPowerEU communication, has set extremely ambitious objectives for renewable hydrogen development that will require an electrolyser capacity of up to 140 GWel by 2030. While the announced hydrogen and electrolyser production projects match this target, a negligible share of announced projects have reached the financial investment decision stage. The financing and viability of those projects will be a key issue.

Additionally, the EU's definition of renewable hydrogen encourages the development of projects directly connected to renewable power plants with low capacity factors. These projects will require a significantly larger installed capacity than grid-connected ones and could monopolise variable renewable energy capacities that could have been used to directly replace fossil fuel electricity production.

The emergency synchronisation of Ukraine and Moldova to the European continental grid serves short- and long-term interests on both sides.

In the short-term, it has allowed Ukraine to secure its electricity supply during intensive Russian bombing, and during maintenance of Ukraine's nuclear plants. It has also allowed Ukraine to export significant amounts of electricity to its European neighbours, thus generating valuable profits.

In the long-term, Ukraine aims to become an important supplier of electricity to Europe, mainly from its nuclear power plants. Recent agreements also point to strong participation in the future hydrogen economy. However, it is likely that these projects will not be possible until the war ends and reconstruction occurs. The readiness of private investors to commit investment despite a heightened risk of asset destruction remains unconfirmed. The support of the EU will be crucial in this future reconstruction.

This study provides seven key recommendations based on these key findings on how the adaptation of EU's infrastructure could be better prepared for a resilient, well-integrated energy system fit for a climate neutral future:

- Remove economic and regulatory barriers to renewable power development, focusing on a review of national auctions for wind power and a facilitation of administrative burden at the Distribution System Operators' level.
- Create and regularly update a bettered assessment of flexibility requirements at the Member State level.
- Remove barriers to self-consumption to optimise grid flexibility, focusing on increasing the self-consumption rate through the use of more attractive tariffs, and stronger incentives for demand management assets (home batteries, Home Energy Management Systems, etc.).
- Change remuneration models for grid operators, shifting from a CAPEX-based remuneration to an OPEX-based one more adapted to a more digitalised and flexible grid.
- Plan for the partial decommissioning of the gas distribution and transmission network resulting from reduced demand for fossil fuels.
- Use biomethane development to limit the decommissioning of the gas distribution network.
- Capitalise on the gas transmission network for the development of hydrogen, but prioritise local production.

1. ENERGY SYSTEM INFRASTRUCTURE: CURRENT STATUS

KEY FINDINGS

The European Union's energy transition has thus far been in line with its 2020 objectives, both in terms of energy demand reduction (Energy Efficiency Directive) and penetration of renewable energies (Renewable Energy Directive). The progress in energy efficiency in industry has been the main cause of demand reduction but is slowing down and will need to be complemented by demand reductions in other sectors.

Sources of renewable electricity have contributed the largest share towards the EU's renewable target, mainly driven by solar and wind power. At the same time, there has been a progressive replacement of coal, oil, and nuclear power plants with gas-fired units. This has had multiple impacts on the energy system infrastructure. First, there has been a decentralisation of power production, which has enlarged the role of distribution system operators and created challenges for the efficient integration of distributed energy sources into the grid. Second, a modest reduction of its reliance on energy imports has occurred, including a strong increase of locally produced biomass. Third, there has been an impact on intraday wholesale electricity prices, with an increase in volatility particularly exacerbated in countries with a high share of renewables.

However, the impact of this transition on long-term and retail energy prices is less obvious. The 2022 surge in energy prices was exacerbated by the EU's increased reliance on imported Russian gas.

1.1. Introduction and Background

The European Union's energy system is in the early stages of an unprecedented transition. A thorough understanding of the recent evolution towards energy system decarbonisation, especially the integration of a high proportion of renewables, is imperative for a better overview of the future challenges to achieving the energy transition.

This chapter provides an analysis of the pillars of the EU's decarbonisation strategy. First, future **energy demand** is evaluated, including total and sector-specific demand, as well as demand by energy carrier. Next, the EU's **electricity sector** is summarised, including installed capacities and associated production. The chapter concludes with an analysis of the impact these changes will have on the decentralisation of electricity production, commercial energy balances, and energy prices.

Note that 2000 was chosen as the baseline year because it represents the starting point of the increase in development of wind and solar (highlighted below in Figure 8).

1.2. Energy Demand

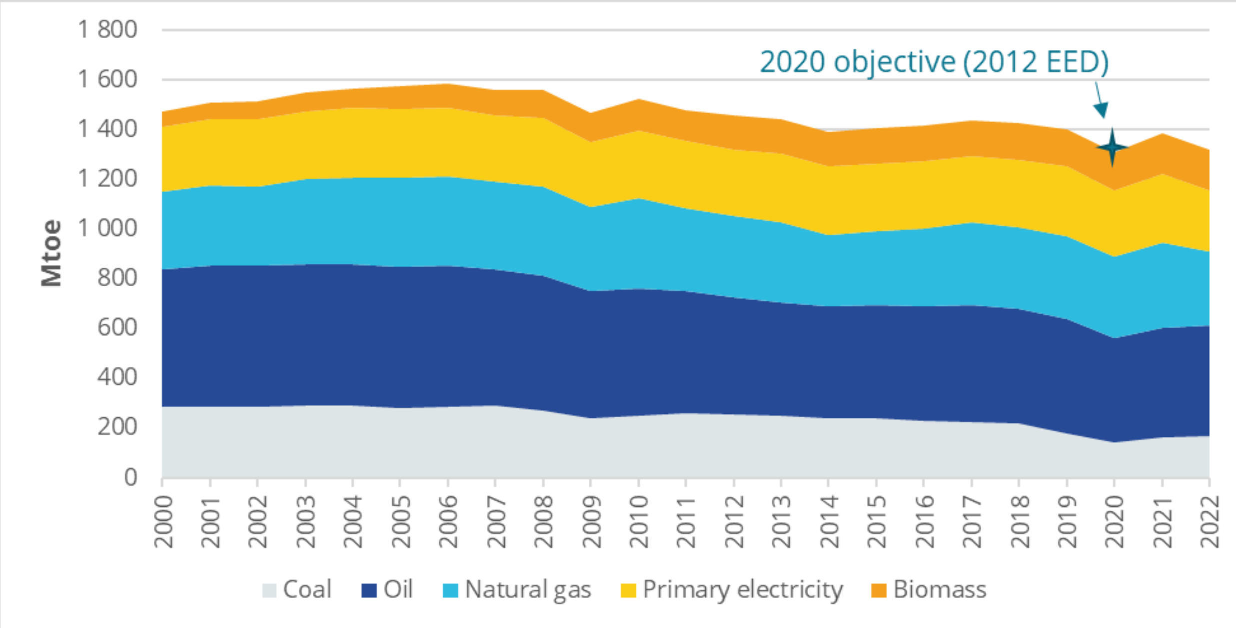
Energy demand must significantly decrease for the energy system to be decarbonised. Three factors contribute to decreases in energy demand: **energy efficiency improvements** (producing the same services or products with less energy), **energy sufficiency** (choosing to use less of a service or product), and **declining economic activity.**

This section includes a detailed overview of energy demand in the EU by carrier, sector, and country, as well as a decomposition analysis.

1.2.1. Trends in European Energy Consumption

Primary energy demand in the EU[1] has steadily decreased over the last 17 years. As shown in Figure 1, after reaching an absolute peak in 2006 of 1,586 Mtoe, demand declined 17% (270 Mtoe) by 2022. During the same period, the EU's GDP increased by 30%. This change in demand resulted in the European Union reaching the savings target in the revised 2012 Energy Efficiency Directive (EED), equivalent to 1,312 Mtoe in 2020[2]. However, this achievement was mostly due to the COVID-19 pandemic, and energy demand rose again in 2020. The 2008 global financial crisis also led to a discernible dip in energy consumption.

Figure 1: EU primary energy demand by energy source (2000-2022)



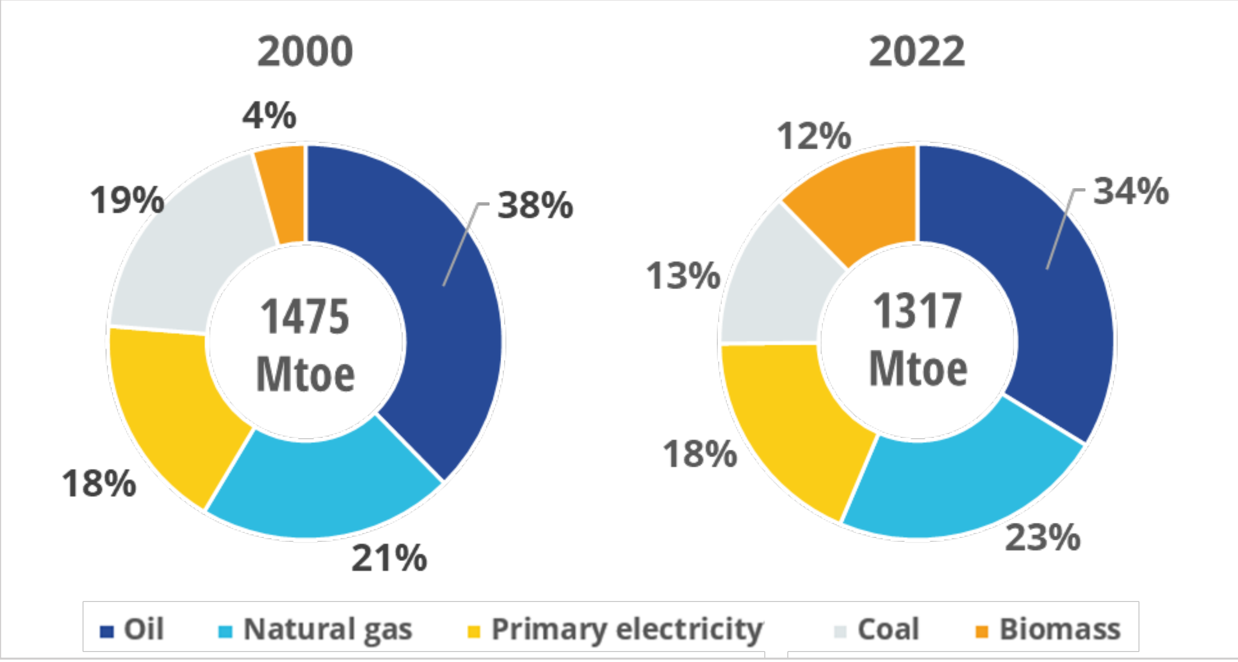
Source: Global Energy and CO2 Data, Enerdata.

Note: Primary Electricity includes heat, nuclear (1 TWh = 0.26 Mtoe), hydroelectricity, wind and solar PV (1 TWh = 0.086 Mtoe), and geothermal (1 TWh = 0.86 Mtoe).

[1] The primary energy demand of a country is measured by its primary energy consumption. In the following, demand and consumption are used interchangeably.

[2] EU targets on primary energy consumption are defined in the Energy Efficiency Directive (2012/27/EU). This directive set in 2012 an objective of 1,474 Mtoe of primary energy consumption. This objective was revised to 1,483 in 2018 and adjusted to 1,312 in 2020 to account for the United Kingdom leaving the EU. More information: https://energy.ec.europa.eu/topics/energy-efficiency/energy-efficiency-targets-directive-and-rules/energy-efficiency-directive_en.

Figure 2: EU primary energy consumption by energy source (2000 vs. 2022)



Source: Global Energy and CO2 Data, Enerdata.

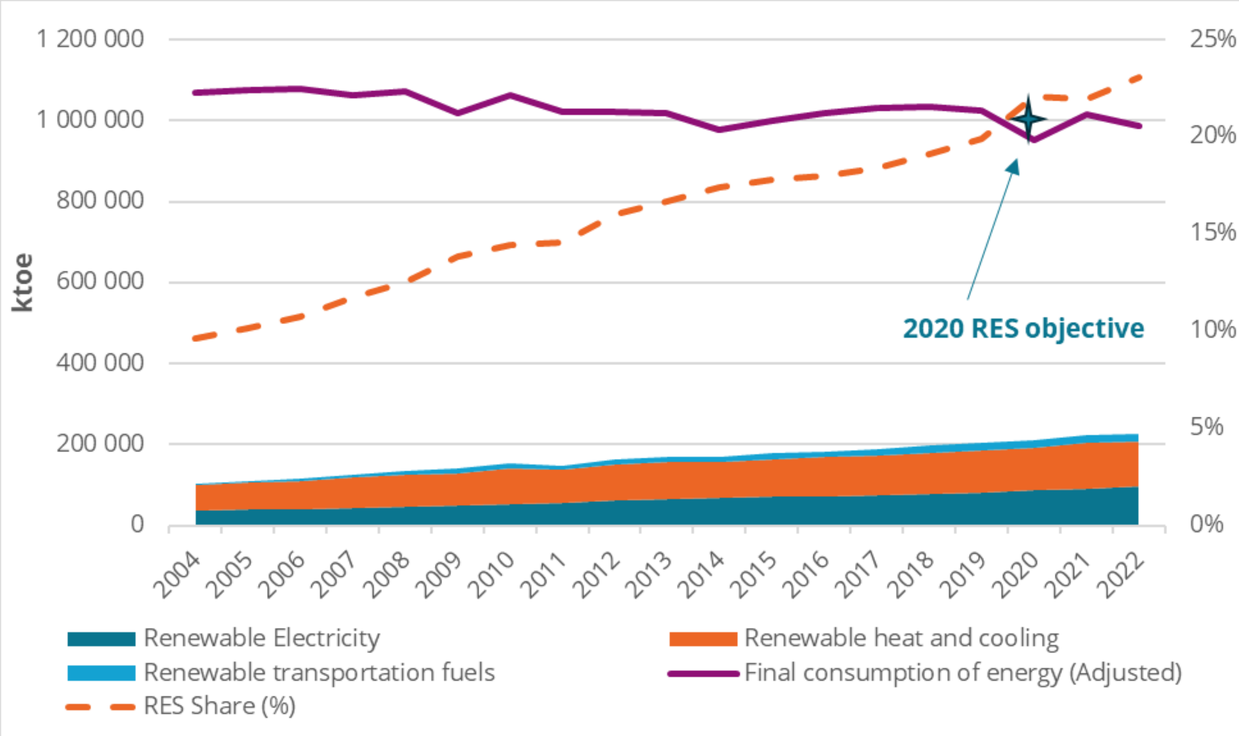
There has been a steady replacement of coal and oil with gas and biomass over the last 22 years; this is difficult to see in Figure 1, but visible in Figure 2. While it appears that there is only a small increase in the natural gas share between 2000 and 2022, it is due to the fact that increases between 2000 and 2010 and 2014 to 2021 were offset by a sudden decline in 2022 due to Russia's war of aggression against Ukraine and the ensuing energy crisis[3]. Conversely, coal consumption dropped by more than half, from 27% in 1990 to 13% in 2022. This decline reflects the commitment of multiple EU Member States[4] to phasing out coal due to its environmental impacts. The increase in demand for biomass was primarily from the transport sector (biofuel) and the residential sector (heating). In 2022, oil, natural gas, and coal accounted for 69% of the European Union's energy demand.

Figure 2 also shows no change in the proportion of primary electricity demand. Although the European Union lacks a defined objective regarding the electrification of demand, all scenarios outlined in Chapter 3 show substantial increases in electrification of end uses, particularly within the residential, transport, and industrial sectors, though electrification is currently at an early stage.

3 The gas demand reduction between 2021 and 2022 is 42 Mtoe according to a recent ITRE study (Bruegel, 2023), available at: https://www.europarl.europa.eu/RegData/etudes/STUD/2023/740094/IPOL_STU(2023)740094_EN.pdf, page 13, Figure 1.

4 This includes France (by 2027), Spain (by 2025), Italy (by 2027), Finland (by 2029), Ireland (by 2025), Greece (by 2028), Hungary (by 2027), and Slovakia (by 2024) according to Beyond Fossil Fuels, see https://beyondfossilfuels.org/europes-coal-exit/.

Figure 3: Development of Renewable Energies and the share of RE (2004-2022)

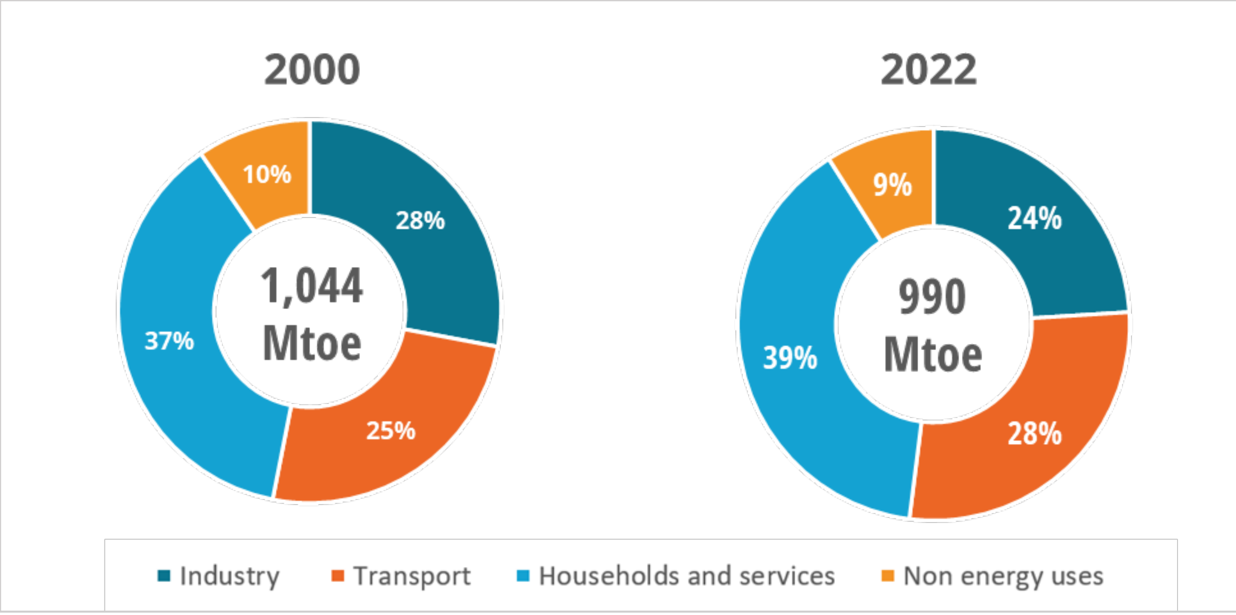


Source: (Eurostat, 2024).

Notes: This analysis is not available before 2004. The final energy consumption is adjusted to match the specific criteria of RED I.

The trend towards less carbon-intensive fuel sources coupled with lower demand has resulted in the EU achieving its 2020 renewable energy objectives. Directive 2009/28/EC (RED I) specified a target of 20% renewable energy in gross final energy consumption by 2020. This target was surpassed in 2020, with a 22% share being achieved, as illustrated in Figure 3. While the substantial reduction in demand attributable to the COVID-19 pandemic played a pivotal role in attaining this objective, the increase in renewables continued in 2021 and 2022, primarily due to increases in renewable heat and cooling. Further, **renewable electricity production grew by 155% between 2004 and 2022**. The evolution of renewable electricity production is detailed in Chapter 1.3.2.

Figure 4: EU final energy consumption by sector (2000 vs. 2022)



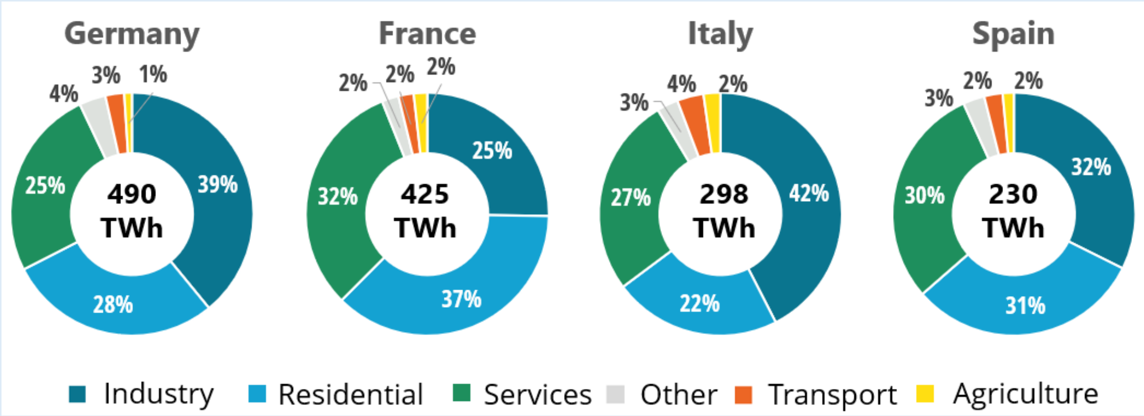
Source: Global Energy and CO2 Data, Enerdata.

Figure 4 shows the distribution of final energy consumption by sector in the EU for the years 2000 and 2022. There are observable shifts in energy usage patterns over this period, in particular for industry. In 1990, industry accounted for 28%[5] of total energy consumption; by 2022, its share had decreased to 24%. During the same period all others sectors relative share grew. This change is further described in the next chapter.

[5] This trend is further accentuated when considering 1990 as a reference point, during which industry accounted for 33% of the energy consumption.

Box 1: Electricity consumption differences by country

Figure 5: National electricity consumption by sector in the top four countries (2022)

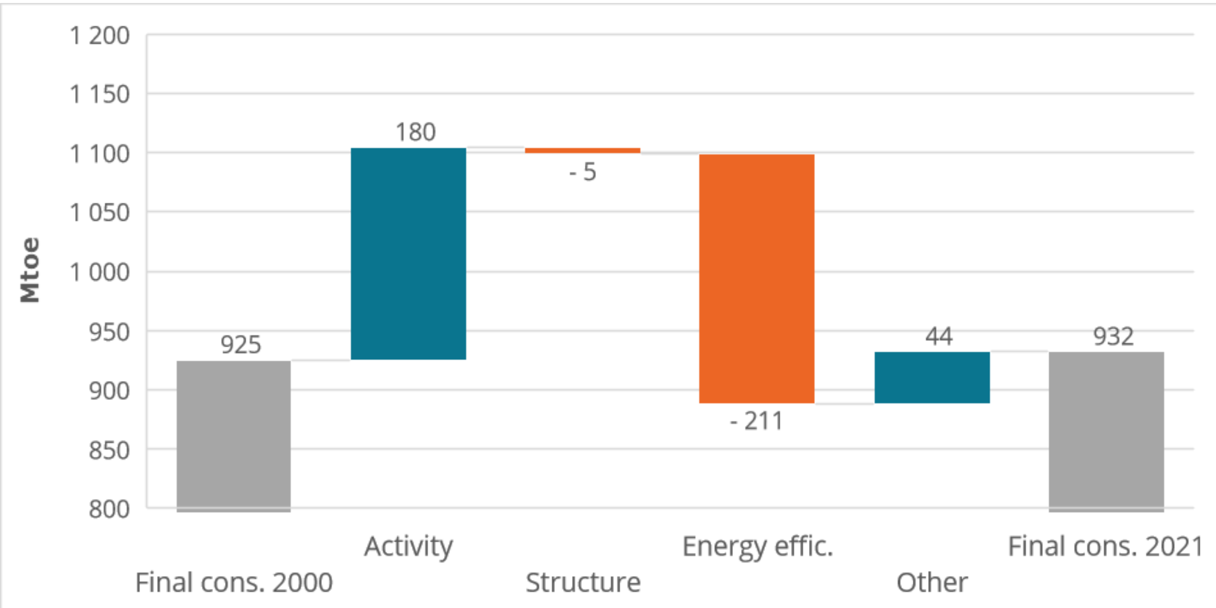


Source: Global Energy and CO2 Data, Enerdata.

The figure above shows the distribution of electricity use in the top four electricity using countries in the European Union. While the distributions are similar, France stands out with high proportions of use in the residential and services sectors, which is attributable to its nuclear program and an extensive heating electrification initiative that started in the 1960s. The ongoing replacement of inefficient heaters stands as a potent catalyst for enhancing energy efficiency.

1.2.2. Decomposition of the European Energy Consumption Decrease

Figure 6: Variation in final energy consumption (with climatic correction) in the EU27



Source: ODYSSEE (https://www.indicators.odyssee-mure.eu/decomposition.html), based on Eurostat and national data (Odyssee, n.d.).

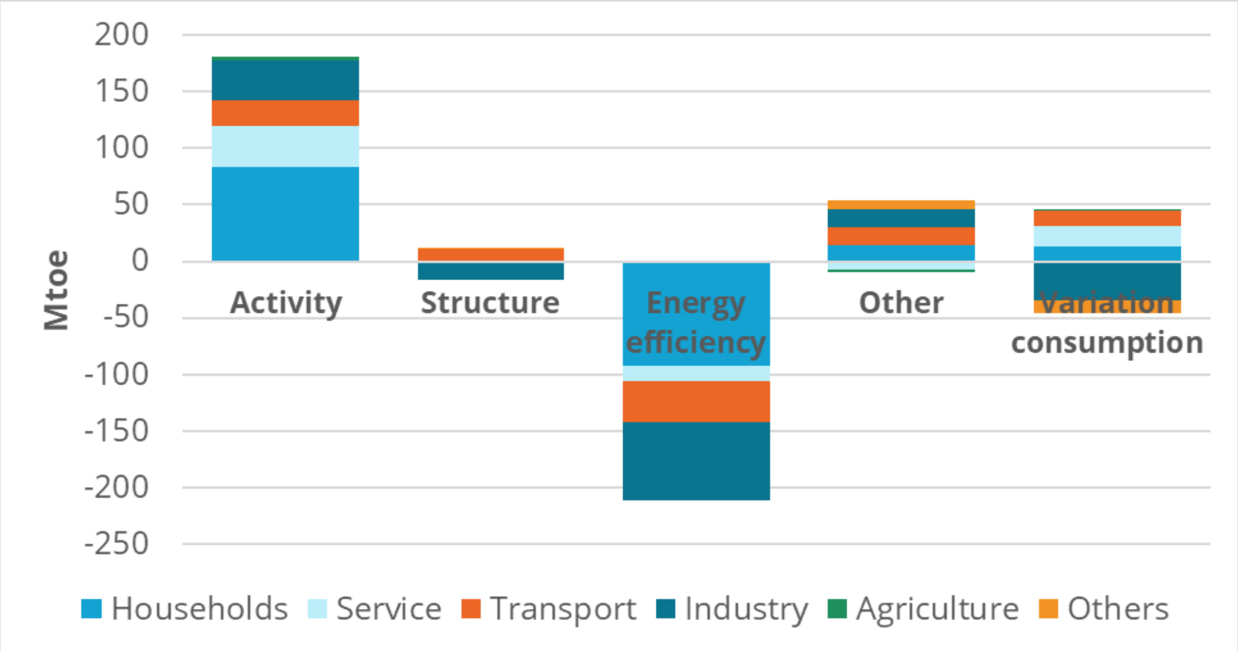
Note: The data for 2022 was not available during the writing of this study.

The shift in energy demand is explained by three factors that have been identified by the Odyssee Project (Odyssee, n.d.), and are illustrated in Figure 6. Most importantly, there is an **evolution in sectoral activity** (changes in value added in industry, services, and agriculture, in traffic in transport, in number of dwellings and appliances and in the size of dwellings for households). Further, **structural**

changes, such as modal shifts in transport contribute to this shift. Finally, **energy efficiency**, in particular technical savings measured through the ODEX[6] indicator, plays a significant role. Other factors include changes in heating energy use in the residential sector and climate impact on heating needs.

Figure 6 shows that **advancements in energy efficiency are the primary driver behind the decline in final energy demand**. In 2021, energy efficiency measures within the European Union reduced demand by 210 Mtoe compared to the year 2000. These savings played a major role in the achievement of the 2012 EED objectives[7]. The figure above illustrates how these savings have more than offset the increase in economic activity.

Figure 7: Decomposition of the EU energy demand evolution by sector (2000 – 2021)



Source: Odyssee-Mure, Enerdata.

Figure 7 shows that **the industrial sector is the main driver of reductions in energy use.** Energy efficiency improvements (and structural changes, due to a shift in manufacturing industries) have enabled this sector to decrease its overall consumption by 11%, despite an increase in industrial activity. **However, most energy efficiency improvements were made before 2007 and progress is slowing down.**

Most future decreases in energy demand are likely to come from other sectors, including the transport sector where advances in electric vehicle development and uptake are expected.

Savings levels have been the highest in the residential sector, but there is still considerable potential through the development and deployment of heat pumps and installation of weatherisation measures such as ceiling insulation. The residential sector has also experienced the highest activity increase of all sectors (due to an increase in population, number of dwellings, and average surface).

[6] ODEX is an indicator developed to measure the energy efficiency progress by main sector. A more detailed definition is available here: https://www.indicators.odyssee-mure.eu/php/odyssee-decomposition/documents/interpretation-of-the-energy-consumption-variation-glossary.pdf.

[7] Energy Efficiency Directive: https://energy.ec.europa.eu/topics/energy-efficiency/energy-efficiency-targets-directive-and-rules/energy-efficiency-directive_en#:~:text=The%202012%20energy%20efficiency%20directive.

Energy efficiency data for 2022 were unavailable. Nonetheless, the significant decline between 2021 and 2022 illustrated in Figure 1 can largely be attributed to escalating energy prices and the corresponding sufficiency measures, particularly in the residential sector, alongside a contraction in economic activity.

1.3. Electricity Production

There has been a transformation in the EU's energy production capacity as energy demand has decreased: **renewable energy production capacity has increased while fossil fuel-based capacity has decreased**. However, the decreases of CO_2 emissions were not commensurate with this shift due to the low capacity factors of wind and solar and to decreases in nuclear production.

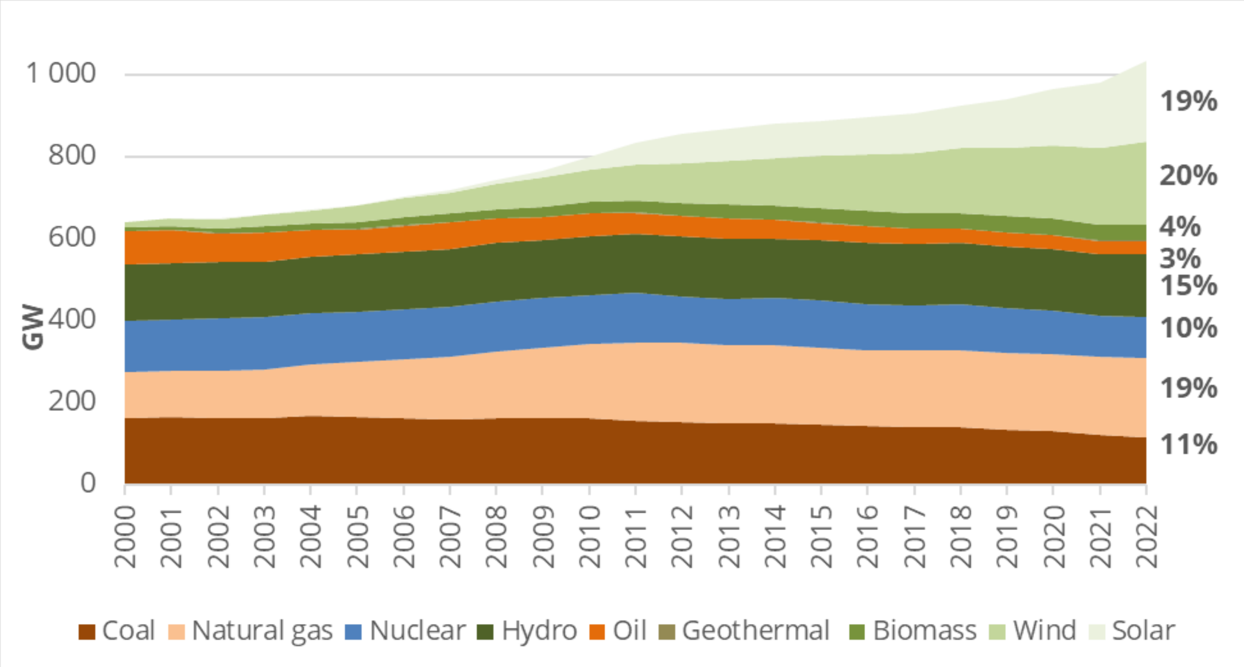
1.3.1. Production Capacities

Until recently, the EU lacked a dedicated goal specifically targeting the advancement of wind and solar energy. The first non-binding objectives for solar energy were published in 2022 as part of the EU Solar Energy Strategy[8] and the first indicative targets for wind were published in 2023 as part of the Wind Power Action Plan[9]. Instead, these sources have been incorporated within RED I's broader global renewable energy share objective (highlighted in Figure 3). As elucidated in the preceding section, the predominant contribution to attaining this objective emanates from electrical renewables. Figure 8 and Figure 9 underscore this point, revealing a remarkable **surge of over 60% in installed electric production capacity since 2000**, culminating in surpassing the 1 TW milestone in 2022. **Renewable energy sources, primarily solar and wind, were primarily responsible for this growth.** Starting with minimal infrastructure for wind, and nearly none for solar power in 2000, each source had an installed capacity of close to 200 GW by 2022.

8 EU Solar Energy Strategy, 2022, available at: https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=COM%3A2022%3A221%3AFIN&qid=1653034500503.

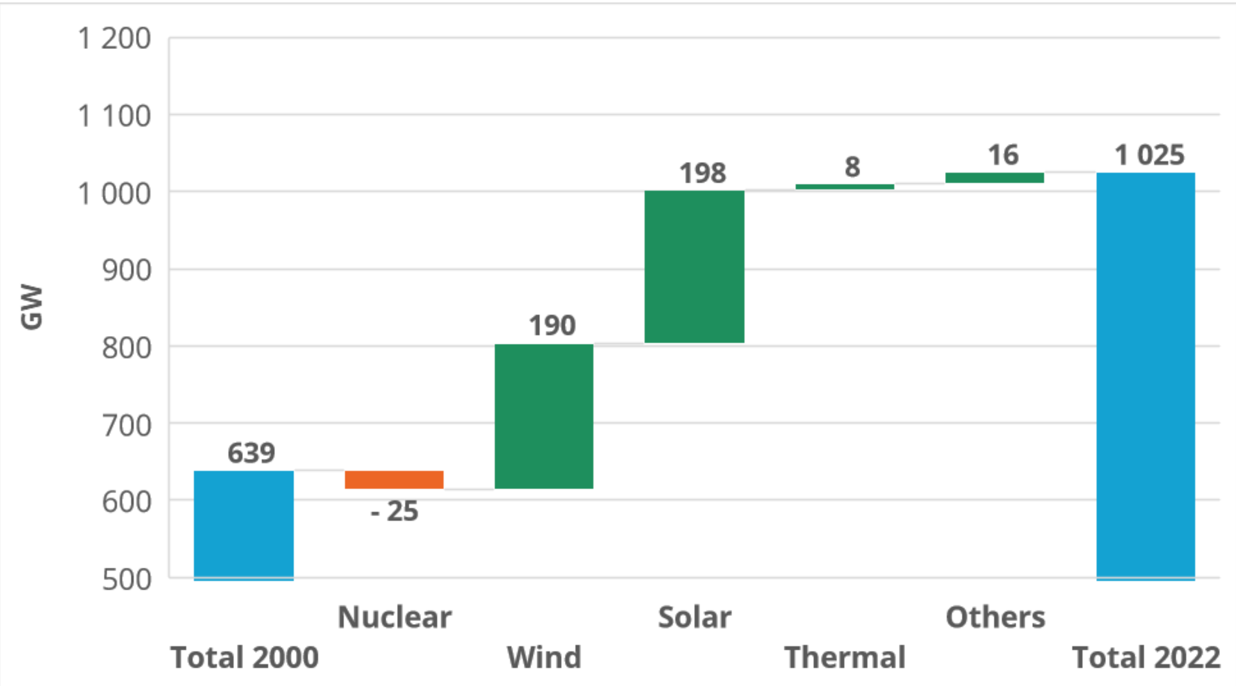
9 European Wind Power Action Plan, 2023, available at: https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX%3A52023DC0669&qid=1702455143415.

Figure 8: EU installed electric capacity



Source: Global Energy and CO2 Data, Enerdata.

Figure 9: EU installed electric capacity changes between 2000 and 2022

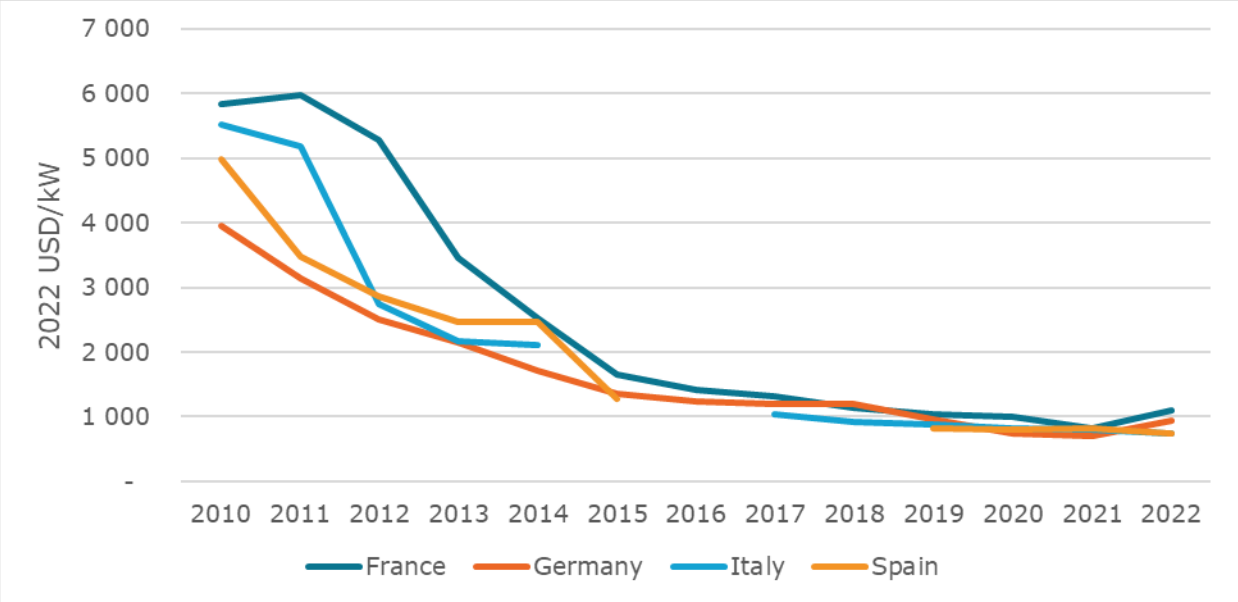


Source: Global Energy and CO2 Data, Enerdata.

Solar power has benefited from favourable national policies coupled with large reductions in installation costs[10]. Although there was a slight uptick in costs in 2022, the trend is for a consistent decrease. During the second quarter of 2023, the cost of PV modules from China was nearly 40% lower than in 2022, as reported by the International Energy Agency (IEA, 2023).

Figure 10 highlights this decrease at the utility-scale, although utility-scale power plants do not reflect the entire European solar market, and in 2022, **small-scale PV systems**[11] **constituted 67% of the installed PV capacity**. Approximately two-thirds of these installations involve self-consumption, wherein system owners utilise a portion of the energy they generated (See Section 3.3.1)[12].

Figure 10: Utility-scale solar PV total installed cost trends in selected countries



Source: (IRENA, 2022).

Wind power has seen similar growth. In addition to favourable national policies, the levelised cost of energy (LCOE) has become increasingly competitive with fossil fuels since 2010 due to a reduction in installation costs and increasing capacity factors. Globally, the weighted-average cost of electricity fell by 69% between 2010 and 2022 (from 0.107 USD/kWh to USD 0.033 USD/kWh) for onshore wind projects, and by 59% for newly commissioned off-shore wind projects (from 0.197 USD/kWh to 0.081 USD/kWh).

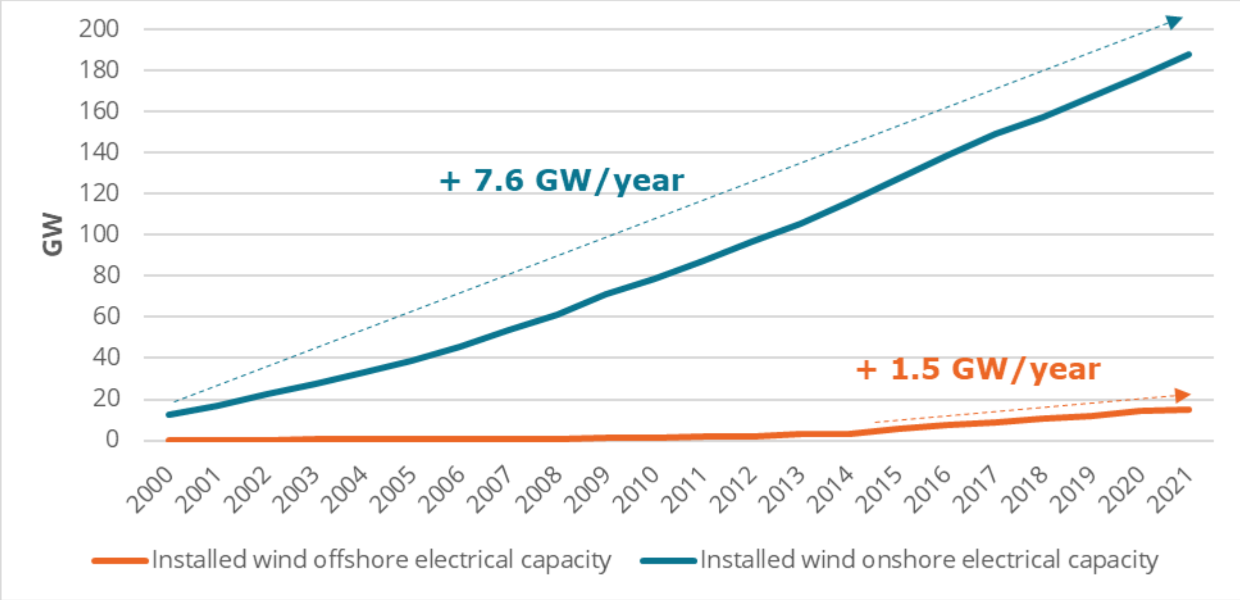
Most of the growth in wind power is from onshore sources, which constituted 91% of the installed wind capacity in the EU in 2021. The offshore segment started growing in 2015, but five times slower than onshore wind. Both the on- and off-shore markets exhibit significant concentration. Specifically, Germany, France, and Spain collectively account for 60% of the installed European onshore capacity, while Germany and Denmark together account for 66% of the installed offshore capacity in the EU.

10 This cost decrease is primarily propelled by the diminishing costs of PV modules that is due to the economies of scale achieved through the expansion of global manufacturing capacities.

11 Small-scale PV is defined here as systems with a capacity below 1 MWp. Those systems are usually installed on rooftops.

12 Enerdata analysis based on national statistics and Solar Power Europe's data.

Figure 11: Cumulative installed wind capacity in the EU between 2000 and 2021



Source: Enerdata, Global Energy and CO2 Data.

Hydropower capacities have exhibited a subdued expansion, with the addition of more than 600 projects and an additional cumulative capacity of 14 GW observed between 2000 and 2022. Notably, 90% of this capacity is attributed to projects exceeding 10 MW, predominantly concentrated in Austria, Germany, Portugal, and Spain[13].

In contrast, geothermal capacities continue to play a negligible role in the European Union's energy production landscape.

The modest rise in thermal capacities, illustrated in Figure 9 (+8 GW), conceals a noteworthy transition in thermal electricity production. **Since 2000, the capacity of gas-fired plants has grown by 70%, while biomass power generation has increased more than fourfold**[14]. Gas and biomass are substitutes for coal and oil, which declined by 30% and 60%, respectively.

Nuclear power capacities have strongly decreased. Only five nuclear reactors were built between 2000 and 2023, all on existing power plants (two in Czechia, one in Slovakia, one in Finland and one in Romania). **During the same period, 43 reactors were shut down**, resulting in a total capacity decrease of 35.3 GW. Germany accounts for 21.5 GW of this decrease, where 19 reactors were shut down between 2011 and 2023 following the country's 2002 decision to accelerate the phase-out of nuclear power by 2023[15]. The decrease in pilot capacity, combined with the significant expansion of Variable Renewable Energies (VRE), will have a substantial impact on the electricity grid, which we discuss in subsequent chapters.

[13] Enerdata analysis based on Enerdata's Power Plant Tracker.

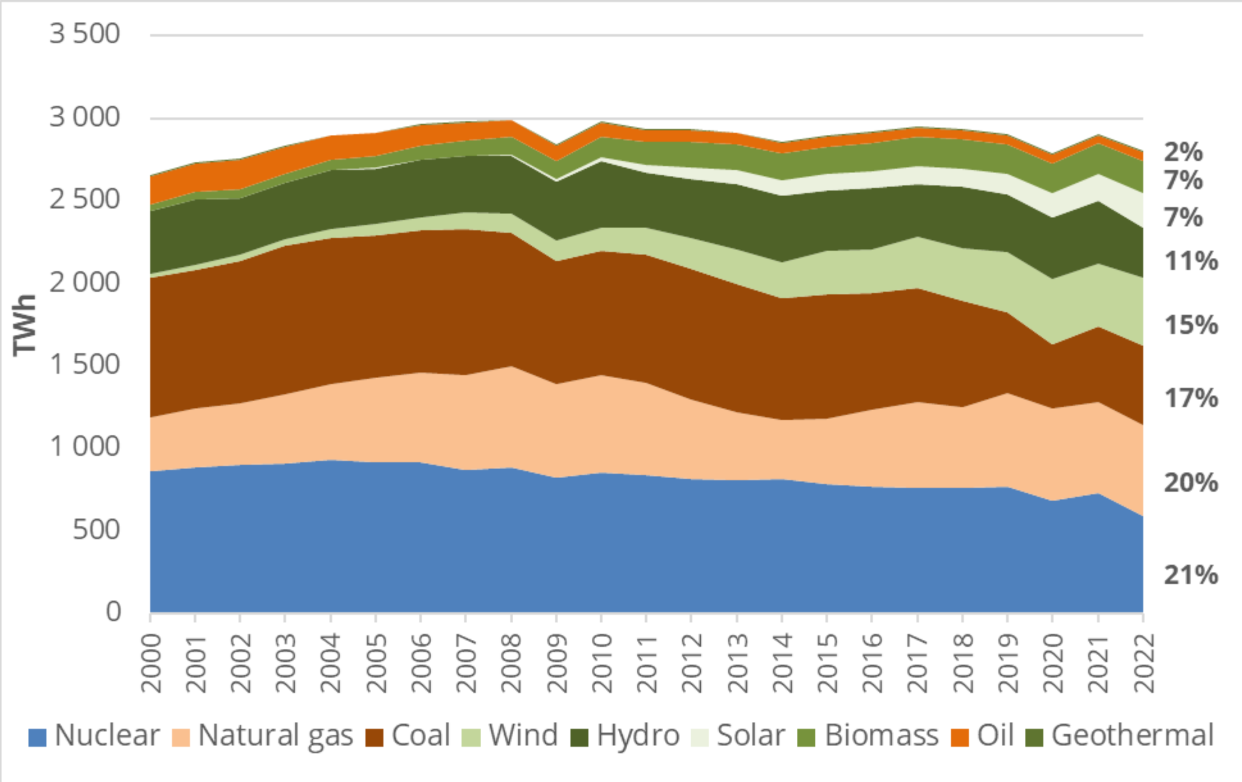
[14] However, it is crucial to note that biomass capacities, although showing substantial growth, still constitute a comparatively minor share when contrasted with those fuelled by fossil fuels.

[15] More information available at: https://www.bmuv.de/en/pressrelease/germany-brings-era-of-nuclear-power-to-an-end.

1.3.2. Electricity Production

a. At European Level

Figure 12: EU power generation by source (2000-2022)



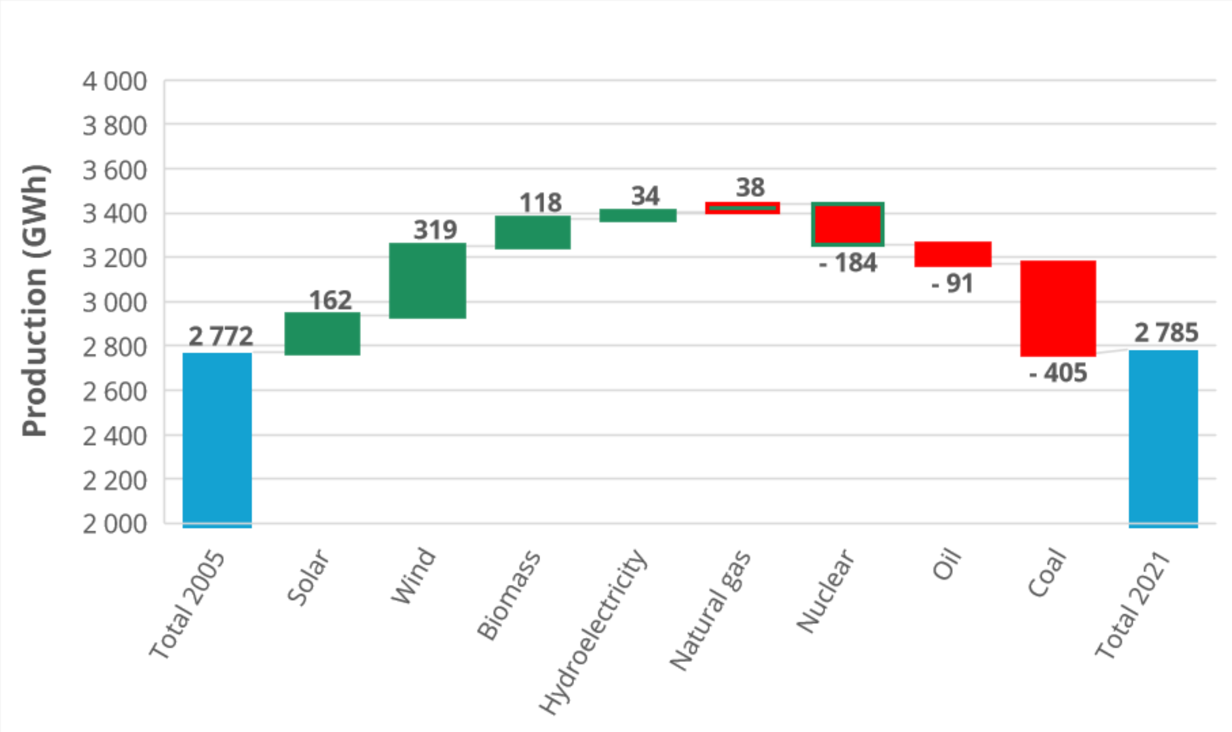
Source: Global Energy and CO2 Data, Enerdata.

Figure 12 and Figure 13 provide a comprehensive overview of **power generation** by source within the EU. **Despite a 60% increase in installed power capacity between 2000 and 2022, power generation only increased 5%,** indicating a diminishing utilisation factor for existing power plants over the years; this is due to increases in wind and solar energy[16]. In 2022, **solar and wind energy** accounted for 22% of the European Union's power generation, constituting 39% of the overall installed capacity. Due to the absence of marginal cost, these sources have been prioritised in grid injection, consequently diminishing the capacity factor of thermal power plants and, to a lesser extent, nuclear power plants.

Coal power generation declined by 43% since 2000, and oil-fired generation dropped 70%, while gas powered generation increased by 65% over the same period.

[16] In 2022, IRENA provided estimations indicating that the capacity factors for onshore wind, offshore wind, and solar were 37%, 42%, and 16.9% respectively.

Figure 13: EU installed electric production changes between 2005 and 2021



Source: Global Energy and CO2 Data, Enerdata.

Note: Rising values have a green background, decreasing ones a red one. Low carbon technologies (solar, wind, biomass, hydroelectricity and nuclear) are surrounded in green, the other ones (natural gas, oil and coal) in red.

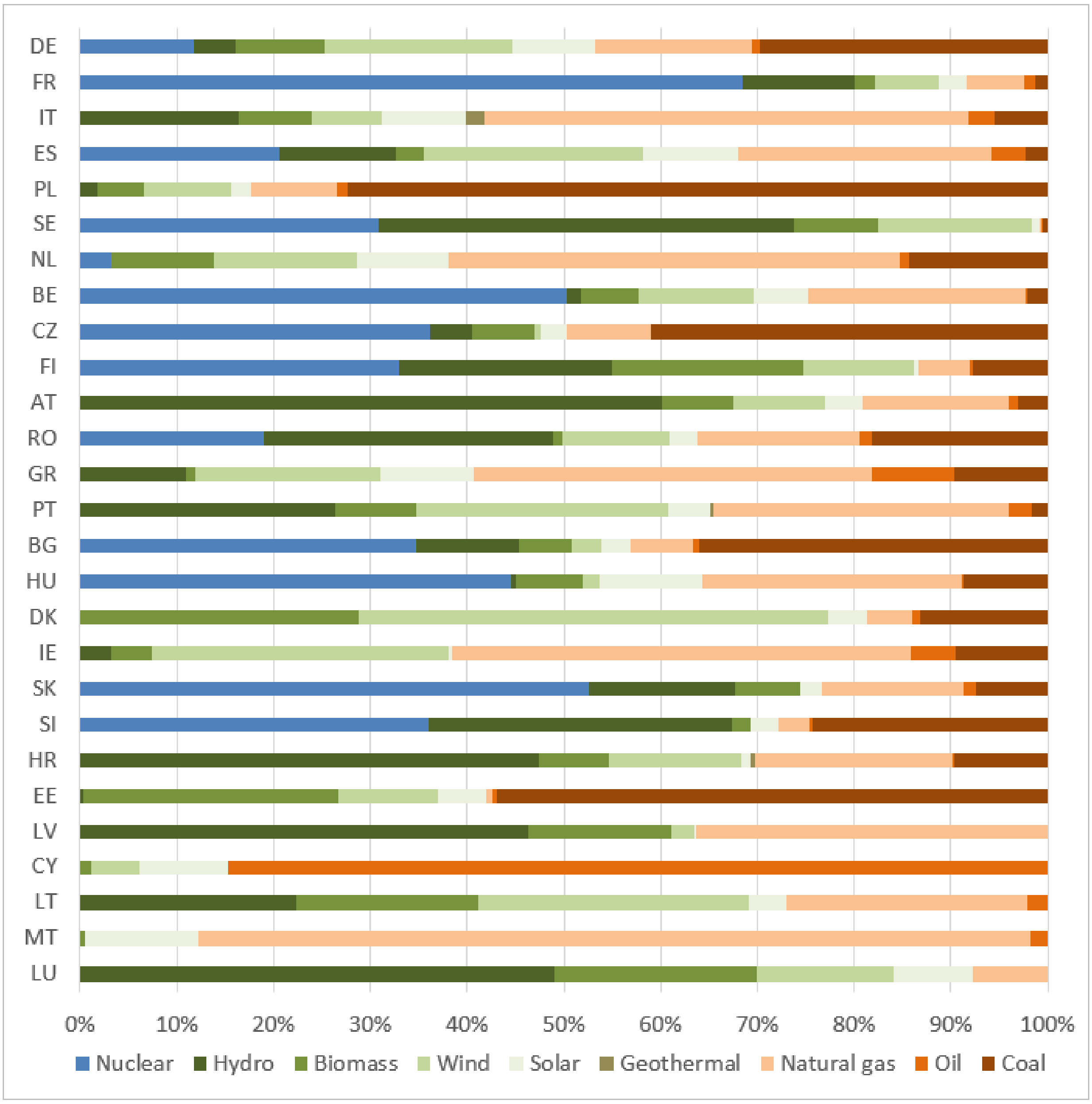
Finally, **nuclear power,** though undergoing a decline and accounting for less than 10% of total installed capacity, has consistently been the largest contributor to the EU's power generation since 1997, reaching 21% in 2022. However, it declined in the same year due to reduced availability of the French nuclear fleet (caused by maintenance issues)[17] and to the closure of last nuclear reactors in Germany.

In the preceding sections we describe how the transition in electricity production has contributed to the attainment of RED I's targets for renewable energy shares; Chapter 2 analyses these developments in light of the more recent EU objectives.

[17] This decline led France, which heavily relies on nuclear power, to become a net importer of electricity for the first time since 1980.

b. National specificities

Figure 14: Electricity production mix by EU country (2021)



Source: Global Energy and CO2 Data, Enerdata.

Note : 2021 was chosen as reference year due to the lack of complete data at the time of writing this report and to avoid any confusion due to France's low nuclear production in 2022.

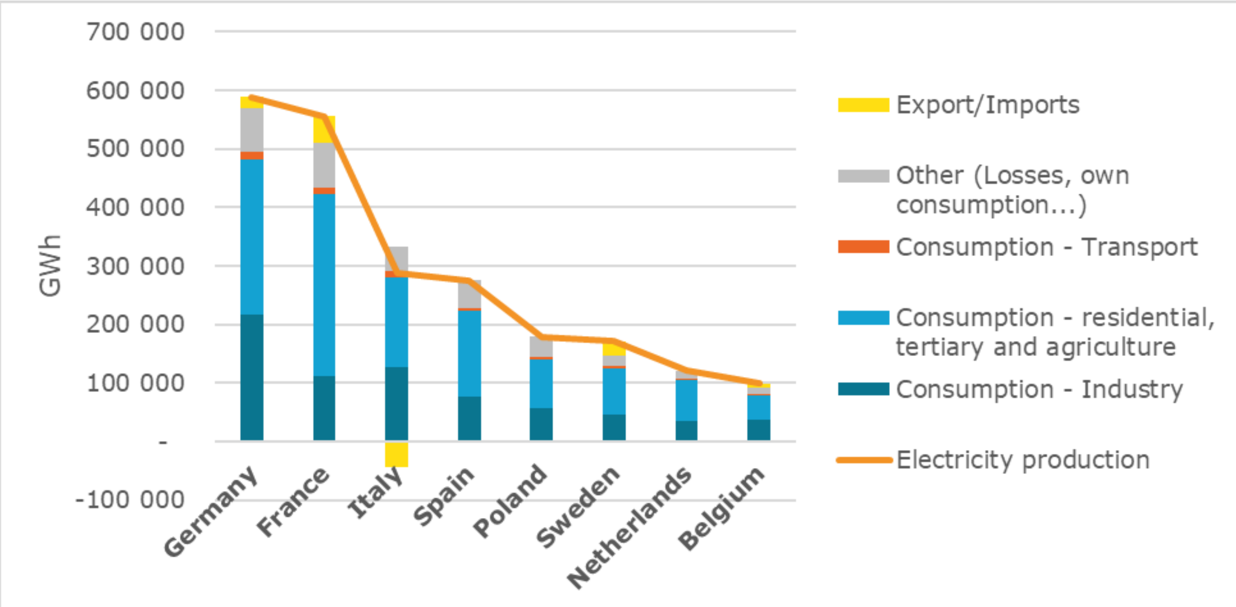
Figure 14 portrays the distribution of energy sources within the national power mix of EU countries, with countries ranked from the largest (top) to the smallest (bottom) electricity producers.

The graph illustrates several trends. One way to categorise countries is based on their energy sources: fossil fuels-dominant, nuclear-based, or renewables-driven. In **fossil fuels-dominant countries,** fossil fuels account for more than half of their electricity generation, such as Poland (82%), Italy, the Netherlands (62%), Greece (59%), Ireland, and Estonia (58%). **Nuclear-based countries** are those where nuclear power constitutes over 30% of electricity generation, including France (68%), Slovakia (53%), Belgium (50%), Hungary (44%), Slovenia, Czechia (36%), Bulgaria (35%), Finland (33%), and Sweden (31%). **Countries with high shares of renewables** in their power mix include Luxembourg

(92%), Austria (81%), Denmark (81%), Lithuania (73%), and Croatia (70%). Germany, the largest producer in the EU, does not fit in any of these categories. It still relies on fossil fuels for almost 50% of its electricity production but is progressively transitioning to other sources. Ultimately, the composition of power mixes is a product of various factors, including geographical attributes, renewable energy potential, and political decisions.

Among the top eight countries (representing 78% of the total EU electricity production) we can identify three main categories of producers. **Nuclear-based** mixes, including France, Belgium, and Sweden (28% of electricity production), **fossil fuel-based** power production, including Italy, the Netherlands and Poland (20% of electricity production), and **distributed production** mixes, which include Germany and Spain (30% of electricity production).

Figure 15: Electricity production and consumption among selected countries (2021)



Source: Global Energy and CO2 Data, Enerdata.

Note: The countries are shown by decreasing levels of electricity production. A positive export/import value means that the country is a net exporter.

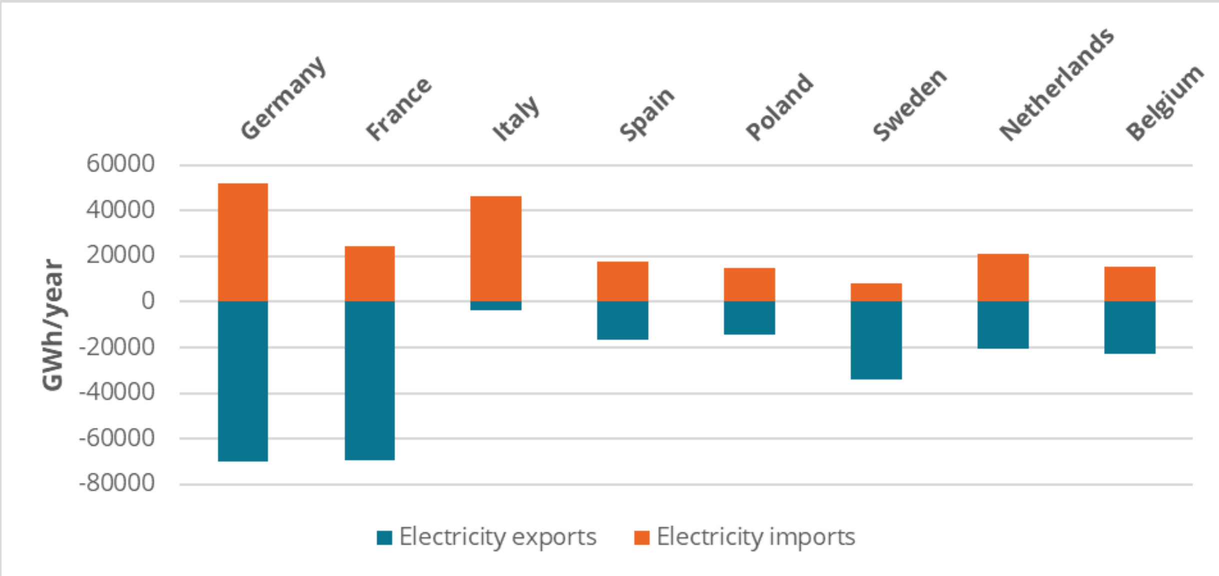
Figure 15 depicts the electricity production volume among the largest electricity producers. The similarities in electricity production between countries of different economic size (e.g., Germany and France; Italy and Spain; Poland and Sweden) is mostly due to their differences in balance of trade. Germany, France, and Sweden were the largest net exporters in 2021, while Italy was the largest net importer. In 2022, the trend was reversed for France due to the situation of its nuclear power plants described above[18].

These statistics reflect the diverse nature of power mixes within countries. Nuclear-based countries predominantly function as net exporters, leveraging exports to capitalise on the reduced electricity prices generated by their extant power plants. Additionally, these countries exhibit a propensity to import electricity during summer days, marked by diminished nuclear capacities owing to factors such as drought and maintenance. This inclination to import aligns with lower electricity prices attributable to heightened solar production and decreased demand. Conversely, countries reliant on fossil fuels

[18] Based on Global Energy and CO2 Data, Enerdata.

engage in smaller exchanges with neighbouring nations, except for Italy, which grapples with a capacity deficit.

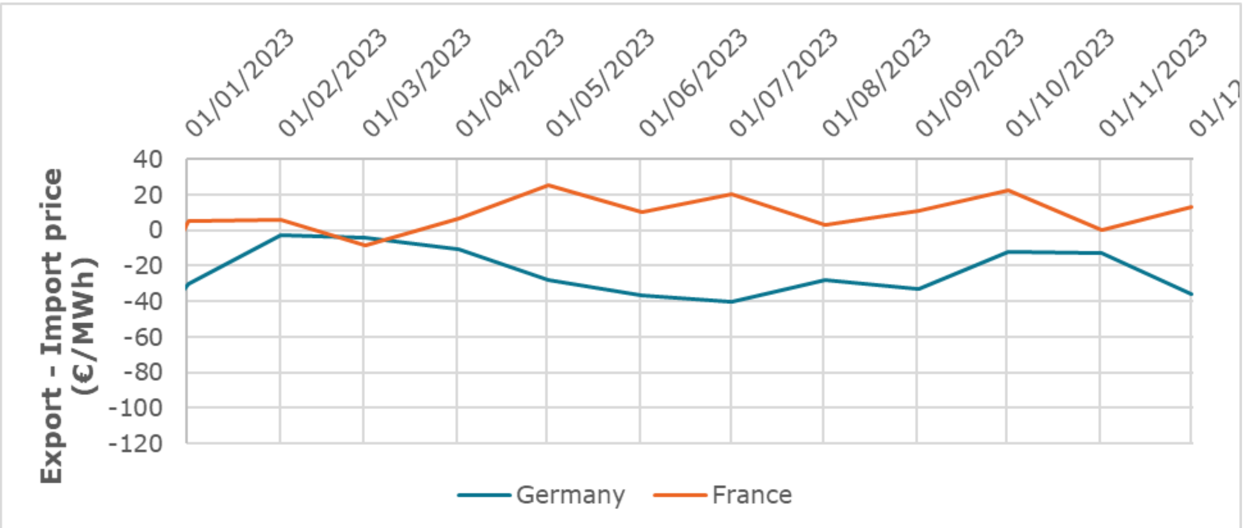
Figure 16: Import and export of the main European electricity producers in 2021



Source: Enerdata Global Energy and CO2 Data.

The trajectory is less discernible for distributed production mixes with increased proportions of wind and solar. Although Germany stands out as a significant electricity exporter, Spain maintains a near-zero net electricity trade balance. Nevertheless, these countries typically export electricity during periods of low (occasionally negative) energy prices, coinciding with heightened wind and solar generation, and import during periods of elevated prices, as depicted in the figure below for the year 2023 comparing France and Germany. The integration of more flexibility (detailed in Sub-chapter 3.1) to lower this financial risk is a challenge today for those countries; it will also be in the future for fossil-fuel based countries, while they are transitioning towards a higher share of VRE in their power mix.

Figure 17: Example of correlation between exchanged electricity and market prices



Source: Enerdata based on ENTSO-E data.

Note: A positive value means that on average, the country has exported electricity at a higher price than it has imported it.

1.4. Energy Transmission Infrastructure

This sub-chapter provides an overview of current European electricity and gas transmission infrastructures. It lays out the baseline upon which anticipated developments will be discussed in the following chapters.

1.4.1. European Electrical Transmission Network

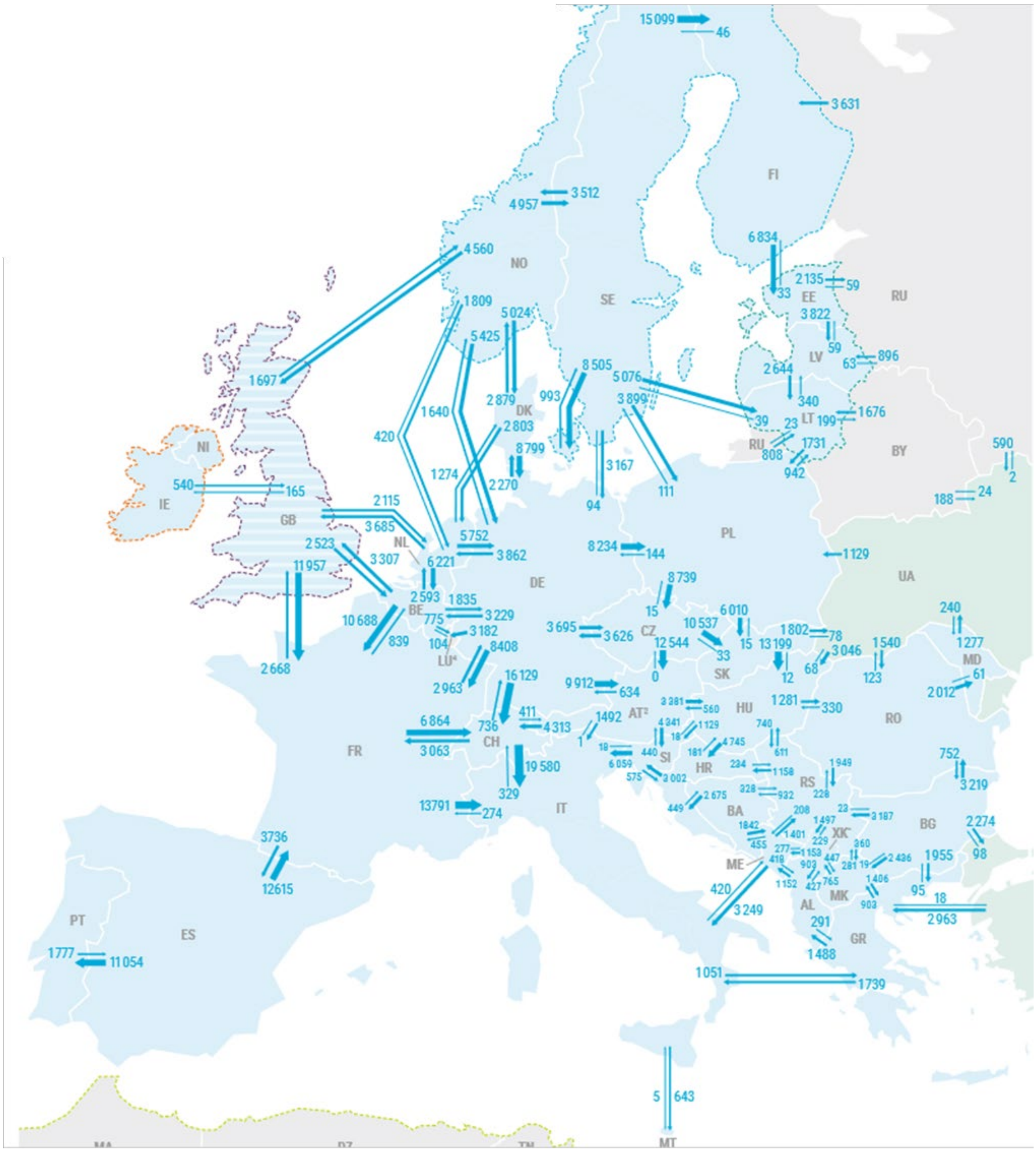
The European Union is home to a synchronised electrical grid combining numerous countries into a single phase-locked 50 Hz frequency electricity grid that serves more than 400 million customers. **Apart from Ireland and countries in the Nordic and Baltic regions, all Member States are integrated into this synchronised grid**. Even though some countries' power grids operate on a different frequency from their neighbours', they still engage in power exchanges. The recent alignment of Ukraine and Moldova with the European power grid is elaborated upon in Chapter 5.

These exchanges are facilitated through three different types of transmission systems: above-ground Alternative Current (AC) lines, underground AC cables, and underground Direct Current (DC) cables. As of the end of 2022, there were 308 AC and 41 DC cross-border connections in operation, allowing power transmission at voltages exceeding 110 kV between European countries. These lines span a total length of **520,000 kilometres for AC (including 400,000 kilometres in EU Member States) and 14,000 kilometres for DC circuits**, representing a substantial growth in interconnection infrastructure compared to previous years. When comparing these figures to those from 2015, an additional 128,000 kilometres of AC and DC lines have been added including 37,000 in EU Member States at a 1.6% CAGR[19]. In comparison, ENTSO-E's 10-year network development plan (TYNDP) that lists 141 key infrastructure projects, envisions the development of only 30,000 kilometres[20] of AC and DC lines by 2040, which is significantly less than the ongoing development (ENTSO-e, 2023).

[19] Enerdata's analysis based on ENTSO-E Transparency platform.

[20] Cumulative length of the 97 infrastructure projects listed in ENTSO-E's ten-year plan and expected to be commissioned before 2030. This is not a forecast of the total length that will be added to the transport grid but an indication of the current development plans.

Figure 18: 2022 power flows across Europe, measured in GWh

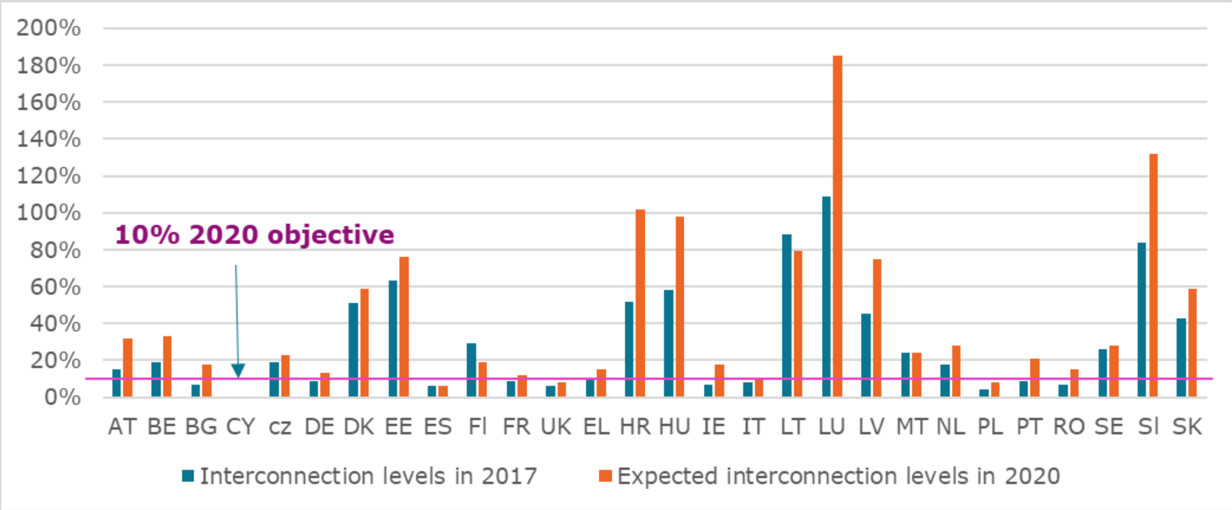


Source: ENTSO-E, 2022 Statistical Factsheet (ENTSOE, 2022).

By 2022, the European power system had 93 GW of cross-border transmission capacity (ENTSO-E, 2023), facilitating the exchange of electricity between countries to effectively manage supply and demand. Interconnection capacities are seen as one of the key elements of energy security and resilience of the power system. Countries with an excess supply of renewables can export electricity to meet demand in other countries where supply is short. Furthermore, an additional 23 GW of cross-border capacity is in construction or in advanced stages of permitting until 2025, which demonstrates the momentum of cross-frontier electrical infrastructures (see Chapter 4 for more detail).

Cross-border infrastructures play a pivotal role in the cohesion of the European market. In scenarios where production increasingly relies on meteorological conditions, facilitating those exchanges becomes crucial. The European Council defined already in 2014 an electricity **interconnection target** of 10% by 2020 for Member States (European Council, 2014)[21]. As seen in Figure 19, the 10% interconnection target was met in most EU Member States, Spain, Italy, and Poland being the largest countries to miss this target.

Figure 19: EU Interconnection levels in 2017 and expected by 2020



Source: TYNDP 2016 and ENTSO-E Vision 2020 (European Commission, 2017).

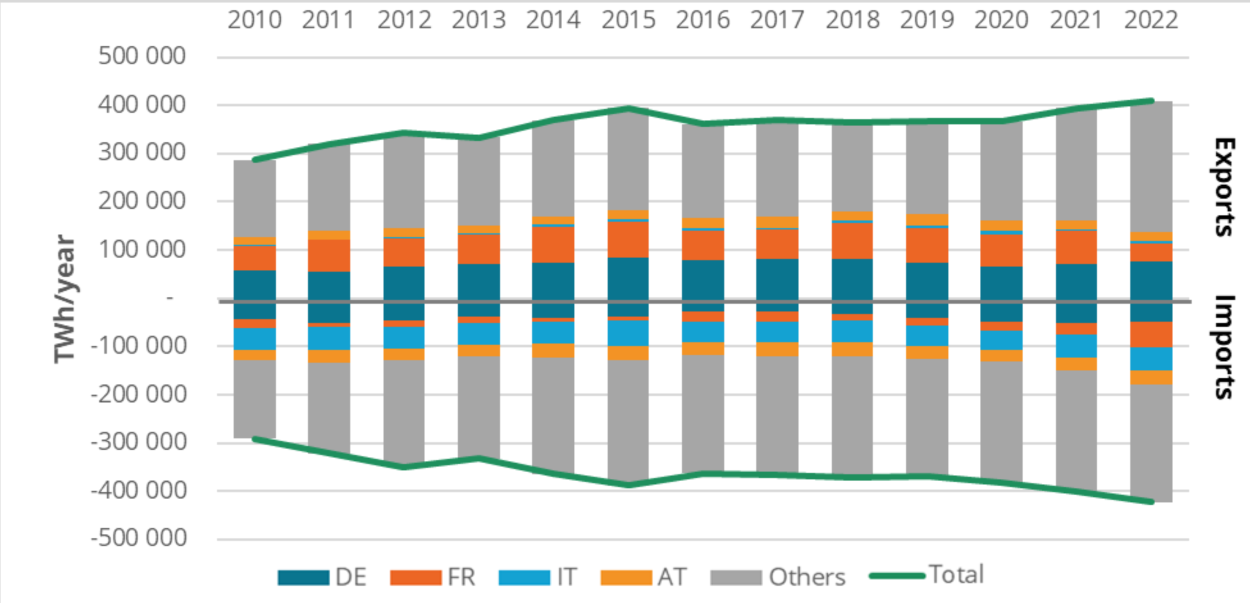
This objective was raised to **15% by 2030** in accordance with the Governance of the Energy Union and Climate Action Regulation (EU) 2018/1999. However, with the development of numerous capacities having a low capacity factor (as discussed in the previous chapter), this indicator has been complemented by additional indicators[22].

Since 2022, the **TEN-E regulation** (EU) 2022/869 sets the current guidelines for the development of EU cross-border infrastructures. This includes the simplification of administrative procedures, the definition of priority corridors and the process for selecting **projects of common and mutual interest** (PCIs and PMIs) that have access to specific funding.

[21] The interconnection is defined as the ratio of net transfer capacity to installed generation capacity. Each country should have in place electricity networks allowing at least 15% of the electricity produced on its territory to be transported across its borders to neighbouring countries.

[22] Namely price differential in the wholesale market and nominal transmission capacity of interconnectors in relation to peak load and to installed renewable generation capacity. More information available at: https://energy.ec.europa.eu/topics/infrastructure/electricity-interconnection-targets_en.

Figure 20: Evolution of gross imports and exports by country at EU level



Source: Enerdata, Eurostat data.

Since 2010, the augmentation of interconnection capacities, along with a conducive electricity market, has facilitated a 42% growth in the gross imports and exports of all Member States, as illustrated in the above figure. This progress represents a pivotal element in the integration of more Variable Renewable Energy (VRE) into the electricity grid (see Section 3.2.1).

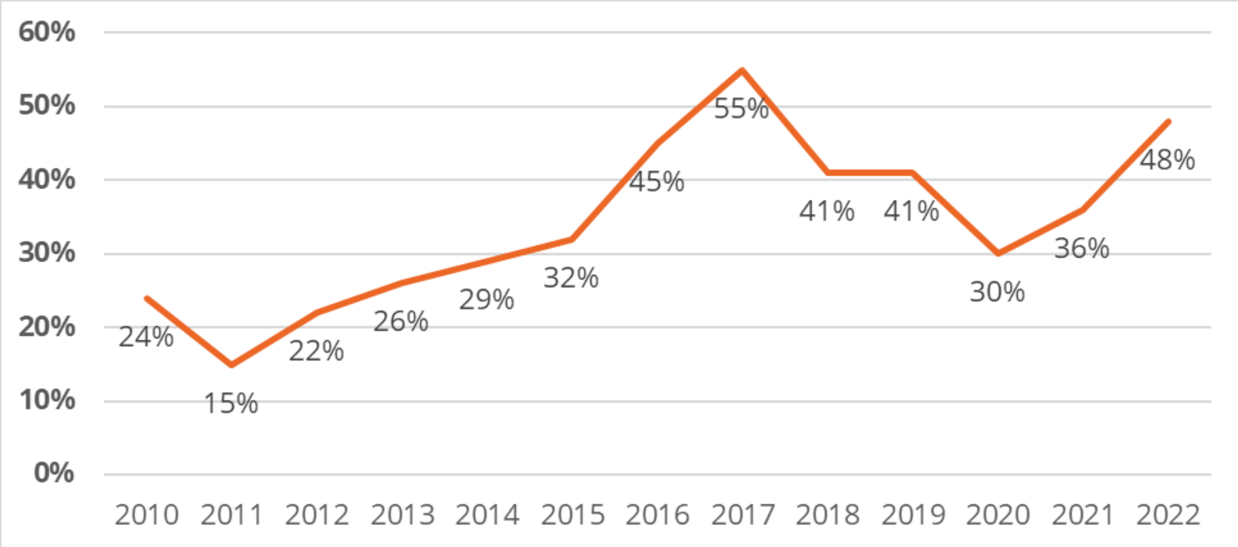
1.4.2. European Gas Transmission Network

In addition to the electricity transmission infrastructure highlighted above, the EU has the most developed natural gas network in the world. It constitutes more than **200,000 km of transmission pipelines**, over **2 million km of distribution networks**, and more than 20,000 compressor and pressure reduction stations. The value of the total infrastructure investments is at least €250 billion, three quarters of it within the distribution network. 40% of European households are connected to the gas network. (ACER, 2021)

The transmission infrastructure is also an effective way to transport large quantities of energy. Cross-frontier gas pipelines allow 23 TWh/d of natural gas exports from EU Member States and 21 TWh/d of imports (ENTSO-G, 2022). The EU countries with the largest gas interconnection capacities are Germany (4.9 TWh/d), the Netherlands (3.1 TWh/d) and Slovakia (2.8 TWh/d). Ireland, Sweden, and Malta do not have cross-frontier interconnection pipelines. Within the EU, the largest transmission capacities are found between Germany and the Czech Republic (2.1 TWh/d), between Slovakia and Austria (1.6 TWh/d) and between the Netherlands and Belgium (1.4 TWh/d).

This infrastructure is transitioning from a development phase to a maintenance phase. According to ACER, the share of Transmission System Operators' (TSO) and Distribution System Operators' (DSO) investment has been considerably growing and reached 48% in 2022 as highlighted in the figure below.

Figure 21: Share of replacement costs over total investment among European gas TSOs



Source: (ACER, 2022), Figure 25.

This infrastructure is on the verge of an important transition. As most scenarios detailed in Chapter 2 anticipate a decrease of the European gas consumption, the Transmission and Distribution system operators face the risk of seeing their assets becoming stranded.

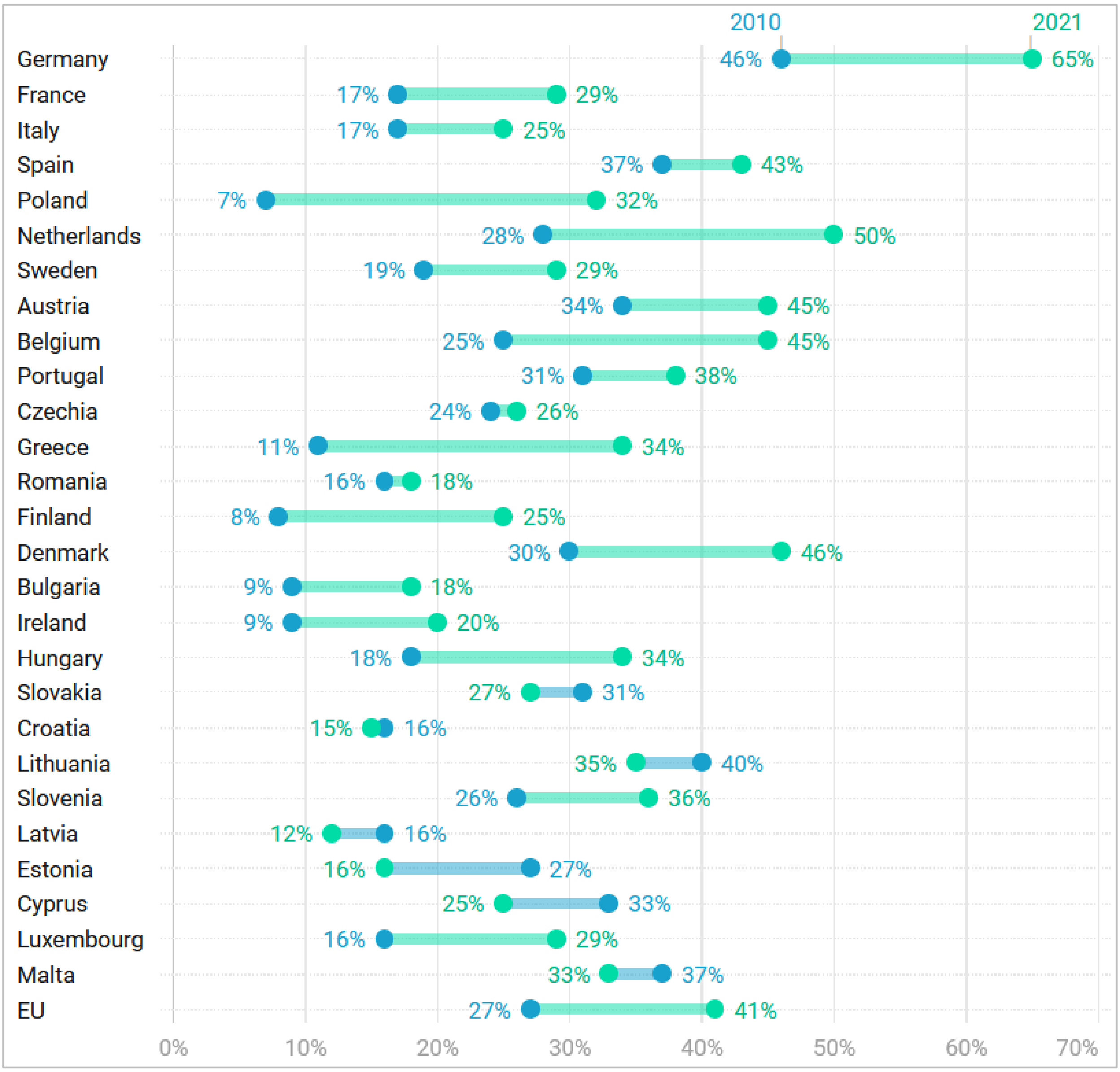
However, the current gas infrastructure holds significant potential as a crucial facilitator of the energy transition across various dimensions. Existing transport pipelines could use a blend of natural gas and hydrogen or undergo conversion to accommodate the transportation of hydrogen, as expounded in Chapter 4. The distribution network can be a key contributor for the efficient injection of biomethane. The gas storage capacities can also be used to lower the electricity peak demand and the overall cost of the evolution of the grid. Nonetheless, **it is imperative to acknowledge that the maintenance of these assets carries inherent risks, particularly in the challenge of diminishing fossil gas demand**. This challenge becomes pronounced in a scenario where the volumes of biomethane, synthetic gas, and green hydrogen may not suffice to ensure the economic viability of the existing infrastructure.

1.5. Impacts of the Past Energy Transition

The previous sections highlighted shifts in energy demand, installed power capacities, and electricity production. Decreases in demand coupled with a progressive replacement of fossil fuel with renewable energy sources has already had a strong impact on the energy system, including on the EU's commercial balance, the development of decentralised production sources, and on retail energy prices.

1.5.1. Development of Decentralised Power Production

Figure 22: Evolution of distributed electric capacity between 2010 and 2021 in EU countries



Source: Power Plant Tracker, Enerdata.

The visual representation in Figure 22, using blue and green dots to denote distributed electric capacity in 2010 and 2021, vividly illustrates a profound transformation in power systems. Within this graph, distributed electric capacity refers to the projected proportion of installed power production capacity stemming from units generating less than 50 MW, irrespective of their geographic location. This pivotal shift is reshaping the electricity network, transitioning from a reliance on a limited number of large thermal power plants to a network characterised by a significantly expanded presence of power plants dispersed across the geographical expanse.

This transition is propelled by the widespread deployment of solar, wind, and biomass power plants, providing valuable insights into the evolution of the grid alongside shifts in the energy sources employed for electricity generation. One discernible trend is that 21 out of 27 countries showed an uptick in the share of distributed electric capacity in 2021 compared to 2010. This trend underscores a **clear trajectory toward the decentralisation of power production assets**.

Within the EU, certain countries already stand out as having notable shares of distributed installed capacities, including Germany with 65%, followed by the Netherlands (50%), Denmark (46%), and Austria and Belgium, both at 45%. Germany's reliance on distributed electric capacity is further accentuated by its strategic decision to decommission nuclear power plants. Moreover, the ongoing dynamics within this sector are marked by a remarkable pace. Over the span of 11 years, notable shifts have been observed, including a 25 percentage point (pp) increase in Poland, a 22 pp increase in the Netherlands, a 23 pp increase in Greece, and a 20 pp increase in Belgium.

These shifts underscore the potential for a swiftly transforming landscape in electricity production. But this comes with challenges. Electricity grids have traditionally been constructed to support large, centralised generators linked to transmission lines and overseen by Transmission System Operators (TSOs). In contrast, a distributed power system necessitates an **expanding role for Distribution System Operators** (DSOs), the amplification of bi-directional electricity flows, and an augmentation of flexibility capacity. Notably, DSOs encounter two primary challenges: a burgeoning backlog of connection requests for new solar and wind capacities, and the curtailment of renewable energy production to avert congestion. For example, during the first half of 2022, approximately 4% of solar and wind electricity generated underwent curtailment[23].

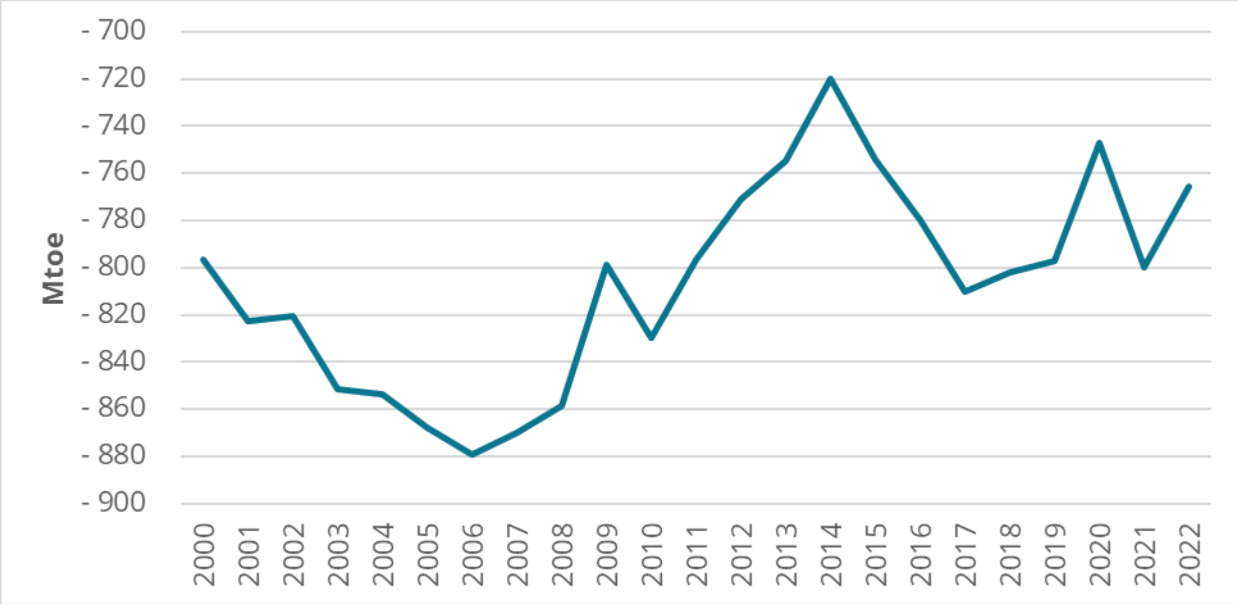
TSOs and DSOs have addressed those challenges through different complementary approaches, including cross border interconnections, transmission and distribution grid development, flexible connections, development of the prosumer's role, and storage (see Chapter 3).

1.5.2. Impact on the EU's Energy Dependency

Figure 23 and Figure 24 depict the European Union's energy dependency, delineated by the disparity between locally produced energy and consumption. Following a period of incremental deterioration from 2000 to 2006, and despite a substantial decline in domestic fossil fuel production, the advancement of renewable energies and the implementation of demand reduction measures have resulted in a **13% reduction in energy dependency on non-EU countries from 2006 to 2022.** The decline between 2014 and 2018 is marked by a time of low solar development and slight increase in energy consumption.

[23] More information (in German) available at: https://taz.de/Zu-langsamer-Ausbau-der-Stromnetze/!5902431/.

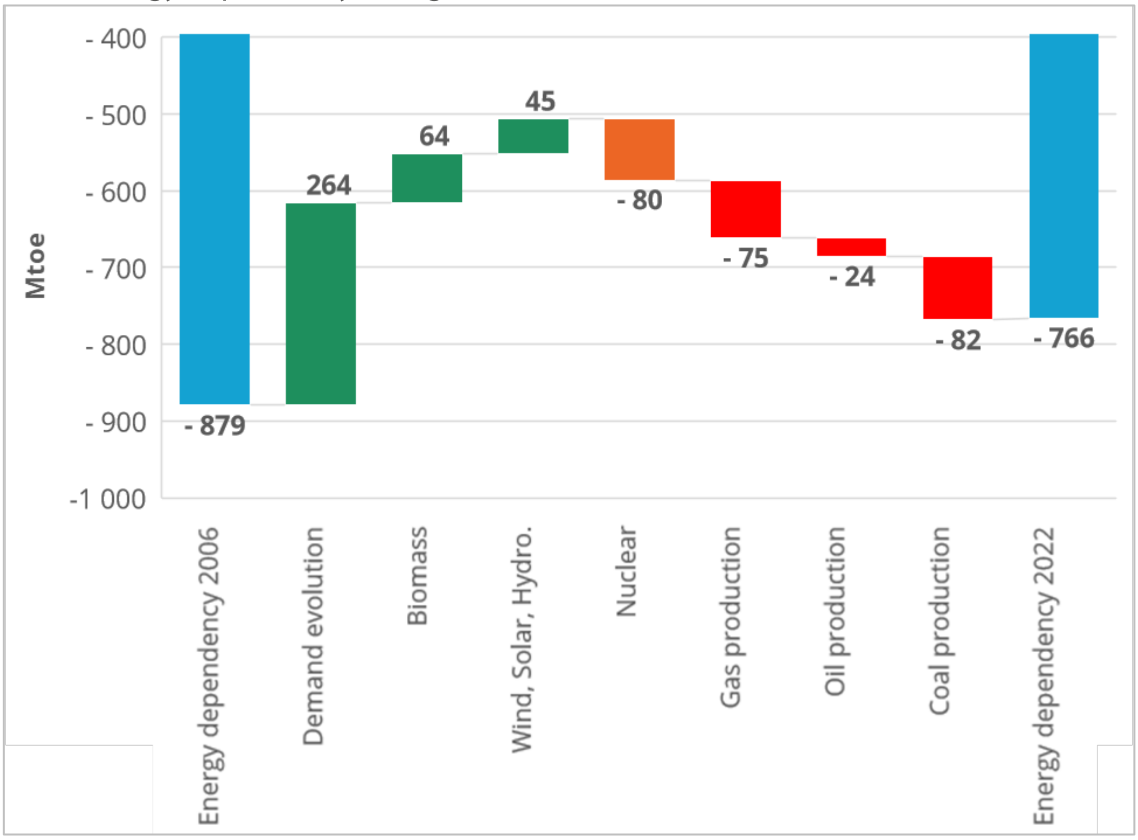
Figure 23: Evolution of the EU's energy dependency between 2000 and 2022



Source: Enerdata.

Note: The energy dependency is determined by the total primary consumption minus the total primary production.

Figure 24: Energy dependency changes between 2006 and 2022



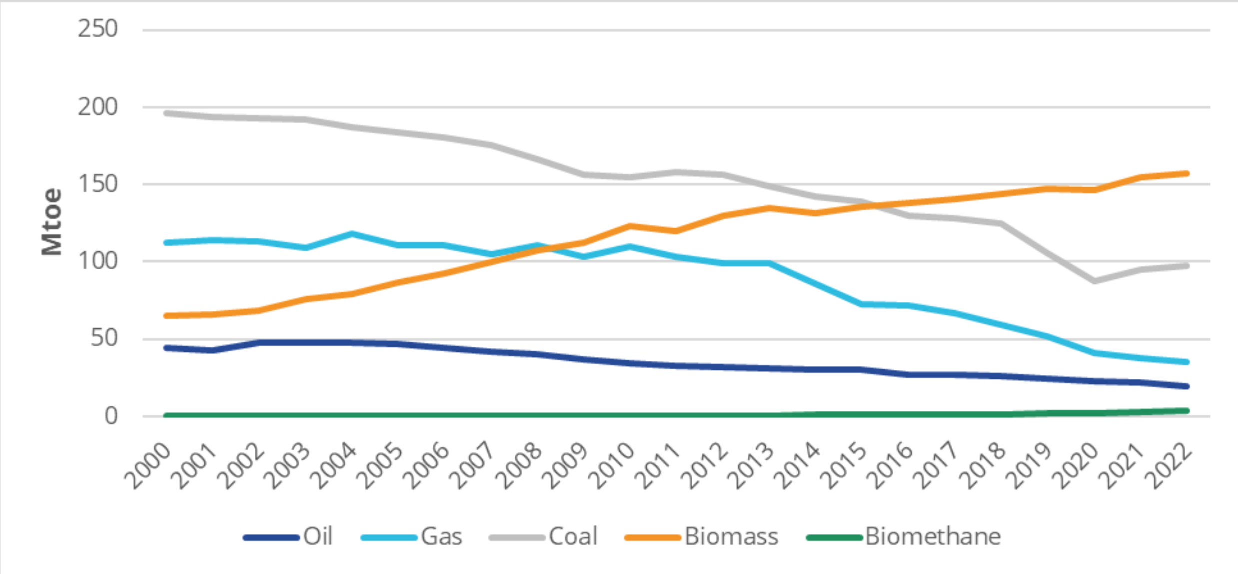
Source: Enerdata's analysis, based on Eurostat and Cedigaz data.

Note: Energy dependency is defined in this study as the amount of energy that needs to be imported to cover the domestic demand (not considering exports). It can be summarised as the energy primary demand minus the local energy production. Electricity production from imported fossil fuel is not considered local production but nuclear production is, due to the low importance of imports (uranium) in its final energy production cost. "Biomass" includes biofuels, biogas, solid biomass, and the biomass share of waste.

The development of electricity production capacities has been marked by a shift from imported energy carriers (coal, oil) to more local ones (biomass, renewables), as discussed in Section 1.3.1. However, in parallel, the European Union faced a strong decrease in its already small fossil fuel extraction capacities.

The following figure illustrates the changes in energy production by energy carrier over the past three decades within the European Union. **The European Union still heavily relies on fossil fuels, which collectively accounted for 69% of energy demand in 2022** (see Figure 25). The EU faces a considerable dependence on imports to satisfy its energy needs because of this. In 2022, the EU's domestic oil production only covered a modest **4% of its consumption**, highlighting the **substantial need for imported oil.** Similarly, gas production within the EU meets just **13% of its demand**, underlining reliance on external sources to fulfil the majority of its natural gas requirements. This energy landscape underscores the EU's ongoing challenge to balance its energy security, environmental sustainability, and economics.

Figure 25: The EU's fossil fuel and biomass primary production



Source: Global Energy and CO2 Data, Enerdata.

Figure 25 shows the long-term trend in primary fossil fuel production, including the steady decrease in the production of natural gas, oil products, and mineral solid fossil fuels (hard coal, brown coal, coke, briquettes, and peat). **Gas production has dwindled by over two-thirds over three decades**, with the Netherlands emerging as the top producer, contributing 41% of the EU's total in 2021. However, Dutch production has seen a sharp decline in recent years, primarily due to the impending closure of the Groningen gas field[24]. The field has been a major gas provider for much of Western Europe since production started in 1963. It was permanently shut down in October 2023 following a government decision. Other notable contributors to gas production include Romania (19%), Germany (10%), and Poland (9%).

Oil production remains exceptionally small compared to the EU's consumption, with Italy leading the production share, accounting for a quarter of the EU's total, followed by Romania (15%) and Denmark (14%) in 2021.

[24] More information: Bedeschi, B., 'Dutch Groningen gas field shuts down permanently', *Gas Outlook*, 16.10.2023; available at: https://gasoutlook.com/analysis/dutch-groningen-gas-field-shuts-down-permanently/.

Coal production in the EU is dominated by Poland and Germany, collectively accounting for more than two-thirds of the EU's production. While Germany is planning to phase out coal by 2038[25], Poland has no immediate plans to diminish its coal production in the short and medium term (a phase-out is announced by 2049).

In stark contrast to the production of fossil fuels, **biomass production for heating, transportation, and electricity has undergone noteworthy and sustained growth, tripling over the past three decades**, surpassing the combined contributions of wind, solar, and hydroelectric power. This expansion primarily stems from the **advancement of firewood**, constituting 65% of biomass production in 2022, marking a twofold increase since 2000. Despite a strong development, liquid biofuels represent only 10% of the biomass production, while biomethane production volumes remain insignificant in the current context (3.5 Mtoe in 2022)[26].

1.5.3. Energy Prices

This section analyses recent trends in gas and electricity wholesale and retail prices and the extent to which the transition described in the previous chapter can be linked to this. The key factor is the **increasing reliance by the EU on natural gas**, which has deepened the recent impact of gas price spikes on wholesale and retail electricity prices.

This analysis does not cover the impact of non-market contracts (Contracts for Difference, Power Purchasing agreements). Those aspects are more deeply analysed in a 2023 ITRE study to demonstrate that the EU electricity markets worked during the gas war and did not require disrupting changes (Bruegel, 2023).

Electricity and gas longer term wholesale prices

Wholesale electricity and gas markets exhibited relative stability until 2021, as illustrated in Figure 26. It is crucial to emphasise that the **development of renewable energies did not markedly influence long-term (calendar) electricity wholesale prices**. The majority of renewable and wind power initiatives within the 2006-2020 span operated under subsidised schemes, such as feed-in tariffs, and were not contingent on wholesale prices. The upswing between end-2020 and 2022 does not directly correlate with renewable development but rather stems from other complementary factors. In the winter of 2020-2021, the post-COVID-19 resurgence prompted heightened demand from non-EU nations, compounded by a cold winter and unexpectedly constrained supply due to a series of outages impeding gas production and export capacity throughout 2021 (IEA, 2021).

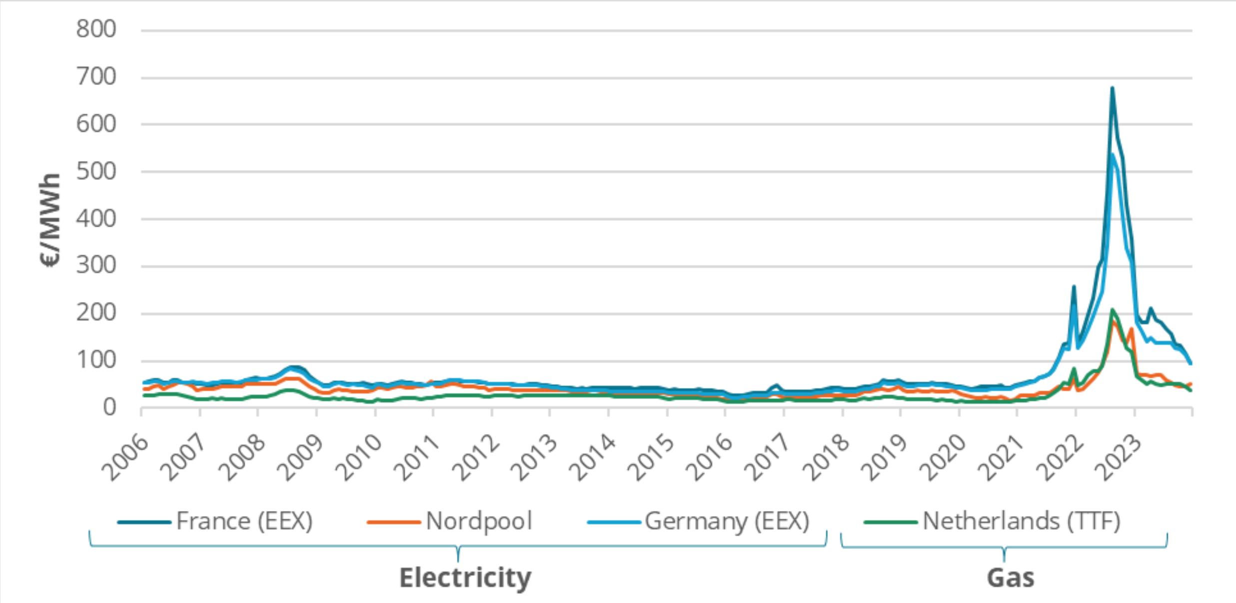
The Russian invasion of Ukraine in February 2022 further disrupted market dynamics, leading to unprecedented fluctuations in gas and electricity prices. The abrupt decline in Russian gas exports underscored Europe's reliance on a singular supplier and highlighted the imperative for a more diversified infrastructure. Following the REPowerEU communication and a shift caused by reduced demand and increased gas imports from non-Russian sources (mainly through the expansion of LNG terminals), wholesale gas prices declined, but are still higher than pre-2021.

The trajectory of electricity wholesale prices is intricately linked to gas prices due to the prevailing structure of the European market design. While this specific aspect remains beyond the scope of this report, it has undergone thorough examination in the 2023 ITRE publication (Bruegel, 2023).

[25] See Gesley, J., 'Germany: A law on Phasing-Out Coal-Powered Energy by 2038 enters into force', *Global Legal Monitor*, 31.08.2020; available at: https://www.loc.gov/item/global-legal-monitor/2020-08-31/germany-law-on-phasing-out-coal-powered-energy-by-2038-enters-into-force/.

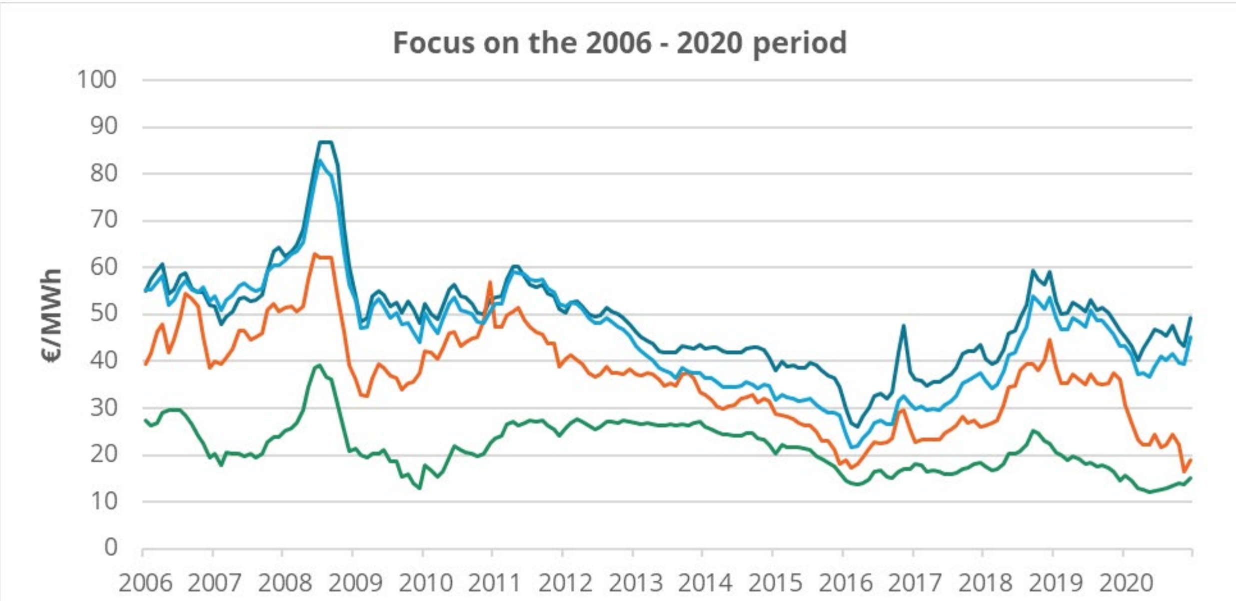
[26] They are concentrated in France, Germany, and Denmark.

Figure 26: Electricity and gas wholesale prices (calendar Y+1) in selected markets



Source: EnergyMarketPrice (https://www.energymarketprice.com/home/en/).

Figure 27: Electricity and gas wholesale prices (calendar Y+1) in selected markets (Focus)



Source: EnergyMarketPrice (https://www.energymarketprice.com/home/en/).

Electricity short-term wholesale prices

The assessment of the impact of VRE penetration on electricity prices is a complex task, often leading to contradictory findings. Three primary trends have been identified.

First, a marginal **decline in average wholesale electricity prices**. A study by the IMF (International Monetary Fund, 2022) showed that in Europe, a 1 percentage point increase in electricity generated from renewables leads to a 0.6 percent average reduction in wholesale electricity prices. This trend is further corroborated by findings in the U.S. electricity market (Joachim Seel, 2018).

Secondly, there is an observable escalation in the **volatility of electricity prices**, characterised by the emergence of negative prices[27]. Negative prices have become prevalent in numerous European power markets, initially surfacing in Germany, and subsequently occurring in other EU power markets post-2018[28] (MAZIDI, 2023).

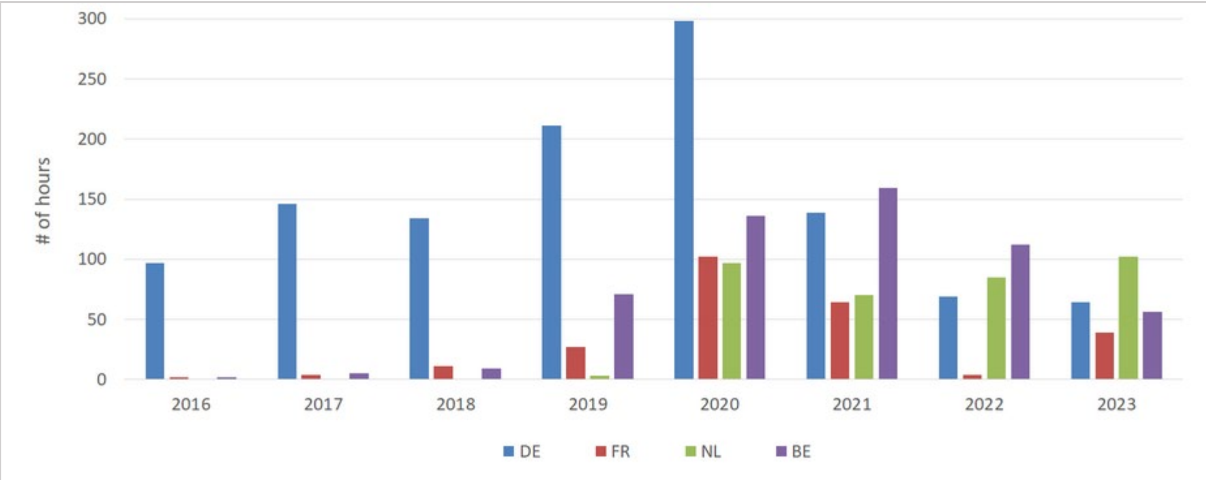
Box 2: What are negative prices?

Negative prices in electricity spot markets, whether in the day-ahead or intraday context, may arise due to substantial, uncontrollable energy output (usually renewable) coinciding with a notable reduction in demand. This situation prompts energy producers to offer payment for the consumption of surplus electricity. More specifically, renewables operating under subsidy schemes and not market price signals contribute to this imbalance. In some countries (e.g., France), renewable assets are forced to curtail their production in case of negative prices. Negative prices are an indicator of not-sufficiently flexible generation, not adequately price-responsive demand, or inadequate storage available to conduct energy arbitrage. They provide strong price signals to invest in solutions and technologies to enhance system flexibility.

Note: See (IEA, 2023) for more information.

Lastly, higher volatility leads to an increase in **ancillary service prices,** which paves the way for the development of clean flexibility solutions discussed in Chapter 3.

Figure 28: Negative power prices in Germany, France, the Netherlands, and Belgium



Source: Energieopwek, energy-charts, ENTSOE-transparency, Nordpool, and EPEX based on (MAZIDI, 2023).

Electricity retail prices

This rise in electricity wholesale prices was also felt by retail customers, but impacts varied by country and by customer.

European electricity retail prices for households escalated by 65% between 2018 and mid-2022, on average. This impacted Member States in different ways. While Nordic countries (Sweden, Finland) had a 50 €/MWh increase in wholesale prices during this period, Western countries including Italy, France,

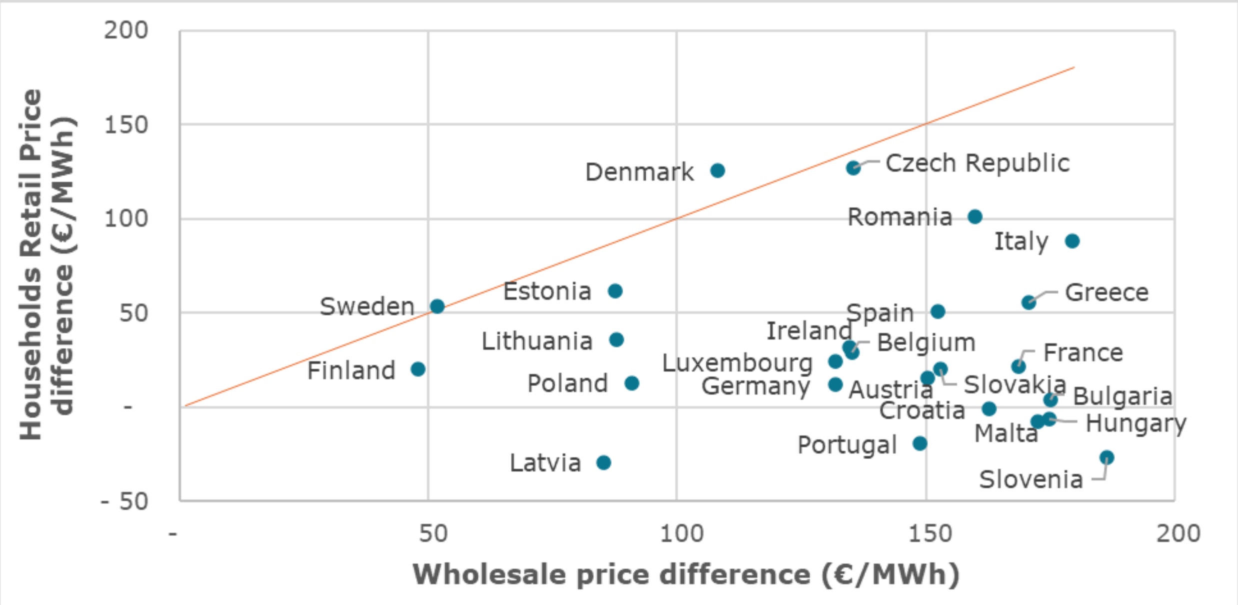
[27] In the U.S., this also leads to diurnal price patterns change, peak net-load hours shift to the evening in high solar futures (Joachim Seel, 2018).

[28] As seen in Chapter 1.3.20, Germany as a precursor in the development of VERs may serve as an early indicator of challenges anticipated in other power markets.

Spain or Germany dealt with a wholesale price increase between 132 and 179 €/MWh during the same period.

Market prices represent only a fraction of retail prices, the remaining including taxes, grid access tariffs and Over-the-Counter contracts (e.g. Renewable Power Purchase Agreements, other national subsidies[29]). Also, countries that offer fixed price contracts tend to be less impacted on average due to the portion of customers still benefiting in 2022 from prices fixed in the preceding years. Customers who benefit from long term fixed price electricity supply contracts are less impacted. Most countries also introduced in 2022 emergency measures including tax reductions to lower the impact on customers. **Retail prices thus tend to face lower increases compared to wholesale prices**, as highlighted in Figure 29. Sweden and Denmark are the only countries that slightly increased their retail prices above the wholesale price increase.

Figure 29: Comparison between retail and wholesale prices for households in 2022



Source: Eurostat, Enerdata, Energymarketprice.

Similar trends have been observed in the gas retail prices but are not detailed in this report. A more detailed description of electricity and gas retail prices by type of customer is available in Annex 0.

These governmental measures and price increases have consequences for the energy transition. They impact the consumers' willingness to convert from fossil to electric sources (e.g., switch to heat pumps, electrify an industrial process, buy an electric vehicle). At the same time, this instability resulted in more Power Purchase Agreements (PPA), where electricity produced by a solar or wind power plant is directly sold to an end-customer (typically industrial) at a fixed price.

Overall, the energy system was considerably more exposed to natural gas wholesale prices during this transition. Increased reliance on natural gas and lower production of nuclear energy are key factors driving price increases, though they were tempered by increased renewable energy development and reductions in demand.

[29] For example, France that sells 25% of its nuclear production at 42 €/MWh, a price fixed by the National Regulatory Authorities.

2. FUTURE DEVELOPMENT OF THE EU'S ENERGY SYSTEM INFRASTRUCTURE

KEY FINDINGS

Meeting the European Union's 2030 GHG emissions reduction objectives and the net-zero target by 2050 poses considerable challenges. First, it requires an increased electrification of end-uses in all sectors but particularly in transport. Second, while growth in solar power aligns with the achievement of the Fit for 55 objectives, there are development challenges for wind power related to its cost, auction mechanisms, and grid connections. Third, this development might go on par with an increase of fossil power plants capacities. Such plants will need to be built with lower capacity factors and at increased costs (Carbon Capture projects, penetration of biomethane in the gas mix). These plants must be developed in parallel with the partial reconversion of gas transmission and distribution infrastructures. Various possibilities (storage, demand response) exist to mitigate the development of these capacities but are currently at a low maturity level.

2.1. Methodology

The "European Climate Law" (Regulation (EU) 2021/1119) sets the objective for reducing EU's GHG emissions to net zero by 2050, and to achieve negative emissions thereafter. The intermediary milestone of a 55% reduction in GHG emissions by 2030 (compared to 1990 levels) was established within the Fit for 55 package; the package was introduced in 2021 and many of the required policy updates were made by the end of 2023.

Various pathways are available to attain these targets. By 2030, Member States are obligated to fulfil binding objectives for Energy Demand (as outlined in the Energy Efficiency Directive) and the proportion of renewable energy (as specified in the Renewable Energy Directive). These objectives are tailored to local contexts within each country's National Energy and Climate Plans (NECP).

In the context of the United Nations Framework Convention on Climate Change (UNFCCC), under the Paris Agreement, contracting parties are required to prepare Nationally Determined Contributions (NDCs) that communicate their GHG objectives by 2030. Parties should also prepare Long-Term Strategies (LTS) that extend these objectives to 2050. Those 2050 objectives often focus on GHG emissions and do not necessarily detail the path expected to attain these objectives.

This chapter describes four scenarios that model the EU's energy system and carbon emissions reductions to 2050; these are based on various interpretations of Member States' announced policies. The respective impacts on Energy Demand, Electrification of the Energy system, Gas demand, and the decarbonisation of the power system are included for each scenario.

2.1.1. Description of Scenarios

Table 1: Scenarios benchmark characteristics

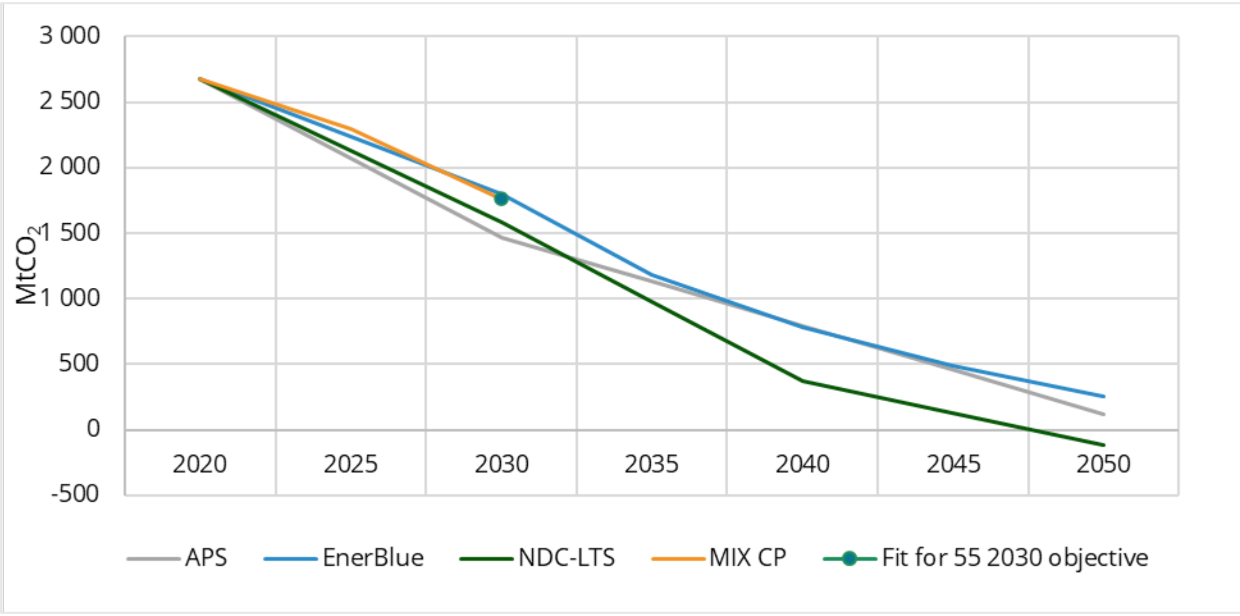
Scenario	Institution	Model	Scenario at a glance
MIX-CP	European Commission	PRIMES	This scenario, starting from the European Commission Reference Scenario 2020[30] and built upon the Climate Target Plan analysis, translates the assessed impact the Fit for 55 packages, and is a reference for the impact assessment of the various associated policies. Compared to the MIX scenario, this variant adopts a more relevant carbon pricing hypothesis. **It does not provide information after 2030.**
EnerBlue	Enerdata	POLES-Enerdata	Published in 2023, this scenario reflects the successful achievement of the latest NDCs (COP 26) and associated NECPs by 2030 and, if existing, by 2050. **It is the least ambitious of the 2050 scenarios.**
Announ-ced Pledge Scenario (APS)	International Energy Agency	World Energy Model -– TIMES	This scenario accounts for the achievement of all announced savings ambitions and targets by August 2022, regardless of whether these announcements were included in legislation or in updated NDCs.
NDC-LTS	Joint Research Centre	POLES-JRC	Accounts for NDC policies (by 2030 and 2050) but assumes that the NDC's conditional targets are also met making it **more ambitious** in the long term than other scenarios.

Note: The scenarios are ordered from the most achievable to the most ambitious.

[30] The EU Reference Scenario of the European Commission based on the policy framework in place in 2020 allows policy-makers to analyse the long-term economic, energy, climate and transport outlook. (See: https://energy.ec.europa.eu/data-and-analysis/energy-modelling/eu-reference-scenario-2020_en).

2.1.2. Comparison of GHG Emissions between Scenarios

Figure 30: Total CO_2 emissions forecast in the EU by scenario



Source: Various scenarios, Enerdata's analysis.

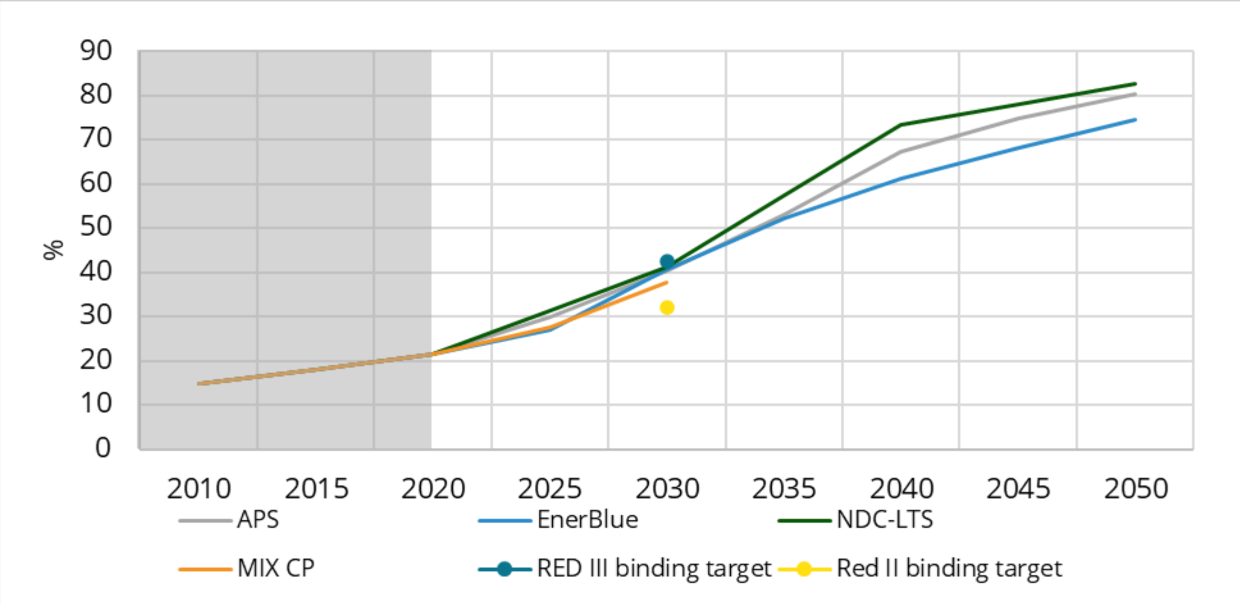
Almost all scenarios align with the Fit for 55 target GHG objectives (EnerBlue scenario misses it by 1%). However, despite aligning with national objectives, the EnerBlue and APS scenarios fall short of carbon neutrality by 2050.

The reduced CO_2 emissions achieved by 2030 in the APS scenario account for the integration of additional announced policies, even if they are not entirely incorporated into updated NDCs.

An important takeaway from this is that ongoing policies are not sufficient for meeting targets and represent the minimum required actions. Additionally, when comparing the Mix CP (aligned with the Fit for 55 objectives) and the NDC-LTS (the sole scenario attaining carbon neutrality), it is evident that, **despite the ambitious nature of the policies within the Fit for 55 package, they might not prove adequate for achieving carbon neutrality**.

2.1.3. Comparison of Levels of Integration of Renewables into the Energy System

Figure 31: Share of renewables in gross final energy consumption in the EU



Source: Various scenarios, Enerdata's analysis.

Figure 31 highlights the differences between the scenarios in terms of the share of renewable energies in the final energy consumption which is the key target defined in both RED II and RED III. All scenarios encompass a higher share of renewables by 2030 than RED II's binding target of 32.5%. It should be noted that **none of those scenarios take into account the RED III**[31] **binding target** of 42.5% (with effort to reach 45%) that only entered into force in November 2023. By 2050, the scenarios are not driven by a targeted share of renewables and tend to diverge reaching a total share between 75% (EnerBlue Scenario) and 83% (NDC-LTS scenario).

2.1.4. Key Limitations

The scenarios described in this chapter should be regarded as illustrative trajectories for attaining climate neutrality objectives in the EU. Specifically, they are delineated along "pessimistic" Business-as-usual paths and "optimistic" successful scenarios. Importantly, these scenarios do not incorporate the most recent targets, such as the RED III target for renewables penetration and the Energy Efficiency Directive (refer to subsequent chapters for details).

These scenarios centre on energy production methods rather than distribution and transport infrastructure. The primary mechanisms for incorporating renewables are detailed in the following chapters.

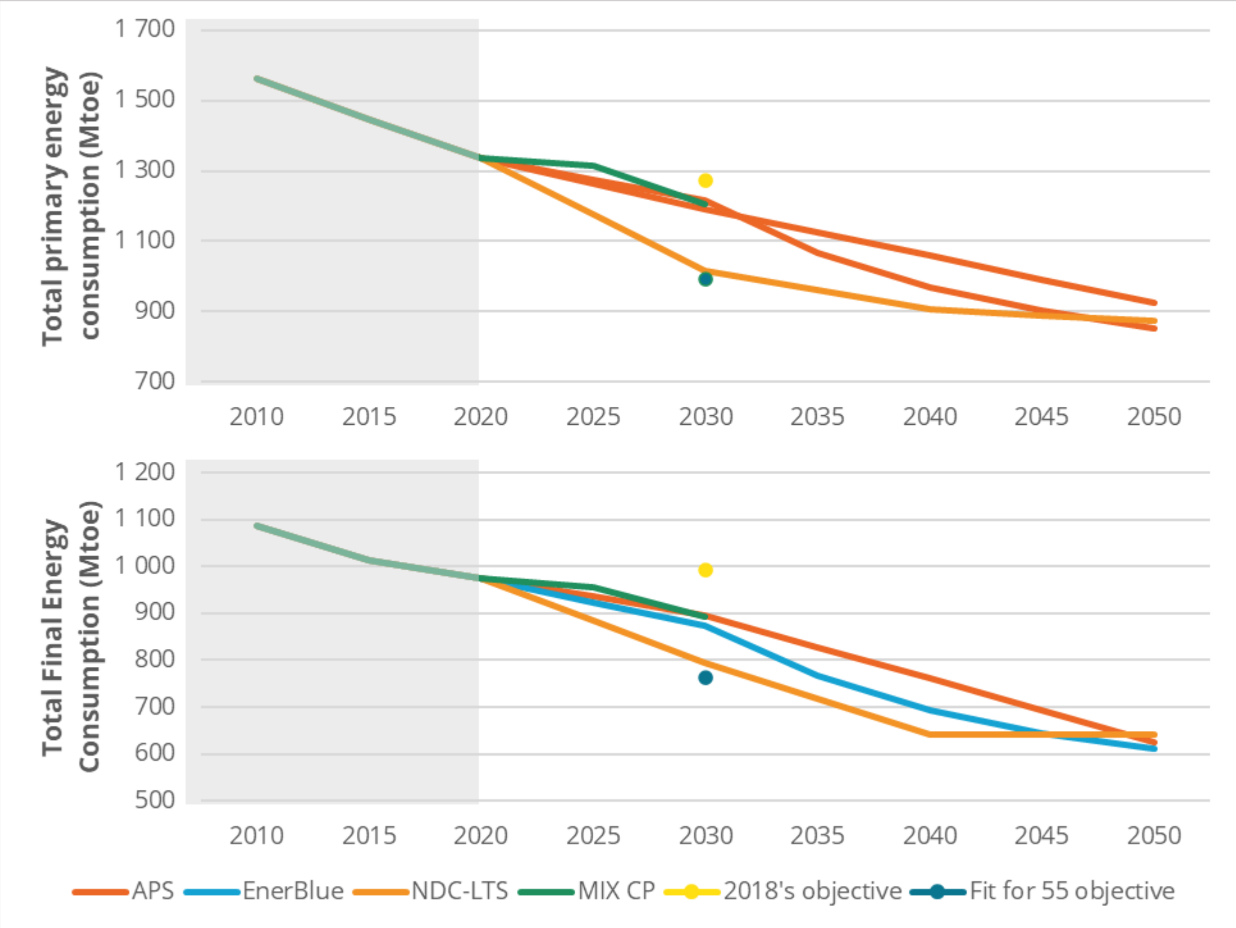
Throughout this chapter, emphasis is sometimes placed on Enerdata's EnerBlue scenario, owing to the more comprehensive information available.

[31] The detailed amended directive is available at: https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX%3A32023L2413&qid=1699364355105.

2.2. Evolution of Energy Demand

The primary and final energy demand of the European Union are depicted below across the four scenarios under consideration. These scenarios align, to varying degrees, with the amended Directive on Energy Efficiency (2018/2002), which establishes new targets of 1273 Mtoe for primary energy demand and 956 Mtoe for final energy demand, in comparison to the 2020 objectives outlined in Chapter 1. However, it is crucial to note that **these scenarios should be considered optimistic**, as they do not encompass the recently endorsed[32] energy efficiency target incorporated into the Fit for 55 package. This legislative package further increased energy efficiency objectives to 992.5 Mtoe for primary energy demand and 763 Mtoe for final energy demand[33].

Figure 32: EU primary and final energy consumption



Source: Various scenarios, Enerdata's analysis.

The energy savings levels achieved between 2010 and 2020, seen in Figure 32, must be further accelerated if the savings objectives outlined in the Fit for 55 initiative are to be achieved. The savings trends in the scenarios show further reductions in primary energy from 2020 to 2030 ranging from -10% (MIX-CP) to -20% (NDC-LTS), compared with the -14% achieved during the 2010-2020 period. It is anticipated that continued energy efficiency improvements will play a pivotal role in this reduction, though a thorough sector-level analysis is required to understand how this would occur.

[32] The REPowerEU plan proposed in May 2022 to raise the energy efficiency targets further. In July 2023, a formal agreement was achieved for the revised EED. The text entered into force in October 2023.

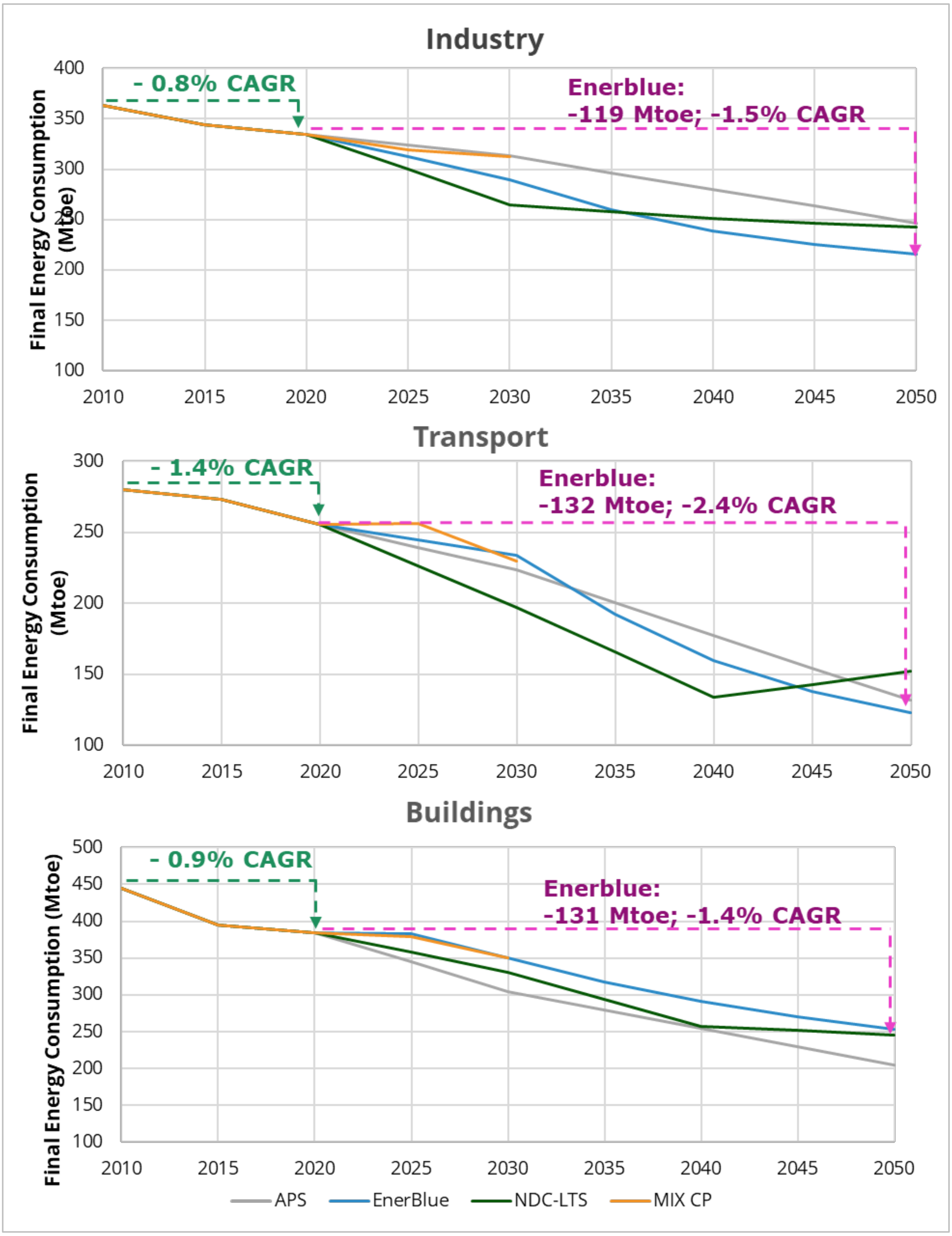
[33] This target sets the goal of reducing EU final energy consumption by 11.7% by 2030, compared to the projected energy use for 2030 (based on the 2020 reference scenario).

The revised EED does not include sectorial objectives (except for the public sector) and each Member State will need to adapt this target in their NECPs by 2025. As shown in Figure 33, **all sectors must further accelerate decreases in their final energy consumption**. This will be particularly challenging for industry as energy efficiency improvements have slowed down in the sector since 2007 (see Section 1.2.2).

The transport sector is anticipated to be the primary contributor to savings reductions in the EnerBlue scenario, with a projected decrease of -232 Mtoe and an expected CAGR of -2.4% between 2020 and 2030, largely due to a proliferation in electric vehicle use.

Across all sectors, declines in energy use primarily stem from enhancements in energy efficiency (including the electrification of end-uses), but **efficiency might not be sufficient. Additional sufficiency measures might be necessary,** in particular for the residential and transport sectors. The term "sufficiency" encompasses behavioural and societal changes directed at curbing energy consumption. Examples include lowering temperatures in buildings, engaging in carpooling, adopting active transportation methods, and using public transport in the realm of transportation. Sufficiency not only contributes to diminished energy usage but also alleviates stress on various environmental concerns such as metal production, resource utilisation, critical minerals.

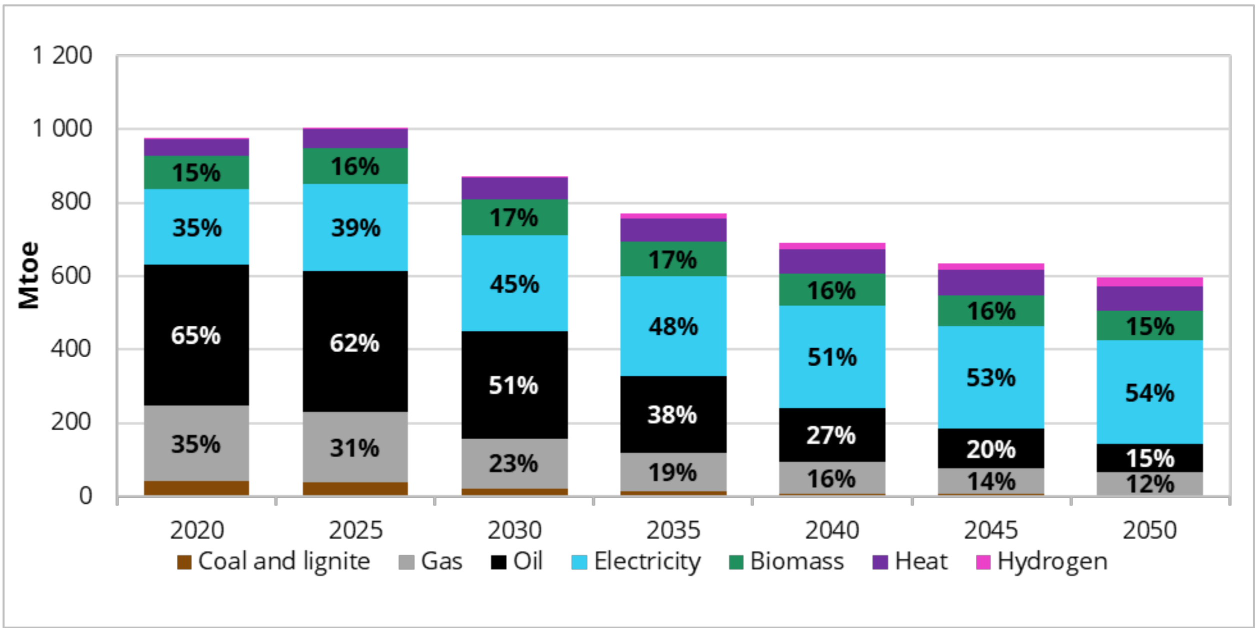
Figure 33: EU final energy consumption by sector



Source: Various scenarios, Enerdata's analysis.

Figure 34 shows decreases in energy use by fuel type in the EnerBlue scenario. The other scenarios show a similar trend in reductions in fossil fuel use and increases in electricity use.

Figure 34: EnerBlue final energy consumption split by fuel in the EU



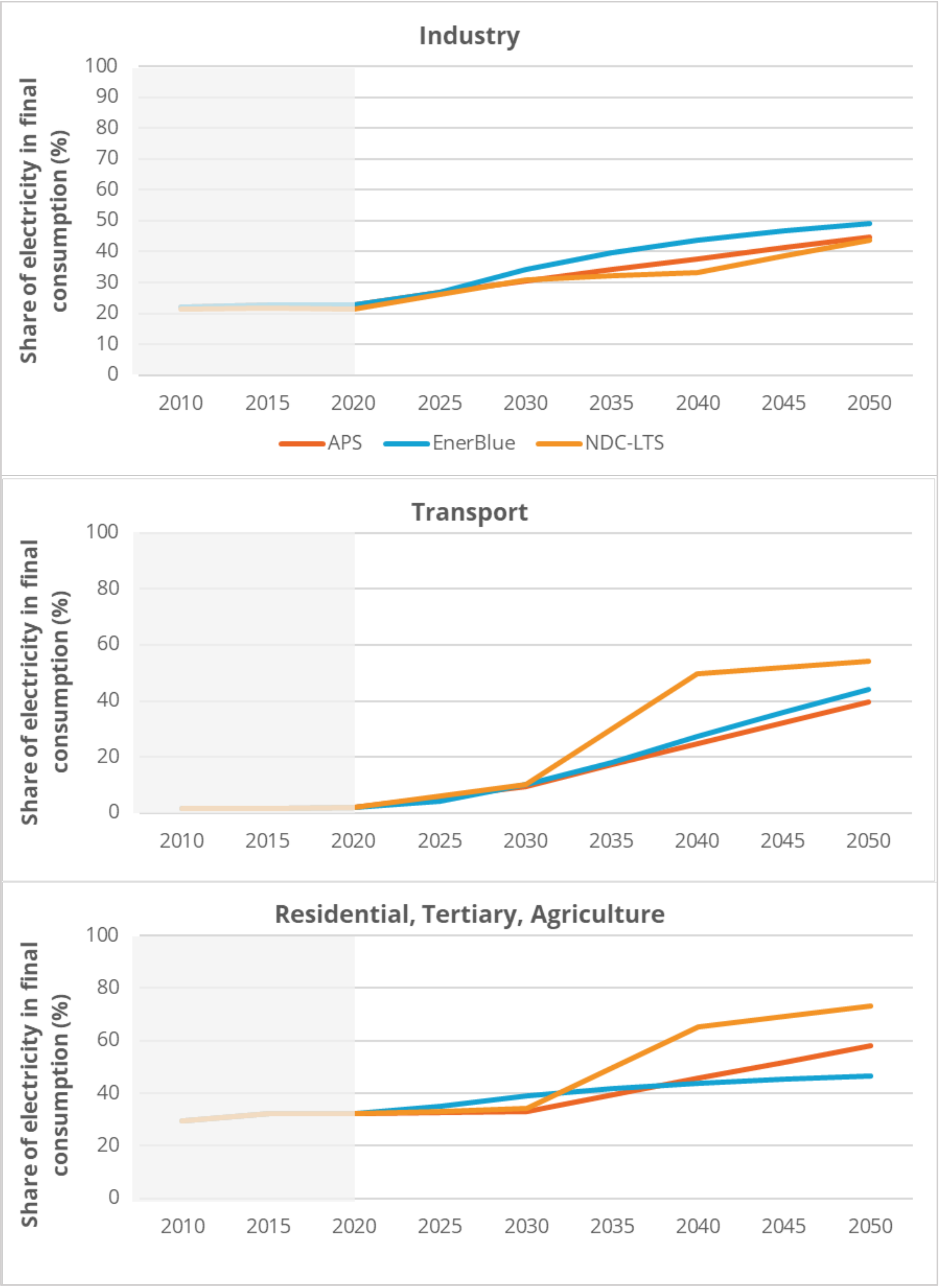
Source: Enerdata, EnerBlue scenario.

Reductions in fossil fuel use need to occur much faster than in the previous decade; electrification of the energy system will play an important role in this. In the EnerBlue scenario, there are **high levels of electrification of the energy system**, increasing from 35% of final energy consumption in 2020 to 54% by 2050. The remaining half of energy consumption is expected to come from oil and gas, either produced biologically or coupled with Carbon Capture and Storage (CCS), heat (mostly coming from cogeneration and biomass) and green hydrogen.

2.2.1. Electrification of the EU's Energy Demand

In all these carbon constrained scenarios, **the increase in electrification is a key decarbonisation factor**. Figure 35 shows the electrification rate in primary sectors: industry, transport and buildings.

Figure 35: Electrification rate by sector and by scenario in the EU



Source: Various scenarios, Enerdata's analysis.

Note: The detailed electrification rate by sector of the MIX-CP scenario was not available.

Substantial variation can be observed in the level of projected electrification by sector. The **industrial sector** is projected to transition from a consistent electrification rate of 20% over the past decade to nearly 50% within the next 30 years. While this shift is progressive in all four scenarios, it could be driven by several large projects, mainly in the steel and the chemical industries. Electrification may occur directly, involving the electrification of specific processes, or indirectly through the utilisation of hydrogen produced by electricity. This transition could exert a significant increase on electricity demand near major production sites, potentially being a source of local congestion. Access to low-cost electricity through a direct connection via renewable Power Purchase Agreements (e.g., H2 Green Steel project in Sweden) is anticipated to play a pivotal role in propelling this transformative process.

Transport is likely to be the most extensively electrified sector due to widespread adoption of electric vehicles. The electrification rate is expected to grow from less than 3% to 40-55% by 2050, with an acceleration expected after 2035 (particularly highlighted in the NDC-LTS scenario). This shift is underpinned by the EU regulation adopted in 2023[34], mandating the discontinuation of production of internal combustion engine cars by 2035, and by a European Commission proposal in 2023 that aims to reduce emissions from new trucks 90% by 2040[35]. This will result in substantial repercussions on the energy infrastructure, mainly the establishment of an extensive charging network. Additionally, it involves addressing the challenges associated with new peak demands, such as holiday demand and night charging. Furthermore, this transformation will add substantial storage capacity (Electric vehicles batteries) to the grid, providing flexibility through mechanisms such as Vehicle-to-Grid or smart charging (outlined in Chapter 3).

The **residential and tertiary sectors** will transform mainly through the electrification of heating and the development of heat pumps. While such devices will increase winter peak demand, heat pumps are a flexibility asset that can be a contributor to demand response flexibility as highlighted in Section 0.

Electrification is still in its early stages, and the shift in power production is still pending. Overall, **electrification of end-uses rises from 21% in 2020 to around 30% in 2030 and to around 50% in 2050 in the various scenarios.**

2.2.2. Evolution of Gas Demand

In terms of final energy[36], **all scenarios show a strong drop in gas consumption by 2030**, ranging between -23% (MIX CP scenario) to -57% (NDC-LTS scenario) compared to 2020 levels. This is conservative compared to recent EU objectives; the REPowerEU communication set a target of a 256 bcm (2,680 TWh) decrease, equivalent to a decline of 60% in gas consumption between 2020 and 2030 (European Commission, 2022).

By 2050 there are 86% to 97% reductions in gas use compared to 2020, the NDC-LTS scenario being the most ambitious. These variations primarily hinge on the influence of Carbon Capture and Storage (CCS) in shaping the final energy mix and on the penetration of renewable gases, namely biomethane and green hydrogen in the power mix.

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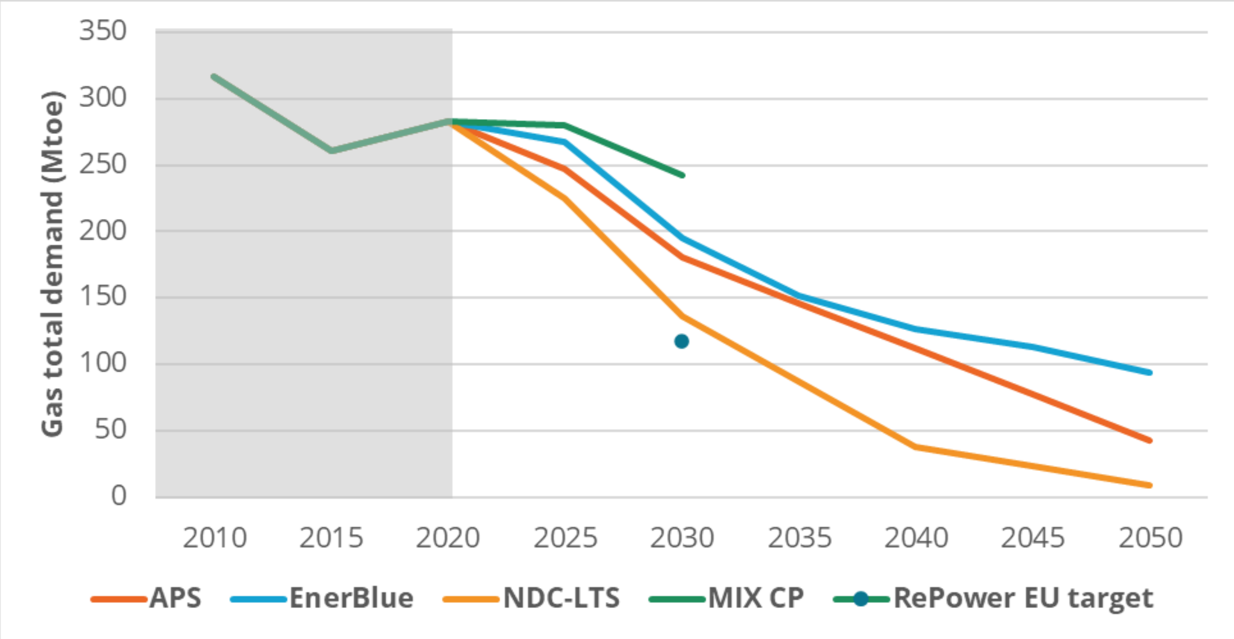
34 Amended regulation (EU) 2023/851; available at: https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX:32023R0851.

35 Proposal for a regulation amending regulation (EU) 2019/1242; available at: https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=COM:2023:88:FIN.

36 Thus, not including gas used for the production of electricity.

Figure 36: Evolution of gas total demand according to each scenario



Source: Scenarios, REpowerEU communication, Enerdata's analysis.

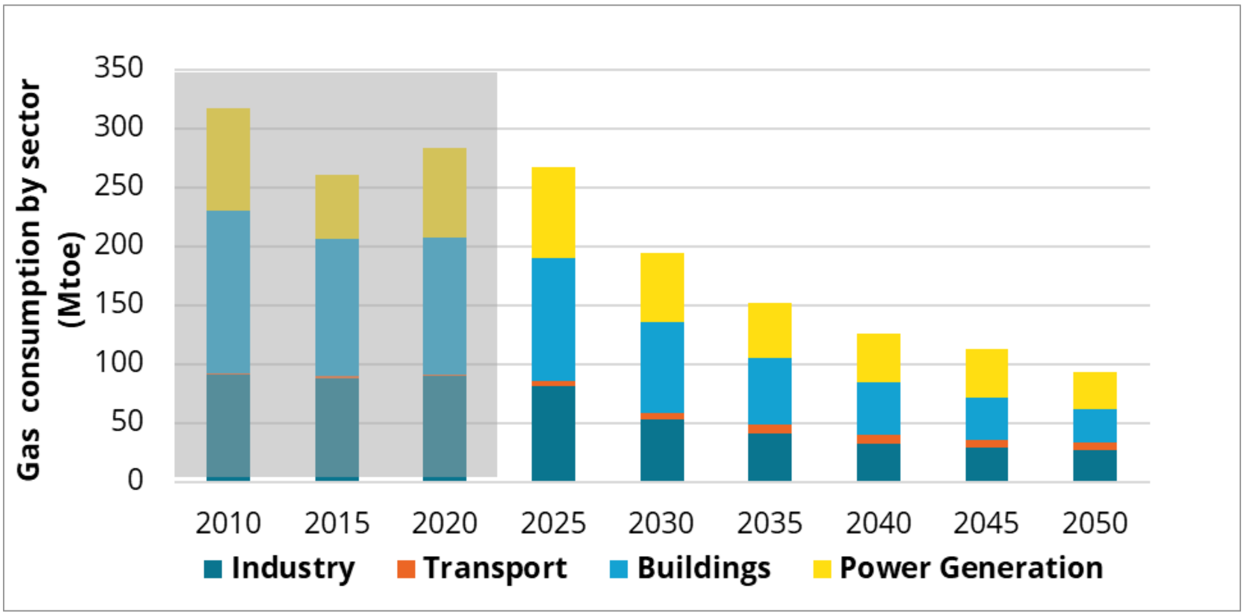
Note: Gas total demand includes both gas final consumption for all sectors and the gas input in electric power plants. It does not include gas losses in transport and the distribution network.

Figure 37 illustrates the distribution of gas consumption by sector in the EnerBlue scenario[37]. **Gas use is expected to substantially decrease in the industrial, buildings, and power generation sectors, but slightly increase in the transportation sector,** in particular for trucks, buses as well as for maritime or air transport.

This decreasing gas use raises concerns about the **potential for the distribution network to become a stranded asset** because a substantial portion of the infrastructure in the distribution sector caters to the residential and tertiary sectors. However, in countries experiencing robust biomethane development, there is the prospect of repurposing the distribution network. This issue warrants a comprehensive examination at the EU level. In France, a recent report by the regulator CRE (CRE, 2023) suggested that only a limited section of the distribution network may require abandonment if adjustments are made to align with the distributed production of biomethane. This optimistic outlook is attributed largely to the recent modernisation of the distribution infrastructure in France. It is important to note that countries with older infrastructures and less developed biomethane markets may arrive at different conclusions.

[37] Due to a lack of available data for other scenarios.

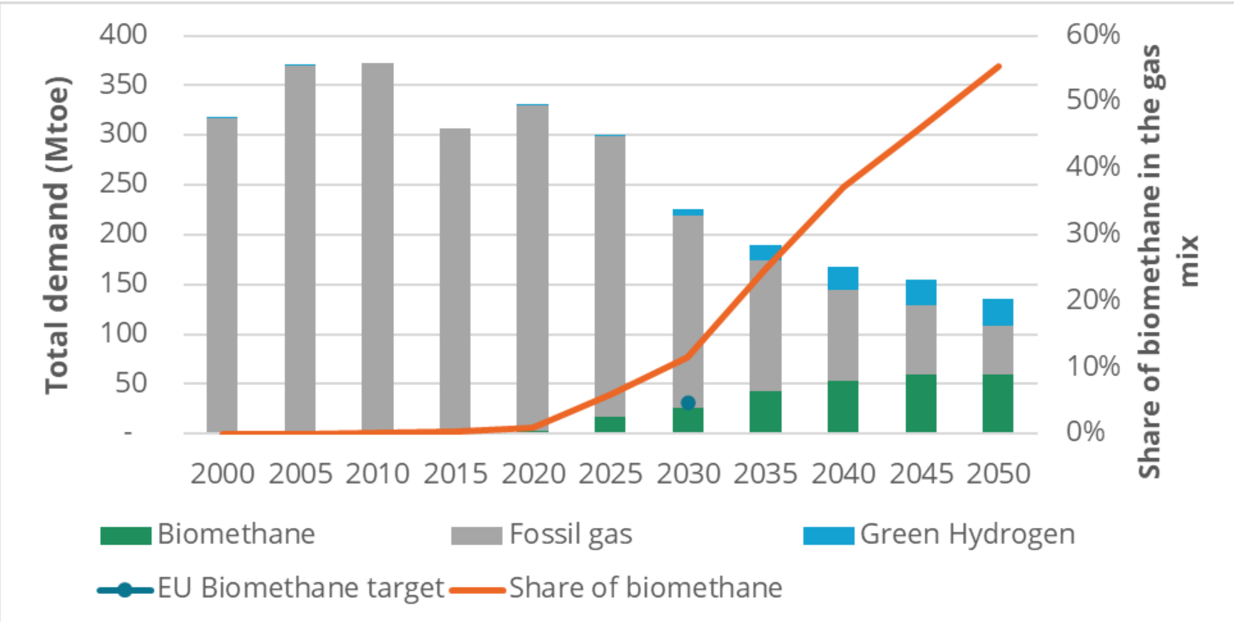
Figure 37: Final consumption of gas by sector - EnerBlue scenario



Source: Enerdata, EnerBlue scenario.

The EnerBlue scenario assumes a growing share of biomethane coupled with the development of green hydrogen used as an energy vector[38] (Figure 38). This scenario does not include the EU biomethane target of 35 bcm of biomethane by 2030 set in the REPowerEU communication, but is already optimistic. Achieving the 2030 objective would require an additional injected capacity of 2.8 Mtoe/year, compared to the 0.8 Mtoe of additional injections that occurred between 2021 and 2022.

Figure 38: Gas uses by type of production - EnerBlue scenario



Source: Enerdata, EnerBlue scenario

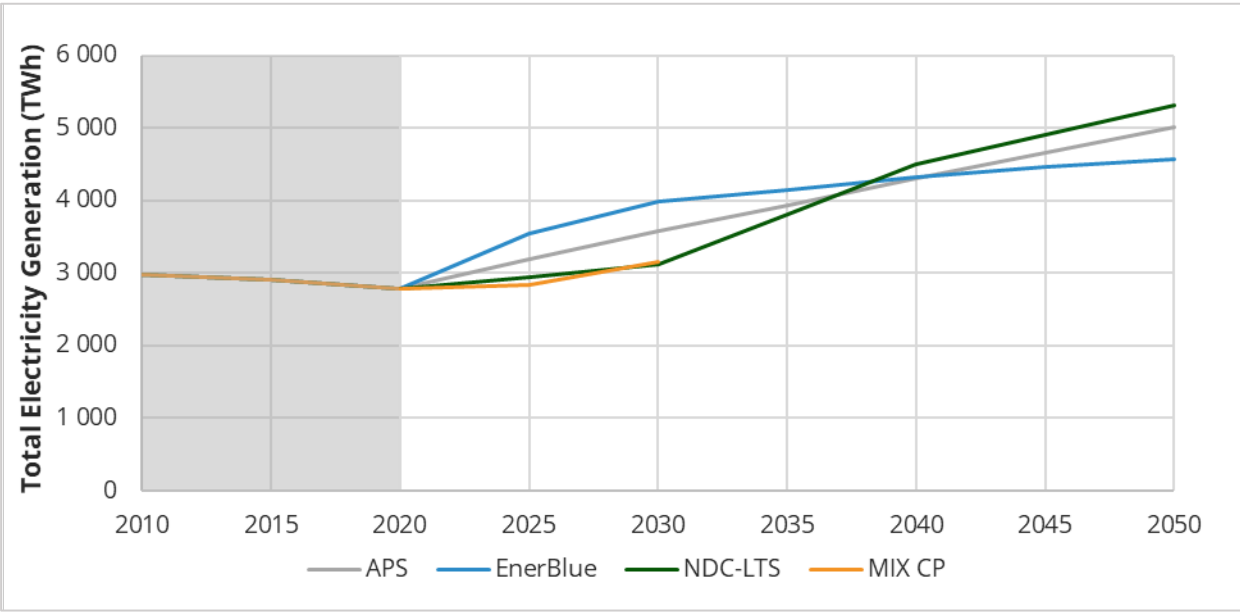
[38] It should be noted that in the EnerBlue scenario, green hydrogen is not necessarily mixed in the gas distribution network but is mostly produced locally or distributed through dedicated infrastructures, not detailed here.

The role of hydrogen increases in all scenarios post-2025, reaching total consumption ranging between 6 and 8 Mtoe by 2030 (which is about three times lower than the production target set in the REPowerEU scenario), then escalating to 25 to 50 Mtoe by 2050. These figures closely align with the "national trends" scenario outlined in the TYNDP 2022, which is 60% below the 2030 EU target for hydrogen production and import specified in the Fit for 55 package (a total of 20 million tonnes). The potential development of green hydrogen and its impact on the EU energy system is extensively detailed in Chapter 4.

2.3. Evolution of Power Production

Even though energy consumption is expected to significantly decline, **electrification is anticipated to lead to an augmentation in electricity production within the EU**. Figure 39 illustrates the escalation in electricity production within the European Union necessary to meet with growing demand.

Figure 39: Total electricity production for the EU



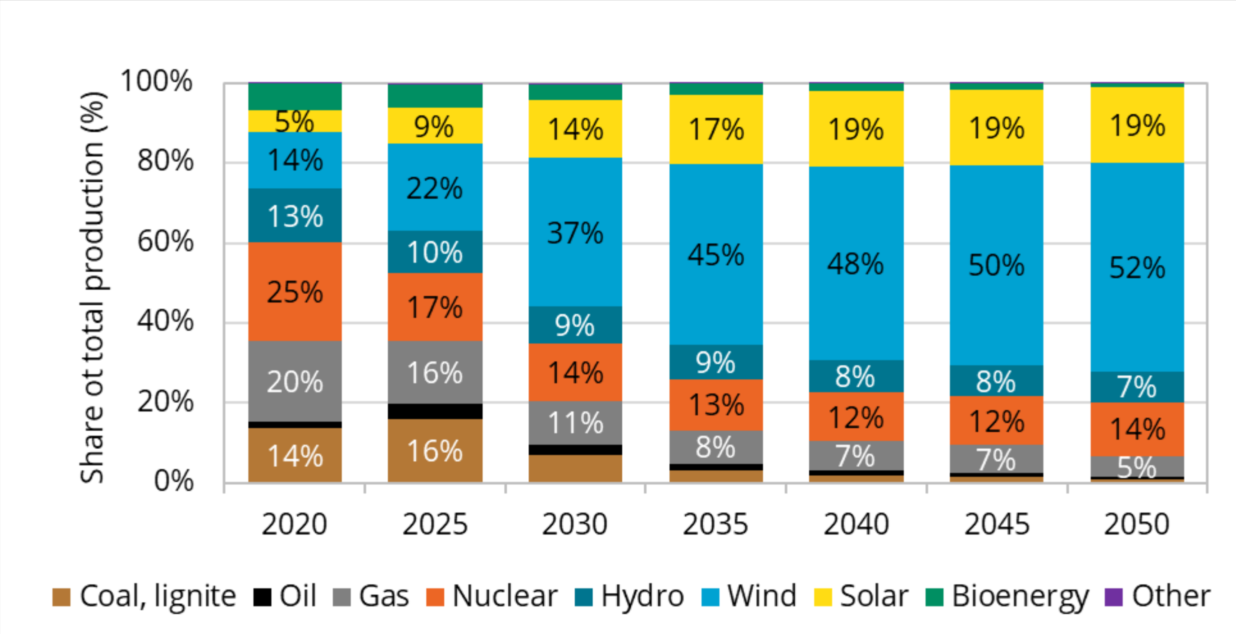
Source: Various scenarios, Enerdata's analysis.

While total European electricity production has slowly decreased between 2010 and 2022, the scenarios reflect continuous growth with an average CAGR of 2% for the period 2020-2050, although there are differences in the repartition of this growth between the 2020-2030 and the 2030-2050 period. EnerBlue anticipates a stronger development in the short term while the NDC-LTS scenario ambitions a strong acceleration to occur post-2030.

EnerBlue is the most ambitious of the scenarios in the short term, reflecting a **4% yearly increase of total electricity generation until 2030** (versus 3% in the APS scenario and 1.2-1.3% in the other scenarios) supported mainly by increased production of wind and gas power plants.

These scenarios assume substantial advancements in production infrastructure – encompassing both centralised and decentralised solar power, onshore and offshore wind, as well as thermal power plants – **that are not in line with the current development pace of power plants (in particular wind)**. Further details regarding the implications for network development will be specified in the next chapter.

Figure 40: Evolution of the EU power mix according to the EnerBlue scenario



Source: Enerdata, EnerBlue Scenario.

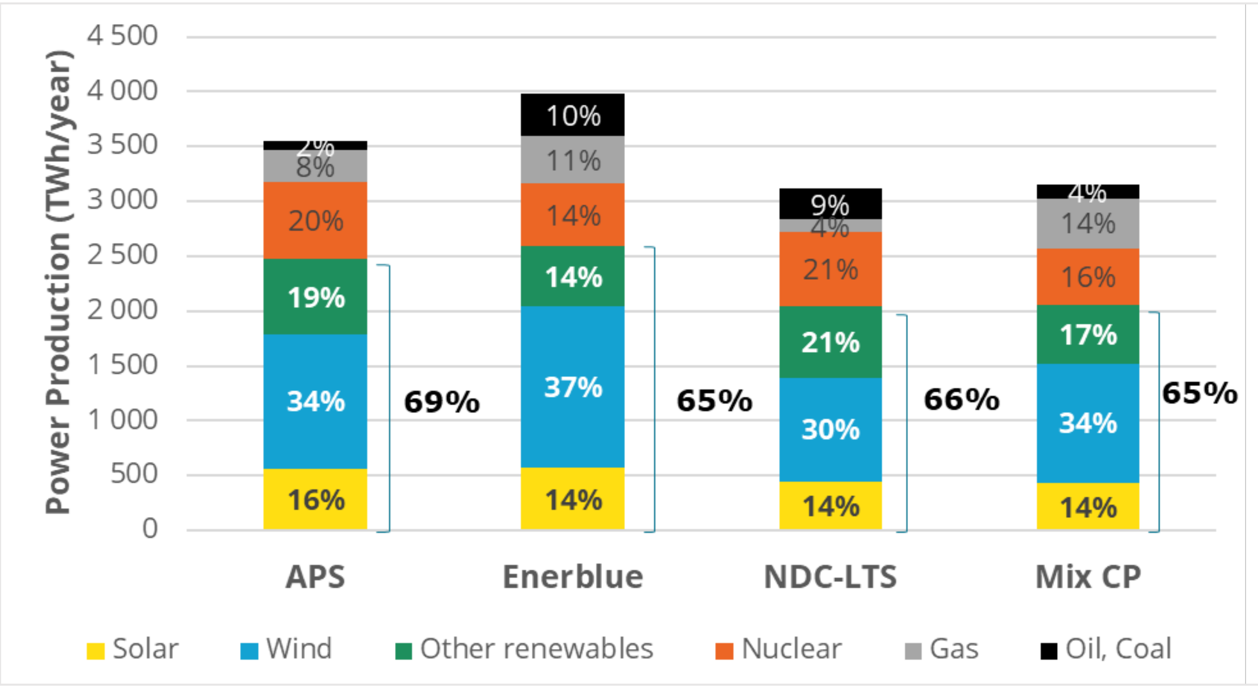
Figure 40 illustrates the distribution of power production by fuel in the EnerBlue scenario. In this scenario, it is anticipated that wind power will constitute more than half of electricity production by 2050, with solar energy accounting for 19%. Coal, lignite, and oil are projected to undergo substantial reductions, nearing phase-out, whereas gas is expected to contribute 5%. Nuclear energy declines until 2030, primarily due to the decommissioning of existing power plants. A stabilisation is then predicted, propelled by the emergence and advancement of new nuclear reactors[39].

Figure 41 shows the power mix in 2030 by scenario. In all scenarios, renewable sources, including hydropower, wind, solar, and bioenergy, are anticipated to dominate the electricity mix, accounting for over 60% of the total by 2030[40], then increasing to between 67% and 90% by 2050. The share of nuclear energy is projected to diminish to 15%; however, it will continue to play a vital role in the decarbonisation of electricity production. Power sector decarbonisation levels are anticipated to be between 80 and 99% by 2050, depending on the scenario.

[39] For further information, see Parliament resolution of 12 December 2023 on small modular reactors, available at: https://www.europarl.europa.eu/doceo/document/TA-9-2023-0456_EN.pdf.

[40] The electricity market designs associated to this development are not discussed in this report but more information can be found here: https://energy.ec.europa.eu/topics/markets-and-consumers/market-legislation/electricity-market-design_en.

Figure 41: Comparison of the EU power mix by 2030 according to each scenario



Source: Various scenarios, Enerdata's analysis.

Note: Other renewables include hydropower, bioenergy, and geothermal energy.

2.3.1. Wind Power

In the EnerBlue scenario, wind power has the potential to generate 1,500 TWh by 2030, and 2,400 TWh by 2050. This projection represents the most ambitious outlook for wind power by 2030 among the four scenarios[41]. Despite this, in none of the scenarios is there sufficient ambition to achieve the RED III target for penetration of renewables in final energy consumption.

Onshore wind represents 90% of expected installed wind capacity (Figure 42). Overall, total wind capacity is expected to increase from around 180 GW in 2020 to around 740 GW by 2030 and 1,350 GW by 2050. This would represent an additional commissioned capacity of 55 GW per year between 2020 and 2030. In comparison, the recent European Commission Action Plan on Wind Power mentions a lower target of 500 GW in 2030 and an expected development pace of 37 GW/year between 2022 and 2030[42]. **These growth rates are extremely ambitious and are not in line with the current pace of development for wind energy.** Only 15 GW of wind power was commissioned in 2022. According to the latest IEA analysis (IEA, 2023), this development was hindered mainly by permitting and grid constraints that led to lengthy project development times.

The pipeline of announced offshore wind projects to be installed by 2030 amount to a total capacity of 114 GW, 75% of the 153 GW necessary to achieve targets. This pipeline might not be sufficient given that an offshore wind project takes between 7 and 11 years to develop[43].

41 However, it is worth noting that by 2050, the APS scenario surpasses the EnerBlue scenario in terms of wind power generation.

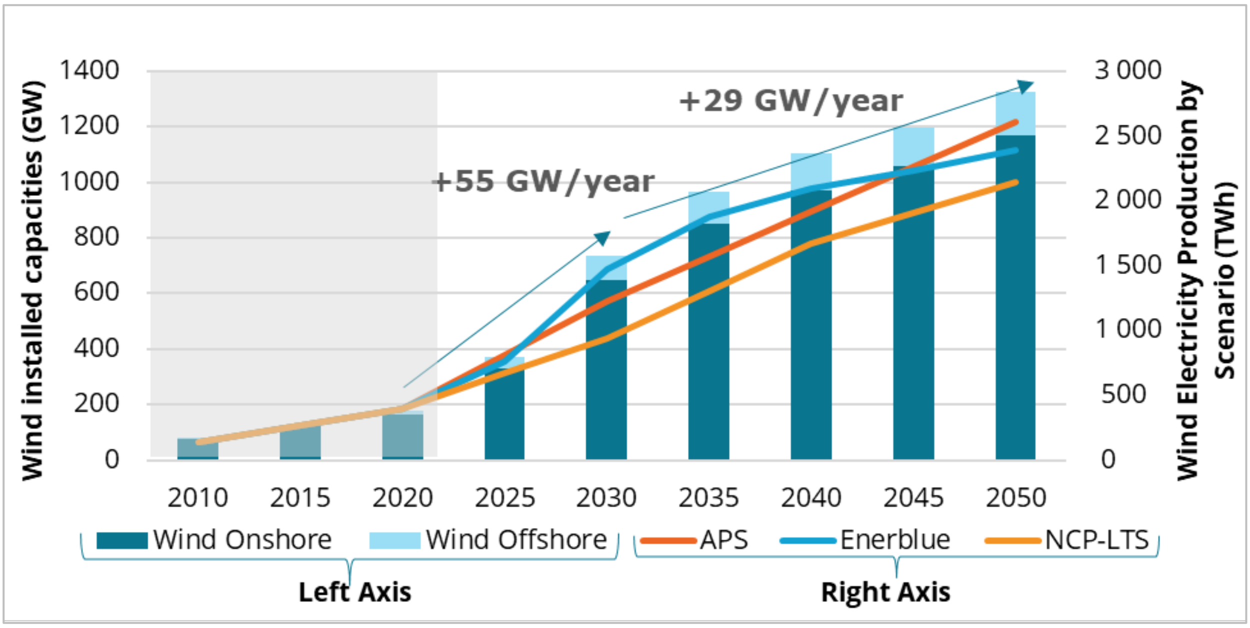
42 *Commission sets out immediate actions to support the European wind power industry*, October 2023: https://ec.europa.eu/commission/presscorner/detail/en/ip_23_5185.

43 According to Iberdrola : https://www.iberdrola.com/about-us/our-activity/offshore-wind-energy/offshore-wind-park-construction#:~:text=Three%20to%20five%20years%20are,to%20four%20years%20to%20construction.

Assessing the continuous pipeline of onshore wind is difficult due to the smaller and more dispersed nature of the projects. The results of awarded auctions show that a cumulative total of 19 GW was granted within the EU between 2021 and 2023[44], which is markedly inadequate to satisfy anticipated growth. Numerous recent auctions were undersubscribed due to uncertainty around pricing and escalating costs (such as labour, equipment, and materials). Additionally, contracts are frequently not indexed to inflation; consequently, an indeterminate proportion of project stakeholders have opted for long-term Power Purchase Agreements to ensure financial stability.

Although other scenarios are less ambitious with regards to wind, all show significant growth in installed capacities during the forecast period.

Figure 42: Wind expected capacities (EnerBlue scenario) vs. production development



Source: Enerdata, based on various scenarios.

Note: The installed capacity was only available for the EnerBlue scenario. To compare with other scenarios, the total wind electricity production of each scenario was added on the right-axis.

2.3.2. Photovoltaic Power

Solar PV follows a different path than wind. **Installed capacities have been surpassing the expectations,** as highlighted in Section 1.3.1. In 2022, 38 GW of PV was installed in the EU and first estimations for 2023 show over 56 GW of newly installed capacities[45].

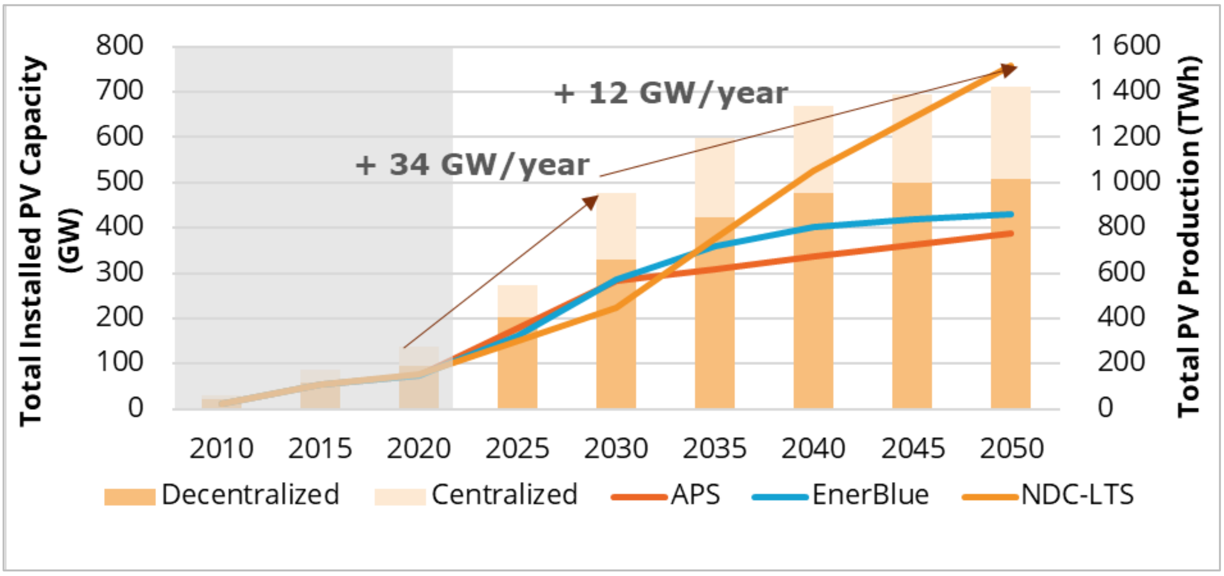
This acceleration surpasses the rates envisaged in existing scenarios. In the EnerBlue scenario, the installation rate exceeds 34 GW per year between 2020 and 2030. This will increase solar capacities from 140 GW in 2020 to 475 GW by 2030, and 700 GW by 2050. In comparison, the EU solar strategy published in 2022 as part of the REPowerEU plan is more ambitious and aims to bring online almost 600 GW of solar by 2030 equivalent to almost 50 GW per year of new solar capacity by 2030. In the EnerBlue scenario, decentralised power, mainly rooftop power plants, will account for over 70% of installed solar capacity compared to 67% today; this relatively small shift happens because centralised solar is expected to grow apace with decentralised production.

44 According to Enerdata's Renewable Energy Auctions Monitor, available at: https://www.enerdata.net/research/res-energy-auctions.html.

45 Estimation by the European Commission: https://energy.ec.europa.eu/topics/renewable-energy/solar-energy_en.

The acceleration of PV may not compensate for the hindered development of wind power. Unlike onshore and offshore wind, PV exhibits considerably lower capacity factors, requiring adjustments to the energy infrastructure. Specifically, managing winter and night demand will be much more challenging, and will require larger capacities for daily storage. A detailed exploration of this subject is undertaken in Sub-chapter 3.4.

Figure 43: PV expected capacities (EnerBlue scenario) vs. production development



Source: Enerdata, EnerBlue scenario.

2.3.3. Fossil Power Plants

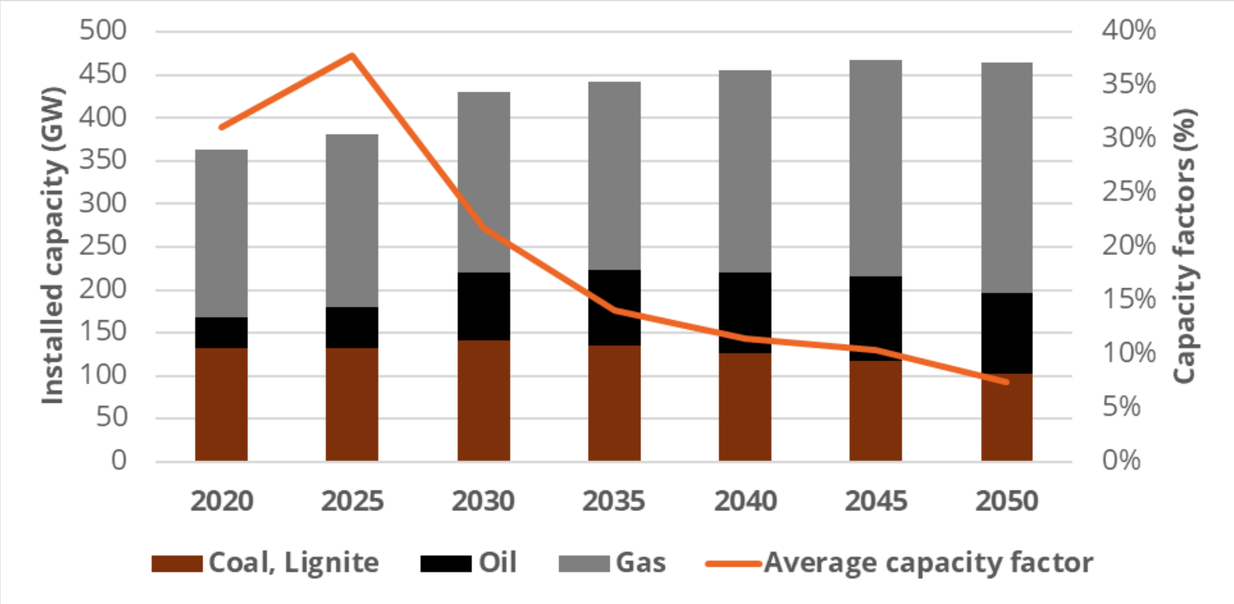
The use of coal, gas and oil for power production is expected to strongly decrease. Most coal and oil power plants are expected to be shut down while gas will continue to be used for peak production. This decrease is expected to accelerate between now and 2030 at a faster rate than it did between 2020 and 2030.

In the EnerBlue scenario, fossil fuels account for 26% of electricity consumption in 2030, and only 8% by 2050, the remaining plants being almost solely gas peaker units.

However, **this drop in fossil fuel consumption may be paired with an increase in capacity to meet rising peak demand.** In the EnerBlue scenario, there is an augmented fossil fuel capacity of 67 GW by 2030 and an additional 34 GW added between 2030 and 2050 (Figure 44). It is likely that most fossil capacity additions will be gas power plants. According to Enerdata's Power Plant Tracker, a cumulative total of 17 GW of gas power production projects are planned in the EU, while only two projects related to oil and coal, amounting to a total of 200 MW, have been announced.

Integrating increased capacities with reduced production levels will significantly diminish the capacity factor of power plants. In the EnerBlue scenario, capacity factors are anticipated to decline from 31% in 2020 to a mere 7% by 2050. This poses a substantial threat to the operational viability of power plant operators. Addressing this challenge requires the fortification of capacity-based remunerations – this issue is not within the scope of this report.

Figure 44: Evolution of installed capacity and capacity factors of fossil power plants in the EnerBlue scenario



Source: Enerdata.

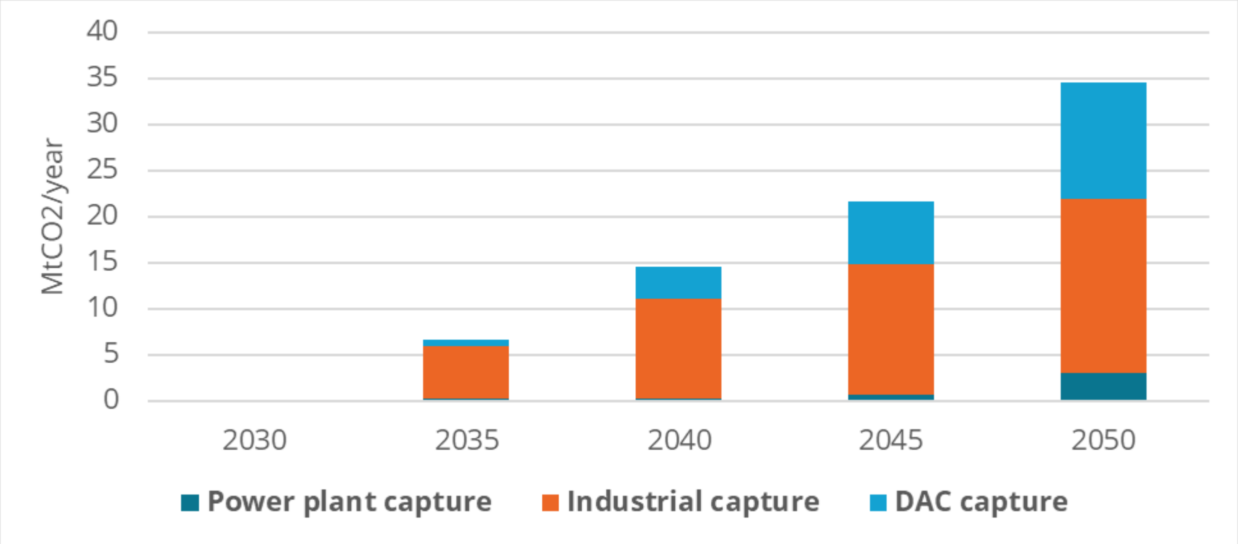
Various complementary approaches not included in this scenario could lower peak demand and mitigate this trend, including increased storage capacity and demand flexibility: these are discussed in the next chapter.

Another issue is the mitigation of CO_2 emissions from remaining fossil plants. Two key approaches are the use of cleaner fuels, namely green hydrogen and biomethane, (discussed in Chapter 4) and the capture of CO_2 emissions from those plants.

In the NDC-LTS scenario (the most ambitious), 90% of fossil power plants integrate carbon capture and storage (CCS) by 2050, with most of this expansion occurring post 2030. The European strategy addressing this matter was only very recently developed. In a recent communication, the strategy outlined by the European Commission sets the goal of 450 million tonnes of CO_2 annually by the year 2050[46]. The NDC-LTS scenario is in line with this target, anticipating the capture of 441 MtCO2/year by 2050, while the EnerBlue scenario is significantly more conservative, anticipating the capture of only 35 MtCO2/year by 2050 (Figure 45).

[46] European Commission, 02/2024, available at: https://ec.europa.eu/commission/presscorner/detail/en/ip_24_585.

Figure 45: Development of CCS in the EnerBlue scenario



Source: Enerdata, EnerBlue scenario.

2.3.4. Nuclear Power

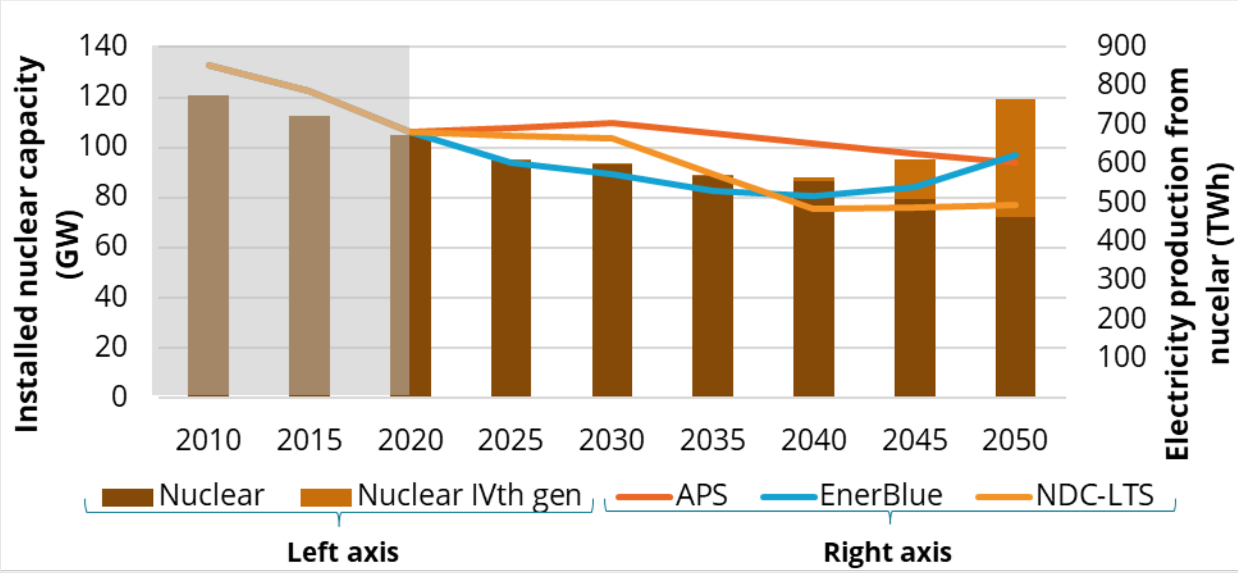
While the historical role of nuclear power plants is to provide baseload power, it can also provide peak power and adapt its load to the demand, thus offering a low carbon alternative to gas.

Figure 46 illustrates long-term projections for nuclear power plants in the EnerBlue scenario. There is an overall decline in nuclear capacities through 2040 due to end-of-life effects, such as in France, or due to nuclear phase-out initiatives, as in Belgium[47]. Meanwhile, the construction of new reactors will take place. Post-2040, the European Union will witness the development of fourth generation nuclear technology, leading to an increase in total installed nuclear capacities.

In the other two scenarios (APS and NDC-LTS), there is a gradual decline in nuclear power production from 2030 to 2050; new capacity additions may prove inadequate to offset the closure of current power plants.

[47] In 2020, the Belgian government announced a phase-out of its nuclear power by 2025. However, after the Russian invasion of Ukraine and the following energy crisis, the country decided to postpone by ten years the closure of the two reactors Doel 4 and Tihange 3. For more information, see 'Nucléaire: accord pour la prolongation de deux réacteurs', *Le Soir*, 18.03.2022, available at: https://www.lesoir.be/431012/article/2022-03-18/nucleaire-accord-pour-la-prolongation-de-deux-reacteurs.

Figure 46: The expected development of the capacities of nuclear power plants



Source: Enerdata, EnerBlue scenario.

There are currently 19 nuclear power plant projects in 8 EU countries, which will add 23 GW in capacity[48]. This includes projects in Poland (6 projects, 9.1 GW), Czechia (4 projects, 4.4 GW), France (3 projects, 4.9 GW), Hungary (2 projects, 2.2 GW), Slovakia, Slovenia, Sweden, and Bulgaria (1 project each). Only three of those projects (Flamanville in France, Paks in Hungary, and Mochovce in Slovakia) are under construction and two of them face strong challenges. The Flamanville unit was initially planned for 2012 and is now expected to be completed in 2024. The Paks II project is managed by the Russian supplier Rosatom. While the European sanctions against Russia have not so far affected this project, it already faces a two-year delay.

The extension of existing power plants' lifespans and the establishment of new facilities are distinct subjects, each with their own timeframes, but need to be considered together. Given the capital-intensive nature of this energy source, government funding is imperative, as is the requirement for a sustainable long-term vision. The decision to incorporate nuclear power within the framework of the Net Zero Industry Act[49] enables Member States to formulate long-term contracts, thereby offering prospective investors a clear vision.

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48 Enerdata: Powerplant Tracker database.

49 This topic is out of the scope of this study but more information can be found here: https://oeil.secure.europarl.europa.eu/oeil/popups/ficheprocedure.do?lang=en&reference=2023/0081(COD).

3. KEY DRIVERS FOR ELECTRICITY SYSTEM INTEGRATION

KEY FINDINGS

As the EU's energy system electrifies, optimising the penetration of Variable Renewable Energies becomes pivotal for a successful energy transition. To reduce the need for fossil power plants, there will be an increased need for flexibility directly proportional to VRE penetration. In addition, the potential overdevelopment of solar over wind may exacerbate this need.

Grid flexibility will be provided by an extensive portfolio of technologies at various levels. Substantial investments are anticipated in the grid infrastructure, including the doubling of cross border interconnections by 2040, ambitious investments in national transmission networks, particularly in Germany, and the expansion of distribution networks to accommodate the growing share of decentralised production assets, thereby reducing the mounting connection queues.

Meeting flexibility requirements necessitates additional storage resources, with batteries playing a significant role in short-term flexibility. Their development should complement longer-duration storage solutions, such as hydropower, to collectively provide up to 40% of the required flexibility. Lastly, influencing the demand side by augmenting the penetration of self-consumed energy and fostering a market for demand response emerges as a crucial complementary driver in steering this transition.

The preceding chapters underscored that the EU's energy transition will be driven by significant increases in electricity production and use. The growth in electricity generation requires substantial new capacity additions, especially from decentralised wind and solar energy, referred to herein as **Variable Renewable Energies (VRE)**[50]. Achieving a 64% increase in electricity production by 2050[51] requires increasing production capacities by over 180%. A key takeaway from Sub-chapter 2.3 is that new wind additions may be insufficient, and meeting the total renewable production requirements will require larger installed capacities than anticipated, driven by increases in solar power.

The development of VRE is a key driver for diminishing GHG emissions, bolstering self-reliance of European energy, and potentially reducing electricity prices[52]. However, the seamless incorporation of VRE into the energy system presents substantial challenges to power grid stability and dependability. Despite being regularly mentioned by industry and regulators, the term "flexibility" is often poorly defined. For the purposes of this report, **flexibility is the portfolio of assets, market mechanisms and technologies that can economically optimise grid stability**.

After describing the impact of VRE penetration on flexibility demand, this chapter explores three aspects of flexibility: the development of grid infrastructure by system operators; the adaptation of demand, with the emergence of prosumers; and the expansion of storage capacity. The role of gas and hydrogen in facilitating the integration of more renewables is discussed in Chapter 4.

[50] Renewable energies that are not constant and fluctuate over time, such as photovoltaic (rooftop and ground-mounted) and wind power (on-shore and off-shore).

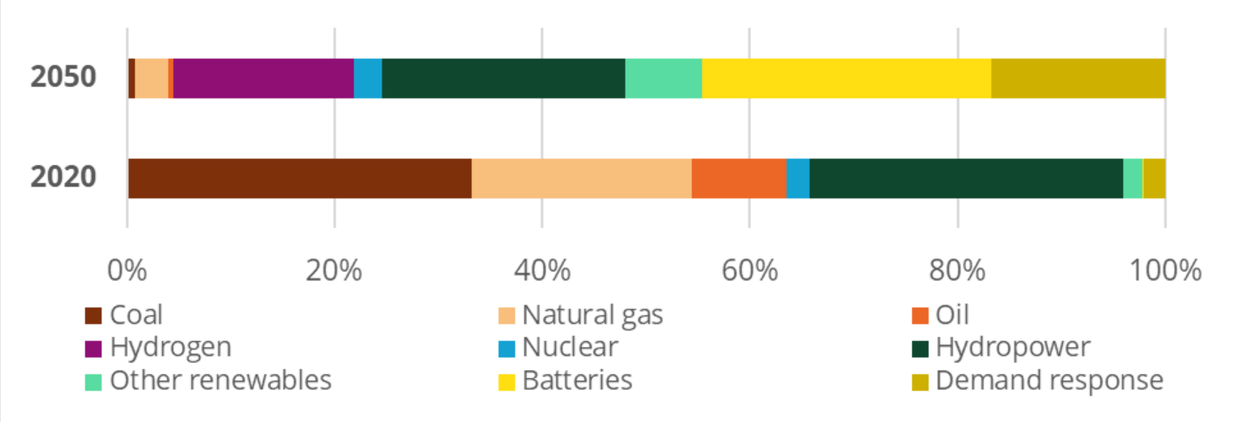
[51] According to the EnerBlue scenario as presented in Chapter 2.

[52] Especially if considering an increasing price of CO_2 emissions.

3.1. Estimating Flexibility Needs

Flexible assets such as gas peakers have been used for many years. However, the evolving energy landscape puts greater demand on flexibility, especially with the gradual phase-out of fossil-fuel power plants, which traditionally served as key flexibility resources. While hydropower is expected to also remain a key flexibility asset, more emerging technologies, especially demand side flexibility, batteries, and potentially hydrogen, are also expected to become important flexibility resources. **A prerequisite for flexibility is the further development of the grid** through cross-border interconnections and the improvement of national transmission and distribution grids. According to the IEA (Figure 47), future portfolios of flexibility assets will consist largely of batteries, hydropower, hydrogen, and demand response; typical flexibility portfolios today also rely on hydropower, but more on coal and natural gas.

Figure 47: Example of flexibility portfolio of global advanced economies



Source: IEA's Net Zero 2050 scenario (IEA, 2021).

Note: Interconnectors and grid enhancements are excluded from the scope of the flexibility portfolio in this context, despite being included in other studies.

A detailed EU-level estimation of flexibility requirements, and an associated roadmap, was recently developed by ENTSO-E, who formulated methodologies and subjected them to testing in three countries—Germany, Belgium, and France—with the aim of enabling Member States to accurately evaluate their flexibility requirements (ENTSOE, 2021). A first European-level analysis was made in the 2022 Ten-Year Network Development Plans (TYNDPs) where sector coupling was used for the first time to provide an overview of flexibility needs. The European Commission, in March 2023, released a proposal advocating for the obligatory assessment of flexibility needs at the national level[53], on which the co-legislators reached a provisional agreement in December 2023.

Further, a recent Joint Research Centre study delineated flexibility requirements within EU Member States for the years 2030 and 2050, factoring in the duration of each asset (JRC, 2023). This study had some critical insights, primarily that demand for flexibility[54] escalates proportionally to the penetration of VRE; requirements for **weekly and daily flexibility exhibit a swifter growth compared to monthly needs as VRE penetration** intensifies (Figure 48). In addition, solar penetration significantly influences daily requirements but exerts negligible impacts on weekly and monthly flexibility needs. Finally, wind

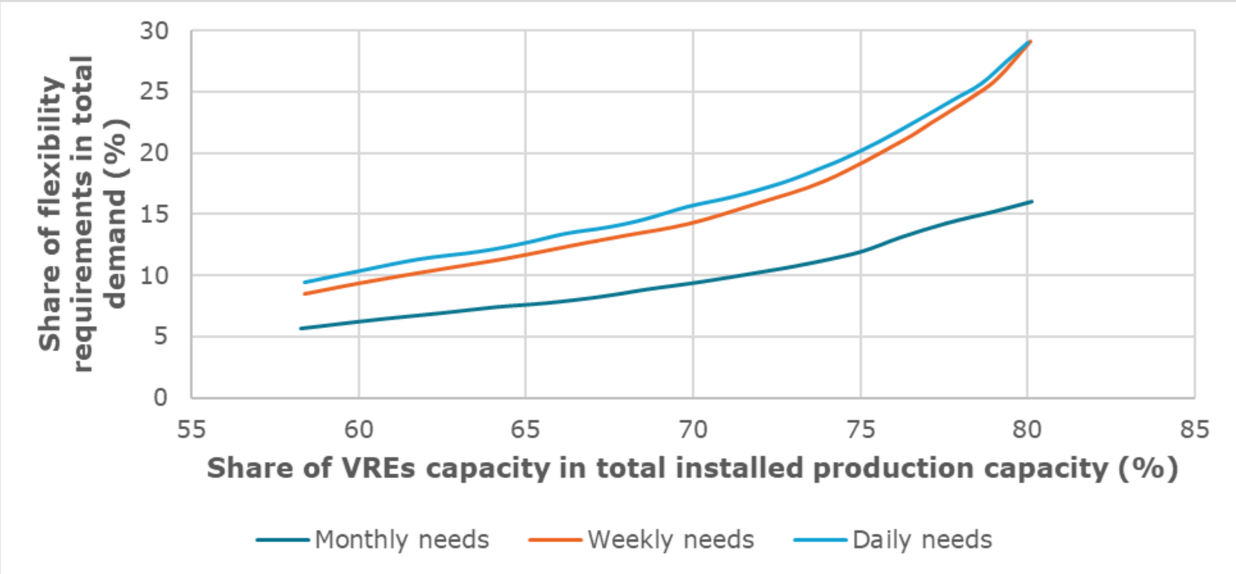
[53] Related documents available at: https://oeil.secure.europarl.europa.eu/oeil/popups/ficheprocedure.do?reference=2023/0077A(COD)&l=en,

[54] In terms energy demand relative to the total demand. Other studies prefer to analyse this demand from a capacity perspective (EASE, 2022).

penetration becomes the most influential factor, impacting flexibility needs at all levels, but particularly demand for weekly and monthly flexibility.

A recent study by the European Association for Storage of Energy analysed the influence of the penetration of wind and solar from a capacity perspective (EASE, 2022). The study showed that overall, a **solar dominated system requires more flexibility, mainly storage, than a wind dominated one**[55].

Figure 48: Impact of VRE penetration on flexibility needs



Source: (JRC, 2023).

Note: VRE penetration is calculated in line with the 2050 split between wind and solar of JRC's MIX H2 scenario where solar would represent 19% of total generation and wind 57%.

JRC estimates that the daily requirements for flexibility in the EU are projected to reach 288 TWh per year by 2030, tripling to 919 TWh per year by 2050. The corresponding volumes for weekly and monthly flexibility needs are marginally lower, reaching 258 TWh and 173 TWh per year, respectively, by 2030, and 775 TWh and 494 TWh per year by 2050. The sum of daily, weekly, and monthly flexibility requirements is 2,188 TWh by 2050, which is 43% of total projected electricity production in the EU (5,000 TWh by 2050) (See Chapter 2); in other words, **by 2050, the electricity used for flexibility could account for almost half of total production**[56].

Among Member States, Germany will have the largest amount of daily flexibility needs; German TSOs estimated that up to 16 GW of additional flexibility could be needed by 2030[57]. The largest absolute growth between 2021 and 2030 is expected in Italy (33.8 TWh).

[55] While a 1% increase of VRE penetration in the power mix would increase the flexibility need by 1-2 GW in a wind dominated system, it would require an additional 4-9 GW in a solar dominated system.

[56] While most of this flexibility could be provided by storage system or demand management, it does not mean that the flexibility demand requires an additional generation.

[57] For more information (in German), see https://www.netztransparenz.de/xspproxy/api/staticfiles/ntp-relaunch/dokumente/%C3%BCber%20uns/studien%20und%20positionspapiere/3.%20strommarkt-forum%20%2829.09.2022%29/strommarkt-forum2022_marktdesign-quovadis.pdf.

3.2. The Integration of Decentralised Electricity Production by the System Operators

All studies mentioned in the previous sub-chapter highlight the key role that grid enhancement and increased market interconnections must play in the development of capacity for flexibility.

Distribution System Operators (DSOs) and Transmission Systems Operators (TSOs) maintain the stability of the electrical grid. While TSOs are in charge of national equilibrium between production and demand, DSOs manage growing connection demands from small-scale renewable production to avoid local congestion. Their challenges can be analysed at the level of European high voltage interconnections, national high-voltage transmission grids, and local low and medium voltage distribution networks.

In November 2023, the European Commission released the "European Grid Action Plan," which includes 14 actions aimed at expediting the enhancement of the European grid (European Commission, 2023). The primary actions include **better identification of system needs** at both the TSO and DSO levels, **streamlined financing** through the acceleration of Projects of Common Interest, the identification of new financing models, and a **review of remuneration models for grid operators**, with a focus on OPEX and the promotion of flexible solutions, limiting CAPEX investments, and reducing queues on grid connections.

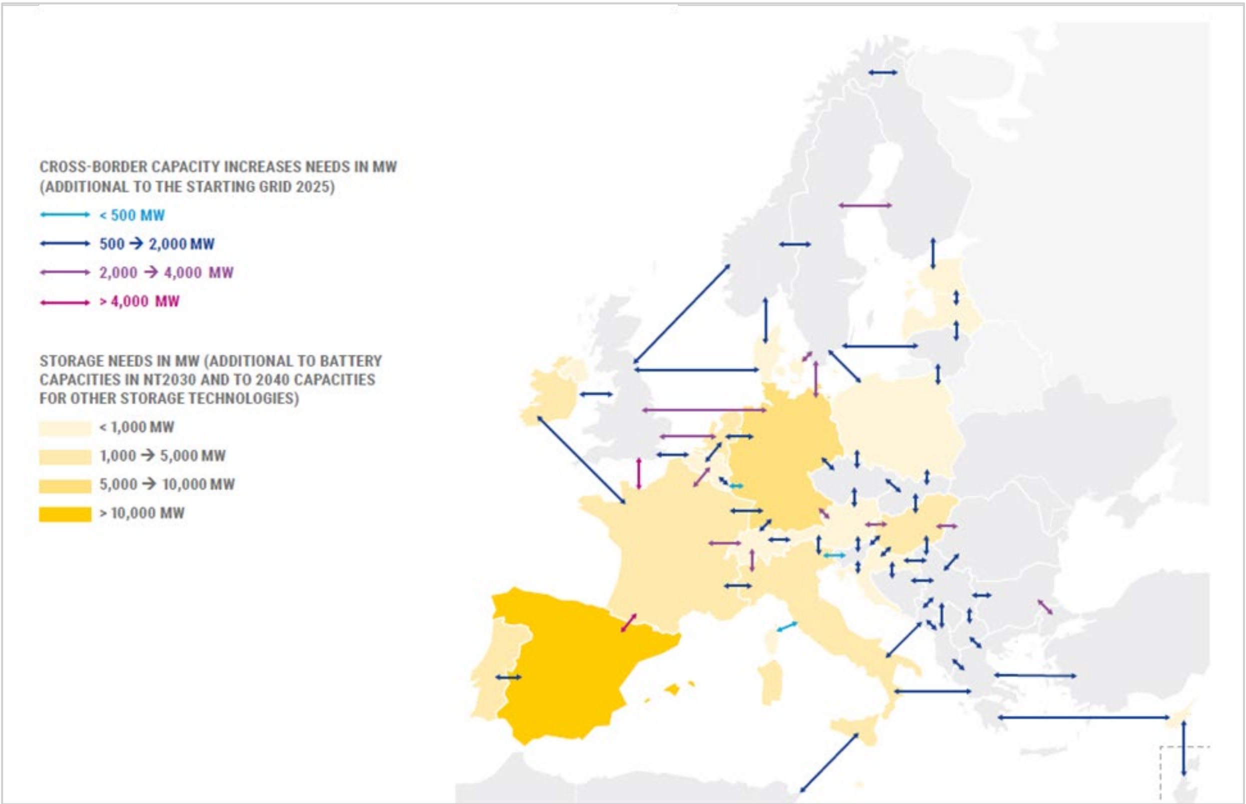
3.2.1. European Electricity Grid Level

Every two years, ENTSO-E and ENTSO-G[58] prepare Ten-Year Network Development Plans (TYNDPs) to adapt the EU power and gas infrastructures to increasing shares of VRE. On the electricity side, ENTSO-E's plan places emphasis on cross-border electricity interconnections and national transmission projects with cross-border relevance (ENTSO-e, 2023). The latest TYNDP for the EU power grid, published in 2022, estimates that **the current cross-border transmission capacity of 93 GW should be increased to 184 GW by 2030** in line with increased development of renewable capacity[59]. To achieve these objectives, 35 GW of cross-border capacities will be built between 2020 and 2025, and over 50 GW of further cross-border interconnection capacity on 71 borders will be required between 2022 and 2030. By 2040, the total additional capacity will be 90 GW, requiring around €17 billion in investments (ENTSO-e, 2023). Most of these investments will be for onshore AC transmission lines (55%), as well as for AC substations (13%), and off-shore DC transmission lines (17%).

[58] The European associations for the cooperation of transmission system operators (TSOs) for electricity and gas, respectively.

[59] It should be noted that in 2017, the European Commission Expert Group on Interconnection Targets (ITEG) proposed that the European Commission complement the existing 15 % interconnection target for every country and electrified island with a new methodology more adapted to distributed generation. This objective is in line with this methodology.

Figure 49: Opportunities for the increase of cross-border transmission, storage, and peaking units' capacities in 2040



Source: (ENTSO-e, 2020).

Note: This scenario is based on National Trends using (bottom-up) data from TSOs up to 2040, translating national policies and strategies as stated end of 2020 and focusing on the sole electricity, methane, and hydrogen energy carriers.

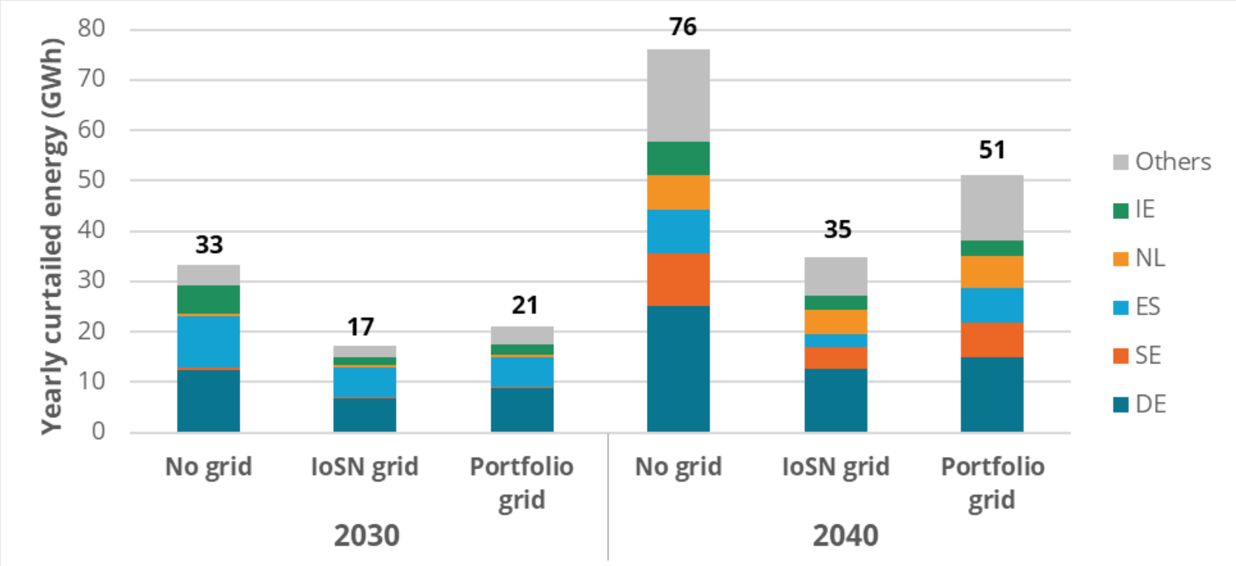
Expected capacity additions are unevenly distributed. There will be significant additions of on-shore and off-shore wind capacity in the northern part of the continent, and solar and on-shore wind additions in southern Europe. To enable complementary use of these resources, **the Union strongly needs electricity interconnections between the North and South**[60]. The countries with the highest additional capacity are Austria (9.8 GW), Germany (8.6 GW), Switzerland (7.2 GW) and France (6.6 GW) (See Figure 49).

One of the advantages of developing cross-border capacities is **mitigating renewable electricity curtailment**[61]. ENTSO-E hopes to reduce curtailment in the EU by 51% to 17 TWh per year by 2030, avoiding 14 Mt of CO_2 annually, and to achieve a net reduction of €5 billion in annual generation costs, compared to a scenario with no new investments after 2025 (Figure 46) (ENTSO-e, 2023). The impact of curtailment is highly concentrated. In a scenario with no additional investments after 2025 ("No grid"), Germany and Spain would account for two thirds of curtailed capacity in the EU. In those two countries, the curtailed energy could represent 2% to 3% of the total electricity production.

[60] Note: This geographical spread is reflected in the north-south electricity price spread.

[61] Curtailment is the deliberate reduction in output below what could have been produced in order to balance energy supply and demand or due to transmission constraints (IEA, 2023).

Figure 45: Curtailed energy in the EU by Member States in the TYNDP scenarios



Source: (ENTSO-e, 2023).

Note: No grid: a scenario where Europe stopped all grid development after 2025. Portfolio grid: a scenario where all projects of the TYNDP 2022 portfolio that are foreseen to be commissioned until 2030 or 2040 respectively have been built; IoSN grid: a scenario where the needs after 2025 identified by ENTSO-E's system needs study have been addressed (ENTSO-e, 2023).

3.2.2. Country Level

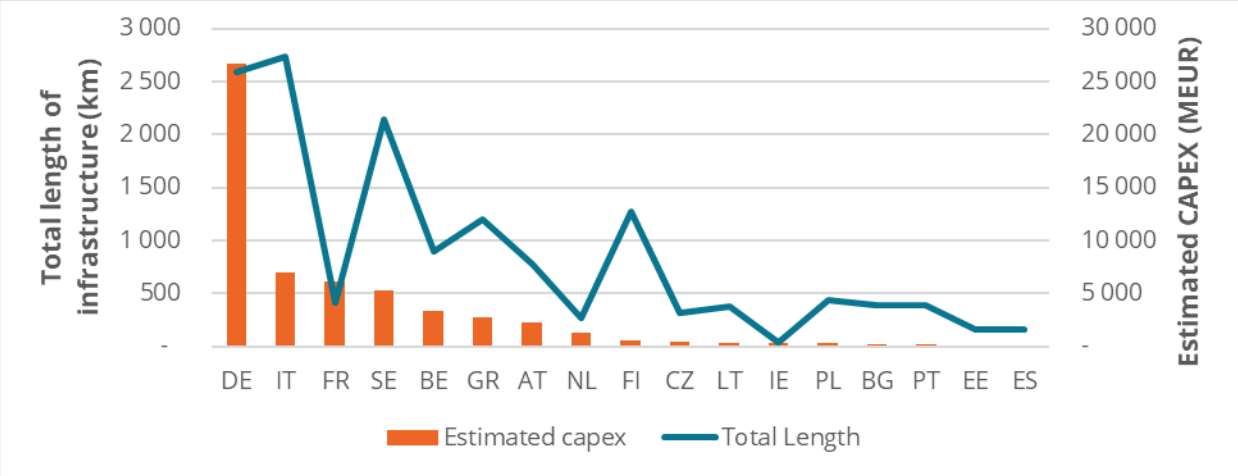
The development of VRE within a country requires the creation of new transmission infrastructures, which connect emerging production zones to consumption hubs. This further reduces national curtailment (see examples below for Germany and Italy), diminishes delays in the development, completion, and connection of renewables projects, and avoids congestion issues leading to redispatch[62].

Among the 31 European TSOs, there are large differences in high-voltage (HV) network adaptation projects. Each project is outlined in National Grid Development (NGD) plans which should be continuously updated. However, substantial differences exist between countries in the timeline of those updates. While certain countries update their NGD every two years with continuous consultations (in time for the TYNDP), others only update them every 5 to 6 years. These differences were identified as a risk for the good management of national networks in a Wind Europe report (Wind Europe, 2020).

At the EU level, the 2022 TYNDP identified 136 key ongoing transmission projects, 51 of them being national (not linked to a cross-border project). Germany has invested by far the most, while Italy has added the most infrastructure (Figure 50).

[62] Redispatch consists of the transmission system operator (TSO) requesting "to adjust the active power feed-in from power plants to avoid or resolve occurring congestion" (TSO 50Hertz, https://www.50hertz.com/en/Grid/Systemcontrol/Redispatch).

Figure 50: Level of investments and additional kilometres of announced transmission projects in the 2022 TYNDP



Source: (ENTSO-e, 2023), Enerdata's analysis.

Two examples of HV transmission line creation in Germany and Italy are detailed below.

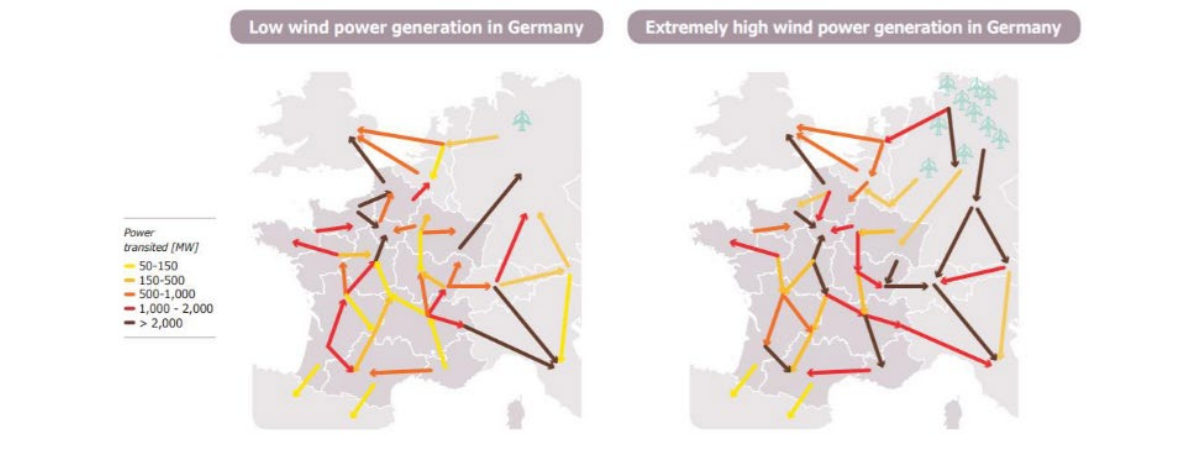
Box 3: Germany –The Corridor project

The Corridor project in Germany is one of the main national transmission line creation projects in Europe. It is designed to solve congestion issues between the northern and southern parts of the country. This congestion exists because:

- In the south, there are highly energy-intensive industries and nuclear power plants that have been phased out.
- In the north, large wind capacities have been installed.

The surplus electricity generated in the northern regions faces challenges in reaching major consumers in the south, thus affecting the interconnected networks of neighbouring countries such as France (see figure below).

Figure 51: Influence of wind generation in Germany on power flows in the French transmission system



Source: (Wind Europe, 2020).

To solve these issues, three main lines are being built:

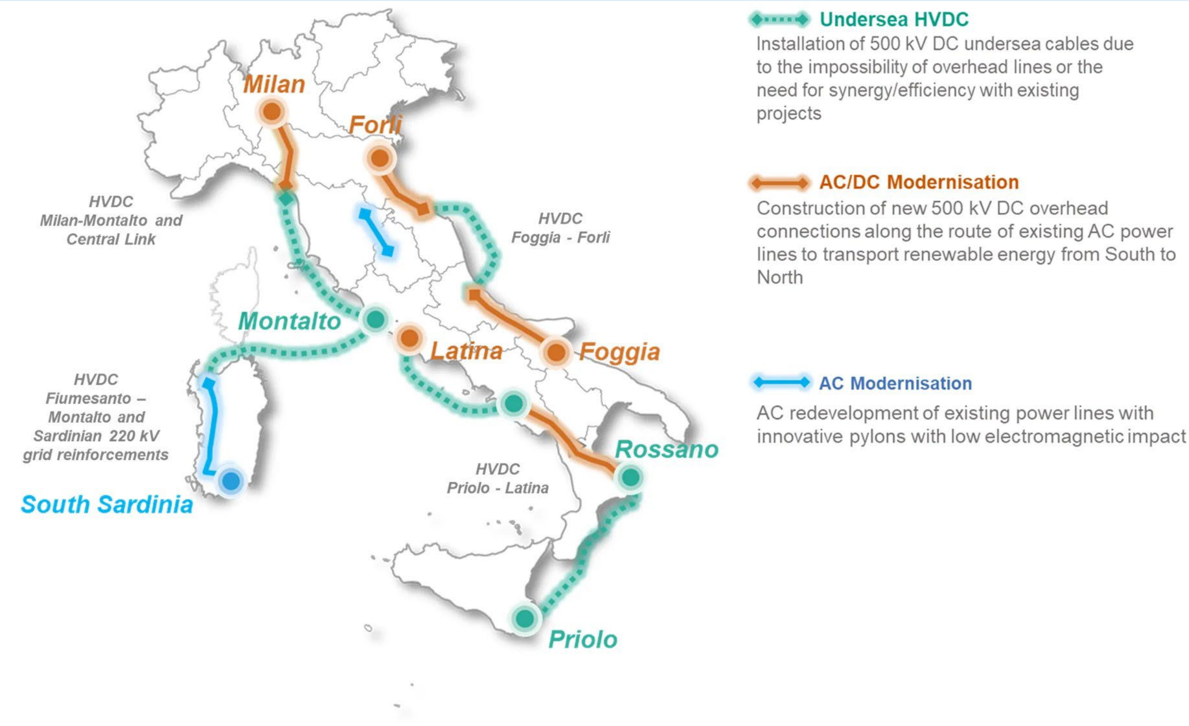
- The SuedLink, 1200 km HVDC 525 kV cable, completion in 2026 for Tennet/transnetBW
- The A-Nord, 640 km HVDC 525 kV cable, completion in 2027 for Amprion
- The Suedoslink, 550 km HVDC 525 kV cable, completion in 2025 for 50hertz/TenneT

Source: (Prysmian Group, n.d.).

Box 4: Italy – The Hypergrid project

To meet the Fit for 55 goals, Italy has planned the development of extra 70 GW in renewable capacity by 2030. However, by the end of January 2023, requests for connection to the high-voltage grid from new renewable power plants were five times higher than the target (340 GW, including 37% from solar and 54% from wind power). To accommodate this surplus capacity, in 2023, Terna, the Italian TSO, released its national development plan, which includes the €11 billion Hypergrid initiative. Hypergrid will create five additional electricity backbones and includes the modernisation of existing AC lines, converting AC lines to DC, and building new undersea HVDC lines. These projects will help integrate renewable projects and double the transmission capacity between market zones (+16.6 GW in transmission capacity from southern to northern Italy). It will also help reduce permitting process times, which are one of the main obstacles to the development of renewable energy in Italy.

Figure 52: Key infrastructure developments included in the Hypergrid initiative



Source: (Terna, 2023)

Source: (RethinkResearch, 2022).

3.2.3. Local and Community Level

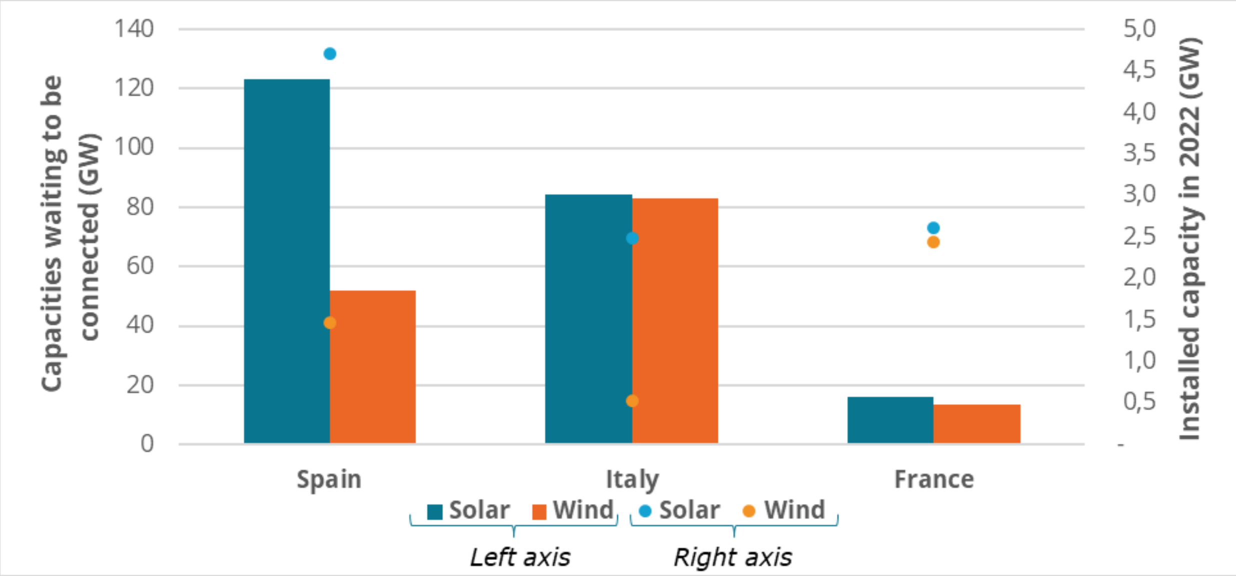
Accommodating this extra capacity is a challenge for DSOs. Solar Power Europe identified four countries lacking sufficient grid capacity to swiftly connect new projects in 2021: the Netherlands[63], Poland[64], Portugal, and Sweden. Such challenges are likely to expand to other Member States in line with their development of solar PV (Solar Power Europe, 2021). Lack of capacity can lead to **longer**

[63] See for instance Kazempour, F.; "The Netherlands' gridlock: a cautionary tale for the US", WoodMackenzie, 5 September 2023, available at: https://www.woodmac.com/news/opinion/netherlands-gridlock/.

[64] Confirmed by the speech of Patryk Demski (VP Tauron Group, representative of PKEE Polish Energy Association) at the EDSO Webinar "Repowering the Grid for Solar PV" on 20 September 2023.

installation delays and result in incomplete projects. As an example, across Spain, Italy, and France – three countries for which the information was available – connecting total pending capacity at the same pace projects were developed in 2022 would take between six years (for solar and wind in France) and 158 years (for wind in Italy) (Figure 53).

Figure 53: Capacity of projects waiting to be connected vs 2022 installed capacity in selected countries



Source: Enerdata, based on BNEF (2022, Figure 3), Terna, Red Electrica, French Ministry of Ecological Transition, end of 2022 data.

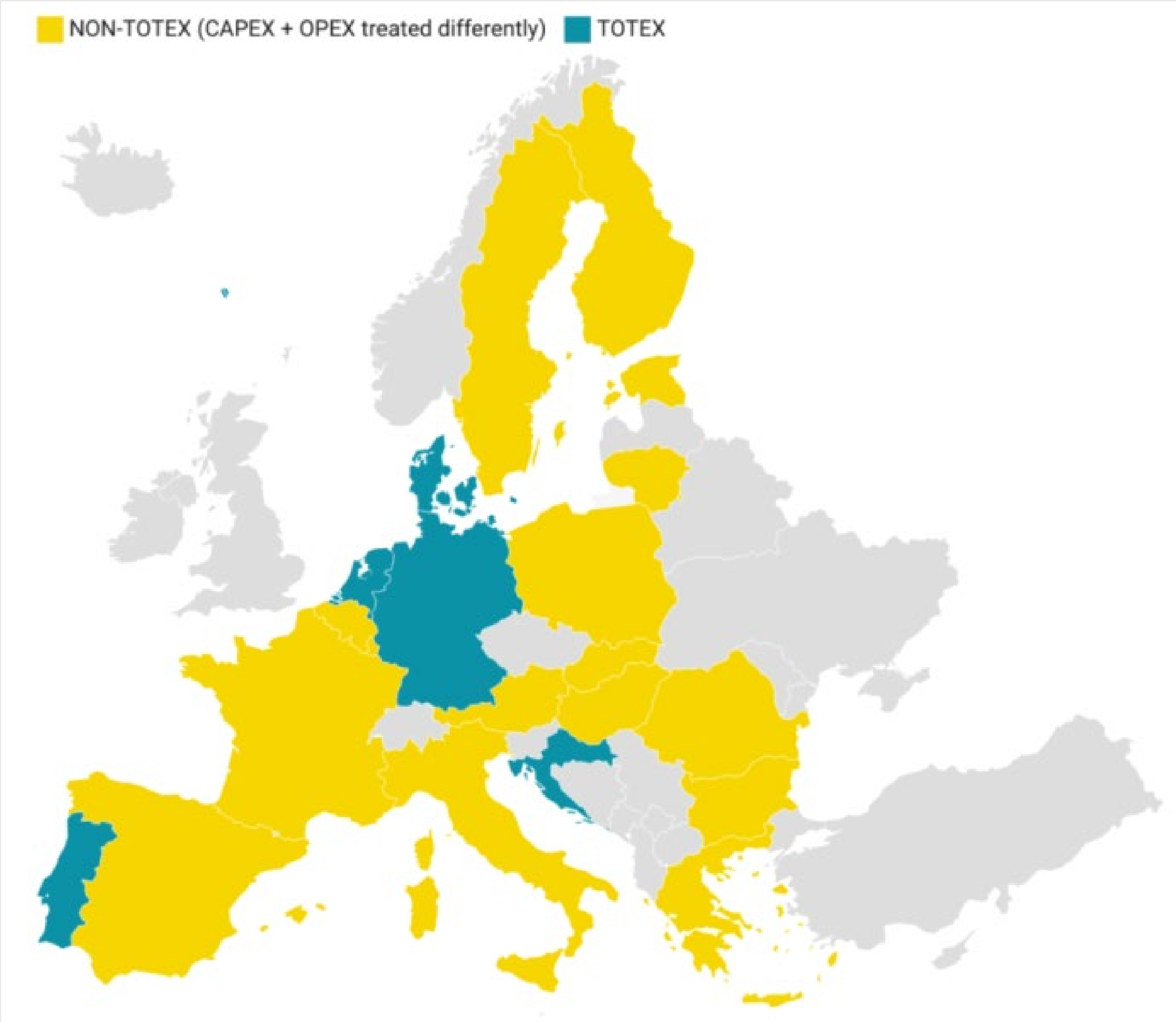
The cost of distribution grid investments between 2020 and 2030 will be between €375-€425 billion (Eurelectric, 2021). This is a **50-70% increase compared to the previous decade**; these estimates may need to be revised further upwards to meet the ambitious goals of REPowerEU. By comparison, the projects identified in 2022 at the TSO level (cross-border and national) account for a total investment of €83 billion by 2030 and the recent EU Action plan for Grids anticipates a need for €584 billion in investments in distribution and transmission grids during the same period (European Commission, 2023).

These investments involve **CAPEX-based investments**, such as increasing the capacity of low and medium networks, establishing new electrical transformers, and enhancing the technical quality, particularly power quality, and the continuity of supply within the grid.

Nevertheless, alternative **OPEX-based approaches** (e.g., smart connection, digitalisation of the power grid, flexible network tariffs, remote control of PV inverters, etc.) **could lower the overall needed CAPEX investment**. For example, connection requests to DSOs are supported by business processes and planning/engineering tools that tend to be inadequate in treating the growing number of requests on time (in particular for small DSOs). Consequently, **many DSOs adopt a worst-case approach, and overbuild grid capacities**.

However, **the current remuneration scheme of most DSOs is not aligned with an OPEX-based approach.** DSOs are often remunerated by state-controlled remuneration mechanisms configured to match their historical CAPEX-based activities (e.g., developing the grid size). Most DSOs' remuneration schemes are calculated based on their costs. OPEX and CAPEX investments are treated differently[65], often in favour of CAPEX activities (Figure 54)[66].

Figure 54: Cost treatment approaches in the European regulatory framework for DSOs



Source: (JRC, 2022).

Note: TOTEX refers to the remuneration scheme of DSOs based on their total expenditure with OPEX and CAPEX being treated indifferently.

3.3. Development of a Prosumer Centred-Approach

Deployment of demand-side resources can be a cost-effective way to deal with large increases in VRE. The electrification of end-uses (heat pumps deployment, electric vehicles, home batteries, etc.) and the development of rooftop solar for both households and businesses has changed the consumer's role in the energy system. A growing share of end-users, including residential, commercial, and industrial customers, are becoming **prosumers**.

[65] Remuneration schemes based on their total expenditure are usually defined as TOTEX.

[66] For more detail see https://www.solarpowereurope.org/insights/thematic-reports/grids-planning-and-grid-connection.

Box 5: The definition of prosumers

While the term **prosumer** is widely used and understood in the context of energy production and consumption, it is not specifically defined in EU legislation. In this study, we define "prosumer" as an individual or entity that **both consumes electricity and provides services to the grid**, either by producing energy (self-producer) or by adapting their demand profile to the grid's needs (demand response). As collective entities, prosumers can also operate grid infrastructure (e.g., collective self-consumption schemes).

In 2018, the revision of the EU Renewable Energy Directive ((EU) 2018/2001) introduced the definition of **renewables self-consumer** (Art. 2 (14)) as a "*final customer, [...], who generates renewable electricity for its own consumption, and who may store or sell self-generated renewable electricity, provided that, for a non-household renewables self-consumer, those activities do not constitute its primary commercial or professional activity*". The entitlements of renewables self-consumers are defined in Art. 21 of the directive.

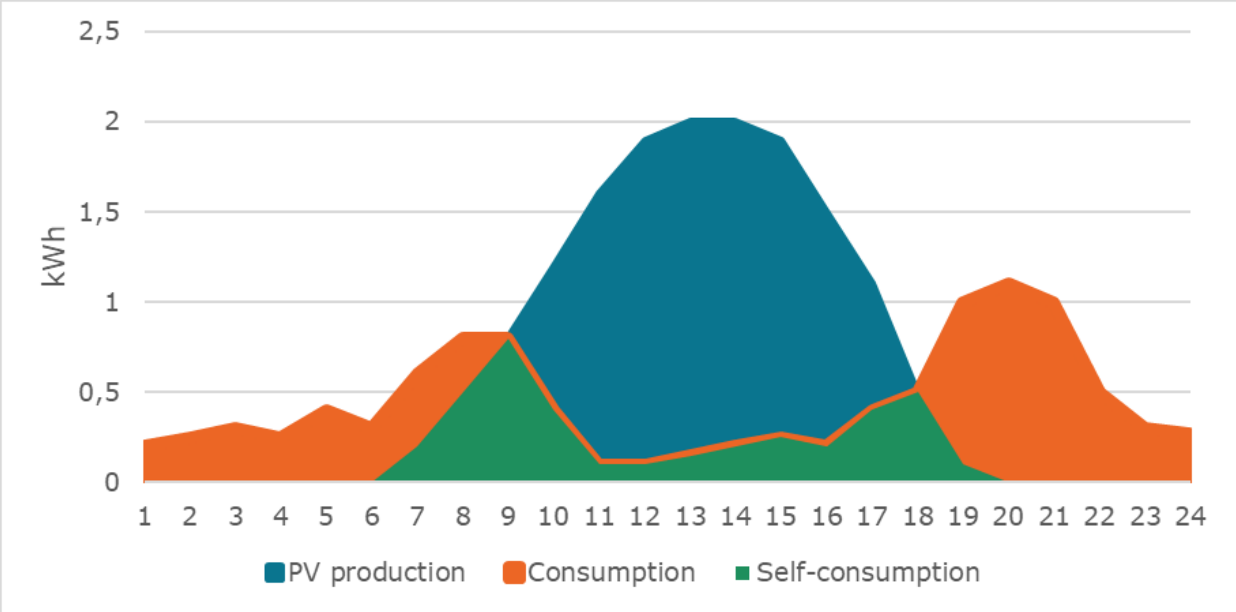
In the next sub-chapters, two distinct yet interrelated approaches to functioning as a prosumer are described. First, optimising **self-consumption** is an efficient method for alleviating the impact of distributed energy on the grid. Second, demand-side flexibility, or **demand response**, is a key mechanism for mitigating peak demand, especially as short-term flexibility resource.

3.3.1. Development of Self-Consumption in the EU

Self-consumption, primarily of photovoltaic energy, plays an important role in defining the prosumer's role. **Rooftop PV represents two-thirds of the 190 GW of the cumulative photovoltaic capacity installed in 2022 in the European Union.** Across numerous EU Member States, these installations mainly operate within a self-consumption framework. Users are incentivised to prioritise the consumption of the electricity they generate, leading to a reduction in their electricity bills. Additionally, such producers are compensated for any surplus energy injected into the grid[67] (Figure 55).

[67] Two significant outliers are Germany, accounting for 31% of the cumulative installed PV capacity in 2022, and France. Despite an increasing number of self-consumers in these countries, they continue to provide specific feed-in tariffs for the complete injection of electricity into the grid.

Figure 55: Illustration of self-consumption for a typical prosumer's production day



Source: Enerdata's analysis.

Note: The green area represents the share of the produced energy that is self-consumed. The shown consumption and production profiles are only indicative.

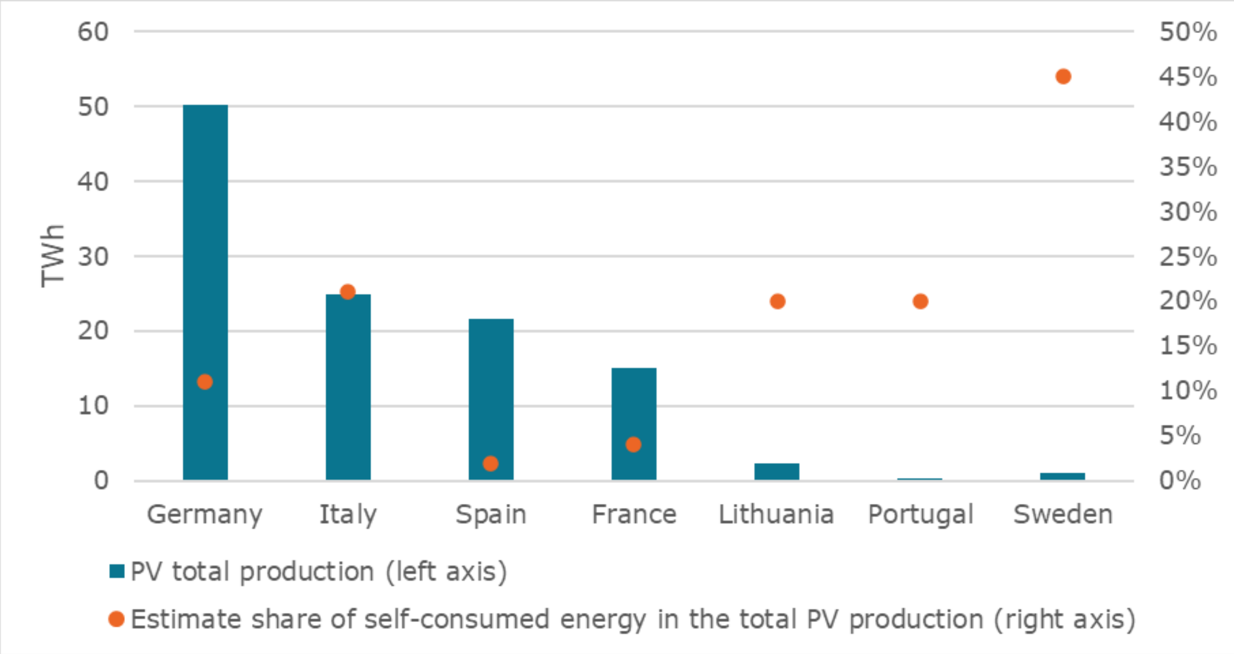
The share of self-consumers is growing in all Member States, mostly due to rising retail electricity prices (see Section 1.5.3). The key markets, in terms of installed self-consumption capacity, are in Germany, Italy, Netherlands, and Poland.

By the end of 2022, an estimated 10.8 million in small-scale[68] solar installations were identified in the EU, for a total estimated self-consumer capacity of 87 GW; this accounts for **46% of the total installed PV capacity** in the EU[69].

[68] Small-scale refers here to installations of less than 1 MWp, usually rooftop.

[69] Enerdata's analysis based on national statistics and own hypothesis.

Figure 56: Estimated share of self-consumption of PV total production in selected countries (2021)



Source: (EUROBSERV'ER, 2022).

There is a **lack of harmonised measurement in the development of self-consumption** in the EU, that is, the share of produced energy that is self-consumed (also called the "self-consumption rate") is not consistently measured across Member States. Estimates by Eurobserver illustrate the high variation in the share of self-consumed energy relative to total PV production in different Member States (Figure 56).

Three factors determine the self-consumption rate. First, the **share of self-consumers among PV installations**. Countries like Spain, which have historically focused their PV development on large-scale power plants injecting all produced electricity into the grid, have very low volumes of self-consumption. Second, by **the size of the installation** (smaller systems tend to inject less power into the grid) and by the remuneration scheme for the energy injected into the grid. For example, the Netherlands offers a net metering scheme[70], which does not encourage users to optimise their self-consumption rate. Third, by the presence of **additional flexible loads** that can adapt the user's consumption profile to PV production. The most common examples are home batteries and electric vehicles (with smart charging functionalities). Home Energy Management Systems are also an effective (but less developed) way of adapting prosumer demand.

The higher the self-consumed energy, the lower the impact on the grid. In addition, constraints can be added by DSOs that will further limit the impact of a PV installation on the grid (e.g., maximum installed capacity in line with the existing connection, maximum amount of injected energy per year, etc.).

[70] A net metering scheme is an electricity billing mechanism that allows consumers who generate some or all their own electricity to use that electricity anytime, instead of when it is generated.

3.3.2. Overview of Demand Response Potential and Limitations in the EU

Demand response is a mechanism to balance power grid demand by encouraging consumers to shift their electricity usage to times of higher availability or lower demand, often incentivised through pricing mechanisms[71]. The impact of demand response on the current EU flexibility is marginal, but will increase due to electrification of end-uses and the connection of more flexible loads, including heat pumps and electric vehicles.

Demand response operates through two primary mechanisms: price-based (**Implicit Demand Response**) mechanisms that employ price signals and tariffs to motivate consumers to adjust their consumption patterns (e.g., peak/off-peak tariffs); and incentive-based programs (**Explicit Demand Response**) that directly compensate consumers participating in demand-side response programs (usually through an installed hardware that can deactivate specific loads) (IEA, 2022).

In terms of markets and mechanisms, the regulatory landscape has evolved to support demand response implementation, involving the expansion of existing programs and the inclusion of smaller demand response resources. The European Union's commitment to digitalise the energy system, as outlined in the 2022 Action Plan, includes provisions for facilitating data access needed for demand response initiatives (European Commission, 2022). Before that, demand response was defined in Regulation (EU) 2019/943 and Directive (EU) 2019/944 as the need for the efficient integration of new production and consumption assets into the electricity grid.

Developing demand response can require the adaptation of existing ancillary services[72]. Currently, **the demand response market is evolving through national and private initiatives but still lacks a European harmonisation.** Since 2018, trans-national initiatives have emerged, driven by platforms like PICASSO, MARI, TERRE, and FCR Cooperation. These platforms introduce standardised products aligned with the technology neutrality principles of the 2019 Electricity Market Directive and Regulation. In addition, ENTSO-E and ACER are collaborating to define common rules that harmonise ancillary services and demand response mechanisms; a non-binding Framework Guideline on Demand Response[73] was published in December 2022. These initiatives are the best driver to increase the potential market for demand response. However, challenges in connection, as indicated in derogations requested by several countries, have slowed down market development.

Leading ancillary services markets across Europe exist in Belgium, Denmark, Finland, France, Slovenia, and the Netherlands. According to a 2020 analysis by LCP Delta (see Figure 57), the theoretical **potential of demand response in Europe**, defined as the sum of flexible assets that could be used for demand response, **was 20 GW in 2020** (75% being explicit demand response) **and could reach 30 GW by 2030** (driven by the electrification of buildings heating, industrial process and electric mobility). **France, Italy, and Spain represent over 50% of demand response potential in 2030**.

Demand response offers load adaptation capacity but does not have a significant impact on overall demand due to the rebound effect[74]. **The short-term energy savings generated by demand response are not a driver of the sustainable reductions in energy demand** discussed in previous chapters.

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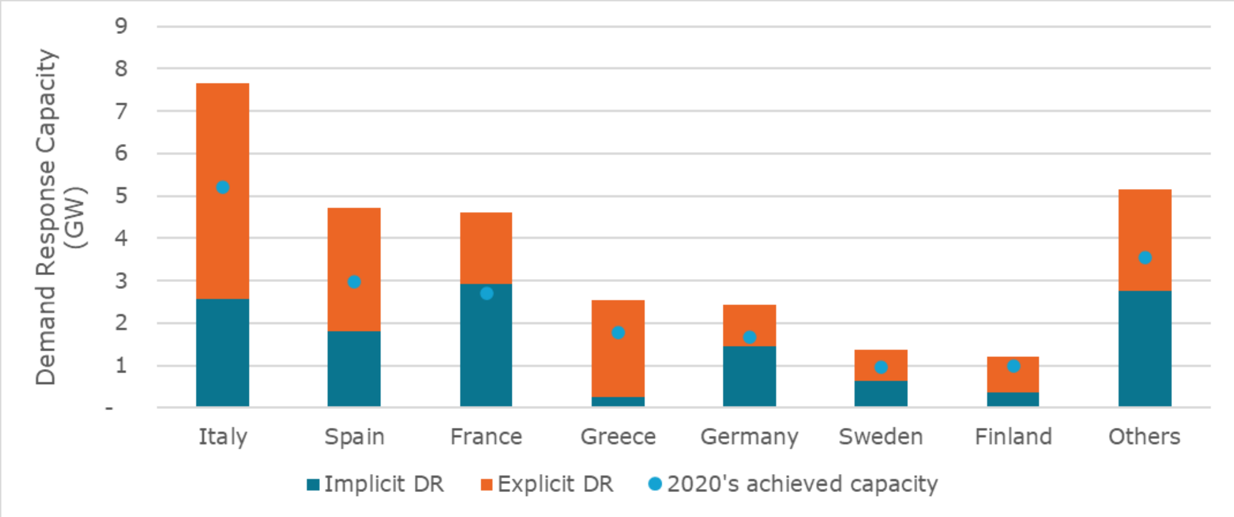
71 IEA definition, available at: https://www.iea.org/energy-system/energy-efficiency-and-demand/demand-response.

72 Ancillary services are all services required by the TSO or DSO to enable them to maintain the integrity and stability of the transmission or distribution system as well as the power quality. They are often classified by the necessary response time.

73 Full document available at: https://acer.europa.eu/sites/default/files/documents/Official_documents/Acts_of_the_Agency/Framework_Guidelines/Framework%20Guidelines/FG_DemandResponse.pdf.

74 The reduction in expected gains from new technologies that increase the efficiency of resource use, because of behavioural or other systemic responses.

Figure 57: Theoretical potential of demand response to offer flexibility by 2030 in the EU



Source: (Delta, 2020), Enerdata's analysis.

3.4. The EU's Storage Needs

Energy storage is the last key driver to integration of VRE into the grid. Storage options are complementary to grid and demand adaptation, topics covered in the previous sub-chapters.

The key characteristics defining an energy storage technology are its maximum power production capacity (in GW), the total energy that can be stored (in GWh), the response time of the technology, its self-discharge (that defines its capacity to store energy for a long time), and its cost (CAPEX and OPEX).

Although **batteries,** especially Lithium-ion batteries, are frequently discussed as the dominant storage technology, they only represented a cumulative installed capacity of **5.9 GW** in 2021 (Enerdata, 2022). This capacity is evenly split between **Energy Storage Systems** (directly connected to the grid) and **behind-the-meter batteries** (installed in residential or commercial settings). Batteries are cost-efficient for short duration storage, typically up to a few hours, yet their total cost escalates significantly when storing energy for multiple days or weeks.

Box 6: Focus on behind-the-meter batteries

Often linked with self-consumption, behind-the-meter batteries are a useful contributor to energy system's security, either by directly providing services to the grid, or as a tool to increase a prosumers' self-consumption rates (see Chapter 3.3.1.).

At the end of 2022, more than one million homes were powered by solar and battery systems in Europe. In its medium scenario, Solar Power Europe estimates that there will be 32 GWh of home batteries in 2026, and 44 GWh in its high scenario, representing 3.9 million homes.

Germany is the largest market for this technology, accounting for almost 59% of the annual European installations by 2021 (total installed capacity was 4.8 GWh at the end of 2021). With 150,000 installed systems in 2021, its market size is four times bigger than the second biggest EU market, Italy (total installed capacity of 616.6 MWh at the end of 2021). The other two major markets in Europe are Austria and Switzerland, with 123 MWh and 79 MWh of storage capacity installed in 2021, respectively.

Markets in Spain and Poland are expected to further grow due to two factors related to increases in residential PV and the attractiveness of self-consumption: the **rise in electricity prices** for the residential sector, which makes it economically more attractive to self-consume the electricity generated by residential solar panels, and the **decreasing cost of batteries**, which is driven by the increasing demand in the automotive sector (Solar Power Europe, 2022).

Pumped-Hydro-Storage (PHS), is the most developed storage technology, with a production capacity exceeding that of batteries by more than fivefold in 2021, with 34 GW in the EU and 40 GW in Europe (Enerdata, n.d.). Pumped storage is an economical and mature solution with a short response time that can be adapted to long-term storage needs. However, it requires **substantial CAPEX**, and there are important environmental considerations affecting its development, such as impacts on local biodiversity and potential population displacements.

The connections between the power grid and renewable gases may be a good alternative for long-term storage either through the conversion of electricity into hydrogen (**Power-to-H2-to-Power**) or methane (**Power-to-Methane**), which can be stored in dedicated reservoirs; this can be achieved by repurposing existing gas transportation and storage infrastructure. Other less mature or developed storage technologies include flywheels, thermal energy storage, supercapacitors[75], vehicle-to-grid[76] and compressed air storage. These technologies are not analysed in this study.

EU storage capacity is expected to at least double by 2030. The European Association for Storage of Energy (EASE) has assessed Europe's storage needs for 2030 and 2050, considering the European targets of a 55% reduction in greenhouse gas emissions and a 45% share of energy from renewable sources by 2030 (EASE, 2022).

EASE estimates that by the year 2030, **out of the overall 456 GW of necessary flexibility**, **energy storage could provide 108 GW to 187 GW.** The primary technologies used for energy storage by 2030 would be PHS (with existing and new projects), accounting for **65 GW by 2030**, and batteries, accounting for up to **67 GW**[77]. Part of this capacity could also be met by demand flexibility solutions

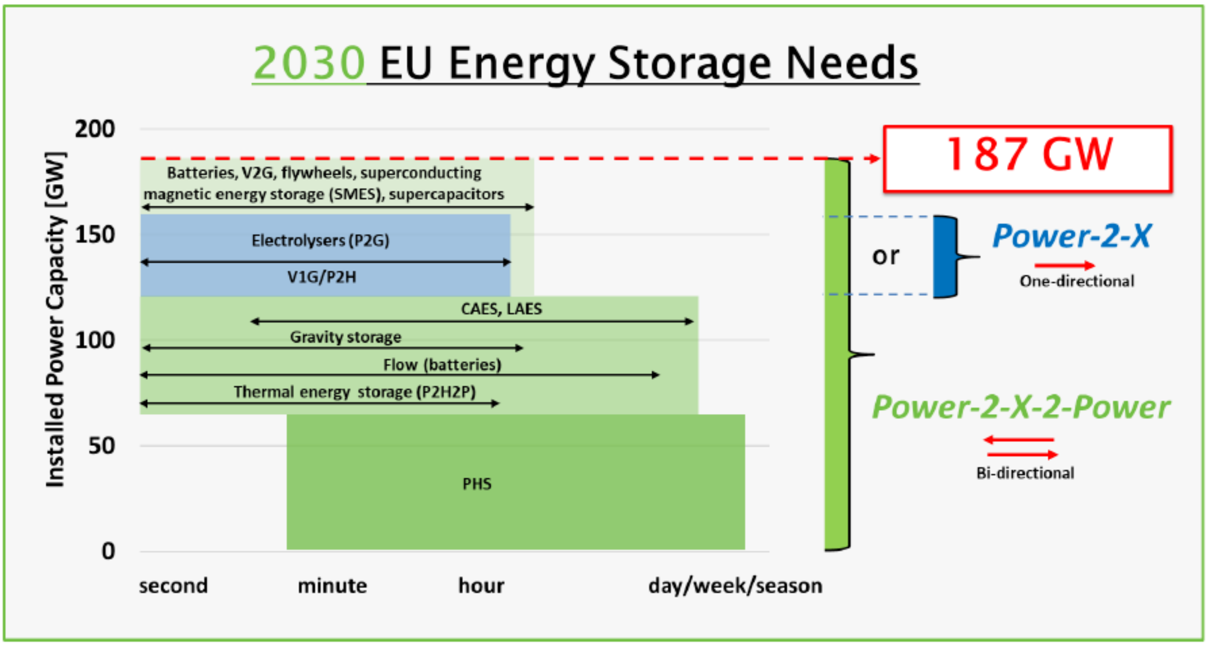
[75] Supercapacitors are used in applications requiring many rapid charge/discharge cycles.

[76] The ability to use an electric vehicles battery to inject electricity into the grid.

[77] In EASE's analysis, the 67 GW of batteries are optimistic as they include 33 GW of Vehicle-To-Grid, a technology that is at its infancy today and still faces major technological and economical challenges.

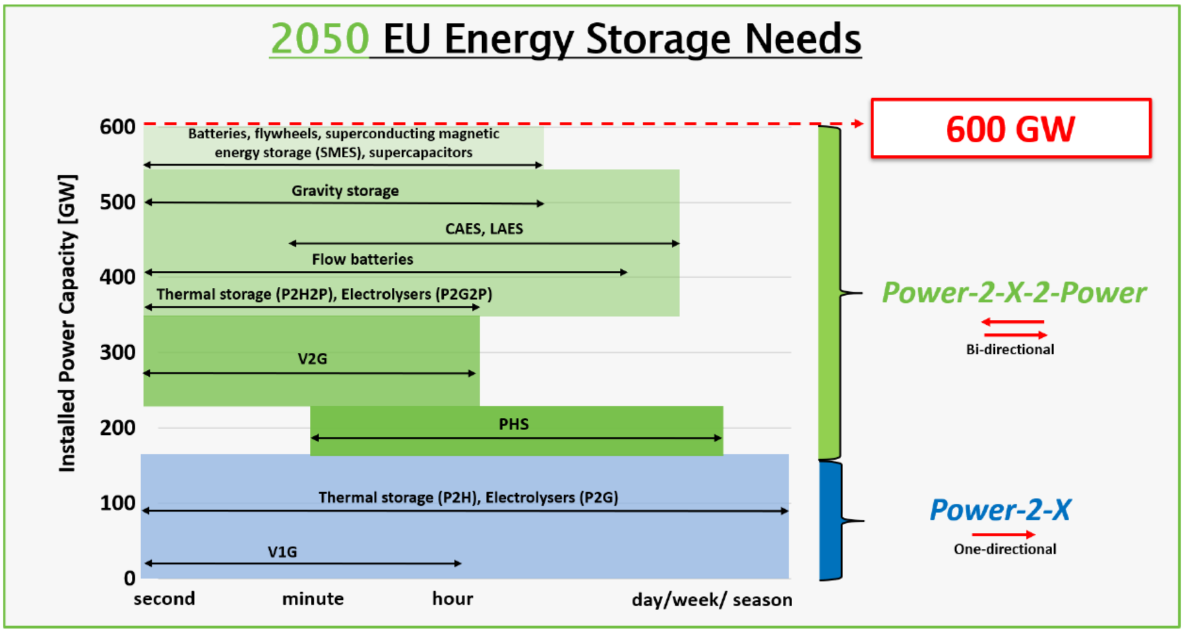
(e.g., smart charging, electrolysers' modulation, demand response, etc.). By 2050, the PHS capacity is expected to remain stable while stationary batteries could reach a capacity of **up to 100 GW.**

Figure 58: 2030 EU Storage needs



Source: (EASE, 2022).

Figure 54: 2050 EU Storage needs



Source: (EASE, 2022).

In conclusion, energy storage will play a pivotal role in the European energy transition, with a projected demand of nearly 600 GW by 2050. The development of stationary batteries for short duration storage is growing at a sufficient pace, mainly driven by electric vehicle demand. Alternative battery technologies primarily focused on longer duration storage exist, for instance flow batteries, but face difficulties as an economic business model in a flexibility market that is currently short-term driven. Currently, pumped-hydro-storage is the sole mature solution providing seasonal storage; however, it is anticipated to achieve its maximum capacity by 2030. Renewable gases, particularly hydrogen, may emerge as a potential solution, as discussed in the subsequent chapter.

4. HYDROGEN PENETRATION ON ENERGY INFRASTRUCTURES

KEY FINDINGS

Renewable and low-carbon hydrogen produced by electrolysis directly or indirectly powered by renewable electricity and nuclear energy has the potential to solve three key issues related to the EU's energy transition. In the short term, it can help decarbonise the currently gas-intensive production of hydrogen, which represents up to a third of industry's natural gas consumption. Additionally, it can partly replace other fossil-intensive end-uses, particularly industrial heat and heavy transport. Finally, in the long-term it could be used as a fuel for existing natural gas power plants, and thus provide long-term energy storage to a decarbonised electricity grid.

Today, hydrogen is produced mostly locally. To achieve a sufficient scale to meet the EU's goals for green hydrogen production, a cost-efficient solution would be to centralise the electrolysis production in large, GW scale projects (in the EU or in neighbouring countries). To this end, the development of a hydrogen transmission network would be an economic solution by avoiding unnecessary development of expensive power lines. This network could benefit from the existing natural gas network, which could be partially retrofitted for this usage.

The EU, through the European Strategy on Hydrogen and the REPowerEU communication has set extremely ambitious objectives for renewable hydrogen development that will require an electrolyser capacity of up to 140 GWel by 2030. While the announced hydrogen and electrolyser production projects match this target, a negligible share of announced projects has reached the financial investment decision stage. The financing and viability of those projects will be a key issue.

Additionally, the EU's definition of renewable hydrogen encourages the development of projects directly connected to renewable power plants with low capacity factors. These projects will require a significantly stronger installed capacity than grid-connected ones and could monopolise VER capacities that could have been used to directly replace fossil fuel electricity production.

The scenarios analysed in Chapter 2 all depict high levels of electrification of the EU's energy system and a progressive decline in gas demand. However, the role of gas (including fossil methane, biomethane and hydrogen) and particularly gas infrastructure remains an important question. As highlighted in Section 1.4.2, the EU has the most developed gas infrastructure in the world, which could help limit the cost of the energy transition if the network is adapted for hydrogen. But this might also keep the EU dependent on fossil gas in the long term, by requiring a minimum gas demand in order to keep the infrastructure profitable.

Based on ENTSO-G's 2022 TYNDP, 358 gas infrastructure projects are planned in the next decade. Figure 59 highlights a **progressive shift in the gas infrastructure towards hydrogen.** New hydrogen infrastructure and retrofit of existing pipelines account for the majority of projects expected to start in 2030. The current emphasis is on the development of natural gas transmission pipelines and LNG facilities to accommodate the shift away from Russian gas.

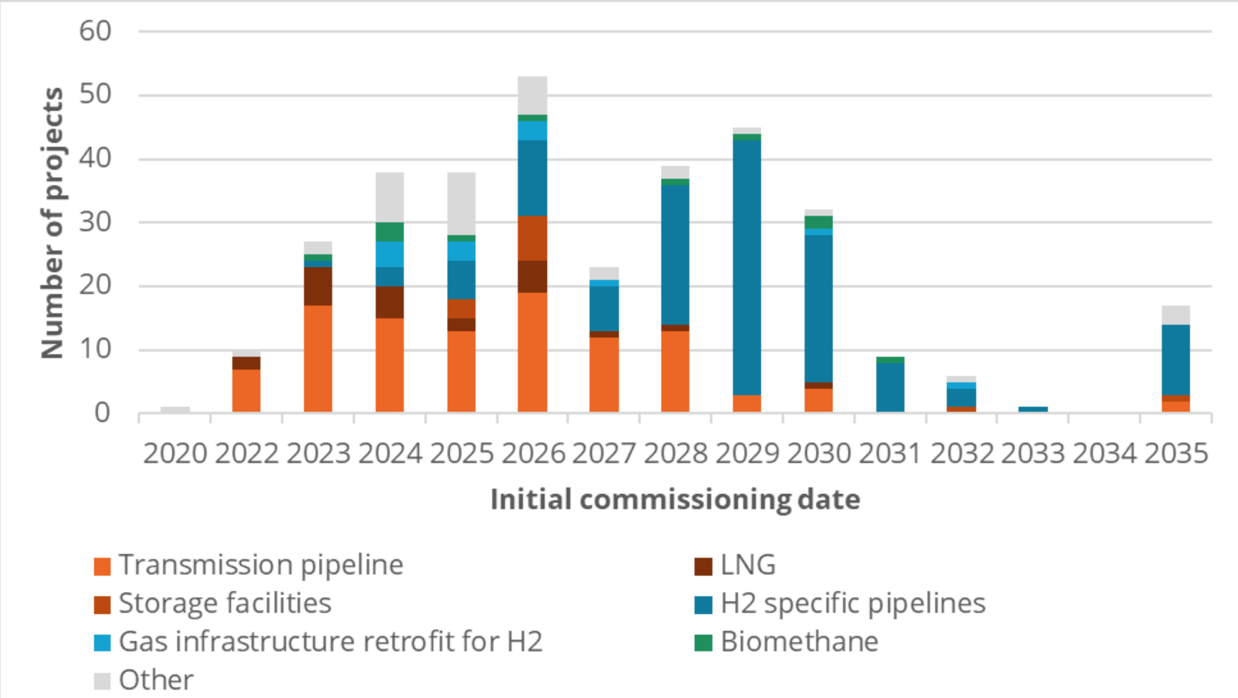
Hydrogen is primarily used for non-energy purposes for now but is anticipated to emerge as a key energy source in the EU's energy system. Its high energy density[78], absence of direct carbon emissions[79], and potential compatibility with a portion of the existing gas infrastructure (either by

[78] The combustion of one kilogram of hydrogen releases three times more energy than the same weight of petrol and emits only water.

[79] But, as seen below, over its lifecycle, hydrogen can be more carbon-intensive than fossil fuels, if produced from natural gas or a carbon-intensive electricity mix.

retrofitting existing infrastructure or through blending with natural gas), all make hydrogen an attractive and likely important part of the EU's future energy mix.

Figure 59: Number of infrastructure projects by type of project and commissioning year in the EU according to the 2022 TYNDP



Source: (ENTSOE - ENTSOG, 2022), Enerdata's analysis.

Note: Natural gas related projects are in brown, hydrogen projects are in blue, biomethane projects are in green. Pre-2022 projects are delayed ones.

However, **there is strong uncertainty about the future availability of renewable hydrogen**. While the REPowerEU communication is very ambitious about its development, its realisation may be different: its applications in the transportation sector are still at a very early stage, its role as a long-term energy storage vector for providing flexibility to the grid is not yet economic, and industry's capacity to switch their existing processes and ongoing investments from carbon-intensive fossil fuels to low-carbon hydrogen in the short-term remains uncertain.

This chapter delves into the role that hydrogen could have on the decarbonisation of the energy system and how a hydrogen infrastructure could help sustain higher shares of renewables. The first focus is on the **current status** of hydrogen (production and associated infrastructure) and on the impact the decarbonisation of its production could have. Then, **expected new end-uses** in relation to European and national objectives are described. Finally, a feasibility analysis of the anticipated **infrastructure** and **associated funding** developments is provided.

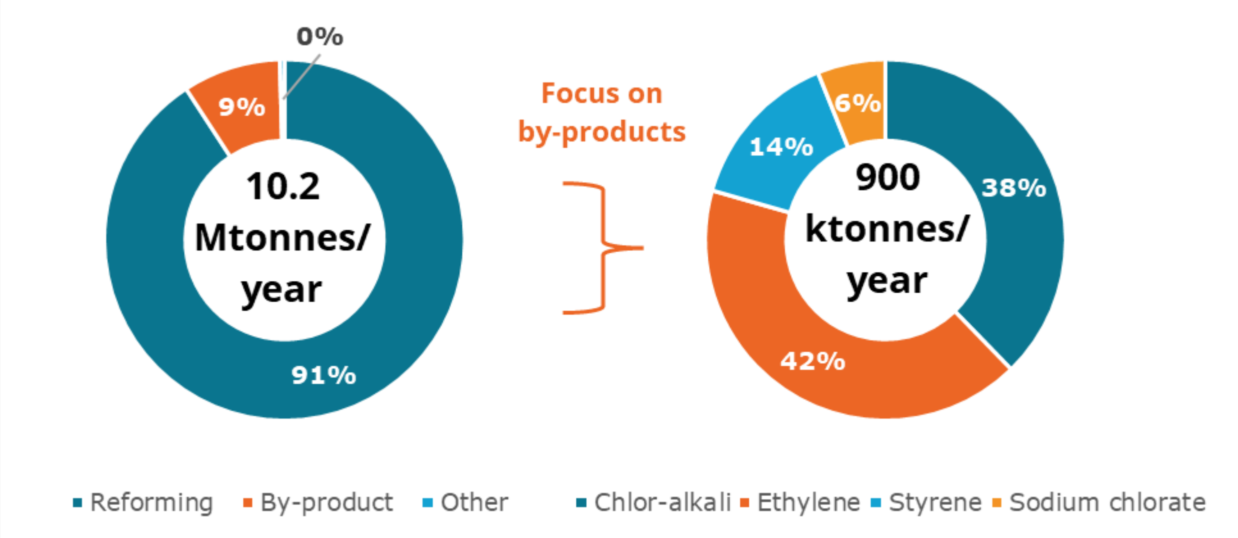
4.1. Current Status of Hydrogen in the EU

4.1.1. Overview of Existing Hydrogen Production

In 2022, the European Union had a hydrogen production capacity of 10.5 Mt/year. 72% of this capacity was used during the same year. This hydrogen was primarily produced using carbon-emitting processes, mainly through **Steam Methane Reforming** (SMR), which accounts for 91% of the production capacity, and as a by-product of other chemical processes (European Hydrogen

Observatory, 2022). These two production methods generate significant CO_2 emissions, however, they are much less expensive than hydrogen produced by electrolysis[80].

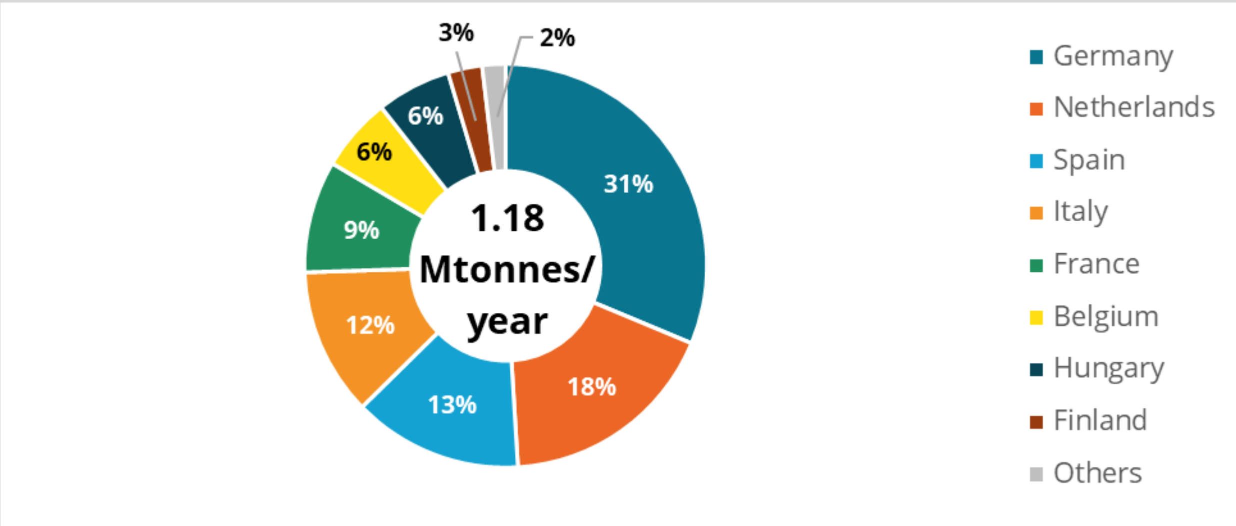
Figure 60: Hydrogen production capacity in the EU by process (2022)



Source: Enerdata with statistics derived from (European Hydrogen Observatory, 2022).

An estimated **87% share of current hydrogen production capacity is dedicated to on-site captive production**[81] (European Hydrogen Observatory, 2023) and does not require new infrastructure. The rest of current hydrogen production (13%) is traded, mainly through existing pipelines or trucks. As highlighted below, this capacity is highly concentrated. Germany and the Netherlands together account for fifty percent of merchant hydrogen production capacity.

Figure 61: Merchant hydrogen production capacity by country (2022)



Source: Enerdata with statistics derived from FCH Observatory.

A negligible amount of hydrogen is currently produced through electrolysis. Less than 140 MW of electrical capacity was installed in the EU in 2022 with a theoretical production capacity of 22 ktonnes

[80] This cost difference was considerably lower in 2022 due to the rising cost of natural gas. This point is analysed in Annex 2.

[81] This estimation is at European level, including the UK, Switzerland and Iceland that together represent a production capacity of 1.1 Mt/year.

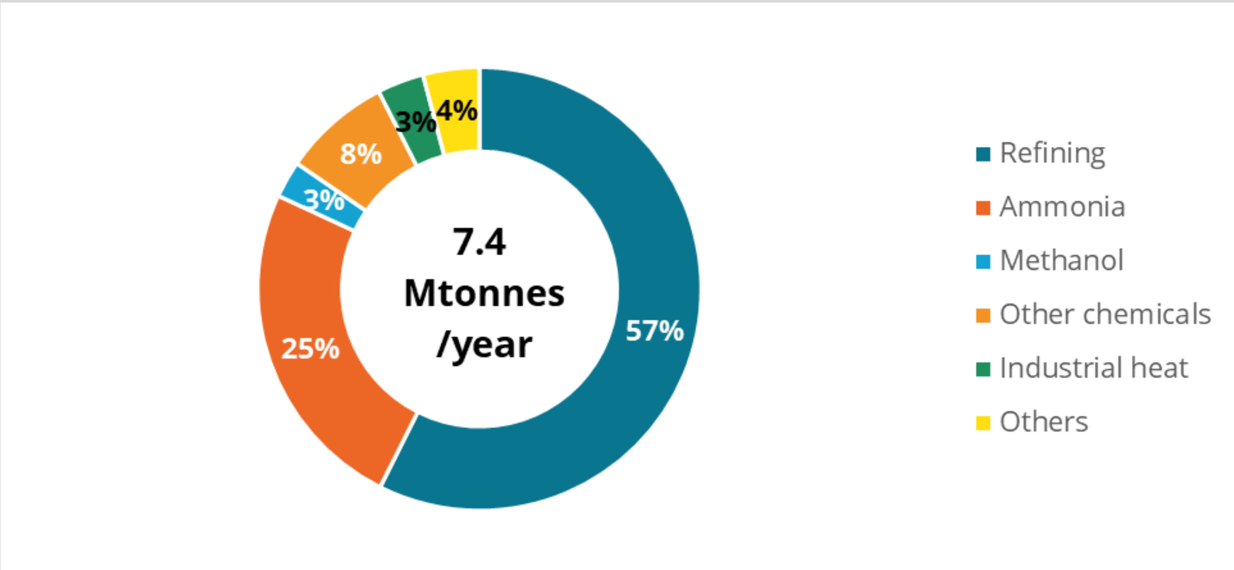
per year (1.8% of the total production capacity). Germany has the highest installed capacity of electrolysers, with Spain, Denmark, and Italy following suit.

4.1.2. Overview of Existing Consumption

Hydrogen production in the EU reached **7.5 Mt in 2022**[82] (Figure 62). 83% of the demand comes from the refining and ammonia production sectors, where it is used as feedstock to production processes. Energy uses, mainly industrial heat, account for only 3% of demand.

Hydrogen production accounts for about a third of natural gas consumption in industry and **11% of the EU's final natural gas consumption**[83]. Electrifying hydrogen production could yield high levels of greenhouse gas savings. However, existing processes are complex for industry to adapt e.g., due to the physical structure of factory layouts and long lifetimes of existing equipment (which make it challenging to replace from business case perspective). There are cases where demand has increased in certain industries, for example TotalEnergies' recent call for tenders for 500 ktonnes of green hydrogen for use in its European refineries[84].

Figure 62: Hydrogen consumption by end-use in the EU (2022)



Source: Enerdata with statistics derived from FCH Observatory.

Note: "Others" is composed of unknown end-uses (almost entirely) and industrial heat.

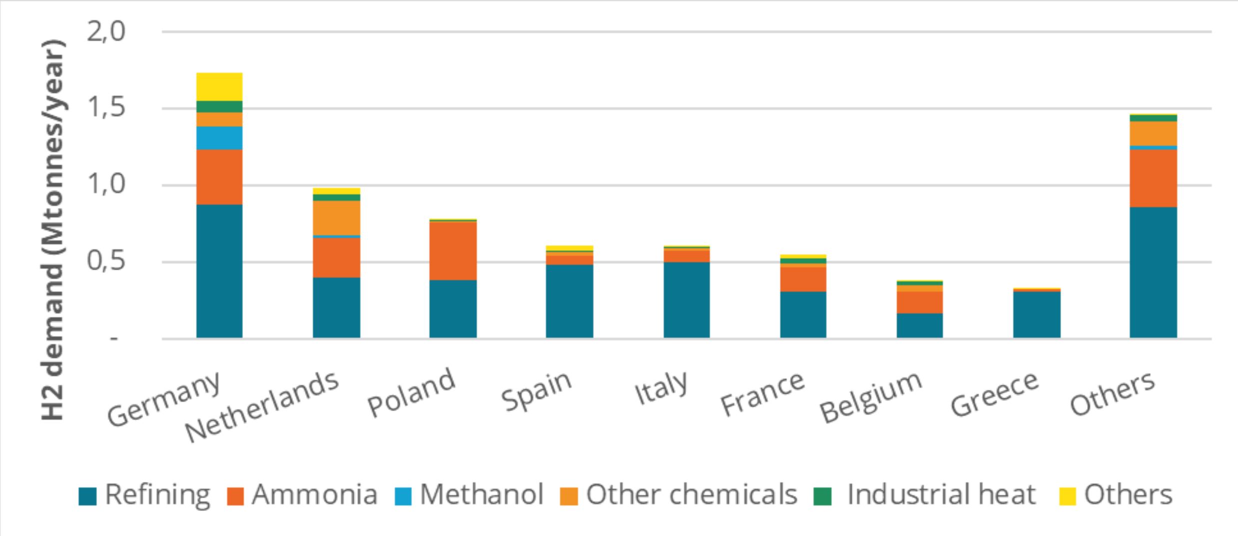
Over half of the European Union's hydrogen consumption is in four countries: Germany (19%), the Netherlands (11%), Poland (9%), and Spain (7%).

[82] Actual demand may differ from less than 1% due to imports, export and hydrogen being vented into the atmosphere (European Hydrogen Observatory, 2023). This value could be underestimated compared to the 9.7 million tonnes estimated by Hydrogen Europe in 2023. See https://hydrogeneurope.eu/wp-content/uploads/2023/05/HQM_Issue-3_website.pdf.

[83] Enerdata's estimation, taking only into account the hydrogen produced by reforming, assuming a 41 kWh_{CH4}/kg_{H2} in line with IEA estimations: https://www.iea.org/data-and-statistics/charts/comparison-of-the-emissions-intensity-of-different-hydrogen-production-routes-2021.

[84] More information at https://totalenergies.com/media/news/press-releases/decarbonizing-refining-totalenergies-launches-call-tenders-supply-500000.

Figure 63: Current European hydrogen consumption by country (2022)



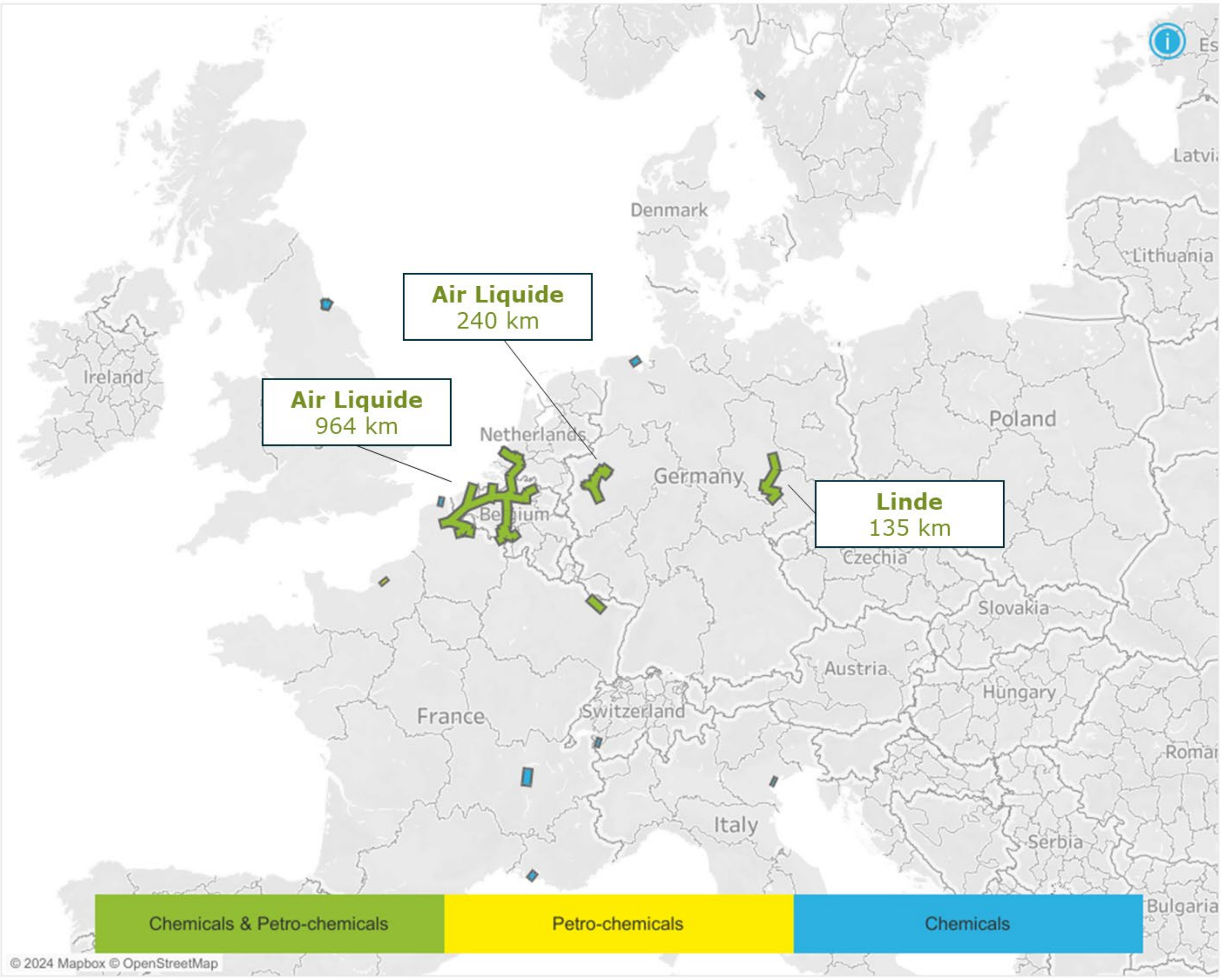
Source: Enerdata with statistics derived from FCH Observatory.

4.1.3. Overview of Existing Hydrogen Infrastructure in Europe

In Europe, there are currently **16 dedicated operational hydrogen pipelines spanning a total length of 1,564 km.** This transport infrastructure is concentrated between France, Belgium, and the Netherlands, with 964 km of the network owned by Air Liquide, or 60% of the installed length. Excluding two additional pipelines, one measuring 240 km and owned by Air Liquide, and another spanning 135 km and owned by Linde, the remaining infrastructure is made up of smaller, remote, and privately owned transportation projects. Compared to the 200,000 km of transmission pipelines and 2 million km of distribution networks for natural gas, **hydrogen's existing infrastructure is negligible.**

Existing pipelines deliver hydrogen to petrochemical and chemical industries (European Hydrogen Observatory). **This transport and distribution network will need to be extended to meet future demand for hydrogen in Europe**.

Figure 64: Map of existing dedicated H_2 pipelines



Source: FCH Observatory.

4.2. Planned Hydrogen Development

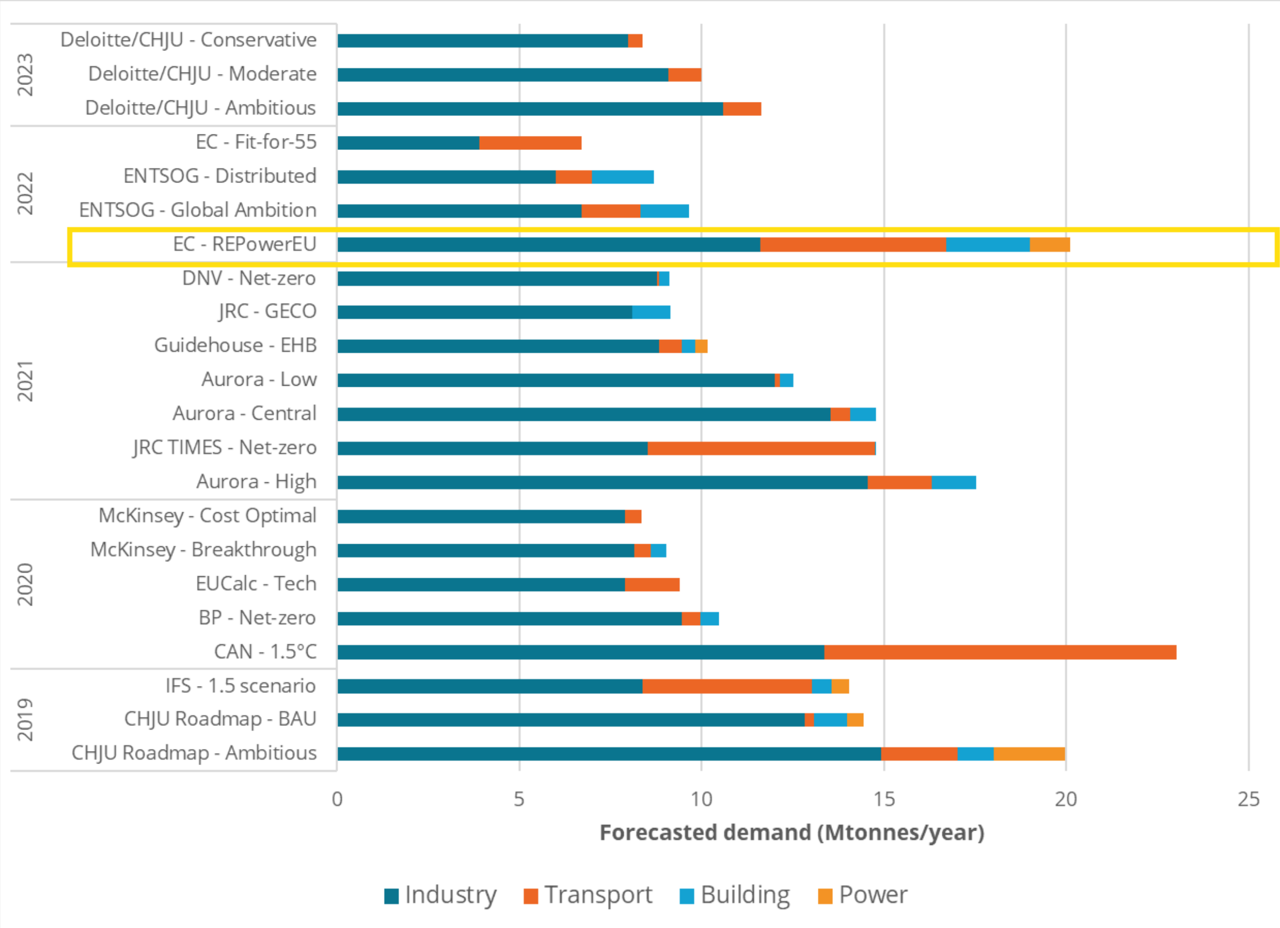
4.2.1. Demand Evolution Scenarios

Most scenarios project a robust expansion of hydrogen this decade, propelled mainly by the advancement of renewable hydrogen produced by electrolysis. The 2020 EU Hydrogen Strategy set a target of 5.6 million tonnes (with an ambition of 10 million tonnes) of renewable hydrogen production by 2030 in the EU; this would require at least 40 GW of electrolysers[85]. The 2022 REPowerEU communication raised the target by introducing an additional ambition of 10 million tonnes of imported renewable hydrogen (including four as ammonia or other derivatives), supplementing the 10 million tonnes locally produced. In addition, several countries have their own strategies and targets for installed hydrogen production capacity by 2030 to support the EU targets, namely Denmark (4–6 GW), France (6.5 GW), Italy (5 GW), Germany (5 GW), and Spain (4 GW).

Numerous scenarios focusing on hydrogen development have been formulated; Figure 65 is a concise summary of a significant portion of these. The scenario developed for the REPowerEU communication (highlighted in the figure) has an exceptionally ambitious trajectory compared to most other scenarios.

[85] EU Hydrogen Strategy: https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX:52020DC0301.

Figure 65: Comparison of multiple hydrogen demand scenarios by sector by 2030

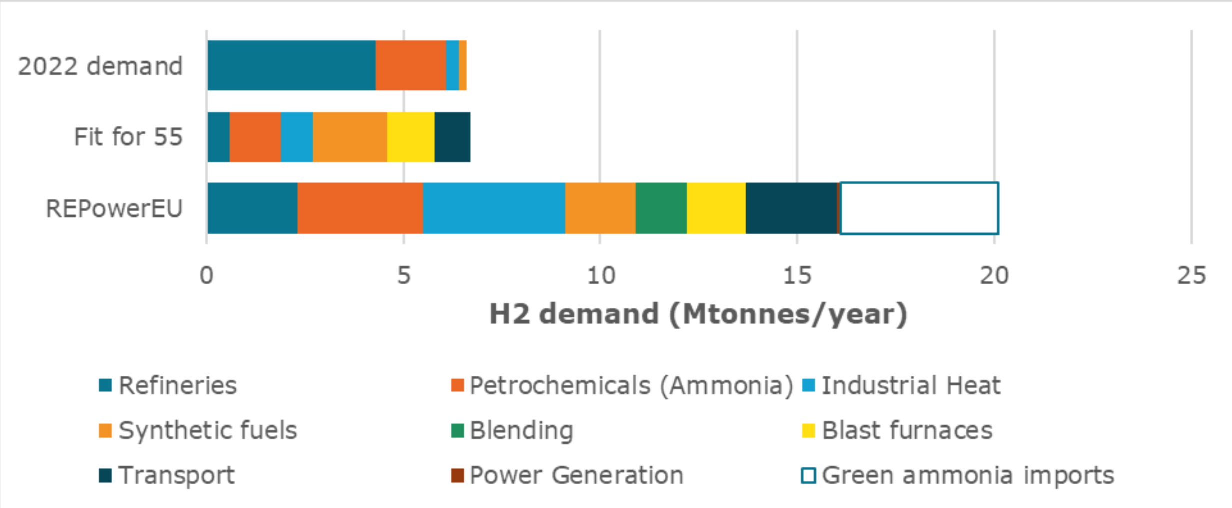


Source: Enerdata's analysis based on European Hydrogen Observatory.

Note: These scenarios are updated by various publishers and usually offer usually more than one projection (high, medium, and low). The date on the left axis is the publication date of the scenario.

As shown in Figure 66, the REPowerEU communication has three key elements to its hydrogen strategy: a reduction in hydrogen demand for refineries, driven by the development of electric vehicles; an increase of the demand by all existing end-uses; and, the development of new end-uses, namely blending of hydrogen in the gas network, in steel production through blast furnaces, and in transportation, with a focus on the heavy duty sector. Hydrogen use in **power generation is not expected to significantly increase by 2030.** Additionally, the REPowerEU communication says that "hydrogen production based on natural gas should be replaced in ammonia production and in hydrogen use by refineries by 2030".

Figure 66: Focus on the increased ambition of REPowerEU compared to the current demand and the Fit for 55 scenario (Mix CP)



Source: (European Hydrogen Observatory, 2023) and REPowerEU SWD.

Note: The Fit for 55 scenario only shows the renewable hydrogen demand without showing the remaining hydrogen demand. The REPowerEU scenario anticipates that the grey hydrogen demand is down to zero.

The long-term trajectory of hydrogen development remains highly uncertain. The 2022 TYNDP (ENTSO-E, ENTSO-G, 2022) delineates three distinct outlooks for prospective hydrogen demand across diverse sectors until 2050, as depicted in Figure 67. The **National Trends** scenario aligns with individual country measures; the **Global Ambition** scenario incorporates optimistic objectives; and the **Distributed Energy** scenario adopts a comprehensive energy perspective, encompassing the coupling of new sectors.

The **additional demand** for hydrogen is projected to be **less than 10 Mt** by 2030 in the 3 scenarios; they do not include REPowerEU targets[86]. By 2040 there are large differences in demand across scenarios ranging from 14 Mt in the National Trends scenario to 44 Mt in the Global Ambition scenario. Projections for 2050 significantly vary (41 Mt in the Distributed Energy scenario and 63 Mt in the Global Ambition scenario).

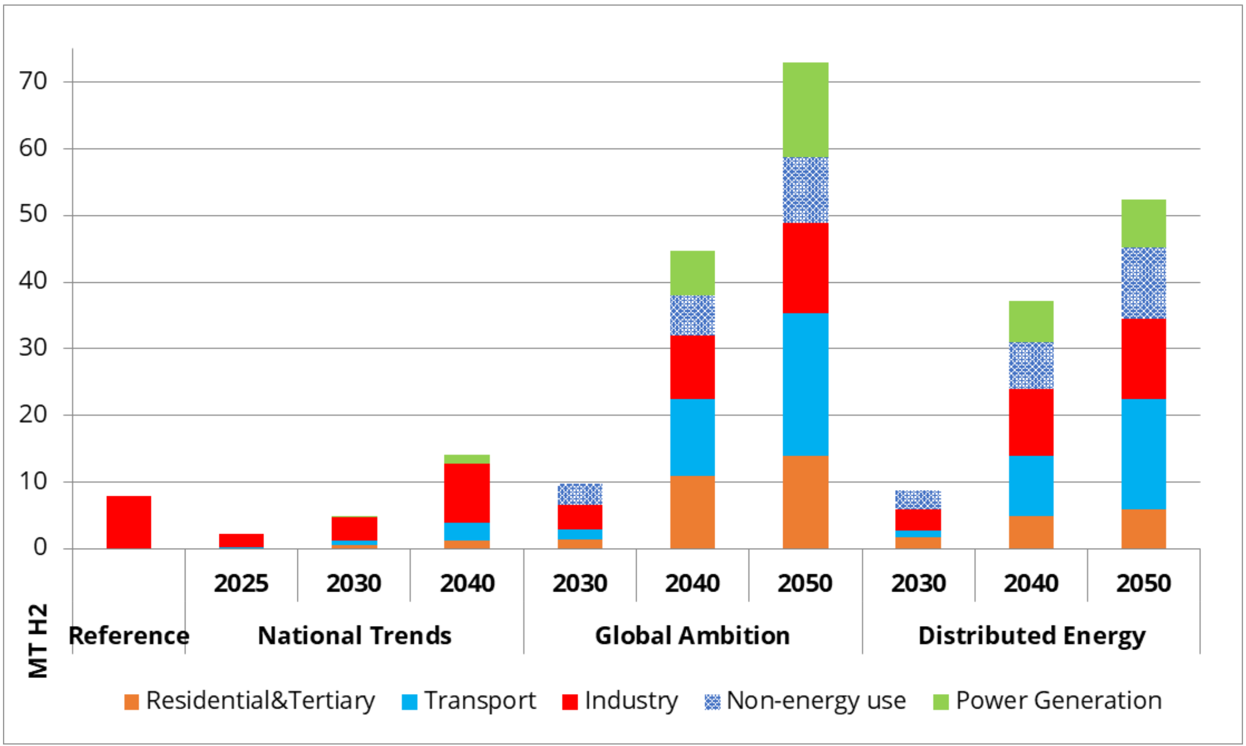
Hydrogen's role in two sectors grows significantly by 2050 in these scenarios: in the **power generation** sector, as a result of switching from fossil to hydrogen as a source for gas turbines, thus playing a long-term electricity storage role[87]; and, in the **residential and tertiary** sectors, for heating. Opinions vary on the value of hydrogen for this second end-use, and there are uncertainties about its feasibility, particularly around the development of the future gas distribution network that it would require (as highlighted in Section 1.4.2). Power generation using hydrogen is already developed in Germany, which recently announced a tender process for 10 GW in gas power-plant capacity that is expected to use hydrogen by 2040[88].

[86] ENTSO-G's forecasts don't include most of the current hydrogen production that is produced locally and is not connected to any network. Also, after the REPowerEU communication, ENTSO-G has adapted its production scenario to match the REPowerEU objectives but not the demand ones.

[87] If developed simultaneously with the development of storage capacities, hydrogen used in gas turbines can be produced in period of high VRE production and stored.

[88] More information: Alkousaa, R., 'Germany outlines $17 bln plan to subsidise gas-to-hydrogen shift', Reuters, 05.02.2024, available at: https://www.reuters.com/business/energy/germany-agrees-subsidy-plans-hydrogen-ready-gas-power-plants-2024-02-05/.

Figure 67: Hydrogen demand scenario by sector until 2050



Source: TYNDP 2022, ENTSO-E and ENTSO-G Scenario report (ENTSOE - ENTSOG, 2022).

4.2.2. Infrastructure Evolution

Achieving these scenarios would have significant impacts on the EU energy systems at two levels: the development of significant electrolyser capacity (and of an associated renewable electricity production infrastructure) and, the creation of an EU-level hydrogen transportation network that would partly benefit from the existing gas infrastructure.

a. Production capacities

The EU's objectives emphasise the advancement of renewable hydrogen. To clarify the definition of this term at EU level, the revised Renewable Energy Directive (**RED II)** introduced the concept of **renewable liquid and gaseous fuels of non-biological origin (RFNBOs).** RFNBOs include fuels made from renewable sources (other than biomass), typically referring to hydrogen-based fuels. The detailed methodology for defining RFNBOs was included in the first and second delegated acts (adopted in February 2023). The **first Delegated Act** ((EU) 2023/1184 of 10 February 2023) defines under which conditions hydrogen, hydrogen-based fuels or other energy carriers can be considered RFNBOs. The Act clarifies the principle of additionality for hydrogen set out in the EU's Renewable Energy Directive. The **second Delegated Act** ((EU) 2023/1185 of 10 February 2023) provides a methodology for calculating life-cycle greenhouse gas emissions for RFNBOs. The methodology considers greenhouse gas emissions across the full lifecycle of the fuels.

The first delegated act introduced **four methodologies endorsed for the production of renewable hydrogen within the EU**:

- Establishing a **direct connection** to one or several facilities generating renewable electricity without sourcing electricity from the grid. The renewable production installation must also be recent[89] (additionality criteria).
- Using **electricity from the grid** and proving the renewable origin of the electricity through the execution of a PPA or guarantees of origin with an energy balance that must respect geographical and temporal correlation criteria[90]. The additionality criteria also applies.
- Sourcing electricity from a **bidding zone**[91] **with a low carbon intensity** (less than 64.8 gCO_2eq/kWh). In this case only a portion of the hydrogen produced using grid electricity is qualified as renewable. This portion is equivalent to the share of renewables in the electricity mix within the bidding zone. Today, only France and Sweden qualify for this option.
- Sourcing electricity from a **bidding zone with renewable electricity exceeding 90%.** In this case, the hydrogen produced automatically qualifies as renewable. Only two bidding zones in Sweden (out of four) qualify for this option at the moment.

This legislation will have a strong but uncertain impact on the total capacity of electrolysers that will be required to meet the EU's renewable hydrogen production targets. A grid-connected electrolyser can have a capacity factor close to 95% while the same project sourced by a direct connection to a solar or wind power plant will divide its production by 2 to 5[92]. Significant uncertainties remain in hydrogen industry about how future projects will be connected, as explained in Section 4.3.1.

The 2024 agreement on the Net Zero Industry Act[93] ambitions an installed electrolyser capacity of at least 100 GWel to meet the 10 million tonnes annual production target by 2030[94]. This ambition makes the hypothesis of a 50% capacity factor. The actual capacity necessary to produce 10 million tonnes of hydrogen **could range between 60 and 140 GWel** depending on the type of connection used for hydrogen production projects[95].

b. Pipelines

Large increases in electrolyser capacity could have significant impacts on the electricity grid at multiple levels. Direct connection projects will require a higher development of renewable capacity to produce a similar hydrogen volume as grid connected ones and could cannibalise the necessary decarbonisation of the electricity grid[96]. On the other hand, the addition of large grid connected electrolysers might require the strengthening of the electricity transmission grid in addition to the development described in Sub-chapter 3.2.

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89 More specifically, the renewable energy installation needs to come into operation not earlier than 36 months before the electrolyser and not have received any public financial support in the form of operating aid or investment aid.

90 The temporal correlation is monthly before 2030 but will become hourly after.

91 A bidding zone is the largest geographical area within which market participants are able to exchange energy without capacity allocation. Currently, bidding zones in Europe are mostly defined by national borders. Some countries like Sweden dispose more than one bidding zone.

92 For example, an electrolyser which is supplied solely by an off-shore wind farm will only be powered 50% of the time, due to the off-shore wind capacity factor. This estimation is optimistic considering the lower yield of electrolysers during low loads.

93 Framework of measures for strengthening Europe's net-zero technology products manufacturing ecosystem (Net Zero Industry Act), available at: https://oeil.secure.europarl.europa.eu/oeil/popups/ficheprocedure.do?lang=en&reference=2023/0081(COD).

94 This objective is significantly raised compared to the previous EU ambition of having an electrolyser capacity of 40 GW by 2030 to produce 5.6 Mt of hydrogen annually in line with the 2020 hydrogen strategy.

95 A 2022 joint declaration by the hydrogen industry estimated a need for 140 GWel of electrolysers by 2030 (European Clean Hydrogen Alliance, 2022) while only 60 GWel with a 95% capacity factor.

96 Producing a GWh of hydrogen requires between 3 and 3.5 GWh of electricity with a 43% capacity factor. In a country where electricity production depends on fossil fuels, directly injecting this energy into the grid should be prioritised.

Further development of hydrogen pipelines could be a cost-effective way to develop grid-connected projects while mitigating the impact on the transmission grid. A 2021 study by the European Hydrogen Backbone[97] project estimated that for high volumes of hydrogen compared to building power lines, **both newly built and repurposed hydrogen pipelines are two to four times more cost-effective.**

In this context, hydrogen development may be more consolidated than it is today. The Hydrogen Europe roadmap for developing 40 GW of electrolyser capacity in the EU by 2030 shows a 6 GW captive market (hydrogen production at the demand location) and a 34 GW distributed market (hydrogen being transported through pipelines), **mostly built around GW-scale electrolysis projects** (Hydrogen Europe, 2021).

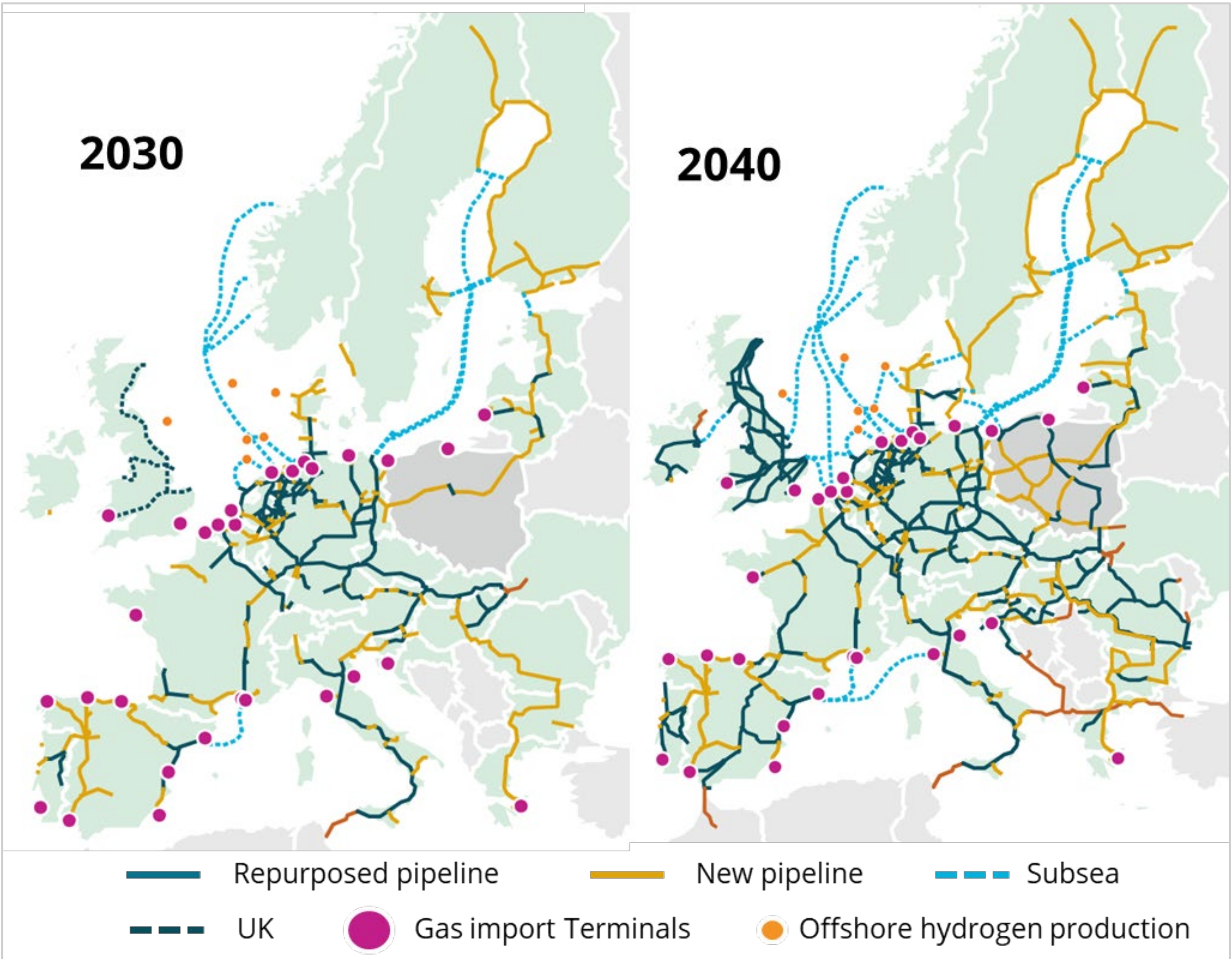
The European Hydrogen Backbone (EHB) initiative, which represents a cluster of European energy infrastructure operators, anticipates a potential future trans-European hydrogen network built around five pipeline corridors[98]. The hydrogen infrastructure in this scenario is envisioned to reach **32,616 km by 2030** of which **60% is repurposed natural gas pipelines**[99]. By 2040, the length of this infrastructure could reach 57,662 km, almost 30% of the current gas transport network. This scenario is mapped in Figure 69. However, these ambitious infrastructure development plans will depend on actual demand and on the need for imports. Figure 69 shows that a large share of the future infrastructure will need to connect gas import terminals to end customers.

[97] See p. 81 of https://ehb.eu/files/downloads/EHB-Analysing-the-future-demand-supply-and-transport-of-hydrogen-June-2021-v3.pdf.

[98] North Africa and Southern Europe; Southwest Europe and North Africa; North Sea; Nordic and Baltic regions; East and South-East Europe.

[99] Repurposing gas pipelines to transport hydrogen involves technical modifications to accommodate the specific nature of hydrogen compared to natural gas. Compared to constructing new pipelines, repurposing existing pipelines requires fraction of the cost.

Figure 68: Planned/announced hydrogen infrastructure projects across Europe until 2040



Source: European Hydrogen Backbone (EHB).

c. Import Infrastructures

In addition to the 10 million tonnes of renewable hydrogen that are expected to be produced locally, the REPowerEU communication says that an additional 10 million tonnes could be imported from non-EU countries, including four million tonnes imported in the form of ammonia[100].

While ammonia can be imported from far away countries with massive renewable electricity potential, such as Chili and Australia, hydrogen gas is preferably imported from nearby countries due to high transportation costs, either in pipelines or liquefied.

In this context, the European Hydrogen Backbone initiative (EHB) identified over **5.4 million tonnes of green hydrogen supply projects** from countries neighbouring the EU along five corridors (EHB, 2022). 46% of this capacity is estimated to be provided by Morocco, Algeria, Tunisia, and Ukraine, while the rest would be provided by Norway and the UK. Due to its favourable solar conditions, the existence of natural gas pipelines and its short distance from the EU, **the Middle East and North Africa (MENA) region** could become an important supplier of renewable hydrogen.

[100] Ammonia, used in particular by the fertilizer industry is significantly easier to transport in long distance ships than hydrogen that needs to be liquefied.

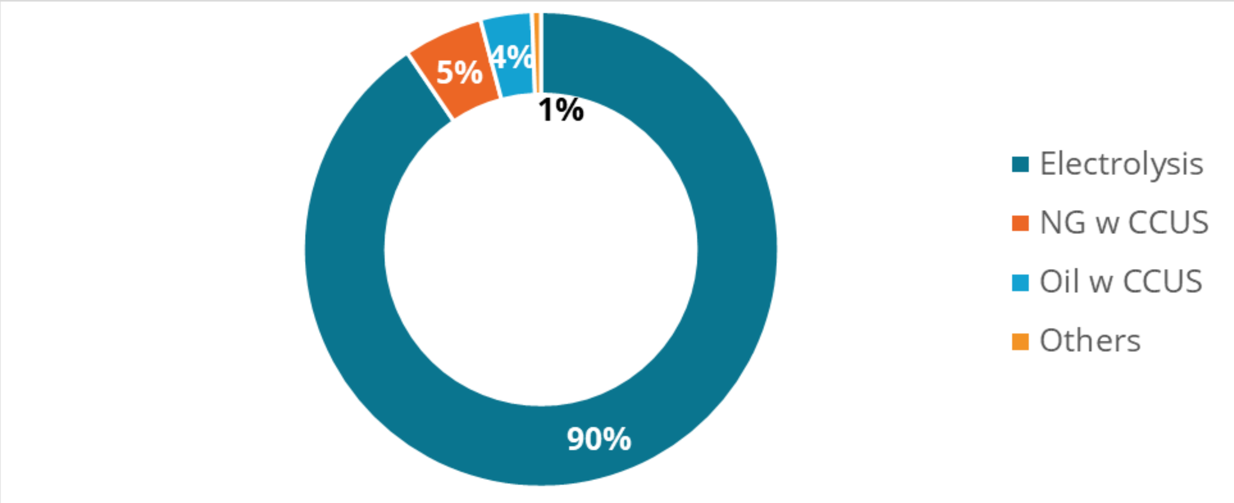
It is important to note that **none of the import projects mentioned in the EHB plan have reached the final investment decision (FID) phase yet** and that these are only projects and infrastructure may only be partially realised (EHB, Estimated Investment & Cost, 2023).

4.3. Analysis of Hydrogen Development Targets

4.3.1. Comparison with Announced Projects

Seven hundred green hydrogen production projects are expected to be completed in Europe by 2030 based on announcements made by the end of 2022. These projects have a total potential production capacity of **28.5 million tonnes of low-carbon hydrogen per year** (IEA, 2022). 90% of the anticipated capacity is expected to come from electrolysis projects (Figure 69).

Figure 69: Expected technology of hydrogen production projects by maximum theoretical capacity

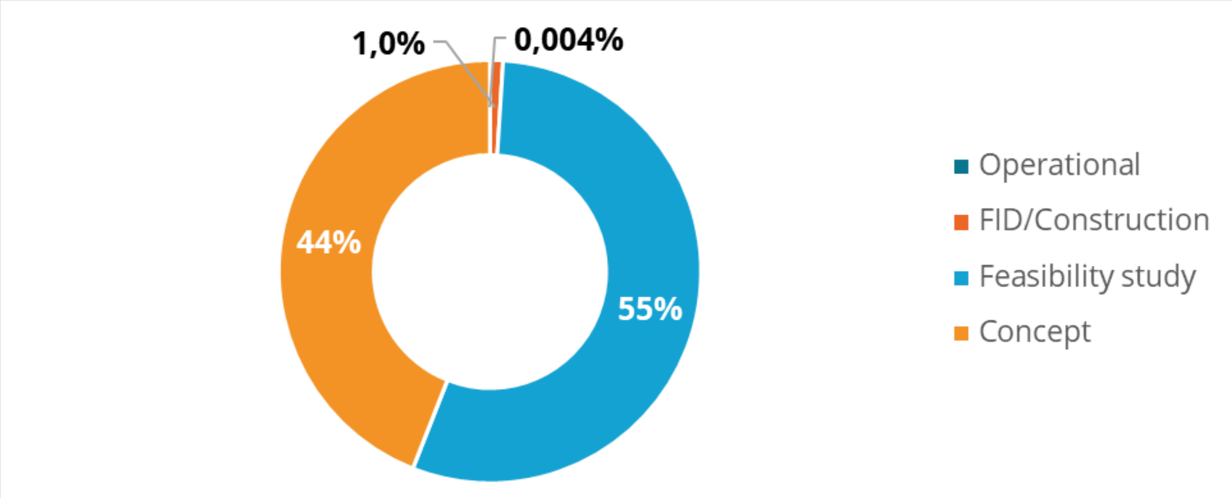


Source: (IEA, 2022).

The announced projects are mainly clustered in six countries: Spain, Denmark, Germany, France, the Netherlands, and Sweden. This aligns with the countries with the largest current hydrogen demand – Germany, the Netherlands, Spain, and France. Denmark and Sweden, newcomers to the hydrogen production landscape, primarily focus on the export market, leveraging their substantial offshore wind (Denmark) and hydropower (Sweden) resources for production.

However, the majority of these projects are immature, with only 1% of announced projects' installed capacity having reached the final investment decision (FID) stage. A substantial portion of operational projects are in the conceptual phase. Numerous companies have unveiled ambitious plans for green hydrogen production without conducting thorough investigations and without securing off-takers. 44% of announced projects are currently in the feasibility study stage, while 55% are at the conceptual level.

Figure 70: Status of announced green hydrogen projects by 2022

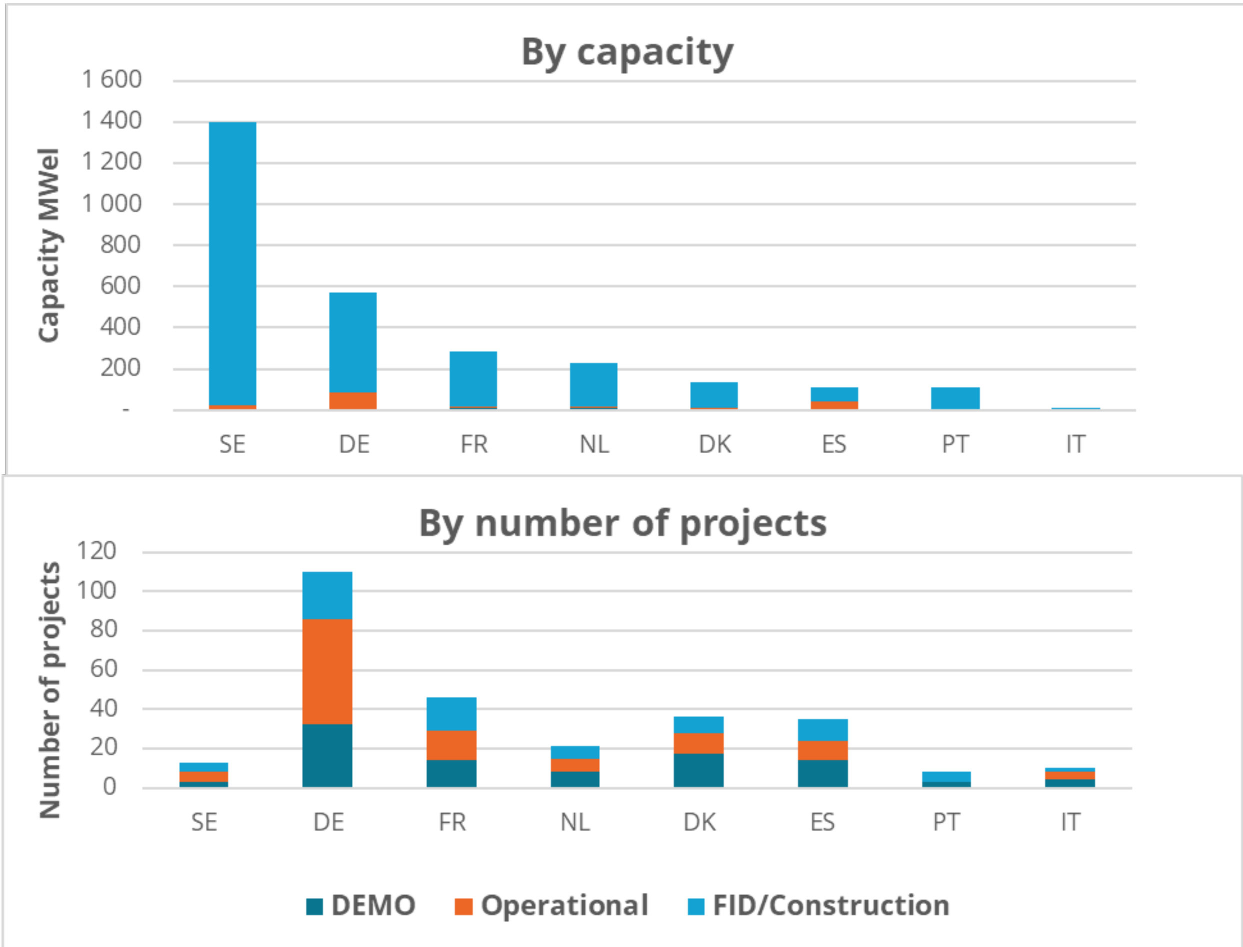


Source: Enerdata with statistics derived from IEA.

Figure 71 includes only projects that have reached the FID stage. Sweden leads in installed capacity, mainly driven by its H2GreenSteel production project, which benefits from low-cost hydropower. Altogether, these projects reaching the FID stage amount to 3 GW in electrolyser capacity, far from the capacity needed by 2030.

Electrolysis projects might not produce at their full potential. As discussed in Section 4.2.2., RED II encourages the development of direct connections between power plants and electrolyser projects that are currently not in low-carbon electricity mixes. Figure 72 shows that **while almost all planned projects plan to be directly connected with a wind or solar power plant, most mature projects are grid connected.** The types of connections and associated capacity factors of projects reaching the FID stage will be key indicators to watch in gauging the future impact of hydrogen on the energy system.

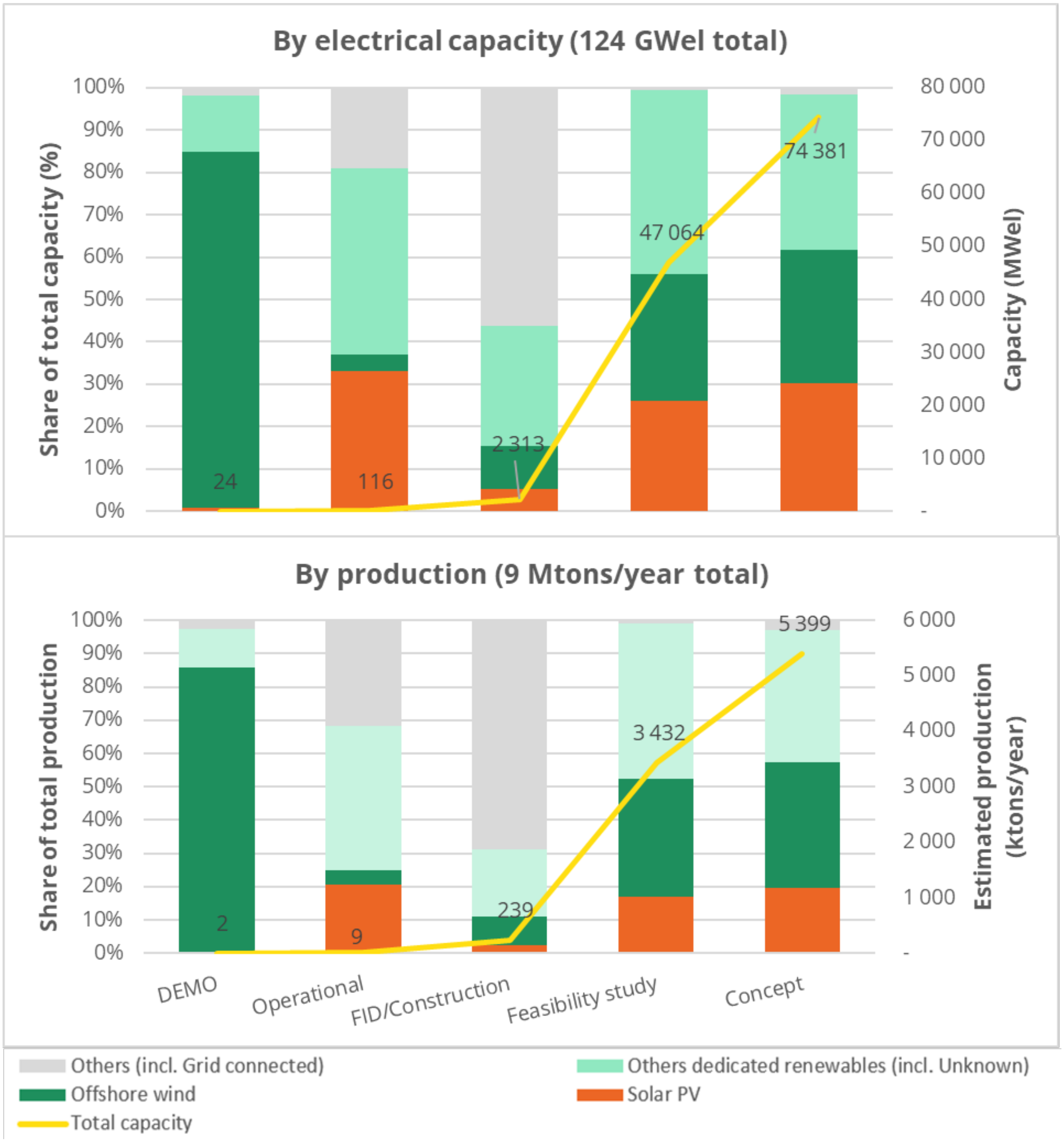
Figure 71: Repartition of mature green H_2 production projects by 2030 by country and status



Source: Enerdata with statistics derived from IEA (IEA, 2022).

Note: The projects with no commissioning date or planned for after 2030 have been excluded from this analysis due to the uncertainty of their completion. Only electrolysis projects are shown in this graph.

Figure 72: Electrolysis projects by type of connection and maturity



Source: IEA, 2022.

4.3.2. Impact on Renewable Electricity Production

Meeting the EU's hydrogen production target could generate an additional demand of **500 TWh of renewable electricity by 2030**, 14% of Europe's current electricity consumption (European Commission, 2023). So far, Hydrogen Europe has tracked announcements for the development of **31 GW of renewables by 2025, reaching up to 139 GW by 2030** to power green hydrogen production in Europe. These projects are not sufficient to power the volume of electrolysers in the planning stages. JRC estimates there is a need to install an additional intermittent renewables capacity of **260 – 300 GW** by 2030 to supply electrolysers. In the least optimised scenario, additional renewables required will total 500 GW (JRC, 2022). By comparison, in the EnerBlue scenario presented in Chapter 2, 900 GW of total additional renewables will need to be installed by 2030.

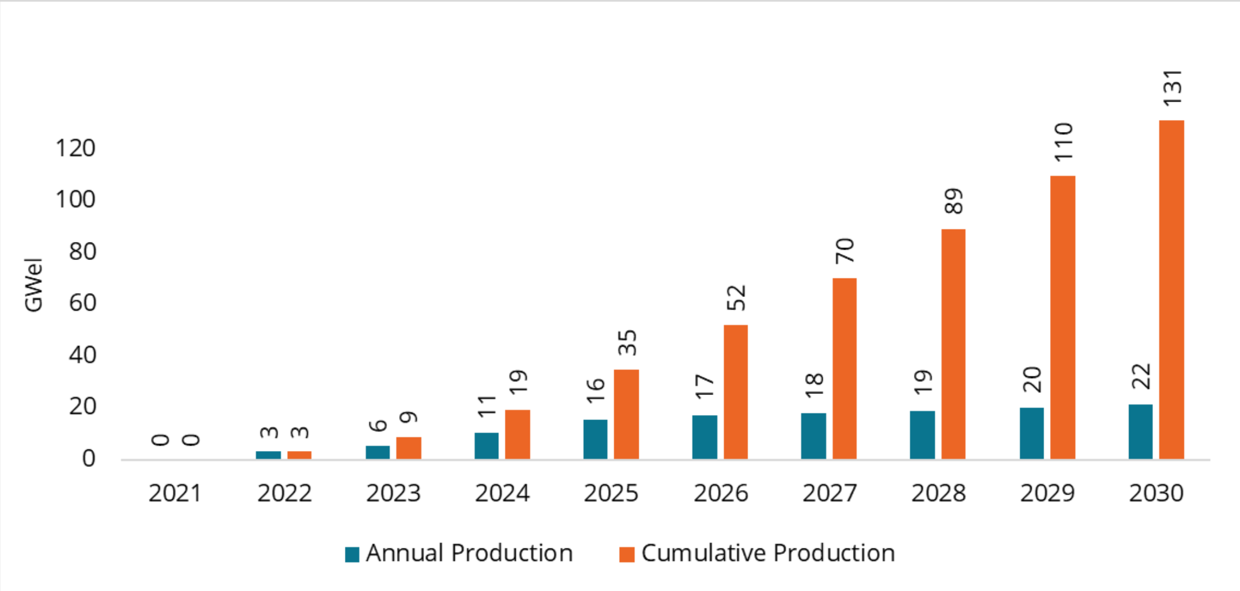
Achieving these objectives poses a significant challenge and carries the considerable risk of prioritising the growth of the hydrogen industry over the decarbonisation of the electricity mix. This challenge is made greater by the fact that a majority of announced projects for renewable hydrogen hinge on wind power, which has a slow pace of development.

4.3.3. Electrolyser Production Capacity

Meeting anticipated demand for hydrogen without impacting the EU's capacity to produce electrolysers within its borders will require the development of a robust hydrogen industry across the value chain. This chapter concentrates on one key element of the value chain: the manufacturing of electrolysers. In their 2022 joint declaration, electrolyser manufacturers declared a common objective of reaching a 25 GWel production capacity within the EU (European Clean Hydrogen Alliance, 2022).

Based on Enerdata's statistics for the announced projects shown in Figure 73, growth in electrolyser manufacturing capacity will result in exponential increases in annual green hydrogen production capacity[101], from just a few megawatts in 2021 to **16 GWel/year in 2025 and 22 GWel/year in 2030.** This growth in annual production capacity adds up to a net production of 35 GWel by 2025 and 131 GWel by 2030. Depending on actual capacity factors, this 131 GWel in electrolyser capacity could produce between 9.4 and 20.7 million tonnes of hydrogen per year by 2030, **in line with the REPowerEU objectives**.

Figure 73: Electrolysers' annual and cumulative production capacity in Europe



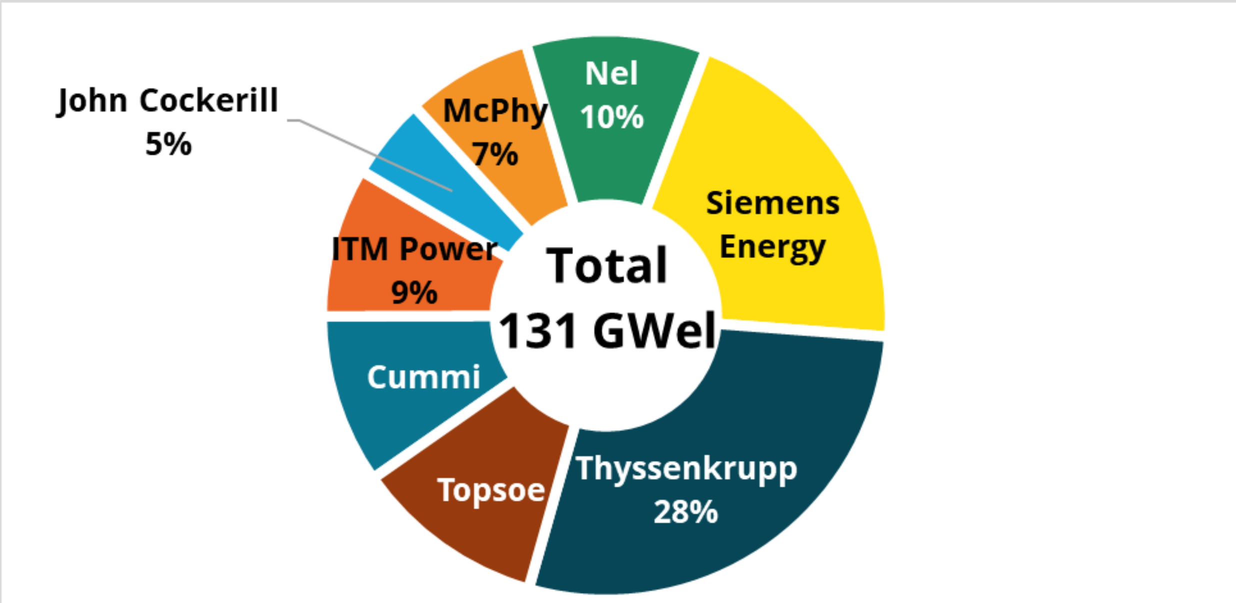
Source: Enerdata based on electrolysis manufacturing projects public announcements.

Note: Cumulative production means that the total electrolyser factories output between 2022 and 2030 would amount to 131 GWel.

[101] Total capacity of the electrolysers produced in Europe, without considering their integration in projects.

These projects have been announced by eight companies in total (Figure 74). Siemens Energy and Thyssenkrupp alone represent almost half of announced capacities.

Figure 74: Cumulative expected electrolysers production capacity by company



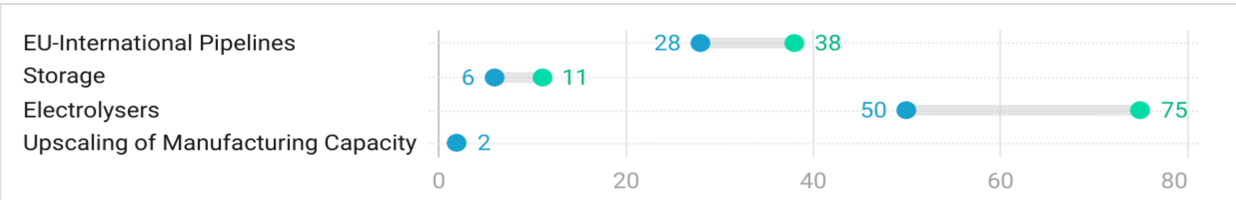
Source: Enerdata Water electrolyser manufacturing capacity report, available at: https://www.enerdata.net/estore/water-electrolyser-worldwide-report.html.

Note: Data is based on announced projects.

4.3.4. Investment Requirements

Meeting the REPowerEU target of 20 Mt of hydrogen produced or imported by 2030 requires considerable investment. The REPowerEU communication specifies an investment budget of **€86 to €126 billion**. Figure 75 shows the distribution of investment needs.

Figure 75: Investment needed for hydrogen infrastructure until 2030 (Min – Maxi in Billion €)



Source: REPowerEU Communication (Hydrogen Europe, 2022).

However, the estimates in REPowerEU are **considerably lower than those in alternative studies and reports**. According to a 2022 Hydrogen for Europe study[102], cumulative investments in the European hydrogen value chain amount to **trillions of euros over the next thirty years** (see Figure 76). Between **€300 billion** (in the Technology Diversification pathway) and **€450 billion** (in the Renewable Push pathway) would need to be mobilised through the mid-2030s to finance the development of the European hydrogen supply chain.

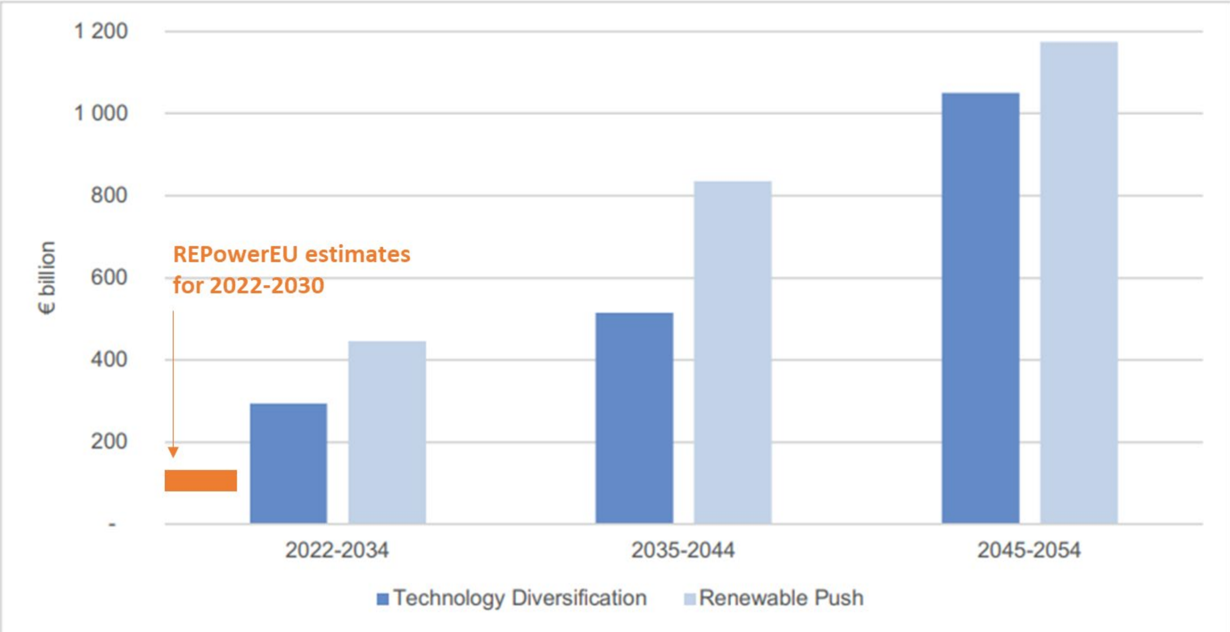
Project financing is particularly at risk over the coming decade due to recent macroeconomic developments, with the post-COVID-19 economic recovery and Ukraine war having resulted in a

102 Hydrogen4EU, IOGP Europe, 2022. Available at: https://www.hydrogen4eu.com/_files/ugd/2c85cf_e934420068d44268aac2ef0d65a01a66.pdf.

marked uptick in inflation. This may cause financing costs to rise, which would particularly affect capital-intensive investments such as those needed for deep decarbonisation and an expansion of hydrogen production and use (IFP Energies Nouvelles, 2022).

The 57,000 km of pipeline in the European Hydrogen Backbone[103] project alone requires an estimated total investment of €80 - €143 billion by 2040 (EHB, Estimated Investment & Cost, 2023). This is **considerably higher than the €28-38 billion envisaged by the Commission in the REPowerEU communication** (Figure 75). Despite differing estimates, what is clear is that the sector will require a combination of public and private funding sources to develop.

Figure 76: Investments in the hydrogen supply chain per period (2022-2054)



Source: Hydrogen for Europe, 2022.

Note: Information based on the Technology Diversification and Renewable Push pathways.

At the EU level, a set of tools exists to fund hydrogen projects at different steps of the project's development. **Important Projects of Common European Interest** (IPCEI) are one of the key pillars of this funding. IPCEIs are a scheme defined in the EU State Aid rules that enable Member States to directly fund key projects with the approval of the European Commission.

In December 2020, twenty-two EU countries and Norway committed to launch IPCEIs for the hydrogen sector. The signatories agreed that projects should cover the full value chain: from renewable and low-carbon hydrogen production to hydrogen storage, transmission and distribution, and hydrogen application notably in industrial sectors.

Two groups of IPCEIs received approval for a total of 76 projects, and public funding of **€10.6 billion**:

- In July 2022, **41 projects from 35 companies,** mainly focused on the **development of technologies** along the hydrogen value chain, were approved ("Hy2Tech"). These projects involve cooperation with over 300 external partners, such as universities, research

[103] This estimate is based on the use of 60% of repurposed natural gas pipelines and 40% of new pipeline stretches. This investment cost estimate includes subsea pipelines and interconnectors linking countries to offshore energy hubs and potential export regions.

organisations and SMEs across Europe. Member States will provide up to **€5.4 billion in public funding**, which is expected to unlock an additional **€8.8 billion** in private investment.

- In September 2022, a second group of 35 projects focused on **hydrogen production and transport infrastructure** ("Hy2Use") received approval with total public funding of **€5.2 billion**, which could attract **€7 billion** in additional private investment.

Further, **a EU Hydrogen Bank** was announced in March 2023, funded by the EU ETS Innovation Fund. This bank aims at supporting the creation of a domestic market for renewable hydrogen, supporting international imports into the EU, and streamlining existing financial instruments. A budget of **€3 billion** was announced that would directly support the hydrogen production.

Finally, following the European Recovery and Resilience Facility (RRF), grants and loans were made available to Member States based on national **Recovery and Resilience Plans (RRPs)** they had proposed. Within RRPs, the cumulative amount of funds available for hydrogen is **€55 billion**, of which almost €12 billion is exclusively for hydrogen technologies. The Member States with the largest total funds available for hydrogen[104] are France (€14.3 billion), Spain (€9.4 billion), Germany (€7.9 billion), and Italy (€7.8 billion). Despite this ambition, this funding **might not be sufficient to meet future hydrogen production capacity needs.**

[104] Either focused on hydrogen or financing hydrogen among other technologies.

5. IMPACT OF UKRAINE'S CONNECTION TO THE POWER GRID

KEY FINDINGS

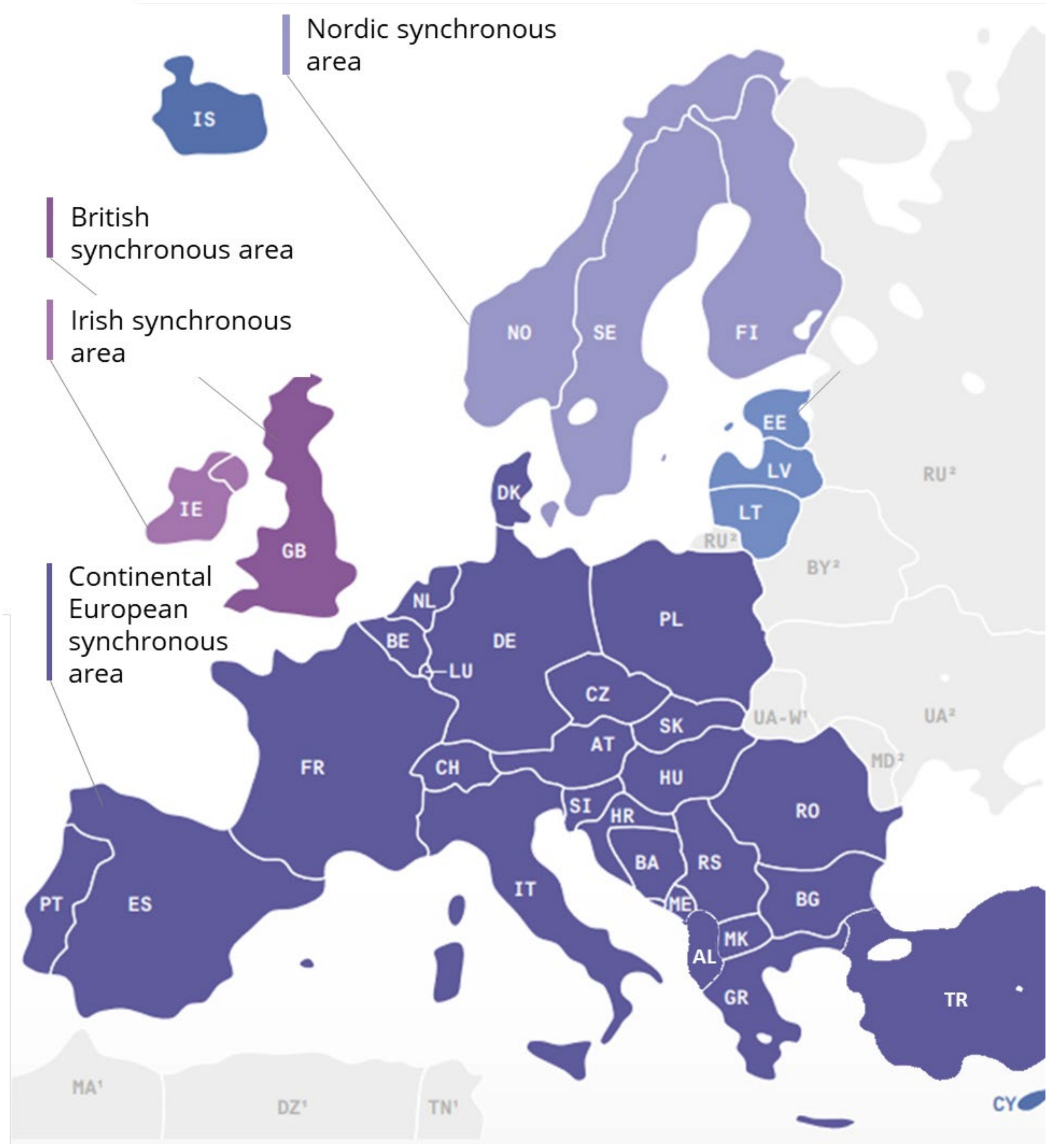
The emergency synchronisation of Ukraine and Moldova to the European continental grid serves short- and long-term interests on both sides. In the short-term, it has allowed Ukraine to secure its electricity supply during intensive Russian bombing, and during maintenance of Ukraine's nuclear plants. It has also allowed Ukraine to export significant amounts of electricity to its European neighbours, thus generating valuable profits.

In the long-term, Ukraine aims to become an important supplier of electricity to Europe, mainly from its nuclear power plants. Recent agreements also point to strong participation in the future hydrogen economy. This partnership will likely not be possible until the war ends and reconstruction occurs. The support of the EU will be crucial in this matter.

Europe's electricity grid is synchronised with numerous countries outside the EU, including Morocco, Algeria, Tunisia, Turkey, and the Balkans (Figure 77). Two independently synchronised grids exist within the EU: the Nordic Synchronous area and the IPS/UPS synchronous area, which is centralised in Russia and to which the Baltic states are still synchronised. These countries are connected to the European area with DC power lines.

Until recently only a small part of Ukraine was synchronised with the European grid, while the majority of its territory remained synchronised with the IPS/UPS synchronous area, making it reliant on Russia. In March 2022, in the aftermath of the Russian invasion of Ukraine, there was an urgent synchronisation of Ukraine's and Moldova's electricity grids with the Continental European Grid. This event expedited implementation of a previously scheduled long-term project. This chapter analyses the impact of this synchronisation, comparing the previous situation to the current one and its potential impacts on the European energy system in the short- and long-term. First, an overview of the pre-war Ukrainian electricity system is provided, followed by an analysis of the synchronisation. Finally, the current and potential impacts this synchronisation could have on the future European energy system are discussed.

Figure 77: Map of the European synchronous areas before 2022



Source: ENTSO-E, 2015; adapted by Enerdata.

Note: [1]Synchronous with the European power system; [2]Synchronous with the Baltic system.

5.1. Pre-2022 Ukrainian and Moldovan electricity market

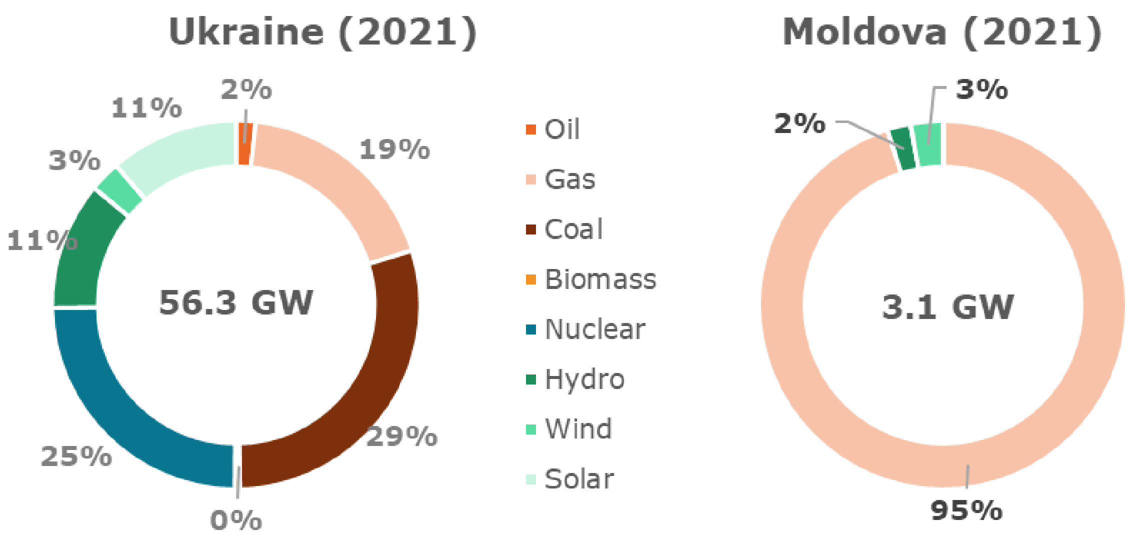
5.1.1. Grid Infrastructure

a. Production capacity

In 2021, **Ukraine's** electricity production mix was comprised of **nuclear power** (25% of the installed capacity), **renewables** (25%), and **fossil fuel plants** (50%). The largest power plants are the Zaporizhzhia nuclear power plant (6 units, 5.7 GW), the Khmelnytskyi nuclear power plant (2 units, 2 GW), and the Zaporizhzhia and Vuhlehirska thermal power plants (3.6 GW each). Ukraine's four nuclear power plants were operated by Energoatom. Compared to its neighbours, Ukraine's production capacity was similar to Poland's (57 GW in 2021) but significantly higher than Hungary's (12 GW), Slovakia's (8 GW), and Romania's (18 GW).

The **Moldovan production mix is highly centralised**; 80% of the country's electricity production capacity comes from the Moldavskaya / Kuchurgan gas power plant (2,520 MW), located in the independent region of Transnistria. Without this power plant, the Moldovan production capacity only amounts to 560 MW.

Figure 78: Installed electric capacity by source in Ukraine and Moldova (2021, %)



Source: Enerdata, Global Energy and CO2 Data.

b. Grid and Interconnections

In 2021, the Ukrainian power transmission system included **23,600 km of overhead lines** (4% of the EU's infrastructure) and 141 substations operated by the state-owned company Ukrenergo. Until 2022, this grid was connected to the IPS/UPS[105] synchronous grid, operating together with Russia, Belarus, and Moldova. There was one exception: the "**Burshtyn Power Island**" (see Figure 84), a zone in the western part of the country that has been synchronised with the Continental European Grid since 2003. This island was powered by three power plants: the Burshtyn coal power plant (bombed in 2022), the Kaluska Combined Heat and Power Plant and the Tereblia-Rikska hydroelectric power plant (Koval, Gaska, & Sribna, 2019).

105 The IPS/UPS is a wide area synchronous transmission grid of some CIS countries (Figure 77).

Figure 79: Interconnections in Ukraine and Moldova as of October 2021

Source: Enerdata based on CESI and (GET, 2022), German Economic Team.

c. Interconnections

Until 2022, **Ukraine** was interconnected with Poland, Slovakia, Hungary, Romania, Moldova, Russia, and Belarus, while Moldova was connected only to Ukraine. Various interconnection projects with the EU have been abandoned and restarted over time[106].

Before March 2022, **Moldova** only exchanged electricity with Ukraine. The interconnection transmission lines between the two countries consisted of seven 330 kV overhead lines, 11 110 kV overhead lines , and two low voltage overhead lines (35 kV and 10 kV). Net electricity imports totalled 111 GWh in 2021, equivalent to only 2% of Moldova's final electricity consumption. While Moldova has the production capacity to meet demand, balancing services were still provided by Ukraine.

[106] For example, the Rzeszów–Khmelnytskyi powerline between Poland and Ukraine went in operation in 1985 but went out in 1992 when Poland was synchronised with the European Continental Grid. There was a plan to re-activate this line after 2010 that was not implemented. This line was finally re-commissioned at the end of April 2023. (Foreign Policy Research Institute, 2023)

Table 2: Details of Ukraine's interconnections with other countries before 2022

Country	Direction[107]	Capacity	Description
Slovakia, Romania	Bidirectional	650 MW	From Burshtyn TPP
Hungary	Bidirectional	2 GW	Albertirsa–Zakhidnoukrainska–Vinnytsia powerline (750 kV)
Romania	Bidirectional	out of order	Isaccea–Yuzhnoukrainsk (400 kV)
Poland	Export	235 MW	220 kV Dobrotvorska TPP – Zamosc transmission lines
Poland	Bidirectional	1300 MW	Rzeszów–Khmelnytskyi powerline (400 kV)
Moldova	Bidirectional	700 MW	-
Belarus	Bidirectional	900 MW	-
Russia	Bidirectional	3,000 MW	-

Source: (Kosatka media, 2020) and Enerdata's analysis.

5.1.2. Electricity Markets

The integration of Ukrainian and Moldovan electricity markets into the European system came after the 2014 Euromaidan revolution[108], followed by the annexation of Crimea and the beginning of the war in Donbass. The initial phase was the merger of the Ukrainian and Moldovan energy systems under the ENTSO-E scheme in 2016. (Koval, Gaska, & Sribna, 2019).

Ukraine's Electricity Market Law, which included a new electricity model consistent with the EU's Third Energy Package, was adopted and transposed into national law in 2017. Since then, several market liberalisation measures were adopted. Various mechanisms for the purchase and sale of electricity were created, namely bilateral agreements (which include Over The Counter trading and bilateral contract auctions), a day-ahead market (DAM), and an intraday market (IDM). Altogether 695 participants had registered by the time of market launch in 2019[109]. Distribution System Operators (DSOs) were also unbundled, thus separating electricity supply activities; the Transmission System Operator (TSO), Ukrenergo, was also unbundled in 2021, and independent electricity suppliers have been allowed to sell electricity to non-residential consumers since 2019.

In Moldova, energy market reforms were decided by the law on electricity No. 107/2016. This law introduced the creation of a day-ahead market, an intra-day market, and a balancing market, all managed by the National Agency for Energy Regulation (ANRE). Further market rules were adopted in August 2020, but as of March 2022, the wholesale market had still not launched, and consisted **only of**

107 Import from this country or export to this country.

108 The Euromaidan revolution in Ukraine, marked by protests against President Yanukovych's rejection of the EU association agreement, began in November 2013 and led to his ousting and subsequent Russian intervention in Ukraine, escalating into the ongoing conflict.

109 REKK, "Economic Analysis Of The Ukrainian And Moldovan Wholesale Electricity Markets And Benefits Of EU Continental Grid Integration", 2020. Information reported by Ukrenergo.

bilateral contracts concluded either at negotiated prices, or at regulated prices, and approved by ANRE.

5.2. 2022 Synchronisation with the EU Continental Grid

5.2.1. Context and Motivation

In June 2017, grid operators in Ukraine (Ukrenergo) and Moldova (Moldelectrica) signed an agreement with ENTSO-E securing future integration into Europe's grid. Despite the outlined market liberalisation initiatives, the complete synchronisation of Ukraine to the European power grid was projected to conclude **no earlier than 2023** (SWP Berlin, 2021). The primary motivation for establishing this connection was to diminish Ukraine's reliance on Russia. Additionally, the project aimed to lower Ukrainian power production costs by exerting competitive pressure on domestic electricity producers.

5.2.2. Technical Difficulties

Synchronising two grids in such a brief timeframe required overcoming major technical challenges. The groundwork laid in anticipation of this synchronisation, particularly the pre-existing interconnections with the Burshtyn Power Island, facilitated the completion of two key tasks by March 2022: first, proving the stability of the Ukrainian power grid through islanding tests[110], and the management of so-called interregional frequency deviations (that may require building new infrastructure[111]) (GET, 2022).

5.2.3. Connexion Timeline

Following Russia's invasion of Ukraine on **24 February 2022**, the TSOs of Continental Europe received an urgent request from Ukrenergo for emergency synchronisation of the Ukrainian power system, including Burshtyn island, with the continental European power system. The Moldovan TSO followed shortly afterwards. The Ukrainian grid was therefore disconnected from the IPS/UPS electricity system in **February 2022**[112] and the emergency synchronisation was completed on **16 March 2022** (ENTSO-E, 2023). Ukraine started commercial electricity exports to EU countries in **June 2022**, but in **October 2022** Russian bombings started targeting Ukraine's power infrastructure resulting in a decision by Ukraine to stop power exports. Ukraine imported power from its neighbours in the middle of winter to compensate for losses incurred by Russian bombing, but by **April 2023,** Ukraine had re-established its ability to export electricity, albeit at a significantly lower level than in 2022. Additional imports occurred in the **summer of 2023** during maintenance procedures at nuclear power plants. These commercial exchanges are shown in Figure 80.

Since June 2022, the maximum exchange capacity was progressively raised from 400 MW (import and export) to **1,700 MW**. This development included the following steps:

- On **March 2023**, the import capacity from the EU to Ukraine was raised from 700 MW to 850 MW. However, the maximum export capacity was left at 400 MW.
- On 20 June 2023, capacity was raised to 1,200 MW.

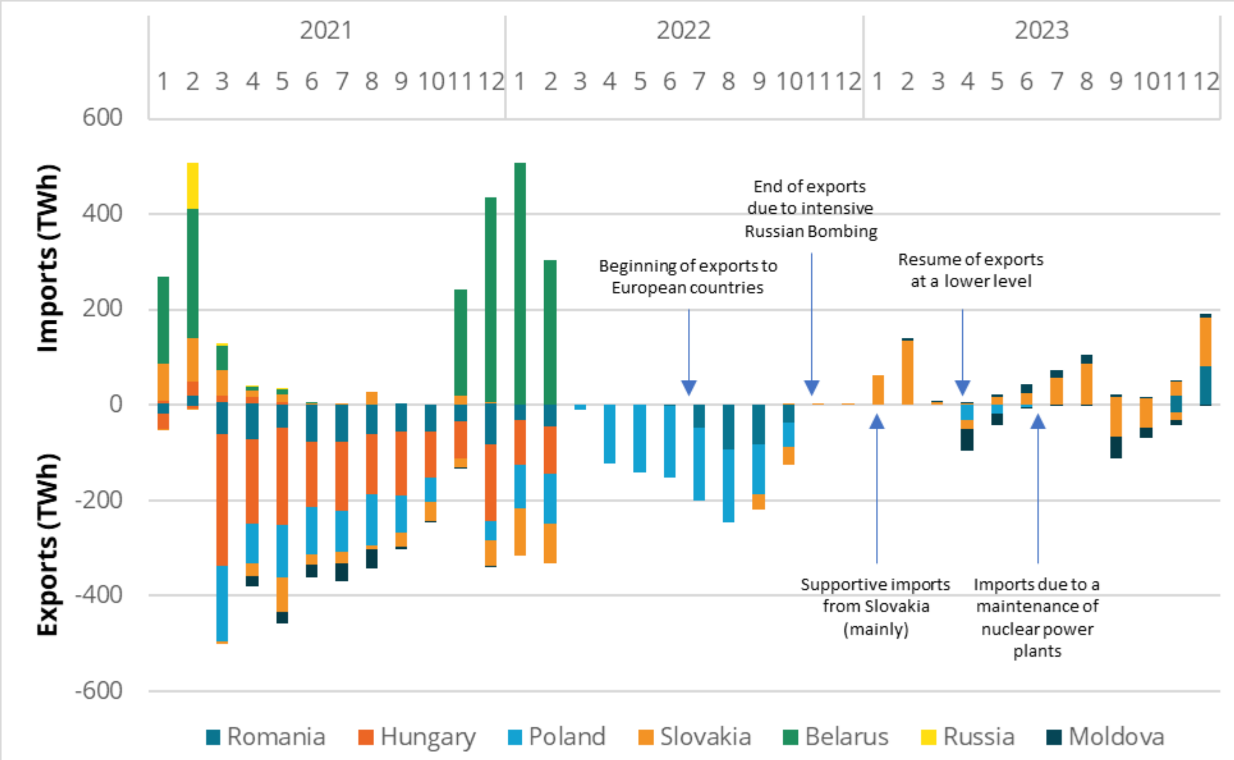
110 Those tests had been made just before the invasion of Ukraine.

111 Including Static synchronous compensator (STATCOM), Modular Static Synchronous Series Compensator (M-SSSC), and batteries.

112 The disconnection was actually an exercise in the context of a stress test that happened hours before the actual Russian invasion. The connection was never reinstalled according to Gavin, G., 'Sick of EU red tape? Bring your green money here, Ukraine says', *Politico*, 12.03.2024. Available at: https://www.politico.eu/article/inside-ukraine-plan-to-electrify-europe-green-energy-electricity/.

- In **November 2023**, the permanent synchronisation of Ukraine to the European power grid was officially achieved. The cross-border capacity was raised to 1,700 MW.

Figure 80: Commercial exchanges between Ukraine and neighbouring countries



Source: ENTSO-E, Enerdata's analysis.

Note: The pre-2022 exchanges were made with the Burshtyn Power Island.

5.3. Impact of the Synchronisation to the European Energy System

5.3.1. Current Impact

The synchronisation with Ukraine was not meant to be a one-way exchange flowing from the European Union towards Ukraine. Pre-war Ukraine had an installed capacity comparable with Poland's, and this could have been an opportunity for Poland and other neighbouring countries to partly decarbonise their electricity production with Ukrainian nuclear-based electricity imports.

Shortly after March 2022, no impact of the synchronisation was seen on the European side[113]. However, **Ukraine has suffered heavy damages to its energy system**. During the winters of 2022 and 2023, Russia heavily targeted Ukraine's energy infrastructure; by February 2023, half of it was either destroyed or occupied. 12.5 million residential consumers (30% of the population) and 400,000 commercial consumers did not have access to power for up to 10 hours a day[114]. This strategy allowed Russia to put

[113] A June 2022 analysis looking at the impact of the synchronisation on grid frequency and cross-border flows and concludes that only insignificant changes can be observed. Böttcher, P. C. et al, "Initial analysis of the impact of the Ukrainian power grid synchronization with Continental Europe", *Energy Advances*, 2/2023; available at: https://pubs.rsc.org/en/content/articlelanding/2023/YA/D2YA00150K.

[114] Evaluation published in Energy Charter Report *Ukrainian energy sector evaluation and damage assessment*, February 2023. Available at: https://www.energycharter.org/fileadmin/DocumentsMedia/Occasional/2023_05_24_UA_sectoral_evaluation_and_damage_assessment_Version_X_final.pdf. This evaluation likely underestimated the damage as there is no complete information on Ukrainian facilities located in the temporarily occupied territories.

civilians under pressure and prevented Ukraine from exporting electricity to the EU (Foreign Policy Research Institute, 2023). Additional heavy damages to energy facilities were caused in spring 2024[115].

Despite this strategy, **Ukraine managed to export 1.4 TWh of electricity** at market prices on day-ahead markets since March 2022[116]. While these exports are modest compared to its pre-war exchanges and to other European countries', it brings substantial economic value to Ukraine, market prices being significantly higher in the EU than the cost of production in Ukraine. Most of these exports occurred between June and October 2022; sales during these months totalled €130 Million (Foreign Policy Research Institute, 2023).

5.3.2. Future Impact

In the **short-term**, Ukraine is focused on the war and on the well-being of its population. Ukraine's Ministry of Energy was tasked in mid-2023 with restoring up to 2.9 GW in power capacity by the end of 2023 in anticipation of the winter of 2023-2024. The EU and other allies, including the US, brought financial support, mainly through the Ukraine Energy Support Fund set up by the Energy Community Secretariat. In 2023, this fund concluded supply contracts valued at around €130 Million for essential equipment, materials, and services[117].

The short-term impact of Ukraine's synchronisation to the EU's energy system is thus limited but beneficial to the EU and to Ukraine. ENTSO-E did not note significant challenges linked to this synchronisation, which is a positive sign given that the Baltic states signed an agreement in August 2023 to synchronise with the European grid by 2025[118]. In its Winter Outlook 2023-2024[119], ENTSO-E considered that both Ukraine and Moldova are both integral part of the European Power System. It anticipated minimal risk to the Ukrainian system during the winter of 2023-2024, highlighting the possibility of augmented electricity imports should substantial damage occur to generation apparatus and grid infrastructure. Nevertheless, the outlook for Moldova, as presented in the same report, is less optimistic. The country grapples with a significant reliance on gas, uncertain imports from Ukraine, a fragile interconnection with Romania, and a heavy dependency on a singular power source. However, the associated risk concerns Moldova and not the European Union. The ongoing construction of the 400kV Vulcanesti-Chisinau power line would be a key contributor to Moldova security of supply.

In the **long-term**, the future energy balance between Ukraine and the EU is unclear but will likely result in Ukraine becoming an important contributor to the EU energy system. According to a report released by the United Nations Development Program, **Kyiv plans to reach at least 9 TWh of net exports** (compared to 3.5 TWh in 2021) and produce 176 TWh of electricity annually (vs. 113.5 TWh in 2022). However, no specific date for these targets has been set (UNDP, 2023). These exports would be equivalent to 15% of Ukraine's European neighbours' total imports in 2022, representing significant contributions to their power mixes.

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[115] Ministry of Energy of Ukraine, 15 April 2024, *Supporting the energy sector and strengthening energy system resilience: German Galushchenko meets with European Commissioner Kadri Simson*; https://www.kmu.gov.ua/en/news/dopomoha-enerhosektoru-ta-posylennia-stiikosti-enerhosystemy-zustrich-hermana-halushchenka-i-ievrokomisara-kadri-simson.

[116] A communication by the Ukrainian Ministry of Energy in October 2022 mentioned a total exported capacity to EU countries of 2.6 TWh between June 2022 and October 2022.

[117] More information: Derewenda, F., 'Ukraine Energy Support Fund contracts €129 million in 2023', CEEnergy News, 15.01.2024; available at: https://ceenergynews.com/finance/ukraine-energy-support-fund-contracts-eur-129-million-in-2023/#:~:text=The%20Ukraine%20Energy%20Support%20Fund%20was%20set%20up%20by%20the,support%20to%20Ukraine's%20energy%20sector.

[118] See the European Commission declaration at https://energy.ec.europa.eu/news/estonia-latvia-lithuania-agree-synchronise-their-electricity-grids-european-grid-early-2025-2023-08-03_en.

[119] Available at: https://www.sttinfo.fi/files/69819787/70057809/37263/fi.

To this end, in addition to a Memorandum of Understanding (MoU) signed in June 2023 associating Ukraine to the Connecting Europe Facility programme[120], Ukraine is actively pursuing bilateral agreements, particularly with Poland. As part of this effort, an antiquated transnational electricity line (dormant since 1992) connecting the Khmelnytskyi nuclear power plant to the Polish city of Rzeszow, was reinstated in April 2023 with an allowed trading capacity of 200 MW from Ukraine to Poland and 350 MW in the opposite direction.

Before the war Ukraine was also seen as a **potential source of green hydrogen** for Europe. As mentioned in Chapter 4, Ukraine was noted by Hydrogen Europe as an important potential exporter in 2020 as part of the 10 million tonnes of hydrogen that the EU expects to import by 2030. In 2021, an MoU on hydrogen collaboration was even signed between Germany and Ukraine on green hydrogen production[121].

While there is no discussion on starting a hydrogen export industry in the middle of a war, in April 2023 Ukraine signed an MoU with the EU resulting in a strategic partnership on "biomethane, hydrogen and other synthetic gases"[122]. In addition, in early 2023, following a meeting between the European Commission and the Prime Minister of Ukraine, Hydrogen Europe published a recovery plan[123] that included the **export of green ammonia,** and the use of **2 – 4 GW of nuclear power for hydrogen production,** with Germany being the preferred off-taker.

Ukraine is expected to become a long-term key contributor to the European energy system through the development of its nuclear infrastructure and the creation of a hydrogen export economy. It is likely**, that these future** projects will **not be built until after the war ends and the country is reconstructed**. In addition, Ukraine's existing nuclear infrastructure is aging; by 2040, thirteen out of its fifteen nuclear reactors will be out of commission. According to Energoatom's CEO Petro Kotin, Ukraine will need to launch the construction of fourteen new nuclear reactors before 2040 (Foreign Policy Research Institute, 2023).

120 Available at https://ec.europa.eu/commission/presscorner/detail/en/ip_23_3061.

121 This MoU was seen as a partial compensation for the possible launch of the Nord Stream 2 pipeline.

122 Available at https://energy.ec.europa.eu/system/files/2023-04/MoU_UA_signed.pdf.

123 'Timmermans Recovery Plan for Ukraine', Hydrogen Europe; available at: https://hydrogeneurope.eu/ukraines-timmermans-recovery-plan/.

6. CONCLUSION AND RECOMMENDATIONS

6.1. Conclusion

During the past decade, the European Union started transitioning to a clean and resilient energy system. There was a significant reduction in energy demand in line with the 2020 Energy Efficiency Directive (EED) objectives, and dependence on fossil fuel imports declined, while renewable energy capacity and production rapidly accelerated, particularly solar.

This study highlights key areas where the current energy infrastructure still requires substantial changes if the Fit for 55 package targets for 2030 and for the 2050 net-zero objective are to be achieved. These include the electrification of end-uses, deeper reductions in demand, more renewables (especially wind), the development of an integrated flexibility portfolio to limit and eventually end the use of fossil plants to manage peak demand and transforming the gas infrastructure to meet the requirements of a hydrogen and biomethane economy.

6.2. Recommendations

The following recommended actions are critical for achieving the Fit for 55 targets:

- Remove economic and regulatory barriers to renewable power development;
- Create and regularly update a bettered assessment of flexibility requirements at the Member State level;
- Remove barriers to self-consumption to optimise grid flexibility;
- Change remuneration models for grid operators;
- Plan for the partial decommissioning of the gas distribution and transmission network;
- Use biomethane development to limit the decommissioning of the gas distribution network; and
- Capitalise on the gas transmission network for the development of hydrogen but prioritise local production.

These recommendations do not address every facet of the energy system transition, rather they focus on pivotal aspects underscored in this study that directly influence critical elements of the EU's energy infrastructure.

6.2.1. Remove economic and regulatory barriers to renewable power development

This study highlights the pivotal roles solar and wind energy play in decarbonising the electricity sector. However, current installation rates fall short of the needed pace. Solar power development is in line with most "Stated Policies" scenarios analysed in Chapter 2 but the rate of wind power construction lags considerably behind expectations – a two- to three-fold increase is needed. Wind power is held back by multiple factors. First, the design of national auctions could be improved[124]. That are often not indexed to inflation and focus on price criteria without offering protection against growing pressure

[124] Other issues from national auctions highlighted in the Wind Power Action plan are the absence of non-price criteria in most Member States, the lack of sufficient penalties for non-execution of projects and the heterogeneity in the design of auctions.

from Chinese competitors[125]. In addition, WindEurope mentioned[126] that 70% of all auctions issued in 2023 used uncapped negative bidding, a type of bidding that is costly for developers. In Germany, for instance, none of the large projects awarded under their uncapped negative bidding auctions in 2023 has reached a final investment decision so far. Secondly, wind projects suffer from complex and long permitting procedures resulting in growing connection queues. Implementing elements of the Wind Power Action Plan, highlighted by the European Commission in November 2023, would help address barriers to further increasing wind power. These elements include the **accelerated implementation of the revised RED on wind permitting** through **digitalisation of permitting processes**, **updated recommendations for Member States** and **potentially extending the ongoing temporary emergency regime**[127]; **increased visibility of upcoming tenders** through **mid-term auction schedules** and **better harmonisation of tenders** across Member States; the mandatory **inclusion of non-price criteria in upcoming national auctions**, including penalty clauses for the non-execution of projects, and price indexation to inflation.

Solar power development would be better encouraged if connection queues were shorter. Over two-thirds of PV installations are small to medium in scale; **it is important for distribution network operators and regulatory authorities to streamline permitting procedures for solar projects and ensure more effective distribution grid planning** in the short and medium term. In the short term, **streamlining requires ensuring easy availability of necessary documentation to permit applicants**, **and that the complexity of permitting procedures be proportional to installation size**, reducing administrative burdens for both applicants and authorities. In the medium term, reducing this administrative burden can be helped by better and more integrated development plans. While DSOs now have an obligation to publish biennial 5-to-10-year National Development Plants, **better coordination at the EU level (data sharing, best practices, guidelines, and specific trainings) would help DSOs, especially the smaller ones, to anticipate their needs for resources, especially in terms of staff and expertise**.

6.2.2. Create and regularly update a bettered assessment of flexibility requirements at the Member State level

Policy makers should consider more than one solution to upcoming decentralised electricity integration issues. Providing cost-efficient grid flexibility requires a portfolio of technologies and methods that constantly evolve technically and economically. This portfolio has three elements: the advancement of the grid, the establishment of storage capacity, and enhanced management of demand load profiles.

A large share of Member States lack a clear view on how to economically use flexibility assets in their future power mixes. The **requirement of the Regulation on electricity market design**[128] **for the regulatory authorities in each Member State to assess and draw up every two years a report on the need for flexibility in the electricity system** for a period of at least five to ten years, is a good step in this direction. Due to the evolving technological environment, particularly for long-term storage, the

[125] Between 2021 and 2022, as large European wind turbine manufacturers including Vestas, Siemens Gamesa, Nordex/Acciona all reduced their take-in orders, Chinese manufacturers grew and now represent 66% of the global take-in orders, compared to 46% in 2021. https://d1owejb4br3l12.cloudfront.net/publications/executive-briefing/wind-turbines-manufacturers-market-share.pdf.

[126] According to Tedesco, E., 'Europe to triple offshore wind auctions this year – lobby', MONTEL News, 18.01.2024; available at: https://montelnews.com/news/1535575/europe-to-triple-offshore-wind-auctions-in-2024-lobby.

[127] This regime voted in 2022 entered into force in January 2023 for a period of 18 months. It is meant to streamline and accelerate the permitting of renewable energy installations and infrastructure in the EU.

[128] See article 19e on Assessment of flexibility needs: https://oeil.secure.europarl.europa.eu/oeil/popups/ficheprocedure.do?reference=2023/0077A(COD)&l=en.

optimal flexibility mix for 2050 cannot be fully determined today. Thus, **requiring Member States to update flexibility needs every two years is a good idea**, **but should be complemented with continuous consultation of National Regulatory Authorities**, similarly to what is done at the EU level in the TYNDP.

6.2.3. Remove barriers to self-consumption to optimise grid flexibility

Self-consumption is an effective and low-cost demand management solution for better integration of rooftop solar power into the electrical system. There are two main barriers to this. There is a political barrier in remaining net-metering tariffs, which discourage the optimisation of prosumers' self-consumption rates. Net-metering tariffs pay the asset owner the same price for electricity that is self-consumed and injected into the grid. **Replacing net-metering tariffs with net-billing tariffs in which the injected electricity is paid for at lower market prices would encourage asset owners to self-consume more energy and limit the impact of distributed assets on the distribution grid.**

The second barrier is informational and economic in nature: the uptake of Home Storage Systems and Home Energy Management Systems and flexible loads, such as heat pumps, needs further encouragement. Behind the meter batteries are valuable flexibility assets. Home Energy Management Systems can be used to facilitate the optimal use of distributed solar, batteries, and flexible loads for both consumers and the grid. But many consumers lack the information and financial resources to buy, install, and effectively manage these assets. **There should be more information campaigns and financial incentives targeting consumers that encourage the uptake of batteries, Home Energy Management Systems, and flexible loads. Self-consumption rates would hence be further optimised for both prosumers and society.**

6.2.4. Change remuneration models for grid operators

To improve grid infrastructure, in addition to the planned development of cross-border capacities and transmission lines, an important topic to further investigate is the remuneration model for grid operators. **Shifting from a CAPEX-based remuneration model to an OPEX-based one would encourage flexible solutions and reduce overall investment needs.** Today's grid operators have more incentives to approve the installation of more equipment (power lines, transformers, etc.) to adopt flexible solutions to better manage existing assets. Among these solutions, the possibility to provide flexible connections to renewable assets[129] and the digitalisation of the prosumer loads[130] are key topics that should be further investigated. This is one of the key changes needed, that is mentioned in the European Commission's Action Plan for Grids, which was released in November 2023.

6.2.5. Plan for the partial decommissioning of the gas distribution and transmission network

All scenarios analysed in Chapter 3 project a significant decrease in natural gas consumption. Decarbonising the existing network is possible only with significantly lower gas demand and much higher demand for renewable gases, namely biomethane and hydrogen. Effectively managing what

[129] In this case, a new solar or wind power plant could be connected to the grid using the existing infrastructure with a required maximum injected capacity. This would allow for a fast integration of the power plant into the grid while still allowing for a strengthening of the infrastructure in the longer term.

[130] Digitalisation of prosumer loads can be done through a better use of smart meters and inverter data to forecast the expected demand and injection of those customers as well as adding remote control possibilities with inverters including curtailment possibilities for distributed power plants.

needs to be done with the existing 200,000 km gas transportation pipelines and the associated distribution infrastructure is crucial for a cost-efficient transition minimising stranded assets.

While renewable gases can benefit from the existing infrastructure, part of the transmission and distribution gas network will have to be decommissioned by 2050. Otherwise, fixed infrastructure prices will be too high compared to the number of remaining customers to offer attractive retail prices. The investment not spent in infrastructure improvements could help finance the rest of the energy transition.

To this end, **in their development plans, TSOs and DSOs need to better account for sections of the existing grid that should be decommissioned.** The recast Directive on common rules for the internal markets for renewable gas, natural gas and hydrogen can be an effective legislative lever to this end[131].

6.2.6. Use biomethane development to limit the decommissioning of the gas distribution network

The distribution infrastructure would benefit from the development of biomethane injections. While the EU target for total injected volume increases by ten-fold in the coming decade, the biomethane market today is concentrated in a small number of countries, while biomass resources are more distributed. **Member States should look at countries where the market is now concentrated, including France and Germany, in creating national biomethane strategies that must be implemented in their updated NECPs**. Further guidance on this could be provided by the European Parliament and the Commission.

6.2.7. Capitalise on the gas transmission network for the development of hydrogen but prioritise local production

The hydrogen industry expects the current gas transport infrastructure to make up an important part of the future hydrogen infrastructure. Sixty percent of hydrogen transport capacity by 2030 is expected to be repurposed gas pipelines. While the future hydrogen network is linked to large volumes of imports, **the short-term focus should be on national transmission pipelines from centralised hydrogen production facilities to large industrial consumers**. There are two main reasons for this: first, REPowerEU targets for hydrogen demand are extremely ambitious compared to the pipeline of projects and might not be met, in which case prioritising local production would be more relevant to achieving EU energy independence; second, targeted hydrogen exporting countries (e.g., MENA countries, Ukraine, Norway) have not built their hydrogen production industries yet and the EU would become reliant on their political decisions. In addition, **transmission needs should be regularly reassessed and revised.** Finally, **hydrogen blending into the distribution network is a limited solution and should be considered very cautiously until the technology is proven.**

[131] See gas and hydrogen markets directive (common rules) at: https://oeil.secure.europarl.europa.eu/oeil/popups/ficheprocedure.do?reference=2021/0425(COD)&l=en.

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ANNEX 1

Country Codes

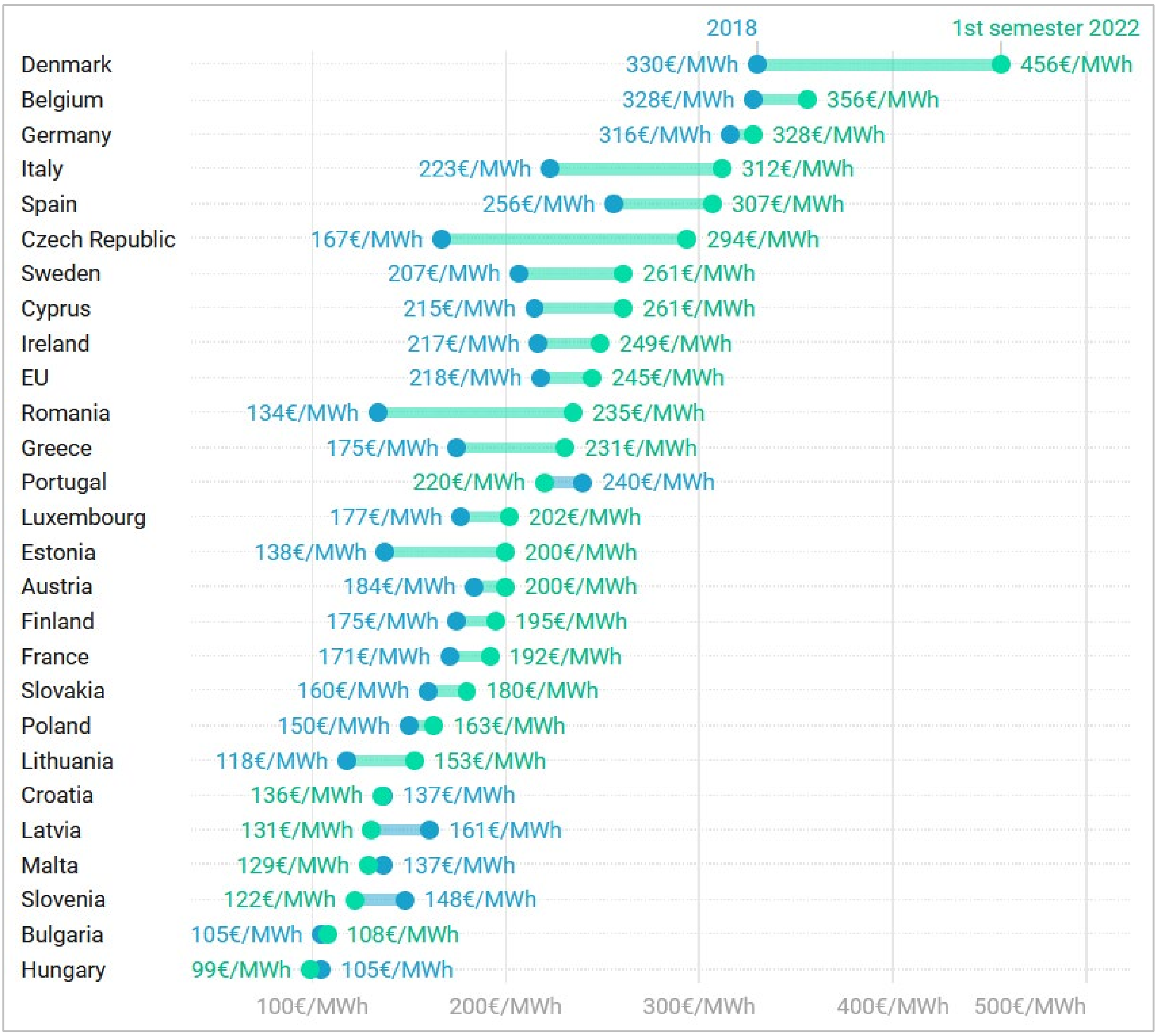
Country	Acronym	Country	Acronym	Country	Acronym
Austria	AT	Germany	DE	Norway	NO
Belarus	BY	Greece	GR	Poland	PL
Belgium	BE	Hungary	HU	Portugal	PT
Bulgaria	BG	Ireland	IE	Romania	RO
Croatia	HR	Italy	IT	Russia	RU
Cyprus	CY	Latvia	LV	Slovakia	SK
Czechia	CZ	Lithuania	LT	Slovenia	SI
Denmark	DK	Luxembourg	LU	Spain	ES
Estonia	EE	Malta	MT	Sweden	SE
Finland	FI	Moldova	MD	Ukraine	UA
France	FR	Netherlands	NL		

ANNEX 2: ENERGY RETAIL PRICES

Electricity Prices

a. Household electricity prices

Figure 81: Change in EU household electricity retail prices between 2018 and 2022



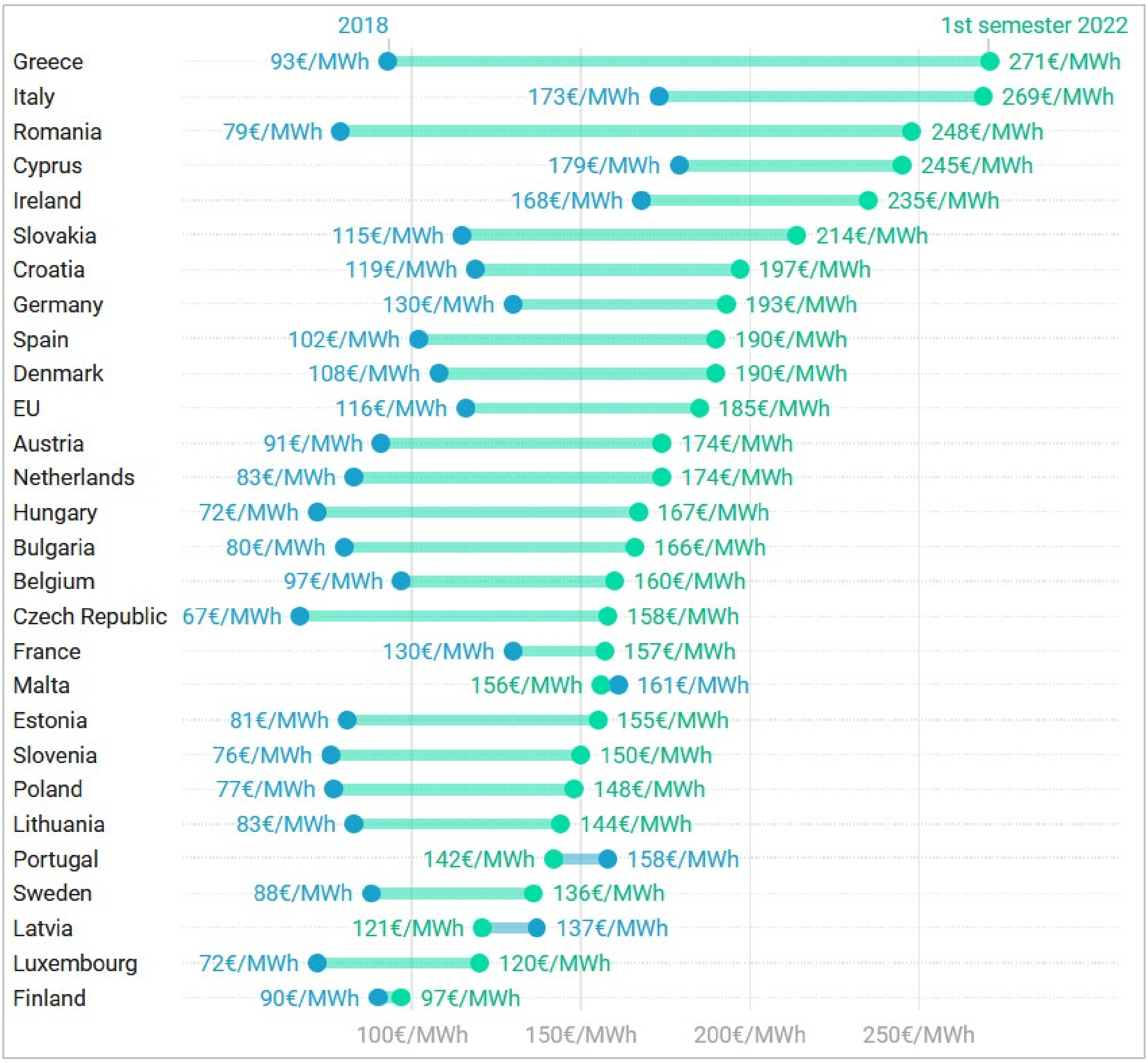
Source: Enerdata's analysis based on Eurostat data.

Note: Average retail electricity prices per kWh for customer having a consumption between 2.5 and 5 MWh (most common).

b. Industrial electricity prices

This section covers prices paid by non-household electricity consumers in EU Member States. It focuses on prices of the Eurostat band ID, covering annual consumption of 2000 to 20,000 MWh. This band is considered representative of mid-size businesses across various sectors.

Figure 82: Change in EU industrial electricity retail prices between 2018 and 2022



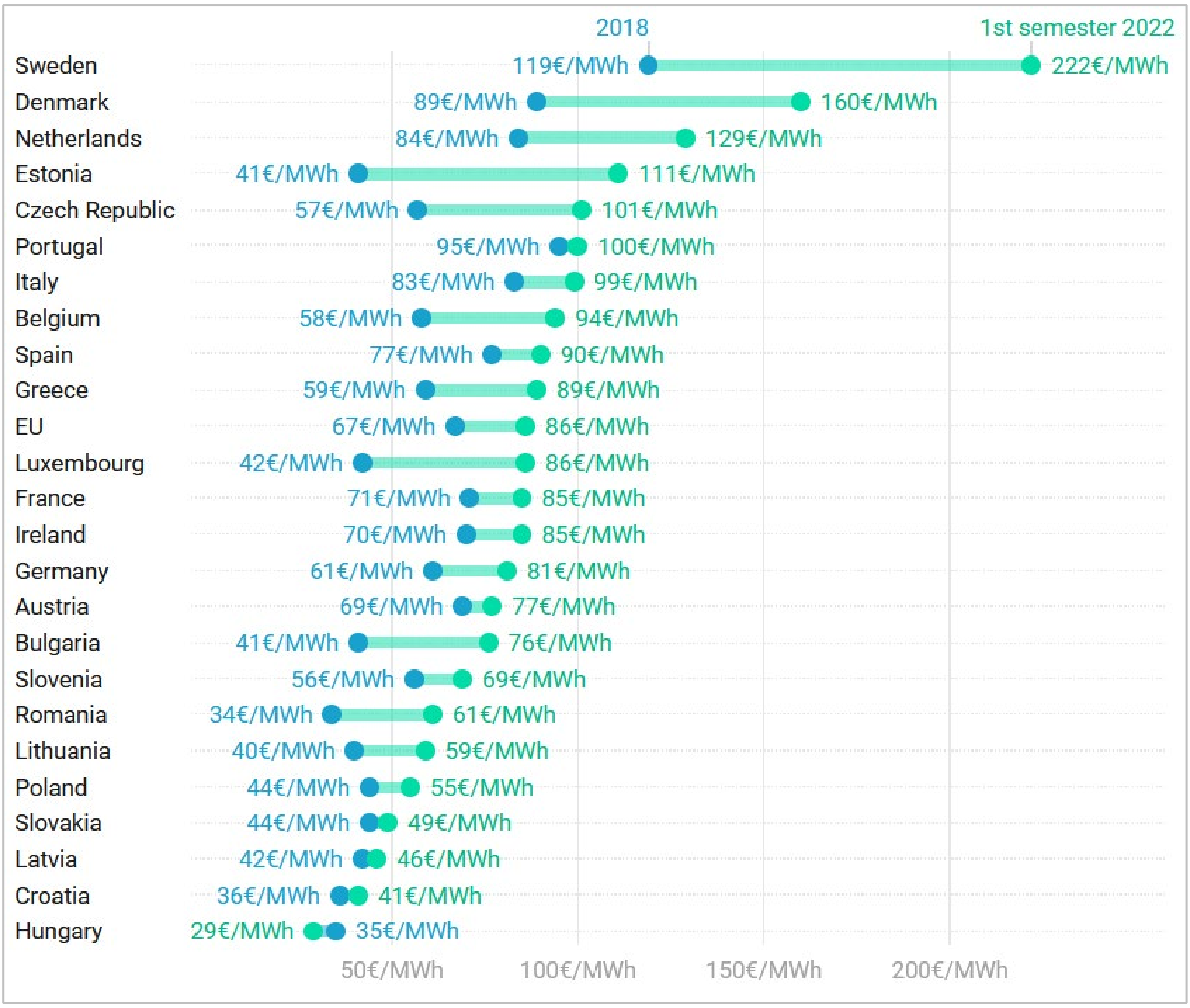
Source: Enerdata's analysis based on Eurostat data.

Natural Gas Prices

a. Household natural gas prices

This section covers gas prices paid by household consumers whose annual consumption falls in the range of 20 to 200 GJ. This consumption band is defined by Eurostat as D2. It is the most representative consumption band in most of the EU countries.

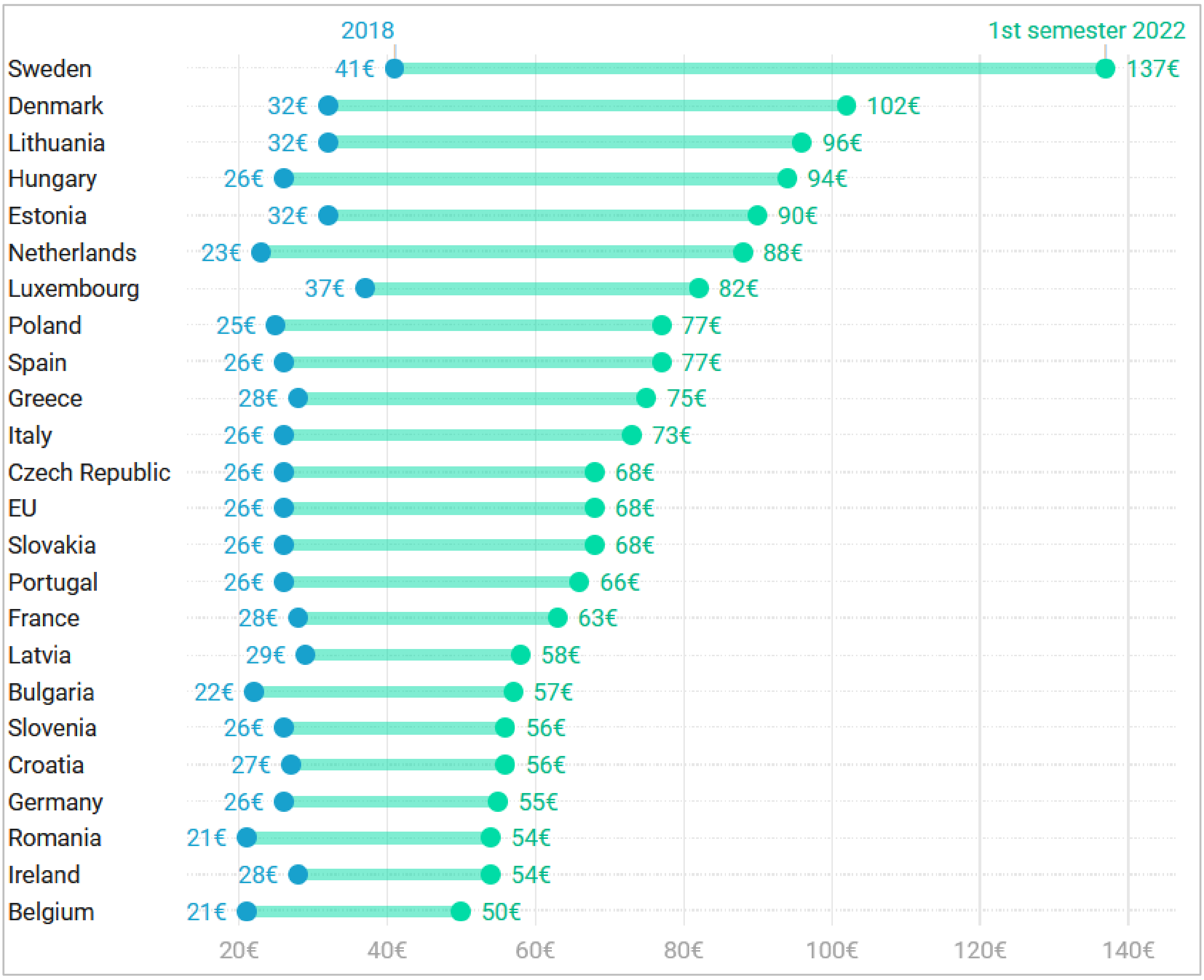
Figure 83: Changes in EU household gas retail prices between 2018 and 2022



Source: Enerdata's analysis based on Eurostat data.

b. Industrial natural gas prices

Figure 84: Change in EU industrial gas retail prices between 2018 and 2022



Source: Enerdata's analysis based on Eurostat data.

This study analyses the present and future of the European electricity and gas infrastructure, exploring production capacity scenarios and their impact on the electricity system (including the role of interconnections, transmission and distribution grids, prosumers, and storage). It also assesses the potential impact of renewable hydrogen development in terms of production and transport. Furthermore, it discusses Ukraine's synchronisation with the EU power grid and its potential impact on the EU energy system.

This document was provided by the Policy Department for Economic, Scientific and Quality of Life Policies at the request of the committee on Industry, Research and Energy (ITRE).

PE 754.207
IP/A/ITRE/2023-04

Print ISBN 978-92-848-1820-4 | doi:10.2861/919970 | QA-09-24-265-EN-C
PDF ISBN 978-92-848-1819-8 | doi:10.2861/214168 | QA-09-24-265-EN-N