Investment needs of European energy infrastructure to enable a decarbonised economy

Final report

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E-mail: ENER-C4-PROJECTS@ec.europa.eu

European Commission
B-1049 Brussels

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Authors

Andrea Finesso (Trinomics)
Anna Kralli (Trinomics)
Csinszka Bene (Trinomics)
Finn Goodall (Trinomics)
Hans Bolscher (Trinomics)
Jeroen van der Laan (Trinomics)
Lenka Volkova (Trinomics)
Mohammad Ansarin (Trinomics)
Timo van Delzen (Trinomics)

Christopher Andrey (Artelys)
Gregoire de Jerphanion (Artelys)
Ouili Nana (Artelys)

Alexandra Ullmann (LBST)
Evi Pschorr (LBST)
Jan Zerhusen (LBST)
Leo Diehl (LBST)
Maximilian Kellner (LBST)

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Abbreviations

Abbreviation	Definition
AC	Alternative Current
ACER	Agency for the Cooperation of Energy Regulators
BEMIP	Baltic Energy Market Interconnection Plan
BESS	Battery Energy Storage System
CAES	Compressed Air Energy Storage
CAPEX	Capital Expenditure
CCS	Carbon Capture and Storage
CCUS	Carbon Capture, Utilization and Storage
CEF	Connection Europe Facility
CSRD	Corporate Sustainability Reporting Directive
DC	Direct Current
DNDP	Distribution Network Development Plan
DNSH	Do No Significant Harm
DSO	Distribution System Operator
EHB	European Hydrogen Backbone
EIB	European Investment Bank
ENTSO-E	European Network of Transmission System Operators for Electricity
ENTSOG	European Network of Transmission System Operators for Gas
ERDF	European Regional Development Fund
ESG	Environmental, Social and Governance
ETS	Emission Trading System
EU-27	27 Member States of the European Union
EV	Electric Vehicles
FID	Final Investment Decision
GA	Global Ambition
GAR	Green Asset Ratio
GHG	Greenhouse Gas
GNI	Gross National Income
HVDC	High-Voltage Direct Current
IEA	International Energy Agency
IF	Innovation Fund
IPCEI	Important Project of Common European Interest
JASPERS	Joint Assistance to Support Projects in European Regions
JTF	Just Transition Fund
LH_2	Liquid Hydrogen
LHV	Lower Heating Value
LNG	Liquefied Natural Gas
LOHC	Liquid Organic Hydrogen Carrier
MaxFND	Maximum Financing Need Dataset
MF	Modernisation Fund
MFF	Multiannual Financial Framework
MinFND	Minimum Financing Need Dataset
NACE	Nomenclature of Economic Activities
NDP	Network Development Plan
NRA	National Regulatory Agency
OECD	Organisation for Economic Co-operation and Development
ONDP	Offshore Network Development Plan
OPEX	Operational Expenditure
PCI	Project of Common Interest
PHS	Pumped Hydro Storage

PMI	Project of Mutual Interest
PV	Photovoltaic
RAB	Regulatory Asset Base
RES	Renewable Energy Sources
RRF	Recovery and Resilience Facility
SC	Substantial Contribution
SFDR	Sustainable Finance Disclosure Regulation
T&D	Transmission and Distribution
TEN-E	Trans-European Networks for Energy
TSC	Technical Screening Criteria
TSO	Transmission System Operator
TYNDP	Ten-Year Network Development Plan
UHS	Underground Hydrogen Storage

Executive Summary

The aim of this project is to identify the investment requirements for energy infrastructure across each TEN-E infrastructure category, as well as for non-TEN-E electricity transmission and distribution infrastructure, in order to enable a decarbonised economy in the EU. It also evaluates the need for EU financial support and explores possible forms of EU funding to address the identified needs within the scope of this study's assessment.

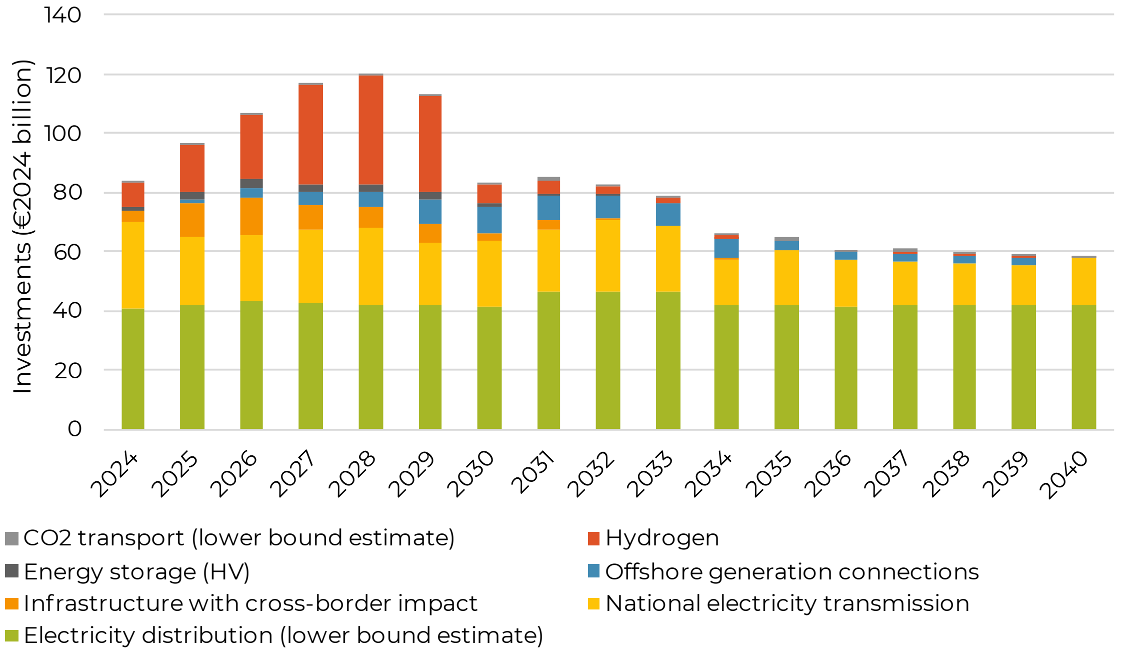
The analysis revealed that the **planned investment needs in EU's energy infrastructure are expected to grow significantly**, with the vast majority directed towards electricity infrastructure, especially at national level. More specifically, **electricity distribution dominates**, accounting for nearly half of the total investment needs (€730 billion) over the period 2024-2040 driven by the shift to renewable energy and electrification, which require extensive modernisation and expansion of networks. The largest part of the so-far planned investments is in North-Western Europe. However, there is limited availability of data on planned investments across several regions in Europe, with Central and Eastern Europe having the least data available, demonstrating only €12 billion of planned investments. **Transmission infrastructure also attracts considerable investment**, with over €472 billion of investment needs in the respective years, largely due to investments in national transmission infrastructure which constitute more than 70% of the investment needs. Nevertheless, around €130 billion is expected to be invested in cross-border projects, increased interconnections and offshore connections. Planned investments in transmission grids are primarily concentrated in the Central Western Europe (CWE) region[1]. **Hydrogen infrastructure also shows substantial investment needs, with planned investments amounting to almost €170 billion between 2024 and 2040.** The majority of those investments (€105.2 billion) are dedicated for hydrogen pipelines and are expected in the period 2024-2034. These investments correspond to 24,162 km of new pipelines and 14,039 km of repurposed pipelines. The other hydrogen categories have forecasted planned investments significantly lower, with storage amounting to €27 billion, import terminals to over €20 billion and electrolysers to €16.3 billion by 2040. Finally, according to the analysis and the current available data, **CO_2 transport and storage infrastructure is the infrastructure category that requires comparatively less investments,** ranging from €13.6 to €19.3 billion up to 2040, which are focused mainly on pipeline development, while this category has also the most uncertain future investment volumes.

We note that the timing of all these investments might change (peak later) due to many uncertainties and unknown future developments.

The analysis also showed that **the energy infrastructure investments are not equally distributed across the EU**, with Germany, France, and the Netherlands together accounting for 53% of total investments up to 2040. This might change over the years and could be partly a result of some Member States being further advanced in planning many years ahead for the energy transition and thus developing more infrastructural plans. Although not certain, other Member States might increase their planned investments at a later stage.

[1] CWE includes France, Germany, Belgium, the Netherlands and Luxembourg, excluding Switzerland for the scope of this study.

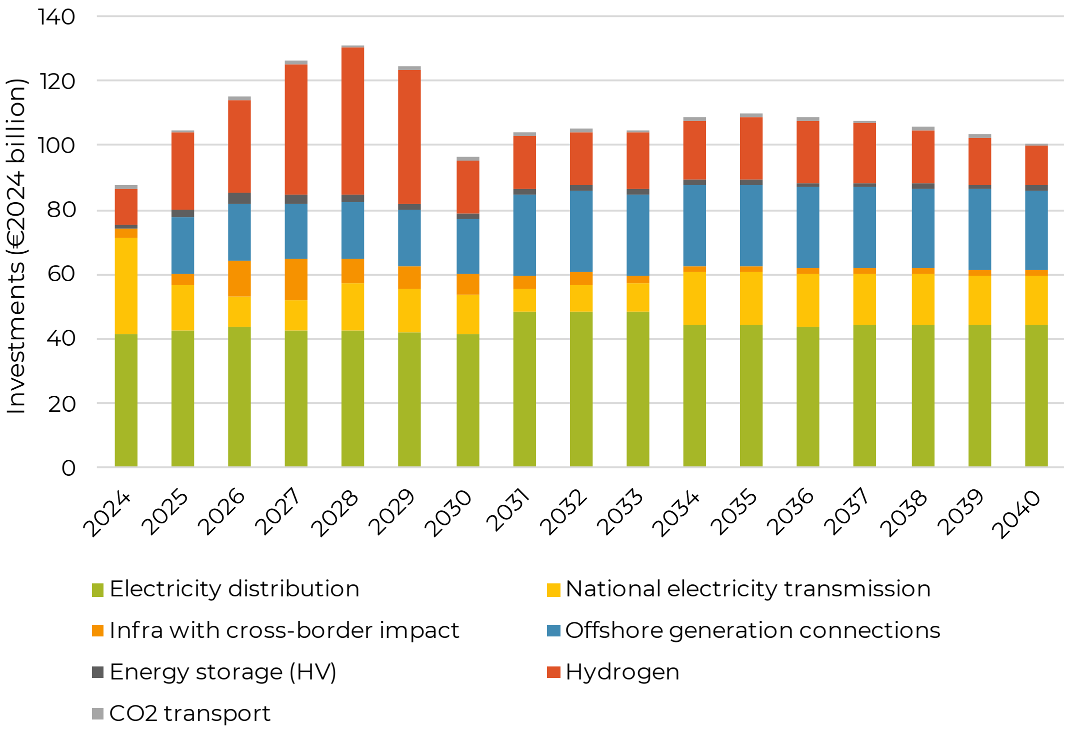
Figure 0-1 Planned investments between different infrastructure categories (2024-2040)



Note: regarding electricity distribution, for 13 Member States, investment data came from distribution NDPs, with some scaled to reflect the entire Member State. However, the coverage of these NDPs varies, with many lacking projections beyond 2032 and some only covering the early years of the forecast. For more information about the figure data please refer to Notes of Figure 2-2 in Chapter 2.

In addition to existing investment plans, additional investments are expected to be announced and developed over the coming years to meet investment needs. To estimate these investments vastly different methods per infrastructure category were used (which are described in the relevant sections of each infrastructure category and within Annex A.1). While these methods can sometimes conflict in assumptions and modelling choices, the results can give a rough estimate of the investment needs per infrastructure category over time.

Figure 0-2 Estimated investments in energy infrastructure



Notes: Estimated investments are a middle-ground estimation, in some cases an average based on upper-bound and lower-bound estimates. More details on methodology can be found in the section on each infrastructure category and in Annex A.1.

The estimated investments in the energy infrastructure in scope of this study tops in the late 2020s. This is due to the early expansion of hydrogen infrastructure, driven mainly by pipeline installations and cross-border projects. The majority of investments (79%) go towards electricity grids, including cross-border, offshore (radial and hybrid), national transmission, and distribution grids. A minority (about 20%) goes towards hydrogen infrastructure, including pipelines, import terminals, underground storage, electrolysers with a grid functionality, and installations for hydrogen use in transport. A very small amount (less than 1%) goes towards CO_2 transport infrastructure but here we also see the highest uncertainty on the outcome.

Comparing planned and estimated investment volumes shows us that these values are somewhat similar in early years but diverge more in later years. These differences are especially stark for some infrastructure categories, namely offshore generation connections and hydrogen infrastructure.

As the expected investment needs in the EU energy infrastructure are significant, the financing of all of these investments becomes an important question, with both public and private funding involved. Public funding, often provided through national governments, the European Commission (e.g., through EU programmes such as the Connecting Europe Facility for Energy, InvestEU, Horizon Europe, RRF, Modernisation Fund) and other EU institutions (e.g., the EIB), plays a pivotal role in de-risking large, capital-intensive projects, particularly those in early stages of development, high-risk technologies and cross border infrastructure. Public funds are also critical in areas with lower private investment attractiveness, such as cross-border interconnections, where profitability may be more uncertain.

The risk and maturity assessment of the in-scope energy infrastructure categories provided an indication on those that are in need for EU funding, as shown in Table 0-1. The overall risk assessment is derived from individual assessments of key risks associated with each energy infrastructure, namely technical and operational, financial viability, regulatory and political, and track record. Each risk type was assessed based on consistently applied criteria further elaborated on in Section 3.3. A summary description of the risk levels is provided in Table 3-8.

The "type of possible EU funding support" column categorises funding needs based on the necessity for additional public funding (EU or national) to ensure the energy infrastructure business model is feasible. Infrastructure classified as requiring "Limited EU/national support" typically operates through regulated returns and generally does not require additional public funding. However, this is not always the case, as the need for support can vary based on context-specific factors and future CAPEX requirements, which may occasionally necessitate additional public or EU funding. "National funding support" applies to infrastructure where costs can be adequately met through state aid, user-based tariffs, or local mechanisms, without requiring EU-level intervention. In contrast, "EU support" is assigned to infrastructure where national support alone is likely to be insufficient, necessitating EU-level funding or support mechanisms to address significant financial risks, private financing gaps, or economic disparities across Member States. This categorisation considers factors such as regulated versus non-regulated asset status, ownership models, financing structures (on-balance sheet vs. off-balance sheet), and variations in Weighted Average Cost of Capital (WACC) among Member States. We note that not all factors considered here automatically align with the framework of EU funding instruments, where for example regulatory frameworks on assets are more relevant than ownership models. The connection between risk levels and funding needs was further refined through literature review and expert insights from financial and energy domains.

Table 0-1 Overview of risk assessment and possible EU funding support per energy infrastructure category

Energy infrastructure category	Risk assessment	Type of possible funding support and other notes
Electricity transmission infrastructure	Low/ Medium	Typically financed via regulated returns, with EU financial support considered in specific circumstances, such as mitigating socially unfeasible tariff increases
Electricity distribution infrastructure	Low/ Medium	Typically financed via regulated returns, with EU support playing a role where tariff increases to end users are socially unfeasible
Electricity transmission lines with significant cross-border impact infrastructure	Medium/ High	Possible national and EU support, notably accounting for the positive externalities and EU added value
Electricity transmission lines related to offshore generation	Medium/ High	Possible national and EU support
Electricity storage directly connected to high voltage transmission and distribution lines	Medium	Possible national and EU support
Hydrogen pipelines	High	Possible national and EU support

Import terminals	High	Mainly private financing
Installations for hydrogen use in transport sector	High	Mainly private financing
Electrolyser facilities	High	Private financing, possible national and EU support
Underground hydrogen storage	High	Possible national and EU support
CO_2 transport and storage infrastructure	Medium/High*	Private financing and possible EU support

* Future projects, following first-mover high-risk projects in the coming years, may have a lower risk assessment.

Drawing on insights from existing EC support programmes within and beyond the MFF, as well as practices from major European and national banks and budgetary support programs, the following actions could improve the financial instruments and support the expansion of energy infrastructure in scope.

Figure 0-3 Conclusions of financial support schemes for the various energy infrastructure categories

Conclusion 1
Expand and develop additional guarantee schemes

Conclusion 2
Increase EU funding for energy infrastructure in scope

Conclusion 3
Continue to support regulatory measures to de-risk energy infrastructure investment

Conclusion 4
Blended finance for high-CAPEX and/or high-risk projects

Conclusion 5
Issuance of green bonds by EU Member States/public authorities

Conclusion 6
Revise state-aid rules to support an enabling environment for energy infrastructure development across MS

Our analysis of the financing needs per type of support for the in-scope infrastructure categories showed that **EU financial support will be significantly important especially in the newer technologies and the cross-border activities**, where the developments are (much) harder to predict. These are the cases for electricity transmission with significant cross border impact, offshore electricity infrastructure, hydrogen, and CO_2 transport and storage infrastructure. The volume of needed support depends on various factors such as the time period of the investment, the type of ownership of infrastructure (e.g., public, private), and the region. The type of financing support depends on the type of infrastructure and the country conditions, but generally it can be in the form of grants, EU-backed loans and guarantees or equity. Mechanisms similar especially to the Connecting Europe Facility for energy (CEF-E) for cross-border investments, and Modernisation Fund, Cohesion Fund, European Regional Development Fund, and Innovation Fund are expected to play an important role to the development of those types of energy infrastructure.

EU financial support can play a role in cases where the returns on infrastructure investments are regulated by national regulatory authorities (NRAs). For Transmission System Operators (TSOs) and Distribution System Operators (DSOs), financial returns on investments are often determined by national regulations, such as a fixed rate of return on regulated assets. These regulations strongly influence whether such investments are attractive or not. In some cases, additional financial support may be needed to reduce the cost burden on grid users, shifting the cost from households and businesses to taxpayers or another large group. This may become more relevant as TSO/DSO investments grow rapidly, potentially leading to higher grid tariffs. However, our analysis suggests that for some DSOs, rising investments can be matched by increasing demand, keeping tariff rates stable. On the other hand, for TSOs and some other DSOs, grid tariffs are more likely to rise, making EU support potentially valuable in limiting these increases and ensuring affordable grid access.

It is important to note that the assessment of EU funding support is uncertain. Both infrastructure costs and the attractiveness of investments for private finance can change considerably. Establishing the necessary revenue streams depends highly on EU-level and national-level policy in the coming years. Additionally, market conditions, such as interest rates, capital costs, project-and infrastructure-specific risks, can significantly influence the attractiveness of these investments. Therefore, the effect of EU funding depends on a combined approach of financial support, demand-stimulating policies, and favourable market developments.

1. Introduction

This project aims to identify the investment needs of energy infrastructure for each TEN-E infrastructure category and of non-TEN-E electricity transmission and distribution infrastructure, in order to enable a decarbonised economy in the EU. It also evaluates the need for EU financial support and explores possible forms of EU funding to address the identified needs in the scope of the assessment of this study.

Chapter 2 presents an overview of investments needs in energy infrastructure, primarily focusing on investments in the EU-27. Insights into neighbouring countries have been provided where available. The infrastructure categories considered in scope are (together with corresponding infrastructure categories of TEN-E Regulation Annexes) the following:

- **Electricity transmission infrastructure (non-TEN-E)** (i.e. national transmission infrastructure without a significant cross-border impact. Transmission lines connecting offshore generation are not included in this category as they are considered separately);
- **Electricity distribution system infrastructure (non-TEN-E)**;
- **Electricity transmission lines with a significant cross-border impact** - (inclusive of cross-border **smart electricity grids**), as per Annex II 1(a) and Annex II 1(e) of the TEN-E;
- **Electricity transmission lines related to offshore generation** (radial and hybrid connections), as per Annex II 1(b) and (f) of the TEN-E;
- **Electricity storage directly connected to high-voltage lines,** as per Annex II 1(c) of the TEN-E;
- **Smart gas grids,** as per Annex II 2 of the TEN-E;
- **Hydrogen infrastructure** (including **pipelines, underground storage, installations for hydrogen use in transport sector**, **import terminals, and electrolyser facilities), as per** Annex II 3 (a-e) and 4 of the TEN-E;
- **CO_2 transport and storage infrastructure;** as per Annex II 5 (a) of the TEN-E.

The categorisation of these technologies primarily follows the infrastructure categories specified in the TEN-E regulation's Annex II, with the addition of national transmission infrastructure and distribution system infrastructure. The categories have been slightly adjusted, and are based on how, in practice, investment needs and financing aspects align with infrastructure categories. The specific details on the scoping considered within each infrastructure category are included in the following sections.

Chapter 3 presents a review of EU funding available for energy infrastructure and how EU sustainable finance policy supports private investment. The chapter also includes an assessment of various financial instruments and support measures—such as grants, loans, guarantees, equity, and quasi-equity—to explore effective options for different energy infrastructure categories. Additionally, a financing narrative for each category is presented, focusing on risks, maturity levels, and financial challenges. The chapter includes conclusions on financial instruments.

Chapter 4 focuses on possible types of funding financing support by energy infrastructure category, taking into consideration various factors that impact the financing needs of each category.

Finally, in the Appendix **A – Annexes** the following sections are included:

1. Methodological notes: it details the methodology used to calculate investment needs for each infrastructure category, for example by detailing data sources and procedures, scoping of infrastructure, and currency conversions.

2. Survey: it includes an overview of the countries that we received NRA responses, along with the respective infrastructure categories that they provided information on.
3. Interview list: it includes an overview of the stakeholders that were consulted whose inputs were used in the analysis of Chapter 2 and 3.
4. Sources for 3.2 includes the literature review sources for Section 2.2 Relevant types of financial instruments and other forms of financial support.
5. Sources for Section 3.3 includes the literature review sources for Section 3.3 Financing narrative per energy infrastructure category.
6. Complementary forms of financial support and instruments (national budgetary schemes and the private sector): an overview of dedicated funding schemes that support energy infrastructure investments in four Member States, namely Denmark, France, Germany, and Slovakia, as well as an overview of financial institutions in the private sector that support relevant projects.

2. Investment needs of infrastructure categories (TEN-E & electricity non-cross-border transmission & distribution

This chapter provides an in-depth overview of the current status and future investment expectations for various categories of energy infrastructure in the European Union. In the electricity system, this covers national transmission and distribution infrastructure, cross-border infrastructure, infrastructure related to the transmission of offshore renewable energy, and energy storage directly connected to high-voltage lines. In addition, hydrogen infrastructure (namely pipelines, installations for hydrogen use in transport sector, import terminals, underground storage, and electrolysers with a significant impact on the grid) are considered. CO_2 infrastructure is also reviewed, primarily focusing on pipelines.

Through desk research, surveys and interviews, both the current state and anticipated developments for each infrastructure category have been analysed. Table 21 presents an overview of the approach and data sources used for each infrastructure category. The last two columns indicate inputs that will be developed further in this report (detailed further in next Chapter).

Table 2-1 Overview of analysis on the information related to different infrastructure categories[2]

Infrastructure category	Data sources	Data granularity	Planning horizon	How achievable are existing planned/committed investments?	How precise are estimated investments (after planning windows)?
Electricity transmission infrastructure	TSO network development plans, NRA and TSO surveys, interviews, Ember (2024), other national documents	Medium; up to 60% (based on investment volume) of planned investments substantiated by project-level data; otherwise MS-level data	Short-long (depending on MS)	Medium-high, depending on country. Commitments are generally bound by NDP regulations which differ significantly per MS.	Low – medium; highly dependent on the realism and planning window of each MS
Electricity distribution infrastructure	DSO network developme	Low; few based on project-level data, most based	Short-medium	Low to high, depending on region; commitments are on	Very low – medium, highly dependent on

[2] Smart gas grids was excluded from this table due to having no planned projects and very low and uncertain estimates of future investments. More details are provided in Section 2.1.6.

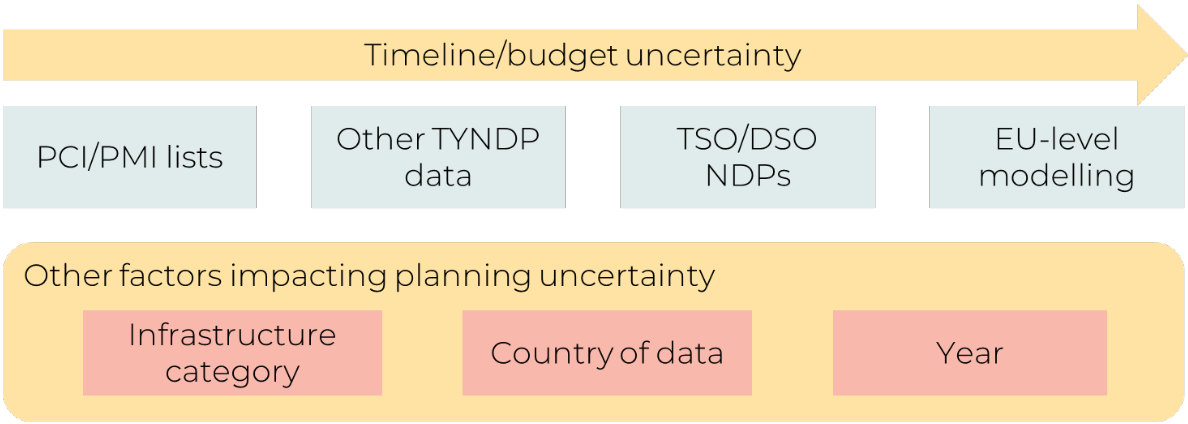
Infrastructure category	Data sources	Data granularity	Planning horizon	How achievable are existing planned/committed investments?	How precise are estimated investments (after planning windows)?
	nt plans, NRA and DSO surveys, interviews, other national documents	on country estimates based on sampling of DNDPs	(depending on MS)	average weaker in DSO NDPs compared to those of TSOs, and there is significant difference between MSs.	DSO availability; estimations also include planned investments of DSOs with missing data.
Electricity transmission lines with a significant cross-border impact	EU-wide project-level data (PCI/PMI lists), EU-wide top-down modelling (Ten Year Network Development Plan (TYNDP) scenarios, system needs study)	Medium-High, analysis includes both top-down modelling and project-based data	Medium-Long	High	Low-medium, top-down scenarios show significant variation in future capacity needs
Electricity infrastructure related to offshore wind generation	EU-wide project-level data (PCI/PMI list), ONDPs, top-down modelling	Medium-High	Medium-Long	Medium, project promoters report significant cost uncertainties	Low-medium, due to significant cost uncertainties
Electricity storage connected to high-voltage lines	EU-wide project-level data (PCI/PMI list, TYNDP projects lists)	High	Short	High	Low, although it is expected to be limited, the share of investments that will fall within TEN-E criteria is unclear.
H_2 pipelines	EU-wide (top-down) modelling, project-level data	High, project-level data to 2034 and EU-level estimates 2040	Long	Low, due to high uncertainty as to overall market ramp-up (policy driven), uncertainty particularly high regarding timeline (not necessarily regarding capacities)	Low-medium (specific costs accurate, but uncertainties on long-term vision from singular source)
System-serving Electrolysers	EU-wide (top-down) modelling,	High, project-level data to 2034 and EU-	Medium	See above	Low, due to high uncertainty on specific costs

Infrastructure category	Data sources	Data granularity	Planning horizon	How achievable are existing planned/committed investments?	How precise are estimated investments (after planning windows)?
(10.9 – 53 GW)	project-level data	level estimates 2040			
Import terminals	EU-wide (top-down) modelling, project-level data	High, project-level data to 2034 and EU-level estimates 2040	Long	See above	Low, due to high uncertainty on specific costs
Underground storage	EU-wide (top-down) modelling, project-level data	Medium-High, project-level data to 2039 and EU-level estimates 2040	Long	See above	Low, due to high uncertainty on specific costs
Installations for hydrogen use in transport sector	Internal estimations	Low (EU-level estimates)	Short	Very low, due to very high uncertainties in transport sector	Low, due to uncertainties as to needs
CO_2 transport and storage infrastructure	EU-wide (top-down) modelling from JRC (2024)	Low; analysis relies on EU-level estimates	Long	Unclear. No developed EU infrastructure plan and unclear amount of need for UK connections, plus unclear role of offshore versus onshore storage.	Low; No developed EU infrastructure plan and unclear amount of need for UK connections, plus unclear role of offshore versus onshore storage.

Our analysis uses multiple data sources with different levels of certainty with regard to project outcomes. We use PCI/PMI[3] project lists where possible – these projects have verified levels of certainty and reliable expectations regarding the project planning, expected investments, and timeline of outcomes, leading to a high degree of certainty with their investment plans. At the second level, (specifically for electricity) projects in the Ten-Year Network Development Plan (TYNDP) portfolio are generally taken to be at a higher priority and more likely to complete based on projected timelines and budgets. Third, planning within TSO National Development Plans (NDPs) have some level of commitment to being realised, and likewise (in general terms) for DSO NDPs. At the last stage of certainty, modelling exercises at the EU level for some infrastructure categories are primarily high-level calculations of what investments may be, given specific conditions, leading to less certain numbers for both timelines and budgets. This last option is more common for nascent infrastructure developments, such as hydrogen and CO_2 pipelines.

[3] Projects of Common Interest and Projects of Mutual Interest

Figure 2-1 Data sources and factors impacting uncertainty of infrastructure investments



The investment amounts reported for each infrastructure category are at different levels of certainty. On one end, TSO infrastructure investments planned for the short-term (i.e. for the next 1-3 years) are highly likely, and in some countries, form regulated commitments. DSO infrastructure investments are less certain, and depend more on the capabilities of DSOs and other project developers (including those of neighbouring DSOs and connecting TSOs) to progress with all stages of infrastructure development as planned. Electricity cross-border and offshore infrastructure investments, and some storage investments are also less certain, and depend to some extent on larger, sometimes international, plans, and may be subject to more uncertainty. Lastly, plans for hydrogen infrastructure and CO_2 infrastructure are far less certain, and represent "best estimates" based on scenario modelling rather than committed infrastructure investments in many cases. The particularities of certainty related to each infrastructure category differ and are discussed in detail within each sub-section further below.

The certainty for investment amounts may also differ per country/region. These differences are best known for TSO and DSO infrastructure investments, where overseeing regulatory schemes on network development activities can differ greatly per MS (and in some cases, per region within an MS), leading to far different levels of commitment required by TSOs/DSOs for the approval of network development plans.

Additionally, the certainty of investments differs per year for some infrastructure categories. Projects closer to the current time are more likely to proceed as planned and within budget, while those with a further timeline are less certain. For TSO and DSO infrastructure, network development plans are seen as commitments to develop infrastructure (to differing degrees of reliability, based on national and regional regulations and oversight). Projects beyond these planning windows are committed to a lesser degree and are more likely to face delays and cost overruns.

All aspects of infrastructure uncertainty differ significantly per infrastructure category. They are thus discussed in more detail within the discussion on each infrastructure category in later sections. We also detail how planned and estimated investments were calculated in Annex A.1.

Clarification note

Although we have based our assessments as much as possible on the best available data, there are two additional comments on the outcomes.

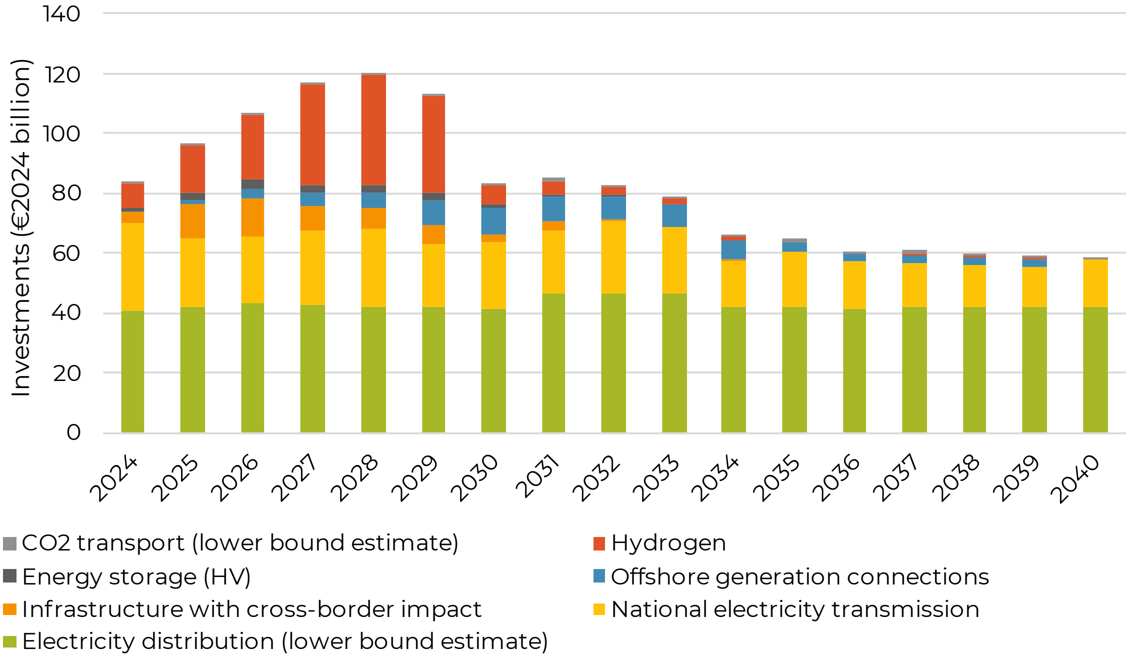
We see consistently higher estimates for North-West European countries, compared to the rest of EU-27. We address this per infrastructure category wherever possible, but we cannot exclude the possibility that a part of this difference is caused by less well-developed future planning for the energy transition in some regions.

In all sectors there are also signals for possible delays; due to changes in political commitments, delays in acquiring materials, permitting delays, or issues concerning transnational agreements. Although we do not capture this in our data, this could postpone the peak investments by 2-5 years, depending on infrastructure category. The details of these impacts are discussed in more detail within the section on each infrastructure category. All Cost are based on best current estimates; however, a strong rise in cost (as sometimes recently reported) can impact the overall figures.

Our overall analysis reveals significant needs for investments in energy infrastructure in the EU in the coming years (Figure 2-2).[4] Most investments are towards electricity infrastructure, primarily at the national level. We see **a peak in investments between 2025-2032**, primarily connected to the planning windows for current infrastructure investments, especially hydrogen and electricity transmission infrastructure.

Electricity distribution consistently dominates the total investment needs across the entire 2024-2040 period. We note here that the numbers reported in Figure 2-2 for electricity distribution infrastructure include both planned investments and lower bound estimates of needs, as planned investments from data collection had too many missing values. High investment needs in electricity distribution infrastructure are expected as the transition to renewable energy and electrification of various end-uses often requires modernising and expanding distribution networks. Driven by this demand and generation growth, these expansions are to extend far beyond those seen in prior years and decades.

Figure 2-2 "Planned" (see Notes) investments for different infrastructure categories, per year



Notes: Electricity distribution includes both planned investments and estimates, due to the availability of data, covering a shorter time-horizon. National electricity transmission includes mostly planned investments, and estimations if provided by NRAs/TSOs, including of offshore lines connecting within national borders. Energy storage only includes energy storage connected to high-

[4] All investments are reported in 2024 € values, unless stated otherwise.

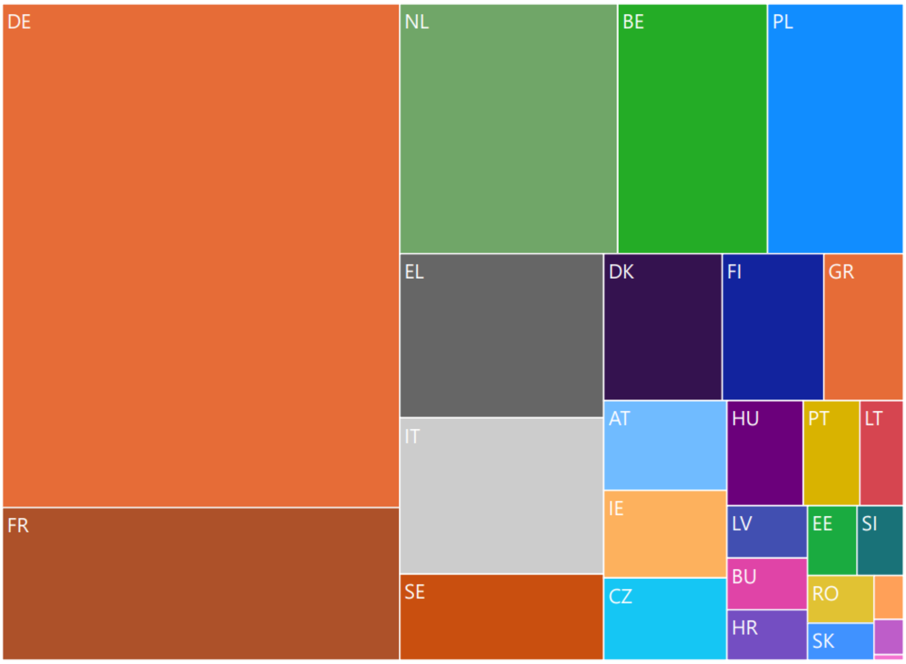
voltage grid. Infrastructure with cross-border impact includes also internal reinforcements with significant cross-border impact. Offshore (radial and hybrid connections) includes only radial and hybrid connections (Annex 2 1.b and 1.f of TEN-E regulation) including planned projects in the first PCI/PMI list and additional projects in the TYNDP projects portfolio. Hydrogen infrastructure includes both planned investments and estimates. CO2 infrastructure includes only estimates. Sources for each infrastructure category are discussed in the following sections on each infrastructure category. Other details on calculation methodology can be found in Annex A.

Electricity transmission infrastructure receives another significant part of investments. Significant investments are driven by new offshore connections, increases in interconnections, and other large cross-border investments. Nonetheless, the majority of investments remain national in the EU-27. These investments are heavily driven as well by the further harmonisation of the EU's electricity system, both in terms of markets and physical infrastructure, while meeting demand and supply requirements with some similar drivers as with electricity distribution grids.

Hydrogen infrastructure experiences substantial peaks from 2027 to 2031, driven by planned investments into international pipelines (sourced from data mainly from TYNDP 2024 and 1st PCI/PMI project lists). Investments in CO_2 infrastructure, which is primarily driven by pipeline development, remain comparatively small throughout the period. These two infrastructure categories are those with less certainty in their investments, and thus have large uncertainty ranges for future investment volume. Their particular uncertainties and possible estimates for future needs are discussed in each respective section.

The investments in energy infrastructure are not equally distributed across the EU (Figure 2-3). Up to 2040, many investments will be focused on regions of the EU with historically high infrastructure investments. Germany, France, and the Netherlands together make up about half (54%) of investments in energy infrastructure up to 2040. Germany is by far the largest investor, with massive investments planned for national TSO (€11.57 billon/year) and DSO (€12.04 billon /year) infrastructure.

Figure 2-3 Average annual (planned) investments per country across all infrastructure categories in scope (€$_{2024}$billion/year)[5]



Country	Annual planned investments (€b/y)
DE	28.01
FR	8.49
NL	7.62
BE	5.24
PL	4.75
EL	4.69
IT	4.46
SE	2.46
DK	2.44
FI	2.09
GR	1.64
AT	1.55
IE	1.51
CZ	1.42
HU	1.12
PT	0.83
LT	0.64
LV	0.59
BU	0.58
HR	0.57
EE	0.48
SI	0.45
RO	0.44
SK	0.34
CY	0.18
LU	0.15
MT	0.02

In addition to existing investment plans, additional investments are expected to be announced and developed over the coming years to meet investment needs. We estimate these investments needs using vastly different methods per infrastructure category, with each described in the relevant sections below and within Annex A.1. While these methods can sometimes conflict in assumptions and modelling choices, the results in Figure 2-4 can give a first estimate of the investment needs per infrastructure category over time.

Clarification note

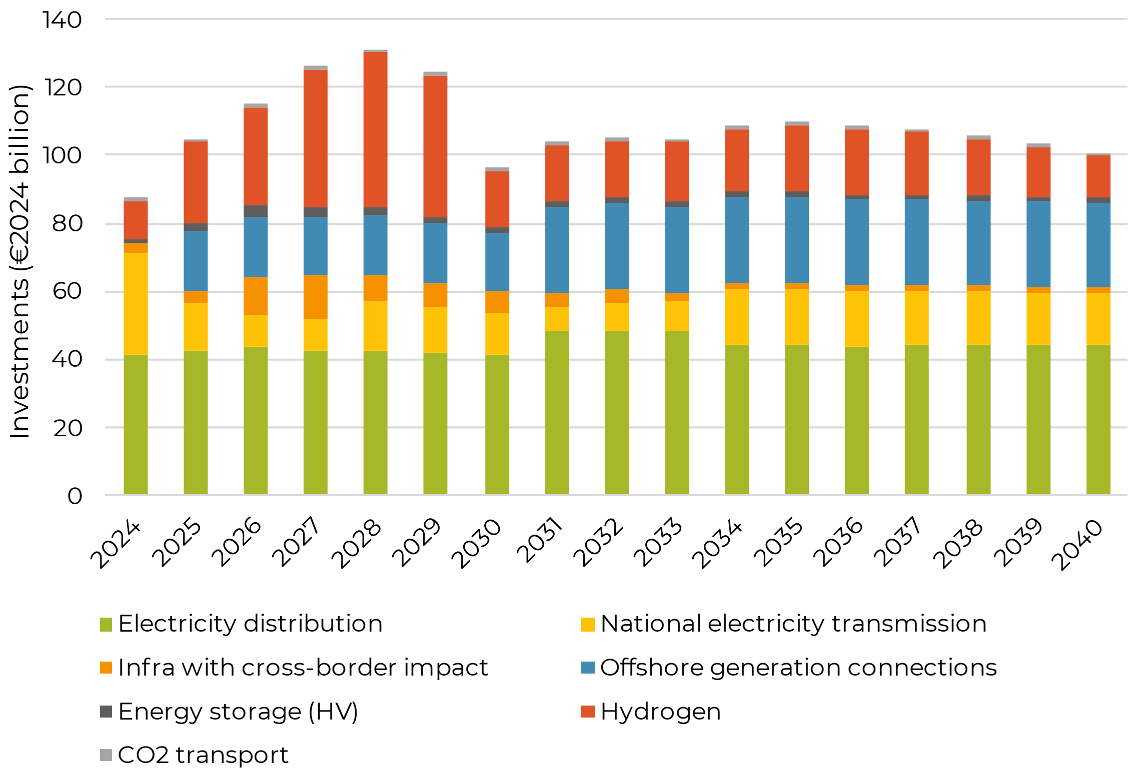
In the upcoming text, and elsewhere in the report, we refer to "estimated" investments as investments expected in the coming years additional to the plans already announced by various stakeholders. These estimates are based on various methods for calculating these values, which are highly different and in some cases conflict on first assumptions, model design, and factors considered. We thus must highlight that these "estimated" investments come with a high degree of uncertainty and must considered as a first approximation, rather than a confident quantitative forecast.

In the figure below, estimates for TSO infrastructure may include some infrastructure with cross-border impact, and internal point-to-point offshore lines. For infrastructure with cross-border impact, investments correspond to planned cross-border projects and internal projects with cross-border impact in the first PCI/PMI list, with the addition of the average of further investment needs in cross-border transmission lines to reach respectively the needs identified for 2040 by the TYNDP 2024 GA scenario and the IoSN study and excluding some possible internal line reinforcements with cross-border impact. For offshore generation connections, both radial and hybrid connections are included based on ONDP estimates. For energy storage, a single estimate was used based on average annual costs of existing projects in the 1st PCI/PMI list and includes battery energy storage,

[5] For more information on how planned and estimated investments were calculated, see Chapter 4.1 (Annex A).

pumped hydro storage, and compressed air energy storage technologies. For hydrogen, infrastructure includes pipelines, storage, import terminals, electrolysers with a grid function, and installations for hydrogen use in transport.

Figure 2-4 Estimated investments in energy infrastructure in scope



Notes: Estimated investments are a middle-ground estimation, in some cases an average based on upper-bound and lower-bound estimates. More details on methodology can be found in the section on each infrastructure category and in Annex A.1.

The estimated investments in the energy infrastructure in scope of this study tops in the late 2020s. This is mainly due to the expansion of hydrogen infrastructure, driven mainly by pipeline installations and cross-border projects. The majority of investments (79%) go towards electricity grids, including cross-border, offshore (radial and hybrid), national transmission, and distribution grids. A minority (about 20%) goes towards hydrogen infrastructure, including pipelines, import terminals, underground storage, electrolysers with a grid functionality, and installations for hydrogen use in transport. A very small amount (less than 1%) goes towards CO_2 transport infrastructure.

Comparing planned and estimated investment volumes shows us that these values are somewhat similar in early years, but diverge more in later years. These differences are especially stark for some infrastructure categories, namely offshore generation connections and hydrogen infrastructure. The reasons for these differences are discussed in more detail in the sections on each infrastructure category.

The following sections delve into the details of investments into each infrastructure category. Each category discusses first the current status and expected future developments of the infrastructure. Next, the planned and estimated needs for investments are discussed, followed by a comparison with other estimates of investment needs from other studies. Sections may also slightly deviate from this structure to best clarify the investments for each infrastructure category.

2.1. Electricity transmission infrastructure

This section focuses on all infrastructure considered under electricity transmission infrastructure, commonly operated and maintained by TSOs. Where possible, the analysis separates national infrastructure (without cross-border impact and not offshore via radial/hybrid lines) and infrastructure with significant cross-border impact (Annex II 1(a) of TEN-E regulation) and/or connected to offshore radial/hybrid infrastructure (Annex II 1(b) of TEN-E regulation; more details are provided in Annex A) and focuses only on the former.

There are however multiple barriers that prevent an adequate in-depth analysis while separating internal national lines as outlined above:

- In many cases, it is difficult, and in a few cases, impossible to determine what constitutes as "cross-border impact" for internal reinforcements.
- Some data sources do not differentiate between these infrastructure categories (details are provided in Annex A).
- Many past studies of investment needs combine all transmission infrastructure and use the regulatory and physical distinctions between transmission and distribution infrastructure to categorise investments in grid infrastructure.

Thus, **in most parts of this section we refer to all transmission infrastructure together.**

2.1.2. Current status and expected future developments

Globally, achieving national goals will require the addition or refurbishment of over 80 million kilometres of grid infrastructure by 2040 worldwide according to the International Energy Agency (IEA)[6]—equivalent to the entire current global grid. These grids are necessary to support the ongoing transition to renewable electricity sources and electrification of major non-electric energy consumptions (including heating, transport, and energy-intensive industry). With the anticipated acceleration of grid expansion, the current length of Europe's transmission network could increase by 20% to 50% by 2040, which would require TSOs to ramp up the pace of network construction by 11 to 27 times. [7]

Significant investments already being made and planned for cross-border transmission capacity by electricity TSOs and private investors, further investment needs have been identified in other studies, including ENTSO-E's System Needs study.[8] Substantial funding is also required to strengthen and expand domestic electricity networks, both at the transmission and distribution levels, to handle the expected increase in distributed wind and solar PV generation, along with the rising adoption of heat pumps, electric vehicles (EVs), and other electrical appliances and equipment.

According to a 2024 study by Ember[9], annual grid spending in EU member states averages around €63 billion, with €28 billion allocated for national transmission grids based on the current NDPs. This level of investment already exceeds prior estimates by the European Commission, which had forecasted a need of approximately €58.4 billion annually[10] until 2030, despite Ember only considering national transmission lines (and thus excluding estimations for cross-border

[6] IEA (2023), Electricity Grids and Secure Energy Transitions.
[7] Compass Lexecon, CurrENT (2024): Prospects for innovative power grid technologies
[8] ENTSO-E (2023), System Needs: Study Opportunities for a more efficient European power system in 2030 and 2040
[9] Ember (2024), Grids for Europe's energy transition.
[10] In 2022, the European Commission estimated that between 2020 and 2030, a total of €584 billion will be needed for electricity grid investments to meet the objectives of the REPowerEU Plan[10].

connections[11]). Of this amount estimated by the EC, 65-72% was said to go toward enhancing distribution grids specifically. While indicating that significant investments are being made to meet EU-wide targets for the energy system, investment increases in recent years may also indicate a growth of costs for both material and labour needed for grid investments. A more recent analysis, namely the impact assessment supporting the European Commission's proposed 90% reduction in greenhouse gas emissions by 2040[12] highlights higher investment needs as well. It estimates that upgrading and expanding transmission and distribution networks may require average annual investments of €85 billion in the power grid between 2031 and 2050 (or about €28 billion annually for transmission grids). The Institute for Climate Economics arrives at a similar investment need for the EU power grid, including both transmission and distribution infrastructure (around €89 billion).[13] Our own analysis suggest yearly spending for transmission grids needs to go above €30 billion annually from 2024 onwards, with national transmission lines making up 80% of these investments. We discuss these comparisons in more detail in the last subsection (2.1.4).

In the subsection below we will first introduce our own analysis, then compare of the resulting investment plans and needs with these other estimates, while providing nuances regarding the feasibility and likelihood of meeting investment needs with investment plans.

2.1.3. Analysis of planned investments data and estimates for investment needs

The below section analyses investments at the transmission level across the EU. The data gathered for this analysis includes reviews of transmission-level network development plans (NDPs) and other public sources of project-level data, survey responses from NRAs, survey responses from TSOs via ENTSO-E, and other public sources. Full details on the methodology used for identifying planned investments and estimating investment needs past planning horizons are further explained in Section A.1.1(Annex A).

Generally, network development plans of TSOs are reviewed by NRAs (and in some cases, other institutions) to ensure that investment plans are adequately addressing needs in the long term (i.e. often longer than the timespan of the commitments made under the NDP). We thus assume that *usually* planned investments in the timespan of the NDP of each TSO is also indicative of the needed investments. In a few cases, planned investments reported in NDPs were assessed to not be indicative of needed investments. This may indicate a future development of investment plans at a later date. In these cases, the planned investments for a given year were thus supplemented by additional estimates of needed investments.

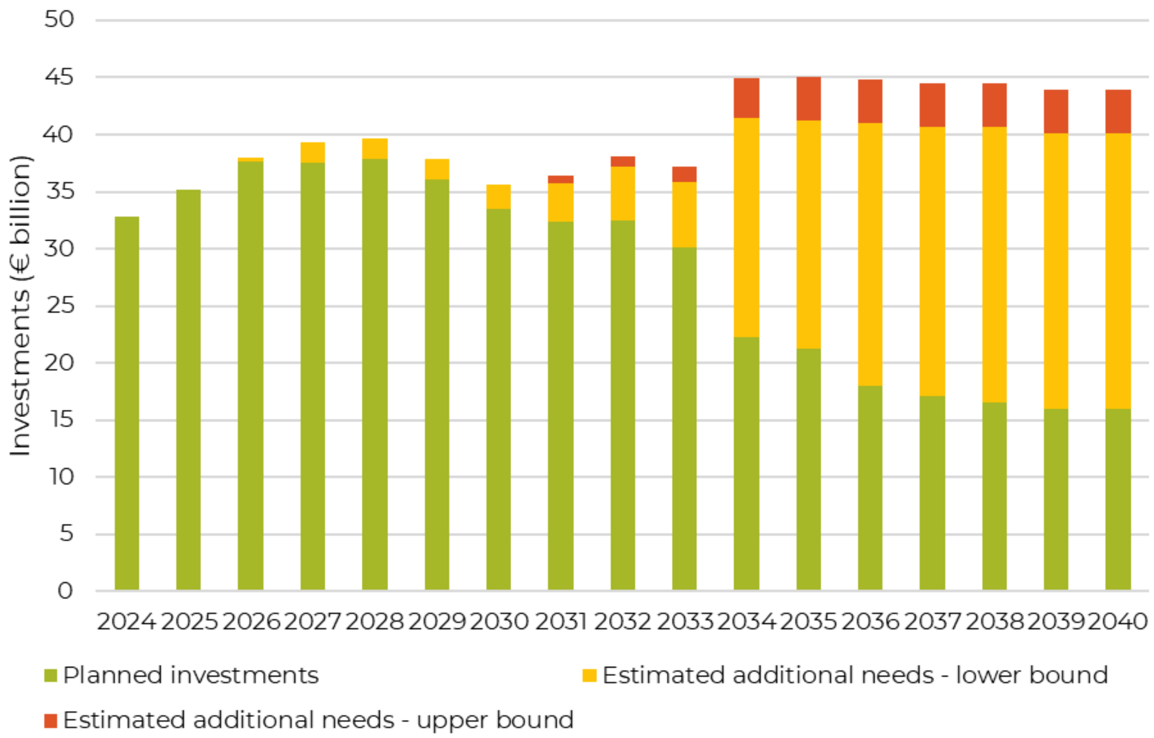
The analysis on planned investments is based on three primary data sets: Survey responses from NRAs and from TSOs, an in-depth review of transmission NDPs, and data from the Ember (2024) study. Details about data availability and usage are included in Annex A.

We also estimated the needed investments for transmission infrastructure outside of the time window of each country's NDP. This estimation was based on a similar methodology to that of the DSO investment needs (i.e. based on demand figures from the EC's impact assessment and the 2040 climate target scenarios), and details on this can be found in the methodological Annex (A). We present results for planned investments and estimates of future needs together below, to ensure consistent representation for different MSs and different time periods. In the 2024-2040 period, at

[11] See 'Methodology' section of the Ember report
[12] European Commission (2024), Europe's 2040 climate target and path to climate neutrality by 2050 building a sustainable, just and prosperous society
[13] European Climate Investment Deficit Report: An Investment Pathway for Europe's Future - European Commission (europa.eu)

least €471 billion is earmarked for transmission grids EU-wide (including national and cross-border lines) in Europe according to our calculations. Planned investment numbers are more certain for the timeframe between 2024 and 2033 as most countries' NDPs do not look beyond this date and data availability is low after it.

Figure 2-5 Planned investments, and estimated investment needs into transmission infrastructure between 2024-2040 (EU-27)



Shown on Figure 2-5, our numbers reveal **planned** yearly investment for transmission lines between €30-39 billion between 2024 and 2033, after which investments seem to slow down, however this is mostly due to the fact that most NDPs don't look to the mid-thirties yet.

National transmission infrastructure (lines with unidentified cross-border impact and not related to offshore generation; i.e. excluding offshore connections and infrastructure with a cross-border impact) constitute about **80%** of the total planned TSO investments in the 2024-2040 timeframe in the EU, or around **€377 billion**. The same downward trend for planned investments post-2033 applies when looking at planned investments in these lines, as for the entirety of the TSO category. Accurately separating internal transmission investments from total transmission investments, on a country level and with yearly granularity has not been possible due to the quality of data available. In general, the TSO category includes reinforcements and new line investments, and all kinds of infrastructure: AC and DC lines, substations, autotransformers, shunt reactors, converter stations, etc. While there is no uniform definition of TSO infrastructure EU-wide, most TSOs regard lines above 110kV to be part of transmission infrastructure, but in some countries all high or extra high voltage lines (i.e. above 35kV count as TSO infrastructure.

Investment needs are estimated for transmission infrastructure outside of the time window of each country's NDP, and (in rare cases) on top of the planned investments. While current levels of investment have laid the groundwork for integrating renewable energy, much more will be required to meet future demand and decarbonisation targets. Our projections indicate that after 2030 a significant gap emerges between planned investments and the estimated additional needs, particularly from 2035 onward. Figure 2-5 shows two ranges for these additional needs: lower bound and upper bound, which were calculated with the help of the forecasted change in demand for the different Member States with help the 2024 Impact Assessment[14] and 2020 EU reference scenarios.[15] This is further explained in the methodology section in Annex A.1.1 . These lower and upper bound needs range from around €5 billion in the early 2030s to over €25 billion by 2040. We note however that the total values for the 2034-2040 period are far less certain, in comparison with prior years. The increase in additional needs after 2030 follows from the planning window of NDPs, which generally have planning windows at or under 10 years. The slight increase in the post-2030 period highlights the need for more investment commitments beyond the near-term. This increase is due to various reasons, including:

1. **Increasing demand**, particularly from the electrification of heating, transport, and energy-intensive industries.
2. **Scaling RES integration**: as Europe moves towards achieving net-zero emissions, the share of electricity generated from renewable sources like wind and solar will continue to grow. This requires expanded transmission capacity to connect renewable generation—often located in remote areas like offshore wind farms—with high-demand urban centres.
3. **Grid modernisation and digitalisation**: future investments must focus not only on physical infrastructure but also on modernising grids through digital (grid enhancing) technologies, improving efficiency, flexibility, and resilience. This will be vital for managing intermittent renewable energy, enabling smart grids, and integrating new demand-side technologies like EVs and battery storage.
4. **Cross-border interconnections**: Europe will increasingly depend on cross-border power flows to balance supply and demand across the continent, making investments in interconnection capacity essential for energy security and market integration.

These increases are somewhat counteracted by increasing economies of scale and higher efficiencies in infrastructure use, but nonetheless result in a slight increase in annual investments up to 2040.

The **planned** investments in transmission infrastructure are not at all equally distributed across the EU-27. As shown in Figure 2-6, investments in transmission grids are highly concentrated in the CWE region and Denmark. Of the €477 billion that is planned to be spent on transmission grids during this time, almost half is coming from Germany alone (€228 billion until 2040). The Netherlands plans to spend €60 billion, and Italy earmarks half of this (close to €30 billion). As comparison, France, although being of similar size and importance as Germany, is so far only planning to spend €33 billion, about 13% of Germany). Belgium is the 5th biggest spender with €26.4 billion.

In Northern Europe, Sweden (€12.8 billion), and Finland (€4.45 billion) show strong investment levels relative to their population sizes. The Baltic States (Lithuania: €1.9 billion, Estonia: €1.3 billion, and Latvia: €0.47 billion) are making relatively lower but still significant investments. These countries are working on the upcoming decoupling from the electricity grids of Russia and Belarus and on integrating with the EU's electricity market[16], thus a big chunk of these investments will go to their interconnections with the Continental European network, such as through the Baltic Synchronisation Project[17].

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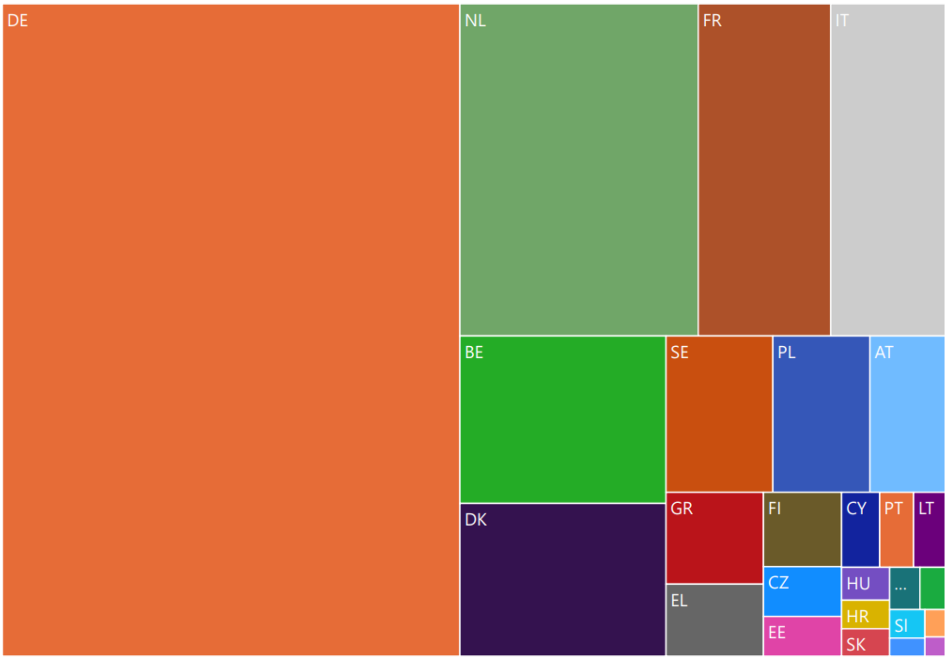
[14] European Commission (2024). Impact assessment report 2024
[15] European Commission (2021). EU reference scenario 2020
[16] Estonia, Latvia & Lithuania agree to synchronise their electricity grids with the European grid by early 2025 (europa.eu)
[17] Baltic Synchronisation Project: works are on track - European Commission (europa.eu)

For CEE, planned investment levels in Poland (€11.53 billion), Czechia (€2.98 billion), and Hungary (€1.21 billion) seem moderate, reflecting the need for grid upgrades to manage their growing RES while transitioning from coal. Romania (€0.89 billion) and Bulgaria (€0.98 billion) have relatively lower investments, indicating a slower pace in grid modernization, which could reflect economic constraints or a slower transition away from coal in these regions.

In Southern Europe, Italy (€29.69 billion) and Spain (€5.38 billion) have notable investments planned in grid infrastructure, which correspond to their goals to increase solar and wind capacities. Italy's higher figure suggests a more aggressive push for grid updates, which is critical given the country's challenges with aging infrastructure and geographic constraints. Portugal (€1.95 billion) and Greece (€6.86 billion) have lower investment levels compared to larger EU members, but these figures likely reflect the smaller scale of their grids.

Figure 2-6 TSO investments - comparing national estimates, (2024-2040)

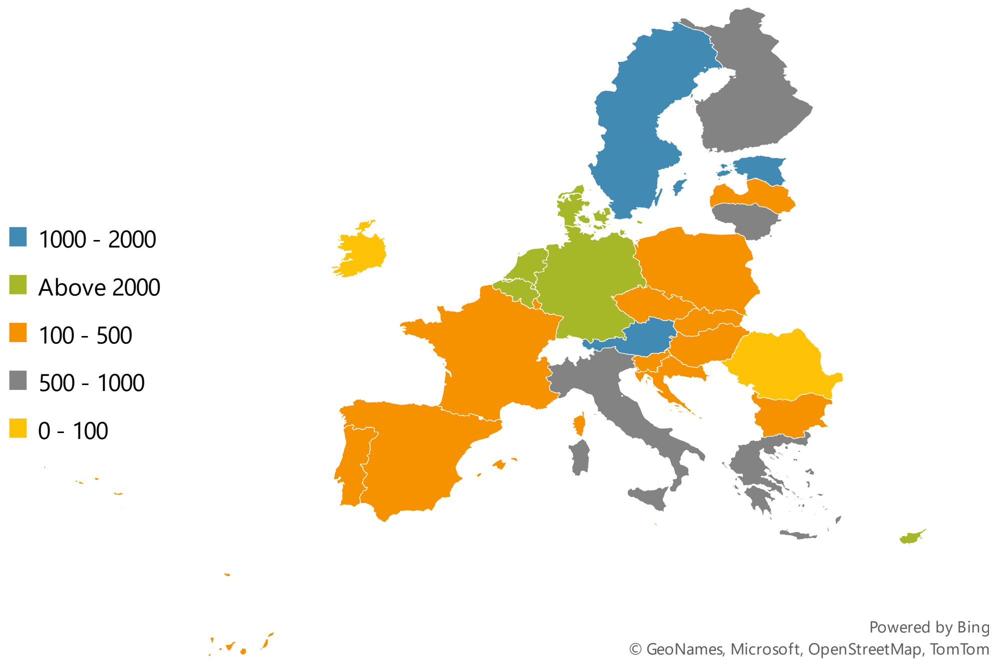


Country	Planned investments (€b)
DE	228.74
NL	60.68
FR	33.72
IT	29.69
BE	26.45
DK	24.13
SE	12.80
PL	11.62
AT	9.27
GR	6.86
EL	5.38
FI	4.45
CZ	2.98
EE	2.38
CY	2.19
PT	1.95
LT	1.94
HU	1.21
HR	1.05
SK	1.01
BU	0.98
RO	0.89
SI	0.77
IE	0.49
LV	0.47
LU	0.33
MT	0.00

A comparison on a per-capita basis across EU-27 MSs can be more indicative of the comparative infrastructural investments across the bloc. As seen on Figure 2-7, Central-Western and Northern Europe spend manyfold of that of other MSs on transmission infrastructure (indicated in brown) per capita. Denmark is in the lead with €4,048, and the Netherlands with a €3,381 figure per capita. Germany, despite having the highest total investment, ranks lower in per capita terms and spends €2,741 on average, with a significant share going to internal reinforcements, particularly towards HVDC lines on the North-South axis. In the Baltics, Estonia has more per capita investments in TSO infrastructure than its neighbours, €1,013 on average.

Eastern Europe, including Poland (€314 per capita), Hungary (€126 per capita), and Romania (€46 per capita), shows much lower per capita investments. These regions face slower transitions away from traditional fossil fuels, and their lower investment might reflect economic and infrastructural constraints they are facing.

Figure 2-7 Per capita cumulative investments into transmission infrastructure between 2024-2040 (€$_{2024}$ billion/year per capita)



The higher investments in electricity transmission infrastructure in some countries are driven by the need to integrate renewable energy, modernise aging grids, achieve energy security, and align with both domestic and EU-wide energy and climate goals. Wealth, industrial needs, and geographic factors also play a key role:

- **Energy transition and RES integration:** Germany is at the forefront of the energy transition with its landmark policy, the *Energiewende*. The country is rapidly transitioning from fossil fuels and nuclear energy to renewable energy sources (mainly wind and solar). Renewables are often located far from demand centres (e.g., offshore wind farms in the north versus industrial centres in the south). This creates a need for significant investment in long-distance electricity transmission infrastructure (including DC links) to connect these regions. Other MSs that are expanding clean energy, like the Netherlands, Spain, and Italy, face similar challenges of integrating new energy sources (including renewable and nuclear) into the national grid. Countries heavily investing in renewables tend to invest more in infrastructure to increase grid flexibility, automation, and reliability as well.
- **Phasing out fossil fuels or nuclear:** Germany is phasing out both coal and nuclear power, which requires substantial investment in transmission to compensate for the lost capacity. The focus is on transporting renewable energy across the country and even across borders. Other countries with significant fossil fuel or nuclear phase-outs will also need to upgrade their infrastructure to handle this energy shift.
- **Economic capacity and policy priorities:** grid operators in wealthier countries, such as Germany and the Netherlands, have easier access to capital to invest in large infrastructure projects. Policy priorities also align in some economies, leading to faster permitting and regulatory procedures. Additionally, Germany has a strong industrial base that depends on reliable and affordable electricity, incentivising investment in grid infrastructure.
- **EU Regulation and cross-border cooperation:** EU policies aimed at creating an integrated energy market count on key players on the market, such as Germany, the Netherlands, France, and Italy, who are heavily engaged in cross-border electricity exchanges. This requires building more interconnected transmission systems, including some high-voltage direct current (HVDC) lines. Countries that are central to the European energy grid invest more to ensure they can

import and export electricity efficiently, balancing supply and demand across borders. As our total estimates in the above figures include cross-border connections, this explains the intensity of investments in these countries.

- **Modernisation needs:** the EU has the biggest synchronous electricity grid in the world, but its average age is also the oldest in the world[18]. Countries with older infrastructure, such as France[19] and others in CEE, may need to invest more in upgrading and modernising their grids to meet current and future energy demands. Germany, despite having invested in its grid earlier, continues to expand it to meet the growing demands of the energy transition. Here, historically, the Western part of the country has seen more robust investment in energy and infrastructure compared to the East, which disparity stems from economic and political differences that have persisted since reunification.
  In Eastern European countries like Poland and Romania, grid modernisation is especially urgent. These regions have older infrastructure and are more reliant on fossil fuels, creating challenges in aligning infrastructure readiness with Europe's climate goals. Investments in these geographies also target enabling greater integration with the rest of Europe's grid, besides integrating new RES sources.
  Wind farms, especially offshore ones in the North Sea and Baltic Sea basins, are often located far from consumption centres, necessitating expanded transmission capacities and cross-border interconnectors (which are representing a big part of the BEMIP regions' transmission investments).
- **Energy security and independence:** countries like Germany prioritise energy security and reducing reliance on imports of fossil fuels, especially after geopolitical shocks like the 2022 Russian invasion of Ukraine. This drives investments in national transmission infrastructure to maximise the use of domestic renewable energy sources and diversify energy imports from various EU countries.

The quality and granularity of data received for the purpose of this study also influences the total estimates: German, Italian, and Danish NRAs/TSOs have provided investment figures up until 2040, while others provided data to the early-2030s or even earlier years. Some NDPs are also planning for longer time frames than others. Germany's NDP[20], for example, sets scenario analyses and based upon this, expected investments, until 2045, while most other countries could not provide estimations for this period.

We also reviewed data sources on the physical transmission infrastructure being installed. The reported volumes in this regard differ significantly across sources, leading to high uncertainties in ascribing specific € values to physical infrastructure growth, such as km lines and number of substations and capacities. Based on rough calculations, about 116,000 km of lines have been planned, with a roughly equal split, for new installation or refurbishment/upgrade in the 2024-2040 period. We estimate that investment needs for the grid to 2040 for the EU-27 would require further expansions of 48,000 to 56,000 km of more lines.

Some challenges were identified throughout the EU-27 as impacting the development of TSO infrastructure. Here, we focus on those impacting non-cross-border and onshore infrastructure, and leave the discussions on the challenges impacting the costs and timelines of investment plans and needs to the following sections on the other infrastructure categories:

- **Materials availability:** The ongoing ramp-up of investments in grid infrastructure has dramatically impacted the markets for materials needed for TSO infrastructure. As grid operators

[18] Europe's Grids Are Not Up To Grade | Breakthrough Energy
[19] The average age of France's grid equipment is 50 years,
[20] Electricity network development plan 2037 with outlook to 2045, version 2023

across Europe require more materials for their expansion and refurbishment plans, the limited manufacturers of these materials have not expanded production at the same pace. International demand for European products in this area has also expanded. These trends are especially significant for higher-capacity cables/lines and larger transformers, where multi-year waiting periods are now the norm. In addition to cost increases, these material shortages have the potential to cause significant delays in network development plans.
We note that in the current study, we do not directly include materials shortages in our analysis, considering that these aspects are considered to some extent across NDPs and data sources (albeit in an inconsistent manner). Nonetheless, we expect that our estimates are conservative with respect to the costs impacts of material shortages.

- **Labour shortage:** the rapid ramp-up of investments in grid infrastructure also impacts labour markets. The high need for grid infrastructure projects, in some regions, strains the available labour supply for the necessary works and studies for projects. This is more the case for construction contracting, which may create delays and cost increases in some regions.
- **Permitting:** the significant scale of TSO infrastructure causes large challenges in permitting requirements for projects. Multiple experts noted that permitting difficulties continue to be a bottleneck for infrastructure development for TSOs. The significant increase in grid projects, coupled with limited administrative capacities (particularly at local and sub-national levels), leads to significant delays for infrastructure projects.
- **Network planning issues:** despite various harmonisation efforts at the EU level, there remain very wide differences in transmission network planning across the EU-27. Many differences in this regard directly impact how investment plans and needs are developed and how feasible and realistic they might be. These differences include overseeing entity for TSO activities, planning procedure timelines, ownership models, planning time windows, assumptions and modelling scenarios developed for network planning, and regulations on investments and returns. Providing a comprehensive overview of these differences and their impact on investment needs and plans is out of scope, but a few notable points emerge.

Firstly, countries with stronger legal commitment within NDPs generally lead to more feasible NDPs. For example, German NDPs are enshrined in state law following NDP approval, following a slight delay. ACER also notes that the binding nature of NDPs varies across EU MS[21]. Secondly, differences in scenario planning are prevalent among TSOs. The development of network plans for TSOs is generally mainly based on projects of supply and demand for the electricity sector. These projections are developed with scenario modelling exercises that identify grid expansion needs up to a time window often longer than the commitments in the NDP. The projections thus ensure that grid plans are developed to meet the ongoing need for infrastructure in the short term, while being considerate of potential future developments in the long term. However, the projections of supply and demand can differ from those of other projections for various reasons:

  - **MS/EU level targets and updates:** for some countries, there can be a significant difference between the demand, supply and other energy/climate policy targets of the country and targets considered for the NDP. As also seen on our figures (plans vs. needs) and pointed out by Ember, the currently planned transmission grid developments may not be sufficient to support the necessary increase in renewable energy to meet energy policy targets. The latest grid plans reveal some misalignment with current policy targets in some countries. This, they state is also a problem for enabling anticipatory grid investments[22].

[21] and thus the obligations derived from these NDPs for the TSOs and the NRAs or ministries (e.g. obligations to build the project, include the relevant costs in tariffs) differ too. ACER Opinion 05-2021 on the electricity national development plans - rectified
[22] ENTSO-E High Level Forum conclusions on anticipatory investments 2023 September 7

This misalignment can happen in cases where for example national targets are updated after the point at which they can be considered for the NDP, for example within revisions of the NECPs. In more critical cases, these targets are far higher than what NDPs take, leading to underinvestment and thus underdevelopment of the grid and causing problems further ahead. The different projections for solar and wind generation are for example highlighted in Ember's 2024 study on transmission grid investments. The study's data illustrates that the main underestimations (comparing industry association predictions and NDPs scenario estimations) are in a few select countries, namely Portugal, Poland, France, and Denmark. Our analysis clarified that some of these countries may already be acting to update NDPs and project plans in the most recent cycle based on updated and more ambitious projections for demand and solar and wind generation.[23]

- **Political considerations** also significantly influence scenario planning for NDPs. Some Member States are committed than others to their NDP projects, and often signing an agreement or planning document does not equal dedicating the financial commitment. Regulatory changes, such as new environmental laws or emissions targets, can alter the cost and feasibility of different energy sources, affecting both supply and demand. Trade policies, including tariffs on imported energy technologies or materials, can influence the availability and cost of electricity generation infrastructure. Lastly, economic policies, such as subsidies for renewable energy or taxes on fossil fuels, can incentivise shifts in electricity production and consumption patterns.

Overall, given the ongoing challenges and underdeveloped frameworks in some regions, the **projected investment numbers could diverge significantly, with a potential for increased costs.** Investments are likely to be higher than current estimates, particularly for countries and regions facing regulatory or spatial planning gaps.

Many TSOs also acknowledge that investment plans beyond a 7-10 year window are inherently flexible. As the energy transition accelerates, new projects and additional RES connections, which are not included in current NDPs, may drive costs up. Offshore wind and new grid connections are among the key drivers of rising investment needs.

Investment ambitions vary across regions and sectors too. For instance, Northern Europe (North Sea countries) is highly committed to offshore wind, demonstrated by well-developed maritime spatial planning frameworks up to 2030. In contrast, Mediterranean countries like Greece have ambitious offshore targets but lack the necessary regulatory frameworks, such as cost-sharing agreements, which make their plans less realistic in the short term. This contrast in planning rigor will lead to varying levels of underinvestment in some countries unless more detailed frameworks are developed.

The Baltic region is working towards synchronising its grid with the rest of the EU, though progress is slower than in the North Sea. For the CEE region, there is significant potential for grid expansion, but the region's diverse energy mix and political landscape make these efforts inconsistent. For instance, Poland's attitude towards offshore wind is changing, with possible hybrid projects in the near future, but it still lags behind Northern Europe in terms of concrete planning.

The increasing frequency and severity of extreme weather events could also add significant risk to both project timelines and costs. Grid infrastructure will need to be more resilient to accommodate

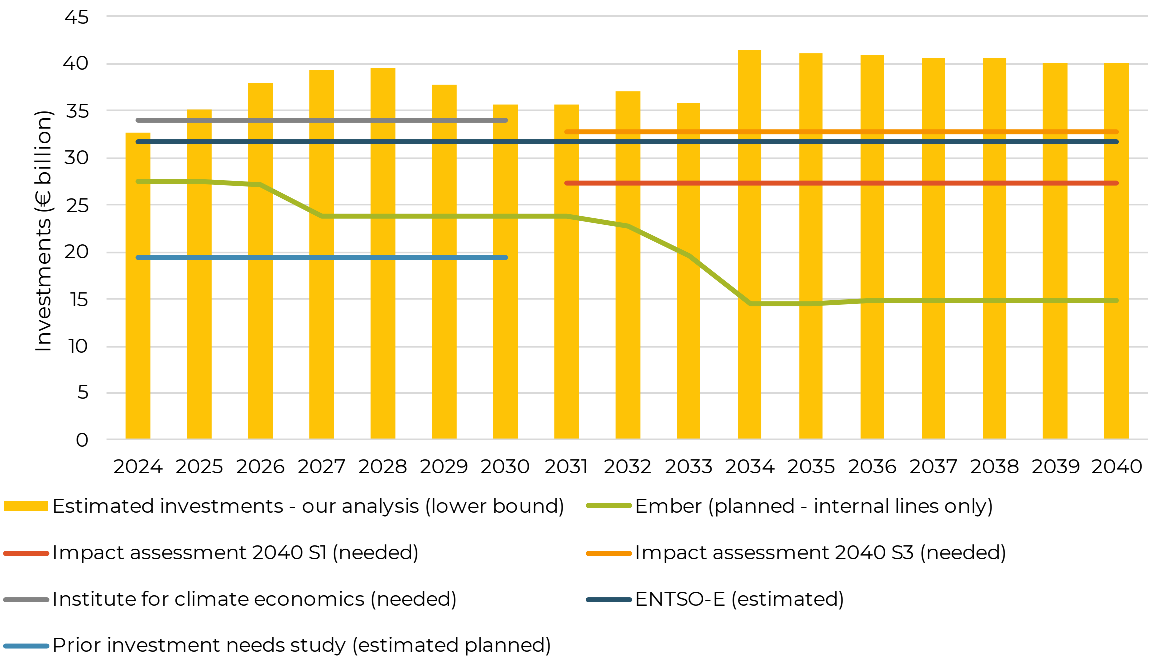
[23] https://www.rte-france.com/analyses-tendances-et-prospectives/le-schema-decennal-de-developpement-du-reseau

these challenges, further pushing up investment levels. In Italy, the sub-Mediterranean interconnection is one example of a project directly impacted by climate conditions, indicating that climate adaptation will become a central part of future infrastructure costs.

2.1.4. Comparison with other estimates of investment needs

We lastly compare investment estimates from several studies with our analysis. Figure 2-8 illustrates a comparison of our analysis of planned investments and estimated needs with those of other studies. The studies include Ember's 'Grids for Europe' study[24], ENTSO-E data[25], data from the Institute for Climate Economics[26], the EC's Impact Assessment of the 2040 climate target[27] (S1 and S3 scenarios), and a prior investment needs study[28].

Figure 2-8 Investment needs comparison with other studies



The above graph compares estimated investments based on our analysis (yellow bars) with estimates from other studies. Up until 2030, our analysis is close to the estimates from ENTSO-E and Ember. ENTSO-E's forecast, shown in dark blue, remains consistently higher than planned investments throughout the timeline, **indicating a belief that current plans may be underestimating the real needs for the electricity grid.**

Ember's planned investments (green line) seem to be lower, most likely due to the fact that the Ember data used for this comparison covers only internal lines and is based on only planned investments. Ember's projections show a slight decline in investments after 2030, then a bigger drop

[24] https://ember-climate.org/insights/research/putting-the-mission-in-transmission-grids-for-europes-energy-transition/#supporting-material
[25] From the 10th Infrastructure Forum 2024, Winter Outlook: https://circabc.europa.eu/ui/group/88886b79-cdea-4633-a933-8b191efb335b/library/be9ce9a2-2a50-4bf0-b197-7ea9a59a48c1/details
[26] European Climate Investment Deficit Report: An Investment Pathway for Europe's Future - European Commission (europa.eu)
[27] resource.html (europa.eu)
[28] https://op.europa.eu/en/publication-detail/-/publication/431bc842-437c-11e8-a9f4-01aa75ed71a1

post-2033. This change only hints at scarce planned investment data after the 2030 timeframe in published network development plans.

The 2040 **Impact Assessment S1** and **S3 scenarios** (red and orange lines) represent higher and lower estimates for needed investments. Both scenarios emphasise a consistent need for spending beyond what is currently planned after 2020, especially as the electricity grid needs to adapt to increased renewable generation, electrification of sectors like transport, and growing storage demands. The S3 scenario reflects an even higher estimate, anticipating robust grid upgrades. Our estimates remain higher than these two assessments, which can be explained by a few factors: first, we took 1/3 of investments in grids (from the IA scenarios) to represent TSO investments, whereas the ratio may be higher in later years (and the lines may instead be shifted higher).

A second factor may explain why our estimates are higher than those of most other studies. Our analysis has included some possible cost increases related to material and labour cost growth in recent years that have been reflected in data sheets used for the estimates. These cost increases may be reflected in our estimates, but possibly not in others.

This comparative view also highlights the gaps between current planning and the broader expectations of different studies. The decline in planned investments after 2030, as per current NDPs, is a concern, as many studies forecast rising grid needs due to the complexities of integrating renewable energy, electrification, and new technologies like hydrogen. However, as pointed out above, this contrast between projected needs and existing commitments might rather be due to the lack of outlooks for these years rather than underfunding in the long-term.

2.2. Electricity distribution infrastructure

Electricity distribution grids are networks that distribute electricity to consumers, connecting the transmission networks to homes, businesses and industries. Additionally, distribution grids enable the integration of distributed RES, such as solar PV, into the energy system. They operate at different voltage levels, including low voltage, medium voltage, and high voltage. In the European Union, these grids are managed by Distribution System Operators (DSOs), which are responsible for operating, maintaining and developing the distribution networks within their designated regions to ensure a reliable supply of electricity to consumers.

2.2.1. Current status and expected future developments

Over the past 50 years, the total length of electricity distribution grid infrastructure has steadily increased, mainly due to expansions in distribution networks.[29] This expansion is primarily driven by changes in demand, following increasing electrification of heating, transport, and industry. Increasing amounts of distributed renewable electricity generation also creates a higher need for distribution grids. Therefore, in advanced economies, we are seeing increased investment in distribution grid infrastructure.

Furthermore, there is an increasing need for grid modernisation and refurbishment. Around 30% of the distribution grid infrastructure is over 40 years old, with some assets much older.[30] To ensure that the grids are strong and reliable, investment in grid replacement and renewal is necessary. Advanced monitoring, including smart meter data and maintenance data, combined with predictive algorithms

[29] IEA (2023). Electricity Grids and Secure Energy Transitions
[30] European Commission (2023). Grids, the missing link – An EU Action Plan for Grids

and digital twins, can help optimise asset health. However, periodic replacement and renewal are still crucial.

Using advanced forecasting and simulation tools to consider grid expansion and customer connection requests also supports proactive investment. Important areas for new investment include system digitalisation and substation automation, renewal and replacement, and targeted resilience.

The rising demand for electrification, driven by factors such as industrial electrification, the widespread installation of heat pumps and electric vehicles, together with the need to replace existing infrastructure is expected to generate additional investment needs, particularly in distribution grids. The Institute for Climate Economics estimates that around 89 billion euros will need to be invested in the European grids each year between 2024 and 2030 to support the evolving energy landscape and meet increasing electricity demand. Distribution grid investments account for 63% of these investment needs, underscoring the critical role of distribution networks in the energy transition.[31] Multiple DSOs and stakeholders also highlighted that electrification is a major priority, with DSOs preparing for rising demand from electric vehicles, electric heating, and industrial consumption. Investment needs are substantial when compared with historical numbers; regulations are critical in ensuring that, while maintaining socially acceptable grid tariffs and system security of supply, DSOs can finance the necessary projects despite limited resources and the complexities of long-term planning. Additionally, this trend is creating more focus on **anticipatory investment**[32] options to ensure grids can rapidly scale up to meet future demand needs. Interestingly, findings from ACER and CEER suggest anticipatory investments are not explicitly defined or treated separately from other grid investments[33]. Instead, forward-looking approaches, such as anticipating future generation and demand, are sometimes embedded in standard network planning processes. While some DSOs limit planning to projects triggered by firm connection requests or focus on areas of high likelihood for utilisation, others are inherently forward-thinking in their methods.

Looking toward the future, the financial landscape of DSOs will be significantly shaped by their ability to navigate evolving regulatory frameworks and secure the necessary funding to meet their **growing investment needs**. Larger DSOs often have the advantage of standardised processes and better communication with TSOs. These organisations also tend to have access to diverse financing options. In contrast, smaller DSOs may find it more difficult to secure financing due to a lack of scale, and they often require more assistance in navigating administrative processes. For example, while EU-level support mechanisms can provide significant financial assistance, smaller DSOs often face challenges in accessing these funds due to complex, time-consuming application processes.

Furthermore, for most DSOs, national financing mechanisms such as tariff-based funding or favourable loan rates are often sufficient, although some recognise that upcoming investment demands may require a stronger focus on securing future financial stability. Additionally, some evidence suggests some DSOs are reluctant to engage with EU funding programs, with the requirements limiting their ability to make ad-hoc investment decisions. Instead, they prefer commercial loans and other forms of financing that offer more flexibility. Other DSOs may view EU funding as a valuable resource to support their growing investment needs.

[31] Institute for climate economics (2024). European Climate Investment Deficit report

[32] "Anticipatory investments" are infrastructure investments undertaken with a forward-looking approach to prepare electricity grids for future needs, even when those needs are not yet fully confirmed or supported by actual connection requests. These investments aim to accommodate expected growth in renewable energy generation, electrification and other drivers of network expansion. Such investments require consideration of future scenarios and often involve higher uncertainty compared to traditional grid investments

[33] ACER and CEER (2024). Position on anticipatory investments

In the below sections we will compare our analysis of investment plans and needs with other estimates, while providing nuances regarding the feasibility and likelihood of meeting investment needs with investment plans.

2.2.2. Analysis of planned investment data

The analysis in this report explores investment requirements at the distribution level across the EU, based on data gathered from various sources, as further explained in Annex A.1.2 . The distribution analysis is grounded in two primary data sets: Survey responses from NRAs and an in-depth review of distribution NDPs.

A targeted survey was distributed to NRAs in the EU-27 countries to collect insights on investment needs at the distribution level. Out of the NRAs contacted, eight provided responses. Additionally, a review of the EU-27 distribution NDPs was conducted. For 13 Member States, investment data came directly from the distribution NDPs, with some being scaled up for the whole Member State based on the largest DSO or multiple DSOs. However, the coverage period of distribution NDPs varies, with many distribution NDPs not providing investment projections beyond 2032, and some even covering shorter periods, providing data only for the earlier years of the forecast. Adapting this approach is thus necessary due to a lack of available data, which might result in an underestimation of investment needs. More information about the survey responses and the availability of data in the DNDPs can be found in Section A.1.2.

Experts highlight varying approaches to how DSOs allocate investments between studies and works,[34] as referred to in the CEF regulation.[35] In some cases, there is no clear separation between the two categories, with studies being viewed as part of the overall project costs rather than as distinct budget items. These DSOs often embed studies within the broader investment strategy, focusing on the overall project implementation rather than itemising specific phases. In contrast, for other DSOs, there is a clearer distinction between studies and works, though **studies remain a minor part of the budget**, typically staying below 5% of total project costs. The consistent trend across DSOs is that while studies are essential, they are kept to a small proportion of the budget to allow the majority of resources to be directed toward grid expansion and system upgrades.

Figure 2-9 presents an overview of the **annual planned investments** for each Member State, with the years for which data is available per country. No data is available for the following member states: Austria, Bulgaria, Croatia, Hungary, Ireland, Luxembourg, Poland, and Sweden. Additionally, Table 2-2 represents the availability of data on planned investments for each Member State, including the range of years covered by the data. The first row of the table, Germany, indicates the Member State with the highest total planned investment, followed by France, which has the second-highest total amount of planned investment. Conversely, Malta represents the country with the lowest planned investments, noting that there are also Member States for which no data is available.

For the available data, it should be noted that it may not cover the full DSO infrastructure of the Member State. However, it can be used to estimate full coverage by extrapolating the data from one DSO to calculate total investments for all DSOs within the Member State. Additionally, in some cases, a downward trend in planned investments can be observed, which may indicate that not all

[34] 'works' means the purchase, supply and deployment of components, systems and services including software, the carrying out of development, repurposing and construction and installation activities relating to a project, the acceptance of installations and the launching of a project; (15) 'studies' means activities needed to prepare project implementation, such as preparatory, feasibility, evaluation, testing and validation studies, including software, and any other technical support measure including prior action to define and develop a project and basis decide on its financing, such as reconnaissance of the sites concerned and preparation of the financial package;
[35] European parliament and Council (2021). CEF regulation

investments for later years are currently known or planned. This suggests that more investments are likely to be planned in later years, leading to a higher percentage of planned investments over time.

The methodology section in Annex 1.2 further elaborates on the methodology used to calculate the investment needs for these Member States, with the help of the forecasted change in demand for the different Member States using the 2024 Impact Assessment[36] and 2020 EU reference scenario.[37]

Table 2-2 Available data on planned investment for each Member State

Member State	Available data	Complete data on full DSO infrastructure without regional estimations	Downward trend in planned investments	Notes
Germany	2024-2032	No	No	Member State with the highest total planned investment
France	2024-2032	No	No	Second highest total planned investment.
Belgium	2024-2038	No	Yes	Likely that not all planned investments after 2034 are known.
Netherlands	2024-2026	Yes	No	
Finland	2024-2036	No	No	
Denmark	2024-2033	Yes	No	
Spain	2024-2026	No	No	
Italy	2024-2026	No	No	
Slovenia	2024-2032	Yes	No	
Greece	2024-2028	No	No	
Latvia	2024-2032	No	No	
Estonia	2024-2035	No	No	
Lithuania	2024-2030	No	No	
Slovakia	2024-2040	No	Yes	Likely that not all planned investments after 2029 are known.
Cyprus	2024-2032	Yes	No	
Portugal	2024-2025	Yes	No	
Romania	2024	No	No	
Malta	2024-2031	Yes	Yes	Country with the lowest planned investments, but more investments after 2027 might be planned.

Note: For the Member States Austria, Bulgaria, Croatia, Czech Republic, Hungary, Ireland, Luxembourg, Poland and Sweden no planned investment data is available.

Germany and France show the highest planned investments, with Germany's total reaching €204.63 billion, reflecting its significant needs for an expansion of its distribution infrastructure. France follows with €54.75 billion in planned investments. Additionally, as can be seen in the table, investment projections cover varying periods for each MS. Notable, there is **limited availability of data on planned investments across multiple regions in Europe**. The least data is available in Central and Eastern Europe, with only €12 billion in planned investments, while the most data is available for

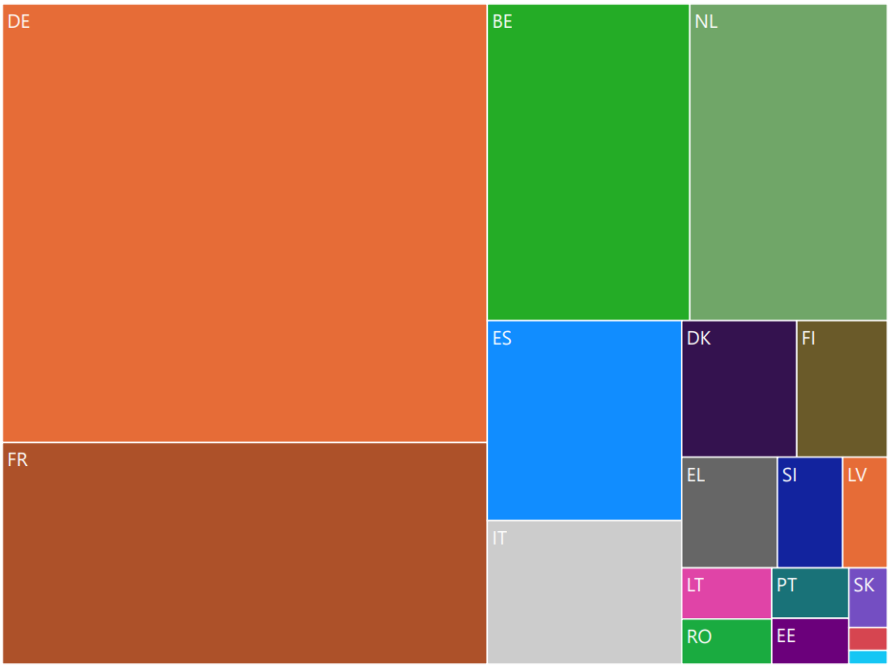
[36] European Commission (2024). Impact assessment report 2024
[37] European Commission (2021). EU reference scenario 2020

Western Europe, which shows a significant €311 billion in planned investments. The breakdown for other regions is as follows: Northern Europe with €18 billion and Southern Europe with €15 billion.

We note that data availability is very different across the EU-27. In Western Europe, projections are in some cases for very long periods of time with reasonably accuracy (e.g., Germany until 2040), or in some cases for shorter durations (e.g., Netherlands until 2026). In Northern Europe, where data is available, it is usually provided until the early to mid-2030s. The Central and Eastern Europe and Southern Europe had less data access, with some countries having very few years of data or no data available at all. Overall, data was not available for Austria, Bulgaria, Croatia, Czech republic, Hungary, Ireland, Luxembourg, Poland, and Sweden. This study aims to estimate the investment needs for these Member States by analysing demand forecasts and relevant infrastructure development patterns of with the methodology is further explained in Annex 1.2. Without these estimates, it would be difficult to form a complete picture of necessary investments in the EU's distribution grids. We first review investments excluding these estimates (i.e. including only planned investments based on available data), and then include them in the overall analysis to present a full picture.

Figure 2-9 presents the annual planned investments, calculated by dividing the total planned investment by the number of years for which data is available . This approach provides a clearer view of the yearly planned investments and highlights the variation between Member States. Additionally, for some countries, a downward trend can be recognised over the years in planned investment, where investment plans are still incomplete for later years. For these countries, investments in later years are not taken into account in the figure. Examples of countries where this is the case are Belgium, Slovakia, and Malta. Later in this section the total numbers are estimated and the total investment needs of the distribution infrastructure is determined instead of only the planned investments, which is further explained in the methodology in Annex 1.2.

Figure 2-9 Annual planned investment into the distribution grid



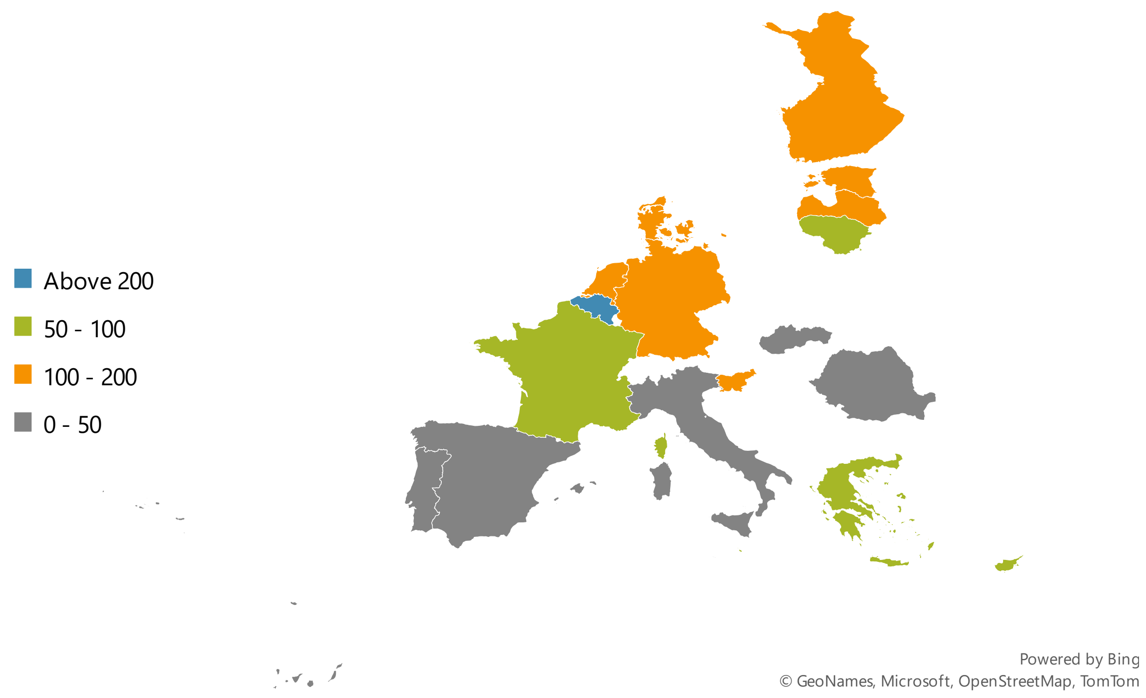
Country	Annual planned investments (€b/y)
DE	12.04
FR	6.08
BE	3.63
NL	3.54
ES	2.20
IT	1.58
DK	0.89
FI	0.70
EL	0.60
SI	0.41
LV	0.28
LT	0.26
RO	0.23
PT	0.22
EE	0.20
SK	0.13
CY	0.05
MT	0.03
AT	0.00
BG	0.00
CZ	0.00
HR	0.00
HU	0.00
IE	0.00
LU	0.00
PL	0.00
SE	0.00

Note: Austria, Bulgaria, Croatia, Czech Republic, Hungary, Ireland, Luxembourg, Poland and Sweden are not taken into account for this analysis, because no planned investment data is available for these Member States. Additionally, for some countries, a downward trend can be recognized over the years in planned investment, which may indicate that not all investments for the later years are already known or planned. It is likely that more investments will be planned in later years, resulting in a higher percentage of planned investments. Therefore, not all planned investments are taken into account in this figure. Examples of countries where this is the case are Belgium, Malta and Slovakia

The numbers from Figure 2-9 indicate that the main source of investment is planned in Western European countries. Germany and France exhibit the highest annual planned investments, with Germany leading at €12.04 billion per year, while France follows with €6.08 billion annually. Belgium and the Netherlands also feature prominently, with annual planned investments of €3.63 billion and €3.54 billion.

Figure 2-10 presents the average **annual per capita costs of planned investments** in the distribution grid for each country. Take into account that, for some countries, planned investments are published for more years than for others, resulting in different time spans being considered when calculating the average cost per year. The average annual cost of the planned investments is then divided by the population of each country to obtain the per capita investment cost. The figure shows a wide range of per capita costs, reflecting differences in both planned investments and population sizes across the different member states. Several countries, including Austria, Bulgaria, Croatia, Czech Republic, Hungary, Ireland, Luxembourg, Poland, and Sweden, are not taken into account for this analysis, because no planned investment data is available for these countries for the analyses of this project. In the next section, planned investments for Member States where data is currently unavailable will be estimated. These estimates will rely on the changing demand forecast of the Member states, as detailed in Annex A.1.2. For these countries, the methodology will generate investment figures for both the planned investments and the investment needs by looking at the European average by a changing demand. For countries where data is available but only for a limited period (e.g. up to 2032), the gaps in projections up to 2040 will be estimated based on trends and relevant factors.

Figure 2-10 Per capita cost per year of planned investment into distribution grid infrastructure (€$_{2024}$ billion/year per capita)



Note: Austria, Bulgaria, Croatia, Check Republic, Hungary, Ireland, Luxembourg, Poland and Sweden are indicated as 0 for this analysis, because no planned investment data is available for these Member States.

Overall, investments on a per-capita per-year basis indicate some differences in how much grid buildout and renovation is being done across the EU. Belgium, with costs of €307 per capita per year, and the Netherlands, with costs of €197 per capita per year, have highest annual per capita costs, reflecting high annual planned investments relative to their populations. These figures can be attributed to a variety of factors, including the extensive grid upgrades countries are undertaking to meet increasing electrification demands and accommodate renewable energy integration. Additionally, the high-voltage nature of the distribution grid projects plays a significant role, as higher voltage lines, common for these DSOs, require more capital-intensive investments. Other countries with high per capita investment costs include Latvia at €150, Denmark at €149 and Estonia at €146 annually. Experts noted that the size of the population is not always a key determinant of investment levels, but that the technical requirements of the grid and regulatory frameworks also play a major role.

Germany, with annual costs of €144 per capita and Finland, with annual costs of €124 per capita, also show considerable investment plans. In Germany, DSOs handle high-voltage lines, adding to the complexity and expense of their grid expansion plans. In contrast, Finland's high per capita costs are driven by the need to expand its grid to cover large, sparsely populated areas, where long lines are required to connect rural consumers to the central grid.

On the other hand, Spain with annual costs of €45.2 per capita and Italy with annual costs of €26.7 per capita, have relatively low annual per capita costs for their published planned investments compared to other EU-27 countries. These figures can be explained by several factors. First, Spain and Italy's DSOs operate primarily at lower voltage levels, which inherently reduces the cost of grid upgrades compared to countries like Germany or Belgium. Additionally, these countries may still be catching up on implementing large-scale grid modernisation and expansion projects.

Experts further noted that different regulatory frameworks across Europe influence the availability of investment data and the scale of planned investments. For example, in France, the government plays a more active role in financing electricity costs, resulting in a different financial model for DSOs compared to countries like Germany, where investment decisions are more market-driven and reflect higher direct costs.

Examples of physical infrastructure in DSO investments

The amount of physical infrastructure corresponding to DSO investments varies greatly across region and time. DSO needs evolve significantly over time, as later investments are expected to be far more in digitalisation and other areas different from "traditional physical grid infrastructure" such as transformers, lines and cables, and structural equipment. Different DSOs across the EU-27 also have vastly different infrastructural needs, in terms of transformers, lines and cables, electronics (including digitalisation and smart metering), structural components, and other materials and equipment. The specific geographical, political, and historical situation of each DSO also creates significant differences between the infrastructural plans of DSOs in the coming years.

In addition to this, our review of data presented little reliable quantitative information on the physical infrastructure corresponding to infrastructure build-out by DSOs. The very different regulatory setups in different countries and varying approaches to DSO management and ownership leads to highly different levels of data availability. In view of this, we review 3 case examples to illustrate briefly how different physical infrastructure is developed at 3 different DSOs in different parts of Europe. These three DSOs provide some level of detail on a long timespan about their expected investments, while each representing a rather different historical, political, and geographical context for DSO network development.

Slovenia - ELES

Slovenia's primary DSO, SODO DOO, was merged with the transmission system operator, ELES DOO, in late 2023. The two systems are thus now managed by the same entity, while having a more complex operational structure (details in the Slovenian energy agency website[38]). For simplicity, we refer here to the grid as planned by the DSO prior to the merger, and reported and discussed in their NDP published in late 2022.

As of 2021, the DSO owned 919 km of 110kV lines, 44726 km of 400V lines, and 17610 km of lines at intermediary voltage levels (35 kV, 20 kV, 10 kV). In terms of substations, the DSO maintains 174 HV-MV and 15882 MV-LV substations.

Over the 2023 to 2032 period, the DSO's plans are strongly characterised by the need to refurbish outdated infrastructure in substations and to a lesser extent lines, improve line capacities to meet demand and connections, and provide adequate improved reliability. These include investments into 63 HV-MV substations, 13543 MV-LV substations, 10440 km of MV lines, and 22706 km of LV lines. The lines consist of about 2/3 new builds, HV-MV substations are mostly refurbishments, and MV-LV substations consist more or less equally of refurbishments and new builds. However, direct information on the developments in the 110kV grid were not available. ELES (formerly SODO) accounts € 3534 million to develop these assets, together with other secondary equipment, documentation, flexibility and digitalisation expenses, and other costs. Investments are expected to scale up from €190 million in 2023 to reach €424 annually in the 2028-2032 period. The share of investment in 110kV facilities is 12%. Overall, about 75% of investments is going towards new builds while 25% is for refurbishments.

France – Enedis

Enedis is the largest French DSO, and the largest in Europe (as of 2021), serving 37 million customers across France. Enedis operates about 660000 km of MV (at 20kV and below) and 730000 km of LV (400V) lines (as of end of 2021). These networks are connected to each other via LV-MV substations (801000) and connected upstream to the HV grid via MV-HV substations (2300).

Enedis's investments in the grid up to 2032 are driven by rapid expected growth in EV chargers, solar and wind generation, and stable demand from other sources. These plans include various buildouts and refurbishments of substations and lines, improvements in digitalization and cybersecurity, and other grid investments, on which precise quantitative data on physical asset changes were not available. Sources (primarily the NDP) indicate the following investments are part of the DSO's investment plans in the 2022-2032 period:
Enedis's investments in the grid up to 2032 include:

- About 10 new primary substations per year.
- Enhancing digitalisation and cybersecurity (enhancing security of primary urban substations, replacement of smart meters)
- Replacement of MV and LV oil paper insulated and other incident-prone cables
- Scheduled refurbishment of 68000 km of lines in 2022-2032 period
- Undergrounding or consolidation of 20000 km of overhead lines, which are considered at risk due to environmental and climate factors.

Estonia - Elektrilevi

The Estonian distribution grid, Elektrilevi, is the major DSO in Estonia, representing about 95% of all connected customers (99% when including its subsidiary Imatra Elekter). The DSO maintains, as

[38] https://www.agen-rs.si/web/en/esp/ee/distribution-network

of 2022, 231 primary substations and 25256 MV-LV substations; 60716 km of lines (distributed among bare overhead, covered overhead, and cabled lines).

Elektrilevi supplies the low-population-density and highly forested country, and faces aging equipment which had a brief pause in refurbishments following Estonia's independence. The NDP for the 2024-2035 period focuses on improving system reliability, while allowing for higher rates of demand and generation to appear on the distribution grid. The NDP highlights that various reliability and system security metrics aim to be improved, including:

- Eliminating bare wire at the low voltage level by 2030, from 1293 km in 2024.
- Reducing bare wire at the medium voltage level from 13383 km in 2024 to 10403 km in 2035.
- Improving weather-proofing of the low voltage network (96% to 100% from 2024 to 2030) and the medium voltage network (47% to 63% from 2024 to 2035).
- Ensuring all medium-voltage masts are earthed by 2030 (currently 12857 unearthed).
- Eliminating old voltage connection points by 2028 (from 306 in 2024).
- Completing requirements for 15-minute metering periods, currently at 8%, to 100% by 2030, which will require a large-scale replacement of meters.
- Reducing the number of faults by one-fifths in 2035 (from estimated 10100 in 2024).

The investment amount allocated for these changes, along with new line developments, is about €859 million over the 2024-2035 period. A more ambitious plan, with higher targets for the aforementioned criteria while requiring €2 billion of investments, is also developed. The ambitious plan has higher dependency on major financing improvements and/or changes in how network assets are accounted for by the regulator.

2.2.3. Analysis of estimates of investment needs

The analyses of the distribution infrastructure investments draw on data from NRA survey responses and DNDPs data. Where data from these sources was unavailable, the planned investments were supplemented by **estimates generated using demand forecasts** and data from the European Commission's 2020 Reference scenario report[39] and 2040 Climate Target Impact Assessment report.[40] The methodology to estimate the annual investment needs is further elaborated in Annex .1.2. For this analysis, **Scenario 1 and Scenario 3** of the 2040 Climate Target Impact Assessment were chosen:

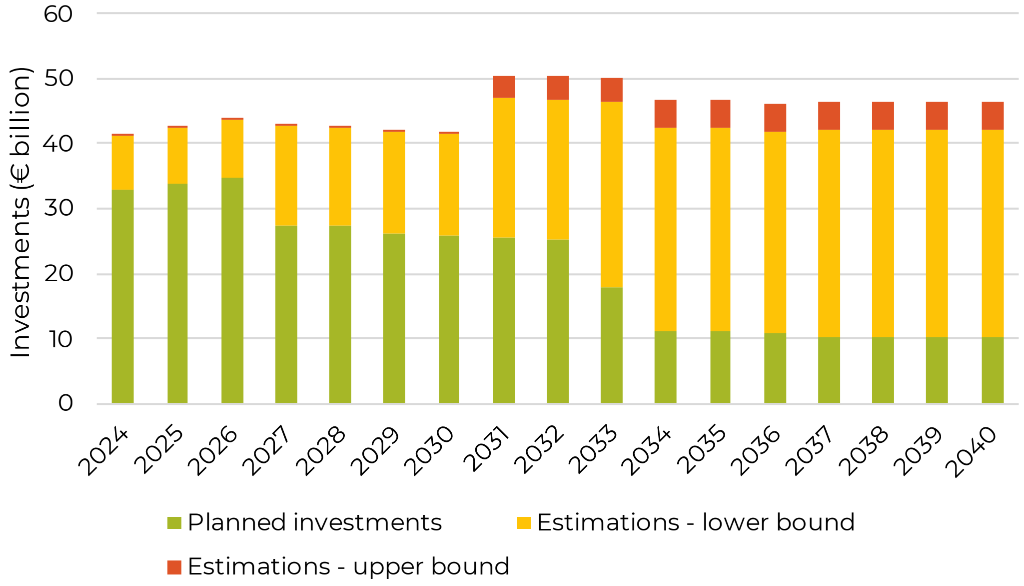
- **Scenario 1** aligns with the "Fit-for-55" energy trends, focusing on a linear reduction in net greenhouse gas emissions by 2040, with further reductions expected to meet climate neutrality goals by 2050.
- **Scenario 3** anticipates a 90% reduction in emissions by 2040, with a substantial increase in renewable energy adoption, electric vehicles and other advanced technologies. It reflects on higher investments required to achieve deep decarbonisation.

Figure 2-11 presents an analysis of **projected investment needs** for EU distribution grids from 2024 to 2040. The data includes the annual planned investments, annual estimated investment on both Scenario 1 and Scenario 3 of the 2040 Climate Target Impact Assessment. The "Planned investment" column presents the actual planned investments in billion euros for each year, based on data from NRA survey responses and investment needs data from DNDPs. The values represent the investment

[39] European Commission (2021). EU reference scenario 2020
[40] European Commission (2024). Impact assessment report 2024

plans already laid out by the Member States. Additionally, the planned investments are supplemented by estimates consisting of a lower and an upper bound, based on Scenario 1 and Scenario 3 of the 2040 Climate Target Impact Assessment.

Figure 2-11 Investments into distribution infrastructure between 2024-2040 (EU-27)



The planned investment levels remain relatively high from 2024 through 2026, partly explained by the fact that most countries have published data on their planned investments during these years. After 2026 a gradual decline is observed until 2030, which is partly due to the lack of detailed investment data beyond 2026. The limited availability of specific planned investments from 2027 onwards results in a higher reliance on estimates for projecting future investment needs. After 2032, this reliance on estimates only increases, as fewer countries have provided concrete plans for investments beyond this point, making projections on investment needs more uncertain and heavily dependent on the demand forecasts and scenarios.

The lower-bound estimates are based on the 2024 Impact Assessment Scenario 1 and the upper-bound estimates, are based on 2024 Impact Assessment Scenario 3, representing a more aggressive need for investment in the distribution grid. The extra added value by the upper bound is very low in the early years, 2024-2030, but increase starting in 2031, reflecting the difference in demand forecast between Scenario 1 and Scenario 3 of the 2040 Climate Target Impact Assessment.

Because the analysis calculates the average cost for the yearly demand growth forecasted for the countries where data is available, as further explained in Annex A.1.2, it can be seen in our results that Scenario 3 acts as the lower bound for the years 2024 to 2030 and the higher bound for the years 2031 to 2040. This is due to the fact that the growth in demand forecast between Scenario 1 and Scenario 3 is the same from 2024 to 2030, but from 2031 onward, the demand forecast in Scenario 3 rises significantly, requiring higher investments.

The higher investment in electricity distribution infrastructure in some Member States are driven by a variety of factors, including the need to integrate renewable energy, modernise aging grids, accommodate shifts in demand patterns, align with both domestic and EU-wide energy policy and geographic factors play a key role:

- **Energy transition and renewable energy integration**: Unlike conventional fossil fuel generation plants, which are typically large and centralised, decentralised renewable generation, such as rooftop solar PV and small wind farms, is distributed across various locations. These renewable sources are often intermittent and geographically spread across a wide area, which presents challenges for distribution grids that were not designed for such capacity and variability. This shift requires investments in grid flexibility, automation, and reliability to manage the fluctuating energy supply and ensure stable access to the distribution network. Member States expanding renewable energy need modern distribution grids capable of handling variable and decentralised energy inputs more efficiently than traditional systems.

- **Shifting demand patterns and peak demand**: Even if total energy demand remains stable, peak demand is expected to rise due to the increasing adoption of electric vehicles, heat pumps and other electrification technologies. This rise in peak demand requires substantial upgrades to distribution infrastructure to handle higher load during peak hours. Member States investing in electrification will need to strengthen their distribution grids accordingly.
- **Digitalisation and smart grid technologies**: The integration of digital technologies, such as smart meters and advanced monitoring systems, is transforming the way distribution grids are managed. Digitalisation enables better visibility, control and efficiency, but it also requires significant initial investments in smart infrastructure. These technologies are crucial for managing demand-response measures and for integrating distributed energy resources into the grid effectively.
- **Refurbishment and modernisation of existing infrastructure**: In many Member States, investments are directed not only towards new infrastructure but also towards refurbishing and upgrading existing distribution networks. The extent of these refurbishments varies based on the age and condition of the current grid. Member States, such as Italy, may require more extensive modernisation efforts, while others are continuously expanding and upgrading their grids to keep pace with evolving energy demand. Additionally, the need for upgrades is influenced by the grid's existing reliance on fossil fuels, with more fossil-dependent infrastructures requiring greater efforts to transition to renewable energy compatibility.
- **Anticipatory investments**: Anticipatory investments involve proactively expanding grid capacity when grid reinforcements or other works are already planned, rather than making incremental upgrades based solely on current needs. This approach is particularly cost-effective, as increasing capacity typically adds only 10-20% to project costs, while providing infrastructure that can handle future demands from electrification, renewable energy integration and other projects. For instance, when upgrading grid components like transformers or cables, most of the project costs are fixed (such as installation and permitting), so increasing capacity slightly raises the overall cost, but by taking a forward-thinking approach, this strategy reduces the need for repeated upgrades as demand grows, saving investment needs in the long run for Member States. However, successful implementation requires accurate long-term forecasts, supported by smart meter data and insights into consumer behaviour. ACER and CEER highlight in their report that anticipatory investments are not explicitly defined or treated as a distinct category in national regulatory frameworks. Instead, forward-looking planning, including the consideration of future generation, demand and renewable connections is already an existing practice for some DSOs[41].
- **EU regulation and cross-border cooperation:** While the focus on cross-border electricity exchanges tends to fall more heavily on transmission infrastructure, distribution networks are also affected by EU energy market integration. Cross-border projects at the distribution level may be increasingly implemented in the future. For example, when Member States are participating in large-scale renewable energy projects, robust distribution systems are

[41] ACER and CEER (2024). Position on anticipatory investments

needed to manage local energy needs while also contributing to broader energy exchanges. Investments in distribution networks ensure that local grids are prepared to handle these investments.

- **Energy security and independence**: Geopolitical shocks, such as the 2022 Russion invasion of Ukraine, have underscored the importance of energy security and independence. Member States like Denmark and Germany are investing heavily in distribution infrastructure to reduce reliance on imported energy and maximise the use of domestically generated renewable energy.

Some challenges were identified across the EU-27 that affect the development of distribution grid infrastructure. These challenges vary significantly between different DSOs, influenced by their size and the Member State in which they operate, as well as across voltage levels. Larger DSOs with more resources often face different obstacles compared to smaller operators, and the regulatory and financial environment of each Member State further shapes these challenges. These differences present distinct barriers to investment timelines, costs, and the overall effectiveness of grid upgrades. Additionally, many of the challenges face by transmission infrastructure, as mentioned in Section 2.1.1, also apply to DSO infrastructure. These include issues like material shortages, labour constraints, political uncertainty and permitting delays. Some specific key challenges impacting distribution infrastructure investments include:

- **Material shortages**: While material shortages were already highlighted as a key challenge for TSO infrastructure, DSOs are facing similar issues. The rising demand for materials like high-capacity cables, transformers and other critical components has not been matched by production capacity. The increased demand together with national and international competition for these materials further adds to the problem, making it harder for DSOs to meet their investment needs.
- **Labour shortages**: In recent years, while also affecting TSOs, labour shortages are particularly challenging for DSOs due to the sharp increase in planned investments and grid projects. For instance, Denmark has seen a significant ramp-up in grid expansion projects, which put additional pressure on the labour market. Across Europe, many DSOs, especially in urban areas, are struggling to find enough qualified personnel to manage the growing number of projects. This shortage of labour leads to significant project delays and rising costs for DSOs, complicating efforts to upgrade and expand distribution grids in line with the increasing demand for electricity.
- **Past underinvestment:** Many DSOs are now dealing with the effects of not investing enough in their grid infrastructure over the years. These outdated networks often lack the capacity to handle new demands. This lack of past investment has left grids unprepared for the energy transition, making urgent upgrades necessary to prevent bottlenecks. In the Netherlands, the impact of this underinvestment is clear, with significant grid congestion becoming a major issue. The rapid growth of solar power has been far higher than originally planned for by grid operators, limiting their ability to distribute electricity efficiently. Many regions are now facing grid capacity limits, preventing new projects from connecting to the system. For example, Greece has experienced long-term effects from underinvestment, particularly after the financial crisis. For years, grid investments were put on hold, limiting the system's ability to support new energy demands. Recently, Greece has started to make major improvements. These upgrades are crucial for handling higher energy demands and the integration of decentralised RES.
- **Permitting and regulatory delays**: Getting permits and regulatory approvals is a slow and complicated process for DSOs. In urban areas with a lot of people and limited space, these processes take even longer. The need to work around existing infrastructure, such as roads, buildings and other utilities, adds significant complexity to project planning. Additionally, the dense environment also increases the likelihood of disruptions to public services during construction, which requires more extensive coordination. Furthermore, smaller DSOs, with

fewer resources, are especially affected by these delays, which can stretch projects out over many years. When EU funding is involved, the approval process becomes even more complicated and time-consuming, causing further delays.

- **Financial constraints and CAPEX bias**: Financial constraints are a persistent issue for smaller DSOs, who struggle to secure sufficient capital for large-scale infrastructure projects.[42] Larger DSOs typically have access to a broader range of financing options, while smaller operators often face challenges due to their lack of scale. The financial limitation is further compounded by CAPEX bias, where CAPEX for infrastructure upgrades is prioritised over OPEX. CAPEX investments are favoured because they can be included in the Regulatory Asset Base (RAB), allowing DSOs to earn a regulated return. As a result, cost-effective operational improvements, such as efficiency upgrades, often receive less attention. However, some DSOS are transitioning to a TOTEX model, which integrates both CAPEX and OPEX into a unified investment framework. In this model OPEX typically stays below 5% of TOTEX, with the majority of expenditures still directed towards CAPEX costs.
- **Capacity for anticipatory investments**: Larger DSOs, with greater financial resources and stronger planning capabilities, are better equipped to make these proactive investments. They can plan for long-term needs, reducing the need for repeated upgrades in the future. Smaller DSOs, however, often lack both the funds and the long-term planning to implement these forward-looking strategies.
- **Network planning issues:** Differences in how Member States plan and manage their grids create challenges for DSOs. Some Member States have stronger legal commitments to their DNDPs, which make their grid expansion projects more reliable. In other regions, outdated plans or inconsistent regulations lead to delays and underinvestment.

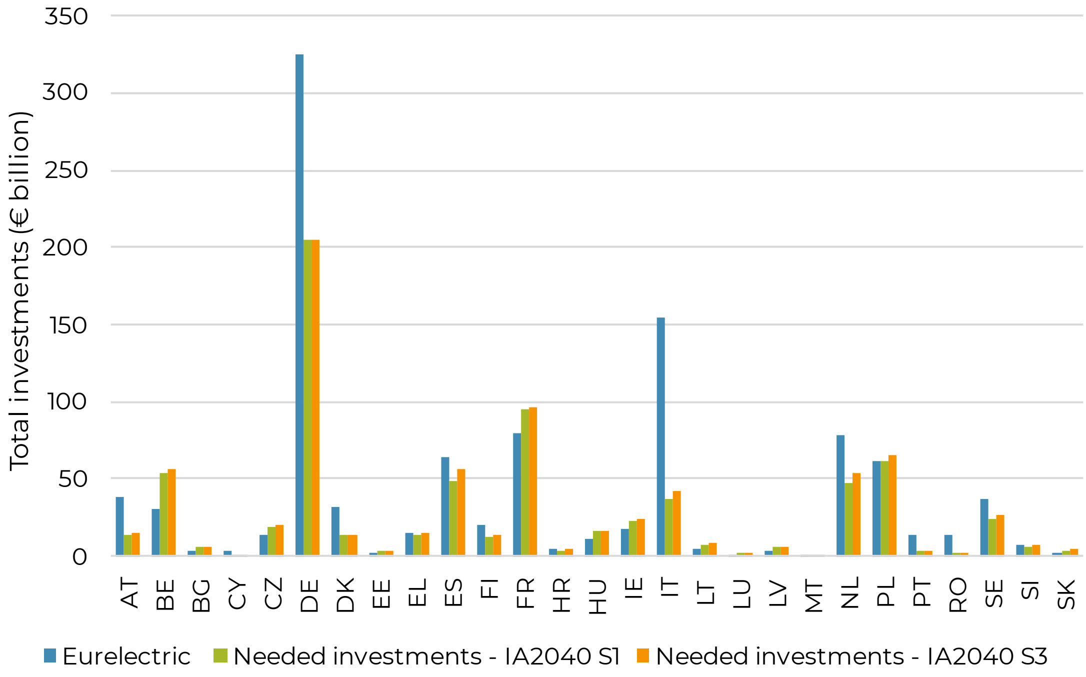
2.2.4. Comparison with other estimates of investment needs

Other studies have been conducted to investigate the investment needs in the distribution grid. Eurelectric's Grids for Speed study[43] states that grid investments need to nearly double from the current €36 billion to an annual average investment of €67 billion until 2050. This increase is primarily for 43% demand-driven reinforcement. The categories for this investment include demand-driven reinforcement, generation-driven reinforcement, replacement and renewal, targeted resilience, smart metering, and automation and system digitalisation. The Eurelectric's study stated that investment may need to double to approximately €72 billion in the year 2040, compared to the current €36 billion, and then continue at 1.7 times the current levels through to 2050. Furthermore, this study also includes an analysis that estimates the annual grid investment requirements for the EU-27 countries + Norway on a country-by-country basis, in the period form 2025 till 2050.

Figure 2-12 presents a comparison of total expected investments from the Eurelectric (2024) study and our estimates based on Scenario 1 and Scenario 3 of the 2040 Climate Target Impact Assessment. The differences between Eurelectric's estimates and those based on Scenarios 1 and 3 underscore the uncertainties and challenges in forecasting investment needs. We note that there are significant differences in scoping and methodology between the Eurelectric (2024) study and this study, leading to differences in outcomes. The studies use differing demand projections, while the Eurelectric study also makes use of projections with generation and other factors impacting grid investments. Moreover, Eurelectric's study relies on a sample grid model optimisation for calculating investments for some countries.

[42] Based on information from interview with Danish DSO, which was part of the current study.
[43] Eurelectric (2024), Grids for Speed

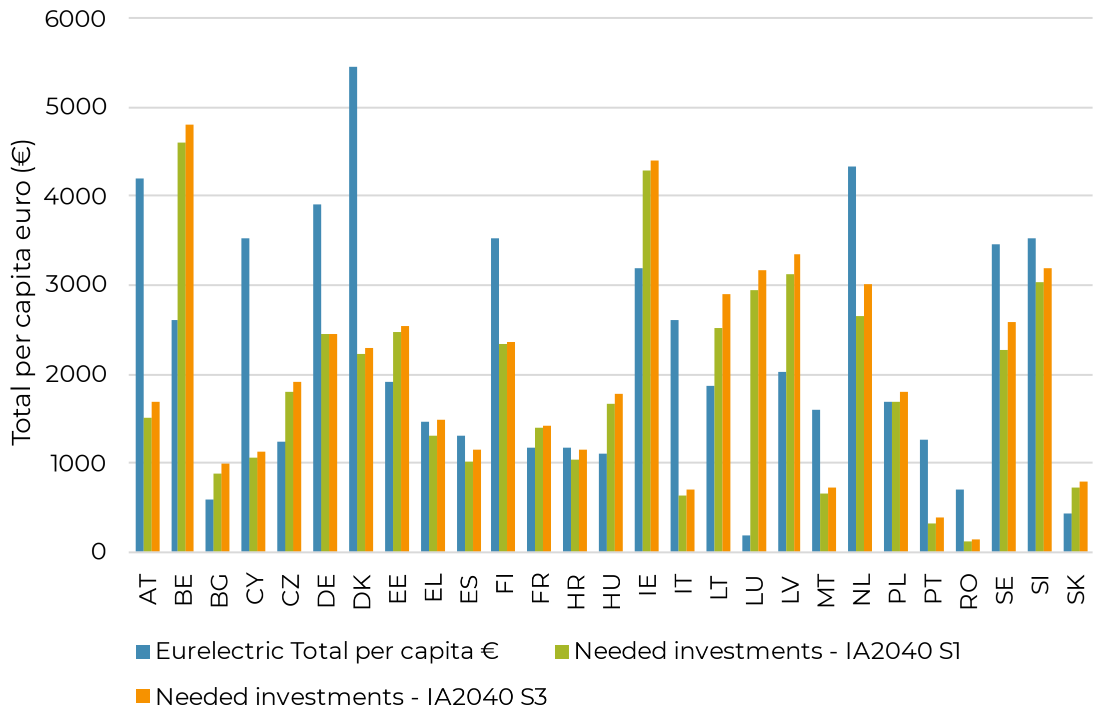
Figure 2-12 Total expected investments into the distribution grid by 2040 – comparison with Eurelectric (2024)



In comparing the investment estimates for distribution grids across various EU countries, some differences emerge between Eurelectric's projections and those based on Scenario 1 and Scenario 3. For Austria, the S1 and S3 scenarios estimate much lower amounts than Eurelectric results with €13.83 billion and €15.45 billion, respectively. In other countries, the situation is reversed. the S1 and S3 scenarios, project for Belgium €54.36 billion and €56.84 billion of investments, thus higher volumes than Eurelectric results. For Germany, both the S1 and S3 scenarios estimate lower investments than Eurelectric results with €204.6 billion. This significant difference suggests that Eurelectric foresees greater investment requirements for Germany's grid infrastructure, possibly due to more conservative estimates or the inclusion of additional factors not considered in the scenarios. In other cases, such as for Slovenia and Poland, investment estimates from the Eurelectric study and the current study are rather similar.

We lastly compare investment volumes on a per-capita basis with the Eurelectric (2024) study. This comparison can present differences in investments across different MS in the EU-27. Figure 2-13 compares the estimated total per capita investments from three sources: Eurelectric's estimates, and the expected investments under IA2040 scenario 1 and IA2040 scenario 3. Denmark has the highest per capita investment costs according to the Eurelectric study, with an estimate between €5 and €6 thousand per person. This figure is significantly higher than the per capita investments projected under IA2040 Scenario 1 (€2,219) and IA2040 Scenario 3 (€2,284). The substantial difference suggests that Eurelectric anticipates much higher investment needs for Denmark's distribution grid compared to the scenario-based estimates. This could be due to factors such as extensive grid modernisation requirements, higher integration of renewable energy sources, or addressing existing grid congestion that may not be fully captured in the scenarios. Overall, both studies highlight that there is significant variation in per-capita investments in distributions grids across the EU-27.

Figure 2-13 Total expected per capita investments into the distribution grid by 2040



These variations in Figure 2-12 and Figure 2-13 across Member States highlight **the impact of different assumptions, methodologies and the projected demand growth** on investment needs for the distribution grid. As mentioned earlier, multiple factors need to be considered. Many assumptions have been made in the analyses of this specific study. These assumptions are further elaborated and detailed in Annex A.1.2 to provide a clearer understanding of the methodologies and frameworks used in these projections.

2.3. Electricity transmission lines with a significant cross-border impact

The infrastructure analysed in this section covers annex II 1 – a of TEN-E, including onshore and subsea transmission lines which are not related to the transmission of offshore renewable energy[44]. The analysis of investment needs for this infrastructure category are mostly based on:

- Top-down studies and scenarios from the TYNDP process (TYNDP System Needs study and TYNDP scenarios)
- Project data available on the PCI/PMI transparency platform
- Project data from TYNDP 2022 and 2024 projects portfolios

2.3.1. Current status and expected future developments

To achieve its climate and energy targets, the EU needs significant investments in power exchange capacities between Member States, as their development brings several benefits to the operation of the European power system. Interconnectivity enables better use of renewables by reducing curtailment, better energy security due to increased network redundancy and the enabling of mutual

[44] Transmission lines related to offshore renewable energy (Annex II 1 – b, f of TEN-E) are addressed in the next section.

support measures, potential avoidance of CO2-emissions, price convergence between market areas, etc. In line with these benefits, the EU has set an interconnection target of at least 15% by 2030[45].

2.3.2. Top-down analysis of investment needs

The analysis of investment needs in this infrastructure category is primarily a top-down analysis based on the outputs of the TYNDP 2024 scenarios modelling process[46] as well as the TYNDP 2022 Identification of System Needs study[47] (later referred to as TYNDP 2022 IoSN). Both provide data on expected evolutions of cross-border capacities based on capacity expansion modelling as well as projects costs by border. Capacity expansion assumes a reference grid as starting infrastructure level, which is the best estimate of the state of cross-border capacities at a given timepoint. The modelling includes a catalogue of investment options with specific costs and cross-border capacity increases. These investment options are based both on real cross-border projects that have been submitted to the TYNDP process and so-called "conceptual projects" which consider standardised assumptions for costs and capacity increases.

Note that despite sharing some methodological principles, both studies have different scopes and methodologies which are further discussed in the dedicated methodology section (Section D.1.3).

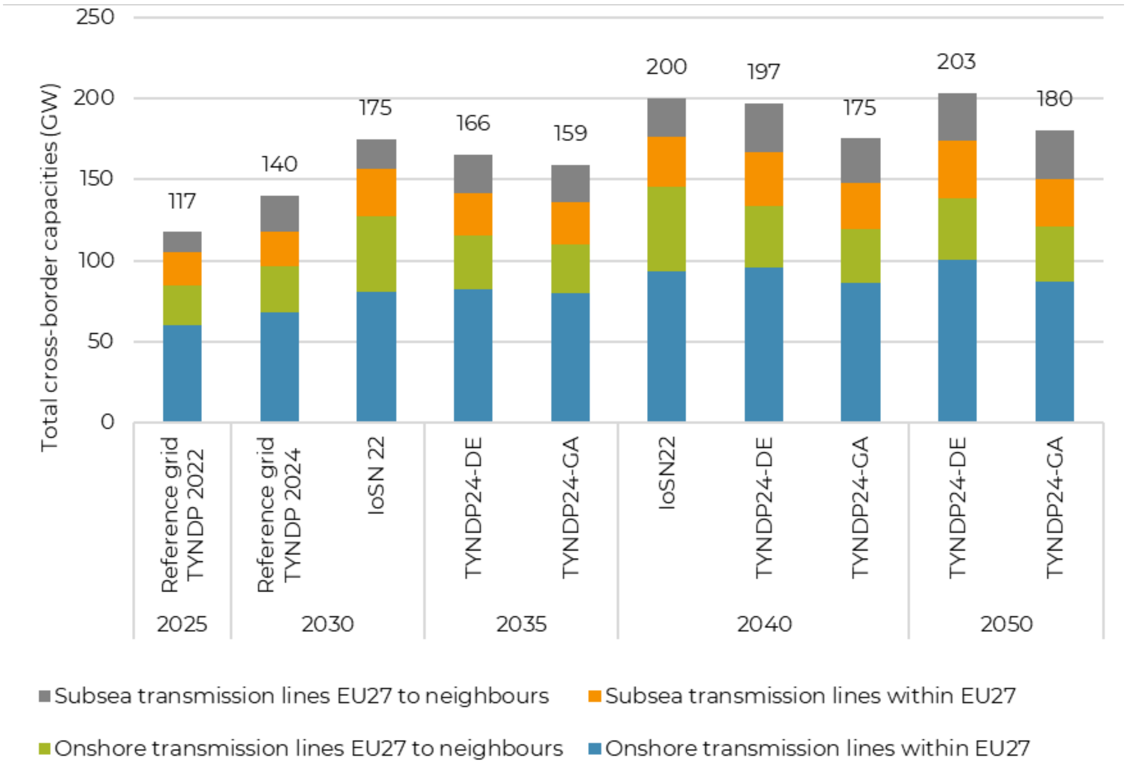
The available datasets allow to compute in each scenario the total transmission capacity on each border, as well as the capacity increases in the different periods and the corresponding investment costs.

Figure 2-14 below provides an illustration of cumulated cross-border transmission capacities across the different scenarios and years that have been analysed. Data has been aggregated with the distinction of the following categories of borders:

- Borders within EU and borders with neighbouring countries
- Land or sea borders

[45] COM(2017) 718 final
[46] (ENTSO-e / ENTSO-g, 2024), TYNDP 2024 Draft scenarios report
[47] (ENTSO-e, 2023), TYNDP 2022 System Needs Study

Figure 2-14 Evolution of cross-border capacities in the TYNDP 2024 scenarios and 2022 System Needs study

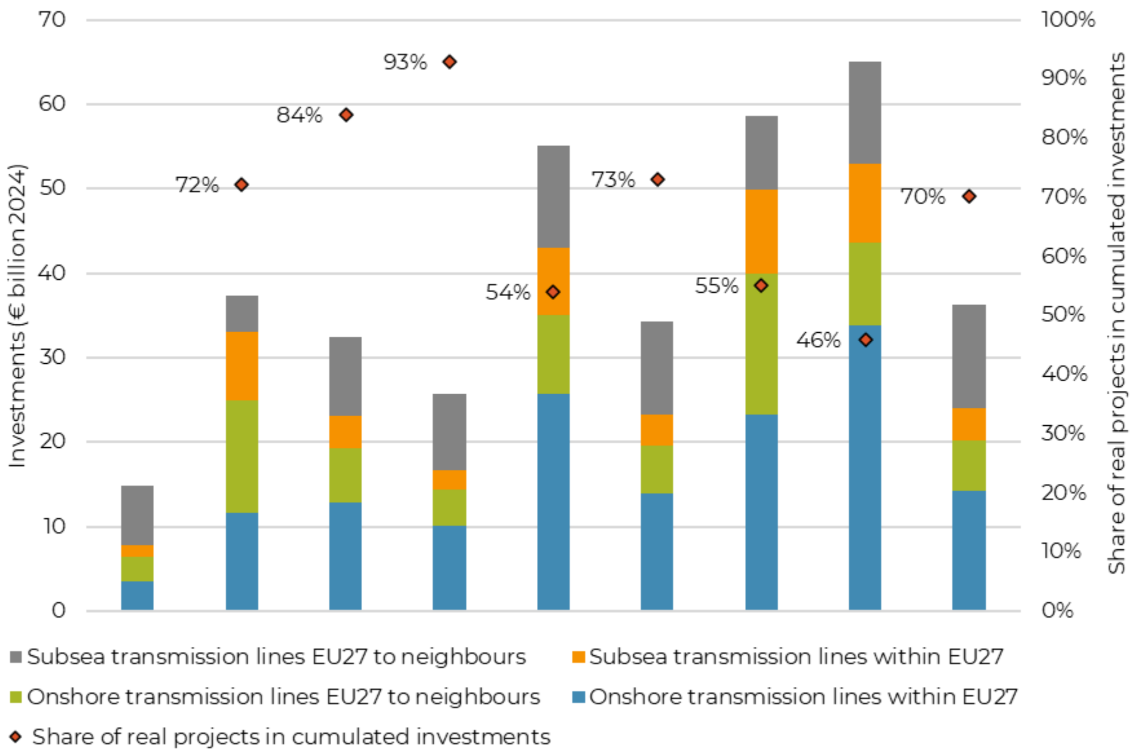


Sources: ENTSO-e, 2023[47] ENTSO-e/ENTSO-g, 2024[46]

Note: Perimeter includes cross-border capacities within EU-27 and with neighbouring countries (Norway, UK, Switzerland, the Balkans, as well as Israel, Turkey, Tunisia and Egypt). In case of asymmetrical capacities for a given border, the maximum capacity is reported. "Subsea transmission lines" category relates to subsea interconnectors (exclusive of hybrid offshore interconnectors which are treated in the next section).

While according to the current pipeline of projects reflected in the 2030 reference grid, the interconnection capacity of the European power system will increase from some 117 GW in 2025 to 140 GW in 2030, all scenarios foresee significant additions after 2030, the interconnection capacity reaching 180 GW to 203 GW in 2050. While the IoSN study does not model the 2050 horizon, it appears in both TYNDP 2024 scenarios that investments post-2040 are limited compared to capacity added up to 2040. Figures for 2030 also highlight a gap between the 58 GW capacity increments that would be cost-efficient in 2030 compared to 2025 according to IoSN study and 23 GW of capacity increments in the current pipeline of projects reflected by the 2030 reference grid.

Figure 2-15 Cumulated investments in cross-border capacities starting from the 2025 reference grid



Sources: ENTSO-e, 2023[47] ENTSO-e/ENTSO-g, 2024[46]

Figure 2-15 displays the corresponding cumulated investment needs compared to the 2025 reference grid, based on investment costs of capacity expansion candidates considered in both studies (in 2024 €) as well as the share of candidate investments labelled as "real projects" in the expansion options proposed to the optimisation (i.e. candidates for which capacity and costs correspond to real projects in the TYNDP portfolio). Overall, cumulated investment needs in cross-border transmission capacities additional to the 2025 reference grid up to 2050 reach some 59-65 billion euros in the IoSN study and in the DE scenario, while the GA scenario foresees significantly lower investment needs (€36 billion)[48]. The share of real projects in the investment candidates selected by the expansion model also reflects the gap between the needs and existing projects, as only some 54-73% of the investment needs up to 2040 can be linked to real projects.

The TYNDP 2022 IoSN investment candidates dataset[49] also provides estimates regarding the share of internal reinforcements in the cost of some of the projects considered in the expansion loop. It shows that the costs of internal reinforcements can significantly vary from a project to the other, from a few percents to up to some 90% in some cases. On average, according to the dataset, internal reinforcements represent around 45% of cross-border projects investment costs. Still, the sample showcases significant variability, with first and third quartiles standing respectively at 20% and 70% of the costs. The high variability illustrates that it is difficult to draw general conclusions about the reinforcement needs related to a cross-border transmission project. Indeed, internal reinforcement

[48] A possible explanation for this result may come from different assumptions regarding EU27 capacity mix in DE and GA scenarios. In particular, GA scenario foresees a lower solar PV capacity in 2050 (1 670 GW vs. 2 008 GW in DE).
[49] (ENTSO-e, 2023) TYNDP 2022 System Needs study Implementation guidelines

needs depend on several factors which may notably include the landing points of the interconnector both sides of the border, the evolutions of consumption and generation close to the landing points, potential other interconnection projects, etc. Typically, landing points would be chosen in such way that total costs are minimised, but other constraints need to be considered (notably projects acceptability). It is also worth noting that internal reinforcement needs may not necessarly be attributed to one cross-border transmission project or the other.

Analysis of planned investments data

The top-down approach can be complemented with a bottom-up analysis of the pipeline of cross-border transmission lines projects in the first PCI/PMI list. Cumulated investment costs associated to electricity transmission lines projects in the first PCI/PMI list reach €60 billion up to 2035 (of which €32 billion of internal projects).

Figure 2-16 Investment costs associated to electricity transmission lines projects in the first PCI/PMI list

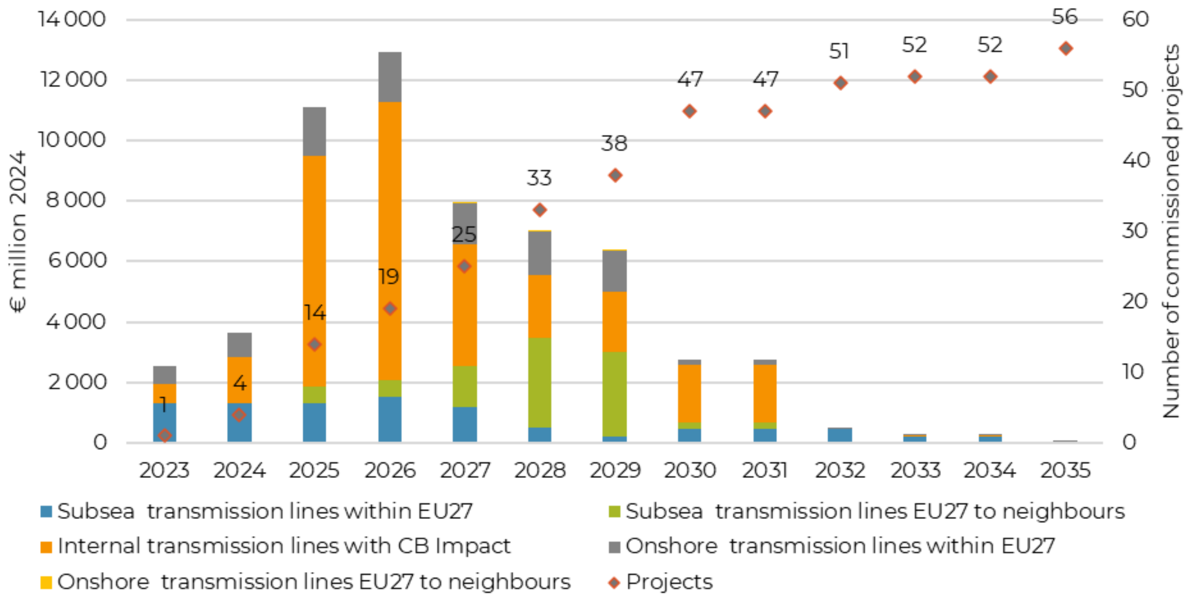
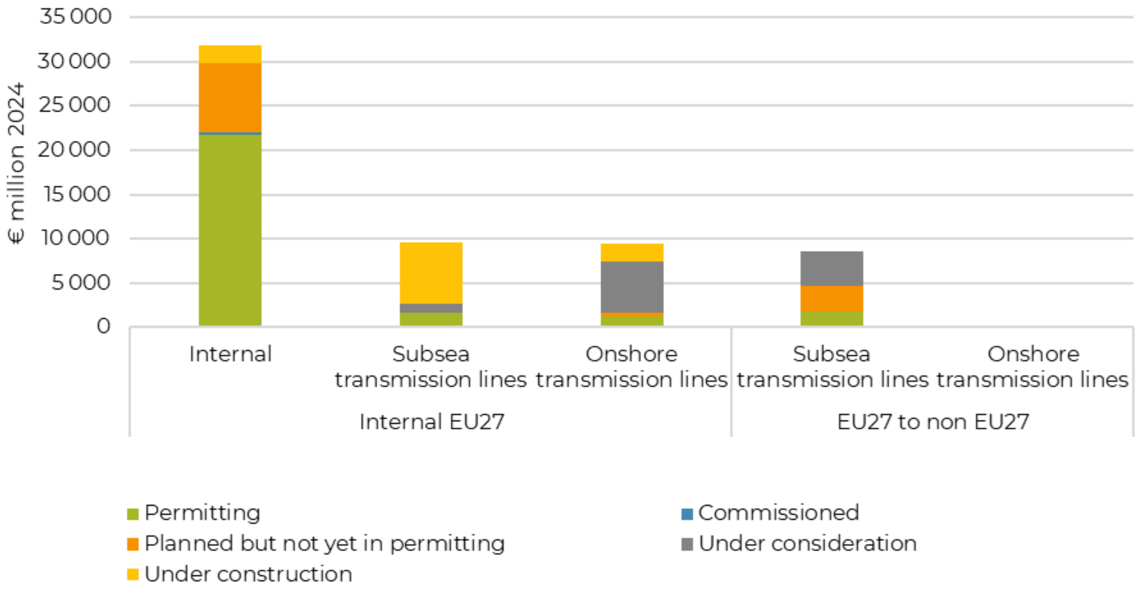


Figure 2-16 displays the yearly investment costs of projects in the PCI/PMI list[50] as well as the cumulated number of commissioned projects, with a disaggregation of projects within the EU-27 and projects including other countries. Planned investments show a peak in 2025 and 2026 which relates to several internal projects in Germany. The cross-border projects from the PCI/PMI list display planned investment costs in the range of €30,000 to €3.3 million per MW of cross-border transmission capacity increase, with an average of €0.73 million/MW, increasing to approximately €1.7 million/MW when considering subsea interconnectors only. "Real" investment candidates considered in the IoSN study display an average investment cost of approximately €0.6 million/MW of capacity increase, which is in the same order of magnitude.

[50] As a first approximation, it is assumed that projects investment costs are equally split across the project construction duration.

Figure 2-17 Distribution of PCI/PMI projects total costs according to project status



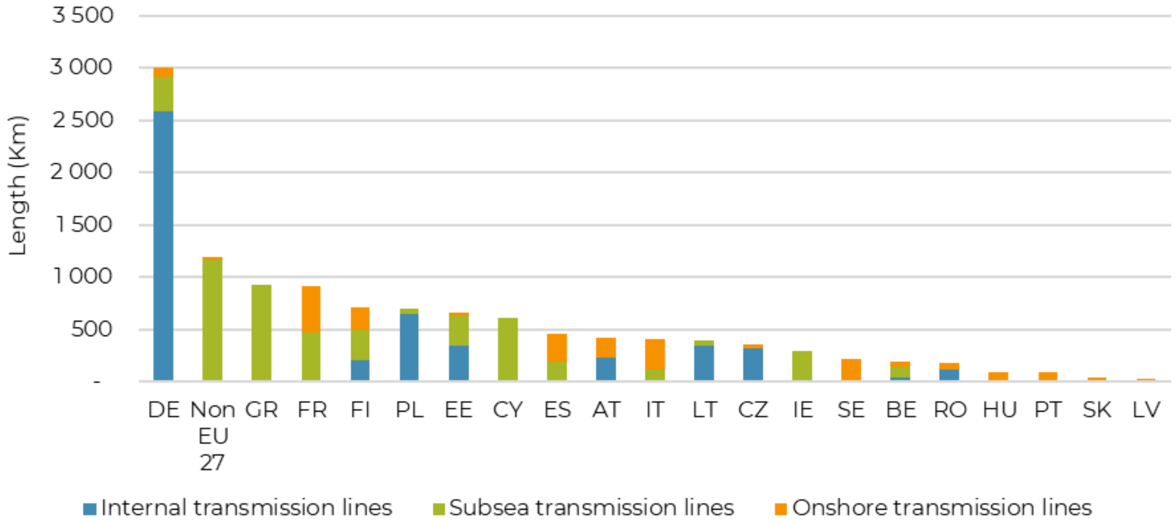
Overall, the planned pipeline of projects showcases a significant level of certainty since projects in permitting or under construction represent 63% of the planned investments, increasing to 70% when considering only projects internal to the EU-27 (Figure 2-17). The planned PCI/PMI projects represent approximately **12,000 km of AC and DC transmission lines** according to data from the PCI/PMI transparency platform. Data submitted by projects promoters to the TYNDP allows to estimate the relative shares of different equipment types in the cost of projects[51] as displayed below.

Table 2-3 Relative shares of equipment types in projects costs

Project type	AC line	HVDC line	Substations and other equipment
Subsea transmission lines	~1-3%	~65-80%	~15-34%
Onshore transmission lines	~60-70%	~30-50%	~8-15%

[51] The TYNDP project submission process allows promoters to submit several investments for a given project and an equipment type for each investment (e.g. AC line or substation). However, this step is not mandatory, and the promoters may submit the project as only one main investment, usually under the AC or DC line category, thus underestimating the share of other equipment (substations, transformers…) in project costs. We therefore report ranges for the different equipment types.

Figure 2-18 - Total length (km) of planned transmission lines by country according to projects from the first PCI/PMI list



Note: Line length is assumed to equally split between countries for cross-border projects

The list of actions funded by CEF has been used to derive an estimate of the shares of studies in projects costs. CINEA defines studies as costs that include “activities needed to prepare project implementation, such as preparatory, mapping, feasibility, evaluation, testing and validation studies, including in the form of software, and any other technical support measures, including prior action to define and develop a project and decide on its financing, such as reconnaissance of the sites concerned and preparation of the financial package”. It appears that for recent electricity transmission projects that have been granted CEF funding both for studies and works, eligible costs for studies have been in the range of 1-2% of eligible costs for works, which gives a first order approximation of the share of studies in total projects costs. ACER also publishes every three year an infrastructure reference cost dataset[52]. Based on data submitted by project promoters, it provides average breakdowns of projects costs for comparable energy infrastructure projects. Data reported by project promoters for transmission lines and substations indicate average relative shares of studies of approximately 0.75 % for overhead lines, 2.30 % for underground lines, and jn the range of 0.7-1.10% for substations[53].

Overall, both approaches converge to orders of magnitude of **1-2% of total project costs for studies**. If studies represent only 7% of funds that have been granted to electricity transmission projects by CEF actions so far[54], it is worth mentioning that studies represent a higher number of CEF actions (49 actions for studies and 26 actions for works so far).

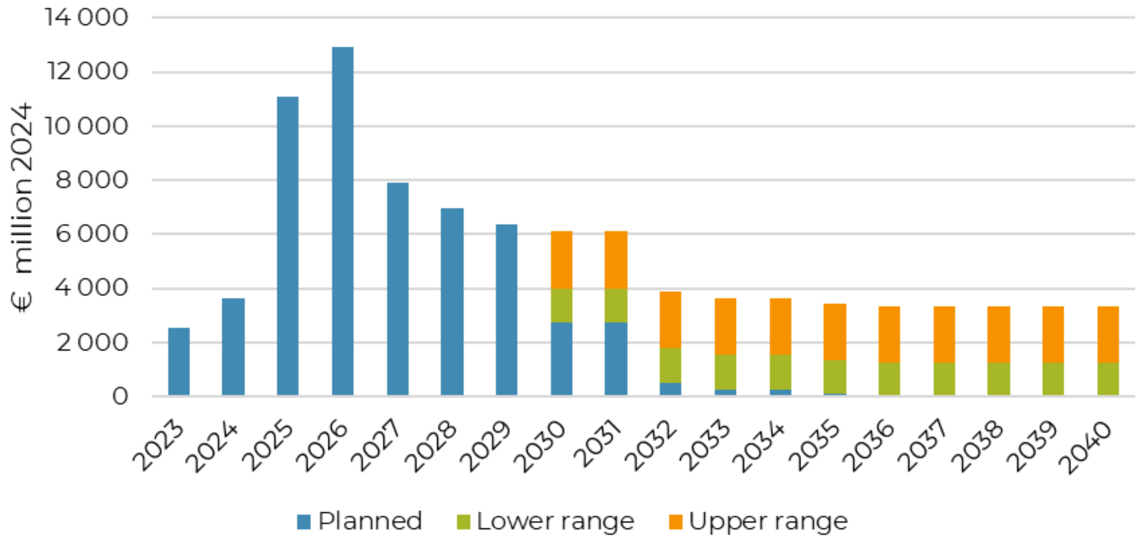
Top-down approach can eventually be used to estimate future investment needs, beyond the planned projects. PCI/PMI electricity transmission projects represent an investment of €60 billion up to 2035, of which €28 billion for cross-border projects, corresponding to an aggregated cross-border capacity increase of 35 GW. Out of the €28 billion (35 GW) planned investments in cross-border capacities, €7 billion (11 GW) correspond to projects that are considered as commissioned in the

[52] (ACER, 2023), Infrastructure reference costs dataset
[53] It was mentioned during expert interview with ACER that the dataset presents limitations to the extent that projects promoters may not submit cost of studies in a harmonized way. Only equipment categories with sample size of more than ten projects have thus been considered.
[54] (CINEA, 2023), CEF energy latest achievements and way forward

reference grid for 2025 used in the TYNDP 2022 IoSN study, meaning that the planned investments in cross-border capacities represent approximately €21 billion additional to the 2025 reference grid. This figure can be compared to a range of €35-58 billion investment needs up to 2040 starting from the 2025 reference grid identified by the IoSN study and TYNDP scenarios (Figure 2-19).

Overall, future investment needs for cross-border transmission capacities can be estimated within the range of €14-37 billion up to 2040, additionally to the already planned PCI/PMI projects.

Figure 2-19 Planned investments and estimated future investment needs



46

Note: "Planned" investments corresponds to planned cross-border projects and internal projects with cross-border impact in the first PCI/PMI list. "Lower range" and "Upper range" correspond to further investment needs in cross-border transmission lines to reach respectively the needs identified for 2040 by the TYNDP 2024 GA scenario and the IoSN study (i.e. summing respectively to €14-37 billion). Estimates do not include internal projects with cross-border impact that are not assessed in top-down studies.

It is noticeable that the planned investments trajectory may reflect a bias tending towards announcing commissioning prior to 2030. As for internal transmission lines with significant cross-border impact for which system needs are not systematically assessed in top-down studies, considering the share of internal and cross-border projects in the current PCI/PMI projects pipelines (of the order of half of projects costs in each category), future investment needs can be estimated within the same range.

Finally, it is also worth mentioning that the draft TYNDP 2024 projects portfolio[55] includes 57 new transmission projects, of which approximately half fall under the infrastructure category analysed in this section (i.e. transmission projects that are not related to offshore generation).

55 A draft TYNDP 2024 projects portfolio has been published but does not yet contain detailed data about projects (costs, dimensioning etc.)

Focus on Projects of Mutual Interest

The first PCI/PMI list includes 5 Projects of Mutual Interest in the electricity interconnectors category, with planned investments summing to €5.4 billion, i.e. some 9% of the planned investments in the list.

- The ELMED projects aims at developing a 600 MW HVDC interconnection between Sicily and Tunisia. The projects sizing is consistent with needs identified in the TYNDP 2022 IoSN study at the Italy-Tunisia border. As of TYNDP 2024 project submission, the project is under permitting, and secured €300 million fundings for works from CEF in 2022.
- The Subotica - Sándorfalva line project aims at developing a 400 kV line connecting Serbian and Hungarian transmission systems. The IoSN study reported a 500 MW capacity need for this border in 2030, and 1000 MW in 2040. The project also includes two internal 400 kV lines in Serbia deemed necessary to enable the 500 MW projected increase in NTC. The elements on the Serbian side of the project represent approximately € 41 million, additionally to the € 24.1 million cost planned for the cross-border section.
- The Cronos project aims at developing a 1400 MW DC interconnector between Belgium and the UK towards 2032. It is worth noting that the project is promoted by an infrastructure development fund (Copenhagen Infrastructure Partners) and does not appear in the Belgian NDP. The project might be competing with other planned projects, in particular the hybrid interconnector Nautilus project between Belgium and the UK which is promoted by ELIA.
- The GREGY interconnector projects aims at developing a 1472 km/3GW subsea interconnector between Egypt and Greece, in connection with the development of renewable electricity in Egypt. The project promoters also plan to invest in 9.5 GW of renewable capacity in Egypt, in connection with the project. The estimated budget is of approximately €3.6 billion, and the interconnector is expected to be commissioned around 2030. It has been included in the TYNDP since 2020. The project is currently carrying out technical studies and according to recent news, splitting the project's route to also supply Italy may be under consideration[56].
- The Tarchon project aims at developing a 1400 MW interconnector between Germany and the UK, with an estimated budget of €1.7 billion and commissioning around 2030. The project is promoted by a private investment fund (CIP, as the Cronos project) and has been included in the TYNDP since 2020. It's worth noting that the IoSN study identified capacity needs up to 2800 MW in 2040 for the Germany-UK border.

Table 2-4 List of interconnectors Projects of Mutual Interest

PMI code	Name	Border	Commissioning year	Project status	Project cost (M€)
1.19	ELMED	Italy Tunisia	2028	Permitting	850
2.12	Subotica - Sándorfalva line	Hungary Serbia	2030	Planned but not yet in permitting	24.1
1.20	Cronos	Belgium UK	2032	Planned but not yet in permitting	937
2.13	GREGY Interconnector	Greece Egypt	2030	Under consideration	3 569
1.21	Tarchon	Germany UK	2030	Planned but not yet in permitting	1 675

The PMI projects represent a total increase of 6.3 GW of transmission capacity with third countries, which can be compared to approximately 38 GW of transmission capacity with third countries

[56] https://energypress.eu/gregy-interconnector-plans-to-add-extra-route-serving-italy/

identified in the IoSN study (Figure 2-14). The draft TYNDP 2024 projects portfolio[57] also includes several new projects involving third countries which are under consideration.

2.3.3. Focus on smart electricity grids

According to the IEA, a smart electricity grid can be defined as "an electricity network that uses digital and other advanced technologies to monitor and manage the transport of electricity from all generation sources to meet the varying electricity demands of end users". The TEN-E regulation defines infrastructure under the smart electricity grids category as "any equipment or installation, digital systems and components integrating information and communication technologies (ICT), through operational digital platforms, control systems and sensor technologies both at transmission and medium and high voltage distribution level, aiming to ensure a more efficient and intelligent electricity transmission and distribution network, increased capacity to integrate new forms of generation, energy storage and consumption and facilitating new business models and market structures".

The smart electricity grid category therefore covers a wide variety of project types, such projects may include many types of equipment, both at transmission and distribution voltage levels, also including components with no digital aspect. For instance, the Danube InGrid project in Hungary and Slovakia includes 400/110 KV substations, 110/22 kV substations, smart devices on high and medium voltage lines, optical fibre to enhance DSO-TSO communication. The available data in network development plans does not allow to make a distinction of investments at the TSO and DSO level that are specifically linked to projects including a digital/smart-grid component. Such equipment is also not represented in top-down scenarios. These investments have therefore been reported in the relevant distribution and transmission infrastructure categories. Still, it is worth mentioning that the first PCI/PMI list includes five projects under the smart electricity grids thematic area. These projects represent a total investment of €2.3 billion.

Table 2-5 Smart electricity grids projects in the first PCI/PMI list

Project name	Description	Commissioning year	Cost (M€ 2024)
ACON (CZ, SK)	ACON - Again COnnected Networks (CZ, SK), to foster the integration of the Czech and Slovak electricity markets by improving efficiency of distribution networks	2025	295,70
CARMEN (HU, RO)	CARMEN (BG, RO), to reinforce cross-border TSO-TSO cooperation and data sharing, enhance TSO-DSO cooperation, invest in grid expansion and increase capacity for integration of new renewables and improve grid stability, security and flexibility	2030	550,19
Danube InGrid (HU, SK)	Danube InGrid (HU, SK), to efficiently integrate the behaviour and actions of all market users connected to the electricity networks in Hungary and Slovakia	2029	523,56
Gabreta (CZ, DE)	Gabreta Smart Grids (CZ, DE), to increase grid hosting capacity, enable remote monitoring and control of MV	2030	740,90

[57] https://tyndp2024.entsoe.eu/projects-map

	grids and improve grid observability and network planning		
GreenSwitch (AT, HR, SI)	GreenSwitch (AT, HR, SI), to increase hosting capacity for distributed renewable sources and efficient integration of new loads, improving observability of the distribution network and increasing cross-border capacity	2028	226,87

2.4. Electricity transmission lines related to offshore generation

2.4.1. Current status and expected future developments

The first offshore wind farm was installed in Denmark in 1991, and the installed offshore wind capacity in the EU was around 19.4 GW in 2023[58]. The EU, with its 5 sea basins, has very significant potentials for developing offshore renewable energy, which makes offshore wind energy at the core of the strategy to reach EU's energy and climate goals. In January 2023, EU member states have agreed on new, ambitious long-term non-binding goals for the deployment of offshore renewable energy up to 2050 in each of the EU's five sea basins, with intermediate objectives to be achieved by 2030 and 2040[59]. The targets of approximately 111 GW in 2030 and 317 GW by 2050 will require massive investments in electricity transmission capacities from offshore generation sites.

While existing offshore capacities are almost all radially connected, meaning that the generation capacities are only connected to the shore of one country (also referred to as "single-purpose" transmission infrastructure), so-called hybrid or dual-purpose / multi-purpose transmission infrastructure projects are expected to play a significant role in the development of offshore electricity networks. These refer to offshore transmission infrastructure topologies that connect two or more member states to an offshore generation site.

The infrastructure categories analysed in this section cover the following:

- Transmission lines enabling transmission of offshore renewable electricity from the offshore generation sites (annex II 1 – b of TEN-E), i.e. radial connections
- Transmission lines having dual functionality: interconnection and offshore grid connection (annex II 1 – f of TEN-E)

This excludes subsea interconnectors, which are not related to transmission of offshore renewable energy and fall under annex II-1-a of TEN-E (considered in the previous section).

For this infrastructure category, the analysis of infrastructure needs both in terms of equipment and investments is mostly based on ENTSO-e's "Offshore Network Development Plans"[60] (ONDPs), published in January 2024, as well as the projects data from the first PCI/PMI list and the draft TYNDP 2024 projects portfolio.

[58] https://energy.ec.europa.eu/topics/renewable-energy/offshore-renewable-energy_en
[59] https://energy.ec.europa.eu/news/member-states-agree-new-ambition-expanding-offshore-renewable-energy-2023-01-19_en
[60] (ENTSO-e, 2024) Offshore Network Development Plans

2.4.2. Top-down analysis of investment needs data

ONDPs are a high-level study translating Member States non-binding targets for wind offshore energy in terms of transmission infrastructure needs, focusing on two questions:

- What are the required investments for connecting all projected capacities at least radially?
- Where are the opportunities to develop hybrid offshore corridors additionally to the already planned projects?

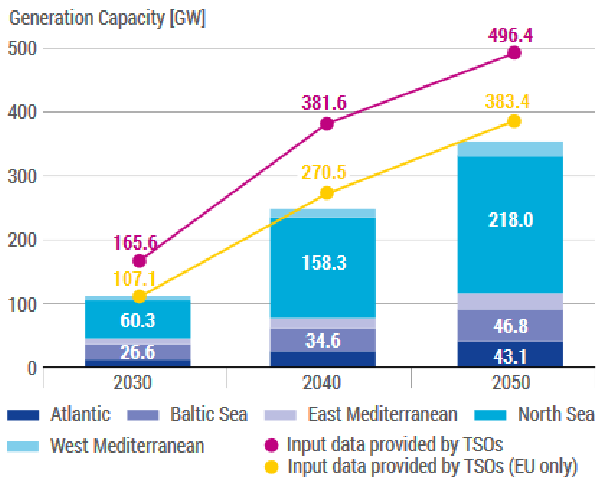
ONDP Methodology

The analysis is based on capacity expansion modelling for 2040 and 2050. In the starting network, the model includes the already planned hybrid corridors[61] and assumes that all capacities will be at least radially connected. The expansion model can then further expand pre-existing radial links into hybrid corridors. Investments selected by the model can thus take different forms:

- Connecting an offshore hub to another Member State
- Connecting an offshore hub to another offshore hub
- Reinforcing a link that exists in the starting grid (reinforcement of a link between two offshore nodes or reinforcement of a link between an offshore node and a country)

Planned wind offshore capacities on the other hand are an input of the study based on data submitted by TSOs (Figure 2-20).

Figure 2-20 Offshore RES Member States' goals and study assumptions per sea basin



*Source: ENTSO-e, 2024*Error! Bookmark not defined.

Note: bars represent MS targets per sea basin while the lines labelled as 'Input data provided by TSOs' represent the sum of the wind offshore capacities that are assumed in the study. Countries provided ranges of planned capacities up to 2050, with a sum of upper ranges that may exceed the targets per sea basin.

The modelling is based on the TYNDP 2022 Distributed Energy (DE) scenario, which has been updated to reflect the 2023 Member States non-binding targets for wind offshore. The electricity demand has been increased by 8% as well to reflect the early figures from the ongoing TYNDP 2024 scenarios development process available at the time of the study. The expansion model is only

[61] There are currently six planned offshore hybrid hubs projects, all located in the Northern Sea and Baltic Sea basins, that have been included in the study. All projects are included in the first PCI/PMI list.

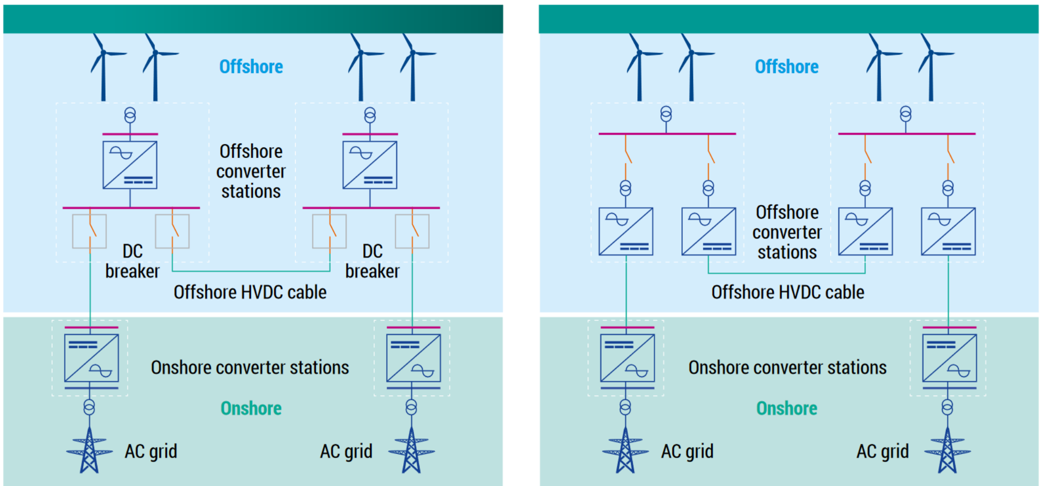
allowed to invest in offshore infrastructure. The onshore grid cross-border capacities follow the TYNDP 2022 DE scenario as well[62].

The model performs a linear optimisation aiming at minimising the total system costs, including both system operation and investment costs. It is to be noted that a significant cost uncertainty is reported in the study methodology report, in particular, the political push towards offshore development might speed-up costs decrease in a way that is difficult to foresee. According to the ONDPs, standard cost uncertainties for this type of infrastructure fall within the range of +30% to +100%. To reflect these uncertainties, different cost set assumptions have been used in the study.

In addition to the uncertainty related to the costs of individual equipment, there is significant uncertainty regarding the evolution of the technical solutions to connect offshore hubs. The cost analysis for expanding the offshore transmission corridors involves two primary configurations:

- "With DC Breakers" configuration: this approach connects the corridors using DC hubs that incorporate DC breakers.
- "Without DC Breakers" configuration: in this setup, the corridors are linked through AC hubs, with each connection employing a dedicated AC/DC converter.

Figure 2-21 Illustration of offshore hubs connection options with (left) and without (right) DC breakers



*Source: ENTSO-e, 2024*Error! Bookmark not defined.

While being more favourable to offshore hubs connections, as it requires less AC/DC converters, the "with DC breakers" configuration involves components that are less mature, both configurations have thus been considered in the study.

Finally, it is also worth noting that internal reinforcements needed onshore are also outside of the scope of the study, the reported costs include cable needs up to the first connection points on the mainland. Detailed internal reinforcement needs are indeed difficult to assess with a harmonised top-down approach as they typically need to be assessed on a project-by-project level. Reinforcement needs would typically depend on the landing point of a connection project, on the forecasts of evolution of demand and generation nearby the landing point. Internal reinforcement needs may

[62] The ONDPs does therefore not assess how onshore interconnectors and hybrid offshore connections could compete, this will be further developed in the TYNDP 2024 system needs study.

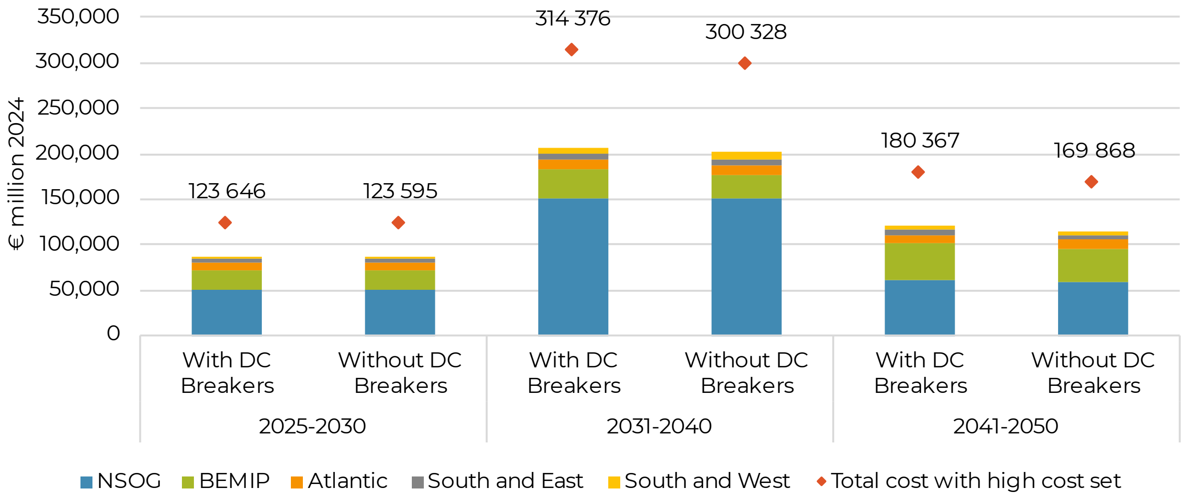
also not necessarily be attributed to one project. Similarly, the potential role of offshore electrolysis and hydrogen pipelines have not been considered in the first edition of the ONDP.

ONDP Main conclusions

The main conclusions of the analysis are that cumulated investment needs in offshore transmission infrastructure up to 2050 sums up to at least some **€400-415 billion**[63]. The future offshore transmission system will be a combination of radially connected farms and hybrid projects. The figures below present the investment costs in offshore transmission infrastructure in 2025-2030, 2031-2040 and 2041-2050 identified by the ONDP study, for both configurations with and without DC breakers:

- For the different sea basins
- For the different possible types of connections

Figure 2-22 ONDP's investment needs per sea basin

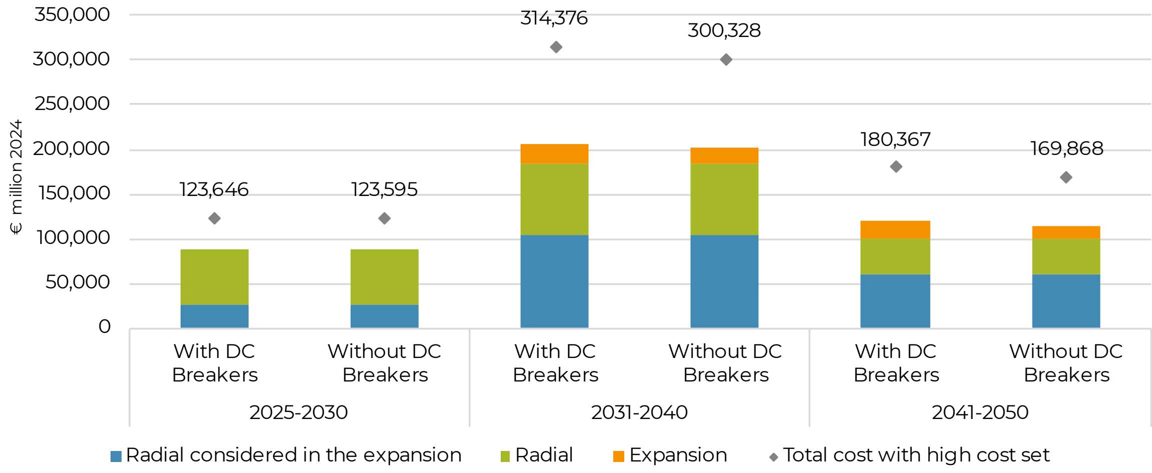


*Source: ENTSO-e, 2024*Error! Bookmark not defined.

Note: Bars represent total costs based on the lower cost set used in the study. The diamonds represent the impact of assuming the less optimistic cost set assumed in the study.

[63] Range of investment needs resulting from both "with" and "without DC breakers" configurations and based on the lower set of unit investment cost assumptions used in the study. The cost includes the entire ENTSO-E area but excludes the cost for the connection of radial capacities in the UK.

Figure 2-23 ONDP's investment needs per types of connections



Source: ENTSO-e, 2024Error! Bookmark not defined.

Note:" Radial" corresponds to the cost of connection of offshore nodes for which no hybrid expansion is allowed in the modelling. "Expansion" corresponds to investments resulting from the capacity optimisation (e.g. adding a link between two offshore nodes, or reinforcement of a pre-existing link)."Radial considered in the expansion" includes the costs for the connection of nodes for which expansion is allowed and planned hybrid projects.

Different cost sets have been used in the ONDP study[64]. Figures reported in the ONDP reports are based on the most optimistic cost set (corresponding to the bars in the graphs above). In the higher costs set, the costs of offshore and onshore AC substations and HVDC converters increase by some 27%, while the costs of cables increase by 79% for offshore HVDC cables and 126% for onshore HVDC cables. The impact on the total cost of considering the higher cost set are reflected by the diamonds in the graphs above. Considering this higher cost set, total costs to connect planned wind offshore capacities would increase **from €400-415 billion to €600-620 billion**, the €400 billion figure is thus to be understood as a lower estimate of the investment needs.

Overall, figures are consistent across both "with" and "without DC breakers" configurations. The ONDPs identify **average yearly investments of €15-21 billion up to 2030, €21-31 billion in 2031-2040 and €12-18 billion in 2041-2050**. The Northern Sea Offshore Grids (NSOG) sea basin concentrates 64% of the investment needs for offshore electricity transmission up to 2050, as it concentrates most of the planned offshore RES capacity (333 GW out of the 496 GW assumed for EU-27).

A further area of uncertainty comes from the costs of connecting floating compared to fixed offshore wind energy infrastructure. Indeed, the ONDPs consider standardised cost set assumptions across all sea basins without distinction of floating and bottom-fixed turbines technologies. However, in the Atlantic Ocean and in the Mediterranean Sea, the development of wind offshore energy will most likely rely on floating technology, due to the depth of their waters.

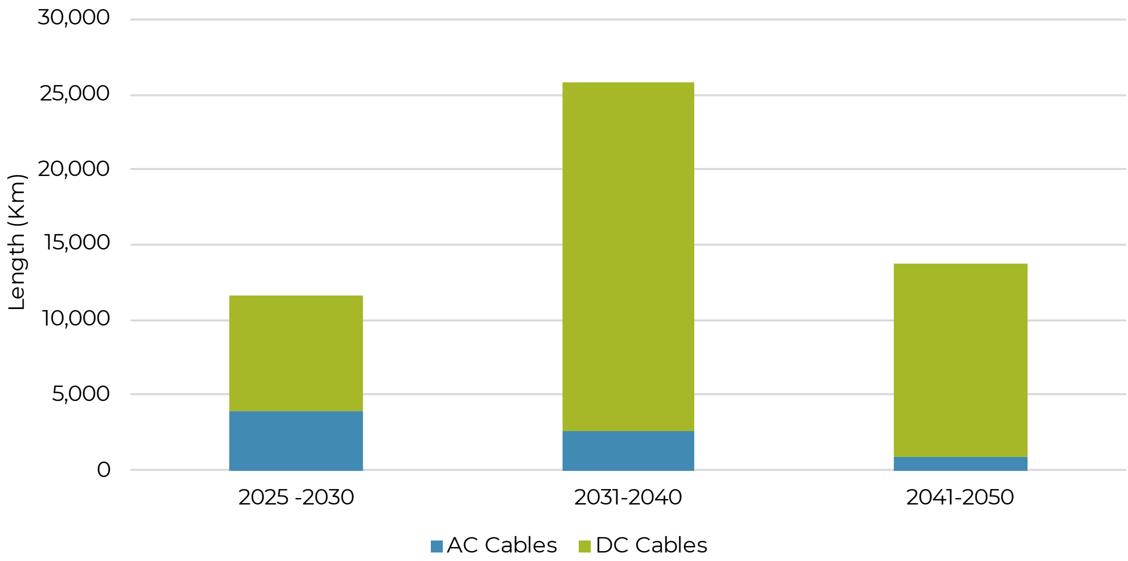
According to a study on the potential of offshore energy in the Atlantic Ocean[65], additional costs could be expected for connecting floating wind turbines if floating substations and dynamic cables are used. The study mentions estimates of additional costs of some 50-150% for the foundations of floating substations and some 15-20% for dynamic cables. Still, the study concludes that the impact

[64] (ENTSO-e, 2024) ONDP methodology report
[65] European Commission (2023), Study on the Offshore Energy Potential in the Atlantic Ocean

on total costs is difficult to measure as not all floating offshore projects would involve floating substations (bottom-fixed substations using deep-water jackets would be suitable in certain cases) and not all cables for offshore transmission must be dynamic. Besides, at the moment, dynamic cables are available up to a 66kV voltage. The higher voltages required for the connection of floating hubs will require further developments, and the impact of dynamic cables on total costs is expected to remain limited once the technology is more mature. Higher costs of floating substations may also be offset by lower installation costs. Finally, since NSOG and BEMIP sea basins where bottom-fixed is the preferred technical solution represent most of the investment needs (85% of the cumulated investments up to 2050), the impact on the overall investment needs up to 2050 is likely to remain limited.

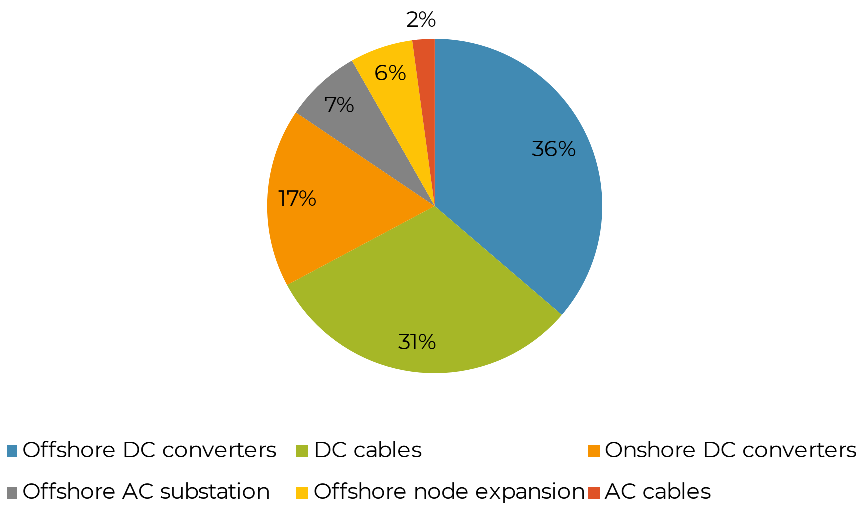
In terms of equipment needs, the study identified needs for approximately **51,000 km of transmission lines**, of which 85% of DC lines. Figure 2-25 displays the share of different equipment types in the total identified investment needs.

Figure 2-24 Line lengths identified by the ONDPs



Note: Figures reported are average of with and without DC breakers configurations

Figure 2-25 Share of equipment types in the costs identified by the ONDPs



*Source: ENTSO-e, 2024***Error! Bookmark not defined.**

However, the total figures may be uncertain as the study faces the challenge of estimating unit investment costs for various types of infrastructure that are not yet mature. In particular, the uncertainty on the ability of the supply chain to meet the demand is difficult to assess, although it is implicitly accounted for in the upper set of cost assumptions. It is also worth noting that this first edition of the study does not model investment in offshore point-to-point/onshore interconnectors and hybrid transmission in an integrated framework (cross-border capacities are fixed to the values of the TYNDP 2022 DE scenario). The study rather focuses on the needs to connect the planned wind offshore capacities and does not explicitly represent the potential competition between hybrid offshore interconnectors and conventional onshore and offshore cross-border capacities. The study may therefore potentially underestimate the benefits of hybrid interconnectors. Integrated assessment of the offshore and onshore systems will be performed in the next edition of the TYNDP System Needs study.

A further area of uncertainty comes from the development of offshore electrolysis, or mixed electricity and hydrogen connection concepts which could reduce the needs for offshore electricity transmission by transporting energy in the form of hydrogen[66]. While the ONDP study includes known offshore electrolysis projects, a fully integrated assessment of both options will be considered in the next TYNDP cycle.

2.4.3. Analysis of planned investments data

The top-down approach based on the ONDP study is complemented with a bottom-up analysis of the pipeline of offshore wind transmission infrastructure projects in the first PCI/PMI list. The graph below displays the yearly investment costs associated to projects in the first PCI/PMI list related to the connection of offshore wind energy, with a distinction of the projects including dual-functionality hybrids and radial projects. There are currently 12 projects in this category in the PCI/PMI list, including 6 hybrid projects. These projects represent a total investment of some **€37 billion** in the projects pipeline up to 2034 which can be compared to the €87-124 billion investments up to 2030 identified by the ONDPs, illustrating the gap between the current pipeline of projects and the needs to meet the 2030 objectives.

The planned projects represent approximately **4,400 km of electricity transmission lines**, which amounts to some 9% of the transmission lines length identified by the ONDP.

[66] See for instance (E-Bridge, 2024), Assessment of connection concepts for Germany's far out North Sea offshore wind areas for an efficient energy transition which concludes on the benefits of mixed electricity and hydrogen offshore connection concepts.

Figure 2-26 Investment costs associated to projects in the first PCI/PMI list related to the connection of offshore wind energy

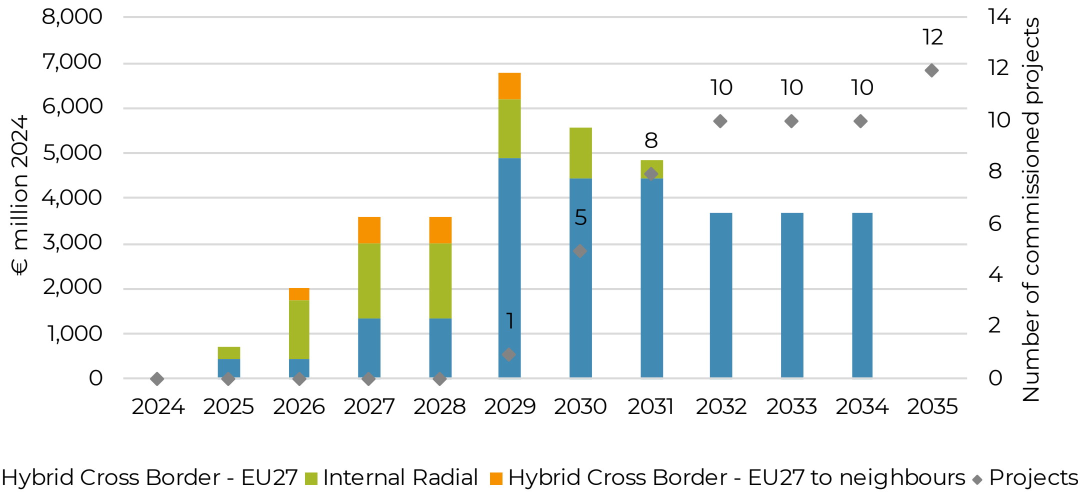
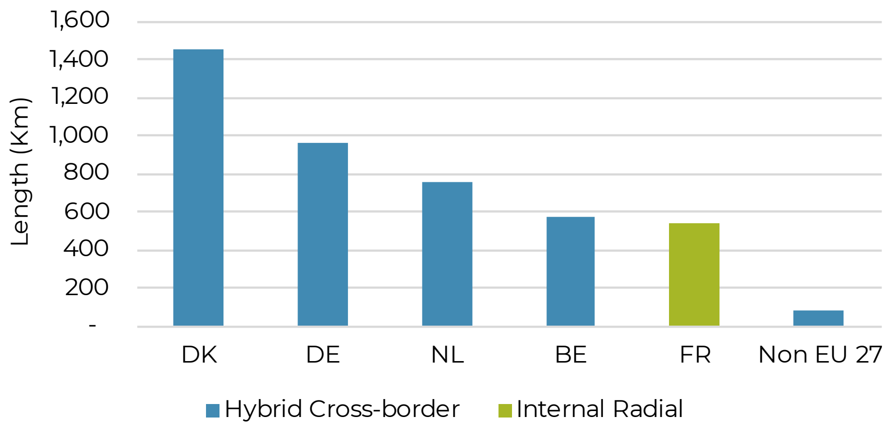


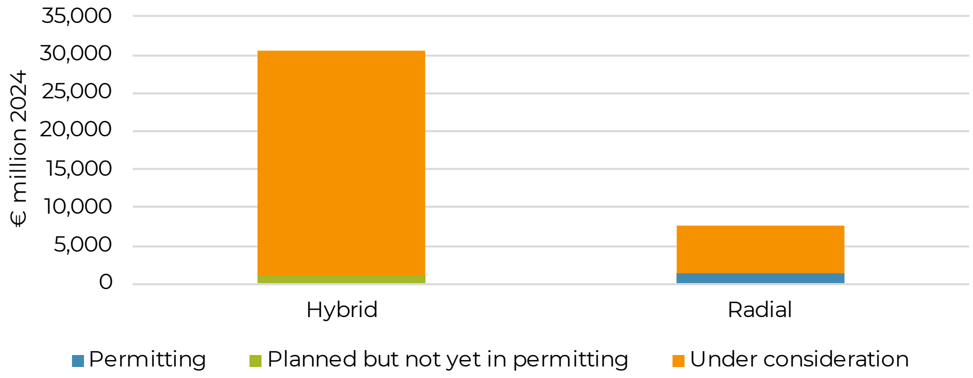
Figure 2-27 - Total length of planned offshore generation transmission lines by country according projects from PCI/PMI list



The current PCI/PMI pipeline of projects represents average planned investments of €3.8 billion per year up to 2035, with a peak in 2029. As the ONDP study does not represent individual projects, a detailed project-based comparison of costs of planned projects and numbers from the ONDP is not possible. To a first approximation, one can compare the average cost per unit of connected wind offshore capacity for both data sources. On average, projects in the PCI/PMI list display investment costs of €1 billion per gigawatt of connected wind offshore capacity, with a range of €0.65 - 1.4 billion/GW. On the other hand, taking into account the cost uncertainties, the total investment costs identified in the ONDP study would fall within the range of €1.04 - 1.55 billion/GW of connected wind offshore capacity.

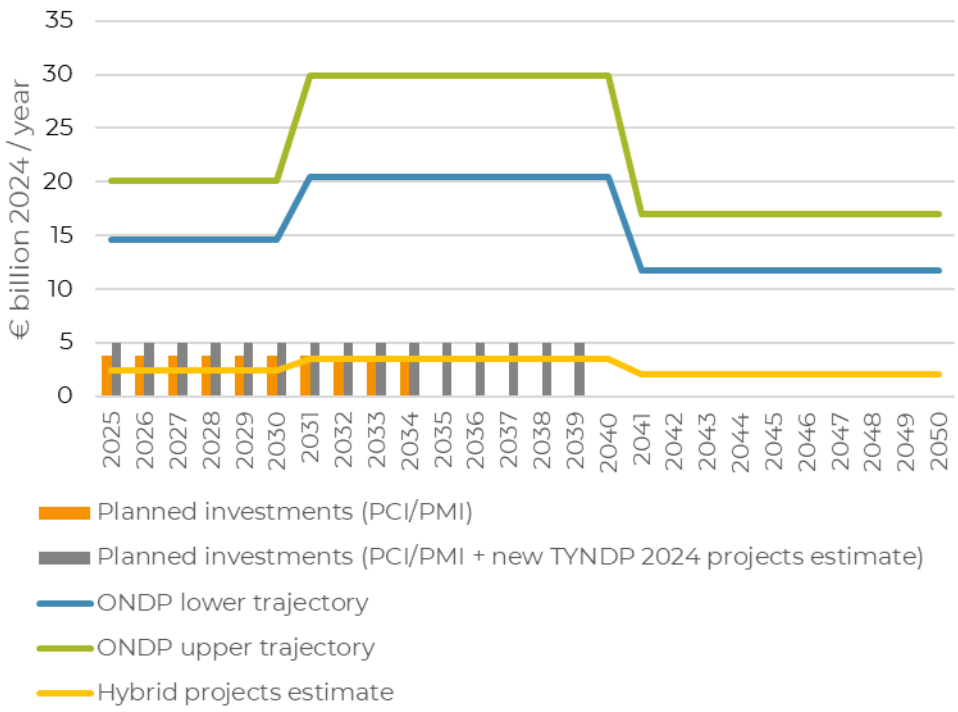
It is also worth noting that these 12 projects are almost all at early stages as can be seen in Figure 2-28. Projects are also more mature in the Northern Sea and Baltic Sea basins.

Figure 2-28 Distribution of PCI/PMI projects total costs according to project status



Still, the development of offshore wind is accelerating in other sea basins, the TYNDP 2024 draft projects portfolio includes 57 new transmission projects, of which 23 projects are linked to wind offshore energy, illustrating a rapid acceleration in the development of projects related to offshore wind energy. The new projects notably include six projects in Portugal and four projects in France, and several hybrid interconnectors under study. An updated trajectory of planned investments up to 2040 is estimated adding projects that are new in the TYNDP 2024 to the planned PCI/PMI projects[67].

Figure 2-29 Offshore transmission planned investments and investment needs trajectories



[67] As the TYNDP 2024 draft portfolio does not yet include detailed cost data, average costs from the PCI/PMI list have been affected to the new projects.

Note: ONDP upper and lower trajectory represent the average investment needs per year identified in the ONDPs in the different planning windows and considering the range of cost uncertainty. Planned investment figures represent average investment per year considering the PCI/PMI list and estimates including the new projects in the TYNDP 2024. "Hybrid projects" estimates reflects an estimate of the cost of hybrid offshore connection projects derived applying a 14% coefficient (minimum share of hybrid projects according to the ONDPs) to the average of the ONDPs investment trajectories.

Taking these projects into account, the pipeline of planned investments would increase to approximately €74 billion up to 2040 i.e., planned investments of €4.9 billion per year on average between 2025 and 2039, which compares to average needs of €16-24 billion per year up to 2050 identified by the ONDP study. It is noticeable that the extent to which the future projects to be developed would meet the criteria to be eligible to becoming PCIs might however be uncertain. The criteria in TEN-E detailing the notion of cross-border impact for offshore renewable electricity transmission state the following (Annex IV - 1-h): "for offshore renewable electricity transmission, the project is designed to transfer electricity from offshore generation sites with capacity of at least 500 MW and allows for electricity transmission to onshore grid of a specific Member State, increasing the volume of renewable electricity available on the internal market. The project shall be developed in the areas with low penetration of offshore renewable electricity and shall demonstrate a significant positive impact on the Union's 2030 targets for energy and climate and its 2050 climate neutrality objective and shall contribute significantly to the sustainability of the energy system and market integration while not hindering the cross-border capacities and flows". These criteria are not as restrictive as the criteria for internal electricity transmission lines not related to offshore renewables (falling under annex II-1-a of TEN-E) where projects should demonstrate the effect of increasing the cross-border grid transfer capacity at the border of the MS, by at least 500 MW, to be eligible to becoming a PCI. For instance, it's worth noting that in France, the projects that are currently in the TYNDP 2024 projects portfolio (all radial connections) cover the connection of approximately 17GW of offshore wind capacity, which corresponds to the capacity to be added to reach the currently planned target in France for the 2035-2040 horizon. Similarly, in Portugal, the projects added in the TYNDP 2024 project portfolio cover the current 10 GW offshore wind capacity target.

The ONDPs therefore provide an upper estimate of the future TEN-E relevant investment needs past the already planned projects, since their scope also includes some projects that might not meet all the TEN-E criteria. As a lower estimate, it can be estimated that the share of projects that would fall under the scope of TEN-E would include at least the dual-purpose hybrid projects, which according to the ONDPs would represent at least 14% of the wind offshore capacity considered in the ONDPs. Considering the trajectory of investment needs estimated in the ONDPs, these would represent average investment costs of approximately €2.7 billion per year up to 2050 (assuming the average of the cost sets used in the ONDPs, see figure above).

Additionally to the hybrid projects, as reflected by some already planned PCI/PMI projects, a certain share of the radial connection projects meeting the criteria mentioned above will also be relevant for the perimeter of TEN-E. However, estimating this share is difficult considering that the TEN-E criteria are of a qualitative nature, and will likely be assessed for each project, based on its location and technical specifications. Given that offshore wind is at early stages of development in most MS, it can be estimated that the "areas with low penetration of offshore renewable electricity" criterion might be most relevant on the longer term and that at the moment, most areas could be considered as areas with low penetration of offshore renewables. Similarly, the "not hindering the cross-border capacities and flows" criterion is also qualitative, and it will require complex project-by-project modelling to estimate the impact of a project on cross-border flows.

Focus on Projects of Mutual Interest

The PCI/PMI list includes two hybrid interconnectors Projects of Mutual Interest, all including the UK:

- The Nautilus project aims at developing a hybrid interconnector with a capacity of 1-2 GW between Belgium and the UK. It has been included in the TYNDP since 2014, and it was decided in 2020 that the project would be a dual-purpose interconnector. The project is promoted both by Belgium and UK TSOs and is currently undergoing technical studies. The project promoters estimate a cost of €1 billion for this project, with a commissioning in 2030. Elia's NDP also include an internal reinforcement project deemed necessary for the integration of wind offshore capacity and Nautilus project[68].

- The LionLink project aims at developing a hybrid interconnector with a capacity of 1.4-1.8 GW between the Netherlands and the UK. It has been included in the TYNDP since 2016. The project is promoted both by Dutch and UK TSOs and is currently undergoing studies and consultation. The project's detailed route and onshore landing points are still to be decided. The project promoters estimate a cost of €850 million for this project, with a commissioning around 2030-2031, FID is expected for 2026.

Eventually, new projects for hybrid interconnectors involving non-EU-27 countries have been submitted to the TYNDP 2024 portfolio, including a Germany-UK hybrid interconnector project and a project by Norwegian TSO Statnett to investigate possible hybrid interconnectors with other countries around the North Sea.

2.5. Electricity storage directly connected to high voltage transmission and distribution lines

2.5.1. Current status and expected future developments

Electricity storage facilities, as defined by Annex II – 1-c of the Trans-European Networks for Energy (TEN-E), encompass both individual and aggregated systems used for storing energy on a permanent or temporary basis. These facilities can be located in above-ground or underground infrastructure or geological sites, provided they are directly connected to high-voltage transmission lines and distribution lines designed for a voltage of 110 kV or more. Annex IV-1-a of the TEN-E regulation also states that storage projects with a significant cross-border impact shall provide at least 225 MW of installed capacity and have a storage capacity that allows a generation of 250 GWh/year.

Currently, most of EU's electricity storage capacity is composed of Pumped Hydro Storage (PHS) facilities, with some 23 GW of closed-loop PHS and 23 GW of open-loop PHS[69]. While projections foresee significant needs to develop electricity storage, the potential of pumped storage is nearly saturated, and there are relatively few greenfield projects, most projects focusing on the extension of existing facilities. Battery Energy Storage (BES) is also expected to play a significant role in the coming years, to accompany the development of renewable electricity, and solar PV in particular. According to SolarPower Europe's 2024 Battery Energy Storage Outlook[70], battery storage capacity in Europe has increased by a factor of 7 between 2020 and 2023 to reach approximately 36 GWh. It is also to be noted that the residential battery storage segment still dominates battery energy storage installations.

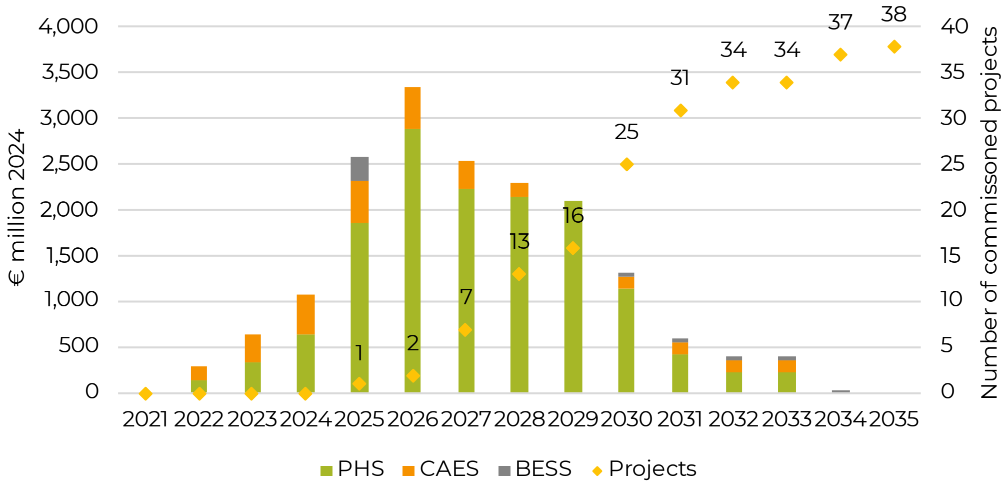
Other technologies such as Compressed Air Energy Storage (CAES) are also developing but are expected to remain relatively marginal compared to other technologies.

[68] https://www.elia.be/en/infrastructure-and-projects/infrastructure-projects/boucle-du-hainaut
[69] (JRC, 2022), Hydropower and pumped hydropower in the European Union
[70] (Solar Power Europe, 2024), European Market Outlook for Battery Storage

2.5.2. Preliminary analysis of investment needs data

The analysis is mostly based on the projects lists from the TYNDP 2022 and the TYNDP 2024 portfolios[71]. These storage projects include pumped hydro storage, battery storage and compressed air storage projects. There are in total 38 storage projects in the TYNDP portfolio that are planned to be commissioned between 2025 and 2035 for a total cost of **€17.6 billion**, including 12 projects in the first PCI/PMI list. The bottom-up analysis shows that planned investments in electricity storage infrastructure are still primarily driven by investments in PHS capacity (29 out of 38 projects), other technologies represent a limited share of projects with only 18% of planned investments. There are 7 CAES projects, located in Germany and the Netherlands and only 2 battery storage projects in Greece and Slovakia. 21 out of the 29 projects are in permitting or under construction as of latest available data. On average, these projects represent **yearly investments of €1.04 billion per year up to 2040**. On average, projects also acknowledge a cost uncertainty that can reach up to 12% of the initial estimates. Pumped hydro storage projects in the portfolio showcase investment costs in the range of 300-2100 €/kW, which is in the range of costs mentioned in JRC hydropower report (in the range of 1400-4000 €/kW for greenfield projects and up to 70% lower for projects using pre-existing infrastructure).

Figure 2-30 Investment costs of storage projects in the TYNDP portfolio)



The fact that there are only two battery storage projects in the TYNDP portfolio seems to contradict projections forecasting an accelerated development of grid-scale battery storage in the mid-term. For instance, according to JRC Clean Energy Technology Observatory 2022 report for battery storage[72], EU battery capacity is expected to reach 80 GW/160 GWh by 2030. The limited number of battery projects in the TYNDP portfolio can be linked to the fact that so far, stationary batteries market is dominated by residential applications. Besides, financing models for grid-scale battery projects are still uncertain and may rely on mostly private funding, resulting in most projects being out of the perimeter of the TYNDP and TEN-E processes. Utility-scale battery energy storage can also be connected at different voltage levels, and it is therefore difficult to predict to what extent investments in battery storage will fall under the TEN-E regulation.

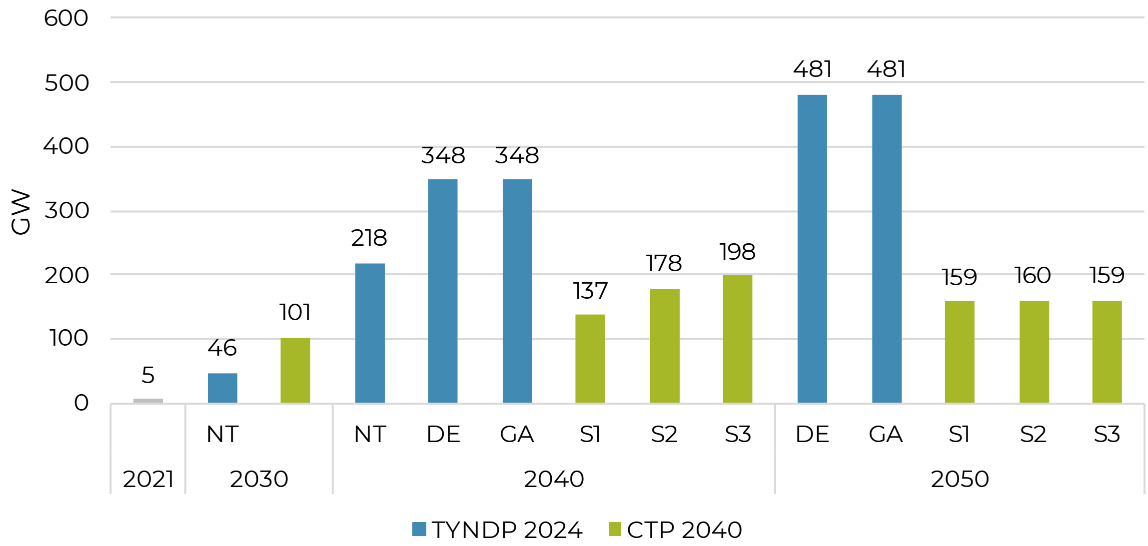
[71] The first PCI/PMI list has also been analysed to complement the data since it is a subset of the TYNDP 2022 projects portfolio

[72] (JRC, 2022), Batteries for energy storage in the European Union

The analysis of investment needs in battery storage can be complemented by a top-down analysis based on prospective scenarios to derive estimates of expected future investments in battery storage. This top-down analysis is based on scenarios from the TYNDP 2024 and the 2040 Climate Target Impact Assessment from the European Commission. These scenarios provide capacity projections for storage technologies based on capacity expansion modelling up to 2050, including BESS. Still, it is worth mentioning that projections of battery storage capacity in such capacity expansion models present some limitations, in particular:

- Such models usually focus on energy-based electricity markets and do not represent balancing markets, they may also include behind-the-meter storage.
- Battery storage projects may have different energy/power ratios (i.e., storage duration at maximum power) depending on the applications. For instance, a battery dimensioned for reserve applications may require a lower storage volume and higher network injection capacity compared to a system designed for arbitrage on the day-ahead market. Such variations are difficult to represent in models and a standard discharge time assumption is usually used as a simplification (4 hours in the TYNDP 2024 for instance), which may impact the energy/power figures.

Figure 2-31 Installed battery storage capacity in selected prospective scenarios



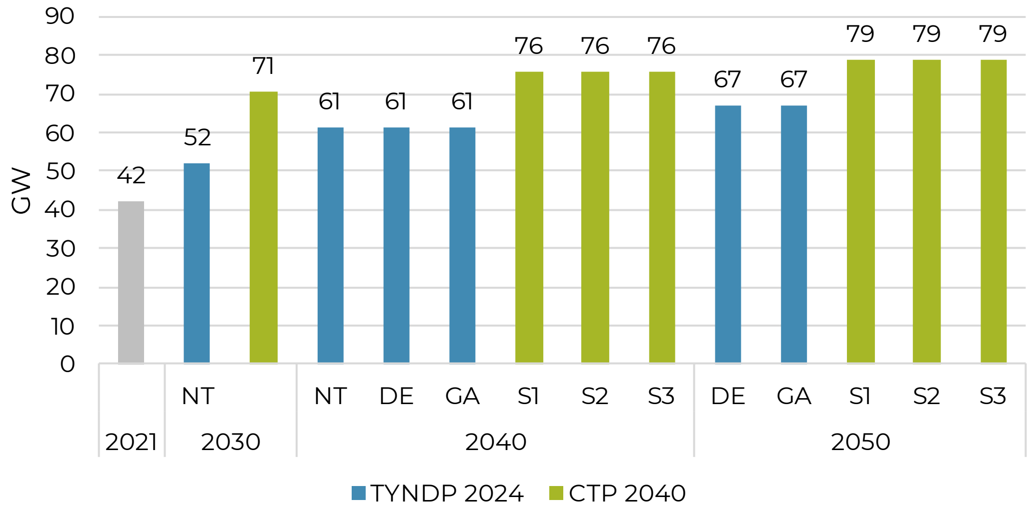
Note: figures for 2021 are based on JRC 2022 Battery energy storage report

TYNDP scenarios foresee a very ambitious increase of battery storage capacity, with 46 GW in 2030, 348 GW in 2040 and up to 481 GW in 2050. Scenarios from the 2040 Climate Target Impact Assessment foresee a capacity of approximately 140-200 GW in 2040, which remains stable up to 2050. According to battery CAPEX assumptions from TYNDP 2024 scenarios[73], investments in utility-scale battery capacity up to 2050 would be in the range of €275-320 billion in total. Note that figures are less ambitious in terms of GW in scenarios from the 2040 Climate Target Plan, which might be

[73] From 700 €/kW in 2030 to 430-645 €/kW in 2050 for 4h utility-scale batteries depending on the scenarios.

explained by different assumptions for investment options in batteries (both in terms of costs and storage/power ratios)[74].

Figure 2-32 Installed pumped storage capacity in selected prospective scenarios



Prospective scenarios also converge on the increase of pumped storage capacities with most of the investments taking place up to 2040 in all scenarios. These figures are also consistent with modelling from the Impact Assessment on Stepping up Europe's 2030 climate ambition[75] which foresees around 18-20 GW to be added to reach approximately 65 GW around 2030 and slower development rates after 2030, with additional 5-10 GW up to 2050.

Battery storage is expected to represent the majority of future investments in energy storage. Given the uncertainty on the share of battery storage projects that could meet the TEN-E regulation criteria, it is difficult to estimate the future investments in electricity storage relevant for TEN-E past the current planning horizon. Nonetheless, it is expected that a low share of battery storage projects will be developed within the TYNDP process. Considering that the number of electricity storage projects in the TYNDP projects portfolio has been rather stable over the recent TYNDPs, future investment needs for electricity storage projects falling within the TEN-E regulation after the current planning window can be estimated by extrapolating the average rhythm of investments for planned projects, which roughly equals €1.5 billion per year.

Prospective scenarios and policy targets

Top-down estimations based on various prospective scenarios have been used for some infrastructure categories (the 2040 Climate Target Plan scenarios, TYNDP 2024 scenarios, as well as the TYNDP 2022 NT and DE scenarios respectively used as basis for the TYNDP 2022 System Needs study and the Offshore Network Development plans). These scenarios are usually designed considering the latest climate and energy policy targets, in particular:

- A 55% reduction in net GHG emissions in 2030 compared to 1990 (Fit-for-55)
- A share of 42.5% in renewable energy in gross final energy consumption by 2030 (Renewable Energy Directive)

[74] Technology assumptions from the 2040 CTP include assumptions for both 2h and 8h batteries, but detailed capacity results per category are not provided.
[75] SWD(2020) 176 final

- A reduction of energy consumption of 11.7% in 2030 compared to projections of the 2020 EU Reference scenario (Energy Efficiency Directive)

TYNDP 2024 DE and GA scenarios are deviations from the 2030 NT+ scenario which meets the 2030 policy targets, in terms of energy efficiency, renewable energy share and GHG emissions, and reach carbon neutrality by 2050. Scenarios from the 2040 Climate Target Plan's Impact Assessment also meet those targets and TYNDP 2022 scenarios also meet the objectives in terms of GHG emissions.

2.6. Smart gas grids

Regarding smart gas grids, currently no explicit projects are publicly announced. Any newly-built project will in both hydrogen and natural gas contexts consider smart grid aspects as confirmed via responses from the survey. Some activities are known in Denmark preparing to explicitly apply under the smart gas grid terminology and intending to support the reverse flow capacity into the transmission system from decentral biomethane (and e-methane) installations. The respective grid operator had applied under the PCI framework with a budget estimation of €246 million over thirty years (including OPEX). Further applications have been considered by Hungary (on introduction of hydrogen-ready chromatographs) to be commissioned by 2025 and Greece and Bulgaria (applying together under the SmartSwitch project) and to be commissioned by 2027[76]. None of the projects have reached PCI-status however.

Due to this fact and seeing the comparatively low annual investment plans over thirty years (€246 million/30 yrs = <€10 million/year) smart gas grids have not been further included in the analysis.

2.7. Hydrogen infrastructure

Hydrogen-related infrastructure elements covered in this study are using the respective definitions of TEN-E. The categories more closely examined are:

- pipelines for the transport of hydrogen (Annex II 3(a) of TEN-E);
- storage facilities connected to high-pressure hydrogen pipelines (Annex II 3(b) of TEN-E);
- reception, storage and regasification or decompression facilities (import terminals) (Annex II 3(c) of TEN-E);
- Installations for hydrogen use in transport sector (Annex II 3(e) of TEN-E);
- electrolyser facilities (Annex II 4 of TEN-E).

In contrast to electricity infrastructure described above, there is no developed trans-European hydrogen gas infrastructure today (except for some proprietary hydrogen pipelines in and around Belgium) and key regulatory elements of the future infrastructure regulations are not fully developed yet (i.e. the transposition into MSs).

Each of the above-listed infrastructure category is analysed individually below, looking at the current status and potential future developments. A preliminary analysis of the investment needs including discussion of the limitations is given.

[76] As received via the survey on PCI/PMI applications

2.7.1. Hydrogen pipelines

Current status and expected future developments

Hydrogen transport will be essential to connect production and demand centres across Europe and pipeline transport is considered for large quantities and distances the most cost-effective alternative to transport hydrogen. Other alternatives using carriers such as ammonia or Liquid Organic Hydrogen Carriers (LOHC) may find applications as well, yet it is commonly accepted that a dedicated hydrogen network is needed to enable a fully decarbonised continent. Guidehouse in a work for the European Hydrogen Backbone (EHB) states that a pan-European hydrogen network would result in cost savings of up to €330 billion over the 2030-2050 period, mainly by reducing the cost of the hydrogen supply mix and reducing the required investment in electricity infrastructure.[77] The corresponding pipeline network is optimised to serve about ~2000 TWh of hydrogen, which is in the order of magnitude of S3 in the IA with ~2150 TWh.[78]

Approach

In order to analyse the investment needs for hydrogen pipelines of European relevance, we pursue the following approach:

1. Development of a pipeline cost model, covering latest price changes.
2. Examine datasets and gather information on planned and existing projects, including technical parameters, project budgets and timelines.
3. Analyse pipeline development models (i.e. the European Hydrogen Backbone) regarding a long-term view up to 2040.

Model for Specific CAPEX

Pipeline costs may vary largely with parameters such as (new-building, repurposing, offshore and diameter). To account for the most important factors influencing the overall cost of projects, parameters were fit (quadratic function[79]) for each of the categories individually (using a quadratic function of new-built and repurposed) and due to data limitations by a linear relationship between diameter and costs for offshore.

This allows to apply latest cost developments across all communicated projects. The base values used for fitting retrieved from the EHB explicitly consider latest cost developments since 2020 like *"[g]lobally impactful factors like COVID, the Russian invasion of Ukraine, rising inflation, and policy responses to climate change"*.[80] The resulting costs represent an average across all European MSs and thus differences between actually communicated costs by the individual projects may differ. It can however be assumed that aggregation towards overall investment costs across all projects leads to averaging in that regard. The cost values are further adjusted to $€_{2024}$

For evaluating the validity of this model, the calculated values were compared against the stated CAPEX in the TYNDP project list, if available. Using the newly-fit model leads to a ~15% cost increase compared to the stated values (in most cases based on estimations before COVID-19, the Russian invasion and high inflation).

[77] Guidehouse (2023), Assessing the benefits of a pan-European hydrogen transmission network,
[78] European Commission (2024), Impact Assessment Part I
[79] Krieg et al. (2012), Konzept und Kosten eines Pipelinesystems zur Versorgung des deutschen Straßenverkehrs mit Wasserstoff
[80] EHB (2023), Implementation Roadmap – Cross Border Projects and Costs Update, European Hydrogen Backbone

Project datasets

For a bottom-up approach, datasets with projects of European relevance are assessed. These include:

- **TYNDP 2024 Annex A:**[81] with hydrogen projects referring to hydrogen pipelines, i. e. with the abbreviation "H2T" in their project code.
- **1st PCI/PMI list:**[82] PCI/PMI projects are inherited in the TYNDP 2024 project list.
- **Draft application of the transmission system operators** for the hydrogen core network, Annex 3[83]: As the German hydrogen core grid („Wasserstoffkernnetz") is a relatively new and comparatively well-advanced development which has not been fully covered by other data sets, latest figures from the core net application at the federal grid agency ("Bundesnetzagentur") were applied. The German core grid comprises over 9,000 km of hydrogen pipelines; a substantial share of the approximately 38,000 km of hydrogen pipelines which are expected to be built in Europe until 2034.
- **EHB:** For an estimation towards 2040 data by EHB were used.

The most relevant technical parameters, regarding the required budget of hydrogen pipeline projects are the length, pipeline diameter, whether it is an onshore (offshore) project and whether the pipeline is newly built or a repurposed natural gas pipeline. Furthermore, the stated CAPEX, location, FID, construction end and commissioning year provide a frame to further analyse and compare the projects.

The best data basis was extractable using the latest TYNDP project list (2024), covering most relevant projects in Europe and providing the above mentioned technical and project parameters consistently. In individual cases, single entries were regrouped or deleted to match latest developments.

Importantly, all TYNDP listed projects for Germany were replaced with the advanced data from Annex 3 of the draft application of the transmission system operators for the hydrogen core network. Note, that all projects, which have a planned commissioning date beyond 2034, were excluded as well to accommodate a consistent "top-down" approach for an estimation towards 2040. Here estimating the required size of the hydrogen pipeline grid until 2040 was based on the latest EHB figures, stating, that the grid should sum up to 57,662 km. As different options are possible to achieve this total number, by deriving two scenarios, the influence of repurposing (versus constructing new pipelines) on the overall costs can be demonstrated (see detailed description below).

Analysis of investment needs data

Planned investments until 2034

The overall cumulated investment needs towards 2034, using the latest cost data, the updated TYNDP project list and the latest application of the German core grid is at €107 billion reaching 38,000 km. For comparison, if considering only the projects that have received PCI/PMI status, the planned investment needs until 2034 cumulate to € 58 billion and about 18,800 km (34% repurposed).

Germany is the country with the biggest investment needs, first of all because of a high demand in hydrogen, secondly because the Germany Hydrogen Core Grid is already planned out in comparatively high level of detail. In Finland, the high CAPEX can be mostly allocated to three big offshore projects constructing new pipelines. Namely, these are Nordic-Baltic Hydrogen Corridor,

[81] ENTSOS (2024), TYNDP 2024 Draft Scenarios Report
[82] DG ENER (2024), Technical information on Projects of Common Interest and Projects of Mutual Interest
[83] FNB (2023), Antragsentwurf der Fernleitungsnetzbetreiber für das Wasserstoff-Kernnetz; Anlage 3

Nordic Hydrogen Route and the Baltic Sea Hydrogen Collector[84]. The latter is a multi-national project connecting demand centres in Germany, Sweden and Finland to offshore hydrogen production. In Spain and France, the establishment of "EHB import Corridor B"[85] results in high investments. Low country-specific investment needs can be the result of a combination of country size, strategic location and specifically planned projects with a varying share of repurposed pipelines.

The future hydrogen network is conceptually dependent not only of intra-EU projects discussed above, but also includes the connection into regions outside direct influence. These include especially the import corridors into Norway ("CHE pipeline"), Ukraine ("Central European Hydrogen Corridor") and Tunisia ("SouthH2corridor").

While the pipeline corridor into Ukraine is not heavily dependent on imports from Ukraine directly, other routes (through Italy into Tunisia and through the North Sea into Norway) have significant investments connected to the parallel ramp-up of production capacities, market adaptations and and infrastructure adaptations in jurisdictions outside of EU-27.

The Tunisian government is actively promoting the opportunities for its economy to become a major hydrogen export hub, aiming at exporting 300 kt/a in 2030, and 1.6 Mt/a by 2040[86]. This was backed by signing agreements with project developers. While pipelines exist for natural gas (extensions of the TransMed-pipeline), the corresponding conversion investments in the country are to be considered.

Equinor (Norway) in contrast has recently announced[87] to not realise the hydrogen pipeline together with German partners. Interestingly the decision is the consequence of ongoing negotiations between Germany and Norway as to the viability of low-carbon or "blue" hydrogen. Since Norway and Equinor remain committed to hydrogen as part of a decarbonised energy system, the corresponding investment needs may therefore realise at a later stage of the hydrogen economy's ramp-up.

Developments in the Ukraine remain highly uncertain[88], with potential hydrogen production centres currently occupied by Russia and overall highly damaged electricity and pipeline infrastructure. However, the small pipeline extension currently considered remains negligible with regards to investment needs for the overall East and South-Eastern hydrogen corridors and high development potentials remain (up to 10 GW for exports by 2030).

[84] EHB (2024), EHB Country Narratives (last retrieved Oct 2024)
[85] EHB (2022), Five hydrogen supply corridors for Europe in 2030
[86] Hdyrogen Insight (2024), New national strategy sets out plans for first H2 exports to Europe by 2030
[87] Reuters (2024), Equinor scraps plans to export blue hydrogen
[88] Fraunhofer ISI (2023), Ukrainian Hydrogen Export Potential: Opportunities and Challenges in the Light of the Ongoing war

Figure 2-33 Cumulated investment needs (planned per country until 2034, estimated EU-wide until 2040)

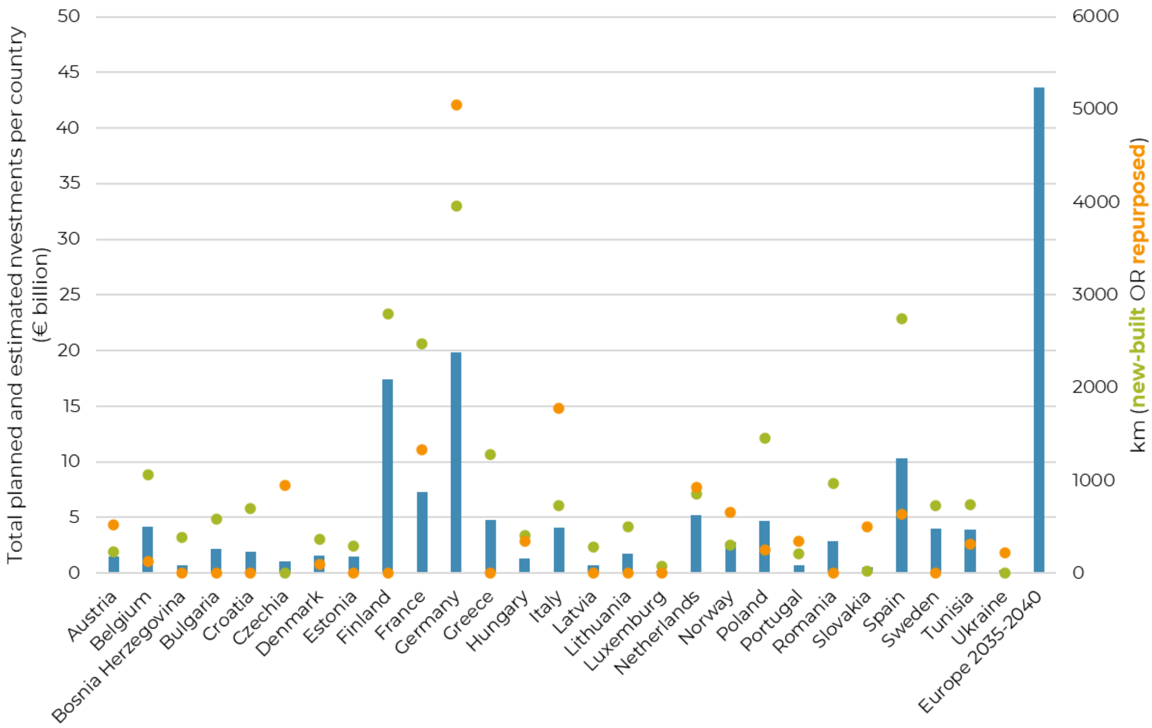


Table 2-6 Share of repurposed vs. new pipelines for the planned investments until 2034

Until 2034	€ billion (sum)	km (new)	km (repurposed)	€ billion new	€ billion repurposed
Austria	1.5	226	520	1.0	0.5
Belgium	4.2	1059	126	4.1	0.1
Bosnia Herzegovina	0.7	388	0	0.7	0.0
Bulgaria	2.2	580	0	2.2	0.0
Croatia	2.2	774	0	2.2	0.
Czechia	1.1	0	947	0.0	1.1
Denmark	1.6	361	93	1.5	0.1
Estonia	1.5	290	0	1.5	0.0
Finland	17.4	2800	0	17.4	0.0
France	7.3	2474	1329	6.5	0.8
Germany	19.9	3961	5050	15.2*	3.2*
Greece	4.8	1285	0	4.8	0.0
Hungary	1.3	408	345	1.1	0.2
Italy	4.1	728	1781	2.3	1.9
Latvia	0.7	288	0	0.7	0.0
Lithuania	1.8	500	0	1.8	0.0
Luxemburg	0.2	80	0	0.2	0.0
Netherlands	5.2	857	929	4.4	0.8
Norway	2.8	300	660	2.0	0.8
Poland	4.7	1457	251	4.5	0.2
Portugal	0.7	212	341	0.5	0.1

Romania	2.9	973	0	2.9	0.0
Slovakia	0.6	19	500	0.1	0.5
Spain	10.4	2745	635	9.9	0.4
Sweden	4.0	726	0	4.0	0.0
Tunisia	3.9	745	310	3.6	0.3
Ukraine	0.3	0	222	0.0	0.3

**compressor stations add additional €1.4 billion combined for new/repurposed*

The planned network until 2034 comprises more than 38,000 km, with a share of approximately 40% being repurposed natural gas pipelines. In comparison, the EHB had assumed/evaluated a share of 51% (59%) repurposed pipelines for the year 2030 (2040)[89], likely not based on the latest project developments. To estimate the annual investment needs towards 2034, an equal distribution within the years between FID and the end of construction/commissioning date was assumed. Most projects analysed aim for a start of operation before 2030 (policy driven). The corresponding FIDs cumulate in the year 2026 (about a third of overall projects) and almost the same number for 2027. The average construction time resulting from the data is approximately three years. Additionally, 2.5% of the CAPEX needs to be spend in the form of DEVEX or "studies" before FID, also assumed to be spread evenly across 3 years before FID. Note that the EHB states, that even though the DEVEXs are only a small share of the total CAPEX (2.5% spread over three years) public DEVEX-funding is crucial to derisk the following investments, enable FIDs and enable leverage and multiplier effects, making this the most effective public funding.[90] The distribution over the years until 2034 is depicted in Figure 2-34.

Figure 2-34 Annual planned investments for pipelines (project basis)

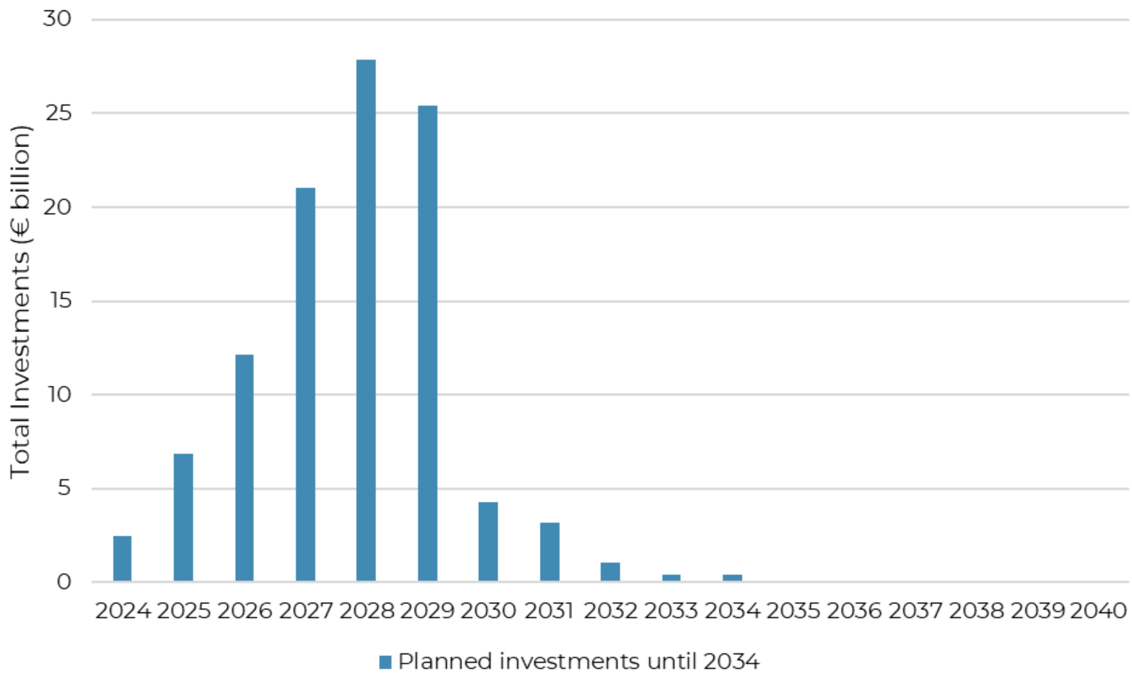


Table 2-7 Table of assumptions for hydrogen pipeline estimation

Assumptions Hydrogen Pipelines	
Assumption	**Source**

[89] EHB, Guidehouse (2023), EHB initiative to provide insights 10 July 2023 on infrastructure development by 2030
[90] EHB, Guidehouse (2024), EHB Implementation Roadmap: Public support as catalyst for hydrogen infrastructure

Specific Costs Pipelines	EHB cost values (€million/km):
	• Onshore & new:
	  ○ 20”: 1.80
	  ○ 36”: 3.20
	  ○ 48”: 4.40
	• Onshore & repurposed:
	  ○ 20”: 0.54
	  ○ 36”: 0.64
	  ○ 48”: 0.88
	• Offshore & new:
	  ○ 36”: 5.44
	  ○ 48”: 7.48
	• Offshore & repurposed:
	  ○ 36”: 1.09
	  ○ 48”: 1.50
		EHB 2024[91]

Specific Costs Compressor	EHB cost values (€million/km):
	• Onshore:
	  ○ 20”: 0.026
	  ○ 36”: 0.093
	  ○ 48”: 0.183
	• Offshore:
	  ○ 36”: 0.158
	  ○ 48”: 0.311
		EHB 2024

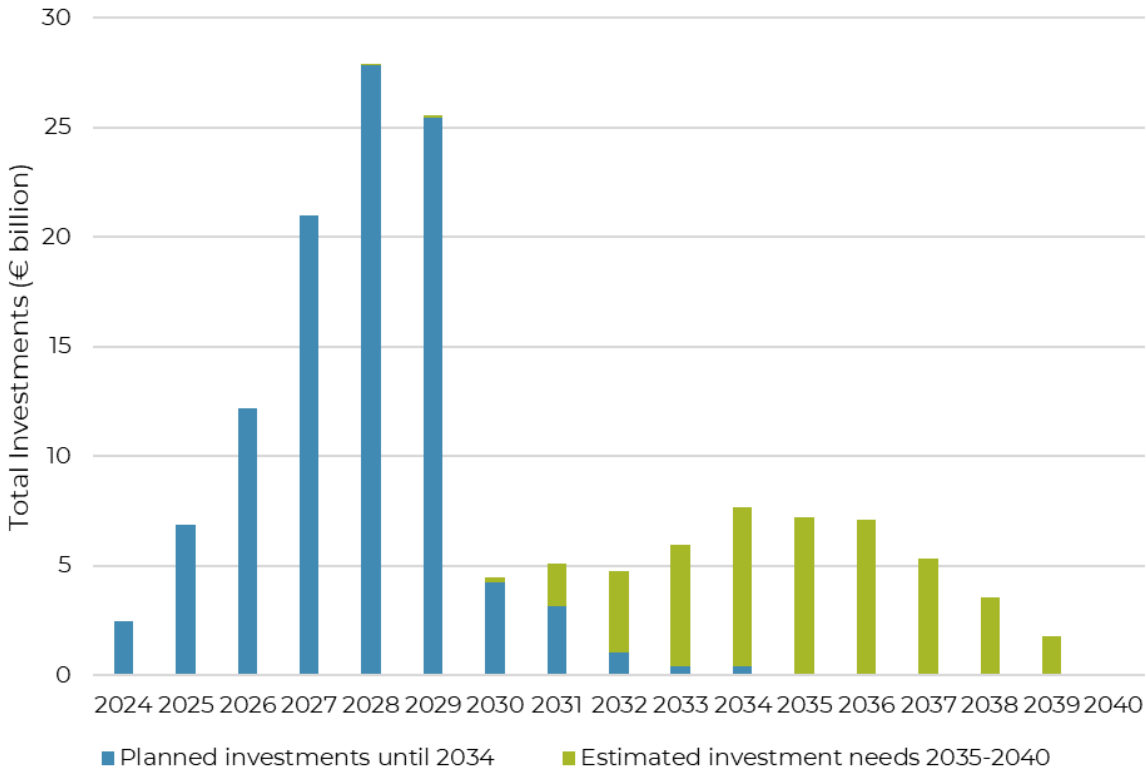
Conversion €$_{2023}$ to €$_{2024}$	European average inflation: 3%	Eurostat 2024[92]
CAPEX Allocation	• DEVEX: 2.5% of CAPEX, spread over three years before FID. • Remaining CAPEX: spread between FID and end of construction.	EHB 2024
Estimation 2035-2040	• Target 2040: 57,662 km • Share offshore-pipelines: 6.4% • Diameter offshore: 1000mm • Diameter onshore: 800mm • Scenario 1: Share repurposed pipelines: 100% • Scenario 2: Share repurposed pipelines: based on data before 2034.	EHB 2024, own assumptions.

Investment need estimations between 2035-2040

To estimate the investment needs beyond 2034, data limitations led to the application of a top-down-approach. Deducting the analysed project data until 2034 from the pipeline network development until 2040 as provided by the EHB[93] (57,662 km) a further expansion by another 19,500 km is expected. Using various assumptions (and estimations of repurposing vs. new-built) the related CAPEX ranges between €14-44 billion, with higher values being the more likely scenario.

[91] EHB, Guidehouse (2024), EHB Implementation Roadmap: Public support as catalyst for hydrogen infrastructure
[92] Eurostat (2024), Harmonised Index of Consumer Prices (last retrieved August 2024)
[93] EHB, Guidehouse (2023), EHB initiative to provide insights 10 July 2023 on infrastructure development by 2030

Figure 2-35 Annual investments for pipelines until 2040



These cost values are based on multiple assumptions:

- Share repurposed pipelines:
  The share of repurposed pipelines highly influences the related costs and is the main driver for the big cost range of this estimation. As the share of repurposed pipelines in the EHB data and TYNDP project list is diverging, two scenarios were derived:

  Scenario 1: "EHB-oriented, optimistic"
  The EHB assumes a share of almost 60% repurposed pipelines until 2040[94]. The data from the TYNDP and hydrogen core grid shows that this figure is much lower until 2034, with only 37% being repurposed. Getting close to this share of 60% until 2040, would imply that after 2034 no more pipelines are new-built, but instead all additional pipelines are repurposed. Under this assumption, the investment needs between 2034 and 2040 would be approximately €14 billion.
  Scenario 2: "TYNDP-oriented, conservative"
  This scenario assumes, that the shares of repurposed pipelines for onshore (41%) and offshore (11.5%) pipelines derived from the TYNDP projects list until 2034 stay constant even beyond 2034. This assumption is strengthened by the fact, that the TYNDP project list comprises 12 onshore projects with more than 5,220 km after 2034, which have a share of 42% being repurposed (not almost 70% as the EHB assumes between 2030 and 2040). The assumption that the shares of repurposed pipelines remain constant, yields to a required investment of approximately €44 billion between 2035 and 2040. It could be argued that this is a slight

[94] EHB, Guidehouse (2023), EHB initiative to provide insights 10 July 2023 on infrastructure development by 2030

overestimation, as due to the phase out natural gas, more gas pipelines are available for repurposing, however no concrete evidence for this conclusion is available.

- Share of offshore pipelines:
  Until 2034, 12.8% of all pipeline kilometres included in TYNDP are offshore. We assume such offshore pipelines being crucial projects which are realised in the first stages of the pipeline grid roll-out. Therefore, we assume that after 2034, the share of offshore projects drops by 50% (to be confirmed via stakeholders) to 1,240 km of the total 19,500 km to be built.

- Diameter:
  The average diameter of offshore pipelines is 994 mm which we will proxy with a 1,000 mm pipeline. For onshore pipeline projects, the average diameter varies between 764 mm (737 mm) for newly built (repurposed) pipelines. We proxy both with a diameter of 800 mm, which is a commonly used pipeline size, being the second most applied diameter among all TYNDP-projects. It could be argued that as the main connections are built in the early stages, after 2034 mainly pipelines with smaller diameters are constructed (e.g. 600 mm or even below for distribution grids rather in the range of 250-300 mm[95]), leading to a slight overestimation.

In total when, as described, using the data from the TYNDP and German Hydrogen Core Grid until 2034, and then estimating the remaining 6 years based on scenario 2, the estimated CAPEX for the described European hydrogen pipeline grid until 2040 is €151 billion. The EHB estimated its previous 53,000 km network to cost €80-143 billion[96]. The EHB admitted that this might be an underestimation as the costs are based on values which do not consider inflation over the years 2019-2023[97]. As our values cover this price increase as well as the latest extension from 53,000 km to 57,000 km the derived estimation is align with the related literature values and can be considered an update of the existing estimation, reaching and rather exceeding the currently discussed upper limits as stated by EHB.

2.7.2. Hydrogen Underground Storage

Current status and expected future developments

Hydrogen underground storage represents a crucial part of the hydrogen infrastructure categories by providing the increasingly required flexibility of a hydrogen economy. Flexibility is essential not only to accommodate the variable supply of renewable hydrogen influenced by weather conditions but also to enable dispatchable power plants to run at peak times.[98] The different types of hydrogen underground storage include salt caverns and porous media covering depleted gas fields and aquifers. Hydrogen underground storages are an essential part of the future European energy system. Given the specific geological requirements for hydrogen underground storages, the incorporation into the energy system and thus the respective cross-border impact depends on the planning of connecting pipelines. Essentially, we consider projects in continental Europe of European relevance.

[95] Hydrogen Distribution(2018) Online overview
[96] EHB, Guidehouse (2022), A European Hydrogen Infrastructure Vision Covering 28 Countries
[97] Hydrogen Insight (2023), Europe's 'hydrogen backbone' of cross-border pipelines will cost billions more euros than initial estimates,
[98] TYNDP 2024 Draft Scenarios Report, May 2024

Energy system models, such as the Ten-Year-Network-Development-Plan (TYNDP) 2024 scenarios by ENTSO-G (and -E)[99], HyStorIES[100] or the Langfristszenarien by Fraunhofer Institute[101] provide scenarios on required hydrogen underground storage capacities for the long term. As prescribed in , until 2030, the projected storage capacities reach between 16 to 28 TWh. By 2040, the HyStorIES and Langfristszenarien models estimate an underground storage requirement of 138 to 139 TWh, while the TYNDP 2024 scenarios assume 14 TWh. The very low value compared to the other energy system models comes from the fact, that other options such as e-fuels production, import terminals, SMR/ATR and others to provide flexibility to the energy system accounting for 114 to 122 TWh in 2040 are considered alongside underground hydrogen storage. However, realistically, the role of the alternative flexibility options can be considered not as strong.[102]

Table 2-8 Hydrogen underground storage capacity scenarios in different energy system studies

Hydrogen storage capacity scenarios	Projected hydrogen storage capacity (TWh) 2030	2040	Geographical scope
TYNDP 2024 scenarios	--	14	EU-27
HyStorIES[103]	28	138	EU-27+UK
Langfristszenarien[104]	16	139	EU-27+UK+NO

In order to analyse the investment needs for hydrogen underground storage of European relevance, we pursue a bottom-up approach with the following steps:

1. Examine datasets and gather information on planned and existing projects including technical parameters, project budgets and project timelines
2. Analyse specific cost data for new and repurposed different types of hydrogen underground storage
3. Apply the specific costs to projects with lacking information on project CAPEX costs

To provide a realistic picture for the more uncertain long-term future, the projects dataset gathered, and the resulting investment needs further will be put in context with the top-down scenarios from the energy system models.

Project datasets

For the bottom-up approach datasets and maps with projects of European relevance are assessed. These include:

- **TYNDP 2024 Annex A** with concrete hydrogen projects referring to hydrogen storage, i.e. with the abbreviation 'H2S' in their project code. This dataset serves as a base.
- **1st PCI/PMI list:** seven hydrogen underground storage projects were awarded PCI status. In the 1st PCI/PMI list. These projects form part of the TYNDP 2024 project list. Lacking information in the TYNDP 2024 project list is added.
- **IPCEI projects:** three projects were selected for IPCEI status of the Hy2Infra-project round.

[99] TYNDP 2024 Draft Scenarios Report, May 2024
[100] HyStoRIES (2022), Major results of techno-economic assessment of future scenarios for deployment of underground renewable hydrogen storages
[101] Fraunhofer Langfristszenarien
[102] Guidehouse (2021), Picturing the value of underground gas storage to the European hydrogen system
[103] Scenario D: larger share of hydrogen imports to Europe and including porous media storage
[104] Scenario O45-H2

- **Past PCI/PMI candidates**
- **H2eart for Europe and h2inframap.eu**

To be able to estimate the investment needs, certain key parameters are required across all projects, especially information regarding the type of storage, information on whether the project aims to build a new or repurpose existing storage sites, storage capacity, i.e. working gas volume, as well as CAPEX costs or costs as communicated for PCI applications (found in the PCI lists), the expected timeline for the FID and commission as well feasibility study timelines, and the country of the project site. The different datasets (listed above) were compared to fill gaps and to check for consistency. Lacking information on technical data was concluded from the example of similar projects by applying average values[105]. Whenever information regarding the working gas volume was included, the lower heating value (LHV) was used for converting numbers into the energy unit of GWh. However, not all existing values could be verified with regard to the application of the lower or the higher heating value.

Projects aiming to store 100% hydrogen are considered, but it is worth mentioning that the repurposing of existing storage sites can be executed stepwise with regard to hydrogen share.[106]

The resulting dataset lists 69 projects including planned project expansions with a total working gas volume exceeding 35 TWh. Although the TYNDP 2024 only covers projects until 2034, the aggregated project list, e.g. from planned project expansions, includes project with commissioning years beyond 2034 and thus allows a firm estimation towards 2040 based on planned projects alone. The main share of the projects and project expansions is represented by salt caverns with a cumulated storage capacity of 21.3 TWh (see Table 2-9). On the other hand, eight porous media projects, i.e. depleted gas fields or aquifers, amounting to 13.8 TWh storage capacity are considered. Only very few projects are part of the respective National Development Plans. This emphasises the systemic and European role of hydrogen underground storage needing European cooperation and firm support on European level.

Table 2-9 Number of underground storage projects assessed in the bottom-up approach by storage type

	Salt caverns		Porous media		Total	
	Cumulated storage capacity	Number of projects	Cumulated storage capacity	Number of projects	Cumulated storage capacity	Number of projects
New	13.0 TWh	39	3.0 TWh	2	16.0 TWh	41
Repurposed	8.3 TWh	22	10.8 TWh	6	19.1 TWh	28
Total	**21.3 TWh**	**62**	**13.8 TWh**	**8**	**35.1 TWh**	**69**

Specific investment costs

Based on literature review as well as information provided by experts in dedicated interviews and concluding from available data of comparable project examples, we use the specific CAPEX costs for hydrogen underground storages as provided in Table 2-10 with all cost data converted to $€_{2024}$. Here, we distinguish between the different types of storage and between new-built and repurposed storages.

[105] Average project durations were applied to set missing dates for FID and the start of feasibility studies.
[106] DBI (2022), Wasserstoff speichern – soviel ist sicher

For new-built storage sites the approach described in HyStorIES [107] is followed, with subsurface-related CAPEX linearly scaling with the working gas volume and surface-related CAPEX with the maximal withdrawal rate.[108] For repurposed hydrogen underground storage DBI (2022)[109] provides a detailed and complete analysis on emerging costs.[110] In comparison with existing project examples however, high divergencies arise for the resulting investment needs for repurposed storage sites. Thus, to reach the right order of magnitude, the (average) specific cost values of representative project examples scaled with the factor 0.7 are applied.

Pre-FID costs, e.g. for feasibility studies, are estimated to range between 2-5% of the CAPEX provided the site is known, based on an expert interview. For the analysis, we apply 3.5% of the CAPEX.

Table 2-10 Specific cost inputs for hydrogen underground storages

Type of storage and construction	Type of costs	Specific costs ($€_{2024}$)	Source
New salt cavern storage	Subsurface CAPEX costs per working gas capacity (LHV)	0.55 €/kWh_{LHV}	HyStorIES[111]
	Surface CAPEX costs per max. withdrawal rate	223 €/kW	
New porous media storage	Subsurface CAPEX costs per working gas capacity (LHV)	0.22 €/kWh_{LHV}	
	Surface CAPEX costs per max. withdrawal rate	972 €/kW	
Repurposed salt cavern storage	Reconversion CAPEX costs per working gas capacity	€ 1.60 /kWh_{LHV}	Based on Energinet project[112]
Repurposed porous media storage	Reconversion CAPEX costs per working gas capacity	0.23 €/kWh_{LHV}	Based on average value of project by Enagás and Hellenic Republic Asset Development Fund[113]

Analysis of investment needs data

The overall investment need for hydrogen underground storage concluded from the bottom-up project list with a total storage capacity of 35.1 TWh, amounts to **€26.9 billion by 2040** with **€20.6 billion required by 2030** and **€6.3 billion beyond 2030**. Based on existing projects, this indicates a robust minimum investment need for building up hydrogen underground storage capacities in Europe until 2040. To provide an estimate on further required investments to scale up the hydrogen underground storage infrastructure to an order of magnitude such that meeting EU climate targets is ensured, the project dataset is brought in the context of the energy system scenario of HyStorIES[114] with a total storage capacity of 138 TWh projected and a top-down scenario for 2031-2040 is applied

[107] HyStorIES D7.2-1 (2022), Life cycle cost assessment of an underground storage site
[108] To estimate the max. withdrawal rate, it was taken into account that it scales linearly with the working gas volume as concluded in HyStorIES D7.1-1 (2022) Conceptual design of salt cavern and porous media underground storage site. For salt caverns, the ratio of max. withdrawal rate is calculated to be 0.09 (GWh/day)/GWh. For porous media sites the value of 0.013 (GWh/day)/GWh is used.
[109] DBI (2022), Wasserstoff speichern – soviel ist sicher
[110] According to DBI (2022), the specific reconversion CAPEX costs with respect to the working gas capacity amount to 0.09 €/kWh for salt caverns and 0.08 €/kWh for media storage.
[111] HyStorIES D7.2-1 (2022), Life cycle cost assessment of an underground storage site
[112] Project CAPEX: €130 million; working gas volume: 100 GWh
[113] Enagás: Project CAPEX of €396 million and working gas volume of 1740 GWh; Hellenic Republic: Project CAPEX of €361 million and working gas volume of 1590 GWh
[114] HyStorIES D5.5-2 (2022), Major results of techno-economic assessment of future scenarios for deployment of underground renewable hydrogen storages, applying scenario D

in addition to the existing projects[115]. An additional investment need of €81.3 billion for the years 2031-2040 representing an additional storage capacity of 103.2 TWh across Europe arises. Thus, in the wider picture, where system study projections are included, the total investment needs amount to **€ 108.2 billion until 2040.**

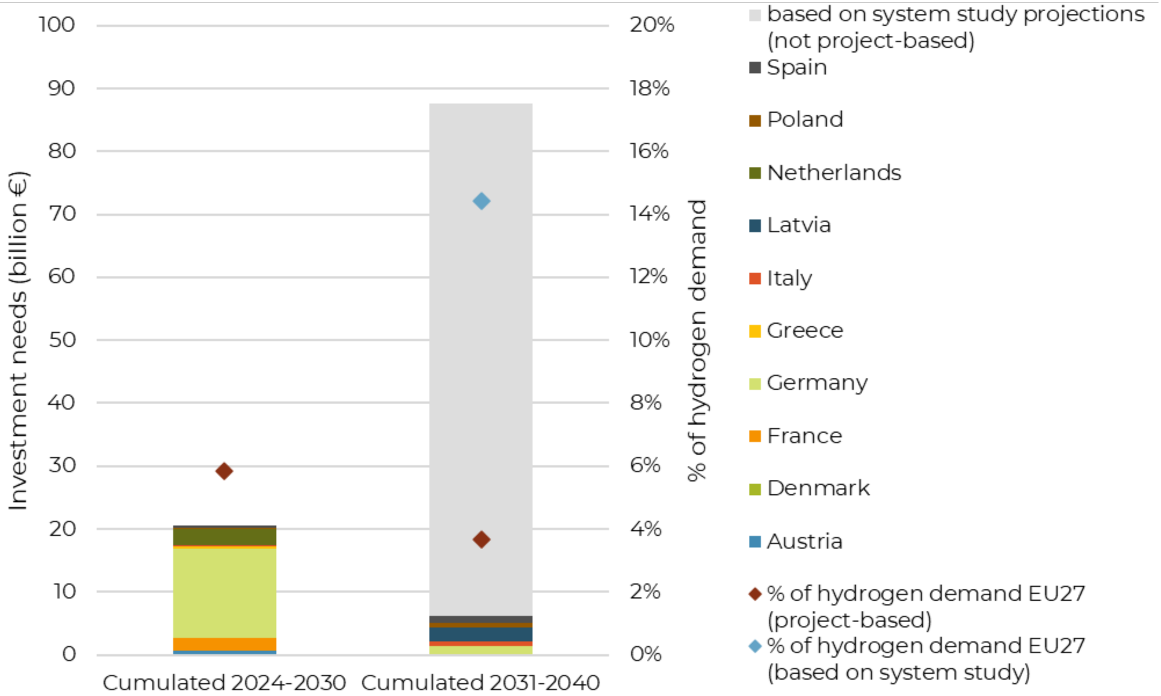
The seven projects with PCI status are planned to provide a total storage capacity of 2759 GWh by 2038. The associated costs are indicated at €2.6 billion. The storage capacity intended for the three IPCEI projects accumulates to 334 GWh and cost estimations based on the specific costs of amount to €415 million.

A study by Artelys and Frontier Economics[116] concluded from detailed modelling that the optimal capacity for hydrogen underground storage is of 45 TWh by 2030 and 270 TWh by 2050. The associated investment costs are €26 billion for 2030 and €135 billion by 2050. Thus, for 2030 our estimation of €23.4 billion aligns with the modelling results, although for about only 50% of the associated storage capacity. Simply assuming a linear build-up in storage capacity in the model, i.e. €80 billion for 157 TWh, our estimates with €108 billion for 138 TWh for 2040 when taking into account the top-down results from system study projections can be considered on track.

The median of different future hydrogen demand scenario analysed by the European Hydrogen Observatory[117] projects a hydrogen demand of 344 TWh per year in 2030 and 959 TWh per year in 2040. As indicated in Figure 2-36, the resulting storage capacity of planned projects accounts for 6% of the hydrogen demand in EU27 in 2030 and for 4% in 2040. Including the additional storage capacity projected from system studies, the total storage capacity accounts for 14% of the hydrogen demand by 2040. The hydrogen underground storage demand is mainly directed by the seasonally varying hydrogen demand and must be configurated for seasonal storage in the energy system. Meanwhile during the ramp-up, hydrogen underground storage will also serve for short-term storage. Due to more cycles of injection and withdrawal, lower percentages of the overall hydrogen demand are applicable.[118]

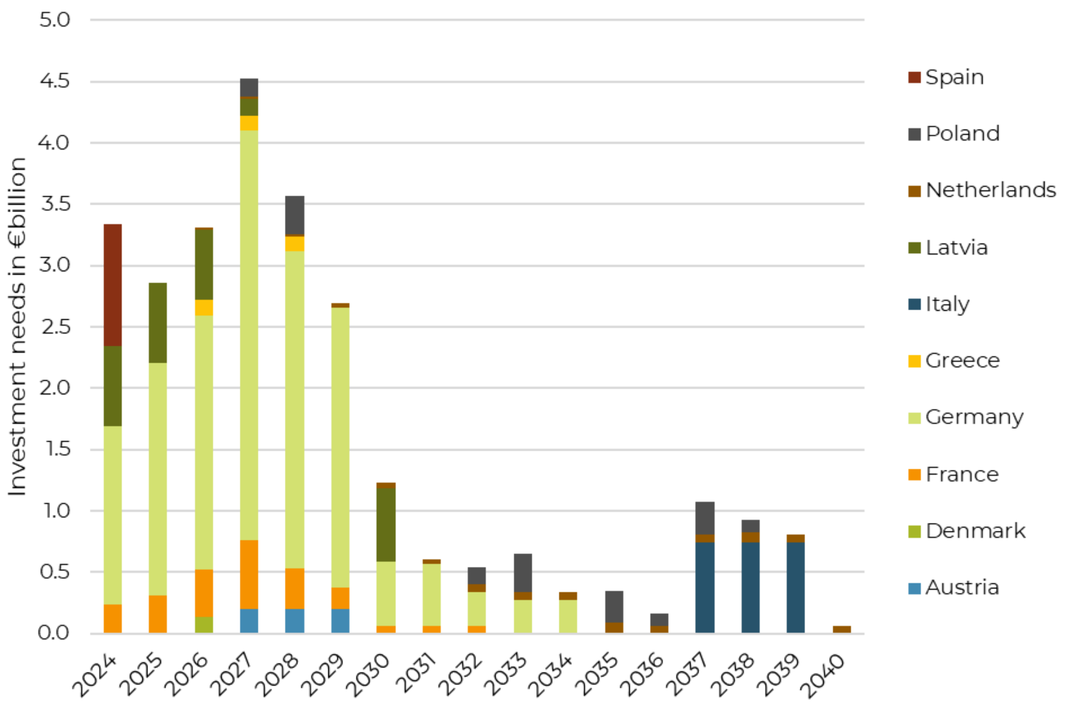
[115] For the analysis, the total working gas volume of the projects is subtracted with respect to the type of storage from the storage capacity projections until 2040 in Scenario D of HyStorIES D5.5-2 (2022) and the shares with respect to new-built and repurposed storages of the existing projects are applied. The associated investment needs are calculated by linearly applying the specific costs from Table 2-. To indicate that the additional storage capacities are yet not planned, they are not country-specific and are attributed to the timeframe of 2031-2040.
[116] Artelys and Frontier Economics (2024), Why European underground hydrogen storage needs should be fulfilled
[117] European Hydrogen Observatory (Clean Hydrogen Partnership), Scenarios for future hydrogen demand
[118] Fraunhofer ISI (2024), Langfristszenarien – Webinar on Energy supply

Figure 2-36 Investment needs cumulated for hydrogen underground storage (Min-Max, excl. study costs) and respective share of hydrogen demand covered by storage capacity



An annual distribution of the investment needs for the bottom-up approach based on the commissioning years and expected construction durations, is shown in Figure 2-37.

Figure 2-37 Investment needs per year and country until 2040 for hydrogen underground storage (excl. study costs)

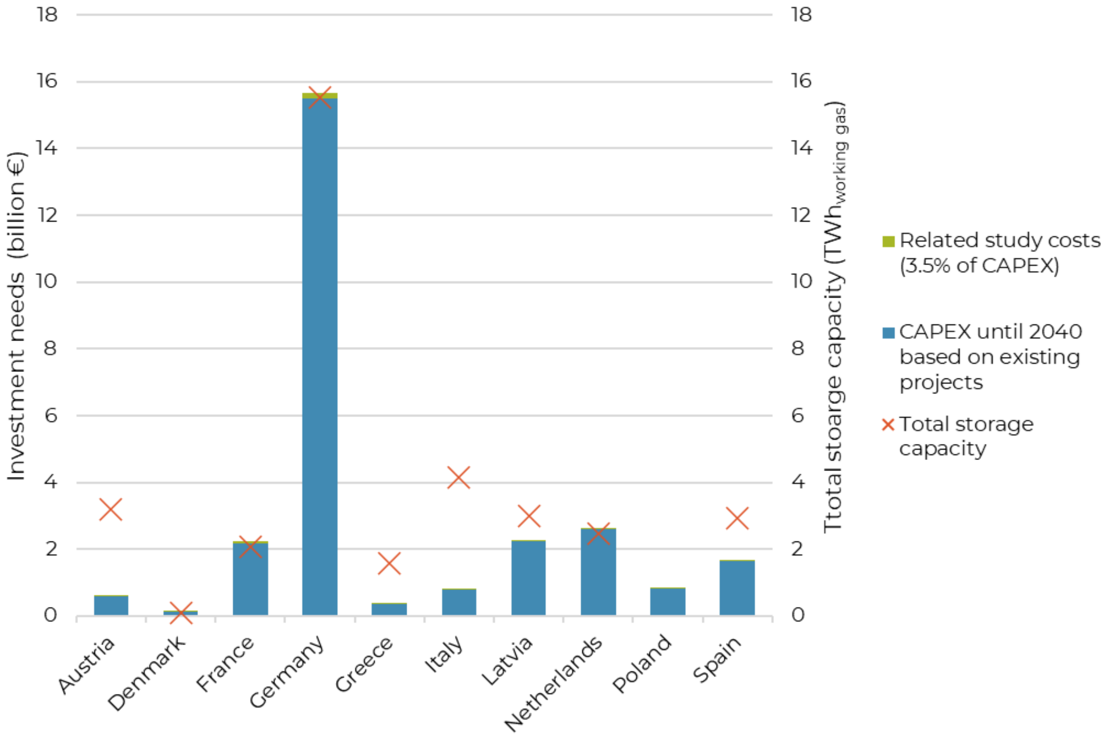


In the bottom-up approach, the investment needs are expected to sharply rise to €4.5 billion in 2027 until they decrease until the early 2030. This effect comes from the fact that the scope of the TYNDP

2024 scenario is limited to 2034. Later investments are mainly assigned to expansion plans of earlier projects. New projects in the long-term view are often not in the pipeline yet. It can be expected that the additional investment needs concluded from the top-down approach for 2031 to 2040 of in total €81.2 billion will be distributed on top of the investment needs projected from existing projects.

Among the Member States, the largest investment needs by orders of magnitude from existing projects are assigned to Germany with €15.5 billion for 35 projects providing 15.5 TWh of storage capacity by 2040. Including costs related to feasibility studies, this amounts to €15.7 billion for projects in Germany. In the Netherlands five projects of total of 2.5 TWh are attributed with €2.6 billion (including study costs) and 10 projects in France amounting to 2.1 TWh and 1 mega project of 3TWh in Latvia require €2.2 billion of investment each. The distribution of investment needs among countries is shown in Figure 2-38.

Figure 2-38 Distribution of investment needs until 2040 for hydrogen underground storages among countries



Pre-FID investments amount to €413 million for the existing projects in the bottom-up approach until 2040. In the case of the complete storage capacity projection from additional system study consideration, the related cumulated study costs until 2040 are €3.3 billion.

Table 2-11 Overview of planned investment needs (in €million) and added capacity (in GWh) per country and per year (if yearly not available cumulated in 2040)

		AT	DK	FR	DE	GR	IT	LV	NL	PL	ES
2024	€million	2	1	255	1506	3	8		654	3	4
	GWh										
2025	€million	2	1	326	1942	3	8		654	3	4
	GWh										

2026	€million	2	130	403	2139	120	1		575	23	4
	GWh			2	135				400		
2027	€million	199		562	3340	120	1		143	24	150
	GWh		100		1141				1039		
2028	€million	199		332	2585	120	4		4	24	313
	GWh			825	2256				400		
2029	€million	199		175	2280		3		4	44	5
	GWh			750	2330	1590	5				436
2030	€million			58	530		44		600	46	5
	GWh	3200		252	5243						
2031	€million			58	508		44			46	6
	GWh				140				644		
2032	€million			58	275		266			65	149
	GWh				2285						
2033	€million				275		225	14		67	312
	GWh			250	306		340				
2034	€million				275		225	14		67	3
	GWh										436
2035	€million							14		87	264
	GWh				1706		3800				
2036	€million							14		65	100
	GWh									N.A.	164
2037	€million							743		65	264
	GWh										
2038	€million							743		85	99
	GWh										164
2039	€million							743		64	
	GWh									N.A.	1740
2040	€million									64	
	GWh							3000			

Regarding reliability of the data, it should be noted that on the one hand many projects (especially those that are very large ambitious) may underlie changes in their announced timelines and expansion steps, which cannot be accounted for explicitly except for a general comment that the further we look into the future the larger the general uncertainty remains. Furthermore, especially project CAPEX costs calculated from the specific costs according to Table 2-10 and technical parameters are subject to uncertainties. €5.1 billion, i.e. 19% of the total investment needs in the bottom-up approach and 5% including the top-down approach, arise from reliable sources such as the 1st PCI/PMI list and the TYNDP 2024 list.

A study by Frontier Economics[119] highlights the urgency of the implementation of a financing mechanism for hydrogen storage to quickly enable FID. The currently long project durations of 6 to 11 years[120] inherit the risk of a gap in storage capacities already by 2030 and a corresponding spread of the projected annual investment needs also into the 2030s. Secured storage capacities with PCI or IPCEI status amount to 3.1 TWh, representing only 11 to 19 % of 2030 projections of system studies.

2.7.3. Hydrogen Import Terminals

Current status and expected future developments

To meet the expected renewable hydrogen demand, alongside domestic production the EU will rely on imports from regions with more advantageous climate conditions such as the MENA region, Chile or Australia leading to lower levelised costs of hydrogen (LCOH). The impact assessment on the EU's 2040 climate targets concluded throughout the different scenarios a required import volume of 20 Mtoe[121], of hydrogen and RFNBOs in 2040.[122] For long transport distances, hydrogen transport by ship remains the most economical transport mode option which makes import terminals for hydrogen an essential category of the hydrogen infrastructure.

Given the low volumetric energy density of hydrogen and costly technologies for pure gaseous hydrogen tankers, the most economical options for future hydrogen transport include the transport vectors of liquid hydrogen carriers, i.e. liquid hydrogen (LH_2), ammonia, liquid organic hydrogen carriers (LOHC), methanol and synthetic methane.

The direct use of green hydrogen derivatives (i.e. without hydrogen reconversion), including **e-ammonia, e-methanol** and **e-methane,** provides the most economical way and is considered the preferred choice of terminal operation throughout studies and as validated by stakeholder interviews[123]. Regarding demand perspectives, green hydrogen derivative imports can replace fossil-derived derivatives while additional demand might arise in the future for the use as alternative maritime fuels. Additional import capacities can become subject to hydrogen reconversion to meet the increasing demand for green hydrogen. Thus, although infrastructure for hydrogen derivatives is already in place, the expansion of capacities is required. Current ammonia import capacities amount to 4 Mt per year, corresponding to 0.7 Mt_{H2}[124], with ambitious plans to reach 10 Mt of ammonia imports (corresponding to 1.7 Mt_{H2}).[125] It should be noted, however, that ammonia cracking is not yet commercially mature. Meanwhile, the production of green methanol and methane requires the supply of CO_2 (from DAC or biogenic sources) which is associated with high costs. As a result, green methanol and methane are not considered typical green hydrogen pathways.[126]

LH_2 technologies and standards for hydrogen import are not yet in place and are expected to be commercially available in the 2030s.[127] Particularly due to boil-off losses and the high energy and cost-intensity of liquefaction the LH_2 pathway is not considered relevant until 2040.

[119] Frontier Economics (2024), Finanzierungsmechanismus für den Aufbau von Wasserstoffspeichern
[120] H2eart for Europe (2024), The role of underground hydrogen storage in Europe
[121] 20 Mtoe = 6.98 Mt_{H2}
[122] EU (2024) Impact Assessment, Part 3
[123] Expert interviews with EHB initiative (Enagas, Guidehouse) and GermanLNG
[124] Hydrogen content in 1 kg of ammonia equals 17.6%
[125] DNV and Frontier Economics (2022), Securing & greening energy for Europe: The role of terminal operators
[126] Gas for Climate (2022), Facilitating hydrogen imports from non-EU countries
[127] Gas for Climate (2022), Facilitating hydrogen imports from non-EU countries

LOHCs are liquid in ambient temperature and can rely on existing oil infrastructure. By applying dehydrogenation, hydrogen can be extracted from the carrier material.

Next to the use of existing import terminals of hydrogen derivatives, the build-out of hydrogen import terminals can be conducted by reconverting existing LNG terminals. Different studies[128] have analysed the technical requirements and costs for repurposing LNG-terminals. It can be concluded that only on-shore import terminals are suitable. Already during the construction of new LNG terminals, the later repurposing to hydrogen can be considered in the terminal design and choice of material. Which is the most economical option being however project dependent. At 1-2.5% of the LNG terminal CAPEX, the tank can be repurposed for ammonia, e.g. with suitable material to avoid corrosion and strengthening tank wells. The largest contribution to the arising costs comes from required adjustments to the boil-off system with 5-8% (modification) or 3-6% (pre-investment) of the LNG terminal CAPEX.[129]

In order to estimate the investment needs until 2040 for building up the required import terminal capacities in the EU, we follow a bottom-up approach with the following steps:

1. Gathering of specific CAPEX costs for hydrogen import terminals
2. Aggregation of datasets of existing projects for hydrogen import terminals
3. Complementing the project list with existing LNG terminals considered in the infrastructure planning of the European Hydrogen Backbone (EHB) initiative
4. Application of specific costs for projects lacking information on project CAPEX

Specific cost data for hydrogen import terminals

Specific CAPEX costs for import terminals of different hydrogen carriers are provided in ENTEC (2022)[130]. It includes specific CAPEX costs for 2030 for new-built import terminals with respect to storage capacities and for hydrogen reconversion facilities with respect to annual conversion volumes. All cost data was converted to $€_{2024}$.

Table 2-12 Specific CAPEX cost inputs for hydrogen import options in terminals

	CAPEX costs	Unit	To be applied to	Typical sizes
LH_2 import terminal	2,443,000	$€/GWh_{H2}$	LH_2 storage capacity	9 GWh_{H2}
LOHC import terminal	67,000	$€/GWh_{LOHC}$	LOHC storage capacity	80 GWh_{H2}
Dehydrogenation plant	30.6	Million $€/(GWh_{H2}/day)$	Hydrogen import capacity	---
Ammonia terminal	373,000	$€/GWh_{NH3}$	Ammonia storage capacity	328 GWh_{NH3}
Ammonia cracker	19.4	Million $€/(GWh_{H2}/day)$	Hydrogen import capacity	---
LNG terminal	461,000	$€/GWh_{LNG}$	LNG storage capacity	1438 GWh_{LNG}

When applying the specific costs to the project list it needs to be considered that costs scale with volume, thus requiring the application of an approximate scaling factor of 0.7 (specific costs are derived from projects of typical sizes as shown in Table 2-12).

[128] E.g. DNV and Frontier Economics (2022), Securing & greening energy for Europe: The role of terminal operators; Fraunhofer ISI (2022), Conversion of LNG Terminals for Liquid Hydrogen or Ammonia
[129] Fraunhofer ISI (2022), Conversion of LNG Terminals for Liquid Hydrogen or Ammonia
[130] ENTEC (2022), The role of renewable H_2 import & storage to scale up the EU deployment of renewable H_2

According to ENTEC (2022), conversion costs of a terminal from LNG to ammonia requires 11% of the original CAPEX. Special consideration must be made to resulting lower storage capacities due to the lower volumetric energy density of the hydrogen carriers. For ammonia, this leads to a at least by 50% reduced storage capacity compared to LNG storage[131] down to 1/3 of remaining tank capacity due to the higher mass of ammonia[132]. For the analysis, a conservative choice with applying the factor 1/3 to repurposed LNG-tanks for ammonia storage was made. For repurposed LOHC terminals, we apply the factor 0.2 for the remaining tank capacity[133].

Dataset of hydrogen import terminal projects

For constructing a dataset of hydrogen import terminal projects of systemic relevance for the EU, the following project lists are assessed and aggregated:

- **TYNDP 2024 Annex A** with hydrogen projects referring to hydrogen import terminals, i.e. with the project code 'H2L'. This dataset serves as a base.
- **1st PCI/PMI list:** eight hydrogen import terminal projects were awarded PCI status in the 1st PCI/PMI list. These projects form part of the TYNDP 2024 project list. Lacking information in the TYNDP 2024 project list is added.
- **IPCEI projects:** two projects were selected for IPCEI status in the Hy2Infra-project round.

Relevant project information for providing a detailed estimate of investment needs for hydrogen import terminals in the EU include the country of the projects, project timelines and CAPEX costs or PCI costs, as well as technical specifications, such as the type of hydrogen carrier imported, information on whether a terminal is new-built or repurposed, the import capacity in GWh_{H2}, the average efficiency for hydrogen conversion and the storage capacity for the hydrogen carriers.

LNG terminals considered by the EHB initiative to complement the dataset

The listed projects based on the TYNDP 2024 are expected to be commissioned at latest in the year 2034 given the temporal scope of the TYNDP 2024. For a further reliable bottom-up approach beyond 2034, the dataset is aggregated with LNG terminals considered in the planning for 2040 of the European Hydrogen Backbone (EHB) initiative[134]. Although for most of these projects currently no announcements regarding repurposing for hydrogen were made, we take their strategic location at the EHB as an indication for repurposing for hydrogen import in the long-term to serve as part of the European hydrogen infrastructure. For example, the German government accepted modifications to the LNG Acceleration Act (LNGG) in 2023, requiring terminals to support hydrogen and its derivatives from 2044.[135] Although it is yet unclear which hydrogen carrier provides the most economical repurposing of LNG terminals, in literature the conversion to ammonia is most represented. Thus, as a general assumption for the analysis of the investment needs, the listed LNG terminals are expected to be repurposed to ammonia terminals. For the commissioning year we apply 2040 as the most optimistic vision. Thus, resulting investment needs arising from these LNG terminals must be considered as an upper bound.

Filling of data gaps with assumptions based on existing data

The dataset is cleaned and data gaps in the project list are filled by estimates based on comparable projects of the dataset, e.g. in the case of the duration of the project works. This includes further an

[131] DNV and Frontier Economics (2022), Securing & greening energy for Europe: The role of terminal operators
[132] Fraunhofer ISI (2022), Conversion of LNG Terminals for Liquid Hydrogen or Ammonia
[133] DNV and Frontier Economics (2022), Securing & greening energy for Europe: The role of terminal operators
[134] EHB (2022), A European hydrogen infrastructure vision covering 28 countries
[135] https://www.bundestag.de/dokumente/textarchiv/2023/kw25-de-lng-beschleunigungsgesetz-954392

estimate for the average efficiency of the conversion to hydrogen of 80% for dehydrogenation and 85% for ammonia cracking. The storage capacities for ammonia at the LNG-terminals situated at EHB are concluded from the LNG storage capacities by applying the factor of 1/3 due to the lower volumetric energy density of ammonia. Remaining estimates on lacking hydrogen import capacities and storage capacities of the hydrogen carrier are made by applying the average ratio of storage capacity to hydrogen import volumes distinguishing between different hydrogen carriers.

Lacking CAPEX costs are calculated by applying the specific costs from and as prescribed. To reflect that ammonia imports firstly will be directly used we apply a factor of 89% derived from the total ammonia import volume projected from the project list and the optimistic ammonia import ambitions of 10 Mt. It should be noted that LH2 and Methanol projects in the dataset already provide CAPEX costs, thus no calculations are needed. Furthermore, projects with extremely high storage capacities were omitted.

The resulting project dataset inherits 43 hydrogen import terminal projects of a total hydrogen importing capacity of 17.6 Mt_{H2} by 2040. 36 projects are ammonia import terminals with a hydrogen importing capacity of 17.2 Mt_{H2} per year including 15 LNG terminals to be potentially repurposed to ammonia terminals which amount represent 5 Mt_{H2} per year. Liquid hydrogen projects are represented by a single project with 0.04 Mt_{H2} per year. Given the remaining technological challenges on LH_2 transport and storage, and relatively high costs, LH_2 is expected to not play a crucial role before 2040. The role of LOHC terminals with 3 representatives of in total 0.01 Mt_{H2} is small until 2040, although the IPCEI status of two LOHC projects could accelerate technological progress. Methanol terminals in the project list only play a minor role with 3 projects of in total 0.4 Mt_{H2}. This can be explained by the fact, that green methanol production requires carbon, of which capturing technologies are still being developed and which is thus expensive.

Table 2-13 Overview of type of projects considered

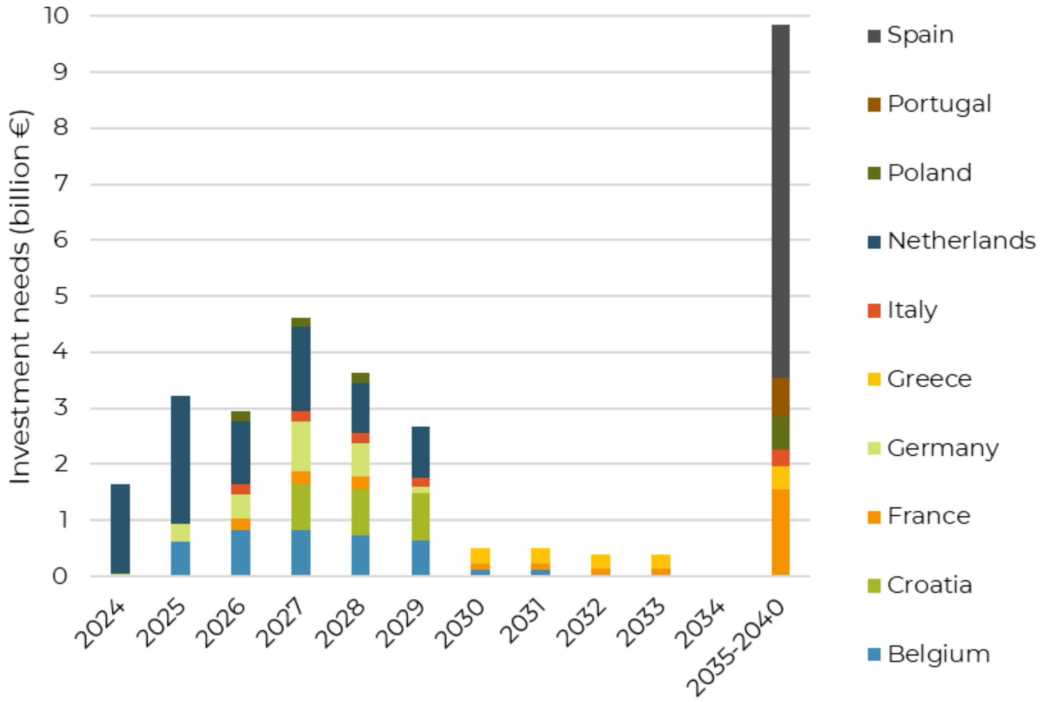
	Ammonia	LH2	Methanol	Other LOHC	Total
New	19	1	3	1	**24**
Repurposed (not specified)	2	0	0	2	**4**
Repurposed LNG Terminal*	15	0	0	0	**15**
Total	**36**	**1**	**3**	**3**	**43**

**The number of the repurposed LNG Terminal comes from the assumption that current LNG terminals located at the EHB will be repurposed to Ammonia in the future.*

Analysis of investment needs data

The resulting bottom-up list of relevant hydrogen terminal projects and additional strategic LNG terminals provides 43 projects amounting to 17.2 Mt hydrogen per year imported and resulting in a total investment need of €30.3 billion by 2040. Given the data structure and the yet unclear plans of repurposing for the listed LNG terminals, granularity with respect to annual investment needs can be provided until the year 2034 with sufficient quality while the investment needs beyond 2034 are cumulated. The results are displayed in Figure 2-39 . In total, the investment needs until 2034 amount to €24.4 billion and to €9.6 billion for 2035 to 2040.

Figure 2-39 Annual investment needs per year and country until 2040 for import terminals (2035-2040 cumulated)



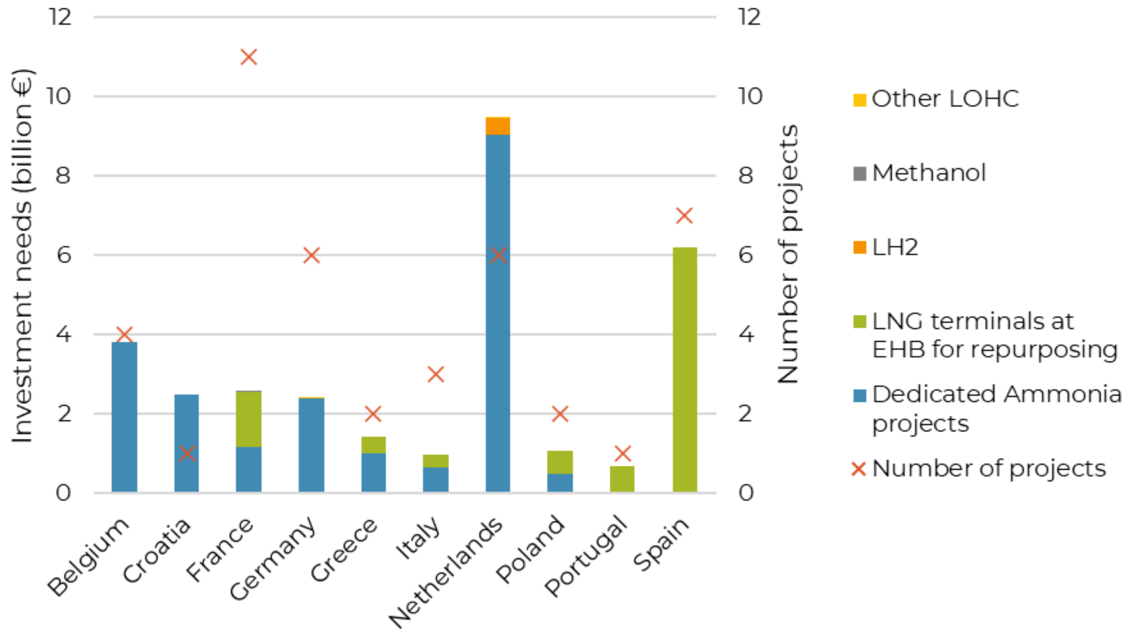
It can be seen from the figure above that the investment needs for building out the hydrogen terminal infrastructure is increasing until reaching a peak of €4.6 billion in 2027. Most of the currently planned projects are expected to be commissioned by 2030, leading to an expected hydrogen import capacity of 10.3 Mt in 2030. Although it must be taken into account that uncertainty remains with regard to project timelines, this aligns well with the EU's ambition of 10 Mt of imported hydrogen by 2030 according to RePowerEU.[136]

Due to the temporal scope of the TYNDP 2024 of 2024-2034, dependent on the data availability, robust estimations for the investment needs until 2034 can be made. Beyond 2034, the main hydrogen import volumes are assumed to come from repurposed LNG terminals for which plans for repurposing are not yet existing and with this assumption merely arising from their location at the EHB. In addition, even if repurposing plans arise, it remains questionable if FID will be reached before 2040.

Figure 2-40 shows that among Member States the largest share of €9.5 billion is allocated to the Netherlands for a resulting H_2 importing capacity of 4.5 Mt_{H2}, followed by Spain with €6.3 billion for 3.3 Mt_{H2} and Belgium with €3.8 billion for in total 2.3 Mt_{H2}. This is not surprising since especially the Netherlands with the Rotterdam port area is already today the most important port area for Europe.

[136] COM/2022/230 final (REPowerEU)

Figure 2-40 Cumulated investement needs per country until 2040 for import terminals



When analysing the investment needs for hydrogen import terminals, the limited data quality is of concern and should be taken into account. The accumulated amount of €10.9 billion, i.e. only 35% of the resulting investment needs, originates from reliable sources such as the 1st PCI/PMI list and the TYNDP 2024 project list while for the remaining share uncertainties remain regarding the assumptions. In particular, the investment needs associated to the LNG terminals situated at the EHB are of high uncertainty since there are no concrete project plans yet. In the analysis we assumed their repurposing for ammonia. However, other hydrogen carriers or LH2 could be in the picture for the repurposing, although Fraunhofer ISI has concluded that the repurposing for LH2 has major limitations and challenges.[137] Furthermore, the LH2 transport pathway is associated with high uncertainties regarding the timeline for technological maturity, increasing the risk for remaining high costs before 2040.[138]

Furthermore, ammonia cracking is not yet commercially available providing uncertainties in the extent of hydrogen reconversion and related costs. In the analysis a rather high share of ammonia to be cracked was used which thus further adds to the uncertainties of the resulting investment needs.

2.7.4. Installations for hydrogen use in transport sector

Current status and expected future developments

We refer to the Regulation 2023/1804[139] on alternative fuels infrastructure (AFIR) for information and definitions for "installations for hydrogen use in transport sector". This regulation determines the number of installations which have to be built in the European Union until 2030 and thus should be considered for support by the European Union. Any further hydrogen infrastructure is strongly dependent on the development of hydrogen mobility, which to date faces multiple challenges

[137] Fraunhofer ISI (2022), Conversion of LNG Terminals for Liquid Hydrogen or Ammonia
[138] DNV and Frontier Economics (2022), Securing & greening energy for Europe: The role of terminal operators
[139] Regulation (EU) 2023/1804 of the European Parliament and of the Council of 13 September 2023 on the deployment of alternative fuels infrastructure, and repealing Directive 2014/94/EU (Text with EEA relevance)

leading to delays and uncertainties. Thus, the requirements for a minimum infrastructure (AFIR) are as follows:

- public installations for hydrogen use in transport sector designed for a minimum cumulative capacity of 1 tonne per day (*Note that this capacity is commonly discussed as only a minimum requirement, most future hydrogen refuelling stations may actually need to exceed this capacity*)
- equipped with at least a 70 MPa dispenser
- designed to serve light-duty and heavy-duty vehicles
- at least one must be available in every urban node
- deployed with a maximum distance of 200 km between them along the TEN-T core and the TEN-T comprehensive network

The TEN-T core road network[140] describes 9 main corridors which are partly overlapping, spanning about 47,000 km and 336 urban nodes and should be implemented by 2030. The comprehensive network covers about 109 000 km and 432 urban nodes and should be realised by 2050.

Analysis of investment needs data

Assuming that installations for hydrogen use in transport sector will be built to meet the AFIR/TEN-T plans a rough estimation of 600 until 2030, 800 until 2040 and 1000 until 2050 can be deducted. Overlapping corridors are neglected. Since the about 100 installations for hydrogen use in transport sector[141] which are already in operation in Europe and technically suitable to be counted under the AFIR regulation (for light- and heavy-duty vehicles) are essentially not evenly distributed along the TEN-T corridors, they are neglected in the estimation.

Assuming a linear annual expansion between 2024 and 2030 and between 2030 and 2050, 100 installations for hydrogen use in transport sector have to be built every year until 2030 and further 20 installations annually between 2030 and 2050 to reach the roll-out plan.

Estimation and forecast of installations costs is difficulty for several reasons:

- Uncertainty about what type of costs are included in the communicated cost values by the individual projects
- Cost of equipment and installation may decrease because of scaling effects, technical progress, technical and regulatory standardisation
- Cost of equipment and installation may increase because of higher technical requirements (e.g. pressures used), inflation effects etc.
- Technical development and uncertainty which vehicle and refuelling technology will prevail, especially concerning heavy duty vehicles and their refuelling infrastructure

The US National Renewable Energy Laboratory (NREL) determined average installation cost of $2.2M using data of 46 installations for hydrogen use in transport sector between 2014 and 2017. Evaluation of the database H2stations.org gives example values of €1.4 million (installation in 2018), €2.5 million (2022), €3.1 million (2024) whereas it is unclear which type of costs are included. Clean Hydrogen Joint Undertaking estimated cost reductions between 20% and 33% for different hydrogen refuelling types between 2024 and 2030[142]. An operator of installations for hydrogen use in transport sector communicated confidentially cost values of €3 – €3.5 million for equipment alone, and €5 – €6 million

[140] TEN-T core road network(last retrieved July 2024)
[141] evaluation of H2stations.org
[142] Clean Hydrogen JU (2022), Strategic Research and Innovation Agenda 2012-2027

for equipment and installation for a hydrogen refuelling station with one 35 MPa and one 70 MPa dispenser, 1000 kg/day capacity. This shows that the construction itself, particularly depending on local conditions (availability of expertise, day-rates etc.) has a large influence on the overall costs. Therefore, a minimum (€3 million) and maximum (€6 million) value per station (1 t/day capacity) was used without further differentiating any cost decrease or increase in the period under review.

Based on these cost values per station and the estimated number of installations for hydrogen use in transport sector to be built, the total annual investment costs are calculated to be about €300 – 600 million / year until 2030 and to be about €60 – 120 million between 2030 and 2040.

Cumulative investment costs until 2040 thus reach between €2.7-5.4 billion for installations for hydrogen use in transport sector in Europe.

2.7.5. Electrolyser facilities

Current status and expected future developments

Electrolysers use electricity to split water into hydrogen and oxygen. When integrated into the broader energy system, they can be operated not only to produce hydrogen but also to offer additional services with the aim of enhancing the system stability within the electricity sector. When integrated with the power grid and hydrogen infrastructure, they offer a critical flexibility option for the energy transition, reducing the need for grid expansion. Electrolysers can support the grid by producing hydrogen primarily with surplus energy during periods in which supply significantly exceeds demand. They can provide system benefits when feeding hydrogen into public hydrogen infrastructure such as a pan-European hydrogen grid, adding liquidity to the hydrogen market and enabling cross-border supply. By producing hydrogen near renewable energy sources, they minimise the need for electricity transport through congestion zones. In contrast, the uncoordinated development of electrolyser projects risks worsening grid bottlenecks, thus increasing the demand for grid expansion. As of this date, the exact criteria for system-serving electrolysers are still to be discussed and defined on country-level (e.g. in Germany as part of TransHyDE[143]). And further confirmed by the survey among European NRAs conducted for this study, where all 9 responsive NRAs confirmed the lack of a fixed definitions in their countries, some assuming this to be applicable to all electrolysers, some with pending definitions.

Electrolyser facilities considered here are defined as (a) electrolysers that (1) have at least 50 MW capacity, (2) the production complies with the life cycle greenhouse gas emissions savings requirement of 70 % relative to a fossil fuel comparator of 94 g $_{CO2e}$/MJ as set out in Article 25(2) and Annex V of Directive (EU) 2018/2001 of the European Parliament and of the Council. Life cycle greenhouse gas emissions savings are calculated using the methodology referred to in Article 28(5) of Directive (EU) 2018/2001 or, alternatively, using ISO 14067 or ISO 14064-1. Quantified lifecycle GHG emission savings are verified in line with Article 30 of Directive (EU) 2018/2001 where applicable, or by an independent third party, and (3) have also a network-related function, and (b) related equipment.

To identify electrolyser projects that align with the definition above, both public and private databases were consulted. Projects are often listed in multiple databases but were lacking sufficient detail as to uniquely identify them. Thus, merging different datasets was mostly avoided to prevent duplication or inaccuracies in the analysis. Due to the very limited quality of available data, a two-fold approach with one dataset describing the minimum financing need and a second dataset describing the maximum financing were created. A **minimum financing need dataset** (MinFND) was

[143] Gätsch et al. (2024) TransHyDE Möglichkeiten zur rechtlichen Steuerung systemdienlicher Elektrolyse-Standorte

constructed based on electrolysers that had already been pre-assessed and successfully classified as PCI projects[144].

The **maximum financing need dataset** (MaxFND) was derived from the most comprehensive database available, the IEA hydrogen production and infrastructure projects database[145]. It was filtered to include projects in EU countries with a minimum hydrogen production capacity of 50 MW. Only projects with a connection to the electricity grid were considered; projects that directly receive their electricity from the renewable energy source via a direct line are excluded. Derivative-producing projects were excluded under the rationale that eligible electrolysers must be operated in a way that is both system-serving and economically viable. It was assumed, that in general, any electrolyser is suitable for system integration, provided no economic factors conflict with its operation. Such economic factors may be the production of hydrogen derivatives (e.g., ammonia, methanol, eSAF), as the synthesis plants rely on a steady supply of hydrogen from both a technical perspective and a business model perspective which may not align with the flexibility demands typically placed on system-critical electrolysers that are intended to respond to fluctuations in the power grid or energy market. Further, projects focused on derivative production may not contribute to liquidity in the hydrogen markets. In the context of this assessment, hydrogen production as a standalone process was deemed potentially system-relevant, while hydrogen produced as an intermediate product was deemed not relevant. Therefore, derivative-producing projects were excluded unless already pre-assessed as system-serving within the PCI and TYNDP frameworks.

From both datasets, projects with insufficient data – such as missing information on planned capacity, name, or location – were excluded, as well as projects that could not be clearly identified with the available information. Additionally, projects with implausible MW sizes or outdated information (e.g., known cancellations) were removed to ensure data accuracy and relevance.

Estimations for financing needs are based on the averaged cost projections for electrolyser projects within the PCI framework. Compared with projections until 2030, for projections until 2040, no further reductions in electrolyser CAPEX per MW are assumed, since cost reductions through technological advancements for projects after 2030 are assumed to be limited[146]. Due to limited availability of data, the financing need was assumed to be evenly distributed across all years from the Final Investment Decision (FID) to the Commercial Operation Date (COD). In line with the TYNDP definition, financing needs are estimated not only for the electrolyser stack (equipment), but the overall project.

[144] Commission Delegated Regulation (EU) 2024/1041
[145] IEA hydrogen production and infrastructure projects database
[146] Reksten et al. (2022), Projecting the future cost of PEM and alkaline water electrolysers; a CAPEX model including electrolyser plant size and technology development

Analysis of investment needs data

Minimum financing need of €16 billion for 11 GW of system-critical electrolyser capacity for projects currently known to be under development (covering a range until 2032).

Based on **MinFND**, a total of 10.9 GW out of the EU ambition of 40 GW production capacity for 2030 are deemed system-serving (assuming the definition described above (TEN-E basis)), amounting to 27 percent of the overall ambition that potentially require financing. The estimated total cost for these projects is €16.4 billion, with an average cost of €1.5 million for each 1 MW of capacity. Cost per MW of capacity for individual projects may range from €550,000 to €2.4 million per MW of capacity. On average, for projects in **MinFND**, the time from the Final Investment Decision (FID) to the Commercial Operation Date (COD) is 3.9 years, while the average time from project initiation to COD spans 7.3 years. The average cost for a system-serving project under this dataset is €1.0 billion. The dataset only includes projects that are known today. Future projects that are still in very early planning stages are not considered due to lack of data. Thus, financing needs estimated with **MinFND** may underestimate the financing needs for system-critical electrolyser infrastructure beyond 2027.

For 2040, depending on the scenario, the EU's hydrogen production capacity is estimated at between 183-302 GW (EC Impact Assessment, Primes) or 278-306 GW (TYNDP 2024). Assuming a similar ratio of system-serving versus non-system serving electrolysis capacity for 2030 and 2040, based on MinFND data between 50-83 GW (27%) would be considered system serving capacity in 2040. The corresponding investment need would likely be at 89–149 billion EUR, assuming a cost of 1.8 million EUR per MW of capacity based on 2% inflation per annum from 2030 (currently, no CAPEX reduction through economies of scale and learning effects considered). This estimation can only be understood as preliminary and should be adjusted, once definitions for system-relevant electrolyser projects become available.

Figure 2-41 Annual investment needs for system-serving electrolysers (based on MinFND)

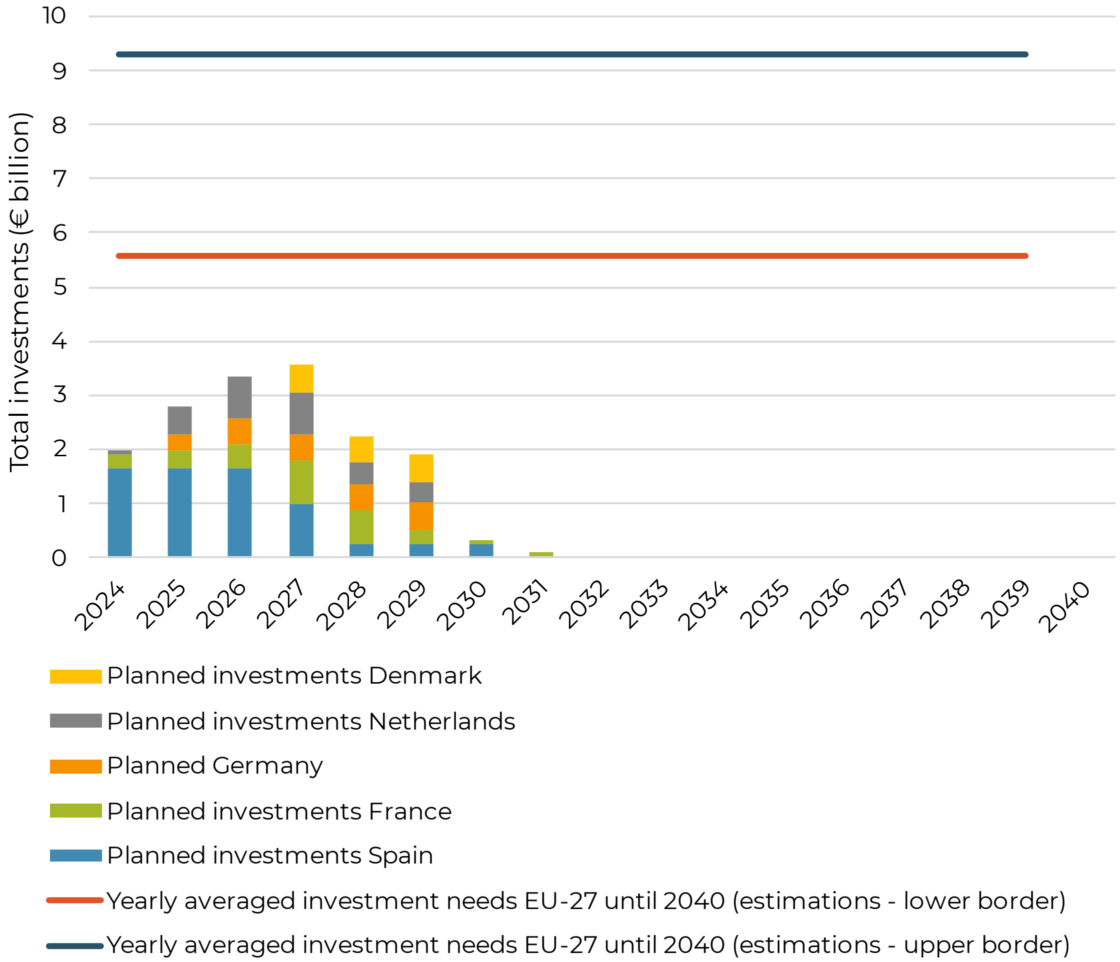
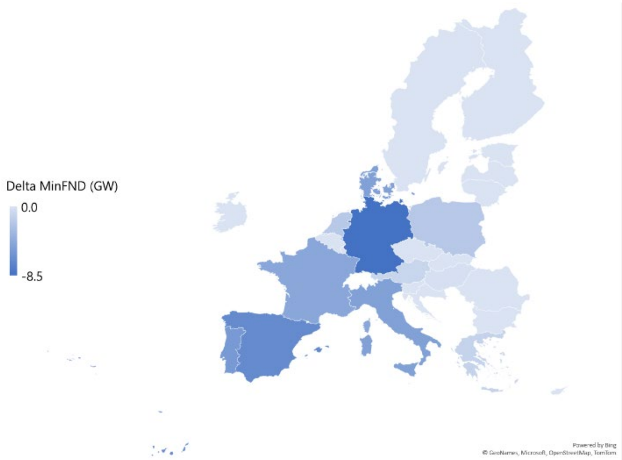


Figure 2-42 compares current project-based investment plans for system-serving electrolysers on a country basis (bottom-up approach) and financing needs for establishing a similar ratio of system-serving vs non-system serving electrolyser projects in line with the EU capacity projections for 2040 (top-down approach).

Based on **MaxFND**, which takes a holistic approach by including all electrolyser projects that were not excluded based on the criteria outlined above, 53 GW of hydrogen production capacity may be considered for financing support at an estimated cost of €80 billion. Cost per MW were estimated based on data from **MinFND** with the average cost for 1 MW electrolyser amounting to €1.5 million. It is noteworthy that **MaxFND** is largely aligned with the cumulative target capacities set by the EU's member states for 2030. The member states' combined hydrogen capacity targets exceed the EU's standalone ambition, amounting to 52 GW compared to the EU's ambition of 40 GW for 2030. **MaxFND** is therefore likely to overestimate the financing needs for system-serving electrolyser projects.

Regarding the projects identified as system-serving, there seems to be a focus on Western European countries. However, the planned projects seem to correspond to the production targets announced by the respective member states. As of today, 12 out of 27 MSs have not issued production targets for 2030. The apparent imbalance between different MSs may thus be explained by the individual MSs' differing capacity targets and economic reliance on hydrogen.

Figure 2-42 Capacity gap with MinFND projects to MSs targets for 2030 (GW)



For this assessment, data quality remains a concern due to several factors. At large, there is insufficient information on project phases and cost efficiencies for later stages of multi-phase projects, which affects the overall reliability of results. Projects that are in the early planning stages or are not yet announced have not been included but may well be relevant for the timeline until 2040. There is currently no differentiation possible between PEM (Proton Exchange Membrane) and AEL (Alkaline Electrolysis) technologies, which limits the accuracy of CAPEX estimations.

In developing a comprehensive picture of the European electrolyser landscape, the upcoming union database will serve an urgent need to improve decision making capabilities.

Overview and discussion of investment needs for hydrogen infrastructure

The overall investment need based on currently planned projects and activities and estimations reaches almost €400 billion by 2040. The largest share lies with the development of the pipeline network with almost €150 billion needed by 2040, also having reached the best degree of planning. The second biggest investments are to be expected for system-serving electrolysis, reaching €89 billion (€149 billion) for 183 GW (306 GW). The high degree of uncertainty is mainly due to the low level of planning beyond 2030. Note that these numbers only cover the share of electrolysers that is considered system-serving (in this work assumed to be 27% (PCI share of existing overall planned electrolyser capacities).

Import terminals may require investments of up to €30 billion, possibly exceeding the targets as communicated by the EC and for example discussed in the EU Impact assessment for the 2040 Climate targets (20 Mtoe).

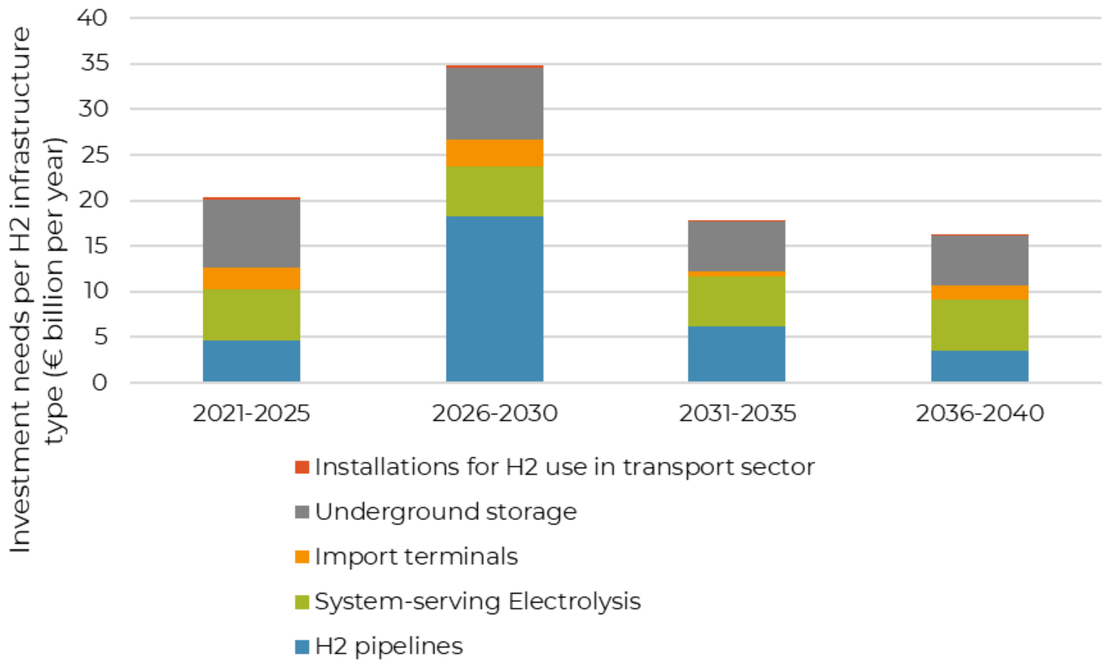
In contrast, for hydrogen underground storage system studies expect much larger capacities of up to 138 TWh, which cannot be met by the to-date planned underground storage projects (37.1 TWh). The corresponding investments planned are at €27 billion thus maybe requiring more than tripling if the systemic optimum is to be reached (overall at €108 billion). The smallest cumulated investment needs can be expected for installations for hydrogen use in transport sector with ~€2.7 billion (lower bound) cumulated investments until 2040 covering the required 800 installations under AFIR.

All discussed figures are summarised below.

Table 2-14 Cumulated investment needs across all hydrogen infrastructure categories and corresponding capacities

H_2 infrastructure type	Cumulated investment needs until 2030 (€ billion)	Cumulated investment needs 2031-2040 (€ billion)	Total investment needs (€ billion)	Corresponding Capacities in 2040
H_2 pipelines (combined bottom-up + Top-down)	100	48	149	~57,000 km
System-serving Electrolysers (and upper bound)	33	56	89 *(149)*	183 GW *(306 GW)*
Import terminals (combined Bottom-Up + Top-Down)	19	11.1	30	17.2 Mt_{H2} /yr
Planned Underground storage *(and estimations for systemic optimum)*	21	6.3	27 (*108*)	37 $TWh_{working\ gas}$ *(138 $TWh_{working\ gas}$)*
Installations for hydrogen use in transport sector (lower bound)	2.1	0.6	2.7	800 installations (AFIR)

Figure 2-43 Annual averaged investment needs per 5-year periods until 2040 across all hydrogen-related infrastructures



The status of planning across all H_2 infrastructure categories allows to expect the highest investment needs in the late 2020s. This mainly stems from project announcements for pipeline infrastructure development. Note that 2030 as a policy driven and somewhat artificial target date has led to many projects announcing commissioning by that date (the basis of this analysis are the "self-declared" planning announcements by projects across all infrastructure (sub-categories) and may in reality, also due to the observed uncertainties in the sector[147], be more evenly spread into the beginning of the 2030s. Stakeholder interaction has however also confirmed that hydrogen pipelines are considered to be developed before hydrogen ramp-up; inherently causing the risk of oversizing in the short term. Therefore, it is of utmost importance to the realisation probability to have sufficient political commitment and financial instruments hedging these risks (see also discussion in the Chapters 3 and 4).

Projects across all infrastructure (sub-)categories do reach FIDs, making it very difficult to assume general delays. Projects on import terminals and underground storage often add very long-term perspectives covering the range until 2040 with expansion steps, while hydrogen pipeline infrastructure projects are mostly planned over the next decade (to ~2034), having reached important milestones with e.g. the core network planning submitted in Germany this year. In contrast electrolysis projects are generally planned over shorter time horizons, thus making predictions towards 2040 uncertain.

2.8. CO2 transport and storage infrastructure

This section focuses on CO2 transport and storage infrastructure, specifically focusing on carbon dioxide pipelines (Annex II 5(a) of TEN-E), and the issues, challenges and opportunities linked to a potential future EU-wide network. Other transport modes for CO_2, such as ship, barge and rail are not part of the TEN-E regulation and are therefore excluded from this section and also given that most data sources used for this section focus on pipeline infrastructure. In addition, other infrastructure categories, as listed in Annex II 5(a) TEN-E have been excluded from the focus of this section. These include injection and surface facilities for geological storage, terminals, compressors, buffer storage and liquefaction facilities.

- **Compressors[148]** are devices used to compress gases, key in attaining the necessary level of pressure when injecting CO_2 into geological layers. It increases the pressure of the recovered CO_2, converting it into a fluid or very dense gas. In addition to compressors, pumps—designed to further elevate the pressure of the fluid—are also critical in storing CO_2 underground in its high-pressure state.
- **Buffer storage[149]** may be required to address the variations in CO_2 production and storage availability across the chain. Therefore, buffers support varying transport and storage capacities, and manage fluctuations in CO_2 supply and demand. Existing buffer technologies include quayside facilities, on-site tanks, geological gas storage, and pipeline system line-packing. According to the IEA , the cost for buffer storage is approximately in line with 5-10% of the transport costs[150].
- **Liquefaction stations** compress and cool CO_2 to transform it into a liquid or dense-phase state, which has properties between those of a gas and a liquid. Liquid or dense-phase CO_2 occupies significantly less volume than its gaseous form, making it more economical and practical to transport and store[151]. Regarding the cost of the liquefaction, it was estimated at between 7 and 14 €/tCO_2, with variations due to the impurities in the CO_2[152].

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[147] McKinsey (2024), The energy transition – where are we really
[148]https://www.globalccsinstitute.com/wp-content/uploads/2023/08/State-of-the-Art-CCS-Technologies-2023-Global-CCS-Institute.pdf
[149]https://ieaghg-publications.s3.eu-north-1.amazonaws.com/Technical+Reports/2023-04+Components+of+CCS+Infrastructure+-+Interim+CO2+Holding+Options.pdf
[150]https://ieaghg-publications.s3.eu-north-1.amazonaws.com/Technical+Reports/2023-04+Components+of+CCS+Infrastructure+-+Interim+CO2+Holding+Options.pdf
[151]https://www.globalccsinstitute.com/wp-content/uploads/2023/08/State-of-the-Art-CCS-Technologies-2023-Global-CCS-Institute.pdf
[152] https://www.sciencedirect.com/science/article/pii/S2772656824000927

- **Terminals** are used by companies not connected to a CO_2 pipeline to ship liquid CO_2, temporarily storing the CO_2, adjusting the pressure, and connecting it to a pipeline for final storage in a reservoir. An example of CO_2 terminal is provided by CO2Next project in the port of Rotterdam and will be connected to the Aramis project[153].

It was decided to concentrate the focus of the investment needs analysis on the pipeline network, first and foremost due to data availability on existing projections and investment needs mostly restricted to this category. Especially, the investment needs estimations developed in this section have mostly been based on the findings of the recent JRC study[154] on the potential future development of the EU CO_2 transport network, which exclusively addresses CO_2 pipelines.

Based on prior discussion with the Commission, when relevant, this section mentions capture and/or storage technologies or projects, or other infrastructure categories (TEN-E Regulation Annex II 5(b) and 5(c)), when referring to the challenges linked to these stages that have implications for the planning of the transport network, while focusing the investment needs analysis on the pipeline transport infrastructure.

2.8.1. Current status and expected future developments

In the effort to limit global warming to 1.5 degrees, in line with the Paris Agreement, carbon capture and storage (CCS) is identified at both EU and international level as a necessary measure, particularly for the so-called hard-to-abate emissions. In particular, the climate strategies put forward by the European Commission partly depend on implementing CCS and CO_2 removal techniques. These include the **Green Deal Industrial Plan**[155] as well as the **Net-Zero Industry Act**[156], which both locate CCS as a necessary technology to achieve climate neutrality. Since some emissions cannot be entirely avoided (i.e. some process emissions in industrial production), capturing these emissions and storing them permanently becomes a necessary solution. According to the IEA, the **current 40 Mtpa of stored**[157] emissions globally are required to rise to over 6,200 Mtpa by 2050 to achieve net-zero and limit global warming to 1.5°C.

Next to the emission trading system (EU ETS) as an incentive to stimulate CCS there are two main support instruments for CCS in the EU. Through the **Innovation Fund**[158], the EU finances eleven large-scale CCS and CCU projects, with another eight projects in grant agreement preparation. Additionally, in November 2023, the European Commission adopted the first list of **Projects of Common Interest** (PCIs) and **Projects of Mutual Interest** (PMIs)[159] under the revised TEN-E Regulation, which includes fourteen CO2 transport network projects. Finally, recognising the crucial role of CCS technologies in addressing emissions from key emitting sectors, the Green Deal Industrial Plan seeks to promote the development and implementation of CCS solutions as a key component in achieving climate neutrality within the European Union.

While the main components of the CCS value chain have been commercialised, they currently operate at a scale much smaller than what is ultimately needed. According to the Global CCS Institute, **41 commercial CCS projects** are currently in operation worldwide[160]. These large-scale facilities capture and store CO_2 generated by industrial sites or fossil fuel power plants. However, most of these projects were not originally developed with climate mitigation purposes: they are not

153 https://co2next.nl/about/
154 JRC (2024)
155 Green Deal Industrial Plan
156 The Net-Zero Industry Act
157 https://www.iea.org/commentaries/the-world-has-vast-capacity-to-store-co2-net-zero-means-we-ll-need-it
158 Innovation Fund
159 List of EU energy Projects of Common and Mutual interest
160 https://www.globalccsinstitute.com/wp-content/uploads/2024/01/Global-Status-of-CCS-Report-1.pdf

obligated to minimise CO_2 emissions in the atmosphere or to maximise CO_2 storage. Many of these projects are driven by commercial interests, where readily available by-product CO_2 is sold to oil field operators for enhanced oil recovery (EOR) in oil production, particularly in the US, where CCS is most developed up to now.

To enable widespread implementation of CCS in Europe, it is necessary to develop transportation networks that use pipelines and ships to move captured CO_2 from its sources to reachable storage sites. As it is currently developing, the expectation in the short term is for the networks to be built regionally and nationally, in the proximity of CO_2 emitting sources and and/or storage sites. In the long term, there is a vision for the integration of the CO_2 networks across Europe, linking emission sources with storage locations across borders.

A significant challenge for carbon dioxide infrastructure development in Europe is that the **current lack of storage capacity** discourages emitters from investing in capture technologies. The persistent "chicken and egg" dilemma, where transport and storage developers are reluctant to invest in infrastructure without guaranteed CO_2 supply from emitters, while emitters hesitate to invest in capture technologies without existing T&S infrastructure, remains a major obstacle. To address this issue, it was suggested to promote **initial overcapacity in transport and storage** facilities.[161] This would entail a public mechanism to support early mover projects build oversized T&S infrastructure. Such an approach would improve infrastructure access for emitters considering CCS as a decarbonisation strategy in the future.

Contrary to hydrogen, where a European backbone[162] is considered to map a potential trans-European network design, such guideline is lacking for CO2 transport and storage infrastructure. However, given the limited options for decarbonisation available to energy intensive industry, the demand for CO_2 transport and storage infrastructure is growing. It was recommended[163] for the government to support infrastructural scale up, either via early infrastructure funding to facilitate overdesign, or through a guarantee that the infrastructure will not be fully utilised as predicted. This would, however, require a political commitment, resulting in a significant government intervention, that is difficult to envisage today, given the current levels of prioritisation of CCS across EU MS.

In addressing the issue of transport and storage infrastructure development and costs, the pioneering study conducted by Carbon Limits AS and DNV AS[164] on the reuse of oil and gas infrastructure for hydrogen and CCS in Europe found that transporting CO_2 in its gaseous phase is feasible using existing onshore and offshore pipelines. Moreover, CO_2 transport in dense phase was found technically possible in more than half of the offshore pipelines and a small portion of the onshore pipelines.

Nonetheless, as it emerged from the interviews with stakeholders, there is not a unanimous consensus over the technical feasibility of repurposing gas infrastructure for CO_2. First, CO_2 has different physical properties compared to natural gas. Pipelines for CO_2 transport might need to operate under different conditions than those used for natural gas, and they might require low levels of impurities, including corrosive substances like water, which can pose challenges for conventional pipeline materials. Additionally, existing gas infrastructure may not be ideally located for future CO_2 transport needs, highlighting the necessity for new infrastructure that can meet EU-wide CO_2 transportation requirements. Finally, new pipelines will eventually need to be built, as the availability of decommissioned oil and gas pipelines in the suitable locations is rare in most European countries.

[161] https://op.europa.eu/en/publication-detail/-/publication/bb3264da-f2ce-11ed-a05c-01aa75ed71a1/language-en
[162] https://ehb.eu/
[163] https://op.europa.eu/en/publication-detail/-/publication/bb3264da-f2ce-11ed-a05c-01aa75ed71a1/language-en
[164] Carbon Limits, DNV (2021)

Relationship with UK and Norway

Estimates indicate significant CO_2 storage potential in the UK and Norway, with around 78 Gt and 80 Gt, respectively[165]. Denmark is also assessing its storage potential, having already achieved the first cross-border carbon capture and storage by capturing CO_2 from Belgium and storing it in a depleted hydrocarbon field beneath the Danish North Sea[166]. To facilitate EU-wide network planning and deployment, it is crucial to estimate all EU CO_2 storage capacities as accurately as possible and to harmonise different national methodologies for more precise estimations. This harmonization would aid in updating the European storage atlas, providing comprehensive and accurate information on storage potential across the continent[167]. By standardizing methodologies and data collection approaches, the updated storage atlas would improve the understanding of storage capacities and support the development of CO2 transport and storage infrastructure, including transport networks, throughout Europe.

The integration of the UK and Norway in a developing European CO_2 network implies advantages and criticalities on both sides. Both countries present clear advantages in terms of geological data and mapping, due to the extensive past resource extraction in the region. There is ample knowledge of the North Sea geological mapping, with known vast potential for CO_2 storage[168]. Therefore, from the perspective of geology, the UK and Norway have a potentially big role to play in European CO_2 storage capacity. However, the UK presents important regulatory obstacles and misalignment with the rest of the EU. Indeed, the UK operates under its own ETS[169] (UK ETS), and in 2023, the government has approved a bill targeting the commercial development of carbon transport and storage. Indeed, the integration of the UK in the EU carbon transport and storage network will have to follow the linking of the two ETSs, which essentially implies higher carbon prices for the UK system.

A positive sign in this regard came from the EU industrial carbon management strategy, opening to the storing of CO_2 in third countries[170]. Additionally, bilateral agreements at national level are also taking place, further driving down barriers to cross-border transport of CO_2. In April 2024, the governments of Belgium, Netherlands, Sweden, Denmark and Norway signed an agreement to facilitate the transportation of captured CO_2 from major industrial emitters in the first three countries to offshore storage sites in Norway and Denmark. This puts Norway in a lead position in providing storage sites for carbon emitters in the North Sea region, ahead of the UK, despite the latter's "natural advantage" given by its geology. In addition, an interviewed stakeholder emphasised that the large storage capacity of the UK will result, in the short term, in a separate national UK T&S infrastructure for captured carbon, but a second phase could see it be integrated in an EU.

On the other hand, based on the interviews with stakeholders, it was found that transporting and storing CO_2 in Norway comes at a significantly higher cost than it can be done in the UK, at an estimate of up to three times the costs per tonne of CO_2. Hence, while the regulatory barrier exists, the availability of cheaper T&S costs in the UK emerges as a key advantage for integrating the UK in an EU network. In any case, the interviews were unanimous is acknowledging the need to involve both the UK and Norway in a European network, eventually.

Carbon dioxide infrastructure network in the EU is projected to benefit from multi-modal transport, pipelines, ships, barges and rail, depending on the needs. This in turn has obvious implications on the expected nature and amount of the investment costs. However, there is little indication up to date

[165] Deep Geological Storage of CO2 on the UK Continental Shelf
[166] Danish CO2 Storage Licenses Map
[167] JRC (2024)
[168] CATF, Unlocking Europe's CO2 Storage Potential
[169] UK The Greenhouse Gas Emissions Trading Scheme Order 2020
[170] https://ec.europa.eu/commission/presscorner/detail/en/qanda_24_586

on each transport mode's relative weight in the network. A recent analysis by ZEP[171] suggests that by 2030, between 6 and 40 marine vessels may be needed for CO_2 transport, though this estimate carries considerable uncertainty due to factors like voyage length, duration, port capacity, and the completion of relevant projects. The lower estimate stems from the six vessels planned for the Northern Lights project in Norway, including three currently under construction and three more expected. It is important to recognise that while various projects are listed under the Union projects and the UK Cluster Sequencing Process, not all will be certainly operational by 2030. Thus, the total number of vessels required will largely depend on the success of several CO_2 transport-by-ship projects. These vessels are likely to be built on a project-by-project basis, specifically designed to transport CO_2 from individual emitters to designated storage sites. Some may be contracted to collect CO_2 from multiple locations before delivering it to a destination port.

2.8.2. Planned infrastructure investment

Compared to the other energy infrastructures addressed in this study, CO_2 transport presents some important differences. First, while there are close to 100 CCS projects announced across the EU, to date, **only one full CCS value chain project** has received FID, the Greensand hub in Denmark. Of course, this does not include the Porthos transport and storage project in Rotterdam, which is projected to become a key storage hub for the region's emitters; the enhanced oil refinery project in Croatia; as well as the already operational projects in Norway, Sleipner[172] and Snohvit[173], which are expected to play an integrated role in developing the EU network. Therefore, beyond these limited cases, estimations on future network developments and related investment needs and costs can only be based on **announced projects, existing policies** at EU and national levels, as well as **potential network design elements**. Indeed, while the EU has agreed on binding carbon capture targets for the coming decades – most notably, a target of 50 Mtoe of captured CO_2 by 2030 – there is **no EU-wide infrastructural plan** for the development of CO_2 transport and storage network. In fact, such plans are lacking for most Member States: only a few national governments, particularly those bordering the North Sea emerging CCS hub, i.e. Netherlands, Belgium, Denmark, Sweden, and to a lesser extent governments in France, Italy, Croatia, Bulgaria, and Romania, have either advanced or proposed plans for CO2 transport and storage infrastructure. For the majority of EU MSs, policy debates over CCS are only recently starting, if at all.

In turn, the potential future design of the CO_2 transport network will greatly depend on the development of storage sites, whether off- or onshore. If more inland countries choose for onshore storage this will greatly impact (reduce) the infrastructural investments. So far, many projections come from North Sea bordering countries with a preference for offshore storage. All this impacts the accuracy of estimations for the development of CO_2 infrastructure, as based on rather variable options. For these reasons, the findings of the JRC study (2024)[174], constitute a significant database, as it provides the most comprehensive projections of network and storage capacity to date. In particular, the JRC develops interesting scenarios of potential future network developments, as well as the related investment needs estimations. Therefore, while using as a basis for the analysis the data from the JRC, additional desk review and stakeholder interviews are used to contextualise and validate some of those findings. In particular, to map existing and planned CO2 transport and storage infrastructure projects in the EU, several sources were used, including the work published by the Zero Emission Platform, the Clean Air Task Force, Bellona, the IOGP and the Global CCS Institute. For the estimation of the infrastructure costs, the JRC figures were used, alongside estimations in the scientific literature to contextualise those estimations. In addition, expert interviews were carried out

[171] https://zeroemissionsplatform.eu/wp-content/uploads/ZEP_report_HD-1.pdf
[172] https://www.equinor.com/energy/sleipner
[173] https://www.equinor.com/news/archive/2008/04/23/CarbonStorageStartedOnSnhvit
[174] JRC (2024) Shaping the future CO2 transport network for Europe

with key stakeholders active in the CO2 transport and storage infrastructure, including three leading advocacy organisations in carbon capture storage and utilisation, and a national TSO.

Due to the early development stage of most CCS projects, unlike other infrastructure categories addressed in this study, estimating national-level investment data is a true challenge. Given that no Member State has yet developed a fully-fledged national CO2 transport and storage infrastructure backbone, investments are available only at project level – if at all: in most cases, projects status is either not advanced enough for the estimation of such costs, or the investment needs figures are not made public.

The table below summarises the available information on announced CCS projects in the EU, providing the project description, status and (if available) investment data.

Table 2-15 Summary of announced CCS projects in the EU (Sources: CATF, IOGP, Global CCS Institute, JRC)

Project name and description	Project status	Investment amount (€m)	PCI/PMI/IF[175]
ANRAV: The objective is to capture the CO2 streams at the Devnya cement plant in Varna (HeidelbergCement group) and though an onshore and offshore pipeline system to store them in a depleted gas field in the Black Sea. Subject to regulatory and permitting aspects, the full-chain CCS project could be operational on 2028.	Early Development Planned start date: 2028	No data	IF
Petrokemija Kutina: CO2 will be captured and transported via the existing pipeline infrastructure to be stored at the depleted oil and gas fields which are found close to Ivanić Grad.	Early Development Planned start date: 2026	No data	
Bio-refinery Project: full chain CCS project which is part of an advanced bioethanol production plant currently being developed at the Sisak refinery site, where advanced bioethanol from biomass will be produced. More specifically, CO2 will be captured and transported via the existing pipeline infrastructure to be stored at the depleted oil and gas fields which are found 40 km away from the site.	Early Development Planned start date: 2025	No data	
CCGeo: A full chain CCS project which intends to make use of a novel combination of existing technologies to generate electricity and heat from the geothermal brine and from the natural gases dissolved into it. The associated CO2 which will be produced will be injected back at the same reservoir from which the geothermal brine was extracted.		No data	IF
CO2 EOR Project Croatia: At Gas Treatment Plant (GTP) found at Molve Municipality 640.000 m3/d of CO2 are produced from the purification of natural gas. The CO2 is	In operation	No data	

[175] Project supported by the Innovation Fund.

Project name and description	Project status	Investment amount (€m)	PCI/PMI/IF[175]
compressed at 30 bar, dehydrated and transported via onshore pipeline 88 km long to the Fractionation Facilities of Ivanić Grad. Subsequently, the CO2 is compressed, liquefied and transported (200 bar) for injection at the mature oil fields Ivanić and Žutica for Enhanced Oil Recovery.			
Geothermal CCS project: construction & repurpose of pipelines to transport CO2 from a cement factory in Beremend (Hungary) and a cement plant in Našice (Croatia) to be stored at a saline aquifer in the north of Croatia (Bockovac site). The project includes also the construction of a geothermal plant for the production of heat and electricity where the produced CO2 will be stored in the same saline aquifer from which the brine is extracted.		No data	PCI
CO2-SPICER: CO2-SPICER (CO2 Storage Pilot In a CarbonatE Reservoir) is a Czech/Norwegian research project that aims at the preparation of a CO2 storage pilot in the mature Zar-3 oil & gas field located 30 km SE from the city of Brno, SE Czech Republic.	In planning Planned start date: 2031	No data	
Greensand	In operation (pilot phase)	No data	
Bifrost: This project will leverage Denmark for CO2 storage for emitters based in Germany, Poland and Denmark	In planning Planned start date: 2030	No data	PCI
Stenlille Demo CO2-storage	In planning Planned start date: 2025	No data	
Norne: Norne aims to have CO2 transport and storage infrastructure built for storage in Denmark, with emitters primarily from Denmark, Sweden, Belgium and Sweden, and the UK	In planning Planned start date: 2026	No data	PCI
Ruby	In planning Planned start date: 2027	No data	
Pycasso: This project will see the transport and storage of CO_2 from emitters based in Spain and in France, for storage in France	In planning Planned start date: 2030	No data	PCI
Prinos: Prinos will serve as a storage site for emissions from Greece, transported by pipeline from Hungary, Cyprus, Greece, Italy and Slovenia by ship.	Early development Planned start date: 2026	No data	PCI
Ravenna CCS : Capture and storage project developed by Italian ENI and SNAM for hard-to-abate emissions (includes Callisto)	Advanced Development	350	PCI

Project name and description	Project status	Investment amount (€m)	PCI/PMI/IF[175]
Porthos: The project intends to provide transport and storage infrastructure to energy intensive industries in the Port of Rotterdam and possibly at a later stage to industries in the Antwerp and North Rhine Westphalia areas. The project will link the CO2 Capture facilities and the existing OCAP pipeline with a new onshore pipeline which will drive the aggregated CO2 in a CO2 hub in the Port of Rotterdam and subsequently via an offshore pipeline in a depleted gas field 20 km off the coast for permanent storage.	FID taken and construction started Planned start date: 2026	1300	PCI
Aramis: The Aramis project aims to contribute to the reduction of CO_2 emissions for hard-to-abate industries. It will do this by providing CO_2 transport to unlock storage capacity for the industry. The CO_2 will be stored in depleted offshore gas fields, deep under the North Sea. It will be based on open access philosophy so that other industrial customers and storage fields can be added incrementally to the system.	In planning Planned start date: 2028	No data	PCI
L10 CCS	Conceptual design phase Planned start date: 2028	No data	
CO2 TransPorts – support CO2 capture, transport and storage from Rotterdam, Antwerp and the North Sea Port areas	Early planning stage		
ECO2CEE – Cross-border CO2 transport and storage project which marks Denmark, Norway, the Netherlands and the UK as possible storage sites	Early planning stage		PCI
Longship (Includes Northern lights): The Longship CCS project plans to capture, transport and store 0.8 Mtpa of CO2. The Northern Lights project is part of the Longship CCS project and involves only the transport and storage part. The project has the vision to expand and receive additional volumes of CO2 from several capture sites in Norway or other countries (1.5Mtpa and then 5 Mtpa).	Advanced development	First and final close of its third fund, Longship Fund III, at €200 million	PMI
CCS Baltic Consortium: a cross border CO2 project between Latvia and Lithuania	Early planning stage		PCI
Delta Rhine Corridor: will aim to store CO2 from Germany and Rotterdam area to offshore storage sites off the Dutch coast	Early planning stage		PCI
EU2NSEA – EU2NSEA: cross-border CO2 network developed between Belgium, Germany, Norway, Denmark, France, Latvia, the Netherlands, Poland and Sweden for storage in the Norwegian continental shelf	Early planning stage		PCI

Project name and description	Project status	Investment amount (€m)	PCI/PMI/IF[175]
Nautilus CCS – aims to capture and transport CO2 from Norway, France and Germany for storage in the North Sea	Early planning stage		PMI

2.8.3. Preliminary analysis of investment needs data

The initial CCS projects under current development will provide insights influencing and driving projects towards 2050. These early movers are being built with technologies capable of operating at mega-tonne scales within the next few years and within a regulatory framework that has successfully permitted multiple storage sites. Despite regulatory mandates for open third-party access and newly established storage targets under the NZIA, some emitters may still face limited access to storage by 2030. Many of the first-of-a-kind (FOAK) CCS projects currently under development are already "sold out", meaning they will not expand storage potential for new capture projects. This issue has already affected projects funded through the Innovation Fund, where securing storage for the required 4.6 Mt CO2/year has been challenging[176]. However, a significant number of new candidate projects for the next Projects of Common Interest (PCI) list are expected to bring additional storage capacity online by 2030.

To maximise economies of scale, CO2 transport and storage infrastructure planned for 2030 would ideally be designed with future projects in mind. However, current market mechanisms that focus on incentivizing emitters to capture CO_2 leave many transport and storage operators unable to bear the financial burden of initially overdesigning their networks, whichh would require higher capital investment.

Financial support for early site exploration and development of storage sites at key locations by bringing them to a point where they are fully characterised, permitted for CO_2 injection, and available for commercial use would reduce technical risk, uncertainty, and the cost of commercial-scale saline storage projects. Given the long development timelines, greater incentives are required for storage operators or independent research organisations to appraise and characterise sites early, to allow for bankable storage capacity to be ready by the time capture projects are ready to enter the market. Next to the already ambitious target of 50 Mtoe of captured CO_2 by 2030, to realise EU climate neutrality by 2050, the deployment of CO_2 capture facilities would need to occur at an even larger scale.

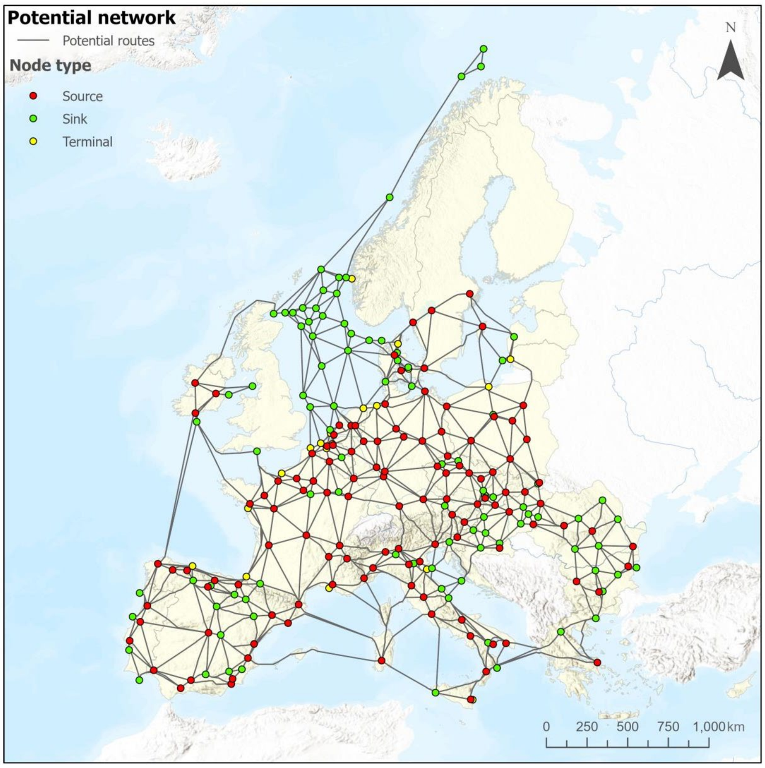
However, the distribution of CO_2 storage sites and capacities across Europe **is not evenly spread**. As a result, it will be necessary to develop storage sites beyond the North Sea and construct an extensive network infrastructure spanning several EU Member States and neighbouring countries. This infrastructure will be crucial in cases where countries do not possess sufficient CO_2 storage potential or when storage is not feasible or politically acceptable. It will also greatly depend on the specific policy priorities and strategies, including the identification of emission hubs and the selected transport infrastructure to connected sinks. Hence the vision for a trans-European network connecting different regions and countries. While desirable, this solution is expected to encounter several technical and financial difficulties. Based on interviews with stakeholders, it was stressed that extended network lengths are associated with significant issues of pressure. Indicatively, it was estimated that after 200km, there would be likely a need for a recompression station along the pipeline[177]. There are several uncertainties in implementing solutions to this problem, particularly in

[176] https://www.catf.us/resource/carbon-capture-storage-what-can-learn-from-project-track-record/
[177] This information is indicative and was shared during one of the interviews with a national TSO.

the case of marine pipes. For this reason, it was argued that transport by ship for marine transport, and potentially barge for inland water, would be best suited for long distance CO_2 transport.

As introduced earlier, the 2024 JRC study elaborates various scenarios of the potential developments of the EU CO_2 infrastructure network. Below, reports a mapping done by the JRC of the potential network design development up to 2050, showing the full potential of the network based on available geological information for potential sinks and emitter sources based on ETS data. When discussing this potential network design with stakeholders, the main considerations regarded the over extension of the network. Indeed, most stakeholders do not see the conditions yet for full CCS value chains development in CEE, particularly Poland, the Baltics, and Romania. The interviews emphasised that currently there is little to no political capacity to push forward a CCS agenda. While partly due to lack of manpower and ability to prioritise this specific issue, public acceptance represents also a strong barrier, particularly for onshore storage. Considering only those storage sites that have currently been announced – most of which are found in the North Sea – there are many parts of inland and Eastern Europe where the current lack of infrastructure and limited access to local storage makes transport costs prohibitively high.

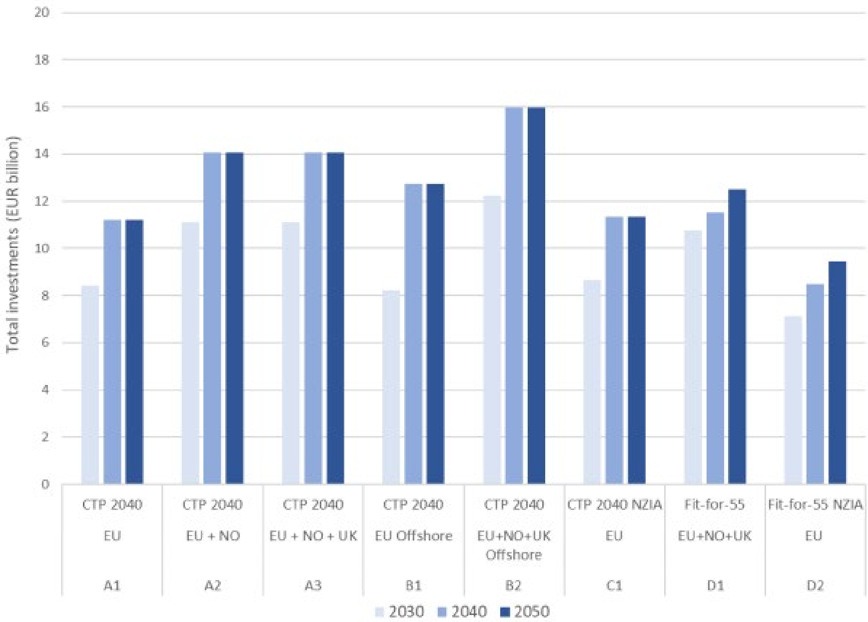
Figure 2-44 Overview of potential CO_2 transport networks, emission sources and sinks (source: JRC, 2024)



Below, reports a summary graph by the JRC on the CO_2 network estimated investment costs. The calculations consider eight possible scenarios, differing based on a) the capture amounts target based on either the Green Deal or the Fit for 55; b) whether only offshore is considered; c) whether the UK and Norway are included in the EU network. Across the scenarios, investments by 2030 are projected to range between €7 and €12 billion. The highest investments are estimated to be necessary in the B2 scenario, with only offshore storage solutions and integration of UK and Norway. The lowest investment need is expected for the scenario D2, where NZIA targets are used as reference and the UK and Norway are not included in the network.

Finally, we also report the projected total investment ranges developed in the same study (JRC, 2024). If the low and high estimates of infrastructure costs are considered, then the variability of investment costs is much wider and range between €8.3 billion and €23.1 billion. When discussing the projected investment figures with stakeholders, they all agreed that the investment will likely lean towards the higher end of the range, for several reasons: first, the scenarios considered more realistic (i.e. including UK and Norway) are associated with significantly higher costs. In addition, the stakeholders emphasised that infrastructure tend on average to incur higher costs as the project is implemented, compared to the planning phase. Especially first movers projects, where technical and legal issues will be addressed for the first time, are expected to incur higher investment costs, which are likely to decrease as know-how is developed for subsequent projects. Overall, internal estimations confirm that for the 1st PCI/PMI list projects, where the Norwegian pipelines are also considered, the total investments for these projects can amount to €29 billion. However, it should be emphasised that investment needs figures developed in this section do not include pipelines to Norway, as most experts, including the JRC study, do not foresee such very long pipelines (relying on shipping). This widely shared expectation might be proven wrong in the future, leading to the materialisation of pipelines connecting Norway to the continent. In this case, the totals would approach the €29 billion EC figure.

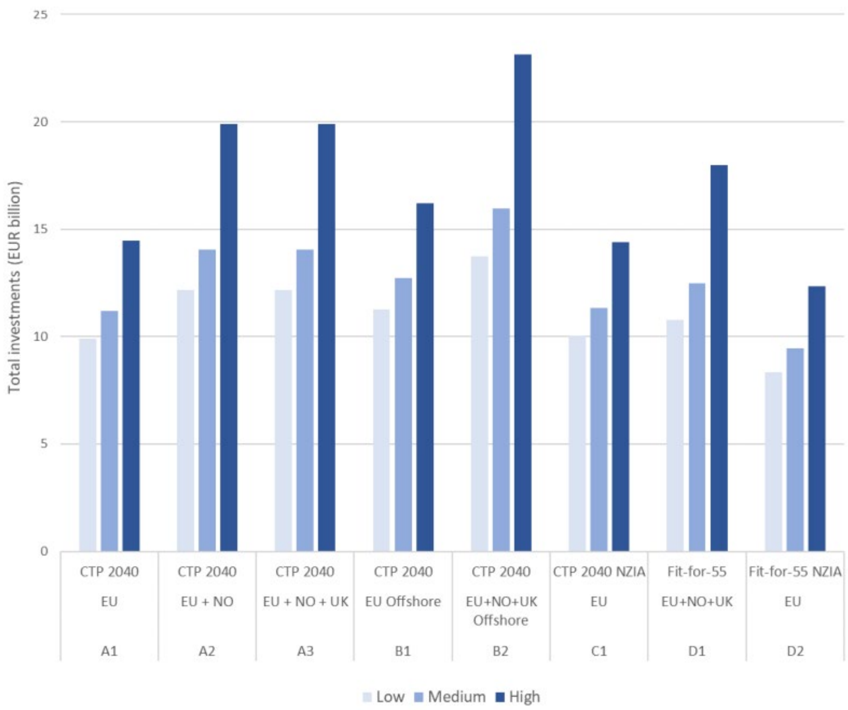
Figure 2-45 Investment costs, medium estimates (source: JRC, 2024[178])



Source: JRC, 2024

[178] JRC (2024)

Figure 2-46 Range of total investments (source: JRC, 2024)



Source: JRC, 2024

While not reflective of the situation in terms of announced projects, data made available by the JRC (2024) provides an MS-level picture of the potential CO2 transport and storage infrastructure development. These are based on the modelled potential network development per MS, showing medium and high investment ranges. For this, scenario A3 was used, namely assuming an EU network interconnected with the UK and Norway, where both offshore and onshore storage, and using the CTP 2040 emission targets.

Figure 2-47 Range of total investment by 2040 by Member State (Own graph based on data from JRC, 2024)

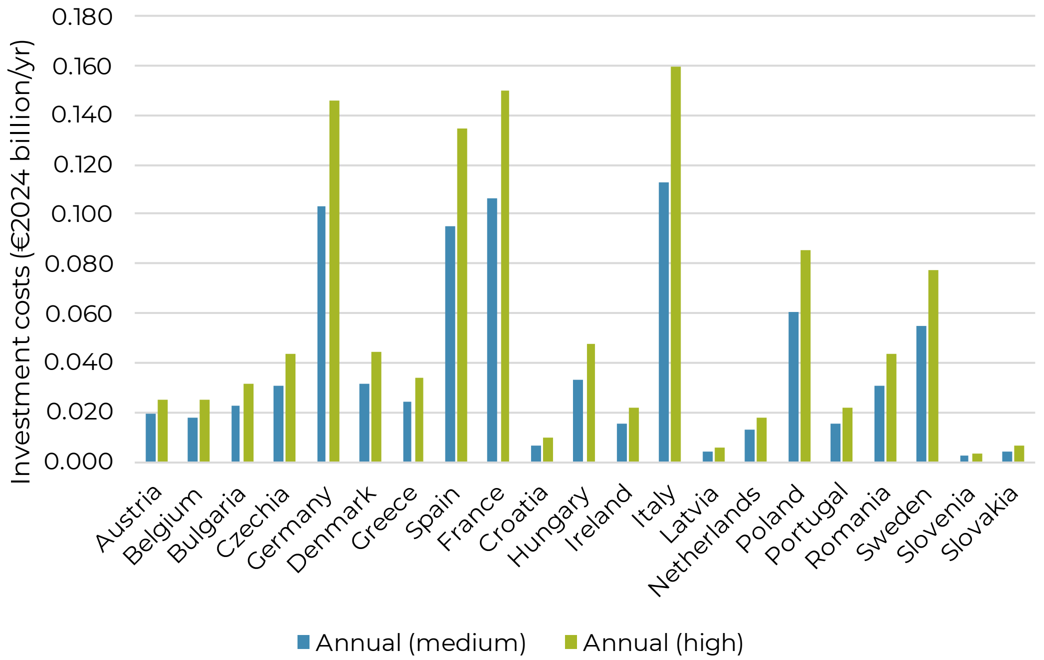
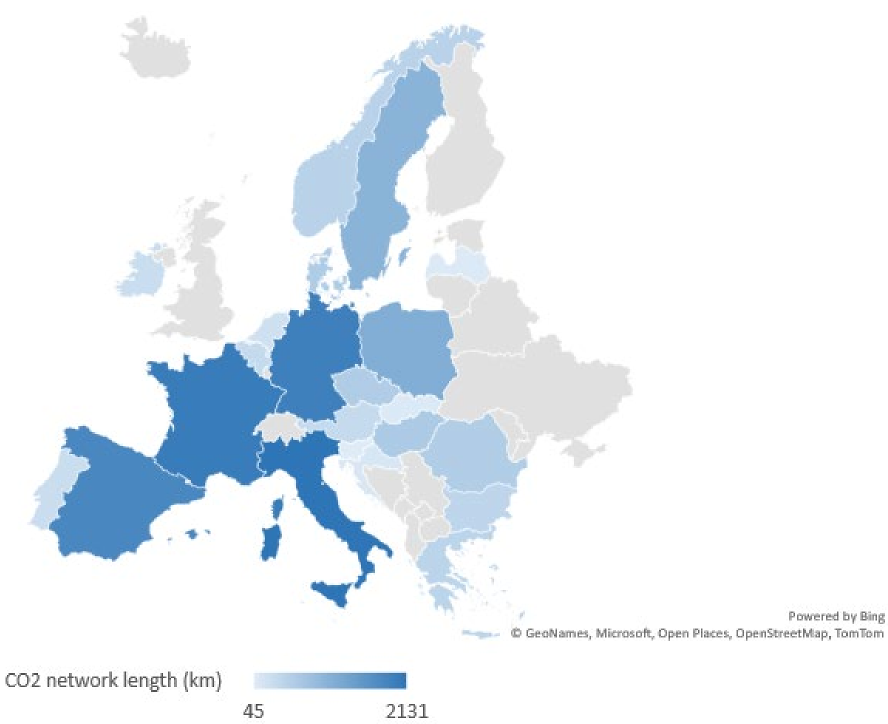


Figure 2-48 Length of potential CO_2 network per MS (in Km) (Own graph based on data from JRC, 2024[179])



The modelling of network development investment needs shows high variations between MS. The bloc's four largest economies show the largest investment need potential, with Italy reporting the highest figure. This could be due to the strategic geographical position of the peninsula a potential emerging hub for CO2 transport and storage infrastructure , connecting the Mediterranean basin states to the rest of the continent. Spain is also expected to have significant investment need potential, although there are currently limited signs of political prioritisation of CCS in the country. The graph shows a comparable level of investment needs for France and Germany, despite the two countries being currently at an asymmetric level of deployment of this technology. At 2040, up to six countries are, according to the JRC model, expected to show any investment in a CO_2 network development: Cyprus, Estonia, Finland, Lithuania, Luxembourg and Malta. Geography and size of the countries can be brought as reasons for this. Countries located far from the main CCS hubs, Northern Sea and Mediterranean, are projected to have significantly lower investment needs, with the important exception of Poland – and to a lesser extent Romania – whose heavy industry and decarbonisation needs likely drive the potential for CO^2 infrastructure to be built.

In summary, the current development state of CO2 transport and storage infrastructure in the EU does not allow for solid investment needs assessments. Several uncertainties determine this, including the expansion of the network beyond the emerging North Sea hub, the technical and economic success of the first full CCS value chains in the EU, as well as the availability of sufficient licensed storage sites. The figures developed by the JRC in their latest study provide a fundamental basis for a first order of magnitude assessment of the potential future investment needs for CO2 transport and storage infrastructure at EU level. As announced projects progress and new ones are

[179] https://publications.jrc.ec.europa.eu/repository/handle/JRC136709

added to the list, and as CCS rises up political agendas across governments, more accurate estimations of national investments will be possible.

3. The role of EU funding and financing in supporting investments

3.1. EU policy frameworks to support energy infrastructure investments

This section provides an overview of the current EU financing programmes, and in particular those that are financed under the Multiannual Financial Framework (MFF), and the EU sustainable finance framework relevant to the energy infrastructure categories that are in scope of this study[180]. Firstly, it presents the investment needs at global and EU level in the electricity network, hydrogen and CO_2 infrastructure. The figures are based on top-down estimates from published (grey) literature. It discusses the importance of public and private funding to close the investment gap as well as the importance of cross border infrastructure in the energy security of the EU. Next, we present the efforts of the EU to implement a stable regulatory and enabling environment that supports energy infrastructure investments, following by an overview of the available funding instruments available.

The aim of this section is to respond to the following research questions, namely:

- Why is EU funding needed in order to scale energy infrastructure within the EU?
- Why should EU funding instruments and other forms of EU financial support be used to fund cross-border infrastructure connections towards Energy Community Contracting Parties and neighbouring countries?
- What is the role of EU sustainable finance policy framework?

3.1.1. Energy infrastructure investments globally and in Europe

The global energy sector is undergoing a profound transformation as countries transition towards cleaner, more sustainable energy systems. This transformation requires large-scale investments in energy infrastructure to support new energy sources, enhance grid flexibility and ensure energy security. According to the IEA, the global annual investments in energy infrastructure are projected to amount to almost $1 trillion by 2030 and around $900 billion by 2050. The study foresees that the expansion and modernisation of the electricity networks will be the primary focus of the investments amounting to $800 billion per year by 2030 and remaining approximately on the same level by 2050. The annual investments for hydrogen, that includes production facilities, installations for hydrogen use in transport sector, and end user equipment are projected to $165 billion per year up to 2030 and more than $470 billion per year up to 2050. Significant investments are also foreseen for the CCUS sector, with annual investments slightly over $200 billion in 2030 and exceeding $160 billion by 2050. [181]

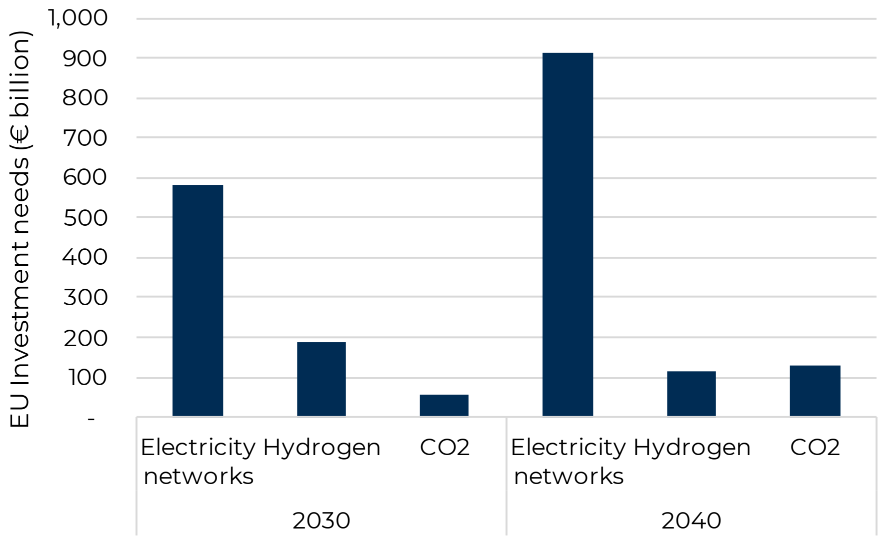
The EU has intensified the climate action efforts through the European Green Deal (EGD), aiming for climate neutrality by 2050. In addition, recent geopolitical events have jeopardised the energy security of the Union and have forced the EU to become more energy independent and overall

[180] Namely, transmission and distribution, hydrogen, cross border, offshore and CO_2 infrastructure.
[181] IEA (2021) Net Zero by 2050 A Roadmap for the Global Energy Sector

become climate neutral faster (e.g. REPowerEU Plan)[182]. Renewable energy and electrification are crucial to the EU's decarbonization goals and require transformation of the energy system, including networks' modernization and expansion. Nevertheless, the path to net zero targets by 2050 and the response to the ongoing energy crisis requires a significant capital investment, that is heavily dependent on public funding but also requires considerable contribution from the private sector.

The analysis of the European Commission estimates that the investment needs in electricity grids between 2020 and 2030 to achieve the REPowerEU Plan will amount to €584 billion, of which 65%-72% will be dedicated to distribution grids.[183] The Impact Assessment supporting the European Commission's proposed 90% GHG emission reduction target by 2040 estimates that enhancing and expanding the transmission and distribution networks will require average annual investments ranging from €82 to €98 billion (depending on the scenario applied) from 2031 to 2040.[184] Regarding hydrogen infrastructure, the cumulative EU investment needs are projected to reach €188 billion by 2030 with H_2 pipelines requiring more than half of these investments. Between 2031 and 2040 the investment needs are forecasted at €117 billion, most of them needed for H_2 pipelines and electrolysers.[185] CO_2 infrastructure is also expected to play a key role in the decarbonisation efforts of the EU. according to the study of JRC[186], it is estimated that by 2030 the CO_2 infrastructure may span 6,700 km and be expanded to 15,600 km by 2050. This would come at an annual cost range of €5.4 to €7.7 billion by 2030 and € 13.1 to €18.5 billion by 2050.[187]

Figure 3-1 EU energy infrastructure investment needs by 2030 and 2040



Notes: TSOs & DSOS investments for the period 2031-2040 consider European Commission 2040 Impact Assessment Scenario 2. CO_2 projections use the medium A3 scenario developed by JRC (2024)

Sources: EC (2022), EC (2024), JRC (2024) and own analysis.

Moreover, cross-border infrastructure has a strategic importance for the EU. Firstly, achieving EU climate targets heavily relies on the integration and modernization of European energy

[182] EESC (2022) Public investment in energy infrastructure as part of the solution to climate issues
[183] Commission Staff Working Document (2022). Implementing the REPowerEU Action Plan: Investment Needs, Hydrogen Accelerator and Achieving the Bio-methane Targets.
[184] European Commission (2024). Europe's 2040 climate target and path to climate neutrality by 2050 building a sustainable, just and prosperous society.
[185] Data based on our own analysis. For more information refer to section 2.1.7 of this report.
[186] JRC (2024) Shaping the future CO2 transport network for Europe
[187] EC (2024) CO2 transport and storage infrastructure: key to achieving climate neutrality by 2050

infrastructure, including cross-border interconnectors and grids, which enhance overall energy efficiency and facilitate the integration of renewable energy sources across borders. [188] The need for cross-border interconnection is validated by the ENTSO-E estimations, according to which the current exchange capacity of the EU falls short by 50-100 GW by 2030 and 2040, which translates to investment needs of approximately €2 billion per year.[189]

Secondly, in light of geopolitical shifts and security concerns following Russia's actions in Ukraine, strengthening energy security and reducing dependency on single suppliers, particularly for fossil fuels, has become imperative. Therefore, investing in diversified energy sources (for example importing LNG from other countries such as Norway and Azerbaijan), and supporting renewable energy projects mitigate the risks associated with reliance on volatile regions.

As indicated in Chapter 2 and in Figure 3-1, the investment needs in the EU energy infrastructure in the coming decades are significant, therefore the support of public and private funding would play a crucial role.[190] Public funding, often provided through national governments, the European Commission (e.g. through EU programmes such as the Connecting Europe Facility for Energy (CEF-E)) and other EU institutions such as the European Investment Bank (EIB), plays a pivotal role in de-risking large, capital-intensive energy infrastructure projects, particularly in early-stage or high-risk technologies such as hydrogen and carbon capture, utilization, and storage (CCUS). Public funds are also critical in areas with lower private investment attractiveness, such as cross-border interconnections, where profitability may be uncertain. Private funding, on the other hand, contributes significantly to established technologies, for instance, renewable energy generation and grid modernization where financial returns are more predictable. Private capital can be mobilised through mechanisms such as public-private partnerships (PPPs) and green bonds.[191] Nevertheless, public investment remains essential for closing financing gaps in areas where private capital alone may be insufficient, particularly in ensuring equality and supporting the social dimensions of the energy transition. Literature indicates that the split between public and private funding for additional investments varies with ratios ranging from 1:5[192] to 1:2,[193] while the distribution is expected to differ between EU Member States. Since 2010, global private investment has focused significantly on the energy and transport sector, with the investments reaching 57% in energy infrastructure projects. [194] Forecasts show that private investments are expecting to increase by 2030, contributing up to 49% of the total energy infrastructure investments in 2030. The forecasts show a decline of 8% in the public investments in the respective year. [195]

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[188] Bruegel (2024) Accelerating strategic investment in the European Union beyond 2026
[189] ENTSO-E (2023) Opportunities for a more efficient European power system in 2030 and 2040
[190] European Environment Agency (2023) Investments in the sustainability transition: leveraging green industrial policy against emerging constraints
[191] Vassileva A. (2022) The Role of the Green Bonds in Public-Private Partnerships as a Sustainable Investment Opportunity, Ecologica, Vol. XXIX, No 106 (2022), pp. 139-147
[192] Darvas Z. and Wolff, G., 2021, A green fiscal pact: climate investment in times of budget consolidation, Policy Contribution 18/2021, Bruegel
[193] Baccianti, C., 2022, 'The Public Spending Needs of Reaching the EU's Climate Targets, in: Cerniglia, F. and Saraceno, F. (eds), Greening Europe 2022 European Public Investment Outlook, (https://www.openbookpublishers.com/books/10.11647/obp.0328).
[194] Global Infrastructure Hub (2022) Renewables dominate private investment in infrastructure
[195] ERT (2024) Strengthening Europe's Energy Infrastructure

Barriers to decarbonise the energy system

Modernising and expanding the existing energy infrastructure requires **substantial initial capital investments** which often can be challenging to secure, particularly in regions with high political or economic instability. Given the major electrification shift that Europe is undergoing, the capital investments in networks are expected to reach half a trillion by 2030 at transmission and in particular at distribution level (as described in the previous section)[196]. In the case of CO_2 infrastructure, the high costs of capturing, transporting, and storing CO_2, coupled with the absence of strong enough carbon pricing mechanism make projects economically challenging. On the other hand, hydrogen infrastructure, such as electrolysis plants, storage facilities, and distribution networks, is largely undeveloped, while hydrogen technologies still come at high CAPEX. Meanwhile, these projects involve complex, large-scale assets, and the returns on investment typically materialise only over the long term, often years after the infrastructure is operational. This long payback period introduces significant financial risk, as evolving market conditions or technological advancements could reduce demand, potentially turning assets into unprofitable investments. The risk is even greater since hydrogen and CCUS infrastructure includes both **regulated and non-regulated assets**. In regulated markets, certain revenues are guaranteed by government policies or tariffs, which can help mitigate investment risks. However, non-regulated infrastructure, such as CCUS storage sites, depends on market demand, which is still uncertain and may not develop as anticipated.

Additionally, the **lack of a mature market** for hydrogen exacerbates these financial risks. The uncertainty around future demand and the cost-competitiveness of hydrogen compounds the risk of stranded assets make investors hesitant to commit large-scale capital to hydrogen projects.[197]

Moreover, public budgets have been significantly impacted by the economic impacts of the COVID-19 pandemic and the ongoing aggression by Russia in Ukraine, while there are multiple sectors that require public investments and are in competition with the energy transition. As a reference the additional annual investment for digitalisation is projected at €125 billion.[198] The demographic transition significantly affects the levels of funding towards energy transition, since governments are expected to increase their contribution for public expenditure in pensions and health while the entire population is shrinking.[199] To that end, the support of EU funds, can maintain or improve the efforts of the national governments to support investments in green transition, especially when the national funds fall short.

Furthermore, COVID-19 and Russia's invasion of Ukraine alongside with the surging demand of clean energy have **significantly increased the costs of materials and energy**. For instance, between 2020 and 2022 the costs of PV modules increased by 25% and of wind turbines by 20% globally, while the increased energy prices have driven up the production costs of energy intensive materials such as cement, steel, ammonia and various materials,[200] that subsequently increase the overall infrastructure costs. Overall, it is expected that the grid investments costs per MWh will double between 2020 and 2030 both in Europe and the US.[201]

Permitting delays can hinder the rapid deployment of energy infrastructure. Lead times for energy infrastructure projects range from 8 to 13 years for transmission grids, 3 to 12 years for hydrogen

[196] Commission Staff Working Document (2022). Implementing the REPowerEU Action Plan: Investment Needs, Hydrogen Accelerator and Achieving the Bio-methane Targets.
[197] ICF (2023) Key financing challenges for the global hydrogen market
[198] European Environment Agency (2023) Investments in the sustainability transition: leveraging green industrial policy against emerging constraints
[199] European Environment Agency (2023) Investments in the sustainability transition: leveraging green industrial policy against emerging constraints
[200] IEA (2023) Energy Technology Perspectives
[201] BloombergNEF (2024) Readying the Global Power Grid for Net Zero

infrastructure and up to 10 years for CO_2 infrastructure. Permitting and approval of the projects can take up to 6 years for transmission grids, while for new infrastructure types (e.g., storage sites for hydrogen, port facilities, etc.) there is ambiguity on the responsibilities among the regulators. [202] However, significant efforts have been made in recent years in Europe to accelerate the permitting times of renewable energy projects. For example, the TEN-E Regulation mandates the EU Member States to ensure a streamlined permit-granting process of 3.5 years for PCIs and PMIs.[203]

Furthermore, **regulatory and policy uncertainty** at EU and Member State level can also impede energy infrastructure deployment. At EU level, the European Commission sets targets and frameworks (e.g., the Clean Energy Package that includes several Regulations and Directives[204]). However, these measures do not necessarily provide the level of certainty that the investors require since they are often not binding, or they provide flexibility to the Member States regarding their implementation. For example, specific Regulations concerning grid access, tariffs, and access to subsidies are often interpreted and applied differently by Member States. Therefore, the inconsistent implementation of the policies can deter investments, especially from the private sector. For instance for CO2 transport and storage infrastructure, although the EU supports carbon capture and storage, national-level regulatory frameworks often lack clarity on carbon pricing mechanisms and the long-term liability of stored CO_2. Cross-border infrastructure projects face even greater challenges due to varying national regulations and permitting processes between countries, despite overarching EU goals.[205]

Finally, while in Europe the public support on the energy transition is relatively high, **energy infrastructure developments are frequently confronted with public opposition.** This can be based on several reasons related among others to impacts on wildlife, agriculture, fisheries, or visual landscape or political ideologies. [206] To that end, the Commission has intensified the efforts to improve public acceptance of infrastructure projects, and in particular related to the grid developments, by improving communication and engagement towards grid acceleration and faster deployment. [207]

3.1.2. EU regulatory framework promoting energy infrastructure investments

The EU has established a comprehensive regulatory framework that plays a critical role in providing stability and predictability for investors. In response to geopolitical and environmental challenges, the EU has implemented a robust regulatory environment that safeguards market stability and supports structural reforms. To that end, the following section provides an overview of EC-related policies as well as other EU-level activities towards energy infrastructure investments.

The **Trans-European Networks for Energy (TEN-E) Regulation**[208] is a key pillar of the EU's policy framework for supporting cross-border energy infrastructure investments. It plays a critical role in ensuring the development of interconnected energy networks across the EU-27 and with third countries, and promotes energy security, market integration, and the efficient flow of energy across borders, reducing the reliance on single suppliers and enhancing energy security of the Union. Updated in 2022, the TEN-E policy identifies eleven priority corridors focusing on electricity, offshore grids, hydrogen and electrolysers, as well as three priority thematic areas including, smart electricity

[202] IEA (2023) Energy Technology Perspectives 2023
[203] European Commission (n.d.) Trans-European Networks for Energy
[204] EC (n.d.) Clean energy for all Europeans package
[205] EIB (2023) Cross-border infrastructure projects
[206] Institute for European Energy and Climate Policy (IEECP) and Renewables Grid Initiative (RGI) (2023) Drivers and barriers of public engagement in energy infrastructure
[207] EC (n.d.) Public acceptance of infrastructure projects
[208] Regulation (EU) 2022/869 of the European Parliament and of the Council of 30 May 2022 on guidelines for trans-European energy infrastructure, amending Regulations (EC) No 715/2009, (EU) 2019/942 and (EU) 2019/943 and Directives 2009/73/EC and (EU) 2019/944, and repealing Regulation (EU) No 347/2013

grids, cross-border carbon dioxide and smart gas grids. The development in these corridors aims for a better-connected energy network, particularly with a view of connecting those regions currently isolated from European energy markets. They will also allow to strengthen existing cross-border interconnections and renewable energy integration. A key aspect of the TEN-E Regulation is the identification and implementation of Projects of Common Interest (PCIs) and Projects of Mutual Interest (PMIs). PCIs are essential for linking the energy systems of EU Member States, while PMIs extend to partnerships with third countries, contributing to enhanced energy security and diversification of supply. The list of PCI and PMI projects is drawn up every two years by the European Commission and is adopted as an EU-wide list by means of a delegated act.[209]

In addition to the TEN-E Regulation, other legislative and strategic documents complement the regulatory environment. The **Electricity Directive**[210] emphasises the importance of modernizing the electricity grid to accommodate the increased share of renewable energy and improve network reliability, through smart grids, network reinforcement and energy storage. It also highlights the role of TSOs and DSOs in maintaining and expanding the electricity infrastructure, including the publication of long-term network development plans. The **Renewable Energy Directive** (RED III)[211] promotes simplified permitting processes for the necessary transmission, distribution and storage infrastructure, and to the extent possible the designation of acceleration areas for that purpose for the development of such infrastructure. The **Energy Efficiency Directive**[212] urges the introduction of cost-effective energy efficiency improvements in the network infrastructure, while it highlights the importance of the "energy efficiency principle" when considering energy infrastructure expansion. Similarly, the **Electricity Regulation**[213] highlights the importance of cross-border infrastructure to achieve flexible generation interconnection, demand response and energy storage, and encourages investments in major new infrastructure. Furthermore, the **Hydrogen and Decarbonised Gas Market Package**[214], which was adopted in May 2024, provides a revision on the Gas Directive and the Gas Regulation and it focuses on the integration of renewable and low-carbon gases, including hydrogen, into the energy market. Among others, it sets out the rules for transport, supply and storage of hydrogen and it establishes an independent body for hydrogen networks, the European Network for Network Operators of Hydrogen (ENNOH).

Another piece of EU regulatory framework to support investments in energy infrastructure is the **REPowerEU Plan.** The Plan stresses the importance of hydrogen infrastructure deployment as well as cross-border hydrogen and electricity infrastructure. It also imposed a series of emergency legislative measures to ease pressure on the energy markets, as well as enable structural reforms of the EU's energy system. An example of such legislative act is the Permitting Regulation[215], which established temporary rules to allow the acceleration of the permit-granting processes applicable to the production of energy from renewable energy sources; it addressed not only the installations, but also their connected to the grid, the related grid, as well as storage assets.

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209 EC (n.d.) PCI and PMI selection process
210 Directive (EU) 2019/944 of the European Parliament and of the Council of 5 June 2019 on common rules for the internal market for electricity and amending Directive 2012/27/EU (recast) (Text with EEA relevance.)
211 Directive (EU) 2023/2413 of the European Parliament and of the Council of 18 October 2023 amending Directive (EU) 2018/2001, Regulation (EU) 2018/1999 and Directive 98/70/EC as regards the promotion of energy from renewable sources, and repealing Council Directive (EU) 2015/652
212 Directive (EU) 2023/1791 of the European Parliament and of the Council of 13 September 2023 on energy efficiency and amending Regulation (EU) 2023/955 (recast) (Text with EEA relevance)
213 Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity (recast) (Text with EEA relevance.)
214 EC (n.d.) Hydrogen and decarbonised gas market
215 Council Regulation (EU) 2022/2577 of 22 December 2022 laying down a framework to accelerate the deployment of renewable energy

The EU also uses other strategic initiatives, such as the **Hydrogen Strategy**[216] and the **Offshore Renewable Energy Strategy**[217], to set out long-term visions for specific sectors within the energy infrastructure landscape. For instance, the goal of the Hydrogen Strategy is to produce 10 million tonnes of hydrogen within the EU and import another 10 million tonnes by 2030, which can materialise by implementing 20 key action points, including an investment agenda for the EU.[218] The Offshore Renewable Energy strategy foresees cumulative regional offshore capacity by 2030 and 317 GW by 2050, making offshore energy a main pillar of the EU's energy mix. Furthermore, in 2023 the EU launched the EU Action Plan for grids[219], identifying the investment needs at EU level up to 2030 at transmission and distribution level. It also identifies the seven core challenges of the networks and proposes 14 action points to support the enhancements of the networks in the next 1.5 years.

EU Emissions Trading System (ETS) is an additional EU climate policy to reduce GHG emission in a cost-effective manner. Established in 2005, it operates on a "cap-and-trade" principle, where a cap is set on the total amount of greenhouse gases that can be emitted by certain sectors (e.g., power plants, heavy industry, and aviation within Europe). The revenues of the EU ETS are used to fund financial instruments that provide support to MSs to reduce their GHG emissions and improve their renewable energy shares, such as the Innovation Fund and the Modernisation Fund. Since 2013, the EU ETS has generated more than €200 billion auction revenues. In 2023 alone the revenues amounted to more than €43 billion, of which €33 billion was allocated directly to the MSs.

Beyond the dedicated EU regulatory framework, the EU fosters a stable policy environment for energy infrastructure investments through long-term strategies and planning mechanisms. The **Ten-Year Network Development Plan (TYNDP)** for electricity and gas, developed by the European Network of Transmission System Operators (ENTSO-E and ENTSOG)[220] is a cornerstone of this approach. The TYNDP provides a roadmap for the development of the European electricity and gas energy grid, identifying future infrastructure needs and proposing projects that align with EU climate and energy objectives. The TYNDPs are published and adopted every two years, based on extensive scenario modelling, which since the 2022 scenarios includes long-term perspective until 2050.

Furthermore, network planning at national level must be consistent with national climate and energy targets, including alignment with **National Energy and Climate Plans (NECPs)**. Regulation 2018/1999 of the European Parliament and of the Council of 11 December 2018 on the Governance of the Energy Union and Climate Action is explicit that key electricity and gas transmission infrastructure projects, and, where relevant, modernisation projects, that are key in achieving targets under the Energy Union have to be included in the integrated NECPs under the 'Internal Energy Market' dimension.[221] The NECP progress reporting also requires for Member States to include information on key electricity and gas transmission infrastructure projects, as well as main infrastructure projects envisaged other than Projects of Common Interest if applicable, including projects involving third countries. While NECPs offer insights into national investments and EU funding, their lack of detail

[216] COMMUNICATION FROM THE COMMISSION TO THE EUROPEAN PARLIAMENT, THE COUNCIL, THE EUROPEAN ECONOMIC AND SOCIAL COMMITTEE AND THE COMMITTEE OF THE REGIONS A hydrogen strategy for a climate-neutral Europe
[217] COMMUNICATION FROM THE COMMISSION TO THE EUROPEAN PARLIAMENT, THE COUNCIL, THE EUROPEAN ECONOMIC AND SOCIAL COMMITTEE AND THE COMMITTEE OF THE REGIONS An EU Strategy to harness the potential of offshore renewable energy for a climate neutral future
[218] EC (n.d.) Key actions of the EU Hydrogen Strategy
[219] COMMUNICATION FROM THE COMMISSION TO THE EUROPEAN PARLIAMENT, THE COUNCIL, THE EUROPEAN ECONOMIC AND SOCIAL COMMITTEE AND THE COMMITTEE OF THE REGIONS Grids, the missing link - An EU Action Plan for Grids
[220] ENTSOG (n.d.) Ten Year Network Development Plan; ENTSO-E (2022) Ten Year Network Development Plan: A European-wide vision for the future of our power network Ten Year Network Development Plan; ENTSO-E (2022) Ten Year Network Development Plan: A European-wide vision for the future of our power network
[221] Regulation (EU) 2018/1999 of the European Parliament and of the Council of 11 December 2018 on the Governance of the Energy Union and Climate Action

can limit clarity on public and private investment needs for energy infrastructure. Though updates were expected in 2023, some countries submitted drafts in 2024, affecting the precision of infrastructure and funding projections.

3.1.3. Current EU financial programmes available

The EU offers a range of EU funding programmes and financial instruments designed to support energy infrastructure investments, that play a critical role in advancing the EU's energy transition and ensuring the security and sustainability of its energy systems. These instruments are tailored to address the significant capital requirements of large-scale energy projects and de-risk investments in innovative and renewable energy technologies. In the case of the Connecting Europe Facility (CEF), the instrument also facilitates cross-border projects in the renewable energy sector. Hereunder we provide a short overview of the EU financial instruments that target energy infrastructure within and outside the EU.

EU financial instruments funded by 2021-2027 Multiannual Financial Framework (MFF)

Connecting Europe Facility (CEF)

CEF, as part of the toolkit of the TEN-E Regulation, operates in the realms of transport, energy, and digital services and supports the development of sustainable and interconnected trans-European networks. CEF for Energy (CEF-E) specifically supports the implementation of PCIs and PMIs under the TEN-E Regulation and focuses on cross-border renewable energy projects. It provides funding to cross-border projects related to electricity infrastructure, smart grids, CO_2 networks, where natural gas was eligible in the past but has been replaced by hydrogen. The budget related to energy activities amounts to €5.84 billion which can be spent in the form of grants. [222]

InvestEU Fund

The InvestEU Fund is the finance pillar of the InvestEU Programme, which supports sustainable investment, innovation and job creation in Europe, as well as REPowerEU and the Just Transition Mechanism (JTM). The other pillars are related advisory facilities to support the implementation of InvestEU funding. The InvestEU Fund provides long-term funding by attracting private and public funds in support of Europe's sustainable recovery. Importantly, it helps to mobilise private investments.[223] InvestEU Fund has four main policy areas, one of which is 'sustainable infrastructure' and it includes energy infrastructure and electricity networks. With a total budget of €26.2 billion, it is expected to stimulate more than €372 billion of public and private investment.

Horizon Europe

Horizon Europe is EU's key funding programme for research and innovation. Support is grouped under six clusters, one of which is "Climate, Energy & Mobility", which includes funding for energy transitions.[224] Horizon Europe will support projects such as: new solutions for smart grids, carbon capture, use and storage (CCUS), and energy storage & hydrogen.[225] the total budget amounts to €93.5 billion of which more than 15 billion are available for the "Climate, Energy & Mobility" cluster.

Cohesion Fund

The Cohesion Fund is designed to bolster the economic, social, and territorial cohesion of the EU by providing support to MSs with a GNI[226] per capita below 90% of the EU-27 average. Focused on

[222] EC (n.d.) CEF Energy
[223] InvestEU (n.d.) What is the InvestEU Programme?
[224] EC (2021) The EU Research & Innovation Programme 2021 – 27
[225] EC (2021) Horizon Europe – Strategic plan 2021-2024; EC (n.d.) Cluster 5: Climate, Energy and Mobility
[226] Gross National Income

fostering cohesion, it directs its assistance toward specific areas, particularly investments in the field of transport infrastructure (TEN-T). Energy infrastructure projects are supported with the objective to develop smart energy systems, grids and storage outside the Trans-European Energy Network (TEN-E)[227]. Examples include solutions for energy storage and smart energy system implementation.[228] The Cohesion Fund operates in shared management responsibility with the European Commission, national, and regional authorities in the respective MS that manage projects funded by the Cohesion Fund. It has a total budget of €37 billion of which 37% of the funding has to targeted towards contributing to climate objectives. "Smart energy systems and related storage" specific objective is projected to receive €4.3 billion.

European Regional Development Fund (ERDF)

The ERDF provides funding to both public and private entities across EU regions with the goal of reducing economic, social and territorial disparities. The current ERDF funding period has five priority objectives, one of which is to make Europe greener, low-carbon and resilient.[229] It falls under the same Regulation as Cohesion Fund and hence they both have the same focus on energy infrastructure projects. With a budget of more than €200 billion, it supports investments through dedicated national or regional programmes. Support can be provided through grants and, increasingly, through financial instruments such as loans, guarantees or equity.

Interreg[230], part of ERDF, is the instrument that focuses on cooperation across regions and countries. The focus of the period 2021-2027 is to support cross-border mobility, environmental protection, emergency services, skilled jobs and access to public services, and as in the case of ERDF, to improve the smart energy systems grids and storage. The budget of Interreg amounts to €394.5 million and the eligible countries are the EU-27 plus Albania, Bosnia and Herzegovina, Moldova, Montenegro, North Macedonia, Norway, Serbia, Switzerland and Ukraine.

Just Transition Fund (JTF)

The JTF is a pillar under the Just Transition Mechanism (JTM) under the European Green Deal, as part of the objective of "leave no one behind". It specifically targets regions in MSs that will be most affected by the transition towards climate neutrality, to avoid regional inequalities. Several activities are eligible for funding, including investments in clean energy, including the promotion of green hydrogen. The total budget amounts to €19.32 billion in the form of grants, procurement and other financial instruments.[231]

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[227] Regulation (EU) 2021/1058 of the European Parliament and of the Council of 24 June 2021 on the European Regional Development Fund and on the Cohesion Fund, Annex I
[228] REGIO IT Reporting (n.d.) 2021-2027 Achievement Details (multi-funds)
[229] EC (n.d.) European Regional Development Fund (ERDF)
[230] Interreg
[231] EC (n.d.) Just Transition Fund

EU financial instruments funded by the EU ETS

Innovation Fund (IF)

The Innovation Fund focuses on funding projects for the demonstration and roll-out of innovative low-carbon technologies. It targets the fields of renewable energy (solar, wind, geothermal), energy-intensive industries (replacing fossil fuels with renewable energy and integration of CCS technologies), energy storage and carbon capture and storage. IF works on the basis of calls for proposals, separating large-scale and small-scale projects, and it has a total budget of €40 billion until 2027.[232]

Modernisation Fund (MF)

The Modernisation Fund supports 13 lower-income EU Member States to meet energy targets by helping to modernise energy systems and improve energy efficiency. Energy storage and the modernisation of energy networks (including electricity grids and increase in the interconnections between MSs) are a priority investment area. MSs are free to decide on the form of support provided under MF: they can use grants, premium, guarantee instruments, loans or capital injections. The available budget of MF amounts to €57 billion. [233]

EU financial instruments funded by NextGenerationEU

Recovery and Resilience Facility (RRF)

The RRF is a temporary instrument under the NextGenerationEU recovery instrument with a budget of €723.8 billion. Its aim is to provide financing to enable Member States to increase resilience and prepare for their digital and green transitions, also supporting REPowerEU. Each MS prepared a national recovery and resilience plan (NRRP), and according to analysis on planned spending energy networks and infrastructure related measures represent €8.5 billion of funding, including development of electricity interconnectors and smart grids, while hydrogen related measures represent €9.3 billion of funding. Both loans and grants are available under the RRF. However, in order to access funding under the RRF, Member States must submit national recovery and resilience plans, that outline the reforms and investments they will implement by the end of 2026.[234]

[232] EC (n.d.) Innovation Fund
[233] Modernisation Fund
[234] EC (n.d.) The Recovery and Resilience Facility

Table 3-1 Overview of EU funding programmes related to energy infrastructure development for the period 2021-2027 applicable to EU-27 Member States

EU funding programme	Total budget)/ Energy infrastructure budget (€ billion)	Type of support	Infrastructure categories	Eligibility criteria
Funded by MFF				
Connecting Europe Facility (CEF) / CEF-Energy	33.7/5.8	Grants	Electricity cross-border infrastructure, hydrogen, electricity storage, CO_2 infrastructure	• PCI and PMI
InvestEU Fund	26.2/9.9[235]	Budget guarantees	Electricity storage, electricity cross-border infrastructure, CO_2 infrastructure	• Investments > EUR 10 million: Sustainability proofing • All investments: Environmental and climate impact monitoring • Use EU-taxonomy or InvestEU markers for tracking
Horizon Europe	93.5/15.1[236]	Grants, prizes	Hydrogen, CO_2 infrastructure, electricity transmission, electricity distribution, electricity cross-border infrastructure	• Clear added value compared to existing EU initiatives in the mission areas • Clear R&I content • Measurable goal, which is realistically reachable within the set timeframe and with the limited budget available
Cohesion Fund	37/not available	Predominantly through grants	Electricity storage, electricity distribution, electricity transmission (outside TEN-E)	• Promoting renewable energy in accordance with Directive (EU) 2018/2001,

[235] For sustainable infrastructure
[236] Under the "Climate, Energy & Mobility" cluster

				including the sustainability criteria set out therein • Developing smart energy systems, grids and storage outside the Trans-European Energy Network (TEN-E)
European Regional Development Fund (ERDF)	226/not available	Grants , guarantees or equity	Electricity storage, electricity distribution, electricity transmission (outside TEN-E)	• Promoting renewable energy in accordance with Directive (EU) 2018/2001, including the sustainability criteria set out therein • Developing smart energy systems, grids and storage outside the Trans-European Energy Network (TEN-E)
Interreg[237]	0.4/~0.08			
Just Transition Fund (JTF)	19.3/ not available	Grants, procurement and other financial instruments	Hydrogen, electricity distribution, electricity transmission, CO_2 infrastructure, cross-border infrastructure, electricity storage	MS develop Just Transition Plans identifying the territories and sectors eligible for funding under the Just Transition Fund
Funded by ETS				
Innovation Fund (IF)	40/ not available	Grants	Hydrogen, electricity storage, CO_2 infrastructure	• Effectiveness of greenhouse gas emissions avoidance • Degree of innovation • Project maturity • Replicability • Cost efficiency
Modernisation Fund (MF)[238]	57/not available	Grants, premium, guarantee instruments, loans or capital injections	Hydrogen, electricity distribution, electricity cross-border infrastructure,	• Compliance with Modernisation Fund requirements set in the ETS

[237] Besides EU-27 includes the countries ALB, BIH, MDA, MNE, MKD, SRB, UKR.
[238] Implementation period is 2021-203. Eligible countries are BG, HR, CZ, EE, GR, HU, LV, LT, PL, PT, RO, SK, SI.

			electricity storage, CO_2 infrastructure	Directive and the Implementing Regulation • Have sufficient funds available in the relevant category on its Modernisation Fund account • Investment proposal is in line with the State aid rules • Investment complies with "do no significant harm" principle (from 1 January 2025) • Investment complies with any other applicable requirements of Union and national law • No double funding of the same costs with another Union or national instrument
Funded by NextGenerationEU				
Recovery and Resilience Facility (RRF)	723.8/184 [239]	Loans and grants	Electricity distribution, electricity transmission, electricity storage, hydrogen	• Measures outlined in MSs' RRP must not result in significant harm to any of the six environmental objectives defined in Article 17 of the EU Taxonomy Regulation

[239] Of which €25 billion dedicated to energy infrastructure and €13.6 billion to hydrogen.

3.1.4. Role of EU sustainable finance policy framework

The EU sustainable finance policy framework plays a central role in shaping the financial landscape to support investors to redirect investments towards sustainable technologies and business, including energy infrastructure projects. The key components of this framework—namely, the EU Taxonomy[240], Sustainable Finance Disclosure Regulation (SFDR)[241], and Corporate Sustainability Reporting Directive (CSRD)[242]—serve as tools for classifying sustainable investments and ensuring transparency in financial markets.

The EU Taxonomy is the cornerstone of the EU's sustainable finance strategy. It establishes a classification system that defines which economic activities are considered environmentally sustainable.[243] This system is particularly important for energy infrastructure projects as it provides clear criteria for what constitutes an energy infrastructure project which substantially contribute to EU's climate change mitigation or adaptation objectives, whilst doing no significant harm to the remaining environmental objectives: water, pollution, circular economy, and biodiversity. By doing so, the EU Taxonomy helps investors identify and prioritise projects that contribute to the EU's climate and environmental goals. The first Taxonomy Climate Delegated Act[244] covered climate change mitigation and adaptation has been up and running since January 2022. In March 2022, the Commission adopted the Complementary Climate Delegated Act[245] including, under certain conditions, specific nuclear and gas energy activities in the list of economic activities covered by the EU taxonomy. In June 2023, the Commission amended and added to the Taxonomy Climate Delegated Act[246] and adopted the Taxonomy Environmental Delegated Act[247], including a new set of criteria for economic activities making a substantial contribution to one or more of the non-climate environmental objectives, which include: sustainable use and protection of water and marine resources, transition to a circular economy, pollution prevention and control and protection and restoration of biodiversity and ecosystems. The most recent update (29th November 2024) provides additional technical clarifications and practical guidance for implementing the Taxonomy

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[240] Regulation (EU) 2020/852 of the European Parliament and of the Council of 18 June 2020 on the establishment of a framework to facilitate sustainable investment and amending Regulation (EU) 2019/2088.
[241] Regulation (EU) 2019/2088 of the European Parliament and of the Council of 27 November 2019 on sustainability-related disclosures in the financial services sector.
[242] Directive (EU) 2022/2464 of the European Parliament and of the Council of 14 December 2022 amending Regulation (EU) No 537/2014, Directive 2004/109/EC, Directive 2006/43/EC and Directive 2013/34/EU, as regards corporate sustainability reporting.
[243] Regulation (EU) 2020/852 of the European Parliament and of the Council of 18 June 2020 on the establishment of a framework to facilitate sustainable investment and amending Regulation (EU) 2019/2088.
[244] Regulation (EU) 2021/2139 of the European Parliament and of the Council by establishing the TSC for determining the conditions under which an economic activity qualifies as contributing substantially to climate change mitigation or climate change adaptation and for determining whether that economic activity causes no significant harm to any of the other environmental objectives.
[245] Regulation (EU) 2022/1214 amending Delegated Regulation (EU) 2021/2139 as regards economic activities in certain energy sectors and Delegated Regulation (EU) 2021/2178 as regards specific public disclosures for those economic activities.
[246] Regulation (EU) 2023/2485 amending Delegated Regulation (EU) 2021/2139 establishing additional TSC for determining the conditions under which certain economic activities qualify as contributing substantially to climate change mitigation or climate change adaptation and for determining whether those activities cause no significant harm to any of the other environmental objectives.
[247] Regulation (EU) 2023/2486 supplementing Regulation (EU) 2020/852 of the European Parliament and of the Council by establishing the TSC for determining the conditions under which an economic activity qualifies as contributing substantially to the sustainable use and protection of water and marine resources, to the transition to a circular economy, to pollution prevention and control, or to the protection and restoration of biodiversity and ecosystems and for determining whether that economic activity causes no significant harm to any of the other environmental objectives and amending Commission Delegated Regulation (EU) 2021/2178 as regards specific public disclosures for those economic activities.

framework. These updates aim to improve usability, reduce reporting burdens for undertakings, and facilitate the effective application of the Taxonomy.[248]

To date, the EU Taxonomy covers over 150 activities across 16 economic sectors. For example, renewable energy projects, such as wind, solar, and geothermal energy, as well as energy-efficient technologies like cogeneration of heat and power, are clearly identified as sustainable under this framework.[249]

The SFDR complements the EU Taxonomy by requiring financial market participants and advisers to disclose ESG activities and product and entity level and how they integrate ESG risks into their investment decisions. This Regulation enhances transparency by providing detailed information on the sustainability impacts of financial products, with the aim to attract further capital. Additionally, the SFDR tackles greenwashing as it sets out a clear and standardised list for what is to be considered sustainable.[250]

The CSRD further supports this framework by mandating that companies provide comprehensive reports on their ESG practices and their performance against the EU Taxonomy.[251] For companies involved in energy infrastructure, the CSRD ensures that they disclose relevant information about their sustainability efforts, which supports transparency and investor confidence to align with EU's broader climate and environmental goals. [252]

However, it is important to note that much of this influence remains indirect, operating through mechanisms such as reporting and disclosure requirements. While these tools are essential for improving transparency and guiding capital flows, the full impact on driving large-scale private investment into sustainable energy infrastructure is still evolving. As the use and disclosure of the EU Taxonomy increase, its impact on investment patterns will likely become more visible and apparent over time. Nonetheless, reporting obligations alone provide limited support to overcome an insufficient risk/return position that often deters private investors.

The role of the EU framework in shaping energy infrastructure investments

The EU sustainable finance policy framework provides a clear and standardised method for identifying sustainable projects. The framework helps reduce market fragmentation and increases investor confidence. This is particularly relevant for large-scale energy infrastructure investments, which require significant capital and long-term commitments.

For instance, energy infrastructure projects that align with the EU Taxonomy can benefit from preferential financing terms, such as lower interest rates through green bonds. For example, the study Robeco[253] on the greenium in high-rated euro bonds shows that while green bonds can indeed offer preferential financing terms, such as lower interest rates, the extent of this benefit—known as

[248] Draft Commission Notice (2024) on the interpretation and and implementation of certain legal provisions of the EU Taxonomy Environmental Delegated Act, the EU Taxonomy Climate Delegated Act and the EU Taxonomy Disclosures Delegated Act
[249] Regulation (EU) 2020/852 of the European Parliament and of the Council of 18 June 2020 on the establishment of a framework to facilitate sustainable investment and amending Regulation (EU) 2019/2088.
[250] Regulation (EU) 2019/2088 of the European Parliament and of the Council of 27 November 2019 on sustainability-related disclosures in the financial services sector.
[251] Directive (EU) 2022/2464 of the European Parliament and of the Council of 14 December 2022 amending Regulation (EU) No 537/2014, Directive 2004/109/EC, Directive 2006/43/EC and Directive 2013/34/EU, as regards corporate sustainability reporting.
[252] Directive (EU) 2022/2464 of the European Parliament and of the Council of 14 December 2022 amending Regulation (EU) No 537/2014, Directive 2004/109/EC, Directive 2006/43/EC and Directive 2013/34/EU, as regards corporate sustainability reporting.
[253] Robeco (2024) The greenium in high-rated euro bonds

the greenium—is often modest and may take time to materialise. The research found a median greenium of around 2.2 basis points (bps), where 1 bps equals 0.01%, for government and government-related issuers. Examples include the EIB, EU, and KFW, with relatively stable premiums of 1.2, 1.3, and 1.8 bps, respectively. Further insights from the Bruegel's report[254] underline the variability of greeniums across European sovereign green bond markets. For instance, the greenium ranged from approximately -3 bps in Denmark to -16 bps in Spain, with Germany averaging -3.6 bps. Extreme values were observed, such as 10bps in Netherlands (March 2020) -22 bps in Spain (September 2021) and France (May 2022). These variations highlight that greeniums can depend significantly on the issuer, the maturity of the bond, and market conditions (such as investor demand and perceived risk).

However, this premium is not always present at issuance, particularly in the primary market, where bonds are often priced at a discount to attract investors. The greenium tends to emerge over time in the secondary market, where bonds are traded after their initial issue, and is influenced by factors such as liquidity and the specific issuer. Therefore, while green bonds linked to sustainable energy infrastructure can offer financial advantages, the immediate benefits may vary, and the greenium may not always be significant.

The European Green Bond Standard (EuGB) which will apply from 20th December 2024, following 12 months after the Regulation was entered into force. The EUGB, along with labels for climate and ESG benchmarks use the technical screening criteria specified in the Delegated Acts under the Taxonomy Regulation. This ensures that investors have access to reliable information, helping to facilitate the flow of capital into projects that support the EU's transition to a low-carbon economy. The European Green Bond Standard (EuGB) and labels for climate and ESG benchmarks, use the technical screening criteria specified in the Delegated Acts under EU Taxonomy Regulation to ensure that investors have access to reliable information, to help facilitate the flow of capital into projects that support the EU's transition to a low-carbon economy.[255]

The EU Taxonomy outlines specific energy infrastructure projects that are eligible for sustainable investment, provided they meet the technical screening criteria specified for Substantial Contribution (SC) to climate change mitigation or/and adaptation under the Climate Delegated Act (EU) 2021/2139 and the complementary Climate Delegated Act (EU) 2022/1214 (including electricity generation from fossil gaseous fuels), whilst meeting Do-No-Significant-Harm (DNSH) to the other environmental objectives under the EU Taxonomy at the same time. These include:

- Energy Storage technologies, including electricity, hydrogen, and thermal energy storage, which are essential for integrating renewable energy into the grid. The economic activities in this category have no dedicated NACE code.
- Transmission and Distribution Networks that facilitate the use of renewable and low-carbon energy sources. Relevant NACE codes in particular are D35.22, F42.21, and H49.90,
- Transmissions and distribution of electricity. Relevant NACE codes, in particular are D35.12, D35.13

These projects, that meet the SC and DNSH criteria of the EU Taxonomy, are considered to contribute significantly to the EU's environmental objectives, such as climate change mitigation and adaptation. Taxonomy eligibility refers to projects that fall within the sectors covered by the Taxonomy, indicating

[254] Bruegel (2022) Greeniums in sovereign bond market
[255] Regulation (EU) 2023/2631 of the European Parliament and of the Council of 22 November 2023 on European Green Bonds and optional disclosures for bonds marketed as environmentally sustainable and for sustainability-linked bonds.

their potential to contribute to these objectives. Financial institutions are increasingly able to assess the proportion of their portfolios that are eligible to become SC to climate or environmental objectives under the EU Taxonomy. This creates a guidance and signalling for financial institutions on how to support assets to become taxonomy aligned or chose investment which are already considered aligned. Taxonomy alignment occurs when projects not only meet the eligibility criteria but also adhere fully to the technical and DNSH criteria, confirming their contribution to the EU's long-term climate and environmental goals. Through these incentives, the TSC helps guide capital towards sustainable energy infrastructure investments, supporting the EU's transition to a low-carbon economy The framework helps standardise for companies and financial institutions what energy infrastructure projects and investments should be considered green and aligned with the EU's long-term climate and environmental goals.

The EU sustainable finance policy framework, including the EU Taxonomy, SFDR, and CSRD, helps to shape the financial landscape for energy infrastructure projects. By providing a clear classification system and enhancing transparency through mandatory disclosures, aims to create an institutionalised form of security for investors, thereby mitigating market fragmentation and attracting preferential borrowing rates on financial markets. The framework ensures that investments are directed towards projects that support the EU's transition to a sustainable, low-carbon economy.

Impact of the EU Sustainable Finance Framework on Public Financial Institutions (EU Funds and National Promotional Banks) in Supporting Private Capital Investments in Energy Infrastructure

The EU Taxonomy is increasingly utilised by public funding bodies to ensure that their investments support the EU's climate and environmental goals. The Recovery and Resilience Facility (RRF), for example, allocates 37% of its total investment towards climate-related projects. The RRF uses the Taxonomy's TSC, along with other intervention fields to assess if a project can be earmarked as 100% substantially contributing to climate mitigation or climate adaptation to reach its 37% target.[256] In regard to, energy infrastructure, public investments thereby support the EU's commitment to achieving climate neutrality.

There is also a growing tendency for EU public funding to become increasingly aligned with the EU Taxonomy and its DNSH principle. This alignment will likely bring additional requirements for private capital investments when projects are financed through blended finance constructions, where EU funds are combined with private investment. As the EU embeds the Taxonomy's criteria into its public funding mechanisms, private investors will face stricter environmental and reporting obligations to ensure their co-financed projects meet the same sustainability standards as public investments.

For instance, the InvestEU programme allows financial intermediaries and implementing partners to voluntarily apply the Taxonomy's TSC to track the environmental performance of their investments.[257] However, once the Taxonomy criteria are adopted, intermediaries must report on them consistently, ensuring alignment with the EU's climate goals. This added layer of transparency provides assurance that projects funded through blended finance meet rigorous environmental standards, and it encourages private investors to align their capital with the EU's sustainability objectives to secure EU support. That said, the mandatory reporting requirements under the Taxonomy could increase administrative complexity and impose additional compliance costs for financial intermediaries,

[256] RFF: Annex Climate Coefficients https://commission.europa.eu/system/files/2021-09/nextgenerationeu_green_bond_framework_-_annex_climate_coefficients.pdf
[257] European Commission (2021) Commission notice on the InvestEU programme climate and environmental tracking guidance

particularly in the first years of reporting. Balancing these compliance demands with the need to attract private investment will be key to ensuring the program remains effective without deterring participation.

The EIB is also aligning its financing activities with the EU Taxonomy. In 2024, the EIB updated its eligibility criteria for financing to align more closely with the EU Taxonomy.[258] The updated criteria ensure that projects financed under the EIB's Climate Action and Environmental Sustainability (CA&ES) initiatives are in line with the substantial contribution criteria outlined in the EU Taxonomy's delegated acts where available for a particular sector/economic activity. More specifically regarding energy infrastructure, EIB's energy lending policy (ELP)[259] introduces an emissions standard of 250 g CO2/kWh for power generation, consistent with the EU Taxonomy's 'Do No Significant Harm' (DNSH) threshold for climate change mitigation. This emissions standard has contributed to the phase-out of lending for unabated fossil fuel projects, guiding EIB funding toward projects that meet the Taxonomy's sustainability benchmarks. With regards to network investments in electricity grids, particularly in Eastern European countries, have been classified as green assets under the Taxonomy, stimulating significant lending increases in this sector. In 2021, 35 energy-related projects were signed, with an approved loan amount of €6.3 billion, a substantial rise from the previous year. Additionally, the technical annexe II of the ELP were updated within the 2023 energy lending policy review to continually reflect the adoption of EU taxonomy and provide further clarification for EIB lending criteria.[260] This shift reflects the impact of the EU Taxonomy in promoting green energy investments and aligning the EIB's financing with the EU taxonomy.

Furthermore, the EIB plans to align its Climate Awareness Bond/Sustainability Awareness Bond (CAB/SAB) frameworks with the EU Green Bond Standard (EUGBS), ensuring that its green bonds are allocated to activities meeting the rigorous environmental criteria of the EU Taxonomy. This alignment enhances the credibility of the EIB's reporting on climate action and environmental sustainability financing to align the policy objectives of the EU. The EIB's efforts to integrate the EU Taxonomy into its financing operations demonstrate how public funds can be used to mobilise private capital for sustainable projects.

National promotional banks are also integrating the EU Taxonomy into their financing strategies to ensure alignment with national and EU climate objectives. For instance, Germany's KfW has implemented the 'Klimaschutzoffensive für den Mittelstand', a programme offering climate grants to SMEs that comply with the EU Taxonomy. This approach not only supports national climate goals but also helps mobilise private capital by making sustainable projects more financially attractive through reduced borrowing costs.[261]

Influence of EU Sustainable Finance Framework on Private Financial Institutions in Financing Energy Infrastructure

Banks are increasingly using the EU Taxonomy to guide their lending strategies, particularly in assessing the sustainability of companies' investment plans. A significant development in this area is the introduction of the Green Asset Ratio (GAR), which EU banks are required to disclose from 2024. The GAR measures the proportion of a bank's assets that are aligned with the EU Taxonomy, providing a clearer picture of how much of their financing is directed towards environmentally

[258] EIB (2024) European Investment Bank Climate Action and Environmental Sustainability List of eligible sectors and eligibility criteria.
[259] EIB (2023) Mid-term review of the EIB energy lending policy
[260] EIB (2023) Energy lending policy
[261] Schütze, F., and J. Stede. (2021). "Mobilising Private Capital for the Green Transition: The Role of National Promotional Banks." Journal of Sustainable Finance & Investment.

sustainable activities.[262] Although the GAR increases transparency, it has limitations, such as its exclusion of certain non-EU exposures from its calculation. Nonetheless, the GAR is a key tool in encouraging banks to increase their sustainable financing activities and align more closely with the EU's environmental objectives.

The SFDR aims to promote a shift in institutional investors and asset managers investment strategies. Currently, 56% of EU funds now promoting environmental or social characteristics or having a sustainable investment objective. The assets aligned with the EU Taxonomy are currently a small but growing part of these portfolios. Moreover, the EU's climate benchmarks, which guide investors in decarbonising their portfolios, have already attracted €180 billion in assets under management.[263] These benchmarks are increasingly recognised as valuable tools for investors aiming to meet the EU's climate goals.

The CSRD and the EU Taxonomy are driving changes in corporate behaviour, particularly in how companies approach sustainability. Under the CSRD, companies are required to disclose how their activities align with the EU's sustainability criteria, which influences their investment decisions and strategic planning. This increased transparency makes it easier for investors to identify companies that are committed to sustainable practices, thus directing more capital towards these businesses. This alignment is bridges corporates who are seeking to attract investment from sustainable investors.[264]

3.2. Relevant types of financial instruments and other forms of financial support

3.2.1. Approach

In this section, we conduct a literature review on financial instruments and forms of financial support that play a role to mobilise investments, overcome market barriers, and support the development of energy infrastructure within the European Union. The financial instruments and forms of financial support in scope for this review include those in the Financial Regulation 2024/2509: loans, guarantees, equity or quasi-equity and other risk-sharing instruments other than investments in dedicated investment vehicles which are provided directly to final recipients or through financial intermediaries, allowing for the sharing of a defined risk between two or more entities.[265] Additionally, we consider grants, technical assistance and bonds. This is to provide an extensive coverage of all relevant financing to energy infrastructure related projects.

Clarification note

The following sections extensively examine all financial instrument options relevant to financing energy infrastructure in the EU in order to provide a comprehensive understanding of how the different sorts of energy infrastructure within the scope is currently financed. This approach ensures that all potential sources and mechanisms are considered, offering a complete picture of

[262] S&P Global (2024). *Your Three Minutes in Climate Disclosure: Benefits and Limitations of the Green Asset Ratio for EU Banks.* Available at: https://www.spglobal.com/ratings/en/research/articles/240411-your-three-minutes-in-climate-disclosure-benefits-and-limitations-of-the-green-asset-ratio-for-eu-banks-13067588

[263] European Commission (2024). *The EU Taxonomy's Uptake on the Ground: How the Sustainable Finance Disclosure Regulation (SFDR) is Shaping Investment Strategies.* https://finance.ec.europa.eu/sustainable-finance/tools-and-standards/eu-taxonomy-sustainable-activities/eu-taxonomys-uptake-ground_en

[264] European Commission (2023). *Corporate Sustainability Reporting Directive (CSRD).* https://ec.europa.eu/info/business-economy-euro/company-reporting-and-auditing/company-reporting/corporate-sustainability-reporting_en

[265] Regulation 2049/2509 of the European Parliament and of the Council of 23 September 2024 on the financial rules applicable to the general budget of the Union.

the current financing landscape. While all instruments are reviewed, certain instruments are particularly significant from the perspective of EU public funding. These include guarantees, technical assistance, grants, blended finance, and green bonds. These instruments can effectively leverage the EU budget and serve as catalysts to attract additional funding from private sector entities and other public sector actors, such as National Promotional Banks, the EIB, and the EIF.
It is important to note, however, that equity and debt remain central to most investors' strategies, serving as the primary means of financing energy infrastructure. Instruments like grants, guarantees, and blended finance, while highly valuable, primarily act as additional incentives to enhance project viability and address specific financing gaps.

This overview table below summarises the key characteristics of each financial instrument and form of support in scope to support the analysis in the subsequent sections.

Table 3-2 Financial instruments and support measures overview

Financial Instrument/ Support Measure	Overview and Characteristics
Category 1: Grants and blended finance	Grants are non-repayable financial contributions provided by public authorities to support specific projects, reducing the upfront cost burden and making them more financially attractive. Blended finance facility is a cooperation framework established between a public entity or other public finance institutions with a view to combining non-repayable forms of support and/or financial instruments and/or budgetary guarantees from the budget and repayable forms of support from development or other public finance institutions, as well as from private-sector finance institutions and private-sector investors.
Category 2: Equity and quasi-equity	Equity involves providing capital in exchange for ownership interests in a company, used for long-term investments and supporting the growth of businesses, especially in high-risk sectors like renewable energy.
	Quasi-equity is a type of financing that ranks between equity and debt, including subordinated loans, venture debt, convertible bonds, and preferred stocks.
Category 3: Debt/guarantees	Loans provide upfront capital necessary for project implementation, which is to be repaid (with interest) over a specified period. This category also includes concessional loans from public sources, such as the EU or EIB, which offer more favourable terms to support large-scale infrastructure projects
	Guarantees cover a borrower's debt in case of default, reducing the risk for lenders and making it easier for borrowers to secure financing.
	Project bonds are fixed-income securities issued by governments or corporations to generate capital. Green bonds are committed to financing or re-financing investments, projects, expenditure or assets helping to address climate and environmental issues.
Category 4: Technical Assistance	Technical assistance provides advisory services to improve capacities and skills in business modelling, financial planning, risk assessment, and project development.

The literature review assessed existing research on financial instruments and other forms of support for financing energy infrastructure projects. The study team identified best practices for financial instrument support by examining key factors such as development stage, risk and maturity profiles, and ownership structures. This review drew on a diverse range of sources, including academic literature, regulatory and policy reports, as well as publications from think tanks, industry bodies, and NGOs. The focus was on evidence-based research that review financial instruments and support measures for the energy infrastructure categories as covered in Section 2. Investment needs of infrastructure categories (TEN-E & electricity non-cross-border transmission & distribution).

The literature review focused on the effectiveness of various financial instruments and forms of support within different energy infrastructure categories along the project development process. The evaluation considers factors such as: Development stage of the infrastructure; Volume of financing required; Risk and maturity profiles; Ownership structures of energy infrastructure companies/projects (public or private)

These components are addressed within the following **research questions** which guide the literature review collection and analysis.

- How do different financial instruments and support measures perform in supporting energy infrastructure projects at various **stages of development (project planning – pre-FID – to full commercial implementation of a project**?)
- Which financial instruments and support measures are most effective for meeting varying levels of **financing volumes** required in energy infrastructure projects?
- What is the effectiveness of different financial instruments and support measures in managing **high and low-risk** energy infrastructure projects?
- How do financial instruments and other forms of financial support differ in their effectiveness for **mature and immature** energy infrastructure projects (immature being the newer technologies with higher risks, such as hydrogen or CCS)?
- Which financial instruments and other financial support measures are better suited for energy infrastructure projects within the **EU compared to neighbouring countries**?
- How do different financial instruments and support measures address **operational (OPEX) and capital (CAPEX)** expenditure considerations in energy infrastructure financing?
- What role does the **ownership structure** of TEN-E infrastructure play in determining the effectiveness of financial instruments and other forms of financial support?

Methodology

An Excel database was created to capture relevant findings and analysis of the identified literature per research question, categorised by the type of financial instrument or form of EU support. The top row of the Excel sheet included all the research questions to capture relevant findings from various sources. It also gathered information per paper on the author, year, title, source, type of financial instrument or form of EU support discussed, an overview and characteristics of the support as defined in the paper, the type of energy infrastructure addressed, and the costs (studies or construction) covered by the financial instruments or form of EU support. General strengths and weaknesses mentioned for each financial instrument or form of support were also included.

Each column of the Excel sheet indicated the financial instrument and the source from which the information was collected. Additional rows were added if a paper covered more than one financial instrument or form of EU support, allowing for the literature review data to be filtered by type of financial instrument or EU support and research question. Additional information on the background and context of each paper was gathered to ensure the literature findings were considered within the review's scope. The goal was to analyse financial instruments and support measures to provide conclusions, ensuring the scope and focus of the papers were kept in mind for valid analysis and conclusions.

Literature collection

To ensure a broad and inclusive review, the literature search included terms related to types of financial instruments and support: “financing”, “funding”, “public funding”, “investments”, “financial instruments”, “technical assistance”, “loans”, “guarantees”, “(quasi-)equity”, etc., combined with energy-related terms, such as: “energy infrastructure”, “renewable energy”, “energy”, “TEN-E”, “PCI”, “PMI”. The search aimed to identify literature addressing a wide range of financial support and instruments related to energy infrastructure and broader energy projects.

Types of sources considered included academic literature, regulatory/policy reports and reports from industry, thanks tanks and NGOs. After completing the initial online search, the study team employed a snowballing approach. This involved examining the reference lists of the reviewed studies or searching an additional string of terms to identify and extract additional relevant literature. To ensure no relevant study was omitted, we also relied on the collective knowledge of the project team members and our in-house senior technical experts. These experts are well-versed in publications, projects, initiatives, and other contributions specifically related to EU support and financial instruments for energy infrastructure.

The Table in Annex A.4 provides an overview of the literature selected and analyses for Section 3.2. The table indicates the types of financial instruments or forms of EU support discussed and analysed in each piece of research. Papers covering more than one type of financial instrument were allocated additional rows in the Excel database, with analysis specific to each instrument or support type based on the research questions.

The following section provides a comprehensive analysis of various financial instruments and support measures for energy infrastructure projects. It covers grants, equity, quasi-equity, debt instrument such as, loans and bonds, and guarantee products. Additionally, this section reviews the provision of technical assistance for energy infrastructure projects within the EU. We present a summary of our findings in response to the Research Questions for each type of financial instrument and support measure at the end of each sub-chapter.

3.2.2. Category 1: Grants and blended finance

Overview and characteristics of grants and blended finance

Grants are non-repayable financial contributions provided by public authorities to support projects, thereby reducing the upfront cost burden and making them more feasible.[266] Grants are awarded based on transparent criteria and can be used in combination with other financial instruments to maximise their impact. However, when financial support from different EU programmes is combined, strict rules are applied to avoid double-funding. They are typically used to support early-stage R&D, demonstration projects, studies and other high-risk initiatives that may not yet be commercially viable. Additionally, they are typically used as a blended finance instrument.

Grants under the CEF programme are an example of how grants are blended with public financing, such as loans from the EIB, National Promotional Banks (NPBs),and other public financial institutions, as well as private-sector finance institutions and investors.[267] Blended finance combines a non-repayable component with a repayable one, enabling public policy objectives that cannot be achieved through market dynamics or legislation alone. While blending attracts private investment by leveraging public contributions, CEF-Energy does not currently have a formal blending facility. Instead, it uses a de facto blending approach, where project promoters independently combine CEF grants with other financial instruments, such as EIB loans or national funding, to meet their financing needs. Unlike formal blending facilities, which integrate grants and repayable instruments into a single financing package, this de facto approach offers flexibility but requires promoters to navigate more complex funding arrangements.

In contrast, CEF Transport (CEF-T) has a formalised Blending Facility launched in 2019, integrating EU grants with financing from the EIB, NPBs, and private investors. A prominent example is the Alternative Fuels Infrastructure Facility (AFIF), which demonstrates how blending can attract private investment and enhance public contributions. [268] AFIF combines EU grants with long-term financing to support the deployment of installations for hydrogen use in transport sector and electric vehicle charging infrastructure across Europe. These projects often face financial barriers, such as high upfront costs and uncertain revenue streams, which deter private investment in the absence of public support. By de-risking these investments, blending ensures the implementation of critical infrastructure that aligns with EU climate and sustainability goals.

Evidence from the mid-term review of CEF transport by ELTI suggests that without blending, many alternative fuel infrastructure projects would struggle to secure financing, particularly due to the early-stage market for hydrogen and electric vehicle infrastructure. [269] AFIF has unlocked over €1.5 billion in EU grants to co-finance projects requiring private-sector contributions, ensuring the development of infrastructure along the Trans-European Transport Network (TEN-T).[270] The counterfactual indicates that projects relying solely on market forces or traditional loans would likely have faced delays or been infeasible. However, the success of a blended finance facility, like AFIF, applicability for CEF-E depends on several factors, including the specific financial and technological challenges of each sector, regulatory frameworks, and the availability of co-financing partners. While

[266] European Parliament (2017) Research for REGI Committee – Financial instruments for energy efficiency and renewable energy
[267] OECD (2017) Financial instruments in Practice: Uptake and Limitations
[268] Polzin & Sanders (2020) How to finance the transition to low-carbon energy in Europe?
[269] ELTI (2024) CEF Transport “alternative fuels infrastructure facility (AFIF)”
[270] CINEA (2023) CEF Transport Alternative Fuels Infrastructure Facility call for proposal

the AFIF model offers a promising framework, its direct applicability to CEF-Energy projects would require careful assessment and adaptation to sector-specific conditions.

The role of grants/blended finance in supporting energy infrastructure development across different stages

Grants are particularly valuable in two particular situations. Firstly, during the early stages of project development, covering the costs of feasibility studies and initial R&D. Secondly, during financial downturns or periods or when projects struggle to attract private investment – whether due to non-investment grade credit ratings, higher perceived default risk, or other barriers to investments—grants provide additional financial stability and enhance project viability. Programmes like the CEF have supported energy infrastructure by bridging financing gaps and accelerating permitting processes. The last-resort principle of the CEF-E fund ensures grants are deployed only when private or other public financing options have been exhausted. This section explores how grants are used to support energy infrastructure projects at various stages of development and under different financial conditions.

Grants in early stages of development

In early stages of energy infrastructure projects, such as feasibility studies and initial development phases, grants are beneficial to cover costs, which private financiers are hesitant to engage in. A non-repayable structure makes grants ideal for feasibility studies or initial development stages where market dynamics are less applicable, and risks are higher. Public grants play a significant role in the early stages of development, where they help cover costs of initial development and demonstration projects, bridging the gap until the technology becomes commercially viable. This is particularly important for new and less established infrastructure and technologies, ensuring that they receive the necessary support to move forward.[271]

The Investors Dialogue for Energy (ID-E) Working Group on Transmission and Distribution (NB Stakeholders opinion and NOT the EC's - WG 2 T&D WGR N.3)[272] [273] notes that grants are more frequently used than loans in the initial development stages to co-finance studies and accelerate project kick-starts. They incentivise beneficiaries to pursue projects less attractive financially but necessary for achieving policy goals.

Grants for high-risk and CAPEX-intensive energy infrastructure projects

Grants are relevant for the development of high-risk, capital-intensive energy infrastructure projects, such as but not limited to, CO_2 transport and storage infrastructure, hydrogen, transmission with significant cross-border impact or transmission lines with offshore generation. By providing non-repayable funding, grants reduce the financial risk for private investors, making it easier for these projects to secure additional financing. This initial support signals project viability and can attract further private capital or public co-financing. Grants enable high-CAPEX projects to move forward by covering some of the substantial upfront costs, ensuring that transformative but risky infrastructure projects receive the necessary support to progress toward commercial viability.[274]

Grants during financial downturns or periods of non-investment grade credit ratings

[271] Polzin & Sanders (2020) How to finance the transition to low-carbon energy in Europe?
[272] ID-E (2023) WG2 Financing models for transmission & distribution (WG2 meeting report 2)
[273] ID-E (2023) WG3 Availability of financial instruments for transmission & distribution (WG2 meeting report 3)
[274] Polzin & Sanders (2020) How to finance the transition to low-carbon energy in Europe?

During financial downturns or periods of non-investment grade credit ratings, grants are seen as essential. Non-investment grade credit ratings, often referred to as "junk" status, indicate a higher risk of default, making traditional financing options more expensive and harder to secure. Grants provide financial stability by offering non-repayable funds, reducing the immediate financial burden on projects and organisations. In times of financial crisis or when TSOs are highly leveraged, meaning they have a significant amount of debt compared to equity, grants can ease the difficulty of raising the necessary equity for a project. They help stabilise electricity transmission fees and prices for consumers. Some ID-E Working Group Members on Transmission and Distribution[275] CAPEX-intensive grid solutions with higher socio-economic benefits, which private financiers might typically avoid due to the higher costs involved. They highlighted this is particularly important in times of uncertainty, such as during inflation, energy price fluctuations, and shortages of equipment parts and raw materials. However, while grants provide these critical advantages, they typically do not enhance the return on equity for developers.[276]

Grants are direct subsidies from the EU or by Member States and are therefore more costly compared to other financial instruments and support measure that rely on private investors or public funding mechanisms that can generate returns. Grants should be used in a cautious and targeted manner to support projects where the market cannot provide the required financial means in the necessary volume or speed. This is particularly relevant as EU grants can accelerate permitting processes and provide financing solutions to contribute to priority energy infrastructure corridors, enhanced energy security and supporting MS climate and environmental policies.[277]

Effectiveness of grants/blended finance in meeting the financing needs of energy infrastructure projects

Grants play a central role in this financing ecosystem but are non-refundable and must be used judiciously and often in limited volumes. Typically, they play a role to catalyse further financing volumes by correcting market failures to reach particular policy goals. The last resort principle of the CEF-E fund aligns with this by ensuring that grants are deployed only when private or other public financing options have been exhausted. This approach ensures that grants are reserved for high-impact projects that are essential for EU energy objectives but face significant financial barriers, thereby maximizing the fund's effectiveness and avoiding market distortion.

Grants as catalysts for larger financing volumes

Grants often serve as a component in mixed financing strategies for large-scale energy infrastructure projects. According to the Bruegel Report (2024)[278], significant energy infrastructure projects typically rely on blended finance including a combination of grant funding, equity, and debt. Although grants from the EU constitute a smaller portion of the overall funding landscape, they are instrumental in attracting private sector investments by reducing overall financial risks and enhancing project feasibility.

For example, grants can ease the process of securing debt financing by acting as a form of equity. Financial institutions often require developers to provide a portion of equity (usually 10-20% of the project value) to secure the remaining capital as debt. For highly leveraged TSOs, grants can replace

[275] ID-E (2023) WG3 Availability of financial instruments for transmission & distribution (WG2 meeting report 3)
[276] ID-E(2023) WG3 Availability of financial instruments for transmission & distribution (WG2 meeting report 3)
[277] ERT (2024) Strengthening Europe's energy infrastructure
[278] Bruegel (2024) Accelerating strategic investment in the European Union beyond 2026

or reduce the need for this equity, facilitating the necessary debt financing.[279] This strategic use of grants not only alleviates funding constraints but also ensures that projects of interest proceeds.

Cost-effectiveness and market-based financing

As grants represent direct subsidies at the national or EU level, they are costly and should target situations where market mechanisms fail to provide the required financial volumes or speed.

The European Union Working Group on T&D mentioned, grants are particularly important for financing T&D projects to support the modernisation of the electricity grids, when there is a limited provision of financing from the private sector. [280] For instance, in their recent report on availability of financial instruments, the Working Group emphasised how grants can initiate projects in less commercially attractive areas or those requiring significant upfront capital.[281] However, due to the high investment needs of the T&D sector, a shift towards more market-based financing forms is necessary. This includes using debt, de-risking instruments, and equity, which although smaller grant volumes play a role in attracting private financing by reducing risks and creating a signalling effect.

The report "Making the TEN-E Regulation compatible with the Green Deal: Eligibility, selection, and cost allocation for PCIs"[282] provides detailed recommendations on the strategic use of grants. It suggests that grants should be focused on projects directly aligned with decarbonisation objectives, such as those involving renewable gases including hydrogen. The report recommended that projects prioritised for CEF-E funding should focus on those enabling a transition to low-carbon energy, especially where existing infrastructure (like gas pipelines) can be repurposed for transporting renewable gases or hydrogen. While electricity infrastructure remains essential, the report advocates focusing grant resources on these areas where private sector investment may fall short, and where such projects offer substantial greenhouse gas reductions that align with the EU's broader decarbonisation targets. [283] Furthermore, grants should be used to bridge affordability gaps, particularly in scenarios where market mechanisms are insufficient or where TSOs face significant financial constraints.[284]

Effectiveness of grants/blended finance for high and low risk energy infrastructure projects.

Grants are more suited for high-risk energy infrastructure projects by supporting those that are financially non-viable through private investment alone.[285] By reducing project risks and financial burdens, grants make projects more appealing to private investors.[286] Initial funding through grants can attract private investors to high-risk or early-stage projects and they reduce the financial burden on companies, encouraging innovation and digitalisation.

The European Clean Hydrogen Alliance mentions grant financing plays a role in advancing high-risk hydrogen projects by covering initial capital outlays, which reduces the financial burden on

[279] Roland and Berger (2011) The structuring and financing of energy infrastructure projects, financing gap and recommendations regarding the new TEN-E financial instrument
[280] ID-E (2023) WG2 Financing models for transmission & distribution (WG2 meeting report 2)
[281] ID-E (2023) WG2 Financing models for transmission & distribution (WG2 meeting report 2)
[282] Schittekatte, et al. (2021) Making the TEN-E regulation compatible with the Green Deal: Eligibility, selection, and cost allocation for PCIs
[283] Schittekatte, et al. (2021) Making the TEN-E regulation compatible with the Green Deal: Eligibility, selection, and cost allocation for PCIs
[284] Schittekatte, et al. (2021) Making the TEN-E regulation compatible with the Green Deal: Eligibility, selection, and cost allocation for PCIs
[285] European Parliament (2017) Research for REGI Committee – Financial instruments for energy efficiency and renewable energy
[286] OECD (2017) Financial instruments in Practice: Uptake and Limitations

infrastructure developers and lowers tariff costs for consumers. Grants are also effective in supporting early-stage studies, allowing projects to assess feasibility and address technical uncertainties, improving their appeal to future investors. However, they also note dependency on grants may reduce incentives for cost discipline and efficiency, potentially impacting long-term market-driven investment dynamics.[287]

Research for the REGI Committee has highlighted that grants can reduce the perceived risk and make high-risk projects more attractive to investors and developers.[288] Additionally, grants are particularly suitable for projects and technologies that are in the early stages of development, such as RD&D activities and pilot projects needing significant funding to move from concept to market.[289] For high-risk innovative projects, grants provide funding and support, ensuring their viability and success.[290]

Effectiveness of grants/blended finance for mature/immature energy infrastructure projects

Grants are typically used to support emerging, high-risk technologies and projects in their early stages. However, they can also be applied to accelerate the deployment of mature technologies when rapid market expansion is necessary, though this is less common. For **mature projects**, grants are used to scale up and expand proven technologies and solutions, thereby facilitating large-scale infrastructure developments.[291] For instance, grants can assist in the implementation phase by reducing the equity required and stabilising transmission fees, as seen in various projects under TEN-E.[292]

On the other hand, grants are particularly useful for **immature projects**, which include early-stage research, development, and pilot projects that bring new technologies to market. Grants provide the necessary funding for feasibility studies and the initial phases of development, making early-stage projects more attractive to private investors.[293]

Furthermore, the combination of grants with other financial instruments under shared management funds has been effective in supporting both mature and immature projects.[294] In the 2021-2027 MFF programming period, a guarantee financial instrument can be combined with grants in the form of capital rebates, provided they cover distinct eligible expenditures. This structure prevents double-funding by ensuring that the grant portion is not used to reimburse the loan. Instead, the investment is split between the guaranteed loan and the capital rebate. [295] This approach allows grants to provide the initial push for innovation and risk mitigation, while the guaranteed loan can support the remaining eligible expenses, facilitating a smooth transition to other financial instruments as projects mature and become more financially viable.

[287] European Clean Hydrogen Alliance (2024) Learnbook: financing of hydrogen infrastructure
[288] European Parliament (2017) Research for REGI Committee – Financial instruments for energy efficiency and renewable energy
[289] Polzin & Sanders (2020) How to finance the transition to low-carbon energy in Europe?
[290] Bruegel (2024) Accelerating strategic investment in the European Union beyond 2026
[291] Bruegel (2024) Accelerating strategic investment in the European Union beyond 2026
[292] Roland and Berger (2011) The structuring and financing of energy infrastructure projects, financing gap and recommendations regarding the new TEN-E financial instrument
[293] Polzin & Sanders (2020) How to finance the transition to low-carbon energy in Europe?
[294] European Commission fi compass (2021) Combination of financial instruments and grants
[295] European Commission fi compass (2021) Combination of financial instruments and grants

Effectiveness of grants/blended finance in supporting EU and cross-border energy infrastructure projects

Cross-border European energy infrastructure projects, connect the EU with non-EU countries, advancing the energy and climate policy goals of the Union. This section explores how grants address the specific challenges associated with cross-border projects, particularly those involving non-commercial externalities.

Addressing non-commercial externalities

Non-commercial externalities refer to benefits or costs not directly reflected in market prices. In cross-border energy infrastructure, these can significantly impact the project's feasibility and attractiveness to private investors.

Security of Supply (SoS) is a prime example. Ensuring a reliable energy supply is crucial for national security and economic stability, but it is not always directly profitable. For instance, building an energy interconnector may enhance supply reliability for both countries, but the financial returns may not justify the investment on a purely commercial basis.[296]

Future developments to increase capacity of energy infrastructure can also represent a significant non-commercial externality. Changes in supply and demand dynamics can affect SoS, and these changes are often difficult to predict and quantify. New energy infrastructure projects might be essential to accommodate future renewable energy production or changes in consumption patterns, but the long-term benefits are not always immediately quantifiable, making such projects less attractive to private investors seeking predictable returns.

Projects affected by non-commercial externalities are complex and challenging to finance through traditional market mechanisms alone. Grants bridge this gap by covering costs that cannot be justified commercially, making it feasible to undergo projects that might otherwise be financially unattractive due to inherent risks and uncertainties.[297]

Role of grants in cross-border projects

Grants are particularly effective in supporting cross-border energy infrastructure projects because they address the unique financing challenges associated with coordinating CAPEX across multiple countries and regulatory frameworks. EU support is even more essential in these cases, as such projects often integrate renewable energy sources and connect markets, requiring substantial early-stage funding to attract private investors and facilitate cross-national cooperation. [298]

The use of grants for large cross-border energy infrastructure projects, such as electricity interconnectors, where the costs and benefits are unevenly distributed across participating countries can be particularly effective. In these projects, one country may bear the majority of the construction costs, while another may benefit more from the project's outcomes, such as improved energy security or reduced energy costs. Grants help to balance this disparity by providing financial support to the countries incurring higher costs, ensuring a more equitable distribution of the financial burden. This

[296] Roland and Berger (2011) The structuring and financing of energy infrastructure projects, financing gap and recommendations regarding the new TEN-E financial instrument
[297] Roland and Berger (2011) The structuring and financing of energy infrastructure projects, financing gap and recommendations regarding the new TEN-E financial instrument
[298] Polzin & Sanders (2020) How to finance the transition to low-carbon energy in Europe?

financial assistance facilitates negotiations and the implementation of these complex, cross-border projects, making them more viable and helping to achieve regional energy integration goals.[299]

Furthermore, the provisions of grants support social/environmental welfare as they ensure non-commercial benefits are considered in project evaluations. Using methodologies like Cost-Benefit Analysis (CBA) and Multi-Criteria Analysis (MCA), grants ensure projects are assessed on economic, social, and environmental impacts, addressing social welfare concerns more effectively than purely market-based solutions.[300]

Role of grants/blended finance in addressing CAPEX and OPEX financing considerations in energy infrastructure

Currently, grants primarily address CAPEX rather than OPEX in energy infrastructure related projects. This focus has both benefits and limitations that impact the long-term sustainability and efficiency of energy infrastructure projects.

CAPEX focus of grants

Typically, grants cover the initial costs of constructing and developing energy infrastructure, to reduce the capital burden on project developers. This financial support makes large-scale and high-risk projects more financially viable, particularly those aligned with EU policy objectives and efficiency goals.[301]

However, often grants do not extend to ongoing OPEX or potential future replacement costs, posing challenges for projects requiring continuous maintenance, upgrades, and operational management. For instance, while funding might be available for the construction of a new renewable energy facility, the ongoing costs of operation and maintenance remain a financial strain over time.[302]

Bridging capacity gaps and initial operational support

Grants are particularly suitable for addressing capacity issues in energy infrastructure. These issues arise when there is a need to increase the capacity of existing infrastructure to meet future demand, even if full utilisation of the new capacity will only occur at a later stage. For example, expanding a power grid to handle greater volumes in the future requires significant upfront investment. Grants can finance these future-oriented upgrades, ensuring that the infrastructure can meet anticipated demand increases. This strategic use of funding acts as a short-term bridging solution until more cost-efficient measures or additional investments are secured.[303]

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[299] Roland and Berger (2011) The structuring and financing of energy infrastructure projects, financing gap and recommendations regarding the new TEN-E financial instrument
[300] Selei, A and Tóth, B (2022) A modelling-based assessment of EU supported natural gas projects of common interest
[301] European Parliament (2017) Research for REGI Committee – Financial instruments for energy efficiency and renewable energy
[302] ID-E (2023) WG2 Financing models for transmission & distribution (WG2 meeting report 2)
[303] Roland and Berger (2011) The structuring and financing of energy infrastructure projects, financing gap and recommendations regarding the new TEN-E financial instrument

Addressing OPEX challenges

While ongoing OPEX are generally not covered by EU grants, operational support in the design and planning phase of a project is often available. These grants can fund essential early-stage activities such as feasibility studies, energy audits, and the development of projects to a bankable stage. This early support is crucial for laying the groundwork for future CAPEX and ensuring that projects are well-prepared to attract additional investment, thus facilitating a smooth transition from planning to implementation.[304]

By funding preliminary studies and capacity advancements, grants can create a foundation for projects long-term success. However, ongoing OPEX needs require complementary financial mechanisms to ensure sustainable operation and maintenance of energy infrastructure projects over time. While primarily geared towards covering CAPEX, the use of grants in initial operational support could play an increasing role in energy infrastructure funding.

Lastly, the regulatory framework for TEN-E infrastructure has a direct influence on the cost-effectiveness and distribution of EU grants. While grants, concessional loans and risk guarantees are viewed as effective by TSOs and DSOs for fostering investment without immediately raising grid tariffs, these instruments must be carefully balanced against the potential administrative and public cost implications they carry. Specifically, assets funded by grants are excluded from the Regulatory Asset Base (RAB), which can prevent immediate increases in grid tariffs and thereby reduce the direct financial impact on consumers.[305] However, grants are financed by the EU budget—funded by taxpayers across Member States—which raises the question of whether EU-wide taxpayers should bear the costs of investments that primarily benefit network users in certain regions.

In contrast, RAB-funded investments are recovered through network tariffs paid by the TSO/DSO's users, directly linking infrastructure costs to those who benefit from it but potentially increasing consumer tariffs. This approach shifts the financial burden to the network's direct users rather than EU taxpayers. Additionally, RAB returns offer a predictable revenue stream, which can be beneficial for long-term financing stability.

An example of grant financing in TSO infrastructure is the €719.7 million grant awarded to support Phase II of synchronising the Baltic States with the Continental European Network. Unlike RAB-funded investments, which are recovered through tariffs paid only by local network users, grants in this context support the broader EU goal of energy security by addressing the cross-border nature of this project. Synchronisation of the Baltic grid reduces reliance on non-EU energy sources and stabilises grid resilience EU-wide. This level of international coordination and shared benefit aligns with EU taxpayers' contributions, supporting security and resilience for all Member States rather than placing the burden solely on regional consumers.[306]

According to our analysis, infrastructure operators, particularly those under regulated returns frameworks, may find EU or other national public grants less attractive due to the impact on their regulated returns. When assets funded through grants are excluded from the RAB, they do not contribute to these returns, which can affect revenue generation via grid tariffs. An example of where this can create disincentives is in how project CAPEX and OPEX are covered by grants. While grants typically cover CAPEX, they do not account for ongoing OPEX or future replacement costs. Such costs are not remunerated within the RAB model, potentially creating a disincentive for infrastructure

[304] ID-E (2023) WG3 Availability of financial instruments for transmission & distribution (WG2 meeting report 3)
[305] ID-E (2023) WG2 Financing models for transmission & distribution (WG2 meeting report 2)
[306] Connecting Europe Facility – Energy (2021) Supported actions 2014-2020

operators to seek grant funding for grid assets requiring sustained operational investment.[307] Nonetheless, the full recovery of investments through regulated mechanisms may become increasingly challenging in the future, given the rising investment needs in electricity transmission and distribution. Potential societal pushback on rising grid costs can lead to broader concerns about affordability and public acceptance of infrastructure funding models. Finally, the administrative burden of applying for and securing EU grants, which is often complex, time-consuming, and resource-intensive, further deters some infrastructure operators from pursuing this form of financing.[308]

The impact of ownership structure on the effectiveness of grants and blended finance for energy infrastructure projects

Both publicly-owned and privately-owned infrastructure projects benefit similarly from grants and blended finance. Thus, these instruments can be similarly effective for projects under both publicy-owned and privately-owned infrastructure operators. We note also that EU funds generally do not distinguish based on ownership structure, rather they consider in some cases the regulatory framework for infrastructural projects.

Table 3-3 Grants and blended finance findings overview

Grants	
RQ.1 Stages of energy infrastructure development	Grants/blended finance can be targeted at early-stage energy projects to cover costs related to feasibility studies and initial development, particularly when private investment is limited due to high risk or capex-intensive projects. During financial downturns: Grants/blended finance can be used to stabilise projects facing funding challenges, ensuring their continuation and viability.
RQ.2 Effectiveness to meet varying volumes of financing	Grants/blended finance can be used strategically as catalysts to unlock larger volumes of financing by correcting market failures. Although more limited in volume, they should aim to reduce risks and enhancing project feasibility, particularly in mixed financing strategies for large-scale projects.
RQ.3 High vs Low risk energy infrastructure projects	Grants/blended finance typically focus on high-risk projects that are financially non-viable through private investment alone. They reduce financial risks, making projects more appealing to private investors.
RQ.4 Mature vs immature energy infrastructure projects	Mature and immature projects: Grants/blended finance are typically deployed strategically to support both mature and immature energy infrastructure projects. For mature projects, grants can help scale up and expand proven technologies, reducing the equity required and stabilising transmission fees. For immature projects, grants can focus on funding early-stage R&D, feasibility studies, and pilot projects, making them more attractive to private investors.
RQ.5 EU vs neighbouring countries	Cross-border projects: Grants/blended finance can be used for cross-border energy infrastructure projects, such as those involving the EU and non-EU countries e.g. as included in the PMI list of CEF. They address non-commercial externalities, such as security of supply and social/environmental welfare, making these complex projects more financially feasible.
RQ.6 CAPEX or OPEX	Primarily CAPEX but to further support OPEX: Grants/blended finance typically cover CAPEX, such as initial construction and development costs. They can also provide an increasing role to support initial operational support for activities like feasibility studies but generally should not be relied upon for ongoing OPEX needs.

[307] ID-E (2023) WG2 Financing models for transmission & distribution (WG2 meeting report 2)
[308] ID-E (2023) WG2 Financing models for transmission & distribution (WG2 meeting report 2)

Grants	
RQ.7 Impact of ownership structure	Public and private ownership: Grants can be effective for publicly owned or privately owned energy infrastructure projects to lower risk, whilst benefit from reduced credit risk without negatively impacting their revenue.

3.2.3. Category 2: Equity and quasi-equity

Overview and Characteristics of Equity

Equity financing involves providing capital in exchange for ownership stakes in a company. This type of financing supports both the growth of new projects and the expansion of existing infrastructure. Equity financing can be sourced internally from a company's own cash flows or externally from outside investors. These different forms of equity financing play distinct roles depending on the scale and stability of the investment required[309]

Internal equity is typically derived from a company's own cash flows and is often sufficient for funding basic infrastructure investments, particularly in stable markets. This is a common approach among TSOs in Europe, allowing these entities to rely on internal funding[310]

In contrast, *external equity* is raised from outside investors and is essential for financing large-scale projects. This form of equity is particularly important when the investment required exceeds what can be covered by internal resources. External investors, such as pension funds, infrastructure funds, and insurance companies, are attracted to these projects due to their potential for long-term, low risk returns[311]

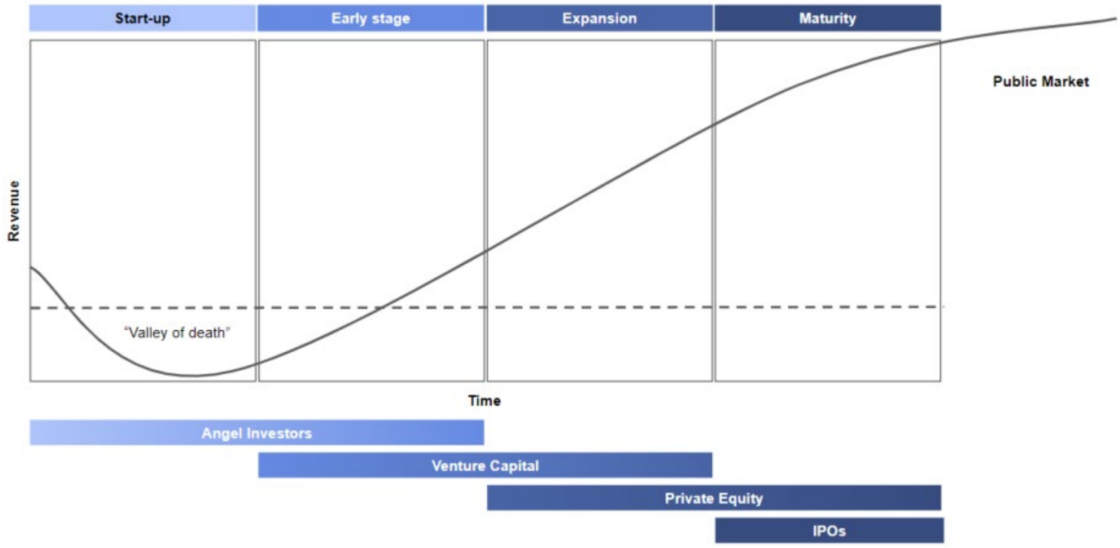
Sources of equity include angel investors, venture capitalists, private equity, IPOs, pension funds, infrastructure funds, insurance companies and quasi-equity options like subordinated loans and convertible bonds.

The role of equity in supporting energy infrastructure development across different stages

Sources of equity typically varies depending on the project stage. As projects evolve from start-up phases through to maturity, the type of equity financing that is most appropriate also changes. The graph provided by I-DE illustrates this cycle, highlighting the involvement of different types of investors at various stages.

[309] European Parliament (2017) Research for REGI Committee – Financial instruments for energy efficiency and renewable energy
[310] Roland and Berger (2011) The structuring and financing of energy infrastructure projects, financing gap and recommendations regarding the new TEN-E financial instrument
[311] Roland and Berger (2011) The structuring and financing of energy infrastructure projects, financing gap and recommendations regarding the new TEN-E financial instrument

Figure 3-2 Development stages of energy infrastructure technology by type of equity investors



* Source: ID-E (2022)[312]

Early develop and initial capital investment

During the early stages of energy infrastructure projects, particularly when transitioning from R&D to commercialisation, public equity plays a crucial role. This phase, often referred to as the "valley of death," is marked by low revenue generation and high capital needs. Public equity, along with support from angel investors, is essential for helping innovative companies navigate this challenging period and move towards growth.[313]

External equity financing is particularly effective in the early development and expansion phases, providing the necessary capital to transition projects from demonstration to commercial readiness. This form of financing is especially valuable for high-tech and innovative firms, such as those in the seed, start-up or early-stage phases, where the risks are typically too high for traditional lenders to engage.[314]

Moreover, external equity is required for covering large upfront costs during the construction phase, a hurdle when revenues have not yet been realised. By securing funds for R&D and commercialisation, external equity enables clean energy companies to progress through these early stages, ensuring that innovative technologies reach the market and begin generating revenue.[315] As projects evolve into the expansion phase, venture capital becomes increasingly significant. Venture capitalists provide financial support at this stage, capitalising on the growth potential of the project as it begins to scale, which further attracts investment and propels the project towards maturity.[316]

Later stage of development and upgrade

[312] ID-E (2022) Equity and quasi-equity schemes for transmission and distribution (WG2 meeting report 5)
[313] Polzin & Sanders (2020) How to finance the transition to low-carbon energy in Europe?
[314] OECD (2017) Financial instruments in Practice: Uptake and Limitations
[315] IEA (2021) The cost of capital in clean energy transitions
[316] Polzin & Sanders (2020) How to finance the transition to low-carbon energy in Europe?

At the later stages of energy infrastructure projects, equity financing takes on a different role, with private equity and IPOs becoming prominent. By this point, projects have typically established stable revenue streams and are considered lower risk compared to earlier stages. Equity markets facilitate IPOs, which allow companies to raise substantial capital by offering shares to the public. This phase also attracts private equity investors who seek long-term, stable investments with predictable returns. S&P Global have shown that private equity is increasingly focused on renewable electricity infrastructure sector, with large scale investments in project entering construction and scaling stages.[317]

Equity financing at this stage is typically aims to support the modernisation, digitalisation, and expansion of infrastructure. This includes developments such as new distribution and transmission assets, including offshore and cross-border transmission, which are essential for integrating renewable energy sources into the grid and enhancing energy security.[318] Furthermore, equity investments are key in financing the repurposing and retrofitting of existing gas assets for green gases like hydrogen. However, regulatory uncertainties and the prospect of low regulatory returns can pose challenges, making TSOs hesitant to fully embrace this form of financing.[319]

Effectiveness of equity in meeting the financing needs of energy infrastructure projects

Large T&D Infrastructure projects

Equity financing for large T&D infrastructure projects face challenges. These projects typically require high investment volumes, making them less attractive to external equity investors due to the substantial capital needed and the relatively low return rates.

One of the primary reasons for the low attractiveness of equity financing in large T&D projects is the regulatory framework governing these projects. Regulatory returns on investment for T&D projects are often capped by national regulators to keep energy prices affordable for consumers. This regulation limits the potential profitability of these projects, making them less appealing to investors who seek higher returns for the risks involved. For instance, regulated returns may fall below the 10% threshold that many large infrastructure funds and private equity investors typically target for their investments.[320]

Moreover, the long development and payback periods associated with large T&D projects further exacerbate the issue. Investors are often required to commit capital for extended periods before realising any returns, which, coupled with the low regulatory returns, results in an unattractive risk-return profile. These conditions necessitate public financial entities' involvement through direct equity stakes to help "crowd-in" private investment by sharing the risks and improving the overall attractiveness of the investment.[321]

[317] S&P Global (2023) Value of private equity-backed renewable investments hits 5-year high of $14.6B
[318] ID-E (2023) WG2 Financing models for transmission & distribution (WG2 meeting report 2)
[319] ID-E (2023) WG2 Financing models for transmission & distribution (WG2 meeting report 2)
[320] ID-E (2023) WG2 Barriers to investments in transmission and distribution (WG2 meeting report 1)
[321] IEA (2020) Energy financing and funding

Regulated TSOs/DSOs Entities

TSOs and DSOs operating under regulated models primarily rely on internal equity and corporate finance. The public ownership of these entities often limits the deployment of external equity due to strategic and political considerations. Publicly owned TSOs and DSOs may prioritise policy objectives, such as ensuring reliable and affordable energy supply, over maximising financial returns. This focus can make external investors wary, as they may perceive a misalignment of interests. Additionally, publicly owned TSOs/DSOs are often reluctant to deploy external equity as they aim to retain ownership for strategic reasons or for public interest. However, internal equity suffices for stable, low-volume investments typical in maintenance and incremental upgrades.[322] Privately owned DSOs tend to rely more on external equity, especially for major investments and anticipatory projects like grid expansion and modernisation. Both private and public DSOs adopt a forward-looking approach, planning 10 to 15 years ahead to accommodate future demands, such as renewable energy connections and EV charging infrastructure. While private DSOs often seek external funding for these initiatives, public DSOs generally use internal financing or corporate bonds to maintain strategic control over their assets.[323]

Effectiveness of equity for high and low risk energy infrastructure projects

Equity and quasi-equity financing play a role in managing energy infrastructure projects with varying risk levels. High-risk projects involve innovative technologies and early-stage companies, facing significant technical, regulatory, and market risks. These require investors willing to accept high risks for potential substantial returns. In contrast, low-risk projects, characterised by established technologies and stable returns, attract conservative investors seeking steady income. This section evaluates how equity and quasi-equity support both high and low-risk energy infrastructure projects, identifying key investor types and financing mechanisms.

High-risk projects

High-risk energy infrastructure projects are characterised by their involvement in innovative technologies, early-stage companies, or projects with uncertain outcomes and long development phases. These projects typically face significant technical, regulatory, and market risks that can deter traditional investors.[324] Equity financing is particularly suited for young innovative companies (start-ups) looking for additional financing but not yet suited to apply for debt financing due to lack of collateral or limited credit history. It is also suitable for larger companies seeking financing for new or additional operations.[325]

Low-risk projects

Low-risk energy infrastructure projects are typically characterised by their stable and predictable returns, often supported by regulatory frameworks and remuneration policies. These projects include established technologies and mature companies with proven track records. The stable nature of these projects makes them attractive to conservative investors such as infrastructure funds, large private equity funds, pension funds, insurance companies, and institutional investors seeking steady income and lower risk.[326]

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[322] Roland and Berger (2011) The structuring and financing of energy infrastructure projects, financing gap and recommendations regarding the new TEN-E financial instrument
[323] ACER and CEER (2024) Position on anticipatory investments
[324] OECD (2017) Financial instruments in Practice: Uptake and Limitations
[325] ID-E (2023) WG3 Availability of financial instruments for transmission & distribution (WG2 meeting report 3)
[326] ID-E (2022) Equity and quasi-equity schemes for transmission and distribution (WG2 meeting report 5)

Low-risk projects, such as energy interconnection projects with cap and floor energy prices, are highly attractive to long-term equity investors. These projects offer predictable returns, making them appealing to investors looking for stable, steady income. The stability of returns is often ensured by regulatory frameworks that guarantee predictable revenue streams.[327][328]

Quasi-equity instruments, which include both elements of debt and equity, are particularly useful in managing higher-risk energy infrastructure projects by providing a flexible financing option that balances risk and return. These instruments, such as subordinated loans (and venture debt), convertible bonds, and preferred stocks, offer various benefits.

Subordinated loans, which rank below senior loans in repayment priority, carry higher risk and thus command higher interest rates. Venture debt, a type of subordinated loan, is commonly used by innovative SMEs and start-ups. It complements equity financing by offering more flexible, performance-based repayment terms, allowing companies to focus on growth. This structure makes both subordinated loans and venture debt suitable for high-risk or early-stage projects where traditional financing may be less accessible.[329]

Convertible bonds, for instance, combine features of debt and equity, offering fixed interest payments with the option to convert into equity, making them suitable for projects where investors seek upside potential in exchange for higher risk.[330] Preferred stocks, on the other hand, provide fixed dividends and have priority over common equity in case of liquidation, making them appealing to investors looking for stable returns while accepting higher risk than conventional debt. This flexibility can attract investors to early-stage or innovative energy infrastructure projects where cash flows may be less predictable and risks are higher.[331]

Effectiveness of equity for mature/immature energy infrastructure projects

Building on the discussion of how equity and quasi-equity financing manage varying levels of project risk, their effectiveness between mature and immature energy infrastructure projects provides similar findings from the literature review. Mature projects alike with low-risk projects typically involve established technologies and companies with proven track records, while immature projects are characterised by innovative technologies, early-stage development, and higher uncertainty.

Mature energy infrastructure projects, such as those involving well-established renewable energy technologies or traditional energy systems, benefit from stability and predictability of returns. These projects are attractive to conservative investors like infrastructure funds, pension funds, and large private equity funds, which seek steady income and lower risk. For mature projects with stable investment needs, internal equity—funds generated from the company's own cash flows—is often sufficient. This approach is particularly effective for TSOs and DSOs operating under regulated models, where predictable income streams reduce perceived risk.[332]

In cases where external funding is required, mature projects can attract substantial external equity from conservative investors. The predictable returns associated with these projects make them appealing to large institutional investors who are looking for long-term, low-risk investments. This

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[327] Gautier (2020) Merchant interconnectors in Europe: Merits and value drivers
[328] ID-E (2023) WG2 Barriers to investments in transmission and distribution (WG2 meeting report 1)
[329] EIB (2024) Venture debt
[330] ID-E (2022) Equity and quasi-equity schemes for transmission and distribution (WG2 meeting report 5)
[331] ID-E (2022) Equity and quasi-equity schemes for transmission and distribution (WG2 meeting report 5)
[332] Roland and Berger (2011) The structuring and financing of energy infrastructure projects, financing gap and recommendations regarding the new TEN-E financial instrument

includes infrastructure funds and insurance companies that prioritise stable returns over high risks.[333] The ENTSO-E (2021)[334] study on 'Why remuneration frameworks need to evolve', in the context of European electricity transmission grids and the energy transition, highlights the importance of adequate remuneration. Remuneration refers to the returns that equity investors receive for their investment, such as dividends or capital gains. If remuneration is sufficient, it attracts investors by ensuring that their investments are profitable. This is essential for maintaining a steady flow of capital, enabling mature projects to finance their operations and expansions. Insufficient remuneration can lead to difficulties in raising equity, as investors may seek higher returns elsewhere. This can result in unsustainable debt levels if projects are forced to rely more heavily on borrowing to meet their funding needs.

Immature energy infrastructure projects

Immature energy infrastructure projects involve innovative technologies and early-stage companies, facing significant risks but offering high returns. For detailed discussion on investor types and mechanisms, refer to the prior high-risk section.

Immature projects often rely on venture capital and angel investors willing to accept high risks for potential high returns. These investors support early-stage development, where traditional debt financing is not viable. Additionally, larger corporations invest in start-ups that align with their strategic interests, supporting scalability and growth of immature projects. [335]

Equity and quasi-equity instruments like subordinated loans and convertible bonds help bridge the financing gap in early-stage projects. They offer flexible terms to balance high risks.[336] Blended finance and public financial entities play a role in de-risking immature projects, making them more attractive to private investors.

Effectiveness of equity in supporting EU and neighbouring countries energy infrastructure projects

Equity financing is particularly important for large cross-border interconnection projects, such as those involving the Germany and the UK, because they often operate under a merchant model. This approach often involves the merchant model, where interconnectors operate independently of the regulated business framework, allowing for greater flexibility and potential profitability.

In general, there are two main financing models for interconnectors. Firstly, the regulated model funded by a TSO, typically through their balance sheet and secondly, a privately funded through a merchant model which is outside the regulated business of implementing TSOs. Private equity joint ventures backed up by EIB loans has been used to expand the UK's interconnectors with the rest of the EU through several merchant interconnection projects.[337] By forming joint ventures, multiple stakeholders can contribute equity to establish a legal entity that operates the interconnector, often under the merchant model. This model can be beneficial as it functions outside the regulated business framework of TSOs, offering higher potential returns which appeal to private equity investors.[338]

[333] ID-E (2022) Equity and quasi-equity schemes for transmission and distribution (WG2 meeting report 5)
[334] ENTSO-e (2021) European electricity transmission grids and the energy transition
[335] OECD (2017) Financial instruments in Practice: Uptake and Limitations
[336] Polzin & Sanders (2020) How to finance the transition to low-carbon energy in Europe?
[337] EIB (2022) EIB provides EUR 400 million to support first ever energy link connecting Germany and the United Kingdom
[338] ID-E (2022) Equity and quasi-equity schemes for transmission and distribution (WG2 meeting report 5)

The merchant model, which currently exists for interconnectors between UK and Belgium, France and Germany operate independently of regulated TSOs, providing flexibility in operations and the potential for higher profitability. This model attracts private equity investors interested in high-return opportunities and can help projects that require significant initial capital investment but promise substantial returns.[339]

Equity financing, while can be effective in some interconnector projects, presents challenges, especially in contexts outside the EU. One major downside is the dependence on market conditions and regulatory frameworks. The success and attractiveness of equity financing are contingent on favourable market conditions and stable regulatory environments for ROE. Countries outside the EU may exhibit variability in their regulatory frameworks and market stability, leading to higher risks for investors.[340]

Role of equity in addressing CAPEX and OPEX financing considerations in energy infrastructure

Equity financing is most used to address CAPEX needs due to the substantial upfront capital required for developing and expanding energy infrastructure projects. This includes investments in renewable energy technologies, grid expansions, and modernisation efforts. Equity financing is typically used to scaling growth and financing new infrastructure. It provides the necessary capital to enable the development and expansion of large-scale energy infrastructure projects and technological advancements.[341]

Equity financing is often combined with debt and other financial sources to close financing gaps in projects to ensure sufficient capital to proceed, particularly for utility-scale renewables and significant grid infrastructure developments. Equity financing is less commonly used to address OPEX. Operational expenses typically require different forms of financial support, such as revenue from operations or debt financing. Equity is primarily directed towards growth and development activities, which are CAPEX-intensive. [342] However, in certain scenarios, equity can be used to cover both CAPEX and OPEX, depending on the specific needs of the project.[343]

The impact of ownership structure on the effectiveness of equity for energy infrastructure projects

The ownership structure of TSOs and DSOs significantly impacts the effectiveness of equity financing. This can be observed through factors regarding public ownership and its related regulations.

Publicly owned energy infrastructure is typically reluctant to dilute ownership stakes, which can limit access to external equity. Publicly owned TSOs and DSOs aim to maintain control over strategic infrastructure, which limits the introduction of external equity.[344] This reluctance is driven by the need to preserve strategic ownership and control over essential public, regulated assets, aligning with national interests and public welfare. This control allows for the prioritisation of long-term strategic goals over short-term financial gains, ensuring that investments are made with a focus on sustainability and reliability rather than solely on profitability.[345] Legal and regulatory constraints imposed by Member States can limit TSOs and DSOs access to capital.[346] Government majority

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[339] ID-E (2022) Equity and quasi-equity schemes for transmission and distribution (WG2 meeting report 5)
[340] ENTSO-e (2021) European electricity transmission grids and the energy transition
[341] Polzin & Sanders (2020) How to finance the transition to low-carbon energy in Europe?
[342] OECD (2017) Financial instruments in Practice: Uptake and Limitations
[343] ID-E (2023) WG2 Barriers to investments in transmission and distribution (WG2 meeting report 1)
[344] ID-E (2023) WG2 Barriers to investments in transmission and distribution (WG2 meeting report 1)
[345] ID-E (2022) Equity and quasi-equity schemes for transmission and distribution (WG2 meeting report 5)
[346] ID-E (2023) WG2 Barriers to investments in transmission and distribution (WG2 meeting report 1)

ownership restricts the influence and control that external investors can exert, making it less appealing or unable for them to invest. This might be particularly challenging where future investment needs are large, and leverage is already high. Public shareholders often accept lower returns, which can deter private investors seeking higher returns on equity, thus limiting the attractiveness of TSOs to external equity investors.[347]

In some instances, public funds take minority stakes, not exceeding 40%, which can facilitate the introduction of external equity while maintaining public control.[348] This approach allows TSOs and DSOs to attract external equity without significantly diluting public ownership, thus maintaining strategic oversight while benefiting from additional capital.[349]

Table 3-4 Equity, quasi-equity and venture capital findings overview

Equity, quasi-equity and venture capital	
RQ.1 Stages of energy infrastructure development	Equity: can be deployed across all stages of energy infrastructure projects. Early-stage ventures to move towards commercialisation as well as for upgrades, expansion, and ongoing modernisation. Internal equity should support continuous upgrades and maintenance, ensuring infrastructure efficiency and adaptability to evolving demands.
	Quasi-equity: can support early-stage projects that have high potential but face significant risks, helping them advance towards market readiness.
	Venture capital: should be directed towards energy projects in the expansion phase, where growth potential is evident and scaling up is essential.
RQ.2 Effectiveness to meet varying volumes of financing	Equity: is suitable for projects requiring significant investment volumes, such as large T&D infrastructure.
	Quasi-equity: should be employed to support early-stage projects with high potential but significant risks. It bridges the gap between debt and equity, offering flexible financing options that can adapt to the project's success, helping it advance towards commercial readiness.
	Venture capital: should be used to cover large upfront energy infrastructure projects.
RQ.3 High vs Low risk energy infrastructure projects	Equity: should target high-risk, innovative projects involving start-ups and new technologies, offering potential high returns. For low-risk, mature infrastructure, internal equity should support ongoing upgrades, expansions, and general maintenance operations to ensure infrastructure remains efficient and capable of meeting evolving demands.
	Quasi-equity: should be employed for high-risk projects, offering flexible financing that adapts to project success, balancing higher risks with the potential for higher returns.
	Venture capital: should be directed towards high-risk projects with significant growth potential, particularly in innovative and start-up phases.
RQ.4 Mature vs immature energy infrastructure projects	Equity: financing should be tailored to the project's maturity. For mature projects, equity is effective in providing stability and predictability, attracting conservative investors seeking steady returns. For immature projects, equity financing should be more flexible, with public financial entities potentially taking direct equity stakes to share risks and attract private investment. Internal equity should also be utilised for ongoing upgrades and maintenance.
	Quasi-equity: instruments should be employed for immature projects, offering flexible financing that combines elements of debt and equity. This approach is particularly useful in managing the higher risks associated with new technologies and early-stage projects, helping them progress towards maturity.

[347] Roland and Berger (2011) The structuring and financing of energy infrastructure projects, financing gap and recommendations regarding the new TEN-E financial instrument
[348] Roland and Berger (2011) The structuring and financing of energy infrastructure projects, financing gap and recommendations regarding the new TEN-E financial instrument
[349] ID-E (2023) WG2 Barriers to investments in transmission and distribution (WG2 meeting report 1)

	Venture capital: should be directed towards immature, high-risk projects with significant growth potential. This includes start-ups and innovative energy technologies that require substantial early-stage investment to reach commercialisation.
RQ.5 EU vs neighbouring countries	Equity: can be effective for large interconnection projects, especially those under the merchant model, offering flexibility and potential high returns. However, its success is contingent on favourable market conditions and stable regulatory frameworks, which may pose challenges outside the EU.
	Quasi-equity: should be employed in high-risk energy infrastructure projects where they are a PMI, particularly where the market conditions are less predictable.
	Venture capital: is dependent on the market condition and rate of returns in the neighbouring countries.
RQ.6 CAPEX or OPEX	Equity: is most effective for addressing CAPEX requirements in energy infrastructure projects, including the development, expansion, and modernisation of infrastructure. While it is less commonly used for OPEX, it may be employed in certain scenarios where project needs require flexibility in funding.
	Quasi-equity: instruments can address both CAPEX and limited OPEX needs, providing a flexible financing option that adapts to the project's success and changing financial requirements.
	Venture capital: should be focused on funding CAPEX for innovative and high-growth energy projects, particularly in the early stages of development. It is less suited for covering ongoing operational expenses.
RQ.7 Impact of ownership structure	Equity: Publicly owned entities should be cautious with external equity due to the desire to maintain control over strategic infrastructure. Privately owned is more suited strategically to sell shares for equity.
	Quasi-equity: can be used in hybrid ownership models to balance risk and return, enabling both public and private entities to invest without significantly diluting public control.
	Venture capital: is best suited for privately owned energy projects where higher risk and higher return are the primary drivers, especially in innovative or early-stage projects.

3.2.4. Category 3: Debt/guarantees

This section examines the role of debt instruments—specifically loans, guarantees, project bonds, and green bonds—in financing energy infrastructure projects. The analysis considers how these tools support projects by addressing risk profiles, meeting both CAPEX and OPEX funding needs, and accommodating various ownership structures.

Loans

Loans are a central component within energy infrastructure funding. Loans are financial products where a borrower receives funds from a lender, which must be repaid with interest over a specified period. Various actors both public and private provide loans, such as, private banks, public financial institutions, and EU funding programmes.[350]

Private banks are major providers of loans, particularly for corporate finance and project finance models. In corporate finance, loans are typically on-balance sheet, supporting the broader financial needs of a company. Project finance, on the other hand, is often off-balance sheet and specific to the project itself, focusing on the cash flows generated by the project to repay the loan.[351] Public financial institutions, such as national promotional banks and the EIB, which benefit from a AAA rating can

[350] Bruegel (2024) Accelerating strategic investment in the European Union beyond 2026
[351] Polzin & Sanders (2020) How to finance the transition to low-carbon energy in Europe?

also provide corporate/project finance and play a significant role by offering concessional or soft loans with long-term and favourable terms, particularly for projects aligned with EU policy goals.[352]

Regarding risk-sharing mechanism, loan guarantees are another common, with public authorities providing guarantees to reduce the risk for lenders, enabling borrowers to access loans on better terms. Loan guarantees are especially important for facilitating investments in projects that might otherwise struggle to secure financing due to higher perceived risks[353]

Early stages of development

During the early stages of energy infrastructure project development, securing loans can be challenging due to the higher perceived risks and uncertainties surrounding the project's financial viability.[354] Borrowers often face stringent creditworthiness requirements, which are difficult to meet during these initial phases, further limiting the accessibility of loans.[355] Additionally, the availability of loan instruments decreases significantly for projects involving low-Technology Readiness Level (TRL) and early-stage technologies, as these are considered higher risk by lenders.[356]

Later stages of development

Loans become more effective and accessible in the later stages of project development, where there is a clearer understanding of the project's financial viability, reducing the perceived risks. [357]. At this point, loans are particularly suitable for covering high upfront costs associated with the construction and expansion of energy infrastructure, including the acquisition of new equipment and the modernisation of existing assets.[358]

A significant portion of loan instruments targets mature, market-ready technologies, particularly at the roll-out stage, with about 54% of identified instruments supporting these types of projects in the T&D.[359] Loans in this context are often backed by regulated revenues, making them attractive to risk-averse investors and ensuring a stable financing source for projects in the roll-out stage.[360] This stability makes loans particularly beneficial for projects with established cash flows, providing the necessary capital for large-scale deployment and infrastructure modernisation.[361]

Effectiveness of loans in meeting the financing needs of energy infrastructure projects

Loans are versatile financial instruments that can be tailored to meet a range of financing needs, from small-scale projects to large infrastructure investments. This scalability allows loans to support varying project sizes effectively, making them suitable for both CAPEX-heavy infrastructure projects to smaller energy efficiency initiatives.

Loans are particularly effective for financing large-scale energy infrastructure projects, where significant upfront capital is required. The availability of long-term loans and bonds makes them suitable for projects with substantial financial needs, such as those in the T&D sector.[362] The scalability

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[352] European Commission fi compass (2021) Combination of financial instruments and grants
[353] ID-E (2023) WG3 Availability of financial instruments for transmission & distribution (WG2 meeting report 3)
[354] European Parliament (2017) Research for REGI Committee – Financial instruments for energy efficiency and renewable energy
[355] OECD (2017) Financial instruments in Practice: Uptake and Limitations
[356] ID-E (2023) WG3 Availability of financial instruments for transmission & distribution (WG2 meeting report 3)
[357] OECD (2017) Financial instruments in Practice: Uptake and Limitations
[358] European Parliament (2017) Research for REGI Committee – Financial instruments for energy efficiency and renewable energy
[359] ID-E (2023) WG3 Availability of financial instruments for transmission & distribution (WG2 meeting report 3)
[360] ID-E (2023) WG2 Financing models for transmission & distribution (WG2 meeting report 2)
[361] ID-E (2023) WG3 Availability of financial instruments for transmission & distribution (WG2 meeting report 3)
[362] ID-E (2023) WG2 Barriers to investments in transmission and distribution (WG2 meeting report 1)

of loans ensures that they can accommodate the financial demands of extensive infrastructure projects, aligning with the high CAPEX nature of such investments.

However, securing large loan volumes comes with challenges, particularly due to regulatory frameworks like Basel IV. Basel IV is an international regulatory framework developed by the Basel Committee on Banking Supervision, which sets stricter capital requirements for banks in order to ensure its solvency. It aims to strengthen the regulation, supervision, and risk management within the banking sector. Basel IV increases the capital that banks must hold to cover potential losses, which in turn makes long-term loans more expensive as banks pass on these costs to borrowers. For energy infrastructure projects, this means higher interest rates and potentially more stringent borrowing conditions, which can affect the overall cost-effectiveness of loans as a financing option.[363] This is particularly pronounced for loans with long tenors: the duration of the loan, combined with Basel IV capital requirements, results in higher interest rates. In contrast, shorter-term loans generally incur lower interest rates due to the reduced risk on the bank's side. In addition, for large-scale energy infrastructure projects, private sector loans typically have maturities of 5 to 10 years. This creates a mismatch with the longer lifespans of these projects, which often extend to 10 to 20 years or more, leading to refinancing risks.[364] Bonds offer advantages over loans in terms of longer maturity rates, often 10 years plus, as well as better interest rates and larger volumes as theoretically they can have an unlimited source of funds whereas bank appetite is limited. However, bonds have less flexibility and much greater transaction costs.[365]

Publicly owned companies often benefit from lower-cost debt due to state-backed guarantees, which reduce the risk for lenders. This advantage is especially significant for state-owned TSOs, which can secure loans at rates close to those offered to the national government. On the other hand, privately-owned companies typically face higher costs of debt due to the lack of such guarantees and higher credit spreads.[366]

Effectiveness of loans for high and low risk energy infrastructure projects

Loans effectiveness varies between high and low-risk endeavours. Typically, loans are most effective for low-risk projects where stable and predictable returns are anticipated. Such projects, including regulated T&D investments, benefit from steady revenue streams and lower risk profiles, making them attractive to lenders.[367]

For low-risk projects, loans offer a stable financing source. The predictability of these projects facilitates easier access to loans, particularly from private banks and public financial institutions such as the EIB.[368] These loans are generally supported by regulated revenues, which reduces the risk for lenders, enabling borrowers to secure loans with favourable terms. This reliability renders loans particularly effective for funding the construction and expansion of infrastructure, where significant upfront capital is needed.[369]

In contrast, high-risk projects, which involve greater uncertainty in terms of revenue generation and technological success, face more challenges in securing loans. Lenders typically exhibit more caution,

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[363] ID-E (2023) WG2 Barriers to investments in transmission and distribution (WG2 meeting report 1)
[364] ID-E (2023) WG2 Barriers to investments in transmission and distribution (WG2 meeting report 1)
[365] AFME (2015) Guide to infrastructure financing
[366] d'Oreye de Lantremange (2015) Financial structure, capital costs and investment risk for European Transmission System Operators
[367] ID-E (2023) WG2 Financing models for transmission & distribution (WG2 meeting report 2)
[368] OECD (2017) Financial instruments in Practice: Uptake and Limitations
[369] European Parliament (2017) Research for REGI Committee – Financial instruments for energy efficiency and renewable energy

demanding additional guarantees, collateral, or more stringent loan conditions to mitigate potential losses.[370] Projects of this nature often contend with higher interest rates and stricter terms due to the perceived risks involved.[371]

Effectiveness of loans for mature/immature energy infrastructure projects

Loans are generally more effective and accessible for mature energy infrastructure projects. As mentioned earlier, low-risk and equally mature infrastructure projects benefit from established cash flows and proven technologies, which reduce the perceived financial risk for lenders. The stability and predictability of revenue streams in mature projects make them particularly suitable for loans.[372] Additionally, the lower risk profile of mature projects allows them to secure loans with more favourable terms, such as longer maturities and lower interest rates, which further enhances their financial viability.[373]

However, even in mature projects, there is the potential risk of refinancing, particularly when private sector loans have shorter maturities, typically between 5 to 10 years, compared to the longer lifespan of these projects, which often range from 10 to 20 years. This creates a mismatch that could lead to refinancing challenges and increased financial strain if new loans are not available on favourable terms when needed. To mitigate such risks, mature projects could combine bank finance with bond finance through structures like "bridge to bond" financing, where banks provide initial loans with the expectation of refinancing through bonds once the project is operational. However, such a scheme has not been popular in the EU market.[374]

In contrast, loans for immature energy infrastructure projects are considerably more challenging to secure. These projects often involve higher perceived risks due to the uncertainty surrounding their financial returns and the nascent stage of the technologies involved.[375]

To make loans more feasible for immature projects, blended finance combining a non-repayable and repayable support are sometimes employed. Blended finance can also be further backed by guarantee to mitigate the risks for private lenders. This approach can help to secure the necessary capital for projects with significant upfront investment needs, despite their higher risk profiles. Public guarantees and financial instruments play a role in making these projects more attractive to private lenders by reducing the perceived risk and potential financial losses.

Effectiveness of loans in supporting EU and neighbouring countries energy infrastructure projects
Loans depending on the context can face challenges when used to finance PMIs involving non-EU countries. In these neighbouring regions, the financial markets are often less developed, leading to higher perceived risks and more stringent loan conditions, such as higher interest rates and stricter collateral[376]

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[370] European Parliament (2017) Research for REGI Committee – Financial instruments for energy efficiency and renewable energy
[371] Polzin & Sanders (2020) How to finance the transition to low-carbon energy in Europe?
[372] ID-E (2023) WG2 Financing models for transmission & distribution (WG2 meeting report 2)
[373] Polzin & Sanders (2020) How to finance the transition to low-carbon energy in Europe?
[374] AFME (2015) Guide to infrastructure financing
[375] European Parliament (2017) Research for REGI Committee – Financial instruments for energy efficiency and renewable energy
[376] ID-E (2023) WG3 Availability of financial instruments for transmission & distribution (WG2 meeting report 3)

Role of loans in addressing CAPEX and OPEX financing considerations in energy infrastructure

Loans are a primarily designed to address CAPEX needs in energy infrastructure projects. CAPEX includes costs associated with new equipment and the development of infrastructure, for the construction and expansion of energy facilities. These expenditures are typically high, making loans an effective solution due to their scalability and relatively long-term repayment structures.[377]

EIB has supported commercial banks in energy infrastructure projects through targeted guarantee facilities. While the €5 billion package for the wind sector specifically targets manufacturers in line with RePowerEU goals, the EIB's broader guarantee initiatives have included support for grid interconnection equipment alongside wind component manufacturing. This package aims to mobilise up to €80 billion in investment, bolstering new capacity by 32 GW and enhancing the European wind industry's role in achieving Green Deal objectives[378]. By reducing the financial risks associated with these projects, EIB guarantees ensure the availability of capital during the most financially demanding stages of project development.[379]

However, while loans are primarily used for CAPEX, they can also be structured to address OPEX. This is particularly relevant during the initial phases of project operations, where the need for working capital is high. Nevertheless, loans are generally less common for ongoing OPEX needs, as these are often better addressed by other financial instruments like internal equity or grants, which offer more flexibility and do not involve fixed repayment schedules.[380]

The impact of private/public ownership structure on the effectiveness of loans for energy infrastructure projects

Publicly energy infrastructure entities, such as state-owned TSOs, could benefit from more favourable loan terms due to the backing of state guarantees. This reduces the perceived risk for lenders, allowing these entities to secure loans at lower interest rates. The implicit or explicit state guarantee provides a level of security that makes loans more effective and accessible, particularly for large-scale infrastructure projects where substantial capital is required.[381] [382]

In contrast, private energy infrastructure companies may face higher borrowing costs due to the absence of state guarantees. These companies typically encounter higher credit spreads, reflecting the increased risk perceived by lenders. As a result, loans for privately owned entities are more expensive due to higher interest rates and include stringent collateral requirements, which can limit the accessibility of debt financing for particularly high-risk projects.[383]

Hybrid ownership models, where both public and private entities share ownership, can potentially benefit from the strengths of both public and private sectors. These models might benefit from lower-cost debt, thanks to the involvement of public entities, while also accessing the flexibility and

[377] European Parliament (2017) Research for REGI Committee – Financial instruments for energy efficiency and renewable energy
[378] EIB (2024) Energy Overview 2024
[379] SDA Bocconi and EIB (2018) EU financing policy in the social infrastructure sectors – implications for EIB's sector and lending policy
[380] ID-E (2023) WG3 Availability of financial instruments for transmission & distribution (WG2 meeting report 3)
[381] d'Oreye de Lantremange (2015) Financial structure, capital costs and investment risk for European Transmission System Operators
[382] ID-E (2023) WG3 Availability of financial instruments for transmission & distribution (WG2 meeting report 3)
[383] d'Oreye de Lantremange (2015) Financial structure, capital costs and investment risk for European Transmission System Operators

innovation typically associated with private sector involvement. In such cases, loans can be tailored to suit the specific needs of both public and private stakeholders as an effective financing tool.[384]

In addition, the lack of a credit rating or an insufficient credit rating can limit access to affordable borrowing, particularly for TSOs in smaller or less developed markets. For example, corporate bond markets, which can provide an alternative to traditional bank loans, are generally inaccessible without a credit rating. This issue is particularly pronounced for Eastern European TSOs and smaller TSOs, where obtaining a credit rating or improving an existing one is vital for expanding debt financing opportunities.[385]

Guarantees

Guarantees are effective tools to support energy infrastructure projects by improving access to debt financing. A guarantee represents a written commitment by a guarantor—typically a public institution such as the EIB or a national government—to assume responsibility for a portion of a borrower's debt in cases of default or other specified events. By mitigating the financial risks for lenders, guarantees encourage commercial banks and other financing entities to extend credit to projects they might otherwise deem too risky. This mechanism enables access to better financing terms, as the guarantor covers a portion of the costs in case of non-repayment, thus enhancing the lender's risk appetite.[386]

EU-backed guarantees, such as those offered under the InvestEU programme have proven instrumental in de-risking high-CAPEX and high-risk projects.[387] For example, Lithuania's Energy Efficiency Fund (ENEF) used guarantees to cover up to 80% of project costs, enabling municipalities to secure loans for infrastructure upgrades and attracting private investment.[388] Similarly, the InvestEU Fund provides a substantial EU budget guarantee, allowing intermediaries like the European Investment Fund (EIF) to support equity and quasi-equity investments in emerging sectors such as hydrogen infrastructure, where market risks remain high.[389]

Guarantees can be structured as either full or partial, depending on the financing needs and risk profile of the project. Full guarantees cover the entire loan amount, which shifts most of the financial risk to the guarantor. In contrast, partial guarantees only cover a pre-defined portion of the loan, leaving the lender with some exposure to risk. This partial guarantee model is generally preferred, as it allows for risk-sharing and discourages moral hazard by ensuring the lender remains invested in the project's success. [390]This model was also recommended by participants in the Investors Dialogue on Energy Working Group (ID-E WG), as it aligns incentives for both lenders and borrowers, ultimately enhancing the selection process for the most promising projects.

For energy infrastructure projects, which often involve substantial upfront costs and longer payback periods, guarantees provide significant value by addressing the high-risk profile associated with these investments. Public guarantees reduce perceived risks for lenders, making loans more accessible for projects with considerable CAPEX needs. This approach is particularly suitable in market conditions where capital is available but offered under restrictive terms due to elevated risk

[384] Bruegel (2024) Accelerating strategic investment in the European Union beyond 2026
[385] Roland and Berger (2011) The structuring and financing of energy infrastructure projects, financing gap and recommendations regarding the new TEN-E financial instrument
[386] I-DE (2023) WG3 Availability of financial instruments for transmission & distribution (WG2 meeting report 3)
[387] European Parliament (2017) Research for REGI Committee – Financial instruments for energy efficiency and renewable energy
[388] European Parliament (2017) Research for REGI Committee – Financial instruments for energy efficiency and renewable energy
[389] EIB (2022) Evaluation of EIB Group equity and quasi-equity support for small businesses and mid-caps
[390] I-DE (2023) Guarantees for transmission and distribution

perceptions.[391] Additionally, loan guarantees can mobilise private investment by lowering potential losses for investors, thereby stimulating infrastructure investments that further the EU's or national energy and climate objectives.[392]

Guarantees can be tailored to match the development stages of various projects. For early-stage projects, guarantees can be combined with grants to support the initial capital requirements, thereby mitigating the significant financial risk that often accompanies unproven technologies. In contrast, for mature, market-ready projects, guarantees covering a specific loan percentage can secure long-term financing by addressing both CAPEX and OPEX needs as the projects stabilise.

In practice, guarantees are usually offered in collaboration with EU funds or by financial entities such as the EIB Group, often in partnership with private banks. For example, the EIB loan to Sorégies Group under the InvestEU Guarantee Programme illustrates how such instruments can facilitate project financing. The EIB provided €250 million to Sorégies to support its €500 million investment plan for 2024-2026, focusing on modernizing electricity distribution networks and expanding renewable energy production. This guarantee-backed loan enables Sorégies to access financing on favourable terms, reducing investment risk and supporting projects that align with EU energy transition goals. [393] This setup provides Sorégies with a financial safety net, making it easier to invest in energy infrastructure and renewable energy projects, while funds are only disbursed by the EIB in case of default, preserving public resources.

Moreover, guarantees can be paired with other financial instruments, such as junior debt, to create a layered approach that further attracts private investment. Junior debt ranks below senior debt in repayment priority and can offer higher returns to compensate for the increased risk, providing an additional incentive for private investors. This aims to enhance financing options for high-risk projects and ensures that public funds are used efficiently to catalyse private capital. [394]

Through risk-sharing mechanisms like guarantees, public institutions play a role in bridging the financing gap for energy infrastructure, enabling projects to proceed despite the inherent financial challenges often associated with energy infrastructure development.

Project bonds and green bonds

Project bonds and green bonds play an important role in financing energy infrastructure projects, particularly those in the power transmission and distribution sectors. These bonds are attractive to institutional investors, such as insurance companies and pension funds, due to their long-term, stable returns.

Project Bonds

Project bonds offer direct lending opportunities for large-scale infrastructure projects. They are often issued on a non-recourse basis, meaning repayment is secured only by the project's own revenue. This approach is often used for projects such as transmission lines, which benefit from predictable revenue streams due to regulated pricing. Transmission lines are seen as low-risk assets with straightforward operating processes, making them a reliable investment. In Europe, project bonds have been successfully utilised for financing strategic grid expansions, offshore wind farm

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[391] Bruegel (2024) Accelerating strategic investment in the European Union beyond 2026
[392] OECD (2017) Financial instruments in Practice: Uptake and Limitations
[393] EU Commission (2023) European Investment Bank lends €250 million to Sorégies Group under InvestEU to speed up its energy transition
[394] OECD (2017) Financial instruments in Practice: Uptake and Limitations

connections, and cross-border transmission projects. This has helped mobilise private capital to develop essential power infrastructure across different geographies.[395] For DSOs, project bonds provide access to substantial capital for modernising and expanding grids, as well as integrating smart technologies. With the bonds secured by the assets themselves, DSOs can fund these investments without increasing corporate debt or impacting their credit profiles.[396]

Bond financing conditions, however, can vary based on asset type and national factors, such as sovereign risk. Projects in countries with lower sovereign risk generally benefit from more favourable bond terms, while those in higher-risk nations may encounter increased financing costs, impacting overall affordability and terms. By offering steady returns through fixed interest payments, project bonds attract risk-averse investors who prefer stable, long-term income streams. This structure aligns well with the predictable cash flows of DSOs, where the long asset lifespan further supports bond financing as an attractive option. As the energy sector transitions towards resilient, modern grids, project bonds are likely to remain a crucial tool in funding sustainable energy infrastructure.[397] [398]

Finally, project bonds serve as a valuable tool for encouraging private investment. By offering steady returns through fixed interest payments, these bonds appeal to risk-averse institutional investors who prefer stable, long-term income streams. This structure aligns well with the regulated energy infrastructure, where predictable cash flows and long asset lifespans make bond financing an attractive option. As the energy sector continues to transition towards modern, resilient grid systems, project bonds will likely remain a consistent financing instrument for substantial capital investments.[399]

Green bonds

Green bonds are specifically designated to fund projects with environmental benefits. In the energy sector, they are commonly utilised for renewable energy projects like solar, wind, and hydroelectric power generation, as well as for energy efficiency initiatives. Green bonds adhere to frameworks such as the International Capital Markets Authority (ICMA) Green Bond Principles.[400] which set guidelines on how funds should be allocated to ensure they meet sustainability criteria. Additionally, public green bonds under the Next Generation EU are often issued under frameworks like the NextGenerationEU Green Bond framework,[401] supporting projects in line with EU sustainability objectives. These frameworks enhance transparency and mitigate the risk of "greenwashing," which, in turn, boosts investor confidence by verifying that proceeds are used for genuinely sustainable projects.

With Europe's ongoing development of the Green Taxonomy, the green bond market is expected to grow as it establishes standardised definitions and criteria for green finance. The EU's Green Bond Framework further clarifies these criteria, enabling institutional investors to align their investments with sustainable development objectives more effectively.[402]

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[395] Crédit Agricole (2019) Project Bonds: Power Transmission Lines
[396] E.DSO (2024) Financing mechanisms for distribution system operators
[397] Crédit Agricole (2019) Project Bonds: Power Transmission Lines
[398] E.DSO (2024) Financing mechanisms for distribution system operators
[399] E.DSO (2024) Financing mechanisms for distribution system operators
[400] ICMA (2022) Green Bond Principle
[401] EU Commission (2021) NextGenerationEU Green Bonds
[402] Polzin & Sanders (2020) How to finance the transition to low-carbon energy in Europe?

A recent example of green bonds supporting energy infrastructure is the €800 million green bond issuance by Elia Transmission Belgium. Under its €6 billion Euro Medium Term Notes programme, Elia successfully issued this bond, which was oversubscribed five times, reflecting strong investor demand. The proceeds are allocated to projects outlined in Elia's Green Finance Framework, which aligns with the ICMA Green Bond Principles and EU Taxonomy standards. This bond issuance enables Elia to finance projects that will enhance Belgium's energy transition, such as expanding its high-voltage grid to better integrate renewable energy sources, increase grid reliability, and improve energy efficiency.[403]

Elia's green bond demonstrates how such financial instruments can effectively mobilise capital for energy infrastructure. By adhering to recognised frameworks, Elia provides transparency to investors regarding the use of funds and environmental impacts. This alignment with sustainability goals not only attracts institutional investors but also strengthens Elia's commitment to Europe's green transition by directing funds toward upgrades in the transmission network. [378][404]

[403] Elia (2024) Elia Transmission Belgium successfully places second EUR 800 million Green bond
[404] Elia (2024) Elia Transmission Belgium succesfully places second EUR 800 million Green bond

Table 3-5 Debt/guarantees findings overview

Loans and guarantees	
RQ.1 Stages of energy infrastructure development	Loans: are typically suited for the construction or operation stages of energy infrastructure development, particularly for projects with established cash flows and reduced perceived risks. Guarantees: can provide to back loans for mature energy projects, particularly in high-risk scenarios, to reduce perceived risks and attract private investment. Project Bonds: Often issued for the construction and operational stages, particularly for assets with predictable revenue, like transmission lines. Green Bonds: Generally issued during construction to finance environmentally beneficial projects, such as renewable energy installations and grid upgrades.
RQ.2 Effectiveness to meet varying volumes of financing	Loans: can offer scalability and are effective across various financing volumes, especially for CAPEX-heavy projects. However, securing large volumes can be challenging due to regulatory constraints like Basel IV, which increases borrowing costs. Guarantees: can be applied to support access to loans for large-scale projects, particularly in high-risk or high-volume financing scenarios. Project Bonds: Effective for large-scale infrastructure projects, allowing substantial capital to be raised through institutional investors seeking stable returns. Green Bonds: Suited for high-volume financing of sustainable projects, often oversubscribed by attracting investors aiming to meet environmental or sustainable targets.
RQ.3 High vs Low risk energy infrastructure projects	Loans: are typically effective for low-risk projects with predictable returns, supported by stable revenues. High-risk projects may require additional guarantees or collateral to secure loan financing. Loan guarantees: should be applied to high-risk projects to reduce perceived risks, making them more attractive to lenders and enabling access to necessary financing. Project Bonds: Typically used for low-risk, stable projects with predictable cash flows but can be structured to include high-risk assets when supported by guarantees. Green Bonds: Typically used for low-medium risk projects, as long as they meet sustainability criteria. Green bonds are particularly appealing for investors looking to balance risk with environmental benefits.
RQ.4 Mature vs immature energy infrastructure projects	Loans: are typically most effective for mature projects with established cash flows and lower risk profiles. These projects can secure loans with favourable terms. For immature projects, loans are harder to obtain, requiring public-backed guarantees, to mitigate risks and make financing feasible. Guarantees: can be applied to support loans for immature projects, reducing perceived risks and making them more attractive to private lenders. This is particularly relevant for projects with high uncertainty and long development phases. Project Bonds: Preferable for mature, stable projects. Green Bonds: Typically support more mature and stable projects or innovative projects with guaranteed/regulated returns.
RQ.5 EU vs neighbouring countries	Loans: involving neighbouring non-EU countries face challenges due to less developed financial markets, leading to higher perceived risks and stringent loan conditions. Grants should be provided for initial studies and construction phases to mitigate these risks. Guarantees: can support loans for cross-border projects, reducing perceived risks and making financing more accessible, particularly in Projects of Mutual Interest less stable financial environments outside the EU. Project Bonds: Can be effective for large-scale cross-border projects within the EU, especially where predictable revenue streams exist, like interconnectors. Green Bonds: Frequently issued in the EU given eligibility frameworks and criteria, but the issuance of green bonds is increasingly globally.

RQ.6 CAPEX or OPEX	Loans: typically fund CAPEX but can further support OPEX: Loans are primarily structured to finance CAPEX, such as the purchase of new equipment or the construction of infrastructure. They can also be structured to support but are generally not ideal for long-term operational costs. Guarantees: can be used to support loans aimed at CAPEX, especially for large-scale energy infrastructure projects. They reduce the financial risk for lenders and facilitate access to necessary capital during the construction phase. Project Bonds: Primarily fund CAPEX needs due to their long-term structure, which aligns with the lifecycle of infrastructure assets. Green Bonds: Mostly directed at CAPEX, supporting projects with a clear environmental benefit.
RQ.7 Impact of ownership structure	Loans: Publicly owned entities benefit from state-backed guarantees, making loans more effective due to lower interest rates and reduced risk. Hybrid ownership models can also utilise this benefit while accessing private sector flexibility. Private energy infrastructure projects that have clear business cases can typically access loans at market rates without an issue. Guarantees: can be used in public, hybrid and private ownership models to reduce borrowing costs and enhance access to loans, particularly for large-scale infrastructure projects. Project Bonds: Publicly issued project bonds can attract investor interest in stable returns, while private issuers can isolate project risk from corporate debt for public or public private projects. Whilst private financed project bonds can be suited for both public and private depending on regulatory frameworks of the energy infrastructure. Green Bonds: Can attract institutional investors which can be suited for all ownership types.

3.2.5. Category 4: Technical assistance

Technical Assistance (TA) refers to a range of support services aimed at enhancing the capabilities of stakeholders involved in the planning, development, and implementation of energy infrastructure projects. Within the EU and EIB, TA is a critical tool in ensuring that projects are not only technically viable but also financially sound and aligned with the EU's energy and climate objectives.

For electricity transmission and distribution, TA has supported the development of cross-border projects under the CEF to help meet TEN-E regulatory requirements. In the offshore and renewable energy sector, TA is particularly useful for connecting offshore wind farms and other renewables to the grid. Programs like CEF and EIB initiatives funding studies and design phases of such projects.

Electricity storage and hydrogen infrastructure projects can also benefit from TA, particularly through Horizon Europe, which ensures their technical feasibility and integration with existing energy networks. Similarly, CO_2 transport and storage projects receive TA through the Modernisation Fund and the Technical Support Instrument (TSI), which aid in ensuring regulatory compliance and project readiness.

TA services include:

- Project Preparation and Design: Assistance in designing projects, including conducting feasibility studies and ensuring compliance with technical standards. The aim is to ensure projects are bankable and attractive to investors, particularly for smaller projects, such as local

DSOs that may lack in-house expertise.[405]

- Financial Planning and Structuring: Providing expertise in business modelling, financial assessments, and structuring financing packages that can attract public and private investment. This type of support is particularly relevant in helping project promoters navigate complex financial landscapes and secure necessary funding.[406]
- Capacity Building: Enhancing the knowledge and skills of managing authorities, local municipalities, and other stakeholders involved in the energy sector. This includes training and workshops that build capacity in project management and implementation.[407]
- Regulatory and Legal Advisory: Offering expertise on regulatory compliance, including adherence to EU standards and State aid rules, which is vital during the design phase of financial instruments and project execution.[408]

Examples of technical assistance initiatives include:

- **InvestEU Advisory Hub**: This initiative provides tailored support to project promoters, helping them develop and structure investment projects, to improve access to finance. It mobilises the expertise of the EIB and other partners.[409]
- **fi-compass Platform**: A knowledge-sharing hub launched by the European Commission in partnership with the EIB, fi-compass offers guidance, case studies, and tools to stakeholders involved in implementing financial instruments, with a focus on best practices in financial planning.[410]
- **Joint Assistance to Support Projects in European Regions (JASPERS)**: Funded by the European Commission and the EIB, JASPERS provides advisory services to help beneficiaries align their projects with EU standards, thereby improving their chances of securing funding. This service is essential for project preparation across various sectors, including energy efficiency.[411]
- **European Local Energy Assistance (ELENA)**: ELENA provides grants for technical assistance aimed at energy efficiency, distributed renewable energy, and urban transport projects. The grants cover activities such as feasibility studies, market analysis, and the creation of project implementation units.[412]
- **Technical Assistance for a Green Energy Transition (TARGET)**: Jointly developed by the European Commission and the EIB, TARGET supports EU regions transitioning from fossil fuels by helping them identify and plan clean energy projects. The facility offers assistance in project preparation and capacity building, ensuring these projects align with just transition goals.[413]

Stages of energy infrastructure development and effectiveness to meet varying volumes of financing

Technical assistance predominantly supports in the early stages of energy infrastructure projects. For early-stage projects, smaller projects often lacking the necessary expertise and resources, TA supports project preparation, design, and making projects bankable. The EU Commission notes that

[405] ID-E (2023) WG2 Financing models for transmission & distribution (WG2 meeting report 2)
[406] ID-E (2023) WG3 Availability of financial instruments for transmission & distribution (WG2 meeting report 3)
[407] EIB and ERDF (2019) Stocktaking study on financial instrument by sector
[408] European Parliament (2017) Research for REGI Committee – Financial instruments for energy efficiency and renewable energy
[409] ID-E (2023) WG2 Barriers to investments in transmission and distribution (WG2 meeting report 1)
[410] European Parliament (2017) Research for REGI Committee – Financial instruments for energy efficiency and renewable energy
[411] Bankwatch Network (2024) Supporting the just transition through dedicated technical assistance
[412] Bankwatch Network (2024) Supporting the just transition through dedicated technical assistance
[413] Bankwatch Network (2024) Supporting the just transition through dedicated technical assistance

such assistance is especially needed for smaller DSOs in countries like Poland and France that struggle with limited human and administrative resources. Here TA is paired with loans and grants to ensure projects are well-prepared and viable for financing.[414] Additionally, the InvestEU Advisory Hub offers synergies between different EU funds like the CEF-T and InvestEU, an effective support measure for project readiness.[415]

In high-risk or immature projects, technical assistance is key in risk assessment and project structuring to make projects more attractive to investors. The ability to conduct thorough risk assessments and develop robust business models, financial planning is enhanced through TA, thereby improving the project's bankability and mitigating potential risks. In the context of EU funding schemes where TA is often paired with guarantee funds to reduce perceived risks and attract investment.[416] Whilst for mature and typically lower risk projects, TA is typically not required or less intensive but can still support optimising design and attracting financing.

Technical assistance supports OPEX by helping stakeholders design and prepare projects that require significant upfront investment. TA ensures that projects are structured in a way that maximises the efficiency of CAPEX, making them more attractive to potential financiers.[417]

The ownership structure of energy infrastructure impacts the provision and effectiveness of technical assistance. Publicly owned entities, such as state-owned TSOs, often have more access to TA through government-backed programs and EU initiatives like JASPERS and ELENA, which are designed to help public authorities develop and implement energy projects.[418] Conversely, privately owned entities may face challenges in accessing the same level of TA, particularly in less developed markets, unless specific programs are designed to address their needs.

Table 3.-6 Technical assistance findings overview

Technical assistance	
RQ.1 Stages of energy infrastructure development	Technical assistance can prioritise for small and risky/innovative energy projects, particularly in regions where resources and expertise are limited. The focus should be on project preparation and development, ensuring these early-stage projects are well-structured, bankable, and capable of securing further investment.
RQ.2 Effectiveness to meet varying volumes of financing	Technical assistance can aim to support early stages of project development, particularly for smaller energy infrastructure projects lacking expertise to ensures that projects can secure the financing, especially when paired with other financial instruments like grants and loans.
RQ.3 High vs Low risk energy infrastructure projects	Technical assistance can support high-risk projects, through risk assessment, financial planning, and project structuring to improve bankability and attract investment.
RQ.4 Mature vs immature energy infrastructure projects	Mature and immature projects: Technical assistance is often needed for immature projects, focusing on risk assessment, business model development, and project structuring to enhance bankability. For mature projects, technical assistance may be less intensive but can still play a role in optimising design and securing financing.

[414] ID-E (2023) WG2 Financing models for transmission & distribution (WG2 meeting report 2)
[415] ID-E (2023) WG2 Financing models for transmission & distribution (WG2 meeting report 2)
[416] ID-E (2023) WG2 Guarantees for transmission and distribution (WG2 meeting report 4)
[417] ID-E (2023) WG2 Guarantees for transmission and distribution (WG2 meeting report 4)

RQ.5 EU vs neighbouring countries	Guarantees can support loans for cross-border projects, reducing perceived risks and making financing more accessible, particularly in less stable financial environments outside the EU.
RQ.6 CAPEX or OPEX	Technical assistance can focus on maximising the efficiency of OPEX by helping stakeholders design and prepare projects that require significant upfront investment.
RQ.7 Impact of ownership structure	Technical assistance is more readily available for publicly owned entities through government-backed programs, while private entities might require tailored support, particularly in less developed markets.

3.3. Financing narrative per energy infrastructure category

The following section undergoes a risk and maturity assessment of the energy infrastructure categories within scope of the study, including:

Table 3-7 Energy infrastructure category and respective risk and maturity assessment

Energy Infrastructure	Scope of risk and maturity assessment
Electricity transmission infrastructure	All infrastructure considered under electricity transmission infrastructure, commonly operated and maintained by TSOs. This does not include transmission lines with a significant cross-border impact or offshore generation.
Electricity distribution infrastructure	Networks that distribute electricity to consumers, connecting the transmission networks to homes, businesses and industries managed by Distribution System Operators (DSOs).
Electricity transmission lines with a significant cross-border impact	The infrastructure analysed in this section covers onshore and subsea transmission lines which are not related to the transmission of offshore renewable energy.
Electricity lines related to offshore generation	Transmission lines enabling transmission of offshore renewable electricity from the offshore generation sites, i.e. radial connections, and transmission lines having dual functionality: interconnection and offshore grid connection.
Electricity storage directly connected to high voltage transmission and distribution lines	Electricity storage facilities encompass both individual and aggregated systems used for storing energy on a permanent or temporary basis. These facilities can be located in above-ground or underground infrastructure or geological sites.
Hydrogen infrastructure	The categories more closely examined are: hydrogen pipelines, storage connected to high-pressure hydrogen pipelines, (import) terminals, installations for hydrogen use in transport sector, and electrolyser facilities with large capacity as per the TEN-E.
CO_2 transport and storage infrastructure	The section analyses building new and repurposing existing pipelines for CO_2 transport.

The analysis for Section 3.3 includes a comprehensive review of risk and maturity factors across various energy infrastructure categories. This involved examining technical and operational risks, financial viability, regulatory challenges, and track record for each infrastructure type. Risk factors denote the potential uncertainties and challenges that may hinder viability of energy infrastructure projects. Maturity in this context refers to another group of risks concerning the readiness of a project, technology, or infrastructure for deployment and long-term operation.

The risk and maturity assessment will review the risk factors present below. An assessment of the possible impacts of individual risks (low, medium, high) will also be provided to clarify the applied risk assessment methodology resulting in an overview per infrastructure category at the end of this section.

- **Technical and operational risks** refer to the potential for failures, delays, or suboptimal performance in the design, construction, operation, and maintenance of energy infrastructure. The assessment of these elements is derived from the literature review wherein a high-level overview of most common risks and their effects in practice is provided. These risks can arise from factors such as technological uncertainties, inadequacies in project management, engineering flaws, or unforeseen environmental impacts. The risks may also include insufficient training of personnel, equipment failures, failures in internal processes or supply chain disruptions.
    - Low risk: Proven technology, efficient management processes, resilient supply chains, effective mitigation procedures of equipment repair or failure.
    - Medium risk: Proven but not deployed at scale technology, acceptable management processes, supply chains partially susceptible to disruption, set mitigation procedures of equipment repair or failure
    - High risk: Untested technology, lack of management processes, unpredictable supply chains, unclear mitigation processes of equipment repair or failure.
- **Financial viability** refers to the potential for financial losses and uncertainties arising from fluctuations in market conditions that can impact the viability of energy infrastructure projects. These risks can be attributed to factors such as increased costs due to potential supply chain disruptions, high inflation, high interest rates, increased competition from new market entrants or technologies, and currency fluctuations in international projects. Financial viability also concerns a project's ability to sustain financial health over its lifecycle. This includes assessing financial feasibility through cost analysis, identifying reliable funding sources, and evaluating potential revenue generation.
    - Low risk: Predictable revenues, strong demand, moderate costs, and well-defined remuneration frameworks.
    - Medium risk: Partially uncertain revenues/demand, high costs, developing incentives, or unclear remuneration frameworks
    - High risk: Uncertain revenues/demand, very high costs, weak incentives, or inadequate remuneration frameworks.
- **Political and Regulatory risk:** refers to the uncertainties and potential losses that arise from changes in government policies and, regulations, and political environments that can affect energy infrastructure projects. These risks include sudden shifts in regulatory frameworks, inconsistent permitting processes, or changes in tax policies. Additionally, local political opposition, lack of regulatory support for innovative technologies, or delays in the approval of necessary permits can severely impact project timelines and financial viability of projects.
    - Low risk: Asset regulation, consistent, implementable and timely permitting processes, political drive, or established regulatory support for innovation.
    - Medium risk: Limited regulation, complex permitting processes, partial political will, and limited regulatory support for innovation.
    - High risk: Lack of (uniform) regulation, inconsistent, untransparent and prolonged permitting processes, political opposition, or lack of regulatory support for innovation.
- **Track record** refers to the historical performance and the readiness of the energy infrastructure category or technology for market entry and large-scale deployment. A strong track record indicates reliability and successful outcomes, while a weak one highlights potential risks. Evaluating a track record also includes maturity of the overall infrastructure, whether the sector is commercially ready or still represented as belonging

to initial development phases, the potential for market adoption, scalability and long-term success in a competitive market.

- Low risk: Established maturity and reliability, high potential of market adoption, high scalability prospect.
- Medium risk: Demonstrated partial maturity, fragmented market adoption, expected but unproven scalability prospect.
- High risk: Energy infrastructure remains in development stages, low potential of market adoption, low scalability prospect.

Additionally, we focused on the specific funding support needs of each category, considering variables such as regulated versus non-regulated asset status, the impact of ownership models, the type of financing required (on-balance sheet vs. off-balance sheet), and the role of economic disparities among MS in influencing state aid limitations and Weighted Average Cost of Capital (WACC) variations.

Based on these factors, we classified the funding needs for each category into three levels:

- **Limited additional public funding** – for energy infrastructure categories that are privately financed and have a viable business model without the need for further public funding support.
- **National funding support** – for infrastructure requiring financial support at the national level, where state aid, user-based tariffs, and local mechanisms can sufficiently cover costs, making EU-level intervention unnecessary.
- **EU support** – where national support alone is insufficient, and additional EU-level funding or support mechanisms are required.

The objective of the risk and maturity assessment is to assess the financing conditions for each energy infrastructure category to pair with suitable financial instruments and forms of EU support to overcome financing barriers and unlock private finance. The identification of suitable types of financial instruments and other forms of financial support is provided per energy infrastructure, considering the levels of risk and the possible need for funding support associated with each energy infrastructure category is provided.

The final table of Section 3.3 will summarise these findings in a table, providing a risk ranking (low, medium, or high) for each infrastructure category considering the risk and maturity factors and indicating the level of funding support possible: no support, possible national support, or possible EU support. By synthesising the analysis in Section 3.3 with the energy infrastructure funding needs based on the risks and maturity assessment developed in this section, we will develop conclusions outlining a possible mix of financial instruments and other financial support for each energy infrastructure category in the following Section 3.4.

The analysis for Section 3.3 involved a literature review analysis on risk and maturity factors related to each energy infrastructure category. The analysis also included conducting interviews with NPBI and other relevant financiers of energy infrastructure on financing risks, barriers and EU funding support needed to overcome these financing challenges. This allows gaining understanding of on-the-ground financing mechanisms and environments that affect energy infrastructure investments.

The following types of sources were reviewed:

- academic literature,
- regulatory/policy reports, and
- industry, think-tank and NGO reports.

The Table in Annex A.5 provides an overview of the literature selected and analysed for Section 3.3. The list of interviewees can also be found in the Annex.

Need for funding support

To assess the need for funding support across different energy infrastructure categories, we conducted interviews with financing experts from National Promotional Banks, the European Investment Bank, and a workshop with in-house energy infrastructure experts. This was done through a two-hour workshop focused on identifying central financial risks and barriers for each energy infrastructure category, as well as the need for national or EU public funding support. The workshop included 7 experts both within our project team and external to the project but within our within our company. These discussions highlighted key variables that influence access to funding, the types of financial instruments, and the relevance of EU or national support. This section examines the impact of various factors, including regulated versus non-regulated infrastructure, ownership models, the use of off-balance sheet project finance (SPV) versus on-balance sheet company finance, and disparities in WACC and liquidity among EU Member States and state aid limitations. By analysing these variables, we identify key variable impacting the energy infrastructure categories and which are typically those most in need of EU or national funding support and which are more self-sufficient, capable of financing projects without additional external assistance.

We will now explore how these factors impact funding support need. Thereafter, the analysis is followed by an assessment of cross-cutting risks and maturity factors common across all infrastructure categories. Finally, we delve into the unique risks and maturity characteristics specific to each energy infrastructure category, providing insights into the ideal mix of funding support and financial instruments needed to address the particular challenges within each infrastructure type. This layered approach will help pinpoint where EU or national funding is essential to overcoming investment barriers

Impact of regulated energy infrastructure assets on energy infrastructure funding

For regulated assets, such as, **TSO, DSO infrastructure and hydrogen network infrastructure**, they often operate under the **Regulated Asset Base (RAB) model**. This model provides clarity on expected returns, as regulators determine allowable returns on investment. It creates a predictable environment for financing, where funding depends less on sourcing new financial instruments and more on regulatory conditions that permit or encourage investment. For regulated assets, **capital remuneration** is typically ensured through tariffs, with the asset's cost depreciated over time and recovered through user fees. This structure provides financial stability but also ties financing challenges directly to regulatory decisions. In cases where regulators cap returns or restrict investment, operators may be unable to pursue new projects, even if the necessary funding is available.

A primary consideration for regulated assets is the **user base's** ability to absorb costs. Network operators rely on stable or growing user bases to ensure that investment costs can be passed on to consumers through tariffs. However, when user growth is uncertain, it can limit revenue potential, despite the predictability associated with regulated returns. The impact on unpredictable user base presents a key variable in the access to EU funding or private finance.

A key consideration for regulated assets is that, while financing may be accessible, regulatory limitations can constrain investment. For example, TSO and DSO operators may have financing in place but cannot proceed without regulatory approval. Often, these restrictions arise due to concerns about passing costs onto consumers, as the financed amounts are eventually passed on to consumers within network tariffs. Moreover, with similar reasoning, regulators aim to limit rates of return on investments as much as possible (see for example recent disagreements on this in

Germany[419]). This limitation on rates of return directly limits the availability of finance for TSOs/DSOs. Thus, root cause relates more to regulatory processes than to the availability of finance. This issue is particularly significant for TSOs and DSOs which envision unprecedented investment volumes in the coming years.

Regulated projects often require de-risking mechanisms, especially when there is uncertainty surrounding user base development. For instance, guarantees can be provided to cover asset depreciation if the expected user base does not materialise as planned. This effectively shares risk between network operators and the government, reducing the financial burden on operators and encouraging investment by mitigating potential losses. Such de-risking mechanisms for regulated projects can help manage risks associated with fluctuating or slow-growing user bases, which will be further discussed in section 2.4.

Increased investment needs for regulated TSO and DSO infrastructure could substantially impact grid usage costs for end users

The scale of investment required to develop European electricity grids is immense. As mentioned in Section 2, electricity distribution infrastructure planned investments needs are €732.33 billion, whilst electricity transmission requires a considerable €471 billion of investment needs across 2024-2040. The impact of these investments by TSO and DSOs' on costs for end users—households and businesses—varies. In some cases, efficiency gains and economies of scale could mitigate increases, or even reduce tariffs over time. In others, higher investment costs may lead to tariff increases.

The feasibility of using higher tariffs to cover these investment needs could be economically efficient but for societal reasons not desirable. Substantial tariff increases risk overburdening households and businesses, potentially eroding public acceptance of critical infrastructure upgrades. TSOs and DSOs currently operate within a predictable, regulated market structure that ensures good access to finance. However, the magnitude of future investment needs may exceed what can be sustainably passed on to end users. Generally, extra financial support for these activities arrives from national sources, such as governmental budgets and related support schemes. In some cases, additional funding support (also paid from taxpayers' contributions) from the EU may become necessary. EU funding support, particularly in the form of grants or blended finance mechanisms, could play a temporary role in alleviating the financial burden on consumers and business. Additionally, de-risking instruments, such as guarantees, could ensure investment viability without requiring all costs to be passed directly to end users. It is however worth highlighting that higher-level support for these investments is, *ceteris paribus*, less economically efficient than support from national budgets and regulated returns, according to our analysis/literature.

Impact of non-regulated energy infrastructure assets on energy infrastructure funding

Non-regulated, or market-driven, assets—typically including, **electricity storage technologies, merchant interconnectors, hydrogen terminals and storage facilities, and CO_2 transport and storage** infrastructure—are exposed to distinct financial risks. Unlike regulated assets, these projects rely on **market pricing to recover costs**, which introduces a level of uncertainty regarding their financial outlook. Key risks associated with non-regulated assets include high upfront capital requirements, unpredictability in cost recovery, and the possibility that market returns may not align with initial projections. The lack of regulated income streams necessitates a higher tolerance for risk among investors.

[419] https://financialpost.com/pmn/business-pmn/german-grid-operators-lose-case-over-investment-return-rates

While non-regulated assets typically entail greater financial risk, they also offer enhanced profit potential and operational flexibility. Since these assets are not subject to regulatory constraints on returns, they can respond dynamically to market conditions, potentially capturing higher profits during favourable market periods. Non-regulated energy infrastructure assets must be prepared to manage the risks associated with fluctuating demand, volatile pricing, and changing market dynamics. The capacity to adjust operations in response to market signals is both a benefit and a challenge, requiring sophisticated risk management strategies. projects, such as cross-border interconnectors and hydrogen storage facilities, often utilise a merchant model. This approach enables the project to secure funding and operate independently, relying on anticipated market returns rather than guaranteed tariffs. The merchant model is attractive to private equity and venture capital investors, as it provides the potential for high returns. However, these energy infrastructure projects often require substantial upfront capital and exposes the project to risks related to market demand and price fluctuations. Consequently, projects using the merchant model must balance the pursuit of profitability with robust financial planning to withstand periods of market volatility.

Impact of ownership models on energy infrastructure funding

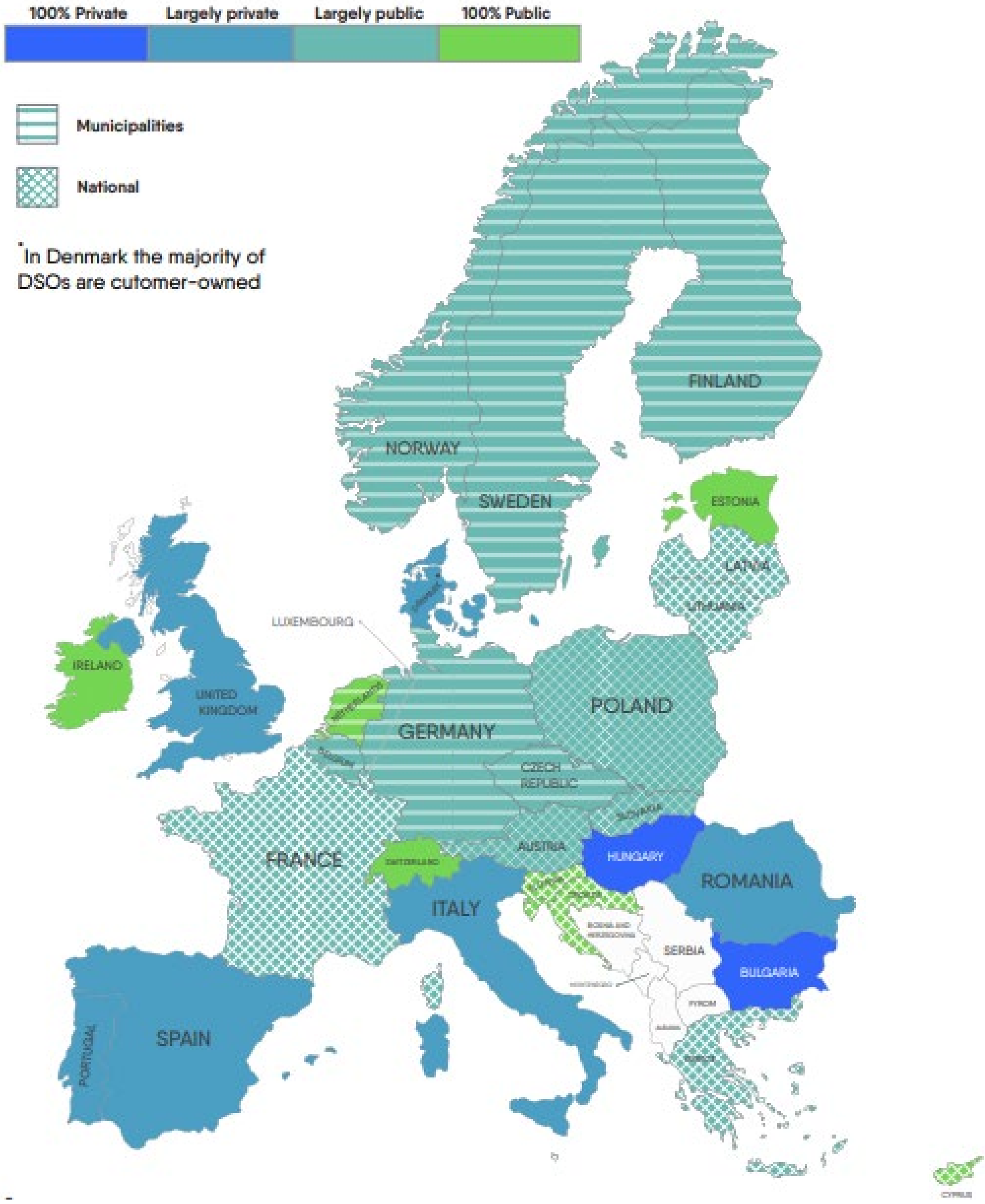
The ownership structure of energy infrastructure projects—whether public, private, or in between — significantly impacts EU and national funding support for these projects.

Public ownership, commonly seen in TSO infrastructure, often benefits from state-backed guarantees or loans with favourable interest rates, allowing access to lower-cost financing. However, public ownership can restrict access to private equity, as governments typically aim to retain control over critical infrastructure to support long-term policy objectives and national interests. Public ownership can be a combination of different entities owning varying stakes, for example co-ownership by municipalities and by national and/or regional governments.

Privately owned energy infrastructure projects usually face higher borrowing costs, making EU or national concessional loans and risk mitigation measures useful to balance financing needs. Private ownership, however, offers flexibility and the ability to adapt quickly, enabling innovation and faster scaling, which is attractive to private investors, particularly in emerging markets. The investors involved in non-regulated energy infrastructure projects typically include private equity firms, infrastructure funds, and pension funds. These entities are well-suited for high-risk, high-reward projects due to their capacity for long-term investment horizons and ability to manage market volatility, making the projects reliant on fluctuating market returns rather than guaranteed income streams.

Infrastructure operators within various regulatory frameworks have a variety of different ownership structures. For example, DSOs generally face strict regulations on the allowable returns for investments into infrastructure. In this regulatory context, DSO ownership across Europe varies significantly, not only across Member States (shown in Figure 3-3) but also within Member States. It is worth noting however that ownership structure is generally not considered within the evaluation of projects for EU funds.

Figure 3-3: DSO ownership across Europe, as of 2020.



Source: Eurelectric (2020), Distribution Grids in Europe Facts and Figures

Off-balance sheet (SPV) and on-balance sheet/company finance impact on energy infrastructure funding

The financing structure of energy infrastructure projects—whether through off-balance sheet project finance or on-balance sheet/company finance—impacts financial risk, access to capital, and the type of funding instruments available. The choice between these structures depends on the regulatory environment, project risk, and the financial strategy of the sponsor.

Off-balance sheet project finance is characterised by the creation of a Special Purpose Vehicle (SPV), which serves to isolate the financial risk of the project from the sponsoring company's balance sheet. This financing structure is particularly suitable for non-regulated, high-risk projects—such as hydrogen terminals, and CO_2 storage infrastructure—where substantial capital investment is required, and revenue streams are subject to market fluctuations. By using an SPV, companies can limit their exposure to project-specific risks while enabling the project to secure financing independently based on its own cash flow potential. The SPV model provides a way to facilitate access to a diverse range of funding sources, including equity investors and lenders who are attracted by the cash flow prospects and risk profiles of these projects. Given off-balance sheet finance is typically required by higher-risk and more emerging technologies, they would require further public funding support to attract private capital.

On-balance sheet / company finance On-balance sheet financing is typically used for projects that are central to a company's core operations and benefit from stable, predictable revenue streams, particularly regulated assets like electricity transmission and distribution networks. By financing these projects directly, firms use their financial strength and credit rating, accessing funds through corporate bonds, loans, or retained earnings, with less need for public funding support. This approach is common in regulated markets, such as Italy, where TSOs and DSOs benefit from reliable revenue through long-term tariffs, making on-balance sheet financing an effective strategy to support core operations and maintain financial stability.

Impact of WACC differences across EU Member States

The Weighted Average Cost of Capital (WACC) varies significantly across EU MS, impacting the financing of energy infrastructure projects often requiring high up-front capital requirements. Sectors like electricity transmission, distribution networks, cross-border interconnectors, hydrogen infrastructure, and CO_2 transport and storage require substantial CAPEX, making the cost of capital a critical factor in their feasibility. In countries with higher WACC, such as Bulgaria and Romania, financing these projects becomes particularly challenging, as the elevated cost can exceed what consumers can afford, especially when tariffs must reflect these higher financing costs.[420]

For high-WACC Member States, EU-level financial support is essential to make these large-scale energy projects viable. Unlike countries with greater financial resources, such as the Netherlands, where the government can provide substantial backing, many Member States need EU grants, guarantees, or low-interest loans to offset the higher financing costs. Such support ensures that energy infrastructure projects can proceed regardless of national capital constraints.

The financial disparity between wealthier and less affluent EU countries further complicates the ability to fund energy infrastructure. Financially stronger Member States can often directly fund projects or easily attract private finance due to favourable WACC, credit ratings, and capital access. In contrast, less wealthy Member States may struggle to raise sufficient financing, even for projects with strong business cases, due to higher borrowing costs and limited public funding options.

State Aid Limitations

State aid regulations add another layer of complexity. These rules are designed to maintain a level playing field across the EU, limiting the extent to which governments can provide direct financial support to energy infrastructure projects. Limitations mean that less affluent Member States may be constrained by state aid rules, even if they wish to support energy infrastructure. The EU provides regional development funds and transition funding to aid these regions, but these resources are not exclusively dedicated to energy infrastructure.

[420] ACER (2023), Report on Investment Evaluation, Risk Assessment and Regulatory Incentives for Energy Network Projects

EU funding mechanisms are therefore crucial for less liquid Member States. By providing these financial resources, the EU can help balance the effects of WACC disparities and state aid limitations, ensuring equitable access to essential energy infrastructure development across all Member States.

Cross-cutting energy infrastructure risks and maturity factors

Before delving into specific risk and maturity assessments per infrastructure category, it is important to note that some risks and maturity factors are shared across energy infrastructures. Therefore, the risks and maturity factors that are applicable to all energy infrastructure types will be presented below while the infrastructure-specific analysis will be provided in dedicated sections.

A significant **financial viability** risk relates to the considerable CAPEX requirements to build and operate energy infrastructure. This is further linked to lacking clarity, especially for technologies that have not yet been deployed at full-scale, on future overall and early-stage revenue streams, competitiveness on the market, and projected users of the produced energy.

When it comes to **operational risks**, the construction and maintenance of energy infrastructures face the shortage of skilled labour.[421] This primarily concerns mechanical and electrical engineering technicians, mechanical machinery assemblers, construction supervisors, machine and plant operators, and heavy transport operators. Similarly, logistical challenges of large-scale construction related to land preparation, sourcing of materials, and ensuring the safety of employees during installation and maintenance arise. These may result in construction or operation delays.[422]

As for **regulatory risks**, the overarching commonality is linked to the permitting processes. These include environmental and planning permits related to, for example, wildlife protection, geological assessments, water protection, etc.[423] Challenges in obtaining necessary permits can delay projects by up to 2 years. Moreover, following the national regulations and guidelines for construction processes and subsequent operation is a must for any energy infrastructure undertaking. This is particularly important to observe when it comes to infrastructure types that either cross borders or may be subject to differing regulations offshore.[424]

Electricity transmission infrastructure

This section will analyse all infrastructure considered under electricity transmission infrastructure, commonly operated and maintained by TSOs. This section will not address transmission lines with a significant cross-border impact or offshore generation, as separate sections have been dedicated to both. It is important to clarify that by "privately-owned" and "publicly-owned," we refer to ownership by non-governmental shareholders and governmental entities, respectively. This distinction avoids confusion with TSOs whose shares are traded on a stock exchange, which may be largely owned by institutional investors but are still accessible to the public for shareholding.

Analysis of main risks (technical and operational, financial viability, and regulatory)

National transmission grid infrastructure is prone to the following **technical risks**. Most are related to the limitations of the current grid network, for example, unclear grid development and retrofitting or maintenance activities. This is related to existing supply chain issues with procuring components such as transformers and cables.[425] Emerging technologies also pose challenges most often related to a lack of developed industry standards, reliance on scaling up demonstrator technology, and incomplete feasibility studies.[426] Moreover, long processes for testing and adopting new technologies slow down innovation, and planned grid developments may be inadequate to support the necessary

[421] EURES (2024), Labour shortages and surpluses in Europe
[422] Eurelectric (2024), Grids for speed
[423] Klijnstra et al (2017) Technical Risks of Offshore Structures
[424] Huang and Hertem (2018) Cross-Border Electricity Transmission Network Investment: Perspective and Risk Framework of Third-Party Investors
[425] IEA (2023) Electricity Grids and Secure Energy Transitions
[426] ID-E (2023) Financial instruments and models for energy production

renewable energy uptake, further complicating the achievement of energy policy goals.[427] This also relates to the preference for digitalisation over hardware which comes with cybersecurity concerns and slower technology implementation, increasing risk.[428] **Operational risks** may arise due to increasing renewable energy demands, which may lead to grid capacity saturation and potentially strand projects if connections do not align with renewable energy targets.

Electricity transmission infrastructure therefore qualifies as **low/medium risk** in technical and operational risks due to well-established base technologies of the existing network. However, observed supply chain issues can pose delays and cost increases, particularly in the procurement of key components such as transformers and cables. Furthermore, the rapid growth in investments for TSO infrastructure may lead to higher grid tariffs in some cases, increasing the financial burden on households and businesses. In such cases, societal considerations might prompt the use of alternative financial support mechanisms. These mechanisms shift the recovery of investment costs from grid users to taxpayers or a broader group, alleviating the cost pressures on grid users while ensuring the necessary infrastructure upgrades are financed. This potential risk is considered when assessing the long-term financial viability of transmission infrastructure investments. While the current risk is considered low due to the mature and regulated nature of the infrastructure, these emerging challenges place the category between low and medium risk when considering future requirements.

The key **financial viability risks** arise due to the lack of incentives to adopt operational expenditure-focused solutions, with a preference for capital expenditure intensive options. Additionally, there are insufficient incentives for innovation and output improvement, meaning operators are not encouraged to adopt cheaper or more efficient solutions. Network operators often favour predetermined solutions, limiting flexibility in addressing issues. Furthermore, countries with grid infrastructure lagging behind energy policy targets will need increased or front-loaded investments.[429] Moreover, insufficient remuneration and low returns on equity discourage equity investments, especially in countries like Czechia and Hungary. Low tariffs, while useful for retrofitting, pose challenges for new transmission capacity investments. Increasing tariffs is difficult due to the economic crisis and consumer resistance, risking consumers going off-grid, which would further reduce the consumer base.[430]

Nonetheless, national transmission grid infrastructure is regulated, which means that the financial return for a grid operator is easy to estimate and recover and there is an existing user base thereby decreasing the risk of investing in national transmission grids. EU grants and financing mechanisms to mitigate financing challenges are open to transmission system operators. However, there is no strong financial incentive for TSOs to pursue such grants due to processing delays and uncertainties of grant results, while existing financing sources have so far proven to be sufficient.[431]

Due to predictable remuneration frameworks and a stable demand base, the financial viability risk for transmission infrastructure is currently **low**. Financial returns (either on the rate of return or another mechanism) on a regulated asset base defines the allowed returns for TSOs/DSOs.

Regulatory risks such as frequent changes in regulations and permitting delays create uncertainty for long-term investors, with stability being a key concern for equity providers. Harmonisation issues

[427] Ember (2024) Putting the mission in transmission: Grids for Europe's energy transition
[428] ID-E (2023) Investors Dialogue on Energy: Financial instruments and models for transmission and distribution
[429] Ember (2024) Putting the mission in transmission: Grids for Europe's energy transition
[430] ID-E (2023) Investors Dialogue on Energy: Financial instruments and models for transmission and distribution
[431] North Sea Wind Power Hub (2022) Economic and Financial Framework for Electrical infrastructure

arise when national grids are involved in interconnection projects needing consistent regulatory frameworks across different regimes. Furthermore, administrative hurdles and inadequate network planning, coupled with time lags between policy development and subsequent grid planning can misalign grid plans with targets.[432] Similarly, changes in law and political force majeure events can disrupt project performance and financial stability, while varying national regulations complicate project execution and the use of congested income.[433]

As a result of its regulated nature, electricity transmission infrastructure overall ranks as **low risk** in relation to regulatory risks, although permitting processes may nonetheless cause delays and the need to keep track of any changes to regulations remains.

Analysis of main maturity factors
The investment in innovative grid technologies already has a positive **track record** in increasing network capacity. Technologies such as advanced power flow control systems, advanced conductors, storage as a transmission asset, dynamic line rating, and grid inertia measurement have been respectively deployed in the United Kingdom, Belgium, Germany, and the United States.[434] However, investment and regulatory barriers continue to pose an obstacle in full roll-out of innovative technologies most of the mentioned innovative grid technologies are mature, however, their adoption is hindered by long processes for network companies to trial and then adopt new innovative solutions. This is related to innovative technologies not always being included in planning processes for grid optimisation initiatives. Another consideration lies in the present path dependent tendencies of TSOs that are biased towards predetermined solutions.[435] Lastly, innovative technologies tend to have higher OPEX than alternatives, facing disincentives when a regulated return structure favours CAPEX-heavy investments (also known as CAPEX bias).

Overall, national transmission grids are a well-established and reputable type of energy infrastructure. Subsequently, its track record is reliable and long-standing, therefore, it is classified as **low risk**.

Conclusion of risks and maturity factors
While electricity transmission is developed and commercially mature in general, innovative grid technologies to optimise and increase grid capacity in particular are still not deployed at scale. This is related to long testing and adoption times as well as the investment needs of the current grids such as repairs, retrofitting, and maintenance. There is limited incentive for TSOs to invest in innovative technologies due to financial constraints, limiting regulations, and lacking skilled labour and transparency of grid planning. However, existing transmission grids are well-established with a broad user base and a clear projection of the return on investment due to the regulated nature under which they function.

Based on the risk and maturity profile of electricity transmission infrastructure, **loans and national guarantees** emerge as typically the suitable financial instruments for TSOs. Transmission infrastructure is generally stable, with predictable revenue streams due to its regulated nature, making it well-suited for long-term loans that align with the asset's lifecycle. National concessional loans can help fund large-scale modernisation projects that might not be feasible solely through on-balance sheet financing. EU funding support could be required in cases where MS lack sufficient national resources or state aid mechanisms to fully support the accelerated development of

[432] ID-E (2023) Investors Dialogue on Energy: Financial instruments and models for transmission and distribution
[433] US Department of Commerce (2021) Understanding power transmission financing
[434] CurrENT, Compass Lexecon (2024) Prospects for innovative power grid technologies
[435] CurrENT, Compass Lexecon (2024) Prospects for innovative power grid technologies

transmission infrastructure. This would also apply to higher-risk modernisation projects or extremely long-term investments that benefit from additional security, such as EU-backed guarantees or concessional loans.

Electricity transmission lines with a significant cross-border impact

Cross-border infrastructure enables transmission between Member States and neighbouring regions. The EU has set an interconnection target of at least 15% by 2030 to encourage EU countries to interconnect their installed electricity production capacity. The target is related to ensuring energy security and reaching net-zero goals by supporting the transmission of electricity sourced from renewables. However, while sixteen Member States have reported reaching the 15% target in 2021, there are significant gaps in expansion plans to ensure the power system needs for 2030 and 2040. Several regions are also considered as critical in building the necessary cross-border infrastructure to ensure true Europe-wide coverage.[436]

The below analysis will focus primarily on risk associated with regulated and merchant interconnectors.

Analysis of risks (technical and operational, financial viability and regulatory)

Though cross-border infrastructure operates using established technologies, **technical risks** are present due to geographical and efficiency factors. Long distances, natural and environmental conditions such as mountain ranges, and under-sea or under-ground connections require bespoke design and construction planning. This is to not only ensure a secure and functional connection, but also to guarantee that energy efficiency levels remain high across the entirety of transmission.[437] Additionally, it is important to factor in the available capacity of the interconnectors due to the limitations of the amount of energy that can transit through them at a given time.[438] Further **operational risks** can be caused by national transmission inconsistencies or drawbacks. Congestion in national markets can be amplified by new imports from interconnectors while national markets can also push congestion to their borders to deal with internal congestion. It is therefore necessary to invest in and maintain national transmission to benefit from new interconnectors and ensure smooth operation across the network.[439]

Although cross-border infrastructure operates on established technologies, its available capacity and interaction with national electricity transmission grids in terms of transmission inconsistencies or congestion lead to the technical risks being ranked as **medium**.

Financial viability risks may arise due to competing energy infrastructure initiatives or geographical factors leading to varying input costs. When it comes to competition, cross-border transmission can be overlooked due to existing investments in other net-zero or renewable energy technologies, their maintenance and research and development costs. As a result, financial prioritisation is aimed elsewhere. Similarly, when transmission projects are positioned as a substitute to local electricity generation, competition, possibly leading to resistance of such projects, may arise.[440] Taking into account another market factor, the volatility of exchange rates affects the remuneration of the

[436] Ember (2023) Breaking borders: The future of Europe's electricity is in interconnectors | Ember (ember-climate.org)
[437] de le Hoye (2020) How to overcome financial barriers to the participation of Europe in a global electrical grid? A feasibility study on a 'Global Grid'
[438] Vaujour (2024) Financing Europe's cross-border interconnectors to deliver energy security, lower priced: a look at incentives and policies
[439] de le Hoye (2020) How to overcome financial barriers to the participation of Europe in a global electrical grid? A feasibility study on a 'Global Grid'
[440] de le Hoye (2020) How to overcome financial barriers to the participation of Europe in a global electrical grid? A feasibility study on a 'Global Grid'

investment in the local currency of the host country. Price zone boundaries and geographic variation in electricity value due to transmission network constraints are central risks to the business case for interconnectors.[441]

The lengthy development timeline may also adversely affect the financial viability of transmission projects. For example, long payback times and changes in circumstance at the start versus the end of a project can affect the project's bankability and investment decisions.[442] In general, transmission project revenues are largely driven by congestion charges. However, these charges are vulnerable over the long term to market changes on both sides of the border, and to fluctuations in price volatility due to the growing share of renewables in the energy mix.[443]

While these financial risks present challenges, it is critical to consider the positive externalities and EU added value that cross-border infrastructure provides. The EU provides decisive support in the expansion and upgrade of cross-border grids, to enable the uptake of additional renewable energy and accommodate the anticipated increase in electricity demand driven by decarbonisation efforts. Cross-border grids facilitate balancing supply and demand, mitigating energy price volatility, and enhancing system resilience. These benefits extend beyond individual Member States, emphasising the need for centralised EU-level action through programmes managed by the European Commission.

Without EU intervention, such as funding under the CEF or similar mechanisms, the market alone may fail to deliver the necessary scale of investments. This is because the costs and benefits of cross-border grids do not always align geographically—costs may be borne by one Member State while benefits are distributed across several others. The absence of these investments could lead to suboptimal outcomes for the EU's energy objectives, further implying the importance of addressing these financial viability challenges at the EU level.

Subsequently, due to the prioritisation of other energy infrastructure categories over transmission lines with cross-border impact, unclear remuneration frameworks susceptible to exchange rate volatility, differing price zone boundaries as well as long development timelines lead, a **medium-high risk** financial viability ranking is made.

Regulatory risks differ based on the type of interconnection projects being developed. European regulatory authorities enforce a restrictive policy on merchant interconnectors. In practice, merchant interconnectors rely on market integration, competition, and limited regulation.[444] To benefit from a merchant scheme, investors must apply for an exemption from the common regulated transmission scheme.[445] To qualify for a merchant scheme, investors must secure an exemption from the EU's regulated transmission framework, which normally enforces tariff controls, third-party access, and regulated returns. This exemption process is complex and may require the project to demonstrate specific cross-border benefits without disrupting regulated markets. Additionally, any granted exemption is typically conditional and time-limited, adding financial uncertainty.[446] As for regulated transmission, risks can still occur. They are mostly related to differing national regulations (as a result

[441] Huang and Hertem (2018) Cross-Border Electricity Transmission Network Investment: Perspective and Risk Framework of Third-Party Investors
[442] Rabobank (2023) The Growing Strategic Importance of Interconnectors: a Look at the North Sea Region
[443] Vaujour (2024) Financing Europe's cross-border interconnectors to deliver energy security, lower priced: a look at incentives and policies
[444] Gautier (2020) Merchant Interconnectors in Europe: Merits and Value Drivers
[445] de le Hoye (2020) How to overcome financial barriers to the participation of Europe in a global electrical grid? A feasibility study on a 'Global Grid'
[446] European Commission (2023) Grids, the missing link – An EU Action Plan for Grids

of a lacking uniform EU-wide framework), environmental permitting delays, and the NIMBY ("not in my back yard") effect.[447] These can also lead to uneven development of cross-border infrastructure on one country's side compared to the other. In addition to the mentioned regulatory risks, differing political ambitions, differing levels of regulatory oversight on infrastructure investments, and differing approaches of either TSOs toward infrastructure development can also impact the rate of progress in developing cross-border infrastructure.

Due to a lack of uniform regulations and TSO approaches across the EU which lead to uneven development and differing political ambitions lead to the regulatory risks for electricity transmission lines with a cross-border impact ranking as **high risk**.

Analysis of main maturity factors

Though some of the aforementioned risks delay project timelines, there is nonetheless a positive **track record** for cross-border infrastructure. In 2021, sixteen EU Member States reported they reached the interconnection target of 15% by 2030 set by the EU. However, some regions' interconnection remains underdeveloped compared to others, requiring more targeted initiatives.[448] Furthermore, Denmark has six existing sub-sea connections and Germany is actively planning the deployment of subsea connections.[449] Lastly, despite EU's restrictive policy on merchant interconnectors, seven merchant projects are in operation in 2020.[450] However, the long development process and potential positioning of cross-border transmission as competition to local electricity production may deter investments in this energy infrastructure. Additionally, cohesive regulations and permitting processes would aid in deploying the projects quicker and allowing them to still be relevant and utilisable for market demands.

Cross-border transmission infrastructure has an existing positive track record and is therefore ranked as **low risk**, however, all abovementioned risks contribute to deployment of cross-border transmission lines to meet the EU's ambitions and needs.

Conclusion of risks and maturity factors

Cross-border infrastructure operates on established technology, though geographical and efficiency factors must be considered. Financial viability risks arise due to exchange rate volatility, price zone boundaries, and transmission network constraints. Additionally, cross-border transmission can be overlooked due to existing investments in other net-zero or renewable energy technologies, their maintenance and research and development costs. As a result, said risks will need to be overcome to meet the EU's 2030 interconnection target. Nonetheless, cross-border infrastructure has a positive track record which leads to the infrastructure being placed as highly mature due to established technology and wide use, and a low volume risk when it comes to financial viability, though transaction costs between MSs may be higher.

For cross-border electricity transmission infrastructure, suitable financial instruments can include **grants** to play a role in covering CAPEX-intensive early-stage construction costs, as well as **initial project studies and cross-border agreements**. Additionally, **loans backed by EU guarantees** could attract private capital by reducing perceived risks, especially given the complex cross-border regulatory environment and the need for long payback periods due to infrastructure development

[447] Huang and Hertem (2018) Cross-Border Electricity Transmission Network Investment: Perspective and Risk Framework of Third-Party Investors
[448] European Commission Electricity interconnection targets (europa.eu)
[449] Rabobank (2023) The Growing Strategic Importance of Interconnectors: a Look at the North Sea Region
[450] Gautier (2020) Merchant Interconnectors in Europe: Merits and Value Drivers

timelines. To further attract private finance, **project-specific green bonds** could finance sustainable infrastructure aspects, such as renewable energy integration into the transmission system.

Electricity transmission lines related to offshore generation

The EU has substantial potential for offshore wind energy and as such has placed offshore infrastructure at the core of the European Green Deal. The EU Member States have agreed on ambitious goals for offshore development. The cumulative EU offshore goals have the following ranges: 109-112 GW by 2030, 215-248 GW by 2040, and 281-354 GW by 2050. Offshore infrastructure development plans were included in the TYNDP signalling that speedy development and expansion will be necessary to meet the aforementioned ambitions.[451] As such, the scope of this section spans fixed-bottom and floating offshore infrastructure.

Analysis of risks (technical and operational, financial viability, and regulatory)

Offshore energy infrastructure faces several **technical risks**. Structural integrity is critical, as extreme weather conditions like high winds, waves, and saltwater corrosion can cause mechanical fatigue, damage, or even failure of key components, including foundations and turbines. Installation and maintenance are also challenging due to the remote locations, requiring specialised vessels and equipment, with weather-related delays adding further complexity. Subsea cables, essential for transmitting power, are vulnerable to damage from seabed movements, fishing activities, and anchors, leading to potential power transmission failures and high repair costs.[452] The technological maturity of certain offshore systems, such as floating wind turbines and wave energy converters, introduces risks associated with unproven technology, which can result in unexpected failures or inefficiencies.[453] Related **operational risks** which can hinder infrastructure functioning also arise. These are largely related to the conditions of the installation environment.[454] It is also important to ensure a stable flow of electricity from offshore to onshore grids. Moreover, offshore operations carry high health and safety risks for employees due to the working conditions. Risks include accidents during maintenance or installation and longer response times in remote conditions. [455] Additionally, offshore energy infrastructure experiences supply chain and critical material challenges.

Fixed-bottom offshore generation infrastructure utilises established infrastructure that is prone to related risks such as corrosion, extreme weather conditions, and mechanical tear, while other technologies remain untested. Operationally, it is important to secure a stable flow of electricity between offshore and onshore grids as well as a supply chain that is currently susceptible to shortages and unpredictability. As a result, the risk level of technical and operational risks is **medium**.

Financial viability risks for offshore energy infrastructure are linked to disruptions in the availability of critical materials like steel and rare earth elements, essential for manufacturing wind turbines and other offshore components, can lead to delays and increased project costs.[456] Additionally, fluctuating energy offtake agreements introduce market uncertainty, as actions by neighbouring EU countries can affect the stability of revenue streams.[457] Moreover, the cost of the grid connection rises significantly when the distance to shore increases. Market dynamics, including global competition

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[451] European Commission (2023) Member States agree new ambition for expanding offshore renewable energy (europa.eu)
[452] Ahlgren and Grudic (2017) Risk Management in Offshore Wind Farm Development
[453] Klijnstra et al (2017) Technical Risks of Offshore Structures
[454] Klijnstra et al (2017) Technical Risks of Offshore Structures
[455] Klijnstra et al (2017) Technical Risks of Offshore Structures
[456] Allianz (2023) A turning point for offshore wind
[457] ACER & CEER (2022) ACER and CEER reflection on the EU strategy to harness the potential of offshore renewable energy for a climate neutral future

for resources and technology, further contribute to these uncertainties, as the rapid expansion of offshore wind worldwide, particularly in Asia and Europe, increases the demand on supply chains.[458]

Offshore energy infrastructure is susceptible to rising costs due to critical material shortages and subsequent sourcing as well as the cost of grid connection overall. Unpredictable offtake agreements similarly contribute to ranking the financial viability risk as **medium**.

Regulatory risks are linked to differing national regulations and priorities. Changes in leadership or shifts in policy priorities – both energy and environmental – affect the development of offshore infrastructure. In particular, offshore energy projects are subject to stringent environmental regulations, mainly concerning the protection of marine ecosystems and wildlife. Regulatory agencies may impose strict conditions to limit the impact on marine life, seabed habitats, and fishing industries. Non-compliance with these regulations can result in fines, project halts, or forced modifications to infrastructure.[459] The environmental regulations are coupled with other permitting processes that can cause significant delays or even cancellations of projects.[460] Offshore infrastructure often operates across multiple jurisdictions, especially in shared seas like the North Sea or Baltic Sea. Agreements regarding potential conflicting national regulations and disputes over responsibilities can complicate operations.

Offshore generation infrastructure development is reliant on compliance with strict regulatory and permitting processes which can be lengthy and inconsistent. This fact is further exacerbated by operations in multiple jurisdictions, for example shared seas. Consequently, the regulatory risk for offshore generation is classified as **high**.

Analysis of main maturity factors

The maturity of offshore infrastructure depends on the type of technology used. Fixed-bottom offshore wind energy technology is mature with decades of operation in the EU. Standardisation and best practices exist to inform further expansion of fixed-bottom offshore infrastructure – though operational risks mentioned above still apply. However, floating offshore wind energy, a form of offshore infrastructure that will unlock remote locations that are too deep for fixed-bottom offshore wind energy, is still in its infancy. Challenges include insufficient port infrastructure and high levelised costs of energy. Standardisation, optimisation and commercialisation which are currently lacking for floating offshore infrastructure are crucial to make floating wind energy cost-competitive.[461]

The overall track record of offshore generation infrastructure, specifically fixed-bottom infrastructure, is well-established. However, floating offshore infrastructure is a younger, less-established technology, while being crucial for expansion into deep-water sea basins. Therefore, the track record overall is ranked as **low risk**.

Conclusion of risks and maturity factors

Though fixed-bottom offshore infrastructure operates on mature technology and is by this point established, it is nonetheless prone to technical risks linked to installation and maintenance considerations. These directly relate to the financial viability risks that can arise as a result of supply chain disruptions. Similarly, fluctuating energy offtake agreements introduce market uncertainty, as actions by neighbouring EU countries can affect the stability of revenue streams. Nonetheless, fixed-bottom offshore infrastructure is a well-established energy infrastructure with existing offshore

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[458] Allianz (2023) A turning point for offshore wind
[459] Nielsen (2018) Corrosion Protection of Offshore Wind Power Plants
[460] Klijnstra et al (2017) Technical Risks of Offshore Structures
[461] Rabobank (2023) Floating Offshore Wind Energy: Reaching Beyond the Reachable by Fixed-Bottom Offshore Wind Energy

windfarm projects. However, the same risk categories are significantly higher for floating offshore infrastructure due to the earlier development stages in which the infrastructure is currently situated. For electricity transmission lines related to offshore generation, **suitable financial instruments** include grants can cover the CAPEX-intensive stages of construction and subsea cable installation, funded by EU programmes like the CEF. Additionally, concessional loans, potentially backed by InvestEU, can attract private capital by mitigating perceived risks associated with long payback periods and operational challenges in the offshore environment. Project-specific green bonds could further finance renewable energy integration into the grid, appealing to institutional investors.

Electricity distribution infrastructure

As Europe accelerates its energy transition toward decarbonisation and electrification, electricity distribution infrastructure plays a central role in ensuring a reliable, efficient, and flexible power system. Around 30% of the distribution infrastructure is over 40 years old, with some assets much older.[462] Components that are being actively installed, refurbished or replaced include new lines, transformers, and other substation components. Upgrading existing distribution infrastructure is therefore crucial alongside investing in new technologies such as integration of smart grids and digital technologies which can then be deployed onto new infrastructure components. The need to refurbish existing infrastructure is driven by the rising demand for electricity, particularly from electric vehicles, heat pumps, and distributed energy resources (DERs).

Analysis of risks (technical and operational, financial viability, and regulatory)

Technical and **operational risks** arise when existing infrastructure is to be upgraded with technology that may not be compatible with the current infrastructure. This includes avoiding overloading and stability issues which are caused by incorrectly sized or planned lines that lead to voltage fluctuations and outages. This is particularly important with the increasing integration of renewables, which cause variable power flows.[463] When it comes to replacing transformers, supply chain disruptions leading to material shortages and long manufacturing times pose one of the biggest challenges.[464] This can lead to issues faced at the level of substations which are also vulnerable to circuit breaker malfunctions, physical and environmental risks, maintenance delays or incorrect switching operations or configuration errors and, with smart monitoring.[465]

While technical and operational risks remain relatively **low** due to the maturity of existing infrastructure and well-established operational methods, these risks are increasing due to supply chain challenges, the integration of renewables, and the adoption of emerging technologies like smart grids. Although financial viability is currently supported by the regulated nature of DSOs and a stable revenue base, these future risks, along with the technical considerations, position electricity distribution infrastructure as **low/medium** risk overall.

Financial viability risk in electricity distribution infrastructure is more closely tied to the challenges of investment planning rather than fluctuations in demand. While electricity grids are predominantly revenue-regulated, allowing operators to adjust tariffs to meet revenue targets even if usage decreases, emerging trends such as increased electricity consumption from electrification (e.g., EV charging and heat pumps) and changes in offtake patterns due to self-consumption (e.g., rooftop solar) introduce new complexities. These shifts amplify uncertainty in determining the appropriate scale and timing for capital deployment, particularly for upgrades to accommodate these evolving

[462] European Commission (2023) Grids, the missing link – An EU Action Plan for Grids
[463] JRC (2023) Future EU power systems: renewables' integration to require up to 7 times larger flexibility
[464] Eurelectric (2024) Why the distribution grid must be a critical enabler of Europe's energy transition
[465] Eurelectric (2024) Why the distribution grid must be a critical enabler of Europe's energy transition

consumption patterns. The value of grid-friendly flexibility and asset performance excellence could be better captured in regulatory frameworks and the incentives provided therein.[466]

Due to the revenue-regulated nature and a strong demand for electricity distribution infrastructure, the financial viability risk overall currently remains **low**. Still, some financing challenges may arise in certain cases with large tariff increases on consumers and businesses, if these increases are seen as socially unfeasible. Rapid increases in CAPEX to modernise and expand distribution networks, as required for the energy transition, may elevate financial risks, if costs are not recovered by grid users but by taxpayers or another larger group. However, for DSOs, unlike TSOs, significant increases in grid tariffs are less likely; the large growth in investments is typically matched by a corresponding or even larger growth in demand, resulting in relatively stable network tariff rates across the EU. Nonetheless, this potential risk is considered when evaluating the long-term financial viability of electricity distribution infrastructure.

The **regulatory risk** landscape for electricity distribution infrastructure is critical but regulation remains underdeveloped in many areas. While the EU's regulatory frameworks support decarbonisation, the lack of harmonised rules across Member States creates uncertainty . The political will to prioritise grid investments varies by country.[467]

Importantly, according to ACER[468], investments in smart grids are generally treated similarly to any other transmission/distribution investments, with no specific regulatory framework for assessing the unique technical challenges that arise from integrating these new technologies. This regulatory approach may not account for the higher risks and technical complexities of smart grids, potentially reducing the ability of these projects to secure the necessary investments or tailored incentives for innovation. CAPEX bias is however also worth mentioning here, as the regulated return schemes of some countries can discourage investments into OPEX-heavy alternatives to grid expansion, such as various smart grid technologies. Consequently, the regulatory risk is considered **medium** due to varying MS approaches to investment priorities and unharmonised rules across the EU, and a lack of regulatory framework for integration of new technologies.

Analysis of maturity factors

Electricity distribution infrastructure is well-established with a strong **track record and commercialisation**. This is best exemplified by the fact that around 30% of the distribution infrastructure is over 40 years old, with some assets much older.[469] This is, however, also a signal that distribution infrastructure is in need of equipment replacement to not only secure stable distribution as a whole, but also be able to handle the influx of new energy sources through renewables generation. However, the track record for smart grid technologies remains limited, with most projects still in early commercialisation stages. Emerging strategies like asset performance excellence and grid-friendly flexibility show promise but are yet to be widely implemented, limiting available data on their long-term reliability and cost-effectiveness. [470] The lack of a fully developed market for grid services, such as flexibility and demand-side management, further complicates the commercialisation of these technologies. As a result, the track record overall remains **low risk,** however, emerging technologies pose a **medium risk.**

Conclusion on risks and maturity factors

[466] Eurelectric (2024), Grids for Speed
[467] ID-E (2023) Financial instruments and models for energy production
[468] ACER (2023) Report on investment evaluation, risk assessment and regulatory incentives for energy network projects
[469] European Commission (2023) Grids, the missing link – An EU Action Plan for Grids
[470] ID-E (2023) Financial instruments and models for energy production

DSOs are among the more mature and established elements of energy infrastructure, handling the physical distribution of electricity through long-standing methods such as cable installation and grid maintenance. This foundational role has remained consistent over time, grounded in well-proven technologies. While integrating newer systems like smart grids introduces less mature elements, these innovations are layered onto a stable, regulated, and time-tested foundation. The challenges posed by new technologies do not outweigh the overall maturity of DSOs, which continue to be a reliable backbone of energy distribution systems.

For electricity distribution infrastructure, **suitable financial instruments** should derive from national or private financing, primarily in the form of loans, given the low risk and regulated nature of DSOs.

DSOs typically have a stable revenue base, allowing them to access traditional debt financing for standard upgrades and maintenance. However, as modernisation efforts, such as the integration of smart grid technologies, introduce additional risks, national grants may be necessary to facilitate R&D and the initial deployment of these innovative solutions. For larger-scale projects aimed at grid upgrades and enhanced flexibility, EU support may be warranted. This can be achieved through blended financing mechanisms like grants paired with (concessional) loans or TA for project preparation.

Electricity storage directly connected to high voltage transmission and distribution lines

Energy storage plays a critical role in the European Union's transition to a low-carbon energy system, enabling greater integration of renewable energy sources and enhancing grid stability. As the EU strives to meet its climate goals, energy storage technologies, from pumped hydro to batteries, are essential for balancing supply and demand, reducing reliance on fossil fuels, and ensuring energy security. However, with the potential of pumped storage nearly saturated, other electricity storage technologies must be considered to meet the EU's net zero goals. This section will therefore focus on battery electricity storage and related risks.

Analysis of risks (technical and operational, financial viability, and regulatory)

Technical risks of BESS are linked to several factors such as battery durability, thermal stability, battery capacity, and battery material. Consequently, it is important to take into account necessary accommodations. These may include regular replacement or refurbishment of existing batteries and the physical space BESS technologies will require to store generated energy.[471] As for battery material, it is vital to consider the extraction processes of metals and its environmental impact. Similar attention should be paid to the environmental and thermal aspects of BESS installation sites to ensure proper function and safety.[472] Supply chain risks are a major **operational concern** for energy storage technologies, particularly for Li-ion batteries, which rely heavily on imported raw materials. Disruptions caused by geopolitical events, such as the Covid-19 pandemic and Russia's invasion of Ukraine, have led to significant price increases for key materials like nickel and aluminium. This risk is most pronounced for commercial-scale technologies. Effective management of supply chains, including boosting domestic raw material production within the EU, is essential to mitigate these risks.[473]

Technical and operational risks of BESS are characterised by a heavy reliance on imported raw materials which are subject to supply chain disruptions. This considerably hinders the necessary

[471] JRC (2022) Batteries for storage in the European Union
[472] Amir et al (2023) Energy storage technologies: An integrated survey of developments, global economical/environmental effects, optimal scheduling model, and sustainable adaption policies
[473] ID-E (2023) Investors Dialogue on Energy: Financial Instruments and models for energy storage

upkeep, replacement or refurbishment of existing batteries to ensure smooth operation and technical quality. Consequently, this warrants a **medium risk** level.

For **financial viability risks**, energy storage projects with long-term contracts, such as those in capacity markets, face lower market risk due to predictable revenue streams, while projects relying on merchant models, like energy arbitrage, encounter higher risks from volatile energy prices, making financing more difficult. The lack of stable, long-term contracts is a major barrier for commercial-scale storage, increasing investment risk and limiting access to financing. Moreover, long-term energy storage options such as flow batteries or hydrogen-to-power are characterised by a higher financial risk profile due to being in early stages of commercial viability. Short-term storage, on the other hand, in the form of batteries has a lower financial risk profile due to being more mature. Mechanisms like EU-backed guarantees and capacity remuneration mechanisms (CRM) have been proposed to provide revenue stability, which is essential for attracting investment and reducing market risk.[474]

The level of financial viability differs based on the type of contracts that are obtainable. The lack of long-term contracts leads to instability and in turn limited access to financing. On the other hand, short-term storage solutions have a lower financial risk profile. Subsequently, the overall financial viability risk is rated as **medium**.

Regulatory risks also affect electricity storage technology, such as outdated definitions that often classify storage as both a consumer and generator, leading to double taxation and unnecessary grid fees when charging and discharging energy. Additionally, restrictive market access policies, such as high bid sizes, price caps, and pre-qualification requirements prevent storage technologies from fully participating in energy markets. This issue then hinders the development of viable business models. As a result, the regulatory risk is ranked **medium**.

Analysis of main maturity factors

Electricity storage technologies, other than pumped-storage hydropower the options of which have been nearly saturated and has a reliable **track record**, are at varying stages of maturity. However, the focus of this section, grid-scale batteries, particularly lithium-ion, have emerged as the most scalable option for short-term grid flexibility. Global capacity for grid-scale batteries grew by over 75% in 2022, reaching nearly 28 GW. This growth reflects the increasing demand for flexible solutions to support the integration of variable renewable energy sources like wind and solar. However, despite significant progress, storage capacity remains behind the targets set by the Net Zero Emissions by 2050 Scenario, which forecasts a need for around 970 GW of battery storage by 2030, showing delays in commercialisation.[475] Markets across Europe, particularly the UK, Italy, and Germany, are seeing steady investment driven by policy support.[476] However, while newer technologies like flow batteries hold potential, they remain in the early stages of commercial viability.

Overall, electricity storage is rapidly evolving but still requires further scaling to meet future energy demands. Therefore, the track record of BESS technologies is rated as **high risk**.

Conclusion of risks and maturity factors

Electricity storage technology has already utilised the available options for pumped hydro storage, therefore, the above section focused on BESS. Short-term storage in the form of grid-scale batteries has a lower financial risk profile due to being more mature. The technology is more mature compared

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[474] ID-E (2023) Investors Dialogue on Energy: Financial Instruments and models for energy storage
[475] IEA (2023) Grid-electricity storage
[476] EES (2024) The Strongest European Markets for Electricity Storage

to flow batteries and hydrogen-to-power storage technologies. Though policy support is provided to BESS, the support is uneven across MSs and as a result storage capacity is lagging compared to the set EU targets.

For electricity storage infrastructure directly connected to high-voltage transmission, **suitable financial instruments** at the national or EU level could include grants to cover early-stage CAPEX-intensive development costs, such as feasibility studies and initial deployment. Loans, potentially backed by EU guarantees, are suitable for supporting mature BESS technologies with predictable revenue streams, especially those integrated with capacity markets. Equity is particularly well-suited for high-risk, early-stage projects and can attract venture capital or private equity for emerging storage technologies, such as long-duration storage solutions, by balancing potential high returns with the associated technology risks. Quasi-equity, such as subordinated loans or convertible debt, is also valuable for storage projects that have revenue but face market fluctuations or operational uncertainties. This flexible financing can bridge the gap between debt and equity, providing support for scaling up capacity, expanding infrastructure, or implementing new technologies while reducing risks for traditional debt financiers.

Hydrogen infrastructure

Hydrogen infrastructure development has a central role in the EU's strategy to decarbonise key sectors of the economy. Hydrogen, especially in its low-carbon form, is seen as an essential solution for sectors that are difficult to electrify, such as energy-intensive industry and long-distance transport. However, the absence of a trans-European hydrogen gas infrastructure poses significant challenges to the EU's ambitious goals, including the REPowerEU target of producing 10 million tonnes of renewable hydrogen annually by 2030. The development of dedicated hydrogen infrastructure, such as pipelines, storage facilities, and terminals, remains in its early stages, with most projects still in the planning or design phase.[477]

The key hydrogen-related infrastructure included within this study include hydrogen pipelines, import terminals, installations for hydrogen use in transport sector, and electrolyser facilities. Each of these categories faces technical, financial, and operational challenges. While plans for the European Hydrogen Backbone (EHB) have been developed by gas TSOs, the broader infrastructure, particularly for storage and electrolysers, remains uncertain in terms of sizing, investment needs, and technological readiness.[478] Moreover, the overarching **regulatory risk** for all hydrogen infrastructure analysed below is the lack of a clear regulatory framework across MSs, standardisation, varying policies, and the lack of business models for these infrastructure elements.[479]

Analysis of risk (technical and operational, and financial viability)

Hydrogen pipelines

Hydrogen pipelines present a multifaceted risk profile, encompassing technical, market, operational, and political/regulatory challenges. **Technically**, one of the major hurdles is the physical difficulty with transporting hydrogen, including by retrofitting existing natural gas pipelines to transport hydrogen. Although repurposing can reduce upfront costs, hydrogen's small molecular size increases the risk of embrittlement in pipeline materials, leading to potential leakage and safety issues. Additionally, hydrogen's low density requires advanced compression systems, making long-distance transport both technically challenging and costly. Offshore pipelines face heightened risks due to uncertainties

[477] ID-E (2023) Financial instruments and models for energy production
[478] European Hydrogen Backbone (2023) Implementation roadmap – cross border projects and cost update
[479] Oxford Institute for Energy Studies, (2024) 2024 state of the European hydrogen market report

in compression and design systems for long-distance transport.[480] Operationally, there is little historical performance data on large-scale dedicated hydrogen pipelines, making it difficult to predict operational performance or costs accurately.[481] Furthermore, the development timelines for hydrogen production and pipeline infrastructure must be carefully coordinated, as hydrogen pipelines are at higher risk than other transport infrastructure of being underutilised and becoming stranded assets. Consequently, the technical and operational risk is rated **high**.

From a **financial viability** perspective, the demand for dedicated hydrogen pipelines is still developing, and this uncertainty poses a significant risk. The hydrogen economy is in its infancy, and many production and transport projects are speculative. Without clear offtake agreements or long-term commitments, securing revenue from pipeline capacity bookings remains difficult. For example, only 4.5% of the supply required to meet the EU's REPowerEU targets has been secured through binding offtake agreements.[482] The market's reliance on public funding and subsidies to close the financial gap also introduces risk, especially if expected government support does not materialise.[483] Hydrogen: Public-private partnerships and EU financial instruments like the Hydrogen Bank and Recovery and Resilience Facility (RRF) are vital in closing the funding gap, but the scale of funding needed still far exceeds current commitments.[484] As a result, the financial viability risk is **high**.

Hydrogen terminals

Hydrogen import terminals, which are essential for receiving and processing hydrogen in liquid or gaseous form, face multiple risks. **Technically**, liquid hydrogen requires extremely low storage temperatures , significantly colder than LNG, making the repurposing of LNG terminals both costly and highly complex. Furthermore, the technology for large-scale hydrogen storage remains in its infancy, contributing to uncertainties around project execution, including potential delays and cost overruns. [485] Modifying existing terminals to handle hydrogen adds additional layers of complexity, from safety concerns to technical challenges, further increasing the risk profile of these projects.[486] **Operational risks** arise from handling liquid hydrogen, which involves challenging logistics and storage at extremely low temperatures. Converting LNG terminals requires extensive upgrades, increasing the risk of technical failures and delays. [487] While ammonia terminals may need fewer changes, pure hydrogen infrastructure remains underdeveloped, potentially creating bottlenecks in supply chains.[488] Consequently, the technical and operational risk is considered **high**.

Financial viability risk stems from the uncertain demand for hydrogen imports, particularly for energy applications. While there is established demand for hydrogen as a feedstock in chemical processes, such as ammonia production and refining, our main focus here is on its potential as an energy vector. This application is still in its early stages of development. As domestic hydrogen production increases, the future need for imports remains unclear, especially for derivatives like ammonia or methanol. These markets are still evolving, relying on industrial adoption, technological advancements, and supportive regulatory frameworks.[489] Due to the uncertain demand in the energy sector, the financial viability risk is assessed as **high**.

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[480] European Hydrogen Backbone (2023) Implementation roadmap – cross border projects and cost update
[481] Oxford Institute for Energy Studies, (2024) 2024 state of the European hydrogen market report
[482] Oxford Institute for Energy Studies, (2024) 2024 state of the European hydrogen market report
[483] European Court of Auditors (2024) Special report 11/2024: The EU's industrial policy on renewable hydrogen
[484] European Parliament (2023) Energy systems infrastructures and investments in hydrogen
[485] ID-E (2023) Financial instruments and models for energy production
[486] Hydrogen Europe (2022) Clean hydrogen Europe
[487] ID-E (2023) Financial instruments and models for energy production
[488] Hydrogen Europe (2022) Clean hydrogen Europe
[489] ID-E (2023) Financial instruments and models for energy production

Grid electrolysers

Grid electrolysers, essential for producing green hydrogen through electrolysis, face notable **technical risks** related to scaling, efficiency, and integration with fluctuating renewable energy sources. Meeting the ambitious REPowerEU target of 10 million tonnes of hydrogen by 2030 requires installing 125 GW of electrolyser capacity, a significant challenge given the current state of technology. Although progress is being made, the efficiency of large-scale electrolysers remains a concern, especially when integrated with intermittent renewable energy.[490] [491]Electrolysers must be able to **operate** flexibly to absorb surplus renewable electricity, but failures in control systems or grid integration could reduce hydrogen production and increase operational costs.[492]

The **financial viability risks** for grid electrolysers stems largely from the high cost of green hydrogen production compared to fossil fuel-based hydrogen. With production costs exceeding €5 per kilogram for electrolytic hydrogen, as opposed to €1 to €3 per kilogram for traditional hydrogen, demand remains limited, particularly in price-sensitive sectors. [493] Furthermore, there is uncertainty about hydrogen's long-term role in the energy mix, as alternatives like battery storage and heat pumps become more viable in specific sectors contributing to more unpredictability for investors.[494] Consequently, the uncertainty associated with the demand for grid electrolysers, financial viability remains **high**.

Installations for hydrogen use in transport sector

This infrastructure supports hydrogen-fuelled transport and faces **technical risks** when serving both light-duty and heavy-duty vehicles. Installations require high-pressure storage and dispensing systems (up to 700 bar), which demand specialised materials resistant to hydrogen embrittlement.[495] The absence of standardised technology across Europe further exacerbates uncertainties regarding operational compatibility and future maintenance costs. [496] **Operational risks** are closely linked to the immature technology used in installations for hydrogen use in transport sector, particularly the high-pressure systems required for dispensing. The risks of equipment failure, leaks, and safety incidents are heightened without proper management and expertise.[497] Furthermore, the low number of hydrogen vehicles on the road, especially during the early stages of deployment, could lead to underutilised installations, increasing operational inefficiencies. As a result, the technical and operational risks are regarded as **high**.

Financial viability risk is significant for installations for hydrogen use in transport sector, primarily due to the uncertain demand for hydrogen vehicles. While regulatory frameworks like the Alternative Fuel Infrastructure Regulation (EU) 2023/1804 mandate a minimum number of installations, the actual uptake of hydrogen-powered vehicles remains limited, particularly in the heavy-duty transport sector. [498] The success of installations is closely tied to vehicle adoption, and delays in this area could result in low utilisation, reducing expected revenue streams. [499] A misalignment between the roll-out of installations and the pace of hydrogen vehicle adoption could result in idle or underperforming installations, driving up operational costs per unit of fuel dispensed. [500] Additionally, the high capital

[490] Oxford Institute for Energy Studies, (2024) 2024 state of the European hydrogen market report
[491] ID-E (2023) Financial instruments and models for energy production
[492] ID-E (2023) Financial instruments and models for energy production
[493] Oxford Institute for Energy Studies, (2024) 2024 state of the European hydrogen market report
[494] Oxford Institute for Energy Studies, (2024) 2024 state of the European hydrogen market report
[495] ID-E (2023) Financial instruments and models for energy production
[496] Hydrogen Europe (2022) Clean hydrogen Europe
[497] ID-E (2023) Financial instruments and models for energy production
[498] Hydrogen Europe (2022) Clean hydrogen Europe
[499] ID-E (2023) Financial instruments and models for energy production
[500] ID-E (2023) Financial instruments and models for energy production

costs required for building these installations, combined with uncertainty around when the hydrogen vehicle market will scale, pose substantial financial risks for investors. As a result of the overarching uncertainty of uptake and demand for installations for hydrogen use in the transport sector, the financial viability risk is assessed as **high**.

Underground storage

Underground Hydrogen Storage (UHS) presents several **technical** challenges due to hydrogen's small molecular size, which increases the risk of leakage, particularly in porous media or salt caverns.[501] Embrittlement of materials used in surface and subsurface infrastructure also remains a concern, with long-term stability under high-pressure hydrogen posing a significant challenge.[502] **Operational** challenges arise primarily from the complexity of constructing and maintaining facilities. Salt caverns, while well-established for gas storage, require extensive maintenance to prevent hydrogen losses through diffusion or interaction with surrounding geological structures. In aquifers, the risk of microbial activity transforming hydrogen into methane presents further operational concerns.[503] Additionally, the lack of large-scale operational data and site-specific geological characteristics can lead to project delays and inefficiencies. Subsequently, the associated technical and operational risks are rated **high**.

Financing of UHS is uncertain due to the early-stage development of hydrogen markets. The long-term demand for hydrogen, particularly in energy systems, is still evolving, leading to unpredictable revenue streams. While hydrogen storage could play a crucial role in supporting grid stability and renewable energy integration, the lack of established demand creates a significant investment risk. Additionally, competition from alternative energy storage technologies further compounds the market uncertainty.[504] Consequently, the unpredictability of UHS leads to a **high** financial viability risk.

Analysis of main maturity factors

While each element of hydrogen infrastructure faces specific technical, operational and financial viability risks, all elements are not yet commercially viable. The conclusion on main maturity factors is therefore applicable for all infrastructure elements. Hydrogen infrastructure overall remains primarily in the early stages of development, with critical components such as pipelines, terminals, electrolysers, and installations for hydrogen use in transport sector still being planned or piloted. For instance, the European Hydrogen Backbone aims to retrofit existing gas pipelines, but much of this is still in the conceptual stage, reliant on future technological advancements and large-scale investments.[505]

When assessing the **track record**, hydrogen infrastructure has limited operational history and remains in the early stages of commercialisation. Dedicated hydrogen pipelines, large-scale electrolysers, and hydrogen import terminals have seen little real-world testing, and most projects remain in pilot phases. This lack of an established track record increases uncertainty about long-term performance, making it difficult for investors to gauge operational reliability and financial returns.[506] [507] As a result, the track record risk remains **high**.

Conclusion of risks and maturity factors

[501] Tarkowski (2019) Underground hydrogen storage: characteristics and prospects
[502] Gianni, et al. (2024) Underground hydrogen storage: The techno-economic perspective
[503] Gianni, et al. (2024) Underground hydrogen storage: The techno-economic perspective
[504] Tarkowski (2019) Underground hydrogen storage: characteristics and prospects
[505] ID-E (2023) Financial instruments and models for energy production
[506] Oxford Institute for Energy Studies, (2024) 2024 state of the European hydrogen market report
[507] European Hydrogen Backbone (2023) Implementation roadmap – cross border projects and cost update

Hydrogen infrastructure is still in its infancy, particularly in areas such as dedicated hydrogen pipelines, import terminals, electrolysers, and installations for hydrogen use in transport sector. The technology remains largely untested at scale, especially in complex long-distance transport and storage. As a result, little historical data exists on large-scale hydrogen projects Hydrogen pipelines face significant technical risks due to issues like hydrogen embrittlement and compression challenges. Financial viability risks are also high due to uncertain demand and the high cost of hydrogen production compared to alternatives. These are further exacerbated by the absence of a unified European framework for hydrogen infrastructure.

For hydrogen infrastructure, **suitable financial instruments** at the EU and national levels could include a mix of grants, loans, equity, and quasi-equity to address the high capital needs, technical and user base uncertainties associated with its development. Grants can play a critical role in covering CAPEX-intensive early-stage costs, including feasibility studies, R&D, and initial deployment of advanced technologies such as electrolysers, hydrogen pipelines, and storage solutions. The EU ETS Innovation Fund, for example, can help offset early-stage costs through competitive grant funding, which is particularly useful for projects with high technical risks and longer development timelines. EU-backed loans with guarantees can enhance the financial attractiveness of hydrogen projects with evolving but relatively stable revenue potential, such as import terminals, installations for hydrogen use in transport sector, and distribution infrastructure. By reducing risk, these guarantees can encourage private lenders to finance larger portions of the capital requirements. Loan guarantee programs within InvestEU and the European Fund for Sustainable Development Plus (EFSD+) are particularly suitable for scaling up hydrogen infrastructure, providing risk-sharing opportunities that attract commercial financiers.

CO_2 transport and storage infrastructure

CO_2 infrastructure is projected to play a significant role in the EU-wide energy network due to the potential of carbon capture storage (CCS) in reaching net-zero goals. However, the successful deployment and integration of CO_2 projects will depend on the development of the necessary storage sites and transport networks. As a result, to date, only one full CCS value chain project has received FID while other projects remain announced or in early development stages. While most MSs currently lack infrastructural plans or guidelines to support the development of CCS, the TEN-E framework includes dedicated pipelines, other than upstream pipeline network, used to transport carbon dioxide from more than one source, for the purpose of permanent geological storage of carbon dioxide as well as fixed facilities for liquefaction, buffer storage and converters of carbon dioxide in view of its further transportation through pipelines and in dedicated modes of transport such as ship, barge, truck, and train, together with surface and injection facilities associated with infrastructure within a geological formation that is used, in accordance with Directive 2009/31/EC, for the permanent geological storage of carbon dioxide, This section will focus on the pipeline networks as the expected backbone of future CO_2 value chains.

Analysis of main risks (technical and operational, financial viability, and regulatory)

While CO_2 pipelines are considered to be commercially viable, **technical risks** arise, such as flow rates, variability in CO_2 composition, and capture technologies across varying industries. Managing flow rates specifically requires further research due to missing operational data. Variability in CO_2 composition poses a twofold challenge – controlling impurities in CO_2 remains under-researched while impurities such as SO_2, NO_2, H_2S, and O_2 present corrosion risks for pipelines. The risk of corrosion is further increased water-containing phases form, which is exacerbated when CO_2 streams from different sources are mixed. Additionally, reusing existing natural gas pipelines for CO_2 transport require detailed assessments to evaluate the aforementioned corrosion risks, fracture toughness, and the differing properties of CO_2 compared to natural gas.[508] Lastly, CO_2 transportation through pipelines and storage relies on physical, residual, dissolution, and mineral trapping mechanisms. These depend heavily on geological conditions, adding variability and risk in ensuring efficiency and reliability.[509]

Managing impurities, preventing compressor issues in the network, and avoiding two-phase flows are crucial to maintaining smooth transport network operations, which require precise control and real-time monitoring. Additionally, the intermittent and variable flow of CO_2 from multiple sources, influenced by market and operational conditions, can introduce complexity and potential disruptions. The reuse of existing pipelines for CO_2 transport requires regular detailed assessments, inspections, and repairs, which may lead to delays.[510] Several challenges are linked to CO_2 storage and transport capacity. Identifying and evaluating suitable storage sites is time-consuming and expensive, with delays potentially caused by technical, regulatory, or community challenges. Once storage sites are established, delays in coordinating transport and storage infrastructure with CO_2 capture projects, especially in the first clusters, can disrupt the entire CCS chain.[511] Similarly, the need to store all captured CO_2 immediately can lead to long transport routes with low capacity, especially in regions lacking sufficient storage.[512] The operational risks related to equipment, tools, and labour are significant for CO2 transport and storage infrastructure. Supply chain issues in sourcing specialised materials, such as corrosion-resistant pipeline components and compressors, can lead to delays and cost increases. The presented technical and operational risks are, therefore, considered **high**.

From a **financial viability perspective,** the development of CO_2 transport and storage infrastructure, such as pipelines and hubs, is essential for attracting investor confidence, as a lack of established networks creates uncertainty around investments in capture and storage. However, the CO_2 transport market is expected to be monopolistic, potentially requiring government regulation to ensure competition and market stability. Additionally, uncertainty in CO_2 supply, including fluctuations in CO_2 capture, can lead to unpredictable transport and storage fees, increasing market risk.[513] The success of CCS is inherently tied to growing demand for carbon reduction services driven by the push for net-zero emissions. The profitability of projects further depends on the development of emission reduction credit markets and industries' willingness to invest in CCS as part of their carbon management strategies.[514]

Moreover, impurities in CO_2 streams raise compression costs and operational expenses, requiring financial models to adapt to fluctuating CO_2 supply and demands. Though reusing existing pipelines can offer cost savings of 1-10% compared to new construction, financial viability depends on detailed assessments and potential additional costs. Long-term liability for CO_2 storage may deter investors unless governments share or cap the associated risks.[515] Financial viability is a major challenge for CCS projects due to uncertain early-stage revenues. The investment recovery challenge and upfront

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[508] Zero Emissions Platform (2020) A trans-European CO2 transportation infrastructure for CCUS opportunities and challenges
[509] Global CCS Institute (2022) Global Status of CCS 2022
[510] Zero Emissions Platform (2020) A trans-European CO2 transportation infrastructure for CCUS opportunities and challenges
[511] Global CCS Institute (2022) Global Status of CCS 2022
[512] Joint Research Centre (2024) Shaping the future CO2 transport network for Europe
[513] Zero Emissions Platform (2020) A trans-European CO2 transportation infrastructure for CCUS opportunities and challenges
[514] Global CCS Institute (2022) Global Status of CCS 2022
[515] Zero Emissions Platform (2020) A trans-European CO2 transportation infrastructure for CCUS opportunities and challenges

financing gap highlight the financial disparity between expected and actual revenues during initial operation. For CO_2 pipelines, public-private partnerships and regulated asset base models are being considered. However, high capital and operating expenditures contribute to financial uncertainty. Therefore, significant upfront capital investment is needed for CO_2 transport and storage infrastructure, especially without incentives like CO_2 enhanced oil recovery. Consequently, the financial viability risks associated with CO_2 transport and storage infrastructure are ranked **high**.

CO_2 infrastructure is heavily influenced by **regulatory** conditions. The legal framework for cross-border CO_2 pipelines remains underdeveloped, with differing national regulations creating potential issues. Government incentives are crucial for supporting transport and storage infrastructure, such as geological storage, which currently lack market drivers. Additionally, regulatory intervention may be required to address the monopolistic nature of the CO_2 transport and storage market and long-term storage liability risks.[516] Therefore, the regulatory risks remain **high** until policy initiatives and frameworks are established.

Analysis of main maturity factors

Though the majority of CO_2 transport networks and CCS projects are in the development stage, assessments can be made in relation to their **track record**. The use of CO_2 pipelines has a proven track record in some CCS projects, particularly for "point-to-point" transportation, but the experience with multi-source pipeline networks and mixed CO_2 compositions is less developed.[517] The historical performance of CCS technologies is varied. While CCS has been successfully implemented in enhanced oil recovery and some dedicated storage projects, the technology is still in the early stages of widespread deployment. The number of operational CCS facilities is growing, but the overall capacity is still far below what is needed to meet global climate goals. The track record is improving as more projects move from the development phase to operation, but there remains a significant gap between current capabilities and future requirements.[518] The shift towards networks and hubs for CO_2 transport and storage is a relatively new development that is essential for scaling up CCS to gigatonne levels. Full-scale deployment of CCS technologies depends heavily on continued technological innovation, supportive policies, and the development of carbon markets.[519] Consequently, the risks associated with assessing the track record of CO_2 transport and storage infrastructure is **high**.

Conclusion of risks and maturity factors

CO_2 infrastructure is an emerging energy infrastructure with storage and CO_2 pipelines still in development. This results in a lack of established operating CO_2 value chains that increases financial viability risks due to uncertainties related to value chain disruptions. While there is a demand for CO_2 to play a bigger role in EU-wide climate neutrality goals, the uncertainties related to the usability of existing and planned CO_2 infrastructure lead to investment aversion. Another concern is the expectation that CO_2 transport market is expected to be monopolistic, potentially requiring government regulation to ensure competition and market stability.

For CO_2 transport infrastructure, a **suitable mix of financial instruments** is necessary to mobilise the required investment and drive project viability. Key financial instruments include grants for early-stage development for first movers or first-of-a-kind developments, such as feasibility studies and

[516] Zero Emissions Platform (2020) A trans-European CO2 transportation infrastructure for CCUS opportunities and challenges
[517] Zero Emissions Platform (2020) A trans-European CO2 transportation infrastructure for CCUS opportunities and challenges
[518] Global CCS Institute (2022) Global Status of CCS 2022
[519] Global CCS Institute (2022) Global Status of CCS 2022

pilot projects. EU funding programs like the Innovation Fund can offer grants specifically for R&D in CO_2 transport technologies, to address technical challenges like corrosion control and flow rate management. EU-backed loans with guarantees, such as, InvestEU, could help scale up CO_2 transport and storage infrastructure. These loans can help to attract private investment by mitigating perceived financial risks, especially given the high CAPEX and delayed revenue profiles associated with such projects. Additionally, project bonds and green bonds are effective for more mature, scalable projects with predictable revenue, like large pipeline networks linked to CCS hubs.

Equity investments play a key role in high-risk, early-stage CO_2 transport projects, such as those requiring technological innovations. Industry players across sectors, particularly in heavy industry, can establish consortia or coalitions to co-invest in CO_2 transport hubs, to maximise economies of scale for multi-user infrastructure. Quasi-equity can further support projects where revenue streams are emerging but not yet stable.

Overview of risk/maturity assessment and need for funding support

The table below provides the findings from Section 3.3 on the need for public funding support across various energy infrastructure categories and the respective levels of risk and maturity. The risk assessment columns summarises the literature review analysis on technical and operational, financial viability, and regulatory risks, with the risks stemming from levels of maturity by track record. Additionally, these findings are informed by insights from expert interviews with National Promotional Banks, the European Investment Bank, and other industry stakeholders, combined with findings from the literature review. Each risk type was assessed individually as either low, medium or high risk based on criteria set out at the beginning of Section 3.3. The individual assessments then led to an overall risk assessment which is subsequently linked to funding support needs.

The need for funding support reflects factors such as whether the infrastructure is regulated or market-driven, financing structures like off-balance sheet versus on-balance sheet financing, and the variability of the WACC across EU MS. This helps to identify which types of infrastructure are self-sufficient, relying primarily on private funding, and which categories would benefit significantly from targeted financial assistance at the EU or national level.

Table 3-8 Overview of individual risk level assessments

Risk type	Low risk	Medium risk	High risk
Technical and operational risk	Proven technology, efficient management processes, resilient supply chains, effective mitigation procedures of equipment repair or failure.	Proven but not deployed at scale technology, acceptable management processes, supply chains partially susceptible to disruption, set mitigation procedures of equipment repair or failure.	Untested technology, lack of management processes, unpredictable supply chains, unclear mitigation processes of equipment repair or failure.
Financial viability risk	Predictable revenues, strong demand, moderate costs, and well-defined remuneration frameworks.	Partially uncertain revenues/demand, high costs, developing incentives, or unclear remuneration frameworks.	Uncertain revenues/demand, very high costs, weak incentives, or inadequate remuneration frameworks.
Regulatory and political risk	Asset regulation, consistent, implementable and timely permitting	Limited asset regulation, complex permitting processes, partial political will, and limited	Lack of (uniform) regulation, inconsistent, untransparent and prolonged permitting

	processes, political drive, or established regulatory support for innovation.	regulatory support for innovation.	processes, political opposition, or lack of regulatory support for innovation.
Track record	Established maturity and reliability, high potential of market adoption, high scalability prospect.	Demonstrated partial maturity, fragmented market adoption, expected but unproven scalability prospect.	Energy infrastructure remains in development stages, low potential of market adoption, low scalability prospect.

Table 3-9 Overview of risk assessment and need for EU funding support per energy infrastructure category

Energy infrastructure category	Risk assessment	Type of funding support required	Reasoning
Electricity transmission infrastructure	Low/ medium	Typically financed via regulated returns/limited EU support required	Transmission infrastructure is generally low risk due to mature technology and stable, regulated returns. Technical risks are primarily associated with ageing infrastructure and emerging technology integration, which are manageable within on-sheet balance, access to private finance or national budgets. Large-scale modernisation projects may require additional support, but most core TSO functions are financially self-sufficient or complimented through national funding. However, given the rapid increase in investments required in transmission infrastructure, it may not always be socially acceptable to pass on costs to the end consumers. In such cases EU funding support may need to play a role.
Electricity distribution infrastructure	Low/ medium	Typically financed via regulated returns/limited	Distribution infrastructure is generally low risk due to its established, regulated nature. While modernising with smart grid technologies introduces some operational and technical risks, DSOs are mature entities with a stable foundation. Most DSOs can rely on national funding for standard upgrades and maintenance. However, larger-scale investments in smart grids and digitalisation may require additional national funding or EU support to address the substantial capital demands.
Electricity transmission lines with significant cross-border impact infrastructure	Medium/high	National and EU support required	Cross-border transmission infrastructure, while technologically mature, involves medium-high risk due to regulatory variations across MS, lengthy permitting processes, and operational challenges related to national market congestion. These factors introduce complexities that can delay projects and increase costs.It is also critical to consider the positive externalities and EU added value that cross-border infrastructure provides. EU support can help to address these regulatory barriers and fund projects that span multiple jurisdictions, while national support may be necessary to enhance grid connectivity domestically.

Electricity transmission lines related to offshore generation	Medium/high	National and EU support required	Offshore transmission infrastructure faces medium-high risk due to technical challenges such as subsea cable vulnerabilities, supply chain disruptions, and the operational complexity of installation in remote environments. Financial viability risks arise from high CAPEX, long payback periods, and market uncertainties tied to fluctuating energy offtake agreements. Regulatory risks are compounded by differing national regulations and lengthy permitting processes. EU funding can support CAPEX-intensive construction stages, while concessional loans could attract private capital. Additionally, First-loss guarantees could further de-risk early-stage investments, addressing challenges such as regulatory/environmental delays.
Electricity storage directly connected to high voltage transmission and distribution lines	Medium	National and EU support required	BESS role in balancing supply and demand, supporting renewable integration, and enhancing grid stability. However, BESS technologies face medium risk due to technical challenges such as battery durability, supply chain issues, and regulatory complexities. Financial viability risks arise, especially for newer storage technologies that rely on merchant models, and uneven policy support further adds to the financial risk. EU and national funding are necessary to scale storage capacity, market access, and facilitate technology development.
Hydrogen pipelines	High	EU support required	High risks include hydrogen embrittlement and compression challenges, especially for retrofitting natural gas pipelines. Additionally, uncertain demand and underdeveloped markets make long-term viability difficult without public support to mitigate financial risks and incentivise investment.
Import terminals	High	EU support required	Hydrogen import terminals face technical challenges with liquefied hydrogen's extreme storage requirements. The limited demand for hydrogen imports and complexity of modifying LNG terminals increases financial uncertainty, making EU funding essential for development and market establishment.
Installations for hydrogen use in transport sector	High	National and EU support required	Installations for hydrogen use in transport sector depend on the adoption of hydrogen vehicles, which remains low. High capital costs and the need for specialised infrastructure pose financial risks. National and EU funding can support infrastructure alignment with vehicle adoption rates in respective regions.
Electrolyser facilities	High	EU support required	Electrolysers must be scaled significantly to meet EU targets, facing high costs and technological hurdles in efficient operation with renewable energy. Early-stage demand and high production costs make profitability uncertain, thus requiring EU support for scaling and market stability.
Underground hydrogen storage	High	EU support needed	Early-stage infrastructure with high technical risks due to hydrogen leakage and embrittlement concerns. Long-term demand is uncertain, and competition with other storage technologies increases financial risks. EU funding is needed to establish market viability and offset high initial costs.

CO_2 transport and storage infrastructure	High	EU support required	CO_2 infrastructure faces high financial risks, due to technical uncertainties including corrosion, flow rate issues, and unreliability in CO_2 composition. Additionally, high initial costs, monopolistic market concerns, and uncertain demand for CCS raises further risks. EU support is essential to help mitigate these risks on early stages or for first-of-a-kind projects..

3.4. Conclusions on types of financial support per energy infrastructure category

The aim of this section is to explore the type of financial and non-financial support that public sector bodies could offer across various energy infrastructure categories. These conclusions are based on an analysis of current role of EU funds, analysis of financial instruments, and stakeholder insights gathered throughout Chapter 3. This section is structured around three core elements:

Assessment of Existing Financial Support Adequacy: Drawing from the findings of Section 3.1 and stakeholder interviews, this subsection evaluates the current financial support and instruments for energy infrastructure. It highlights gaps between the EU and national governments' provisions and the real-world needs of public financiers and practitioners, identifying where additional or adjusted support could be necessary.

Exploration of Complementary Financial Support Options: This part reviews potential complementary support sources beyond the EU public sector framework, including the EIB, national government schemes, and private sector investments. The focus will be on prominent financiers in major EU economies, providing a snapshot of how these sources can complement public funding.

Consolidated Conclusions: This final subsection outlines key conclusions drawn from research and interviews, organised by the type of support (e.g., regulatory measures, state-aid adjustments, and de-risking instruments) rather than by infrastructure category. These conclusions focus on specific infrastructure needs across electricity, hydrogen, and CO_2 infrastructure and suggest scaling successful instruments.

3.4.1. Adequacy of current financial support mechanisms

This section evaluates the alignment of current EU funding programs and financial instruments with the evolving needs of various energy infrastructure categories. While a wide array of financial mechanisms is in place to support the EU's energy transition objectives, this analysis explores the extent to which these resources meet the projected post-2027 investment needs for different types of infrastructure. By examining gaps between existing support and on-the-ground requirements, as identified through stakeholder interviews, this section highlights where additional, or modified funding mechanisms may be necessary.

Across the EU funding landscape, interviewees frequently cited the need for additional de-risking instruments and measures to attract private investment, particularly for capital-intensive and emerging sectors like hydrogen infrastructure, electricity storage, and CO_2 transport. Instruments such as guarantees, concessional loans, and blended finance (e.g., grants paired with loans) are critical for offsetting financial risks and attracting private capital. However, current funds, such as CEF-Energy, the Innovation and Modernisation Funds, may lack the scale and flexibility to address the substantial financing volume needed for these sectors. These sectors also carry higher risks due to the simultaneous need for market and infrastructure development, especially for hydrogen and CO_2 projects. Enhanced flexibility and targeted funding mechanisms are essential to mitigate these risks and support the large-scale infrastructure investments required to meet the EU's energy and climate goals.

Additionally, a recurring theme in stakeholder feedback was the administrative burden associated with accessing EU funds. InvestEU, guarantee products for example, was highlighted for its challenging application process, particularly for intermediate financing involving multiple stakeholders, including National Promotional Banks (NPB). Whilst, in regulated sectors such as transmission and distribution, national regulations on cost recovery, typically creates a clear business case and enables mordernisation, upgrades or new infrastructure to be financed via private loans or on-balance sheet investments, with less need for EU to step in.

The following program-specific observations are derived from interviews with external energy infrastructure experts at National Promotional Banks, the EIB, and research organisations, which provide relevant reflections on the future of EU funding policies and potential solutions.

Programme-Specific Observations

1. **Connecting Europe Facility:**
   With a €5.84 billion budget, the CEF focuses on PCIs/PMIs that address EU-wide energy network bottlenecks. Although recent updates expand CEF eligibility to include cross-border renewable energy and hydrogen transmission, the programme's limited budget restrict its capacity to support new infrastructure needs outside of immediate cross-border priorities. As a result, CEF may struggle to keep pace unless its budget is dimensionated taking into account the underlying investments needs of the eligible crossborder energy infrastructure projects.

2. **InvestEU Fund:**
   InvestEU's budget guarantees help mobilise private capital for sustainable infrastructure, with €9.9 billion allocated to energy projects. Despite this, stakeholders from National Promotional Banks (NPBs) noted that the programme's application complexity poses a barrier for multi-stakeholder projects. While InvestEU can de-risk certain investments, through guarantees to enable enable participating stakeholders to benefit from bettered lending conditions to finance their projects. such as energy storage, hydrogen or CO2 transport and storage. However, interviews with energy experts at NPBIs have stressed its current structure does not fully align and support the high-risk emerging sectors, which require more substantial de-risking support, particularly in areas like hydrogen production.

3. **Horizon Europe:**
   This programme dedicates €15.1 billion to supporting R&D for innovative energy technologies, mainly through grants for early-stage projects. Interviewees highlighted that, while Horizon Europe plays an essential role in non-mature sectors, there remains a gap in later-stage financing and deployment support—especially for high-risk hydrogen projects. Hydrogen infrastructure, including installations for hydrogen use in transport sector and electrolysers, relies heavily on private investment and is largely unregulated (although it will become move towards a more regulated framework as the hydrogen and decarbonised gas market comes into force[520]). Here, expanded EU and national de-risking mechanisms could bridge funding gaps and stimulate private sector involvement, particularly through revenue-stabilising mechanisms.

[520] https://energy.ec.europa.eu/topics/markets-and-consumers/hydrogen-and-decarbonised-gas-market_en

4. **Innovation Fund:**
The Innovation Fund, with a €40 billion budget, is a key source of early-stage CAPEX for low-carbon technologies. However, stakeholders indicated that the scale of support may not be sufficient for the anticipated demand in sectors like hydrogen. Additional mechanisms, such as concessional loans or guarantees, would help mitigate the risks associated with these projects and increase the fund's impact by attracting private investment for high-CAPEX, high-risk infrastructure.

5. **Modernisation Fund:**
Targeting lower-income EU Member States, the €57 billion Modernisation Fund supports energy infrastructure projects such as storage and CO2 transport. While the fund provides grants and loans, stakeholders noted that high-capital-cost projects in these regions may benefit from enhanced de-risking through EIB-backed guarantees. Additionally, the fund's reliance on ETS auction revenues may lead to variability in funding, which could limit its capacity to fully meet increasing infrastructure demands as the EU accelerates its energy transition.

3.4.2. Complementary forms of financial support and instruments

This section focuses on financial support and instruments outside the EU public sector framework for energy infrastructure investments. While the main report will include an overview of EIB financial support and instruments, details on national budgetary schemes and private sector contributions will be provided in Annex A.6. The key topics covered are:

- EIB financial support and instruments: Including the energy lending policy, loans for public and private sectors, intermediated loans, and active financial instruments across EU Member States.
- National budgetary schemes: Covering examples from Denmark, France, Germany, and Slovakia (Annex A.6).
- Private sector – financial institutions: Highlighting contributions from Deutsche Bank, BNP Paribas, Banco Santander, PKO Bank Polski, and Nordea (Annex A.6).

EIB financial support

EIB Energy Lending Policy

The EIB Energy Lending Policy presents four thematic areas through which it aims to support the energy transformation. The two areas pertinent to this study are securing the enabling infrastructure which focuses on strengthening electricity networks, and supporting innovation and new energy infrastructure. The overarching principle guiding the Energy Lending Policy is phasing out lending to fossil-fuel energy projects.

In support of strengthening electricity networks, the EIB will continue to support interconnection projects as defined in the list of projects of common interest. These can benefit from EU grants under the Connecting Europe Facility, but the EIB remains committed to further support.[521] Long-term investments in electricity transmission and distribution infrastructure are also in line with the EIB's long-term lender position to support the necessary anticipatory investment needs. The EIB's financial support will depend on network companies' investment plans and national regulatory frameworks. High priority will be given to projects that enable the integration of renewables and contribute to the

[521] EIB (2023) EIB energy lending policy

development of electromobility and decentralised flexibility sources connected to distribution networks.[522]

As for financial support for innovative technologies, the EIB focuses its support based on alignment of projects with EU roadmaps and funding programmes, such as the EU Strategic Energy Technology Plan, Horizon Europe, and the Innovation Fund. The EIB funds project at the research, development and innovation stage as well as pilot and demonstration plants, or initial full-scale commercial production lines related to breakthrough technologies as long as they are aligned and/or funded by the previously mentioned EU programmes and roadmaps.[523] To support diffusion of new technologies to consumers, especially via smaller companies that encounter challenges in raising financing, the EIB will continue to deploy tailored instruments in the field such as through venture debt and equity funds.[524]

For developing and deploying new types of energy infrastructure such as battery storage, demand response and decentralised energy sources, the EIB expects to support the projects by EC risk-sharing mandates and states that the financing is likely to be modest, but should exhibit a strong early demonstration effect. This is then expected to maximise additional sector investment.[525]

EIB Loans for the Public and Private Sectors

To obtain an EIB loan either as a public or private sector representative, the projects or investment programmes that are to be financed must be aligned with one or more EIB priorities. In the case of energy infrastructure, this entails alignment with the EIB's Sustainable energy and natural resources agenda.[526]

For the **public sector**, two options for obtaining loans are available. Both are available to the following potential recipients: sovereign states, national agencies, departments, institutions and ministries, regional or local authorities, and public sector companies (e.g. utilities). The first loan scheme is dedicated to public sector entities that wish to finance a single large investment project of investment programme, with the loan starting at €25 million. This loan is eligible for investment costs, typically over a period of up to three years, but can be for longer periods. The EIB typically covers up to 50% of a project's total cost.[527]

The second option takes the form of framework loans. These are flexible loans meant to finance an investment programme which consists of smaller projects. The loan will have pre-defined objectives, aligned with one or more EIB priorities. This option is eligible for investment costs (typically over a period of 3-5 years) of the different sub-projects of the investment programme. The EIB covers up to 50% of the programme's costs, which usually start from €100 million. If the programme also benefits from EU Funds, EIB and EU finance cannot exceed 70% of the total project investment costs (this is subject to exceptions on a case-by-case basis).[528]

When it comes to local and regional authorities utilising a framework loan, the following conditions apply[529]:

[522] EIB (2023) EIB energy lending policy
[523] EIB (2023) EIB energy lending policy
[524] EIB (2023) EIB energy lending policy
[525] EIB (2023) EIB energy lending policy
[526] EIB (2024) Priorities of the EIB
[527] EIB (2024) Loans for the public sector
[528] EIB (2024) Framework loans for the public sector
[529] EIB (n.d.) Financing a city's or region's long-term capital investment programme: EIB framework loans

- Projects under €25 million are selected by the borrower in line with EIB eligibility requirements under the finance contract, and the EIB confirms the selection and allocation of the projects to the loan after disbursement (EIB ex-post confirmation);
- Projects between €25-50 million need to be approved by the EIB before EIB funds can be used to finance them according to a project fiche (EIB ex-ante confirmation);
- Projects above €50 million need a full separate stand-alone appraisal and approval by the EIB Board; generally the framework loan is not used for investments over €50 million but it is possible.

Large corporates or groups, mid-caps, and Special Purpose Vehicles for project finance are eligible for **private sector** financing. Eligible under this scheme are investment costs (typically over a period of up to three years, but can be longer), such as for research and development expenditures on facilities or activities. The EIB typically covers up to 50% of a project's total cost. These loans typically start at €25 million and in certain cases the EIB will consider lower amounts. Financing options for the private sector include corporate loans, growth finance for mid-caps, project finance loans, and corporate hybrid debt.[530]

Active Financial Instruments in Member States

The EIB currently manages thirteen financial instruments in six countries, of which only those pertaining to energy infrastructure will be presented.[531] The EIB is supporting a Greek financial instrument that can support wind farms, photovoltaic installations, biomass and biogas plants and hydroelectric power stations as well as new investments to improve energy efficiency in public and private buildings. The EIB manages €450 million on behalf of the country. Public and private entities, and enterprises and/or special purpose vehicles entitled to implement and operate the supported projects within the territory of Greece are eligible to receive this funding.[532]

The EIB is similarly supporting the Polish region of Kujawsko-Pomorskie in investing in renewable energy and energy efficiency. EIB's investments in renewable energy sources help to increase the level of energy production and energy security in the region. The construction or modernisation of installations designed for the production, processing and storage of electricity derived from RES (biogas, biomass, solar power or hydropower), including connection of the source to the distribution/transmission network is eligible to receive funding. Potential beneficiaries include businesses, local government units, their unions and associations, public authorities, government administration, state organisational units, and non-governmental organisations.[533]

3.4.3. Conclusions

Based on the findings of existing EC support facilities within and beyond the MFF, along with current practices from key European and national banks/budgetary support schemes, we have developed the following conclusions on financial instruments to strengthen or expanding the support to the energy infrastructure categories in scope.

Conclusion 1: Expand and develop additional guarantee schemes

Justification: Guarantee schemes have a strong role in de-risking energy infrastructure projects and attracting crowding in private investment by offering a safety net against potential losses. By

[530] EIB (2024) Loans for the private sector
[531] EIB (2024) Shared management funds and financial instruments
[532] EIB (2024) Infrastructure Fund of Funds – Greece
[533] EIB (2024) Fund of funds Kujawsko-Pomorskie – Poland

expanding and enhancing EU-backed guarantees, such as through the InvestEU programme, the EU can make these projects more attractive to private investors and financial institutions.

One area to expand guarantee facilities can be through the InvestEU Guarantee. The InvestEU guarantee is a valuable for managing risk exposure, helping reduce liabilities for financial institutions that support energy projects. However, given the stringent requirements for accessing this assistance, a simplified application process would help ensure broader access to these resources.

Benefits of additional or new guarantee facilities:

- Multiplier effects: Expanding guarantee schemes allows the EU to attract larger private investments with a smaller initial capital base. Portfolio guarantees covering first-loss positions, for example, can create a multiplier effect that maximises the impact of EU funding.
- Support for high-risk, emerging sectors: Guarantees are particularly crucial for emerging sectors, where financial stability is essential to attract investment. Projects such as installations for hydrogen use in transport sector, electrolysers, and hydrogen import terminals face high capital costs, uncertain demand, and technical risks. By reducing these investment barriers, guarantee schemes enable these sectors to contribute to the EU's energy transition goals
- Debt cost mitigation: Rising debt costs challenge the viability of capital-intensive projects. Guarantee schemes lower a project's risk profile and financing costs, making them vital for sectors without stable revenue streams and for fostering growth in emerging technologies.

Expanding and developing guarantee schemes can enhance investment in energy infrastructure across the EU, particularly in sectors with high CAPEX and risk. Through the use of de-risking instruments such as InvestEU guarantees, the EU can provide stronger support for early-stage technologies and emerging sectors. This approach helps attract private capital to infrastructure projects essential for the energy transition, helping to reduce financial barriers and supporting investment flows to key energy infrastructure.

Conclusion 2: Increase EU funding for energy infrastructure in scope

Justification: To meet the EU's decarbonisation and energy transition goals, EU energy infrastructure funding should continue to prioritise and expand support for categories with high investment needs and a significant reliance on EU public funding, particularly through instruments like **CEF-E,** which helps closing the funding gap. These are areas where the business case alone is insufficient to attract private investment, and where national funding or support mechanisms fall short. Key categories include electricity transmission lines with significant cross-border impact, transmission lines related to offshore generation, electricity storage, hydrogen infrastructure (pipelines, storage, and electrolysers), and CO_2 transport and storage. Additionally, the scale of future investments required by TSOs and DSOs, coupled with challenges in passing costs onto end-users through tariffs, may necessitate greater EU funding support, as discussed earlier in the report.

Electricity transmission lines with significant cross-border impact are essential for integrating EU energy markets and facilitating cross-border energy flows. The primary funding mechanism is CEF-E, which - according to our analysis - historically has covered up to 30% of project costs. Given the substantial investment needs, CEF-E grants will remain critical and need to expand support, alongside complementary instruments such as guarantees and green bonds. Similarly, electricity storage will be further needed to balance supply and demand and enabling renewable integration. BESS typically face revenue volatility, making de-risking mechanisms, including CEF-E grants and guarantees, essential to attract private investment.

Hydrogen infrastructure, particularly pipelines, storage, and electrolysers, will require EU funding to meet substantial investment needs. Expanding EU funds, such as the Innovation Fund, can address technical risks and demand uncertainty, while CEF-E can provide critical support to close the funding gap for cross-border pipelines and infrastructure. Given the immaturity of the hydrogen market, public funding will be indispensable for de-risking and securing private capital. First-of-a-kind projects for CO_2 transport and storage infrastructure, with annual investment needs of approximately €1 billion through 2040, will continue to rely on CEF-E as the primary funding source for cross-border projects, complemented by Innovation Fund contributions for early-stage development.

Expanding EU funding instruments, particularly CEF-E, alongside complementary support such as, Modernisation and Innovation Funds, will be necessary to meet the EU's energy transition and decarbonisation goals. A coordinated approach will ensure that high-priority infrastructure projects are adequately funded, enabling sustainable progress across Member States.

Conclusion 3: Continue to support regulatory measures to de-risk energy infrastructure investment

Justification: In regulated markets, stable returns and cost-recovery mechanisms create an incentivising environment for investment by reducing perceived risk. By contrast, non-regulated or emerging sectors, such as hydrogen infrastructure, lack this stability, increasing investor hesitation. Ensuring user demand through price caps, floors, or guaranteed tariffs provides a predictable revenue stream, thereby solidifying a business case and attracting investors. For example, Italy's mature energy infrastructure, such as electricity and gas transmission and distribution, operates under long-term concessions with predictable tariffs, making these assets more viable for balance sheet financing through corporate bonds or loans.

For non-regulated sectors, project finance structures are generally necessary, with reliance on anticipated cash flows and project collateral. To de-risk these cases, blended regulatory tools—such as tariff guarantees, feed-in tariffs, and enhanced EU ETS mechanisms—can encourage investment by driving demand in lower carbon energy infrastructure. Strengthening the EU ETS by introducing more stringent emission caps and ensuring higher carbon prices can further incentivise private capital flow toward lower-carbon infrastructure. As demonstrated in France, renewable energy projects benefit from regulatory support like feed-in tariffs and contracts for difference, which stabilise revenue streams despite market fluctuations.

To further support energy infrastructure across both mature and emerging sectors, EU and national policymakers could consider:

- User-Based Guarantees: Regulatory instruments such as price caps and floors, as used in Germany's cap-and-floor interconnector model, can ensure that infrastructure projects maintain a minimum revenue threshold, mitigating risk and improving financial viability.
- Regulatory Flexibility: Introducing regulatory frameworks to subsidise initial tariffs and offer long-term revenue assurances could de-risk early-stage projects. This approach helps align project investment timelines with market development and, if necessary, phases out subsidies once user demand and market dynamics become established.

Conclusion 4: Blended finance for high-CAPEX and/or high-risk projects

Justification: Blended finance, which combines non-repayable elements (such as grants or guarantees) with repayable components (such as concessional loans or equity), offers a flexible approach to supporting high-CAPEX and/or high-risk projects. This mechanism facilitates risk-sharing between public and private sectors, attracting private capital to areas like hydrogen infrastructure, energy storage, and CO_2 transport. While blended finance has been a stressed as success in CEF-T, particularly through AFIF by energy experts at National Promotional Banks we have interviews, its applicability to CEF-E in the energy sector requires careful consideration due to complexities, such as administrative burdens and potentially creating further difficulties in accessing funds.

However, through the literature review and interviews blended finance schemes have been perceived as particularly valuable for early-stage and high-risk projects, such as hydrogen pipelines and innovative energy storage solutions, where a mix of grants and equity can mitigate risks and attract private capital. For the energy sector, replicating the success of blended finance seen in CEF-T will require addressing the challenges specific to CEF-E. Simplifying processes and ensuring clear guidelines will be essential to enhancing its accessibility and effectiveness.

Integrating TA within blended finance schemes can further support smaller and local operators, helping to bridge capability gaps and improve project bankability. TA can assist with project preparation, financial structuring, and application processes, ensuring that a wider range of stakeholders can successfully access EU funding.

While blended finance has demonstrated its utility in CEF-T, its implementation under CEF-E must be carefully assessed to account for the distinct needs and challenges of energy infrastructure projects. If these considerations are addressed, blended finance has significant potential to mobilise investment and drive progress in high-CAPEX and high-risk areas critical to the energy transition.

Conclusion 5: Issuance of green bonds by EU Member States/public authorities

Justification: Green bonds are a cost-effective mechanism for financing sustainable energy projects, but non-AAA rated countries often face higher borrowing costs. To address this, according to our analysis EU Member States and public authorities could issue green bonds through the EIB Group, benefiting from the EIB's AAA rating to secure concessional interest rates. This approach would allow financially constrained Member States to access affordable financing for essential infrastructure projects, such as hydrogen and grid development.

Green bonds, like those successfully used in Belgium for offshore projects, have proven their effectiveness in attracting institutional investors. However, expanded EU-level involvement could further enhance their impact. By issuing green bonds under the EIB's umbrella, Member States could utilise a standardised framework to reduce transaction costs and ensure broader accessibility to green finance. This would be particularly valuable for countries with limited capital markets or higher borrowing costs, creating a level playing field for investment in green energy across the EU.

Advantages of Green Bonds in Energy Financing:

- Enhanced accessibility and affordability: Utilising EIB's credit rating allows MS to issue green bonds at lower rates, reducing the cost of capital for energy infrastructure projects.
- Increased investor confidence: The oversubscription of green bonds has been a clear example of how they attract institutional investors, and EU-backed issuance could amplify this crowding-in effect, mobilising greater private investment.
- Long-term support for high-CAPEX projects: Green bonds can support high-cost and long-term investments in sectors like hydrogen, cross border infrastructure such as interconnectors, and CO_2 infrastructure by providing lower-cost capital.

Issuing green bonds with EIB support would significantly lower financing costs and unlock the potential for larger investments in renewable energy infrastructure.

Conclusion 6: Revise state-aid rules to support an enabling environment for energy infrastructure development across Member States

Justification: Revising state-aid rules to enable greater flexibility for Member States to invest in energy infrastructure according to their economic capacity can improve the financeability of energy infrastructures, as long as potential distortive effects on national competitiveness due to varying tariff levels are adequately considered and mitigated. Wealthier countries can extend substantial state support to energy projects, while less affluent Member States, often lack comparable resources.

Adjusting state-aid frameworks would potentially free-up targeted EU funding support for energy infrastructure, to less affluent MS, particularly where domestic state aid alone cannot bridge funding gaps. The recent increase to the General Block Exemption Regulation (GBER) threshold for energy infrastructure to €70 million, is a step in the right direction towards further enabling a broader range of infrastructure projects to receive state aid without requiring individual Commission approval. Further, differentiating GBER thresholds between transmission and distribution projects could facilitate targeted support for distributed energy system needs—such as expanding distribution networks for household, EV, and renewable energy connections—with fewer potential distortive impacts on energy intensive industry competitiveness between Member States.

Moreover, exploring the further harmonisation of EU transmission tariff structures and common solutions to enhance industry competitiveness could help mitigate disparities, where energy-intensive industries benefit from lower tariffs in one MS compared to another. To further address regional imbalances, using targeted funds like the Regional Development Fund would be essential, as it provides specific support for geographic areas facing structural challenges, enabling infrastructure investments that address regional disparities.

By streamlining state aid procedures and making EU support mechanisms like the Innovation Fund more accessible for high-CAPEX projects, the EU can ensure that all Member States have equitable access to the necessary funding for energy infrastructure.

4. EU financing support per infrastructure category

The analysis in this chapter follows from two outcomes of prior chapters:

- From Chapter 2 , a detailed breakdown of the investment needs per infrastructure category in scope, including details on planned investments and estimations up to 2040. This will build a quantitative basis upon which to identify the need for EU financial support.
- From Chapter 3, input on the financing narrative per infrastructure category, and following conclusions on type of financial support per infrastructure category. These inputs will clarify what portion of the investment needs could be met by EU financial support, in particular from a centrally managed programme, or other sources of financing.

Investments in infrastructure are in general based on a 'business case' where project cost (CAPEX and OPEX), cost of capital, and revenues are all brought together over the years of the investment. Where this study is focussing mainly on the project cost side, and to some extent the cost of capital, revenues are also relevant for deciding what type of financing support from the EU level might be best. When the EC policy is creating a stable and predictable revenue source, revenue risk is more limited and no funding support or guarantees might be necessary. In higher risk/more uncertain projects, the need for support/subsidy is normallyy higher. Guarantees and concessional loans can play an important role in between.

EU financial support comes out strong mainly in the newer technologies and cross border activities. For hydrogen and CO_2 infrastructure, developments are harder to predict and EU support can provide a basis for further investments. For cross-border activities, centrally managed EU support can play a big role in boosting the development of international interconnections.

EU financial support may also be considered relevant in cases where returns on assets are regulated by NRAs. Such a regulatory scheme exists for TSO and DSO infrastructural investments, where regulation on financial returns (either on the rate of return or another mechanism) on a regulated asset base defines the allowed returns for TSOs/DSOs. The infrastructural investments here are thus primarily motivated/demotivated by adjustments to this regulation, which is a national regulatory competency. In some cases, when there are societal arguments for reducing cost burdens on grid users, other financial support may provide capital for these investments. Costs are then not recovered by grid users but by taxpayers or another larger group. This may be a possible consequence of the rapid growth in investments for TSO/DSO infrastructure, where a connected increase in grid tariffs can put more cost burden on households and competitive businesses. However, multiple sources indicate that for DSOs, this increase in grid tariffs is less likely to materialise: a large growth in investments is met with a large growth in demand, leading to overall similar network tariff rates across the EU.[534] This is less the case with TSO infrastructural investments, where increases in grid tariffs are more likely (such as in the Netherlands[535]); in some specific cases, there may be additional value in EU support towards limiting increases in grid tariffs.

[534] For example: Eurelectric (2024), Grids for Speed;
[535] https://www.tennet.eu/nl/nieuws/tienjaarsprognose-voorspelt-stijging-transporttarieven-vanaf-2027

Generally, we find that the requirement for EU financing support for various infrastructure categories is rather different. For some infrastructure categories, namely electricity distribution, electricity transmission (national), and offshore radial lines, we see a role for EU support from programmes where budget pre-allocations per MS with national ceilings are applied (as it is the case of Cohesion Funds and RRF). For electricity cross-border, offshore hybrids, cross-border hydrogen and CO_2 transport and storage infrastructure, we establish some rough estimates of potential support for EU support, mainly from CEF-E funding as an EU-level centrally managed programme. Generally, the estimates here are highly uncertain due to the dynamic nature of both the investment needs for these infrastructure categories and energy infrastructure financing. Thus, the quantified values embed not just the uncertainties of the investments in later (often unplanned) years for infrastructure investments (the project cost noted earlier), but also the uncertainties of the revenue and financing aspects for infrastructure development (revenues and cost of capital). Both the overall volume as well as the type of EU financial support can vary greatly over time.

We organise this chapter based on infrastructure categories in scope. For each infrastructure category, we first review the main relevant factors that impact the financial support needed for its development, and then provide estimates and other considerations for financial support.

4.1. Electricity transmission infrastructure

In this section, we focus only on national transmission infrastructure, i.e. not considering infrastructure with a cross-border impact (including interconnectors) and infrastructure for offshore generation (radial and hybrid connections). Referrals to "TSO infrastructure" in this section, including any quantitative references, are made only to national infrastructure and exclude the aforementioned two categories.

National transmission infrastructure is generally supported by regulated returns on an asset base owned by TSOs. The TSOs raise funds for infrastructure investments from private finance sources, regulated returns on the asset base, and via national sources (namely national loans and/or grants). TSO ownership structure across the EU is primarily public ownership, by state, regional, and/or municipal institutions, or other intermediate entities connected to public institutions. [536]

The main factors impacting the financing of TSO infrastructure are:

- **Region:** TSOs in MSs with above-average GNI generally have adequate access to finance, whereas others may struggle with financing of investments.
- **Time period:** analysis in Chapter 2 shows that planned and needed investments by 2040 are slightly different between the 2028-2034 and 2035-2040 time periods.

In regions with suitable national schemes, there is limited need for EU support for investments in TSO infrastructure. TSOs in these regions have adequate financial resources, primarily from public sources and national banks, to raise capital for large investments projects. This may not be the case for areas with insufficient national support, such as those covered by the Cohesion Fund (BG, CZ, EE, EL, CY, LV, LT, HR, HU, MT, PL, PT, RO, SI, and SK for the 2021-2027 period). These areas may require further EU support for investments in TSO infrastructure, and are thus distinguished here as the "below-average-GNI region".

While we distinguish between the below-average-GNI region and the other region in this analysis, it is highly difficult to ascribe specific EU financing needs to these projects. This is especially relevant

[536] ACER (2021), Opinion No 05/2021 of the European Union Agency for the Cooperation of Energy Regulators on the electricity national development plans

given the uncertainty of ETS funds available in the future years, which would have a significant impact on how much funding may otherwise be required from the EU's MFF, mainly in this case its Cohesion and Regional Development funds.

Table 4.-1 Financing options for TSO infrastructure

Region	Timeline	Main financing sources	EU financing options	Investment needs (€ billion/yr; lower bound estimate)	Other considerations
Below average GNI	2028–2034	National schemes, private finance, EU support	Loans, guarantees, grants	1.60	Some possibilities for financing support via grants, (concessional) loans, and guarantees.
Other	2028–2034	National schemes, private finance	-	14.2	Little need for EU financing, as national schemes and private finance are usually sufficient.
Below average GNI	2035-2040	National schemes, private finance, EU support	Loans, guarantees, grants	2.26	Some possibilities for financing support via grants, (concessional) loans, and guarantees.
Other	2035-2040	National schemes, private finance	-	16.3	Little need for EU financing, as national schemes and private finance are usually sufficient.

While traditional TSO infrastructure receives the major share of investments in coming years, limited investments will also be made into innovative grid technologies. The limitations for these innovative grid technologies are generally seen as regulatory, and steps are taken in many areas to ensure that their investments also meet adequate returns for investments to happen.

4.2. Electricity distribution infrastructure

The main factors relevant for electricity distribution infrastructure are:

- **Time period:** analysis in Section 2.1.2 shows that planned and needed investments by 2040 are slightly different between the 2028-2034 and 2035-2040 time periods. Estimations for the second time period indicate a slightly higher investment volume, so the two time periods will be distinguished.
- **Ownership model:** DSOs vary greatly across the EU in their ownership structure. While some DSOs are fully privately owned and operated, others may be majority-owned by municipal, regional, or national authorities. The ownership structure makes a massive difference in the capital structure and internal incentives for investments, and also impact the regulatory regimes applicable to the DSO. Some DSOs are owned by their users (i.e. as a cooperative), and for financing aspects these are also considered as privately-owned. We use Eurelectric's survey of ownership structure[537] among EU DSOs to distinguish those that are majority publicly-owned and those that are majority privately-owned.[538]
- **Region:** DSOs in MSs with above-average GNI generally have adequate access to finance, whereas others may struggle with financing of investments.

[537] Eurelectric (2020), Distribution Grids in Europe Facts and Figures 2020.
[538] A lesser impact may exist from the domicile of the shareholders of the DSO, e.g., if DSO shareholders are majority foreign to its country of operation. This factor is less relevant for investment financing and more so for strategic and geopolitical considerations, and is thus not considered further here.

Electricity distribution infrastructure is generally low risk and regulated. Both private finance and national schemes (mainly returns on the RAB, and in some cases national and regional support measures) greatly contribute to the capital needs of DSO investments. This is especially the case for DSOs with more private shareholders, which can improve access to market-based finance (particularly for equity).

Many DSOs have benefitted from EU grant financing, for example within the ERDF or RRF programmes. However, our analysis shows that DSOs generally tend to forego public funding due to time constraints: some urgent investments may not be delayed so that the relevant processes for public funding can be carried out. Lastly, the administrative burden for submitting applications for EU funding opportunities is seen as a general barrier to applying for this funding, particularly for smaller DSOs.

The aforementioned factors similarly discourage DSOs from seeking EIB loans. The rates from EIB loans are not noticeably better than those of other lenders, while the requirements from other lenders (e.g., restrictions on how the funds are used) may be less strict.[539]

Table 41 summarises the financing options for DSO infrastructure, based on the 2 main factors considered here. Generally, the main financing options at the EU level are (concessional) loans and guarantees to boost investments where financing from private sources and national schemes is not sufficient. These needs would be very limited, as generally all DSO financing is expected to be provided rather adequately up to 2040. The main barrier faced by DSO investments is specific regulatory designs in some MSs that limit (based on the treatment of regulation of returns on investment) the flexibility of DSOs in how investing is done and what capital sources are used. Insofar as these regulatory designs are expected to improve in the coming years, potentially (if ambitiously) through the establishment of EU-wide rules, EU financing needs may even diminish further.

[539] E.DSO (2024), Financing mechanisms for distribution system operators.

Table 4-2 Financing options for DSO infrastructure

Majority ownership	Timeline	Main financing sources	EU financing options	Investment Needs (€ billion/yr)	Other considerations
Public	2028–2034	Private finance, National schemes	Loans, guarantees	36.9	Some benefit for EU financing in countries and regions with limited national schemes
Private	2028–2034	Mainly private finance	-	7.28	Little incentive to use non-private finance
Public	2035-2040	Private finance, National schemes	Loans, guarantees	33.8	Some benefit for EU financing in countries and regions with limited national schemes
Private	2035-2040	Mainly private finance	-	8.25	Little incentive to use non-private finance

Financing needs for DSO infrastructure is also rather different per region. Generally, countries with above-average GNI face fewer issues with raising the necessary capital for infrastructural investments. Input during the project indicated that financing challenges faced by DSOs in these countries (if any exist) may not require EU action, while solutions are instead pursued at the national level. Nonetheless, in cases where concessional loans and guarantees would be beneficial from the EU level, it can be highly difficult to predict what ratio of these financing needs the loans and guarantees would represent .

In some cases, DSOs may require funds for projects outside of the regular, low risk and mature investments. These can include cases with novel technologies and pilot infrastructure projects, such as those involving smart grid technologies. The investment volumes for these rare cases, while small, can be provided via R&I funding both at the national and the EU level. This support can be offered via grants, concessional loans, and/or TA.

This could alter dramatically when for societal reasons a country or region decides they want lower tariffs for their industry or citizens as is being presented in several MSs. This so called 'tariff subsidy' would most likely come from public sources. The source for such tariff subsidies in these mature and regulated markets would come from national or EU-level sources.

4.3. Electricity transmission lines with a significant cross-border impact

Electricity transmission lines with significant cross-border impact generally receive considerable funding from EU-level sources. The primary funding instrument for these projects is the CEF-E grant which supports the integration of energy systems via the TEN-E infrastructure. We focus the analysis on the funds provided by CEF-E primarily as they make up the bulk of investment support for these projects.

Overall, our analysis shows that the EU-27 expect, as a middle-ground estimate, €4.45 billion/year investments in the 2028-2034 period, and €2.33 billion/year for the 2035-2040 period. Some PCI/PMI list projects are receiving funding from CEF-E, making up about 30% of total project costs. This estimate includes both projects receiving and not receiving CEF-E funds and considers projects that have begun construction or are commissioned, as others may still apply for CEF-E funds. Assuming that a similar ratio of project costs will be supported by CEF-E in the future, CEF-E funds may make up about **€1.335 billion/year (2028-2034 period) and €0.70 billion/year (for the 2035-2040 period) of funding for cross-border projects.** This figure includes both studies and works, while it is worth noting that the investments are mostly going towards works (see detailed discussion on amount allocated to studies versus works in Section 2.1.3). This may however represent a conservative estimate, as other forms of support (such as guarantees and green bonds) in the future may reduce the dependency on CEF funds for interconnection projects.

Table 4.-3 Financing options for electricity infrastructure with a cross-border impact

Timeline	Main financing sources	EU financing options	Investment needs (€ billion/yr; lower bound estimate)	Other considerations
2028–2034	National schemes, private finance, EU support	CEF-E (grants)	4.45	Some possibilities for financing support via grants, (concessional) loans, guarantees, and green bonds.
2035-2040	National schemes, private finance, EU support	CEF-E (grants)	2.33	Similar role for financing support via grants, (concessional) loans, guarantees, and green bonds, with growing role for the latter two options.

4.4. Electricity transmission lines related to offshore generation

For offshore transmission lines, about €17.9 billion/year is expected for the 2028-2034 period and about €20.4 billion/year is expected for the 2035-2040 period. These numbers represent significant investment volumes and are based on the lower-bound estimates of ENTSO-E's ONDP. We highlight an important caveat: it is unclear what ratio of these investment volumes will fall into the scope of TEN-E (and are thus within scope here). As a lower estimate, it can be estimated that the share of projects that would fall under the scope of TEN-E would include at least the dual-purpose hybrid projects, which according to the ONDPs would represent at least 14% of the wind offshore capacity considered in the ONDPs. Considering the trajectory of investment needs estimated in the ONDPs, these would represent average investment costs of approximately €2.7 billion per year up to 2050 (assuming the average of the cost sets used in the ONDPs, see figure above). More details on this are discussed in Section 2.4.2, and the analysis here should be considered as an upper-bound estimate of possible financing needs.

Offshore infrastructure which falls under TEN-E specifications is applicable for CEF funding. Currently, little funding for this infrastructure category comes from CEF, as the category has been added relatively recently compared to other categories. Nonetheless, radials are expected to be mostly financed via national frameworks (either by a regulated asset base model or as part of the generation costs) or by budget pre-allocations per MS with national ceilings (such as Cohesion Funds and RRF). On the other hand, there is high added-value in EU-centrally managed support for hybrids. Support to these projects can be expected to receive less CEF funding (as a percentage of total funding needs) compared to other cross-border transmission projects, with an estimated co-funding rate between 10% and 30%. Given that many offshore projects included in the 1st PCI/PMI list are in the early stages or are planning for future PCI/PMI inclusion, it can be difficult to estimate what percentage of funding CEF may represent in the coming years. This is especially the case when other forms of support may be complementary: EIB (concessional) loans and/or guarantees from varying sources, and project-specific green bonds can in some cases provide sufficient funding for offshore projects.

Table 4-4 Financing options for electricity transmission lines related to offshore generation

Timeline	Main financing sources	EU financing options	Investment needs (€ billion/yr; offshore hybrids)	Other considerations
2028–2034	National schemes, private finance, EU support	CEF-E (grants), guarantees, loans	2.7	Most support may be complemented by guarantees and/or loans from EIB, and via green bonds
2035-2040	National schemes, private finance, EU support	CEF-E (grants), guarantees, loans	2.7	Most support may be complemented by guarantees and/or loans from EIB, and via green bonds

4.5. Electricity storage directly connected to high voltage transmission and distribution lines

The analysis in Section 2.1.5 identifies electricity storage as an area for increased investment by 2040 to support. However, the amounts are lower compared to the other infrastructure categories in scope. According to the TYNDP portfolio, there are currently 38 storage projects scheduled for commissioning between 2025 and 2035, with an estimated total cost of €17.6 billion. This includes 12 PCI and PMI projects. The yearly investment needs for these projects average €1.04 billion up to 2040. Additionally, CAPEX assumptions from the TYNDP 2024 suggest that investments in utility-scale battery storage could reach between €275 and €320 billion by 2050, reflecting the scale of infrastructure expansion required to meet future demand. Although it is not certain what portion of these significant investments are within TEN-E-relevant projects, an extrapolation based on current investments in planned projects suggests that approximately €1.5 billion annually will fall under TEN-E. As described in Section 2.1.5, we will assume that the current pace of TEN-E project investments to continue up to 2040.

There are a few factors that impact the financing needs of electricity storage projects. These include ownership models, regulatory frameworks, technology used, and other regional differences. We discuss each within the paragraphs below, focusing on the first three in the next paragraph due to their interlinkages.

Ownership models and regulatory frameworks for electricity storage vary significantly by technology. Pumped Hydro Storage (PHS), often publicly owned, operates within regulated returns frameworks based on a Regulated Asset Base (RAB). This framework provides stable revenue streams aligned with its large scale and long-term nature. Battery Energy Storage Systems (BESS) are market-driven, modular assets that attract private investors such as venture capital and private equity, who are drawn to the revenue potential within energy markets. Unlike PHS, BESS projects depend on volatile revenue streams from energy arbitrage, capacity markets, and ancillary services, exposing them to greater market risk. Compressed Air Energy Storage (CAES) projects typically see a mixed ownership model. CAES is a technology that is less widespread than other storage options vary by country and project maturity. Many CAES projects are privately owned, often by energy companies and private investors interested in experimental or pilot projects. However, these projects typically involve public funding support, especially during the R&D and early deployment stages.

Electricity storage infrastructure projects differ in their risk profile and thus their financing needs based on **technology**. PHS benefits from regulatory stability through public ownership and long-term contracts, reducing its financial risk. Conversely, BESS, as a non-regulated asset, relies on market pricing, which can increase revenue volatility. Private investors, drawn to BESS's potential for high returns, often engage through financial instruments such as grants for early-stage needs, EU-backed loans for mature projects, and equity or quasi-equity for innovative storage technologies.

There are also notable **regional differences** in financing availability for electricity storage projects across the EU. High-GNI Member States generally have greater access to private financing sources, allowing these countries to make use of private capital for infrastructure investments. By contrast, lower-GNI countries face more financing constraints, making EU funding essential to support development. In these cases, funds like the Cohesion Fund and the ERDF provide grants and, where necessary, guarantees to bridge these financing gaps and promote equitable infrastructure growth. Additionally, the Innovation Fund and Modernisation Fund can offer grants, concessional loans, and/or guarantees, with the flexibility to support both high-risk early-stage and CAPEX-intensive projects in underfunded regions, ensuring that all Member States can access support for electricity storage infrastructure.

Both national and EU-level support are essential to scaling storage capacity and achieving the EU's energy transition goals. Table 4-5 provides an overview of investment requirements for PCI/PMI projects listed in TYNDP 2022 and 2024, detailing total investment needs by commissioning year for 2028–2034 and 2035–2040 across electricity storage technologies. Both public and private funding sources are viable for electricity storage, including EU financing support. It explores financing instruments—such as grants, guarantees, and loans—that could be used to bridge the financing gaps in specific cases such as in early-stage and high-CAPEX projects, particularly in regions with lower access to private capital. Private investment plays a significant role, especially for BESS, which rely on modular, market-driven business models. Public funding, including grants, concessional loans, and guarantees, can further attract private capital by reducing investment risks and supporting the early deployment of innovative technologies.

Table 4-5 Financing options for PCI/PMI electricity storage infrastructure

Technology	Timeline	Main financing sources	EU financing options	Investment Needs (€ billion/yr)	Other considerations
PHS	2028–2034	National schemes and EU funds	EU and national backed loans	0.90	Largely public ownership, long-term, often a regulated framework for revenue
PHS	2035-2040	National schemes and EU funds	EU and national backed loans	0.90*	
CAES	2028–2034	Private investment, public-private partnerships	Grants and guarantees	0.10	Early-stage, high CAPEX; requires R&D and de-risking
CAES	2035-2040	Private investment, public-private partnerships	Grants and guarantees	0.10*	
BESS	2028–2034	Private equity, venture capital	Grants, loans, and guarantees	0.03	Market-driven, revenue from capacity markets and energy arbitrage
BESS	2035-2040	Private equity, venture capital	Grants, loans, and guarantees	0.03*	

**Note: Investment needs for electricity storage in the period 2035-2040 are projected based on annual average planned investments between 2028-2034 from the PCI/PMI list and project list from TYNPD 2022 and 2024. The* *study team has not identified a need for increased investment within the TYNDP list, as the projected need for electricity storage in the 2024 TYNDP has decreased compared to the 2022 TYNDP.*

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4.6. Hydrogen infrastructure

According to the analysis provided in Section 2.1.7, the investment needs in hydrogen infrastructure are expected to reach between €89 billion and €278 from 2028 to 2040.[540] The bulk of those investments are expected to be related to pipelines with the investment needs between €62.6 billion and €106.2 billion in this category. Underground storage planned investments are expected to reach approximately €13.8 billion, planned electrolysers around €4.5 billion[541] and import terminals between €8 billion and €17,7 billion[542]. Installations for hydrogen use in transport sector have relatively low estimated investment needs of only €1.5 billion until 2040.

An important factor that will determine the need of public financial support is the ownership **structure of the respective regulated/non-regulated assets** (whether these are open access and regulated or embedded in an industrial process).Private projects often rely on market-driven investments but may need EU support to de-risk innovative technologies. Public projects on the other hand typically require substantial EU funding to ensure their viability while achieving broader societal goals such as energy transition and regional development. The current hydrogen infrastructure is not regulated at the moment, and in the most part owned by private operators, yet it is expected to be regulated soon. The ownership structure of new hydrogen infrastructure (including repurposed natural gas infrastructure) will vary depending on the type:

- **New (or refurbished) pipelines:** Most newly constructed or repurposed pipelines for hydrogen transportation will be subject to regulation, specifically under third-party access (TPA) requirements. These pipelines are expected to be owned and operated by national or regional grid operators (both private and public), depending on the regulatory framework and policies of each country. A small proportion of these new pipelines however will remain unregulated (without TPA) and will be privately owned.
- **Hydrogen storage:** Large-scale hydrogen storage facilities, such as underground storage caverns, will generally be regulated to ensure TPA. These facilities will likely be owned by companies with either public or private shareholder structures, allowing for both public interest and commercial investment. Conversely, small-scale storage assets—designed for more localised or niche storage needs—are expected not to be regulated and to remain in the private sector, owned and operated by private companies.
- **Import terminals:** The ownership and regulation of import (and export) terminals for hydrogen derivatives like ammonia and methanol will differ based on the terminal's purpose and design. Terminals designated solely for importing or exporting ammonia and methanol are anticipated to remain unregulated and predominantly owned by private companies, due to their role in supporting specific trade routes and commercial supply chains. On the other hand, import terminals with regasification facilities will in principle be regulated and owned by companies, which can have private and/or public shareholders.
- **Installations for hydrogen use in transport sector:** This infrastructure is not expected to be regulated, with ownership remaining largely private. However, certain public entities, such as

[540] Low bound based on planned investments and higher bound based on planned and estimated investments.
[541] However, almost €12 billion are projected to be invested in electrolysers during the period 2024-2028.
[542] Low bound based on planned investments and higher bound based on planned and estimated investments

port authorities, may also invest in refuelling infrastructure to support regional hydrogen deployment and transportation objectives.

Another important consideration is the expected **geographical location** of new (or repurposed) hydrogen infrastructure that will be developed. From the analysis of Chapter 2 it is clear that the planned investments in the various hydrogen infrastructure categories are mainly concentrated in a limited number of EU Member States, and strongly focus on cross-border pipelines that connect potential sourcing countries with industrial clusters. These investments should enable the development of a cross-border backbone between large hydrogen production plants and import facilities in the EU on the one hand, and industrial hydrogen clusters or valleys on the other hand. As hydrogen markets are still underdeveloped, they might be inclined to look towards public sources for funding. These countries have smaller national budgets to support these developments and are current beneficiaries under the Modernisation Fund; thus, they may seek further funding from the EC.

Finally, the lack of **market maturity** is another important factor to consider. Hydrogen infrastructure development still faces several critical challenges, primarily due to high demand uncertainty and substantial investment risks. Therefore, investments in hydrogen infrastructure are heavily reliant on national public support, co-funding, and state guarantees, and EU-backed funding mechanisms. This especially the case for the period up to 2034, during which the majority of existing projects are planned to be implemented. At the same time, specific national and EU financial instruments will play a crucial role in de-risking these investments.

Hydrogen pipelines are forecasted to represent the majority of the investment needs and have high upfront CAPEX costs. Public support will be required, both at the EU level (in particular for cross-border projects) and at the national level. The public support can take the form of grants, co-funding (equity or loans), or state guarantees, and can be complemented by regulatory measures to ensure that network costs can be recovered while not jeopardising market development (e.g., by implementing progressive depreciation). The experience of existing EU funds, such as the CEF-E, indicate support for similar projects as hydrogen pipelines with similar strategic importance and maturity risk considerations. These selected cross-border projects with high positive externalities, which eligibility could represent around a 50% of the estimated investment needs (as reflected in Table 4.6), could be supported by grants at approximately 10-20%, and we can foresee a similar EU funding level for hydrogen pipelines.

Hydrogen storage would also require national and/or EU co-funding in the form of subsidies and guarantees or loans, while in the best-case scenario the projects will be funded entirely by private finance. Import terminals involve also high CAPEX but are expected to be mainly privately funded. Investments in electrolysers will require also de-risking schemes, for instance via long-term purchasing (electricity) and supply (hydrogen) contracts, coupled with two-sided CfDs secured by national authorities. Finally, installations for hydrogen use in the transport sector have the lowest investment needs compared to the other hydrogen categories and will – if hydrogen becomes competitive for transport - mainly be privately funded.

Table 4-6 Financing options for hydrogen infrastructure

Technology	Majority ownership	Main financing sources	EU financing options	Timeline	Investment Needs (€ billion/year)	Other considerations
Hydrogen pipelines	Mainly public	EU funds and national schemes	Grants, loans, equity, guarantees	2028-2034	5.81	Need for public funding will be required especially up to 2034 when market is not well
				2035-2040	2.08	

						established and initial costs are high
Hydrogen storage	Mix	EU funds and national schemes	Grants	2028-2034	3.14	Need for public funding will be required especially up to 2034 when market is not well established and capital and operational costs are high
			Guarantees, Grants	2035-2040	2.67	
Import terminals	Mainly private	Mainly private finance	-	2028-2034	0.57	Little incentive to use non-private finance
				2035-2040	0.81	
Electrolysers	Mainly private	Private finance, EU funds and national schemes	Grants, guarantees	2028-2034	2.78	Need for public funding will be required especially up to 2034
		Private	-	2035-2040	2.78	
Installations for hydrogen use in transport sector	Mainly private	Mainly private finance	-	2028-2034	0.08	Smaller investment needs compared to the other categories; can be covered by private finance.
				2035-2040	0.03	

Note: the table shows investment needs figures adjusted by the expected TEN-E eligibility

4.7. CO_2 transport and storage infrastructure

Expanding CO_2 transport and storage infrastructure is necessary to achieve EU's decarbonisation targets. To that end, significant upfront investment is required to establish pipelines and storage sites before the widespread adoption of carbon capture technologies. This early investment is essential to overcome the existing "chicken-and-egg" dilemma: transport and storage developers are hesitant to invest without assured CO_2 supply from emitters, while emitters are reluctant to commit without available transport and storage infrastructure. Other technical, regulatory, and market uncertainties all contribute to a high-risk profile, which could decrease to medium risk when clarity on those uncertain market aspects are clarified in the coming years. Public support, in the form of grants, guarantees, loans and subsidies, can alleviate where relevant **initial financial barriers**, enabling infrastructure to be built with capacity for future emitters. As ETS prices rise and capture commitments increase, a gradual shift to private funding is anticipated by 2040.

For CO_2 infrastructure, ownership models and regional variations are important factors to consider for EU funding needs**. Ownership models** for CO_2 transport and storage infrastructure are typically mixed, often involving both public and private entities due to high CAPEX and the public benefits of emissions reduction. Equity and quasi-equity funding are effective in drawing private capital for early-stage, high-risk projects. Initial public funding has been essential to attract private investment when innovation externalities existed, while the need of further public support remains uncertain once the CO2 infrastructure model is determined, This uncertainty impacts any estimation of future EU funding needs..

CO2 transport and storage infrastructure development across the EU varies significantly, with some regions, especially high-GNI countries, actively advancing CCS projects, while many lower-GNI Member States lack adequate funding for initial development. EU mechanisms, such as the Innovation Fund and Modernisation Fund, can further support underfunded regions, while funds such as InvestEU can help provide necessary resources to scale and attract private investments for CCS projects.

CO_2 transport and storage projects require substantial early funding for feasibility studies, permitting, and initial construction phases. Our analysis shows that grants and equity investments could be essential for high upfront costs, while long-term loans and guarantees could support CAPEX-intensive stages. Once operational, infrastructure can attract private finance through debt, such as green bonds or/and equity.

Table 4-7 summarises the financing needs for CO_2 transport and storage infrastructure under the JRC's 2024 A3 CTP scenario. This scenario envisions an EU network interconnected with the UK and Norway, incorporating both offshore and onshore storage, and aligned with the 2040 emission targets. Given the limited number of current projects and mixed funding needs, the table aggregates investment needs rather than splitting by public/private sources, while it shows the average investment needs between the medium and high estimates.

According to the analysis presented in Chapters 2 and 3, the majority of identified CO_2 infrastructure projects are primarily funded through two key mechanisms: the Innovation Fund and the CEF-E, particularly for cross-border CO_2 projects under the PCI/PMI list which constitute first-of-a-kind initiatives in a region. Currently, CEF-E supports around 4

3% of the total eligible costs for CO_2 first-mover projects, although CAPEX details remain unavailable for PCI projects that have not yet received CEF-E funding. On the other hand, the current contributions of the Innovation Fund to CO_2 transport and storage projects amounts to almost €500 million over all years for three projects across Europe (Iceland and Belgium)[543] .

Table 4-7 Financing options for CO_2 transport and storage infrastructure

Timeline	Main financing sources	EU financing options	Investment Needs (€ billion/yr)	Other considerations
2028–2034	Public grants, equity investments, private co-investments	Grants, equity, loans, guarantees	0.97	Initial public funding and guarantees essential to mitigate early-stage risks.
2035-2040	Increased private finance alongside public support	Project bonds, green bonds, quasi-equity, guarantees	0.97	Gradual transition to private funding as sector matures and ETS prices rise; green bonds and guarantees effective for revenue-stable projects.

[543] Dashboard Innovation fund- Portfolio of signed projects

A. Annexes

A.1. Methodological notes

The investment needs in this report were calculated as €$_{2024}$ values (unless described otherwise). Any values in other nominal currencies were converted to € values based on the relevant exchange rate. To convert between € currency in different years, the EU-27 Harmonised Index of Consumer Prices (HICP) was used, using annual data for 2023 and prior years and July 2024 monthly data for 2024.

A.1.1. Electricity transmission infrastructure

Our analysis of investment numbers for transmission infrastructure relied on multiple sources. First, we used data from the latest NDP of each MS's TSO(s) to find annual numbers. Second, we used survey responses to validate these annual numbers. These annual numbers were found, for years varying from 2024-2026 to 2024-2040, for 25 MSs (Hungary does not provide any public data on investment amounts, and Malta does not have a TSO). For those countries where the NDPs or other national strategies did not provide sufficient information, we either 1) used open source data from Ember's recent Grid study[544] or 2) relied on media articles. We tried to validate for all countries whether the investment data found included cross-border connections, and in the case of those MSs for which only national transmission investments were reported (notably the ones where we used Ember's data), we adjusted these yearly figures with the yearly average figures spent on cross-border lines, reported by Artelys, to arrive at national investment figures.

For project-level data, we relied again on multiple sources:

1. Public information available within NDPs and TSO websites on project timelines, investment values, etc. 2 Member States did not list any projects in their NDPs, while other 15 NDPs had projects lists, but did not provide investment numbers.
2. NRA survey responses with project data sheets.
3. TSO survey responses with project data sheets.

The project level data took precedence over annual data, where available and complete. After having received few responses only to our survey from NRAs, we have launched a survey to TSOs directly via ENTSO-E, to which 18 replies arrives in total. Some TSO data (for 2 MSs) was also received within the boundaries of a non-disclosure agreement. The TSO data sheets received were corroborated and validated versus existing NDP data, interview input, various project lists from offshore generation and cross-border infrastructure, and other sources. Where the data sheets were difficult to interpret, the information was incomplete or the figures to diverges significantly from those in the approved NDPs, fell back on data from the NDPs and other sources. Unless stated otherwise, we assumed that the TSO investment data we received applies to the NDP timeframes.

Following the data cleaning and validation step, data used were the following:

[544] Grids for Europe's energy transition | Ember (ember-climate.org)

- 11 MSs: project-level data was provided with costs, timeline, and other information, either via NRAs or via TSOs directly.
- 10 MSs: annual data for the country were gathered from the NDPs for the relevant TSOs/organisations.
- 3 MSs: annual data was provided within TSO response sheets.
- 1 MS: annual data was provided in the NRA response.
- 1 MS: annual data was gathered from an external source.
- 1 MS: Malta has no TSO.

A few studies/data sources were used to compare investment numbers. These studies include a report by Ember on transmission system investments[545], 2 scenarios of the 2040 Climate Target Plan Impact Assessment of the European Commission (S1 and S3), an ENTSO-E estimate reported in 2023, the prior study on investment needs[546], and an estimate from a study from the Institute for Climate Economics.[547]

To identify the physical infrastructure corresponding to investments in transmission infrastructure, various data sources were used. First, primary data was collected from selected NDPs; this was supplemented by data from other sources, particularly the Ember (2024) study. The amount of km lines corresponding to investments was compared to identify a per-country €/km figure. About half of overall planned investments, i.e. approximately €207 billion, were adequately connected to line build-outs. On the basis of this parameter, the amount of km lines was scaled up based on planned investments for countries for which data on km lines was not available, and based on the calculated upper bound and lower bound estimates for investment needs up to 2040.

The methodology for estimating the investment needs of TSO infrastructure for investments that are not yet planned or approved (i.e notably from the mid-2030s) and for regions or timeframes where no data is available, is based on the same approach used for DSO estimates on investment needs.

To summarise: for which years direct data on planned investments was unavailable, estimates were derived using the European Commission's 2020 reference scenario[548] and the 2040 Climate Target Plan Impact Assessment[549]. Two scenarios, IA2040 S1 (lower bound) and IA2040 S3 (upper bound), where use to define the range of investment estimates. The following steps outline the methodology used to estimate energy demand growth and related investment needs for TSO infrastructure from 2024 to 2040. Steps 1 to 4 are exactly the same for both TSO and DSO infrastructure.

- Step 1: Obtaining country specific forecasted final energy consumption from the 2020 reference scenario.

For each EU-27 country, the forecasted final energy consumption between 2020 and 2040 was gathered from the 2020 reference scenario report. This report provides country-specific energy demand projections, serving as the foundation for the comparison.

- Step 2: Obtaining EU wide forecasted final energy consumption from the 2040 Climate Target Impact Assessment.

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[545] Ember (2024), Putting the mission in transmission: Grids for Europe's energy transition
[546] COWI (2017). INVESTMENT NEEDS IN TRANS-EUROPEAN ENERGY INFRASTRUCTURE UP TO 2030 AND BEYOND
[547] I4CE (2024). European Climate Investment Deficit report: An investment pathway for Europe's future
[548] European Commission (2021). EU reference scenario 2020
[549] European Commission (2024). Impact assessment report 2024

From the 2040 Climate Target Impact Assessment, produced in 2024, the forecasted total energy consumption for the EU as a whole is available for the period from 2020 to 2040.

- Step 3: Comparing the 2040 Climate Target Impact Assessment with the 2020 reference scenario.

The EU-wide energy consumption forecast from the 2040 Climate Target Impact Assessment is compared with the corresponding forecast of the 2020 reference scenario. This comparison helps to estimate country-specific impact assessment numbers by distributing the EU-wide forecast proportionally across individual EU-27 countries for both scenarios. This applies to both scenario 1 and scenario 3 of the impact assessment.

- Step 4: Calculating yearly demand growth for each country

For each country and each year between 2020 and 2040, the growth in energy demand is calculated. This calculation is done for both the 2020 reference scenario and the 2040 Climate Target Impact Assessment, providing a year-by-year forecast of energy demand changes.

- Step 5: Calculating cost per unit of demand growth

For countries with available data on planned investments in the transmission grid, the cost per unit of energy demand growth, measured in ktoe, in calculated in euros.[550]

- Step 6: Calculating the European average cost of demand growth

The average cost for a unit of energy demand growth is calculated for the EU as a whole, based on the available planned investment data on transmission infrastructure. Additionally, for countries with data, the analysis determines how much their costs diverge from this European average.

- Step 7: Estimating investment costs for countries with no or partly unavailable data

For countries and years without available planned investment data on the transmission grid, the expected investment cost is estimated based on the growth in energy demand, the European average cost of demand growth and country-specific factors derived from the analysis. For transmission infrastructure, in practice, this step was skipped because data was available for all countries at least for 2 years.

- Step 8: Calculating the total investment costs for each country in the period 2024 till 2040 and calculating the EU wide costs per year.

For each country, the total investment needs in transmission infrastructure over the period 2024 to 2040 are determined. Additionally, the total cost for the EU transmission infrastructure as a whole is determined on a yearly basis, providing an overview of expected investment needs across the region. This is done using estimates based on scenario 1 and scenario 3 of the 2040 Climate Target Impact Assessment.

[550] For countries with available data on planned investments, the cost per unit of energy demand growth, measured in ktoe, is calculated in euros. However, after reviewing the data, it became evident that for some countries, the planned investments appear to decline in the medium- or long-term forecasts. Following expert insights and external interviews, it was concluded that, in some cases, the planned investments no longer accurately reflect the total investment needs beyond a certain year. As a result, these numbers were adjusted, and new estimates were made to ensure a more accurate representation of the required investments.

A.1.2. Electricity distribution infrastructure

In order to assess the investment needs at the distribution level, this study has employed a combination of methods to gather relevant data. The following approaches were implemented:

- **Survey for NRAs**

A targeted survey was designed and sent to NRAs across various countries to collect insights into the investment requirements at the DSO level. Out of the NRAs contacted, 8 provided responses, which formed a critical component of the analysis. The countries that provided data on the electricity distribution infrastructure category were Denmark, Slovak Republic, Italy, Germany, Malta, Latvia and Slovenia.

For Denmark, the Danish regulatory provided the project with a link to the distribution NDPs from all Danish DSOs. In addition, the EU DSO entity supplied consolidated investment figures for all Danish DSOs, offering a comprehensive view of the average annual planned investments at the national level up to 2033. For the Slovak Republic, the NRA provided detailed project-level data of planned investments up to 2040. However, it is noteworthy that the planned investments decrease significantly over the years. This decline may suggest either a front-loading of investments in the short term or indicate that additional investments will need to be planned over the long term to meet future infrastructure needs. The Italian NRA also provided the study with a link to all distribution NDPs. However, in the Italian case, most DSOs do not publish spreadsheets detailing planned investments, which will be further discussed in the next section. The German NRA provided figures in the form of total investment needs for the period 2024-2033, as well as total investment needs for the period 2034-2045, giving a broader outlook on long-term investment requirements. Malta provided the study with data on planned investments up to 2031. When examining these numbers in the NDPs, it becomes clear that these figures only cover the investment costs of project that are categorised by the DSO as major projects, raising uncertainty about whether additional investment costs need to be accounted for in smaller, less significant projects. Furthermore, the data shows a significant decline in investment amounts over time, which may indicate that more projects still need to be planned for the long term to meet future infrastructure needs. The Latvian regulator provided data that, upon review of the distribution NDP of the largest DSO, appeared to be not related to the distribution grid planned investments. Both the transmission and distribution investment numbers were reviewed, and it was concluded that the provided data did not pertain to the distribution network. Therefore, the data from the survey for Latvia's distribution planned investments was not used in the study for the distribution grid investment needs. Lastly, the Slovenian regulator provided the consultants carrying out the study with the latest NDP. The regulator specifically highlighted the relevant pages where project-level data up to 2032 could be found, including detailed information on the region, scope and timing of investments.

- **Distribution National Development Plans (DNDPs)**

An in-depth review of the DNDPs of several DSOs across different regions was conducted. ACER finds that DSOs have prepared electricity development plants in more than 80% of the EU Member States and Norway.[551] These DNDPs are strategic documents outlining the planned investments required to maintain and expand distribution grid over the coming years. However, not all DNDPs include specific data on planned investments. For a total of 13 member states, the investment data was sourced directly from Distribution Network Development Plans (DNDPs). For some countries, the

[551] ACER (2021), Opinion No 05/2021 of the European Union Agency for the Cooperation of Energy Regulators on the electricity national development plans

data was based on the largest DSO or one of the bigger DSOs, which were then scaled up to provide a comprehensive national outlook. In other cases, data was aggregated from multiple entities, with some of this information also being scaled. A few countries had investment needs reported by a single DSO. Additionally, the timeframe covered by these DNDPs varies significantly, with most DNDPs not providing investment projections beyond the year 2032. Table A-1 provides an overview of the received data of the investments in distribution networks across various Member States. It outlines the percentage of data covering the total timespan of the investment plans (2024-2040), the source of the data (such as the largest DSO, multiple DSOs, or NRA survey response). Additionally, it highlights the percentage of data covering the entire region for each country. All the data that is presented in the study is converted to 2024 euros to ensure consistency and comparability across Member States.

Table A-1 Source of data for distribution grid investment per Member state

MS	Planned investments	% of data covering total timespan	Source of data	% of data covering total region
AT	No data	0%	-	0%
BE	2024-2038	88%	2 DNDPs with a total of 1.318.239 connections illustrating planned investments. Decrease in planned investments from 2034	21%
BG	No data	0%	-	0%
CY	2024-2032	53%	1 DNDP with 546.500 connections illustrating planned investments	100%
CZ	2024-2032	0%	-	0%
DE	2024-2040	100%	Survey response, average planned investments from 2024-2034 and from 2034-2040 for 45.420.854 connections	90%
DK	2024-2032	53%	Survey response + EU-DSO-entity, average 2024-2032 planned investments for 3.361.816 connections	100%
EE	2024-2035	71%	1 DNDP with 650.000 connections with average planned investments	92%
EL	2024-2028	29%	DNDP of Single DSO of Member state with 7.500.000 connections illustrating planned investments	100%
ES	2024-2036	76%	2 DNDPs with a total of 23.118.587 connections illustrating planned investments	77%
FI	2024-2036	76%	3 DNDPs with a total of 1.304.000 connections illustrating planned investments	36%
FR	2024-2032	53%	1 DNDP with a total of 36.000.000 connections illustrating planned investments	88%
HR	No data	0%	-	0%
HU	No data	0%	-	0%
IE	No data	0%	-	0%
IT	2024-2027	24%	2 DNDPs with a total of 32.642.962 connections illustrating planned investments	89%
LT	2024-2030	41%	1 DNDP of Single DSO of Member State with 1.600.000 connections illustrating planned investments	89%
LU	No data	0%	-	0%

LV	2024-2032	53%	1 DNDP with 811.000 connections illustrating planned investments	48%
MT	2024-2031	47%	Survey response illustrating project level data. Decrease in planned investments from 2027.	100%
NL	2024-2026	18%	3 DNDPs with a total of 8.549.000 connections illustrating planned investments	100%
PL	No data	0%	-	0%
PT	2024-2025	12%	1 DNDP with a total of 6.277.358 connections illustrating planned investments	100%
RO	2024	6%	1 DNDP with a total of 2.810.235 connections illustrating planned investments	30%
SE	No data	0%	-	0%
SI	2024-2032	53%	1 DNDP of Single DSO of Member state with 997.106 connections illustrating project level data	100%
SK	2024-2040	100%	Survey Response providing project level data of largest DSO with 785.000 connections. Decrease in planned investments from 2029.	31%

In conclusion, the analysis of the data provided by the survey and the NDPs reveals that, on average, for the timespan up to 2040, at least some data is available for 35% of the years. Of the available data, the survey and DNDPs cover, on average, 77% of the total connections for each Member State.

However, even though not every DSO provided investment plans in the DNDP or through the NRA in the survey, it is expected that most of these DSOs do have investment plans, which were simply not included in the study. This gap in data results in a lower percentage of planned investments being accounted for in the overall analysis compared to the actual investment needs. When focusing on Member States where at least some planned investments are known, 41% of the total investment needs are represented by these planned investments.

- **Estimates based on available data and demand forecasts in different member states**

Where direct data from NRA responses and DNDPs was unavailable, estimations of the investment needs are based on existing data and demand forecast within different bidding zones as projected in the European Commission reference scenario[552] and the European Commission 2040 Climate Target Impact assessment.[553] To estimate future investment needs, two scenarios are utilised to define a range of estimates: A lower bound and an upper bound. These scenarios are derived from the 2040 Climate Target Impact Assessment scenarios.

The lower bound estimate is based on scenario 1 of the 2040 Climate Target Impact Assessment. This scenario aligns with the Fit-for-55 energy trends up to 2040, aiming for a linear reduction in net greenhouse gas emissions between 2030 and 2050. After 2040, this scenario expects that major reductions in greenhouse gas emissions will be needed to meet climate neutrality by 2050.

The upper bound estimate comes from scenario 3 of the 2040 Climate Target Impact Assessment, which aims for at least a 90% reduction in greenhouse gas emissions by 2040. It assumes significant advancements in electricity-related technologies. Specifically, it envisions a major increase in the use of renewable energy sources and the high adaptation of electric vehicles and other electric

[552] European Commission (2021). EU reference scenario 2020
[553] European Commission (2024). Impact assessment report 2024

technologies. Therefore, by 2040, this scenario expects a substantial shift towards a decarbonised electricity system, which involves higher investments in advanced electric technologies and infrastructure.

The following steps outline the methodology used to estimate the energy demand growth and related investment costs for each EU country from 2024 to 2040. Steps 1 to 4 are exactly the same for both TSO and DSO infrastructure. Furthermore, this methodology outlines how the analysis compares the 2020 reference scenario with the 2024 Climate Target Impact Assessment in steps 1 through 4 to calculate demand growth, which applies equally to both TSO and DSO infrastructure.

- Step 1: Obtaining country specific forecasted final energy consumption from the 2020 reference scenario.

For each EU-27 country, the forecasted final energy consumption between 2020 and 2040 was gathered from the 2020 reference scenario report. This report provides country-specific energy demand projections, serving as the foundation for the comparison.

- Step 2: Obtaining EU wide forecasted final energy consumption from the 2040 Climate Target Impact Assessment.

From the 2040 Climate Target Impact Assessment, produced in 2024, the forecasted total energy consumption for the EU as a whole is available for the period from 2020 to 2040.

- Step 3: Comparing the 2040 Climate Target Impact Assessment with the 2020 reference scenario.

The EU-wide energy consumption forecast from the 2040 Climate Target Impact Assessment is compared with the corresponding forecast of the 2020 reference scenario. This comparison helps to estimate country-specific impact assessment numbers by distributing the EU-wide forecast proportionally across individual EU-27 countries for both scenarios. This applies to both scenario 1 and scenario 3 of the impact assessment.

- Step 4: Calculating yearly demand growth for each country

For each country and each year between 2020 and 2040, the growth in energy demand is calculated. This calculation is done for both the 2020 reference scenario and the 2040 Climate Target Impact Assessment, providing a year-by-year forecast of energy demand changes.

- Step 5: Calculating cost per unit of demand growth

For countries with available data on planned investments in the distribution infrastructure, the cost per unit of energy demand growth, measured in ktoe, in calculated in euros.[554]

- Step 6: Calculating the European average cost of demand growth

[554] For countries with available data on planned investments, the cost per unit of energy demand growth, measured in ktoe, is calculated in euros. However, after reviewing the data, it became evident that for some countries, the planned investments appear to decline in the medium- or long-term forecasts. Following expert insights and external interviews, it was concluded that, in some cases, the planned investments no longer accurately reflect the total investment needs beyond a certain year. As a result, these numbers were adjusted, and new estimates were made to ensure a more accurate representation of the required investments.

The average cost for a unit of energy demand growth is calculated for the EU as a whole, based on the available planned investment data in the distribution grid. Additionally, for countries with data, the analysis determines how much their costs diverge from this European average.

- Step 7: Estimating investment costs for countries with no or partly unavailable data

For countries and years without available planned investment data on the distribution grid, the expected investment cost is estimated based on the growth in energy demand, the European average cost of demand growth and country-specific factors derived from the analysis.

- Step 8: Calculating the total investment costs for each country in the period 2024 till 2040 and calculating the EU wide costs per year.

For each country, the total investment needs in distribution infrastructure over the period 2024 to 2040 are determined. Additionally, the total cost for the EU distribution infrastructure as a whole is determined on a yearly basis, providing an overview of expected investment needs across the region. This is done using estimates based on scenario 1 and scenario 3 of the 2040 Climate Target Impact Assessment.

- **Expert interviews**

To supplement the quantitative data, we conducted a series of expert interviews with key stakeholders in the distribution infrastructure sector. These interviews provided valuable qualitative insights into the challenges and opportunities facing the distribution grid. This qualitative input is essential for understanding the broader context behind the numbers and for refining our estimates of investment needs.

A.1.3. Electricity transmission lines with a significant cross-border impact

Top-down estimations for this infrastructure category have been based on the TYNDP 2024 scenarios as well as the TYNDP 2022 Identification of System Needs study (IoSN). The sections below present details about the modelling methodology used in the studies and the methodology applied to derive investment needs figures.

Expansion perimeter

Both studies build upon a capacity expansion model which can invest in some assets with the objective to minimise the total system cost, composed of both investment and operation costs. While the IoSN study takes a given TYNDP scenario (the TYNDP 2022 NT scenario) as an input setting fixed infrastructure levels for most technologies and focuses on investments in cross-border electricity transmission lines and some additional flexibilities, the TYNDP 2024 scenarios modelling process considers more technologies in the capacity optimisation perimeter as part of the scenario establishing process. In particular, the hydrogen system is explicitly modelled in the TYNDP 2024 scenarios modelling process, with possible investments in electrolysers, hydrogen storage and pipelines, which are not represented in the IoSN study, meaning that the competition between electricity and hydrogen transport is not captured in the same way in both studies.

Differences in the investment needs identified in both studies can therefore not be linked only to fundamental assumptions of the scenarios (e.g. level of RES penetration, or demand-side flexibility assumptions).

Electricity transmission expansion candidates

The modelling process aims to reflect the existence of actual interconnection projects without over restricting the investment options proposed to the model, in order to identify the needs where actual projects might not be sufficient. Different types of potential capacity increases are thus considered in the capacity optimisation process:

- Real projects, corresponding to actual projects that are part of the TYNDP projects portfolio at the time the study was conducted,
- Additional conceptual capacity increments that do not correspond to actual projects,

Potential capacity increases are passed to the optimisation model as a sequential list of projects with investment costs assumptions and impacts on cross-border capacities. Investment costs assumptions are submitted by TSOs. Investment costs might be less certain for conceptual projects.

Electricity reference grid

Both studies consider optimised infrastructure levels starting from a reference grid, which is the best estimate of the cross-border capacities of the network at a given timepoint. A reference grid is composed of existing infrastructure, as well as capacity increments related to the projects most likely to be commissioned by a given year. In the TYNDP 2022 IoSN study, the base year is 2025 whereas it is 2030 in the TYNDP 2024 scenarios modelling process. The differences between the 2030 reference grid considered in TYNDP 2024 scenarios and the 2025 reference grid considered in the TYNDP 2022 IoSN study reflects the current pipeline of projects expected to be commissioned by 2030. Note that the detailed list of projects considered to have been commissioned in the 2030 reference grid compared to the 2025 reference grid is not available (only capacities by border in both reference grids are available, not the detailed list of projects with cost). Investments associated with capacity increases from the 2025 to the 2030 reference grid have therefore been estimated based on the evolution of capacities in GW and average investment costs per border available in the IoSN study assumptions.

It is also worth noting that some projects that are assumed to be commissioned in the reference grid used as a starting point in the TYNDP 2022 IoSN study are not yet operational and may still appear in the bottom-up analysis of the pipeline of projects. The costs of these projects therefore don't appear in the total investment needs identified by the top-down studies. An identification of the projects considered to be commissioned in the IoSN reference grid ant that still appear in the PCI/PMI list has been necessary to improve the comparability of the top-down and bottom-up approaches.

The table below presents the perimeter and main characteristics of both studies methodologies.

Table A-2: Modelling perimeter of IoSN study and TYNDP 2024 scenarios

	TYNDP 2022 IoSN	TYNDP 2024 scenarios
Base year	2025	2030
Years modelled	2030, 2040	2035, 2040, 2050
Base scenario	TYNDP 2022 NT	N/A
Granularity	Bidding zone	Bidding zone
Modelling perimeter	Electricity system	Electricity and hydrogen system
Capacity expansion perimeter	2030: transmissions 2040: transmissions, battery storage, peak capacity	Electricity: renewable capacities, battery storage, transmissions Hydrogen: electrolysis, storage, pipelines

Methodology

The available datasets in the studies eventually allow to extract the following data:

- Lists of considered investment candidates on each represented border with investment costs, related capacity increases, and the type of project (real or conceptual)
- Capacities on each border according to the 2025 and 2030 reference grids
- The list of candidate projects selected by the optimization in the different scenarios and horizons

The datasets thus allow to compute in each scenario the total transmission capacity on each border, as well as the capacity increases in the different periods and the related investment costs. All cost data has been converted to 2024 € based on Eurostat Harmonised Consumer Price Index data for EU-27.

A.1.4. Equipment enabling transmission of offshore renewable electricity, including dual-functionality equipment

Two main data sources have been used for this infrastructure category:

- ENTSO-E's Offshore Network Development Plans (ONDPs)
- The pipeline of projects in the first PCI/PMI list

Datasets from modelling results of the ONDP study have been shared by ENTSO-e for this study. The datasets include details on investment costs per type of equipment, sea basin, and time horizon, for both configurations studied in the ONDPs (as presented in the ONDPs reports). Figures from the ONDP report are provided in $€_{2023}$ currency and have been converted to $€_{2024}$ currency.

A.1.5. Electricity storage directly connected to high voltage transmission and distribution lines

Two main data sources have been used for this infrastructure category:

- The pipeline of projects in TYNDP 2022 and 2024 projects portfolios the first PCI/PMI list
- Top-down estimates from 2040 Climate Target Plan's Impact Assessment and TYNDP 2024 scenarios

As part of the bottom-up evaluation of investment needs in high-voltage grid-connected storage capacity, certain methodological assumptions were made for the projects considered from the

TYNDP 2022 and TYNDP 2024 projects lists. Five projects from the TYNDP 2022 are not present in the TYNDP 2024 and have been retained in the analysis.

The characteristics of the projects that are new in TYNDP 2024 do not always have a sufficient level of detail regarding project capacities and cost estimates. When CAPEX data is not available, assumptions were made:

- If the project capacity is available, the CAPEX is calculated by multiplying the withdrawal capacity by the average CAPEX per MW of projects of the same technology from TYNDP 2022 (€1.3M/MW for new PHS, €0.32M/MW for upgrading existing PHS, €0.94M/MW for BESS, and €1.08M/MW for CAES).
- If the project capacity is not available, the CAPEX is calculated by multiplying cost assumptions with capacities collected from the project developers' websites.
- Some projects from the TYNDP 2024 list are also in the PCI/PMI list. If the CAPEX is not available in the various TYNDP project lists, the CAPEX provided in the PCI/PMI list is used. All else being equal, the CAPEX from TYNDP 2022 is always prioritised over those from the PCI list.

The 23 available and the 15 calculated CAPEX from the TYNDP 2022 data are in 2022 euros since TYNDP projects submission guidelines require to submit CAPEX in euros of the corresponding TYNDP year. For this report, a conversion was made to have these values in 2024 euros based on Eurostat price consumer index.

Finally, some projects currently do not have a specified construction duration, a construction period of 5 years was assumed for these projects to split investment needs over the construction duration (based on average of other projects).

A.1.6. Hydrogen infrastructure

Hydrogen infrastructure was covered by evaluating pipelines, electrolysers, underground storage, import terminals and installations for hydrogen use in transport sector via approaches adjusted to data and other limitations individually. The respective approaches and methodologies are described in the corresponding sections of the data in chapter .

A.1.7. CO_2 infrastructure

Three main data sources have been used for this infrastructure category:

- Estimates developed as part of the JRC study published in mid-2024, along specific data shared by the JRC at country level
- Additional desk review and stakeholder interviews to map existing and planned CCS projects in the EU, including the work published by the Zero Emission Platform, the Clean Air Task Force, Bellona, the IOGP and the Global CCS Institute.
- Expert interviews carried out with key stakeholders in the CCS world, including three leading advocacy organisations in carbon capture storage and utilisation, and a national TSO.

A.2. Survey

A survey was distributed to all NRAs in the EU-27 Member States, inviting them to provide insights and data related to energy infrastructure investment needs. The primary focus of the survey was to gather detailed data on investment requirements across multiple infrastructure categories: Electricity transmission infrastructure, electricity distribution infrastructure, cross-border and hybrid infrastructure and hydrogen infrastructure. The survey also offered respondents the option to submit aggregated data or project-level information. To facilitate this, a support letter from the European

Commission was provided to the project team to distribute alongside the survey, reinforcing the importance of the survey to the overall objectives of the study.

Out of the 27 NRAs, 8 NRAs responded to the survey. These 8 responses provided valuable data across the following categories: Table D-3 provides an overview of the respondents and the categories for which they provided answers. Each row represents the Member State of a NRA that responded to the survey, while the columns correspond to different categories of infrastructure. If a respondent answered to questions in a particular category, it is market with an "X" in the relevant column.

Table A-3 Overview of NRA Survey responses

Member State	Electricity transmission infrastructure	Electricity distribution infrastructure	Cross-border and hybrid infrastructure	Hydrogen
Denmark	X	X	X	X
Slovak Republic	X	X		X
Italy	X	X	X	X
Austria				X
Germany	X	X		X
Malta	X	X	X	X
Latvia	X	X	X	X
Slovenia	X	X		

The survey provided to the NRAs, specifically requested project-level data, aiming to capture detailed investment plans for electricity transmission infrastructure, electricity distribution infrastructure, cross-border and hybrid infrastructure and hydrogen infrastructure. Table D-4 provides an overview of which NRAs submitted project-level. Each row represents the Member State of the responding NRA, and a cross ("X") in the relevant column indicates that project-level data was provided for that specific category of infrastructure.

Table A-4 Overview of NRA Survey Responses - Project-Level Data

Member State	Electricity transmission infrastructure	Electricity distribution infrastructure	Cross-border and hybrid infrastructure	Hydrogen
Denmark		X		
Slovak Republic	X	X		X
Italy				
Austria				
Germany	X			X
Malta		X		
Latvia				
Slovenia				

Note: Although not all NRAs provided project-level data themselves, for electricity transmission infrastructure; the NRAs from Italy, Latvia, Slovenia and Denmark provided links to NDPs are other documents with project-level data. For electricity distribution infrastructure, the NRAs from Italy, Germany, Latvia and Slovenia provided links to DNDPs. For hydrogen infrastructure the NRAs from Germany and Denmark provided links to documents with project level data.

Additionally, a tailored survey has also been distributed to TSOs via ENTSO-E to collect detailed, following a workshop facilitated by the project team in collaboration with ENTSO-E. the workshop aimed to explain the purpose of the survey and encourage participation to collect detailed project-level data on the electricity transmission grid.

As of this report, 18 TSOs from EU 27-Member States and neighbouring countries have provided responses to the survey. Each TSO was asked to provide project-level data, including details on infrastructure developments and the duration for which they have data available.

Table D-5 provides an overview of the survey responses, indicating whether a TSO from a specific Member State provided a response, the name of the TSO, and whether project-level data was submitted. If a TSO from a Member State provided a response to the survey it is market with a "X". Furthermore, if this TSO provided Project-level data it is market with another "X".

Table A-5 EU-27 Member States TSO survey responses

Member State	Survey response	TSO	Project-level data
Austria	X	APG	
Belgium			
Bulgaria			
Cyprus			
Czechia	X	CEPS	X
Germany			
Denmark			
Estonia	X	Elering	
Greece	X	IPTO	X
Spain	X	REE	X
Finland	X	Fingrid	X
France			
Croatia			
Hungary	X	HOPS	X
Ireland			
Italy	X	Terna	X
Lithuania	X	Litgrid	
Luxembourg	X	CREOS	X
Latvia			
Malta			
Netherlands			
Poland	X	PSE	
Portugal	X	REN	X
Romania			
Sweden	X	SVK	X
Slovenia	X	ELES d.o.o.	
Slovakia	X	SEPSAS	X

The participation from neighbouring countries such as Montenegro, Norway and Serbia, as shown in Table D-6, further enhance the understanding of cross-border and regional transmission infrastructure needs, particularly in the context of interconnected energy system. . If a TSO from a Non-EU neighbouring country provided a response to the survey it is market with a "X". Furthermore, if this TSO provided Project-level data it is market with another "X".

Table A-6 EU-27 neighbouring Member States TSO survey responses

Non-EU neighbouring country	Survey response	TSO name	Project-level data
Montenegro	X	CGES	X
Norway	X	Stattnet	X
Servia	X	EMS	X

A.3. Interview list

Table A-7 Interview list of Chapter 2

Organisation name	Region	Role	Interview date	Infrastructure category
ENTSO-E	EU	TSO association	8/10/2024	National TSO, cross-border, offshore
EU.DSO Entity	EU	DSO association	9/09/2024	DSO
Eurelectric	EU	Industry association	2/08/2024	DSO
ACER	EU	EU-level NRA association	3/10/2024	National TSO, DSO. Cross-border, offshore, energy storage, gas (including H2)
Brunsbüttel LNG-Terminal	DE	Import terminal operator/developer	30/09/2024	gas (including H2)
Gas infrastructure Europe/EHB	EU	Hydrogen pipelines, general H2 infra	7/10/2024	gas (including H2)
Bellona	EU	International advocacy group	7/08/2024	CO2 transport
Gasunie	NL	National TSO	13/08/2024	CO2 transport
ARERA	IT	NRA	8/10/2024	National TSO, DSO, cross-border, offshore
PSE	PL	TSO	15/10/2024	National TSO, cross-border, offshore
BNetzA	DE	NRA	11/10/2024	National TSO, DSO, cross-border, offshore
Wienernetze	AT	DSO	4/10/2024	DSO
Netze BW	DE	DSO	11/10/2024	DSO
Cerius / Radius	DK	DSO	10/09/2024	DSO
Hedno	EL	DSO	4/10/2024	DSO

Table A-8 Interview list of Chapter 3

Organisation name	Region	Role	Interview date
Caisse des Depots	FR	National Promotional Bank	27/09/2024
Cassa Depositi e Prestiti	IT	National Promotional Bank	19/09/2024
KfW Development Bank	DE	National Promotional Bank	09/09/2024
EIB	EU	Financial institution	10/10/2024
Artelys	FR	Consultancy company	11/10/2024
LBST	DE	Consultancy company	11/10/2024
Trinomics (energy experts)	NL	Consultancy company	09/10/2024

A.4. Sources for Section 3.2

Table A-9 Literature sources reviewed

No.	Author	Year	Title	Source	Type of Financial Instruments / Form of EU Support
1	Bruegel Report	2024	Accelerating strategic investment in the European Union beyond 2026	Link	Grants, Loans, technical assistance
2	EIB	2023	EIB Energy Lending Policy – Supporting the Energy Transformation	Link	Loans
3	EIB – European Commission	2020	Stocktaking study on financial instruments by sector Synthesis – The use of financial instruments in the 'Renewable Energy' sector	Link	Guarantees, Loans, Technical Assistance, Grants
4	European Commission – fi Compass (2021)	2021	Combination of financial instruments and grants under shared management funds in the 2021-2027 programming period	Link	Grants in combination with financial instruments
5	Eulalia Rubio	2018	Financing the Energy Transition in Europe: Towards a More Holistic and Integrated Approach	Link	Green Bonds, All direct financial support and market-based schemes
6	Investors Dialogue on Energy	2023	Barriers to Investments in transmissions and distribution	Link	Equity, Debt (bank loans and corporate bonds), technical assistance
7	Investors Dialogue on Energy	2023	Financing models for transmission and distribution	Link	Bonds, Loans, Equity, Grants, technical assistance
8	Investors Dialogue on Energy	2023	Availability of financial instruments for transmission and distribution	Link	Bonds, Technical Assistance, Guarantees, Blended finance, Quasi-equity, Equity, Grants, Loans
9	Investors Dialogue on Energy	2023	Guarantees for transmission and distribution	Link	Guarantees
10	Investors Dialogue on Energy	2023	Equity and Quasi-equity for transmission and distribution	Link	Equity, Quasi-equity
11	European Parliament - Directorate-General for internal policies	2017	Research for REGI Committee – Financial instruments for energy efficiency and renewable energy	Link	Equity, Guarantees, Loans, Technical Assistance, Grants
12	European Regional Development Fund	2019	A Policy Brief from the Policy Learning Platform on Low-carbon economy	Link	Grants, Loans, Guarantees, Public revolving funds/soft loans, Third-party finance and energy contracting
13	OECD	2017	Financial instruments in Practice: Uptake and Limitations	Link	Loans, Equity, Grants
14	Polzin, F. & Sanders, M.	2020	How to finance the transition to low-carbon energy in Europe?	Link	Grants, Debt (bank loans), Equity, Institutional investors
15	Schlomann, B.	2021	Energy efficiency funds in Europe	Link	Not relevant
16	Thiemann. M., Mocanu. D.	2024	Evaluating the EU's financial instruments for the Green	Link	Blended finance

			Transformation: Accountability, Deliberation and Policy Steer		
17	Bankwatch Network	2024	Supporting the just transition through dedicated technical assistance	Link	Technical assistance
18	AFME	2015	Guide to infrastructure financing	Link	Loans
19	E.DSO	2024	Financing mechanism for distribution system operators	Link	Equity, loans, grants
20	ENTSO-e	2021	European electricity transmission grids and the energy transition	Link	Equity and debt
22	Roland Berger	2011	The structuring and financing of energy infrastructure projects, financing gap and recommendations regarding the new TEN-E financial instrument	Link	Equity, loans, grants, bonds
22	Schittekatte, et al.	2021	Making the TEN-E regulation compatible with the Green Deal: Eligibility, selection, and cost allocation for PCIs	Link	Grants
23	SDA Bocconi & EIB	2018	EU financing policy in the social infrastructure sectors – implications for EIB's sector and lending policy	Link	Grants, loans, bonds, equity

A.5. Sources for Section 3.3

Table A-10 Literature sources reviewed

No.	Author	Year	Title	Source	Type of energy infrastructure
1	Investors Dialogue on Energy	2023	Financial instruments and models for energy production - Investors Dialogue on Energy	Link	National transmission grid, Distribution grid, Hydrogen
2	Investors Dialogue on Energy	2023	Financial instruments and models for transmission and distribution	Link	National transmission grid, Distribution grid
3	The European Hydrogen Backbone	2023	EHB - Implementation roadmap - Cross border projects and costs updates	Link	Hydrogen
4	CurrENT, Compass Lexecon	2024	Prospects for innovative power grid technologies	Link	National transmission grid, Distribution grid
5	Ernst and Young	2024	Grids for speed	Link	Distribution grid
6	Ember	2024	Putting the mission in transmission: Grids for Europe's energy transition	Link	National transmission grid
7	Monitor Deloitte	2021	Connecting the dots: Distribution grid investment to power the energy transition	Link	Distribution grid
8	Eurelectric	2024	How can DSOs rise to the investments challenge?	Link	Distribution grid
9	Eurelectric	2023	Decarbonisation Speedways	Link	Distribution grid
10	International Energy Agency	2023	Electricity Grids and Secure Energy Transition	Link	National transmission grid, Distribution grid

11	Joint Research Centre	2024	Shaping the future CO2 transport network for Europe	Link	CO2 infrastructure
12	Rabobank	2023	The Growing strategic importance of interconnectors: a look at the north sea region	Link	Cross-border and off-shore infrastructure
13	Axel Gauiter	2020	Merchant Interconnectors in Europe: Merits and Value Drivers	Link	Cross-border and off-shore infrastructure
14	US Department of Commerce	2021	Understanding power transmission financing	Link	National transmission grid
15	North Sea Wind Power Hub	2022	Economic and Financial Framework for Electrical infrastructure	Link	National transmission grid
16	Jean-Baptiste Vaujour	2024	Financing Europe's cross-border Interconnectors to deliver energy security, lower prices: a look at incentives and policies	Link	Cross-border and off-shore infrastructure
17	.Maximilien de le Hoye	2020	How to overcome financial barriers to the participation of Europe in a global electrical grid? A feasibility study on a 'Global Grid'.	Link	Cross-border and off-shore infrastructure
18	D. Huang and D. Hertem	2018	Cross-Border Electricity Transmission Network Investment: Perspective and Risk Framework of Third-Party Investors	Link	Cross-border and off-shore infrastructure
19	J. Vasiljevska and T. Efthimiadis	2022	Selection of smart grids projects of common interest—past experiences and future perspectives.	Link	Smart electricity grids
20	Zero Emissions Platform	2020	A trans-European CO2 transportation infrastructure for CCUS opportunities and challenges	Link	CO2 infrastructure
21	Global CCS Institute	2022	Global status of CCS 2022	Link	CO2 infrastructure
22	European Court of Auditors	2024	Special report 11/2024: The EU's industrial policy on renewable hydrogen	Link	Hydrogen
23	Hydrogen Europe	2022	Clean hydrogen Europe	Link	Hydrogen
24	European Hydrogen Backbone	2022	A European Hydrogen Infrastructure Vision Covering 28 Countries	Link	Hydrogen
25	The Oxford Institute for Energy Studies	2024	2024 State of the European Hydrogen Market Report	Link	Hydrogen
26	European Commission	n.d.	Electricity interconnection targets	Link	Cross-border and off-shore infrastructure
27	Ember	2023	Power in Unity: Doubling electricity interconnection can boost Europe's green transition and strengthen security of supply	Link	Cross-border and off-shore infrastructure

A.6. Complementary forms of financial support and instruments (national budgetary schemes and the private sector)

National Budgetary Schemes

Member States also have dedicated funding schemes that support energy infrastructure investments. Focus will be given to four Member States: Denmark, France, Germany, and Slovakia to provide insights from multiple EU regions.

Denmark

Denmark has several national initiatives through which energy infrastructure is being upgraded or installed. One of the key initiatives is expanding and strengthening the Danish electricity transmission grid via an investment of DKK 41 billion (almost €5.5 billion) between 2023 and 2026. The investment is being carried out by Energinet, an independent public enterprise owned by the Danish Ministry of Climate, Energy and Utilities.[555] The **Green Fund** is also instrumental in supporting energy infrastructure – in 2023, the Danish government earmarked DKK 53.5 billion (approximately €7.2 billion) from the Green Fund to support various green financing projects from 2024 to 2040. This includes substantial investments aimed at enhancing the national electricity network and facilitating renewable energy integration.[556] Green hydrogen production via the Power to X initiative and CCS initiatives will also receive substantial investment in the next few years. For example, DKK 510 million (approximately €68.3 million) per year for 15 years could be allocated to a new CCS tender starting in 2027.[557]

France

The France 2030 Investment Plan has allocated €8 billion specifically for energy sector development, including €1.9 billion for green hydrogen projects and investments in renewable energies are worth €1 billion projected increase of ten times of the renewable power installed capacity by 2050, up to 100 GW.[558] 40 GW will come from offshore wind farms. €5.6 billion of the energy envelope has been dedicated to industry decarbonisation as a whole. While specific amounts for transmission and distribution were not detailed, the France 2030 plan encompasses investments aimed at enhancing the electrical grid's efficiency and capacity, particularly in relation to renewable energy integration.[559] This includes investments in smart grid technologies to enhance the efficiency and flexibility of electricity transmission. Similarly, amounts are not disclosed for storage in the form of developing grid-scale battery systems to store renewable electricity.[560]

Germany

There are several government schemes and funds in Germany that support the expansion and modernisation of electricity transmission and distribution networks as well as innovative infrastructures such as hydrogen. The Energy and Climate Fund (EKF) which has been incorporated into the broader **Climate and Transformation Fund (KTF)** has allocated an estimated €177.5 billion between 2023 and 2026 to facilitate a reliable energy supply. One of the measures includes investing in grid expansion for renewable energy integration to ensure gird stability and flexibility due to fluctuating renewable energy supplies. This also includes the expansion of charging infrastructure.[561]

[555] Energinet (2023) Energinet establishes 3,300 km of electricity connections – and much more is on the way
[556] Ministry of Climate, Energy and Utilities (2024) Climate Programme 2024
[557] Ministry of Climate, Energy and Utilities (2024) Climate Programme 2024
[558] ADEME – the French Agency for Ecological Transition (n.d.) Funding
[559] ADEME – the French Agency for Ecological Transition (n.d.) Funding
[560] ADEME – the French Agency for Ecological Transition (n.d.) Funding
[561] Bundesregierung (n.d.) Climate and Transformation Special Fund

Specific targets for 2024 include the ramp-up of the hydrogen economy, including the hydrogen strategy for foreign trade (including H2Global) and the decarbonisation of industry (around €3.7 billion) and the promotion of electromobility in the BMWK, including battery cell production (around €1.6 billion).[562] The Federal Ministry for Economic Affairs and Climate Action is largely responsible for the management of said funds.

Private sector – financial institutions

Deutsche Bank, Germany

As part of its broader sustainability strategy, Deutsche Bank has established a Sustainable Instruments Framework. The Framework covers all Sustainable Financing Instruments that can be issued in the form of (covered) bonds, commercial papers (CPs), repurchase agreements (Repos), and deposits. This includes financing and investments related to renewable energy projects, including, but not limited to, wind (onshore/offshore), solar (photovoltaic/concentrated solar power), geothermal energy, hydro power, ocean energy and bioenergy.[563] The energy efficiency envelope of the framework also covers financing and investments related to the development and implementation of products or technology that reduce the use of energy. Examples include, but are not limited to, energy storage (e.g. fuel cells), and improvement in energy services (e.g. smart grid meters).[564] The Deutsche Bank has also been actively cooperating and cofinancing projects with the EIB, such as pan-EU wind power packages.[565] This provides an example of how multiple financing schemes outside the EU public sector can be utilised in unison.

BNP Paribas, France

BNP Paribas has developed a green bond framework dedicated to investing in renewable energy projects and energy efficiency initiatives that also cover the modernisation of electricity transmission and distribution infrastructure. For renewable energy, assets related to the acquisition, development, manufacture, construction, installation, and/or operation of renewable energy are eligible. This includes the manufacture of renewable energy technologies, manufacture of equipment for the production and use of hydrogen, manufacture of hydrogen, and installation, maintenance and repair of renewable energy technologies.[566]

Energy efficiency projects within the scope of this study include assets related to the development, construction, installation, operation and improvement of energy efficient solutions, infrastructures, facilities and/or equipment. Therefore, infrastructure for the transmission and distribution of electricity for which over 67% of newly enabled generation assets have a 100gCO_2e/kWh threshold (over a rolling 5-year period), or the grid's average emissions factor is less than 100gCO2e/kWh, smart grid technology, manufacturing and operation of Energy Storage Systems (ESS), and facilities exclusively for storage and distribution of green hydrogen are eligible.[567]

The bank has also launched the Climate Impact Infrastructure Debt fund which will target is €500-750 million from institutional investors to allocate to transactions in continental European countries. The aim is to support energy transition projects that are in line with the bank's investment

[562] The Federal Ministry of Economic Affairs and Climate Action (2023) Federal Cabinet adopts economic plan of the Climate and Transformation Fund (KTF)
[563] Deutsche Bank (2024) Sustainable Instruments Framework
[564] Deutsche Bank (2024) Sustainable Instruments Framework
[565] EIB (2024) Germany: EIB and Deutsche Bank to boost Europe's wind energy manufacturers
[566] BNP Paribas (2024) Green Bond Framework
[567] BNP Paribas (2024) Green Bond Framework

philosophy by focusing on renewable energy, clean mobility and the circular economy, including new sectors such as batteries, hydrogen and carbon capture.[568]

Banco Santander, Spain

The Santander Alternatives Platform offers global equity and credit funds that invest in the infrastructure and energy markets. Through the platform, Banco Santander provides direct investment in renewable solar and wind energy projects, with sustainable investment as an objective. The Santander Iberia Renewable Energy fund will invest, directly or indirectly, in shares or stocks of unlisted commercial companies that carry out their activity in the electricity generation sector through the use of renewable technology, including solar photovoltaic and wind power, as well as storage systems or batteries associated with them. In particular, the fund will invest, directly or indirectly, in companies that own one or more photovoltaic and/or wind energy projects that are in an advanced stage of processing the corresponding permits, licenses and authorisations required by regulations or are in the construction phase (without assuming development risk) or are already in the operation phase.[569]

The bank also offers an Innoenergy Climate fund to invest in the energy transition through Climate Tech, aimed at investing in European start-ups in the early stages of development and fostering environmental characteristics. This is embodied in the objective of the fund to generate value for its participants by taking temporary stakes in companies in the seed and early stage investment phases that develop their activity preferably but not limited to, in the areas of renewable energy, energy storage, smart electricity grid, and other energy efficiency measures which are out of the scope of the study.[570]

PKO Bank Polski, Poland

PKO Bank Polski is the leader of the Polish banking sector and reinforces its foreign presence via corporate branches operating in Germany, Czechia and Slovakia, and via KredoBank operating in Ukraine.[571] PKO Bank Polski in partnership with PKO TFI have launched the PKO Renewable Energy the goal of which is to generate long-term relatively stable rates of return for its participants based on cash flows from wind assets held – primarily wind farms and photovoltaic installations. PKO Bank Polski is committed to invest up to PLN 500 million (approximately €116.4 million). The fund was set up in 2021 following the analysis that an obstacle in the development of a domestic Polish RES market is the limited access to capital.[572]

The bank recently established a green bond framework in an effort to support the competitiveness of Polish companies in the face of high energy prices, business and regulatory requirements throughout the ongoing energy transition. The eligible assets pertinent to this study are concentrated under the renewable energy agenda which is exemplified by loans to finance/or refinance expenditures and/or investments for the acquisition, development, manufacturing, construction, distribution and maintenance of renewable energy generation sources from solar energy: onshore and offshore photovoltaics, concentrated solar power and solar thermal facilities; and wind energy: onshore and offshore wind energy generation facilities.[573]

Nordea Bank, Nordics

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[568] BNP Paribas (2023) BNP Paribas launches the Climate Impact Infrastructure Debt fund
[569] Santander Alternatives (2023) Information brochure of Santander Iberia Renewable Energy
[570] Santander Alternatives (2023) Information brochure of Santander Innoenergy Climate Fund
[571] VSB (2021) Strong partnership: PKO Bank Polski finances further wind energy project of VSB Group in Poland
[572] PKO Bank Polski (2021) PKO TFI: Energy Transformation Fund
[573] PKO Bank Polski (2024) Green Bond Framework

Nordea primarily serves the Danish, Finnish, Norwegian and Swedish markets with presence in Estonia and Poland. The bank primarily utilises green bonds to raise capital for renewable energy and energy efficiency projects that generate identifiable climate or environmental benefits.[574] The remaining categories financed by the green bond scheme are outside the scope of this study. Eligible renewable energy projects include the following. The generation and transmission of energy from renewable sources and the manufacturing of related equipment for: wind power, solar power, hydropower, and integrating renewable energy sources into the transmission network. The production of hydrogen is also eligible to where the process results in lifecycle GHG emissions less than $3tCO_2/tH_2$ and the electricity used for production emits less than 100g CO_2 per kWh, and if the GHG savings from the use of hydrogen-based synthetic fuels amount to at least 70%. CO_2 capture and storage is eligible if CO_2 transport from the capture point to the injection point does not lead to a leakage of more than 0.5% of the mass of the transported CO_2 and if a leakage detection system is in place and complies with national regulations for the underground permanent geological storage of CO_2.[575]

Energy efficiency projects are included in this section as the scope of the eligible activities also pertains to modernisation of energy infrastructure and process related to its transmission and storage. The conditions to obtain funding include automation and intelligence in the power transmission network, distribution and related systems, and the transmission of electricity produced by renewable sources from the production site to the system grid.[576]

[574] Nordea Bank (2023) Nordea green funding framework
[575] Nordea Bank (2023) Nordea green funding framework
[576] Nordea Bank (2023) Nordea green funding framework

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