ACER

European Union Agency for the Cooperation of Energy Regulators

Electricity infrastructure development to support a competitive and sustainable energy system

2024 Monitoring Report

16 December 2024

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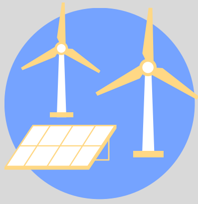
Electricity grids are essential to connect clean energy and transport it to consumers

2.5 more renewables and exponential growth in electrification expected in Europe by 2030.



High stakes of persistent delays in increasing power grid capacity

EU risks missing out on benefits of an integrated power market, such as security of supply, resilience to price shocks, flexibility.

Containing rising system costs is key for EU competitiveness

Power system costs will be a main driver of electricity costs. Consider 'efficiency first', as grid investments need to double by 2050.

1 As Europe moves towards a decarbonised energy system, the links between electricity, gas and hydrogen will grow. It is crucial to assess all energy carriers and develop infrastructure in a coordinated, cost-effective way. Electricity grid development must be coordinated with other energy sectors. The European Union Agency for the Cooperation of Energy Regulators (ACER) and the Council of energy regulators (CEER) emphasised the need to discontinue single-sector infrastructure planning in favour of a pan-European multi-sectoral plan[1].

2 This first ACER infrastructure monitoring report focuses on electricity grid developments as multi-sectoral planning[2] is not yet a reality. Electricity transmission and distributions grids will be key in the future multi-carrier energy system. Network operators must ensure enough grid capacity for renewable energy supply, rising demand and cross-zonal electricity trade.

Grids are key to enabling more renewables and increased electrification

> Massive investment in local, national and cross-border electricity grids needed to keep pace with the growth in renewables and power consumption

3 Local, national and cross-border electricity grids face major challenges in accommodating more renewables and consumption. Wind capacity is expected to double and solar photovoltaic capacity to nearly triple by 2030. Electrification of heating is expected to grow by 50% and electric mobility will see exponential growth. While these trends benefit the EU, they challenge local, national and cross-border grids. ACER and the European Environmental Agency (EEA) underlined that flexibility needs will double by 2030 to keep pace with the growth in renewables[3]. ACER finds the costs of managing electricity grids congestion in the EU continues to rise (costing EUR 4.2 billion in 2023)[4], and several Member States are already experiencing grid-connection delays for renewables generation due to limited grid capacities. During the summer of 2024, insufficient transmission capacity to Eastern Europe contributed to price divergence and evening-time electricity price spikes in the region.

1 ACER, CEER, position paper on the challenges of the future electricity system,2024, https://www.acer.europa.eu/sites/default/files/documents/Publications/Future_electricity_system_challenges_2024.pdf.

2 For a perspective on linkages between the electricity and hydrogen sectors, see: ACER, European hydrogen markets, 2024 Market Monitoring Report, https://www.acer.europa.eu/sites/default/files/documents/Publications/ACER_2024_MMR_Hydrogen_Markets.pdf.

3 ACER, European Environmental Agency, Flexibility solutions to support a decarbonised and secure EU electricity system, 2023, https://www.acer.europa.eu/sites/default/files/documents/Publications/EEA-ACER_Flexibility_solutions_support_decarbonised_secure_EU_electricity_system.pdf.

4 ACER, Transmission capacities to support cross-zonal trade and congestion management, 2024 Market Monitoring Report, https://www.acer.europa.eu/sites/default/files/documents/Publications/ACER_2024_MMR_Crosszonal_electricity_trade_capacities.pdf.

4 These examples show the need for more grid capacity to support cross-zonal electricity trade, reduce congestion, share flexibility and deliver the benefits of a secure and sustainable integrated EU power system. Upgrading all grids will require massive investment, at twice the current EU pace. EU citizens must see that decarbonisation is on track, delivering promised benefits, and that the investment is cost-effective, keeping energy costs affordable for consumers and industry, and globally competitive.

Gaps between planned investment and grid needs threaten both timely decarbonisation and affordable energy

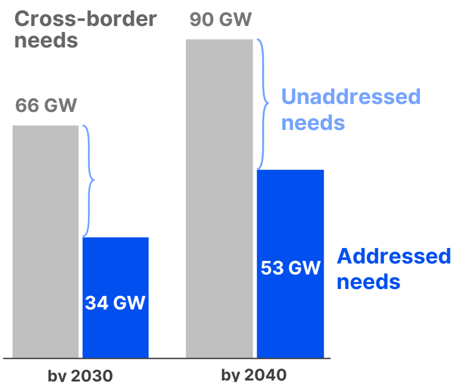
5 The most recent ENTSO-E pan-European grid planning[5] of 2022 shows half of total cross-border capacity needs are not paired with a planned investment (Figure I). This misalignment raises the risks of missing out on the benefits of having an interconnected power system (e.g. providing security of supply, resilience to price and supply shocks, unlocking flexibility, enabling the clean energy transition).

6 Investment efforts should address all grid needs while accelerating project implementation. Otherwise, delays in renewables integration already observed today through congestion or grid connection queues may further accumulate. Missing or delayed investment can lead to lost benefits of an integrated EU power grid.

As grid costs become a main driver of electricity costs, containing their rise is key for competitiveness.

Unaddressed cross-border capacity needs make the benefits of an interconnected EU power market unattainable

Figure I. Cross-border capacity needs.



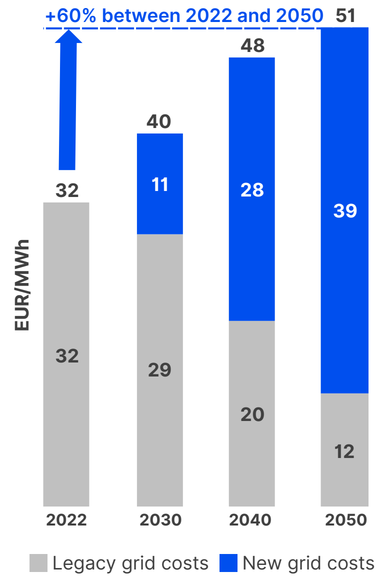
7 Annual grid investment in Europe is estimated to double until 2050, reaching up to EUR 100 billion, with lower estimates at EUR 75 billion. At that pace, total grid costs for consumers may rise considerably by 2050, reaching over 50% more than the current costs in 2050, or even nearly double in the highest investment scenario (Figure II). As grid costs become a main driver of electricity costs, containing their rise is key for competitiveness. Cost-effective grid investments are indispensable to keeping total electricity costs low for end-consumers.

8 By 2050, grid costs for distribution-connected consumers, including industry, will face the largest burden as they will cover about two-thirds of the future investment. Up to 90% of transmission costs are passed on to these consumers who also benefit from transmission services. While measures to alleviate one user group could be considered, such measures would increase costs for others and distort the efficiency signals in the network tariffs.

Grid costs for consumers could nearly double by 2050

Figure II. Evolution of total grid costs

Legacy grid costs cover historic investment and decrease by further depreciating assets while new grid costs represent investment between 2025 and 2050 (based on Ember).



Estimates give the ***order of magnitude****; they are sensitive to many assumptions and based on partial data.*

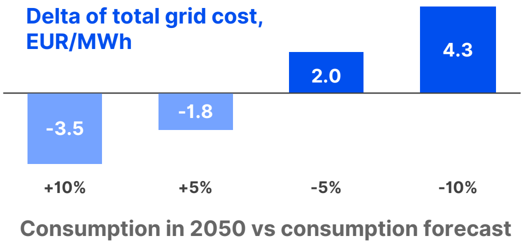
5 ENTSO-E, TYNDP 2022 System Needs Study - Opportunities for a more efficient European power system in 2030 and 2040, 2022. https://eepublicdownloads.blob.core.windows.net/public-cdn-container/tyndp-documents/TYNDP2022/public/system-needs-report.pdf.

9 Targeting investments to realistic future consumption is key to avoiding a cost spiralling effect (Figure III) that could discourage electrification if investment benefits do not materialise. Electrification could still be encouraged without artificially lowering the grid bill, avoiding aggravating the spiralling effect.

10 The significance of grid costs will vary per Member State, depending on their commitment to planned investments and their national uptake of renewables and electrification.

Unrealistic forecasts of future grid consumers raise costs for actual consumers and give rise to potential sunk cost

Figure III. Grid cost sensitivity to long-term consumption forecast errors



Accelerating on-target grid investment while sustaining affordability and competitiveness

11 Several measures[6] should be introduced to accelerate investment and meet decarbonisation targets while sustaining affordability.

12 Integrated (multi-sectoral) planning across the local, national and EU levels should be swiftly implemented (and be based on latest methodologies) to prioritise investments that address needs and deliver benefits at lowest costs. To speed up investment in regional infrastructure, the existing bottom-up planning approach could be complemented with a top-down approach; policymakers could empower energy regulators to request that electricity transmission system operators (TSOs) address regional infrastructure gaps.

13 The 'efficiency-first' principle should be applied consistently to grid investment; this would mean a careful design of network tariffs and other signals to reduce grid needs, and incentives to consider innovative grid technologies, such as digitalisation and grid-enhancing technologies (GETs). Regulators must review their network tariffs designs[7] and investment frameworks[8] considering this principle.

14 As grid costs become a main driver of total energy costs, governments and regulators may feel pressured to shift the burden from one consumer group to another or to socialise it through taxes. ACER invites policymakers to exercise caution due to the potential negative effects of such actions, and to favour coordinated approaches.

15 If needed investment of regional interest disproportionately impacts grids costs in some countries, they may be reluctant to host such investment; to better reflect the costs and benefits of electricity network infrastructure arising from cross-border trade, policymakers and regulators should holistically review existing cost-sharing mechanisms.

16 To handle the acceleration of grid investment, the EU and the Member States must address upscaling issues. The EU should ensure secure critical supply chains, including skilled labour and technical experts. Member States must prepare their distribution system operators (DSOs) to play a larger role, including handling digitalisation, data management, innovative grid technologies, and methodical grid planning. This requires upscaling and pooling of resources and professional skills that may not be widely available in the fragmented DSO landscape.

6 See note 1.

7 ACER, Report on Electricity Transmission and Distribution Tariff Methodologies in Europe, 2023, https://www.acer.europa.eu/sites/default/files/documents/Publications/ACER_electricity_network_tariff_report.pdf.

8 ACER, Position on incentivising smart investments to improve the efficient use of electricity transmission assets, 2021, https://acer.europa.eu/sites/default/files/documents/Official_documents/Position_Papers/Position papers/Position Paper on infrastructure efficiency.pdf.

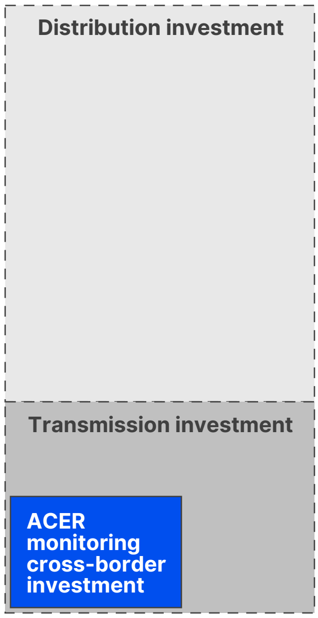
17 Finally, while the benefits of many grid investments are becoming more uncertain, lack of action can be even costlier. Regulators approving uncertain (anticipatory) investments, should have transparency on the associated risks[9] and mitigating measures.

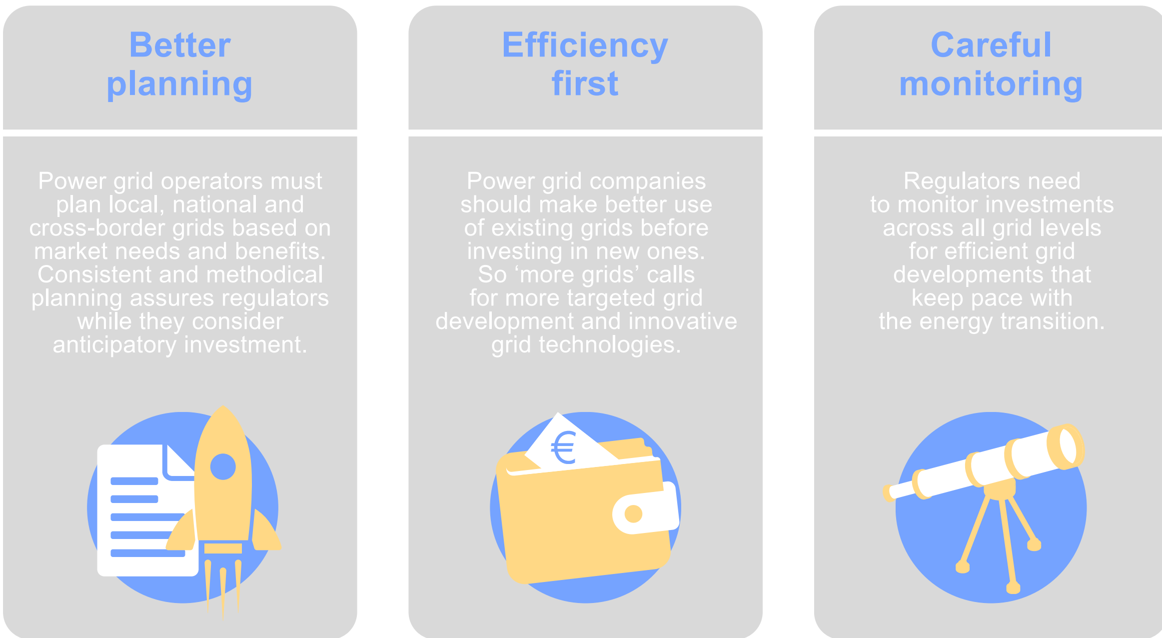
18 This report concludes that focused development of distribution, transmission and cross-border capacities is essential for a secure, sustainable and competitive EU energy system. This requires comprehensive monitoring to track whether infrastructure keeps pace with the energy transition. However, this first electricity infrastructure report by ACER identifies some blind spots for comprehensive monitoring – data for national transmission and distribution grid planning and investment is not easily available or comparable. Based on available data, ACER's current electricity grid monitoring covers merely 10% to 15% of all power grid investment in the EU (Figure IV).

Monitoring blind spot?

Figure IV. ACER's investment monitoring

ACER's monitoring of investment with cross-border relevance covers about 10% to 15% of all EU power grid investment. Other grid investment data is scattered, making comprehensive monitoring infeasible.



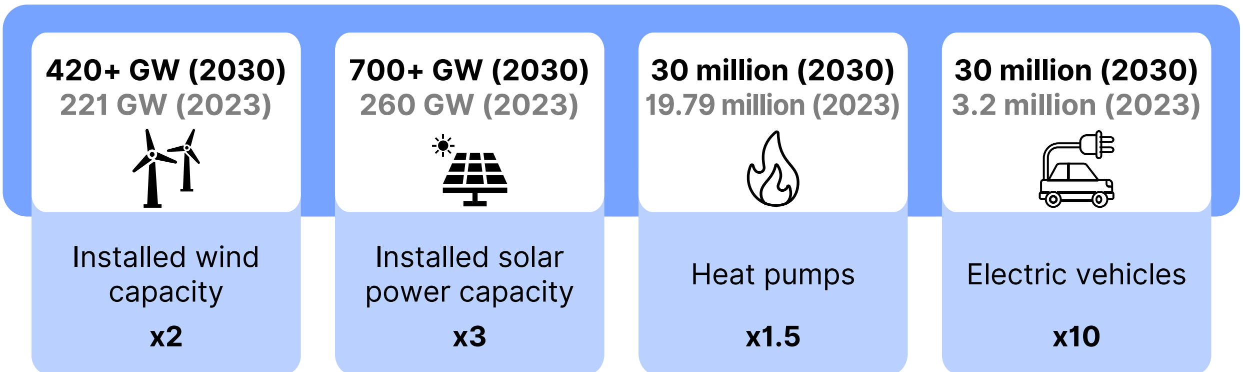


9 ACER, CEER, Position on anticipatory investments, 2024, https://www.acer.europa.eu/sites/default/files/documents/Position Papers/ACER-CEER_Paper_anticipatory_investments.pdf.

Introduction

1 The EU energy system's transformation for achieving decarbonisation[10] necessitates enabling the large-scale integration of renewables. The vast expansion of renewables is exemplified by wind capacity doubling and solar photovoltaic almost tripling by 2030. At the same time, connecting newly electrified energy services, such as heat pumps is expected to increase by 50% by 2030 while registrations of electric vehicles are to grow exponentially in the same timeframe. Meanwhile, fossil fuel use will decrease at the EU, national and local levels. **Consequently, the renewable energy transition, with its variable energy generation and growing demand, presents substantial challenges to the energy system.**

Figure 1: The decarbonisation challenge: integrating renewables and electrifying energy demand



Sources: European Commission, 'RePowerEU – 2 years on'. European Commission, 'Mobility Strategy EU'. European Heat Pump Association, 'European Heat Pump Market and Statistics Report 2023'. International Energy Agency, 'Global EV Outlook 2024 – Trends in electric cars'. WindEurope, 'Wind energy in Europe: 2023 Statistics and the outlook for 2024–2030'.

2 **Grid infrastructure is key to enabling the integration of renewable energy sources (RES) and electrification of energy demand, and to unlocking the benefits of market integration**[11]. The development of transmission and distribution capacity to connect generation and consumption and to interconnect markets has thereby become one of the focal points in the energy transition. Interconnection between countries furthermore supports market integration, security of supply and flexibility, along with price stability and competitiveness.

3 As Europe advances towards a decarbonised energy system, dependencies between electricity, gas and hydrogen will increase. Hydrogen production requires electricity, directly impacting the need for electrical grids. It can also be used to produce electricity, thus establishing a storage potential covering even seasonal flexibility requirements of the electricity system. Hydrogen could also be a carrier to transport energy. The economic viability of these options remains an open question. Natural gas would likely continue to be used in the near and mid-term future to compensate for variable renewable energy deficits, directly impacting the electrical system, while potentially also facilitating hydrogen uptake through repurposed natural gas pipelines. Despite each energy carrier having its own consumer structure of which a majority cannot shift carriers quickly (an exception being hybrid heat pumps), mid-to-long term network planning should take all energy carriers into account and develop energy infrastructure in an integrated, cost-effective way. Such integrated planning should explore complementarities between energy carriers and aim to optimise energy infrastructure investments. Furthermore, the multi-vector energy system might even be necessary on our path to decarbonisation. Individual energy carriers face hurdles that might only be overcome by utilising sectoral synergies instead of focusing on a single energy carrier. Responding to the requirements of the first TEN-E regulation, the European Union Agency for the Cooperation of Energy Regulators (ACER) issued it opinion[12] on the 'interlinked model' in

10 European Commission, 'REPowerEU: Affordable, secure and sustainable energy for Europe', https://commission.europa.eu/strategy-and-policy/priorities-2019-2024/european-green-deal/repowereu-affordable-secure-and-sustainable-energy-europe_en.

11 ENTSO-E estimates monetised annual benefits of projects with cross-border relevance included in TYNDP 2022 at EUR 38.9 billion per year (national trends scenario).

12 ACER Opinion 07-2017 on ENTSOS' Draft Consistent and Interlinked Electricity and Gas Market and Network Model. https://www.acer.europa.eu/sites/default/files/documents/Publications/Opinions/ACER%20Opinion%2007-2017.pdf.

2017, addressing the topic of integrated planning. As the objective remains unmet, ACER continues its engagement under the new Trans-European energy networks (TEN-E) framework, closely following the task of the European Network of Transmission System Operators for Electricity (ENTSO-E) and the European Network of Transmission System Operators for Gas (ENTSOG) to provide a consistent and progressively integrated model that will provide consistency between single-sector methodologies based on common assumptions including electricity, gas and hydrogen transmission infrastructure as along with storage facilities, liquefied natural gas and electrolysers. However, ENTSO-E's and ENTSOG's work is not yet concluded. Moreover, ACER and the Council of European Energy Regulators (CEER) emphasise the need to discontinue single-sector planning in favour of a pan-EU multi-sectoral plan[13]. As we are not there yet, the area of integrated planning remains largely out of scope of this report. This infrastructure report focuses on monitoring electricity grid development as electricity transmission and distributions grids will be key in ensuring that sufficient grid capacity is in place to connect RES and more electrified services, along with interconnecting markets to help manage volatility. Although these challenges may appear to be ahead of us, their pressing nature has already been observed and analysed in several of ACER's market monitoring reports.

4 The current European electricity infrastructure comprises a network of national grids and interconnectors spanning across EU member states and neighbouring countries. It was historically developed to transport a steady electricity supply to where it was needed from mostly large generation centres that were located relatively close to the consumption centres. That architecture is changing as offshore generation and distributed generation are integrated in the network.

5 ACER's report on cross-zonal trading[14] signals that insufficient grid capacity becomes evident as demand for congestion management increases. The EU's power system is experiencing growing congestion, with a 14.5% rise in congestion management volumes (GWh) in 2023, resulting in significant system costs. In the same year, congestion management expenses for the EU power grid exceeded EUR 4 billion, with 60% of these costs borne by the German system. The fact that grid expansion is not catching up to decrease current congestion, coupled with the rapid adoption of RES, is likely to exacerbate grid congestion going forward. This situation may hinder efforts to further integrate the electricity markets across the EU and delay the transition to a carbon-neutral and cost-efficient power system[15]. A well-functioning internal electricity market, enabled through cross-zonal electricity exchange, is essential for the EU's decarbonisation and enhances the security of electricity supply. Therefore, **the development of cross-border electricity infrastructure and the optimal use of interconnections across the EU are vital for completing the internal electricity market and expanding cross-zonal trading opportunities whilst managing congestion.**

6 The power system's flexibility requirements are projected to double by 2030 to accommodate the increasing integration of RES, as highlighted in the ACER–EEA 2023 flexibility report[16]. The frequent occurrence of negative wholesale prices in various countries underscores the unmet flexibility needs through increased renewable energy variability[17]. To address this, appropriate price signals and regular information dissemination to consumers can facilitate their participation in providing flexibility, thereby reducing reliance on more costly flexibility resources. However, as observed in ACER's report on barriers to demand response and other distributed energy resources,

13 ACER, CEER, Challenges of the future electricity system: Recommendations and commitments, July 2024, https://www.acer.europa.eu/sites/default/files/documents/Publications/Future_electricity_system_challenges_2024.pdf.

14 ACER, Transmission capacities to support cross-zonal trade and congestion management, 2024 Market Monitoring Report, https://www.acer.europa.eu/sites/default/files/documents/Publications/ACER_2024_MMR_Crosszonal_electricity_trade_capacities.pdf.

15 Additionally, from 2020/21 to 2022, redispatching costs almost doubled to EUR 4.2 billion, whilst countertrading volumes doubled to EUR 0.8 billion, and other costs decreased to about one third to EUR 0.2 billion.

16 EEA, ACER, Flexibility solutions to support a decarbonised and secure EU electricity system, October 2023, https://acer.europa.eu/sites/default/files/documents/Publications/EEA-ACER_Flexibility_solutions_support_decarbonised_secure_EU_electricity_system.pdf.

17 Electricity prices diverged considerably during the summer months of 2024, which mostly resulted in evening price spikes in eastern European bidding zones. A major contributing factor was a lack of sufficient commercial transmission capacity to exchange electricity to these bidding zones. Some of this can be traced back to physical congestions due to relatively weak transmission lines.

numerous minor barriers to demand response remain[18]. In addition to addressing these barriers and raising energy-system flexibility, **upgrading grid infrastructure, including grid management technologies, is crucial to handling renewable energy variability and sharing flexibility across borders.**

7 The occurrence of grid connection queues shows that grid capacity for integrating RES is limited in some locations. More than 500 GW of wind capacity from newly built or repowered wind farms in Croatia, France, Germany, Ireland, Italy, Norway, Poland, Romania, Spain and the United Kingdom are currently waiting for grid connection assessment, exceeding the installed generation capacity in several addressed individual countries by a multitude[19]. **The integration of massive capacities of wind power, in particular offshore, necessitates grid capacities to be added urgently** to connect these generation units to the electricity system and to transport electricity to the centres of consumption.

8 **The development of local, national and cross-border electricity grids that bring forth the benefits of a secure and sustainable integrated EU energy system is therefore vital. While a wave of investment in the needed grid capacities lies ahead of the EU, sustaining the EU's competitiveness means that electricity grid investment must be on target and cost-efficient.**

9 EU policies acknowledge the essential role of energy infrastructure including cross-border electricity networks.

- The TEN-E framework and the selection of projects of common interest (PCIs) and projects of mutual interest (PMIs).
- The Council of the European Union approved a series of measures aimed at creating an interconnected and resilient electricity network across Europe, emphasising the need for long-term, coordinated electricity grid infrastructure planning at the European level, combined with bottom-up coordination of national plans at the regional level[20].
- The European Commission's EU action plan for grids sets out to enhance the planning robustness, interconnectivity, digitalisation and cyber-resilience of Europe's electricity grids[21].

10 *The Future of European Competitiveness* report emphasises 'A central element in accelerating decarbonisation will be unlocking the potential of clean energy through a collective EU focus on grids. … Delivering a step-change in grid deployment will require a new approach to planning at the EU and Member State levels, including the ability to effectively reach decisions and accelerate permitting, to mobilise adequate public and private financing and to innovate grid assets and processes.' [22]

11 As local, national and cross-border electricity grids will be essential to building the EU's secure, sustainable and competitive electricity system, ACER finds it timely and necessary to undertake monitoring of electricity grid development in Europe, complementing the well-known market monitoring reports

12 With this report, ACER focuses on the advancement of interconnection while also looking more comprehensively at investment in electricity transmission and distribution networks as all of these elements are essential for a sustainable electricity system. Although the report relies on ACER-monitored data on infrastructure with cross-border relevance, complemented by publicly available data, most findings and recommendations extend to both the transmission and distribution levels,

18 ACER, Demand response and other distributed energy resources: what barriers are holding them back? 2023 Market Monitoring Report, https://www.acer.europa.eu/sites/default/files/documents/Publications/ACER_MMR_2023_Barriers_to_demand_response.pdf.

19 WindEurope, 2024. Grid access challenges for wind farms in Europe, https://windeurope.org/intelligence-platform/product/grid-access-challenges-for-wind-farms-in-europe/.

20 Council of the European Union, 'Sustainable electricity grids: Council approves conclusions', press release, 30 May 2024, https://www.consilium.europa.eu/en/press/press-releases/2024/05/30/sustainable-electricity-grids-council-approves-conclusions/.

21 European Commission, 'Commission sets out actions to accelerate the roll-out of electricity grids', press release, 28 November 2023, https://ec.europa.eu/commission/presscorner/detail/en/ip_23_6044.

22 European Commission, The Future of European Competitiveness, 2024, https://commission.europa.eu/topics/strengthening-european-competitiveness/eu-competitiveness-looking-ahead_en.

underlining the interlocking of both system levels and highlighting the need for closer collaboration of both systems, as well as monitoring them. While the report focuses on the development of the electricity system, ACER emphasises that the future EU energy system must be developed in an integrated way and consider energy vectors other than electricity.

13 This report is produced pursuant to Article 15 of Regulation (EU) 2019/942 establishing a European Union Agency for the Cooperation of Energy Regulators, as part of ACER's monitoring activities. These activities are intended to assess, and report on, the barriers to the completion of the internal market for electricity.

14 This report is structured as follows: Chapter 1 provides an overview of how grid capacity needs are identified and addressed via grid planning, assessing the consequences of unfocused grid development and prolonged project implementation, and building recommendations from it. Chapter 2 reviews investment and assesses the effect on grid costs and the associated effects on affordability and competitiveness. Chapter 3 concludes with the findings in this report.

15 This first edition of a monitoring report dedicated to infrastructure relies on publicly available data and data already monitored by ACER, which may affect the findings and conclusions presented. The variable availability of data posed some constraints, as certain data sets were either incomplete, difficult to access or from an earlier period. Inconsistencies in the timings and geography covered by the available data further convoluted the analysis. Other factors, such as methodological constraints in the analysis also contributed to the limitations of this report. These factors should be considered when viewing the results and recommendations. Possible future work on the topics included in this report could therefore be supported by dedicated comprehensive data collection that would allow for a more accurate assessment of the progress in grid investment.

1. Monitoring progress of grid capacity development

16 This chapter provides an overview of network development in Europe, from planning the grid to implementing capacity-raising projects, outlining the risks of not addressing network needs in a timely manner and proposing potential solutions for a more focused grid development. The chapter starts by explaining how electricity network development planning and project implementation works and how it is done at the EU and national level. The chapter also presents findings on the progress of grid development and the risks for decarbonisation. Finally, it explores potential solutions for a more focused grid development.

1.1. How are electricity grids planned and built?

1.1.1. Electricity grid development planning

17 As outlined in the introduction, electricity infrastructure is key to enabling the uptake of energy from renewables and to connecting markets. To develop an electricity grid that appropriates the system changes, current and future grid capacity needs are identified and addressed via electricity grid planning.

18 Electricity grid planning, as well as planning networks for other energy carriers such as gas and hydrogen, typically involves three essential components: the development of scenarios, a needs identification identifying where additional grid capacity is needed, and project identification (and selection) which includes an assessment of how capacity needs can best be addressed considering project costs and benefits[23].

- **Scenarios development.** This step involves system operators exploring and evaluating the evolution of consumption and supply of electricity and other energy vectors, considering factors such as population growth, societal changes, economic development, and technological advancements. Scenarios development is typically the first step of grid planning. The identification of grid capacity needs and the estimation of project benefits depend strongly on the scenario used. As the foundation of all other activities to prepare the electricity grid development plan, it is crucial that scenarios are robust, based on timely information and developed through a stakeholder-inclusive process[24]. However, scenario building comes at an early stage of the network development planning. As a result, there is an inevitable time gap between the development of scenarios and the subsequent preparation of needs and project assessments, which can be considerably reduced by streamlining the different processes. In 2023, ACER published framework guidelines for robust development of the scenarios to be used in the EU level network development plan (TYNDP Scenarios Guidelines)[25].

- **Needs identification.** Starting from the existing grid capacities and the considered scenario, this step refers to the identification of where additional grid capacity might be needed to support the integration of RES, alleviate bottlenecks, enhance cross-border electricity flows and improve the overall reliability and resilience of the grid.

23 New infrastructure does not necessarily mean new transmission lines. It may include an upgrade of existing electricity infrastructure or applying efficiency measures through, for example, the implementation of grid enhancing technologies.

24 Timely scenario preparation processes are essential to ensuring the use of assumptions that are as up-to-date as possible to avoid risks linked to early data collections, such as obsolete data and assumptions. Given a high degree of uncertainty of future developments in the energy sector, possible projections of future electricity demand and supply can only be approximated based on current knowledge and assumptions. Various factors, including technological advancements, regulatory and policy changes and geopolitical events, among others, may influence future energy demand and supply patterns. Due to these uncertainties, robust assumptions and inputs are crucial for scenarios to remain reliable and effective under varying and uncertain future conditions, ensuring that they can accommodate a wide range of potential developments. Stakeholder-inclusive processes help ensure that scenarios cover an agreed and widely accepted vision on the future energy system, which may facilitate public acceptance of infrastructure development.

25 ACERs Framework Guidelines for the joint TYNDP scenarios establish criteria for transparent, non-discriminatory and robust development of scenarios at EU-level in the context of energy network development. https://www.acer.europa.eu/sites/default/files/documents/Official_documents/Acts_of_the_Agency/Framework_Guidelines/Framework%20Guidelines/FG_For_Joint_TYNDP_Scenarios.pdf.

- **Project identification.** Project promoters, who are most commonly transmission system operators (TSOs) or distribution system operators (DSOs), develop a solution to an identified need. These solutions may include new transmission or distribution lines, or upgrading existing infrastructure or other non-wire solutions. Regulatory approval of a project should be based on project benefits outweighing costs.

19 **At the national level**, Member States plan their electricity transmission grid through National Development Plans (NDPs) that are revised at least every two years. NDPs are typically formulated by TSOs under scrutiny by national regulatory authorities (NRAs) and/or ministries and with the involvement of other system-relevant stakeholders such as DSOs, generators and consumers. NDPs today might not consider alternative solutions to grid buildout for inclusion.

20 While the EU rules require that NDPs indicate the main infrastructures that need to be built or upgraded over the next 10 years, along with already decided investment, each Member State defines its own process for development of national scenarios, how needs identification is carried out and how potential solutions addressing those needs are assessed before their inclusion in the NDP[26]. ACER's recent report on investment evaluation notes that currently very few countries conduct a methodical needs identification, despite its importance in planning the right projects[27]. The project identification by TSOs is done in many cases without justifying the project benefits in a quantitative way (e.g. a cost-benefit analysis (CBA)).

21 **At local level**, distribution infrastructure is built and maintained by DSOs. A distribution network development plan should be carried out at least every 2 years with the involvement of the TSO and other relevant stakeholders and under the scrutiny of the regulatory authority. However, this planning requirement often applies only to larger DSOs[28]. In many instances where DSOs are involved in project identification, they do so without a quantitative assessment of the project's benefits.

22 As the role of decentralised renewables production increases and electrification of energy demand grows, network planning at the distribution level and coordination between TSOs and DSOs (integrated electricity system planning) are becoming increasingly important. In this evolving context, the DSO landscape, which varies from a single to several hundred large and small DSOs in a country, will have to deal with these new challenges to a varying degree, including advanced planning, digitalisation and data management.

23 **At the European level**, the EU-wide Ten-Year Network Development Plan (TYNDP) provides a view on the EU's cross-border infrastructure needs and planned capacities to address these needs. It is a non-binding plan that is repeated every 2 years by ENTSO-E. It comprises scenarios development[29] and electricity infrastructure gaps identification based on those scenarios. TYNDP is a bottom-up planning exercise in which projects are not proposed by ENTSO-E but directly collected from TSOs and third-party project promoters. Apart from storage, alternative solutions to grid buildout are not included in the TYNDP.

24 ENTSO-E also assesses projects with cross-border relevance in a quantitative way by identifying the benefit that each project brings to the society compared to its costs[30]. This helps to identify the most important projects from a European perspective, i.e. PCIs and PMIs[31].

26 ACER's opinion on the electricity development plans observed that the frequencies and the timing of carrying out NDPs differ between Member States and the EU-wide TYNDP. Furthermore, there is a very limited number of electricity NDPs for which scenarios are jointly developed, for example joint gas-electricity development. Moreover, there are differences in the needs identification processes. While some needs identifications are based on the EU-TYNDP processes, others use their own assessments, and some do not conduct formal needs identification at all.

27 ACER, Report on investment evaluation, risk assessment and regulatory incentives for energy network projects, 2023, https://acer.europa.eu/sites/default/files/documents/Publications/ACER_Report_Risks_Incentives.pdf.

28 Regulatory authorities may decide not to require such a network development plan from DSOs which serve less than 100000 customers or serve small isolated systems.

29 EU-wide TYNDP scenarios are developed jointly by ENTSO-E and the European Network of Transmission System Operators for Gas (ENTSOG), and in the future also the European Network of Network Operators for Hydrogen (ENNOH).

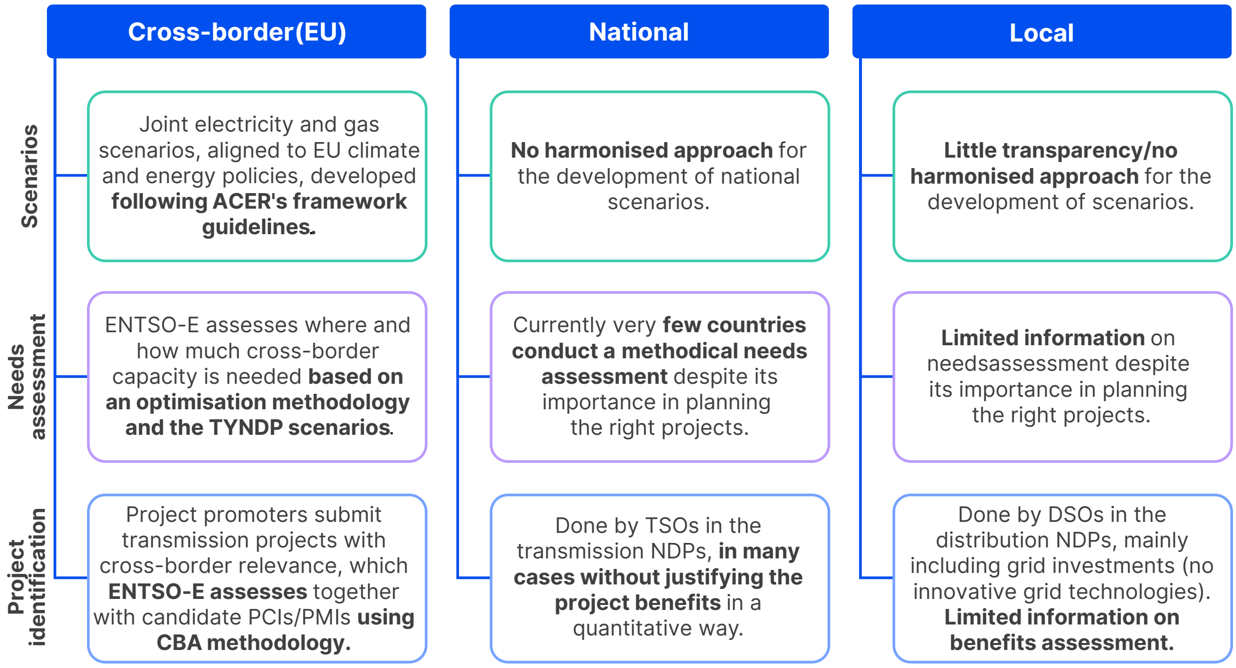
30 CBAs are carried out according to a methodology adopted by the European Commission.

31 Both PCIs and PMIs are selected for their significant potential for regional benefits, the difference being that PCIs are intra-EU projects and PMIs are projects between Member States and non-EU countries.

25 To ensure effective electricity system planning, alignment of planning approaches is required between the EU-wide TYNDP, national NDPs for transmission, and distribution network plans covering local networks. This alignment has not yet been achieved as illustrated in Figure 2.

26 Furthermore, to advance the transition from sector-specific electricity and gas systems to an integrated multi-vector energy system, the joint development of TYNDP scenarios by ENTSO-E and ENTSOG may not be sufficient.

Figure 2: Grid planning on the European and national levels



1.1.2. Electricity grid project implementation

27 Once a project comes to life as part of grid planning, steps need to be taken to implement the project and integrate it in the electricity grid. In general terms, project promoters such as TSOs and DSOs navigate through four implementation phases, of which some activities may advance in parallel, until a project becomes operational through its commissioning.

28 At first, as part of the network development planning at the various levels discussed above, project promoters consider potential solutions to meet an identified capacity need. While a project is **under consideration**, preliminary technical and economic feasibility studies may be carried out, leading into more in-depth feasibility studies and ultimately to an infrastructure project proposal.

29 In the **project planning and approval** stage, the project promoter works on specifying the types of equipment, materials, and technologies to be used. Details about the impact on the environment of the selected location along with regulatory standards defined by each Member State and the EU through, for example, network codes, feed into the design of engineering plans for infrastructure. Usually, this phase ends with the regulatory approval of the project.

30 The powers of NRAs are diverging across Member States. While some regulatory authorities approve transmission NDPs, others play only a consultative role during most of the implementation steps. NRAs are the primary actor in the last step in the project planning and approval phase – the formal investment approval, which includes cost scrutiny.

31 The **permitting** includes all the activities for obtaining the necessary permits and approvals from local, regional, and national authorities; these permits are necessary to comply with regulatory, social and environmental standards. This may involve environmental assessments, land use permissions, and compliance with safety regulations. Over the last years, stakeholder engagement

via public consultations or community involvement has also grown in importance. This is not least due to the vocality of public disapproval of newly built large infrastructure such as electricity transmission lines.

32 The permitting phase involves project promoters to prepare the permitting application, but is mostly in the hands of several environmental and permitting authorities who follow local and national procedures. For PCIs, a single national competent authority is appointed to facilitate the permitting process(es). Court proceedings may happen if permits are appealed, lengthening the duration of this phase.

33 After successfully receiving all required permits, a project enters **construction**. Construction of electricity network infrastructure often relies on scarce skilled labour and specialised manufacturers and procurement of specific materials and specialised equipment, necessitating the timely start of tendering and contract negotiations, which may already start in parallel with permitting activities. The construction of a project is completed once quality control and technical testing confirm the project's readiness for commissioning and eventual integration into the electricity grid.

34 The responsibility for advancing an infrastructure project along the implementation steps lie with different entities. The activities during the consideration and project planning steps, along with tendering for construction are mostly carried out solely by the project promoter, thereby placing the initiation and completion power in their hands. Construction activities are controlled by the project promoter alongside the contractors carrying out the work.

1.2. Unaddressed grid capacity needs put benefits of decarbonisation at risk

35 To effectively support the energy transition, it is essential that grid capacity needs are addressed efficiently and in a timely manner. Network development planning, both at the national and EU levels, should be based on a methodical system-needs identification exercise, which builds on robust scenarios about future consumption and generation that are compliant with energy targets and climate neutrality by 2050. The network development plan should include the planned capacities that address these needs, preferably complemented by a full quantitative assessment of the project benefits. However, in many countries the methodical needs identification is missing; where needs identification is carried out, it may not be driving the network development but merely be a complementing information.

36 For the analysis in this chapter, ACER relied on its monitoring data covering the EU-wide TYNDP and PCIs. At the time of completing this report, **the most recent available TYNDP prepared by ENTSO-E was the 2022 edition**. That edition includes assessments based on the national trends (NT) scenario, which reflects national policies and strategies included in the National Energy and Climate Plans (NECPs) prepared around 2020[32]. ACER's PCI monitoring data was last updated in 2023 and covers PCIs identified as such in 2021 and earlier.

37 While the observations are based on cross-border data, the identified issues and potential instruments to address them provide insights that can be applied to other grid levels.

1.2.1. Planned investment falls short of addressing identified cross-border capacity needs

38 The challenges for the future (and current) energy system that come with more RES and increased electrification were laid out in the introduction to this report. It is widely acknowledged that capacity for connection and interconnection must rise to achieve net zero by 2050.

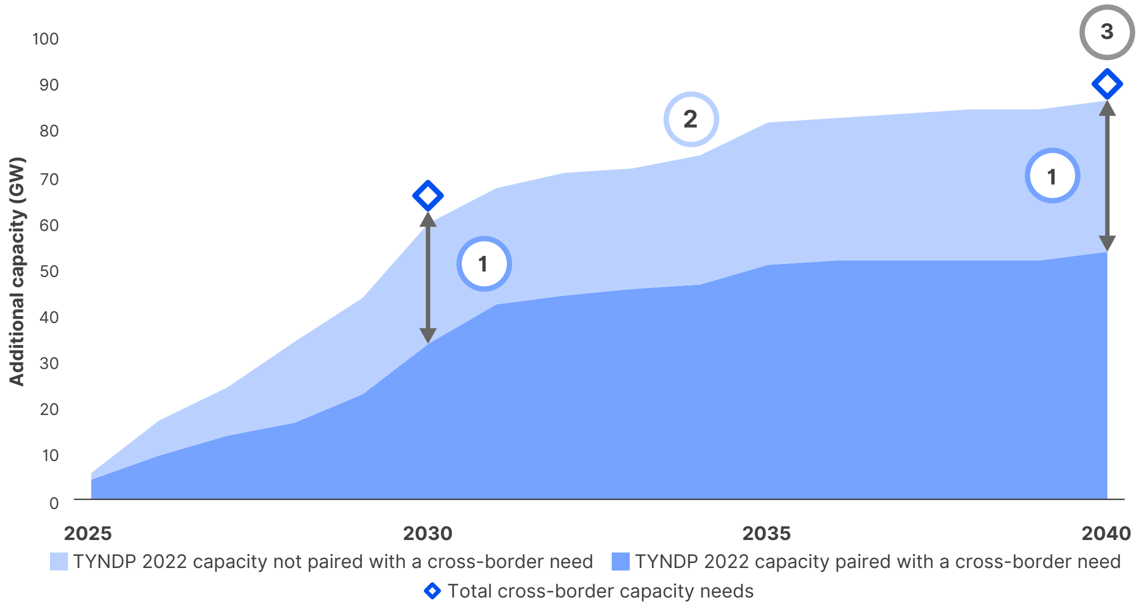
32 TYNDP 2022 considers one scenario based on the NECPs (i.e., national trends, NT) and two top-down scenarios for the mid- and long-term (i.e., 'distributed energy' and 'global Ambition').

39 While capacity needs arise across the local distribution level, the national transmission and the cross-border level, ACER monitors here the advancement of interconnection by looking at the capacity proposed in TYNDP 2022 in comparison to the identified cross-border capacity needs[33].

40 It should be noted that ACER had many comments on the TYNDP 2022 needs study. The 2022 scenarios were based on outdated assumptions. The needs assessment did not explicitly assess the country internal constraints including some cross-zonal borders, with potential distortion of the identified needs. The needs analysis does not address all benefits and a full CBA is needed as the most complete analysis to identify projects; it is also acknowledged that the TYNDP transmission projects can be proposed by both TSO and non-TSO promoters and that there is no optimisation of their project portfolios.

41 Based on ENTSO-E's system needs study, which was included in the TYNDP 2022, the total additional needs for infrastructure capacity identified across nearly 70 national[34] borders amount to 66 GW by 2030 (compared to the starting grid assumed to be in place by 2025) and an additional 24 GW by 2040 (compared to the grid assumed to be in place by 2030)[35]. These needs correspond to linearly adding about 13 GW of additional grid capacity per year until 2030 and about 2.5 GW per year until 2040[36].

Figure 3: Identified cross-border capacity needs vs capacity investment included in TYNDP 2022



Source: ACER calculation based on ENTSO-E's TYNDP 2022 data.

Note: ENTSO-E's needs identification is performed for the individual years 2030 and 2040. ENTSO-E's scope of needs identification and proposed projects includes EU internal borders as well as borders with and among Albania, Bosnia and Herzegovina, Montenegro, North Macedonia, Norway, Serbia, and Switzerland. Further borders with non-EU countries include Egypt, Israel, Tunisia, Türkiye and the United Kingdom.

33 In the TYNDP 2022 needs identification, interconnection needs are identified cross-border, in contrast to a zonal identification, which would assess needs between bidding zone borders. Cross-zonal trading relies on sufficient interconnection between bidding zones.

34 The ENTSO-E system needs study has a geographical scope including EU borders and borders with and among Albania, Bosnia and Herzegovina, Montenegro, North Macedonia, Norway, Serbia, and Switzerland. Further borders with non-EU countries include Egypt, Israel, Tunisia, Türkiye and the United Kingdom.

35 The starting grid includes cross-border capacities of projects that are relatively certain to be operational by 2025, i.e. projects which were under construction or in an advanced stage of permitting at the time of the study.

36 The large difference in the necessary yearly linear increase to 2030 and 2040 can partly be explained by the inclusion of flexibility assets (storage and CO_2-free peaking units) in the 2040 horizon, in addition to increases in cross-border capacities, leading to a lower level of identified interconnection needs.

42 Regarding the capacities of the projects proposed by project promoters and included in the TYNDP 2022 by ENTSO-E, Figure 3 shows identified needs by 2030 and 2040, planned capacities that address identified needs at each border without exceeding them, i.e. excluding projects competing for the same need, and national investment that has a cross-border effect while not being paired with a cross-border need[37].

43 The comparison of the identified capacity needs and the proposed capacity brings forth two observations:

- **The first observation** (marked ① in Figure 3, top) indicates that, when including a border-by-border perspective, planned capacities, if any, are insufficient or not timely in addressing needs at all borders where a grid capacity need was identified. The TYNDP 2022 data shows that for several borders with identified capacity needs by 2030 or 2040, no capacity is proposed for inclusion in the TYNDP[38]. This accumulates to 32 GW missing grid capacity across all borders by 2030 and 37 GW by 2040. It should be noted that planned capacity by 2040 is still 13 GW below the capacity needs identified by 2030.

- **The second observation** (marked ② in Figure 3, bottom) relates to investment included in the TYNDP 2022 that raises cross-border capacity without being paired to an identified cross-border capacity need by 2030 and 2040: 26 GW unpaired capacity by 2030 and 33 GW by 2040[39]. These unpaired projects include investment planned at the national level to address a national need while their effect on cross-border capacity is of secondary order, for example when an internal line also raises cross-zonal capacity; their inclusion in the TYNDP stems from the current bottom-up approach by which TSOs propose projects and ENTSO-E assesses their cross-border relevance, irrespective of the pairing with an identified cross-border need. Other projects that are proposed and address the same cross-border need were still under consideration and may not be approved for implementation if other projects are prioritised. The integrated review of national and pan-EU capacity needs and planned capacities would deliver insights into how the various planning levels interact but is challenging as information is dispersed and was not available to ACER within the timeframe of preparing this report.

44 It should also be noted that some projects included in TYNDP 2022, have commissioning dates that are after the time horizon for which the needs identification was carried out.

45 These two observations indicate that a **project identification that is not driven by a robust needs identification raises the risk** of investment interests falling short of cross-border needs.

46 **A third observation** (marked ③ in Figure 3, top) relates to the needs identification itself. To ensure a focused grid development driven by capacity needs identification, the needs identification must be based on robust scenarios that are fed into a state-of-the-art methodology.

47 In its various opinions[40] on TYNDP scenarios and in its TYNDP Scenarios Guidelines, ACER emphasises the key elements of robust scenario development, including focusing on a best estimate scenario that is stress-tested in a balanced way, timely scenario preparation that considers assumptions based on recent information about the evolution of electricity supply and consumption and other energy vectors. ACER sees shortcomings in the long scenario building process, which takes nearly 2 years, resulting in an increased risk of using outdated data at the time of the needs identification (and later when assessing project benefits).

37 It must be repeated that the proposed projects are not driven by ENTSO-E's needs identification but collected bottom-up from TSOs and third-party promoters.

38 29 out of the 57 borders with identified needs by 2030 and 21 out of 67 borders with identified needs by 2040 have no planned capacity proposed for inclusion in the TYNDP. When interpreting the numbers, it should be noted that planned investment at the borders A-B and B-C may address a need identified at border A-C.

39 20 borders by 2030 (and 21 borders by 2040) have planned capacity included in the TYNDP that surpasses the identified needs.

40 ACER Opinion 10/2018 on the ENTSO-E and ENTSOG draft TYNDP 2018 Scenario Report. https://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Opinions/Opinions/ACER%20Opinion%2010-2018%20on%20the%20ENTSO-E%20and%20ENTSOG%20draft%20TYNDP%202018%20Scenario%20Report.pdf. ACER Opinion 06/2020 on the ENTSO-E and ENTSOG draft TYNDP 2020 Scenario Report. https://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Opinions/Opinions/ACER%20Opinion%2006-2020%20on%20ENTSO-E%20and%20ENTSOG%20draft%20TYNDP%202020%20Scenario%20Report.pdf. ACER Opinion 06/2022 on key elements of ENTSO-E and ENTSOG draft TYNDP 2022 Scenario Report. https://www.acer.europa.eu/sites/default/files/documents/Official_documents/Acts_of_the_Agency/Opinions/Opinions/ACER%20Opinion%2006-2022%20on%20draft%20TYNDP%202022%20Scenario%20Report.pdf.

48 In addition to the scenarios, ACER has signalled shortcomings to the methodology used for the TYNDP needs study in its TYNDP opinions, for instance with respect to the grid that is considered to be in place[41].

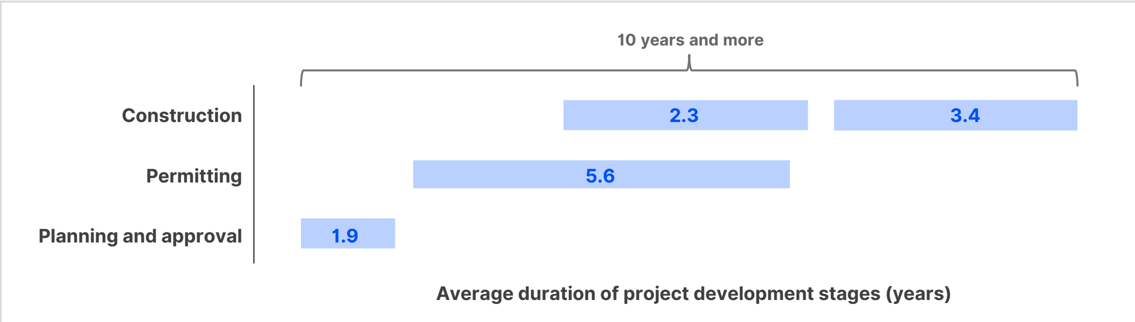
49 **If the needs identification is not robust (enough), the project identification risks being inadequate.**

1.2.2. Building infrastructure takes long, and completion is expected later than planned

50 To ensure efficient development of the electricity grid, the implementation of individual projects should also be timely and aligned with the generation or consumption need it addresses.

51 Based on ACER's PCI monitoring data, Figure 4 illustrates the different project implementation phases with respect to their average durations and relative timing within the overall project implementation timeline, from the end of consideration phase[42] until the end of construction and commissioning.

Figure 4: The average project implementation timeline



Source: ACER calculation based on PCI monitoring data.

Note: The project implementation phases include estimated dates for phases that are still pending and actual data for phases that have been concluded, as reported by the project promoters. Construction comprises tendering for construction (average duration 2.3 years) and actual construction (3.4 years). The 'under consideration' phase is not depicted as it is not always clearly delineated.

According to WindEurope, the average implementation timeline for an offshore wind project takes about 10 years, whereas onshore wind projects take between 4 and 8 years to be developed and connected to the grid.

52 **The average implementation time of a transmission project is more than 10 years**[43], of which more than half is devoted to permitting (5 years and more), which may run (partially) in parallel to the tendering of construction. The actual construction work commences after an average of 5 to 6 years of preparation after receiving the regulatory approval (which marks the end of the project planning phase). In comparison, the average implementation timeline for an offshore wind project also takes about 10 years, whereas onshore wind projects take considerably less time to be developed and connected to the grid, at 4 and 8 years[44].

53 While not included in the depicted timeline, grid projects spend an average of around 2–3 years 'under consideration', bringing the total project implementation time to approximately 14 years from being considered until the project's commissioning[45].

41 ACER Opinion 03-2021 on the Methodological Aspects of the ENTSO-E Draft TYNDP 2020. https://acer.europa.eu/sites/default/files/documents/Publications/Opinions/ACER%20Opinion%2003-2021%20on%20the%20methodological%20aspects%20of%20the%20ENTSO-E%20draft%20TYNDP%202020.pdf. ACER Opinion 03-2023 on the methodological aspects of the ENTSO-E TYNDP 2022. https://acer.europa.eu/sites/default/files/documents/Official_documents/Acts_of_the_Agency/Opinions/Opinions/ACER_Opinion_03-2023-ENTSO-E_draft_TYNDP_2022.pdf.

42 The conclusion of the consideration phase often marks the beginning of concrete project planning, assuming the project proceeds.

43 As PCIs are a subset of TYNDP projects that have significant cross-border impact and usually require implementation efforts in multiple countries. As a result, the implementation of PCIs is likely to take longer compared to projects without cross-border relevance.

44 WindEurope, bilateral exchange, September 2024.

45 The graph and the provided durations do not include time spent 'under consideration'. This phase was excluded from the analysis due to its unclear start, which leads to incomparable data.

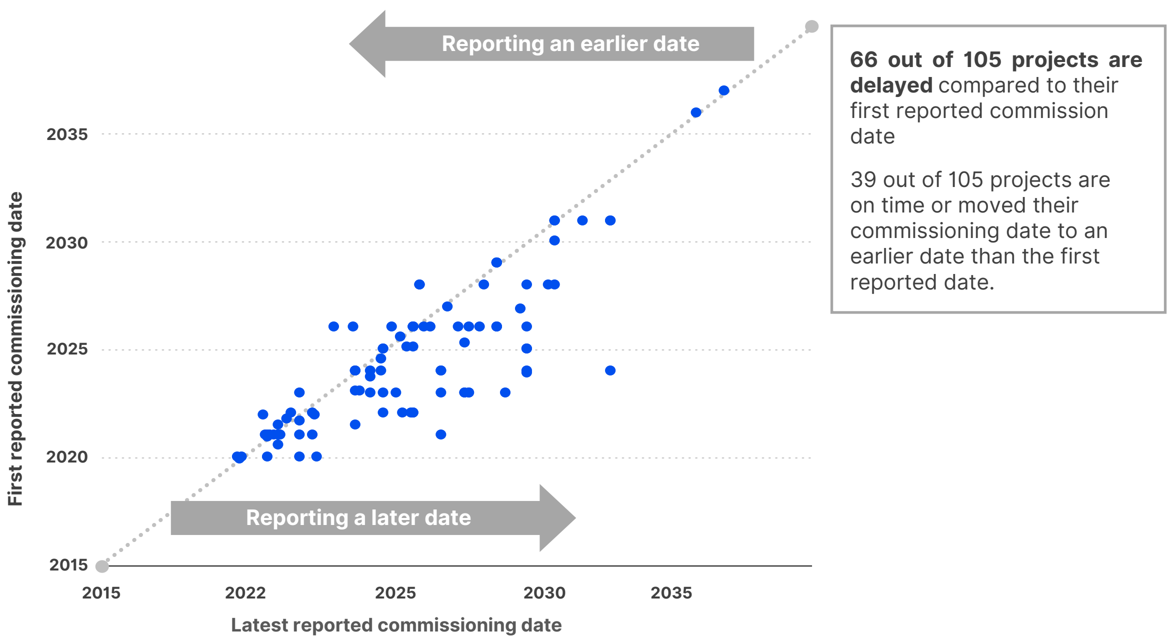
54 The long permitting phase indicates a long process of gaining public acceptance for a project and obtaining the required permits. A lack of public support for a project might lead to appeal procedures which extend the permitting processes. Building public support for energy infrastructure is essential to advance decarbonisation. However, prolonged public engagement cycles indicate strong opposition to the building of grids, which might be due to a lack of awareness of the benefits – which may be national or even EU-wide, covering the environmental or aesthetical hindrances or a disagreeable impact on a community altogether. Therefore, extensive efforts by project promoters to build public support are needed, alongside streamlining permitting processes, to prevent bottlenecks in the implementation process.

55 In addition to the lengthy lead time of electricity grid projects, project promoters face challenges in accurately anticipating the implementation timeline. Most PCIs updated their (expected) commissioning date at least once between their first and latest (or final) reporting to ACER, as illustrated in Figure 5[46].

56 The main reason for updates in the (estimated) commissioning date of PCIs, as reported by project promoters, are delays in the permit granting process. Further explanations relate to the tendering (e.g. supply chain constraints) or auctioning procedures along with lawsuits and court proceedings that cause changes in the planning.

57 To ensure the timely integration of increased grid capacities, implementation must be streamlined, addressing the bottlenecks in the implementation process and focusing the promoter's resources on the projects that address an identified need. At the same time, project planning should consider lead times based on historic experience, to avoid underestimating the commissioning date and to provide a realistic best estimate of when new capacity will be integrated in the grid. While these observations are based on data covering cross-border electricity grid infrastructure, the implementation challenges are believed to be very similar for large national transmission projects, while distribution projects, typically smaller in scale, would suffer less from extensive implementation timelines.

Figure 5: Commissioning time updates over project lifecycle



Source: Calculation based on ACER's PCI monitoring data.

Note: The latest commissioning date is referred to as the actual commissioning date if the project has already been commissioned. If the project is still pending commissioning, it is referred to as the estimated commissioning date. Projects located to the right of the grey dotted line updated their commissioning dates to a later date (the horizontal distance from the diagonal represents the delay).

58 Lengthy project implementation risks missing capacity at the time when it is needed.

46 ACER has collected PCI data from NRAs and project promoters since 2018.

1.2.3. Effects of off-target and delayed investment on decarbonisation benefits and cost efficiency

59 In observing unfocused project identification alongside lengthy project implementation timelines, three major risks for the EU electricity system and for consumers come to light: the risk of missing decarbonisation targets and the associated benefits, the risk of unfocused investment and the risk of an inefficient allocation of scarce resources.

Risk of missing decarbonisation targets and project benefits

60 The risk of missing decarbonisation targets becomes evident when project identification is not driven by robust needs identification, which in turn must be based on robust scenarios. When scenarios are not robust, the needs identification may not sufficiently reflect actual needs and inadequate projects may be proposed to address needs, or a project may target an unlikely need. Furthermore, extended implementation timelines and frequent delays compared to initial project planning induce a risk that infrastructure projects will not be integrated on time to deliver the needed capacity for the integration of renewables and the integration of newly electrified energy services, along with the flexibility needs.

61 Project benefits associated with unaddressed capacity needs will not be achieved or will be delayed, which may result in higher total costs of electricity (than if capacity needs were addressed on time) and other missed benefits.

Inefficient allocation of scarce resources

62 Grid development based on planning methods with shortcomings may lead to too much investment in some locations and too little in others. The latter coincides with missing decarbonisation targets when the grid cannot take in RES when it is ready, whereas the former negatively impacts competitiveness and affordability. These topics are explored in detail in Chapter 2.

63 Transparency on the risks, including planning risk, involved in investing is vital for the regulatory authorities approving investment, and the observed development issues obfuscate those risks.

64 Misallocation of scarce resources, whether monetary or other, may lead to more and longer project delays and drive up costs. Over the past few years, project promoters have faced increasing global competition along the entire supply chain, confronted with limited availability of critical materials/contractors and limited financial resources. This evolution could jeopardise the implementation and the budget of the projects, along with creating competition between countries. Also, manufacturers and technology providers may not have sufficient visibility on the future demand of their products. Projected high demand for increased grid reinforcements in the future is expected to aggravate such situations, inevitably affecting the pace of infrastructure development in Europe.

1.3. Recommendations to grid developers, regulators and governments on focused and timely grid development

65 To meet the EU's decarbonisation targets and unlock the great many benefits associated with grid investment, in a cost-effective way, it is paramount to appropriately focus and prioritise grid investment.

1.3.1. Grid developers to improve consistency and robustness of scenarios and needs identification

66 At the pan-European level, both the scenarios development and the needs identification performed should be further improved, to make them more transparent, reliable and replicable[47].

Grid developers to extend the use of multi-vector scenarios to grid development planning at the national level and ensure consistency between EU TYNDP and national scenarios

67 At the cross-border level, multi-vector scenarios, jointly developed by ENTSO-E, ENTSOG and in the future the European Network of Network Operators for Hydrogen (ENNOH), ensure a common view on the evolution of consumption and supply of electricity and other energy vectors that is in line with meeting EU and national energy and climate targets. These joint scenarios must be used for the needs identification and assessments of project benefits. This is not yet the case for national scenarios developed and used in some countries. Consistent scenarios that underpin the network development across all grid levels are essential for a more integrated planning of the electricity grid within the broader energy system[48].

68 ACER's TYNDP Scenarios Guidelines provide a framework for robust scenarios development focusing on a best-estimate scenario alongside stress-testing in a balanced way while including stakeholders to help raise the robustness of the assumptions. They also address the issue of the long development time of scenarios, which induces a risk that some assumptions may be outdated by the time the scenarios are used in the needs identification and CBA assessments that are part of the EU TYNDP. While these guidelines apply to the TYNDP scenarios, the guidance contained in them could also help national scenarios development, facilitating a more methodical way of developing scenarios.

69 It must be emphasised that energy efficiency should come first, reducing the need for additional grid capacity, and be included appropriately in the assumptions about the evolution of energy consumption, as along with the responsiveness of consumption to price and other signals.

Grid developers to conduct methodical and consistent needs identifications at national and regional (and EU) levels

70 Methodical infrastructure needs identification is still missing from the vast majority of the national transmission planning frameworks, while in about half of the Member States, quantitative assessments of projects' benefits, for example using CBA, are not performed. A consistent network planning across the national and cross-border level would benefit from conducting structured and consistent needs identifications at the national/regional level. While most experience with needs identification has been gathered in the context of the EU-wide TYNDP, guidelines for needs identification could be issued by ACER to improve the EU-wide exercise and ensure consistency of the national assessments. Prioritisation could be improved by including a quantitative assessment of project benefits, which may help with project identification and implementation[49].

47 See note 4.

48 ACER Opinion 05/2021 on electricity NDPs recommends that at least one robust EU TYNDP scenario is considered to construct NDPs' scenarios, https://acer.europa.eu/Official_documents/Acts_of_the_Agency/Opinions/Opinions/ACER%20Opinion%2005-2021%20on%20the%20electricity%20national%20development%20plans.pdf.

49 ACER-CEER Position on anticipatory investments, March 2024, https://www.acer.europa.eu/sites/default/files/documents/Position%20Papers/ACER-CEER_Paper_anticipatory_investments.pdf.

71 In the future, a further integrated energy-system planning might consider **multi-vector needs identification**, in which needs for energy transportation are assessed regardless of the energy vector (electricity, hydrogen, decarbonised gas) that will address that need.

72 ACER commits to continue promoting improvements in scenario-building, needs identification and CBA at the European level. In addition, ACER is starting a new activity to provide guidance on distribution network planning.

Grid developers to further integrate the local level in the network development framework.

73 Most investments are expected to take place at the level of distribution grids. Additionally, distribution-connected users have a high potential to offer flexibility to the electricity system. This means that DSOs will benefit from a methodical approach to grid planning[50], and integrating them fully into the national and, where relevant, EU-wide planning exercises to consider the interdependencies that exist between these levels.

74 Overall, there is a need for more coordination of national planning, including the local level as appropriate, and organised supply of information about the planned investments at the national level, to be able to identify possible gaps between the overall planned investments and the expected needs.

1.3.2. Grid developers to identify and select investment based on needs identification and benefits assessment

Policymakers to complement the current bottom-up project identification with a top-down mechanism to propose projects that are driven by regional needs

75 Today, the TYNDPs are built bottom-up from the national projects which are assessed vis-à-vis pan-EU scenarios and pan-EU needs identification defined at the EU level by the ENTSOs. The pan-European strategy to determine infrastructure requirements using EU scenarios and methodologies in the TYNDP brings a genuinely holistic approach, whilst the bottom-up method that suggests projects from a unilateral or bilateral viewpoint through national plans may not fully capture the European interest in creating effective pan-European infrastructure planning.

76 As recommended in the ACER–CEER paper on challenges of the future electricity system, the EU energy regulators suggest introducing a complementary EU planning approach to identify regional infrastructure solutions with an EU dimension. This could involve empowering regional or EU entities to propose high-level infrastructure solutions. In that regard, ACER should monitor unmet infrastructure needs and energy regulators should be empowered to request TSOs to develop projects addressing these gaps[51].

50 See note 40.

51 See note 4.

Case box: Addressing bottlenecks in the Dutch electricity transmission system

Due to a swift expansion of renewable energy production, such as rooftop photovoltaic alongside accelerating electrification, the Dutch high- and middle-voltage grids in several regions approached maximum capacity, with few connections available for new customers, or the maximum available transmission capacity was already reached. The congestion, however, was time-dependent, meaning that capacity remained available during off-peak hours while network scarcity occurred mostly during the peak hours of electricity consumption.

The Dutch energy regulator, Authority for Consumers and Markets, introduced comprehensive measures to address this grid congestion and ensure continued possibilities for connection to the grid.

Measures to address grid congestion

Beside faster grid construction, grid congestion is mitigated by **time signals embedded in network tariffs** to encourage large-scale users to reduce or avoid grid usage during peak hours, thereby freeing up capacity for other users and sustainable electricity producers:

- a discount of up to 50% for use during off-peak hours for large-scale users, and increased prices when using the network close to the capacity rating of the connection during peak hours (time-of-use charges);
- two alternative transport contracts that have contractual restrictions on when the user can use the network in exchange for lower network charges.

As the additional grid access waiting list is also growing, the regulator has added **a prioritisation framework enabling system operators to rank connection projects based on their societal value**. This includes 'congestion softeners' like battery systems that enhance capacity for others, security-related bodies such as national defence, police and medical first responders, and essential services such as drinking water and education.

Other measures include a closer **monitoring of actual use of contracted capacity** in order to free unused capacity, and **a mandate for system operators to experiment** with ways to use the existing capacity more efficiently.

After evaluation with the system operators and other market participants, improvements in the execution of these measures such as mandatory participation to increase involved large-scale users, together with standardisation of contracts and compensations to increase contracting, are expected to make these measures more frequently used.

Beside regulatory measures, capacity hosting maps are also used by the Dutch TSO, TenneT, to offer visibility on the availability of transmission capacity.

Grid developers to apply project identification based on identified needs and quantitatively assessed project benefits while integrating 'efficiency first' logic

77 Project identification must become smarter and transparently consider projects to reduce needs (optimise the use of existing capacities), alternative solutions to raise capacity and traditional infrastructure projects; identification should be based on the benefits delivered by the project including the potential to reduce or address a capacity need.

78 First, efforts should be made to reduce the need for more capacity by optimising the use of the existing infrastructure. Such optimisation relies on signalling, via the network fees (and zonal market prices), when (and where) network congestions happen so that network users can change their consumption (or production) behaviour, thus benefiting from demand response and other flexibility. In this case, regulators must integrate those signals in the network tariffs (see Section 2.3). Signals may also be in the form of information, like TSO and DSO capacity-hosting maps that show where new connections to the grid may be constrained[52]. In the context of acute grid congestion in the Netherlands, such non-wire measures have helped mitigate the problems (see Case box: Addressing bottlenecks in the Dutch electricity transmission system). These possibilities should already be considered as much as possible in the scenarios.

Case box: Role and potential of grid-enhancing technologies

GETs are referred to as **advanced tools designed to optimise the efficiency, reliability, and capacity of electrical power grids** through improved monitoring and control.

While GETs may offer considerable cost and time savings, they are **not systematically considered for application by system operators**. For example, suppliers of GETs put forward theoretical potential increases of overall network capacity in Europe by 20 to 40% by 2040 and cost reductions by 35% compared to traditional network expansion by the 2040[53].

In case studies[54] in the U.S., GETs are said to leverage the environmental benefits of renewables, potentially increasing renewable energy utilisation by 5 to 20% and reducing carbon emissions by 30 to 70%. Under certain market conditions, however, they may lead to increased carbon emissions.

The little deployment of GETS may be founded in the l**ack of adequate investment incentives and their technical complexity**. Also, regulatory frameworks that make traditional (CAPEX-heavy) investment financially more attractive create barriers for the adoption of smart grids and other innovative technologies that rely more on OPEX, including GETs[55].

79 Second, to raise capacity, TSOs and DSOs should also consider non-wire measures to make additional capacity available without adding network assets[56]. Grid-enhancing technologies or GETs (see Case box: Role and potential of grid-enhancing technologies), digitalisation and data management have some potential to increase capacity of the electricity system reducing or postponing the need for infrastructure investment. Alternative solutions might also be faster to implement if they do not require lengthy permitting and construction. These alternative solutions should be integrated in the project identification process based on their potential to address, partially or temporary, an identified need, and be included in NDPs and the EU-wide TYNDP.

52 The publication of capacity-hosting maps became a requirement by the electricity market reform of May 2024, https://energy.ec.europa.eu/topics/markets-and-consumers/electricity-market-design_en.

53 Compass Lexecon, *Prospects for innovative power grid technologies*, June 2024, https://www.currenteurope.eu/wp-content/uploads/2024/06/CL-CurrENT-BE-Prospects-for-Innovative-Grid-Technologies-final-report-20240617-2.pdf.

54 U.S. Department of Energy, *Grid-Enhancing Technologies: A Case Study on Ratepayer Impact*, 2022, https://www.energy.gov/sites/default/files/2022-04/Grid%20Enhancing%20Technologies%20-%20A%20Case%20Study%20on%20Ratepayer%20Impact%20-%20February%202022%20CLEAN%20as%20of%20032322.pdf. Omid Mirzapour, Xinyang Rui, Mostafa Sahraei-Ardakani. *Grid-enhancing technologies: Progress, challenges, and future research directions*, Electric Power Systems Research, Volume 230, May 2024. https://doi.org/10.1016/j.epsr.2024.110304.

55 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, IV. Incentivising better usage of the grids, COM(2023) 757, eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:52023DC0757.

56 Trinomics, *Advancing cross-system solutions to address electricity network challenges*, 2024, https://www.acer.europa.eu/sites/default/files/documents/Publications/Consultancy_study_Electricity_Network_Solutions_2024.pdf.

80 Traditional infrastructure buildout projects remain essential for raising grid capacities in response to identified needs where the first and second options are insufficient.

81 ACER's work on infrastructure efficiency acknowledged that the regulatory framework governing TSOs and DSOs may impact their choice between traditional solutions (e.g., network expansion) and non-wire alternatives and that innovation in these frameworks should be explored[57]. Proper incentives are needed to displace investment risks that accompany non-wire solutions and a possible incentive innovation consists of allowing a system operator to retain part of the economic savings generated by choosing an alternative, cheaper solution than traditional grid buildout[58]. While non-wire alternatives are more prevalent at the transmission level (e.g. dynamic line rating technology), they remain niche at the distribution level. The regulatory framework for investment is further examined in Chapter 2.

Regulators to scrutinise grid plans.

82 To ensure a proper balance of roles and remove potential biases (or perception of biases) in infrastructure planning, the level of scrutiny by ACER and NRAs should be increased by empowering ACER (at the pan-European level) and NRAs (at the national level) to make a final decision on the methodologies governing infrastructure planning (complementing the existing CBA methodology at the EU level approved by the European Commission, and enabling methodical planning approaches at all grid levels) as well as the NRAs with the approval[59] of their respective NDPs.

83 The projects included in the national NDPs (and EU-wide TYNDP) should therefore meet an identified need at a national or regional level and show that no lower-cost alternative is available.

1.3.3. Grid developers to do more structured public engagement to accelerate implementation

84 While ACER recommends that overly optimistic projections of the expected commissioning dates should be avoided[60], it acknowledges the challenges of building trust and public support for large infrastructure projects, and that these challenges may have significant impact on a project's progress.

Forward-looking planning and partial approvals for pre-construction activities.

85 Infrastructure development is a lengthy process, so by being more forward-looking in the planning and anticipating permitting-related activities, the overall project implementation could be sped up. The ACER–CEER position paper on anticipatory investment recommends: 'NRAs could consider greenlight to a project to progress permit granting and other preconstruction activities as much as possible, without the regulatory approval of the project construction (which would come later, when the need is confirmed); such an approach would speed up the project implementation, while limiting the risks of "sunk costs" for the society to the (small) pre-construction costs, in case the need will never be confirmed.'

57 ACER position paper on incentivising smart investments to improve the efficient use of electricity transmission assets, November 2021. https://www.acer.europa.eu/sites/default/files/documents/Position%20Papers/Position%20Paper%20on%20infrastructure%20efficiency.pdf.

58 Florence School of Regulation, 2024. Benefit-based remuneration of efficient infrastructure investments. Study for ACER. https://www.acer.europa.eu/sites/default/files/documents/Publications/2024_Report_Benefit_based_remuneration_infrastructure_investments.pdf.

59 See note 40.

60 ACER Opinion 03/2023 on the methodological aspects of the ENTSO-E TYNDP 2022, see note 32. ACER Opinion 04/2023 on electricity projects in the draft ENTSO-E TYNDP 2022 and in the National Development Plans (NDPs), https://acer.europa.eu/sites/default/files/documents/Official_documents/Acts_of_the_Agency/Opinions/Opinions/ACER_Opinion_04-2023-Ele_projects_ENTSO-E_draft_TYNDP_2022%26NDPs.pdf.

Grid developers to build trust and public acceptance through sustained public engagement.

86 While permitting is identified as the main bottleneck in the implementation process of electricity infrastructure, low public acceptance could be an important factor in lengthy lead times for obtaining permits when appeal procedures are initiated. Improving public acceptance through public engagement may mitigate this bottleneck.

87 Member States' actions on public engagement for grid planning are rather unknown as the monitoring of public engagement practices on a national level lacks a mandate to do so holistically.

88 As part of involving stakeholders in grid planning at the EU level, ACER's TYNDP scenarios guidelines required ENTSO-E (and ENTSOG) to have a continuous stakeholder dialogue based on an agreed stakeholder engagement plan. TSOs and DSOs could replicate and adjust such an approach to public engagement and systematically adopt 'public engagement plans', which could be developed separately to network development plans, where TSOs and DSOs would set up participatory processes and describe the planned actions and related costs[61]. Where financing public engagement is not well-established, such plans should be approved by NRAs in order to recognise the inherent costs, while in other jurisdictions such plans would mainly serve to further professionalise public engagement approaches and share best practices. ACER, ENTSO-E and the EU DSO entity could be assigned the task of facilitating exchanges of best practices and providing practical guidance.

89 Public awareness initiatives at the national level through impartial entities (e.g. academia, experts) should also be promoted. In addition, interest groups such as consumer groups or municipality organisations could raise awareness at either the national or local levels.

90 Concerning permitting, EU legislation could introduce the obligation of a biennial monitoring of the permit granting hurdles for projects, aiming to identify the causes for permit-granting delays and the related solutions. Based on national reports, the European Commission could assess the adopted and foreseen country-specific measures and provide an EU-wide assessment of the permitting challenges, identify best practices and promote further mitigating measures where necessary. This assessment can inform and guide further amendments and improvement of the EU legislation.

91 In addition, public engagement activities and permitting processes require significant efforts from project promoters and permitting authorities; these efforts would best be aligned to priority projects focused on robust identified needs.

1.3.4. The EU and Member States should address upscaling issues

The EU to secure supply chains and encourage investment in scarce resources

92 In its report[62] on 'Electricity Grids and Secure Energy Transitions', the International Energy Agency (IEA) already signalled the need to develop secured supply chains and skilled workforces.

93 According to the IEA, '*Accelerated grid capacity development and deployment of new technologies will place increasing strain on supply chains. Governments can support expansion of these supply chains by creating firm and transparent project pipelines and by standardising procurement and technical installations. At the same time, a focus on interoperability of different solutions will support flexibility in the future, while cybersecurity concerns for grid components should be addressed.*' It further notes: 'There is already a significant need for a high number of skilled white- and blue-collar workers across the entire supply chain, as well as at operators and in regulating institutions.'

61 European Commission, 'Commission launches a new "Pact for Engagement" with electricity sector', press release, 28 November 2023, https://energy.ec.europa.eu/news/commission-launches-new-pact-engagement-electricity-sector-2023-11-28_en.

62 IEA, 2023, *Electricity Grids and Secure Energy Transitions*, https://iea.blob.core.windows.net/assets/ea2ff609-8180-4312-8de9-494bcf21696d/ElectricityGridsandSecureEnergyTransitions.pdf.

94 The adoption of standardised equipment to reduce the design time and limit the delays caused by individualisation of requests should be promoted among grid developers, as this could also facilitate the permitting phase and ease the observed constraints on the supply chain and facilitate a more efficient project implementation.

95 Regional or EU-wide platforms to facilitate the procurement of critical materials/contractors to build the relevant infrastructures could also help to reduce supply chain delays. Additionally, EU institutions should explore the possibility to promote the adoption of EU risk preparedness plans in the event of supply chain disruptions.

Member States to ensure their DSOs are ready to successfully take on their enlarged role

96 The growing importance of data management and digitalisation alongside an increasing role of distribution systems within the electricity system requires that DSOs take on a larger role. That role requires advanced methodical approaches to planning, including appropriate needs identification (including modelling) and project identification based on quantitatively assessed benefits. DSOs will have to adopt GETs and engage in real-time monitoring of their local systems while coordinating with other grid levels. Facing these challenges will require upscaling and pooling of resources and professional skills that may not be present everywhere in the fragmented landscape of DSOs in Europe.

97 Member States must ensure their DSOs are ready to successfully take on the enlarged role that is expected of them.

2. Monitoring infrastructure investments and their cost impact

98 While Chapter 1 highlights the need to focus grid investment on addressing identified capacity needs, this chapter explores the investment costs and their impacts on affordability and the competitiveness of final energy prices (compared to the rest of the world).

99 Chapter 2 outlines how investment and cost recovery works, followed by an estimation of future grid costs, and concludes with recommendations to ensure that investments continue to bring affordable energy.

2.1. How do grid investment and cost recovery work?

100 Electricity transmission and distribution networks are expensive. They also have no other economic use than to transport electricity. Anyone investing in such assets requires long term security from the users so that the CAPEX and OPEX can be recovered and that a risk-covering remuneration can be earned.

101 Intensive investment requires substantial capital, which is commonly financed through equity (funds raised by shareholders), debt (funds borrowing) or a combination of both. To attract equity financing, the remuneration that shareholders can earn must be high enough to withstand competition from other potential investments with a similar risk profile. Similarly, debt financing requires the creditors to earn a premium that covers their credit risk, which is most often measured by credit rating agencies. Regardless of the sources of financing, the costs must be covered by revenues.

102 As TSOs and DSOs are natural monopolies operating in a regulated sector, the framework for cost recovery and remuneration, known together as the 'allowed revenues', is set by the regulator (see Case box: A simplified view on the 'allowed revenues' framework). These allowed revenues are then charged to industry, households and other users, mainly in the form of network tariffs.

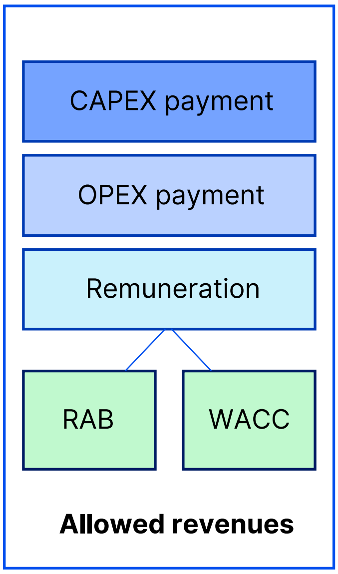
Case box: A simplified view on the 'allowed revenues' framework

Every year the system operator recovers the depreciated part of its capital assets, which is the CAPEX component.

The operational cost to carry out its business makes up the yearly OPEX component.

The regulated remuneration in its simplest form corresponds to multiplying the regulated value of all non-depreciated assets (regulated assets base, RAB) with the weighted cost of capital (WACC). The WACC considers the mix of equity and debt financing and their respective appropriate cost.

Inflation is another element to be considered.



103 The regulatory framework must strike a balance between offering high enough returns to attract equity and debt investors, while also keeping grid costs affordable for users.

Table 1: Overview of regulatory parameters and how they affect grid costs

Regulatory parameter	Sensitivity of grid costs to the parameter
CAPEX	Higher CAPEX directly leads to higher grid costs.
OPEX	Higher OPEX directly leads to higher grid costs
Depreciation rate (~asset lifetime) (varies by asset)	A slower depreciation rate spreads costs over a longer period, lowering their annual impact while keeping assets longer in the RAB on which a remuneration remains due. A slower depreciation rate lowers grid costs (today) and makes future generations pay for costs decided today.
Risk-free rate (RFR) WACC (Cost of Equity and Cost of Debt)	Determined by the condition of a country's economy and fiscal policy. A higher risk-free rate makes financing investments costlier. In 2024, the risk-free rate doubled compared to 2015–2021. A rise of the risk-free rate raises grid costs
Market-risk premium equity (Rm) WACC (Cost of Equity)	A higher market-risk premium (above risk-free rate) makes financing of investment more expensive. Reflects the sector and individual performance of a TSO/DSO. A higher premium raises grid costs.
Beta WACC (Cost of Equity)	Represents volatility of the company relative to the market. A higher beta raises financing costs and thus grid costs.
Gearing (g) (debt / (debt + equity)) WACC	Gearing represents the debt financing part in total financing A highly geared company may get a reduced credit rating, which may increase the debt risk premium to attract debt investment. A gearing that is too low means relying on equity financing that is usually more expensive than debt financing.
Debt risk premium (Rd) WACC (Cost of Debt)	If the debt risk premium is higher, financing of investment will be more expensive and grid costs will rise.
WACC	A higher WACC raises grid costs to be paid by consumers. WACC = g × Cost of Debt + (1–g) × Cost of Equity – Cost of Equity = RFR + (beta × Rm) – Cost of Debt = RFR + Rd

104 Grid costs, along with system operation costs (e.g. losses, congestion management costs, costs of adequacy and flexibility schemes) make up the 'system costs' for delivering electricity. **When monitoring the affordability of electricity prices for industry, the commercial sector and households, and their competitiveness vis-à-vis the rest of the world, rising system costs matter. These** system costs must be assessed together with the costs of energy, which may decrease with further integration of zero-marginal-cost RES.

2.2. Massive grid investment will affect affordability and competitiveness

105 As established in the last section of Chapter 1, the wave of investments should be as targeted as possible, addressing capacity needs efficiently and achieving project benefits in a cost-effective way.

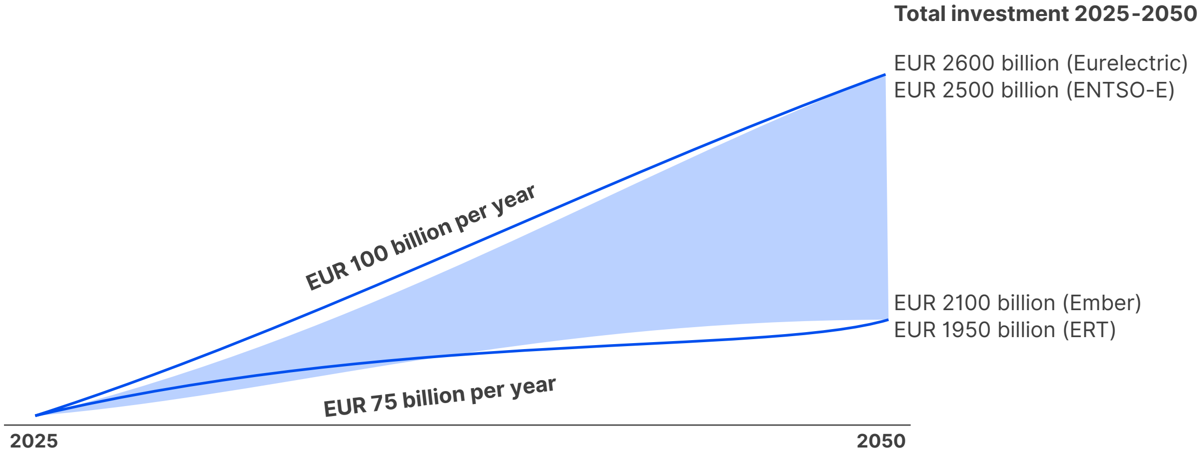
106 While grid capacity and investment needs are strongly interwoven, there is limited information available on them, beyond broad projections of investment needs and the associated challenge.

107 This section attempts to provide some insight on the evolution of grid costs (combined for transmission and distribution), including an indicative assessment of their sensitivity to the levels of investment and consumption, and concludes with a discussion on how rising grid costs could affect affordability for end consumers.

2.2.1. Comprehensively monitoring investment: do we have a blind spot?

108 To build a decarbonised EU energy system, **investment of an unprecedented magnitude will be needed in the electricity transmission and distribution grids reaching net zero, doubling and even tripling annual investment rates of the past decades.** While the trend is agreed on, the estimates of the EU's annual investment needs coming from various sources vary between EUR 75 billion (total projected investment of EUR 1950 billion between 2025 and 2050) and EUR 100 billion (total projected investment of EUR 2600 billion between 2025 and 2050) (Figure 6). In these projections, it is assumed that the transmission level accounts for a smaller portion (about one third) compared to the distribution level (about two thirds).

Figure 6: Transmission and distribution investment needs projections for 2025–2050



Source: ACER estimates based on Ember, ENTSO-E, ERT and Eurelectric.[63]

Note: European Round Table for Industry (ERT) projects annual investment needs of EUR 75 billion according to projections (mid-point of the EUR 70 billion to EUR 80 billion range in ERT's study); Ember projects annual investment needs of EUR 63 billion, rising to EUR 85 billion after 2030; ENTSOE-E projects annual investment needs of EUR 96 billion (calculated by ACER from ENTSO-E's transmission-level total investment projection); Eurelectric projects annual investment needs of EUR 100 billion (calculated by ACER from Eurelectric's distribution-level annual needs projection).

All numbers were recalculated for the time span 2025–2050, and scoped, where possible, to cover the EU and excluding non-EU countries. A proportion of two thirds distribution-level investment and one-third transmission-level investment was used to calibrate sources projecting investment needs for only transmission or distribution.

109 The average annual investment costs of all proposed projects in the TYNDP 2022 (similar for earlier TYNDP editions) amounts to less than EUR 10 billion, which would represent merely 10% to 15% of the projected annual investment needs for the whole electricity grid[64]. The gap between projected annual investment needs and TYNDP investment is assumed to comprise transmission projects without cross-border relevance and distribution projects; however, the information about such non-TYNDP projects is scattered and not easily available in a comparable format[65], which hinders proper comprehensive monitoring of electricity infrastructure development and analysis by interest groups and independent research institutions.

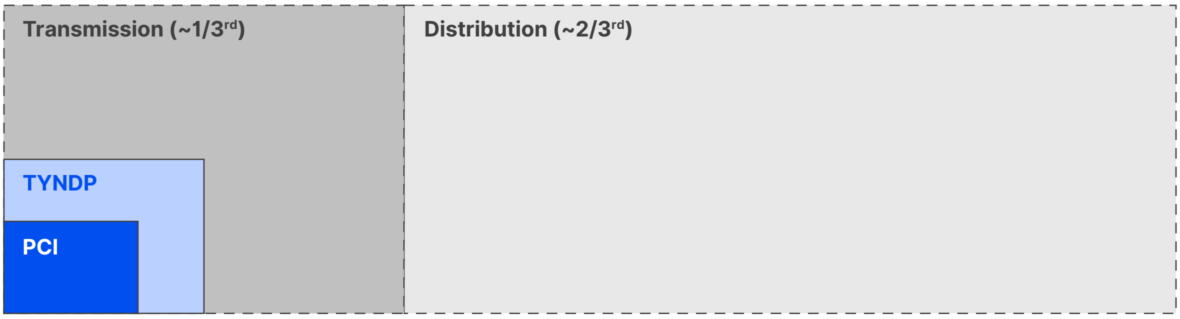
110 Figure 7 depicts the relative share of projected distribution investment, transmission investment, investment with cross-border relevance (TYNDP) and PCIs, which is a subset of cross-border relevant investment. ACER's infrastructure monitoring comprises cross-border relevant investment.

63 Ember, Putting the Mission in Transmission: Grids for Europe's energy transition, 2024, https://ember-climate.org/insights/research/putting-the-mission-in-transmission-grids-for-europes-energy-transition/. ENTSO-E, Regulatory systems of EU Electricity Transmission System Operators need to be adapted to ensure that the massive grid transmission investment plans can be financed, https://www.entsoe.eu/2024/08/02/regulatory-systems-of-eu-electricity-transmission-system-operators-need-to-be-adapted-to-ensure-that-the-massive-grid-transmission-investment-plans-can-be-financed/. ERT, Strengthening Europe's Energy Infrastructure, 2024, https://ert.eu/wp-content/uploads/2024/04/ERT-Strengthening-Europes-energy-infrastructure_March-2024.pdf. Eurelectric, Grids for speed, 2024, https://powersummit2024.eurelectric.org/grids-for-speed/.

64 Furthermore, as observed in Chapter 1, some TYNDP projects lack focus and do not address an identified capacity need, investing too much in some locations and too little in others.

65 Ember, *Putting the Mission in Transmission: Grids for Europe's energy transition*, see note 54.

Figure 7: Visual approximation of relative investment by grid level monitored by ACER



Note: ACER's monitoring mandate covers investment with cross-border relevance, which corresponds to investment included in the EU-wide TYNDP and the subset of PCI (and PMI) projects. While distribution investment and a large part of transmission investment is not monitored by ACER, those investments are crucial for the EU electricity grid, within EU's decarbonising energy system.

2.2.2. Insights on the estimated evolution of grid costs

111 Before launching the discussion on cost impacts of the upcoming investment wave, a number of caveats must be spelled out to avoid misinterpretation of the estimated effects, which serve to raise awareness of the possible evolution of grid costs among decision-makers, including regulatory authorities.

- Grid costs are recovered via network tariffs. Rising grid costs usually mean increasing overall network tariffs. Tariff setting practices vary considerably across the EU and, due to lack of data, the projection of future tariffs is not pursued in this report. Instead, projected cost impacts are monitored relying on a **simplified calculation of allowed revenues to recover the investments taking place between 2025 and 2050, dividing them by projected consumption levels**.
- To complement available information, it was necessary to make assumptions about certain regulatory parameters and extend projections about investment and consumption. The uncertainty and arbitrariness of some assumptions is fully acknowledged and details on the methods and data sets used can be found in the Annex.
- As these calculations rely on assumptions about annual investment, regulatory parameters and future consumption, the numbers should not be read as predictions, but as giving **an order of magnitude of the grid cost impacts by the upcoming massive investment**.

112 In this report, future grid costs are imagined to be composed of 'legacy grid costs', which represent payments due to recover the historic investment carried out in the past and can no longer be influenced, and 'new grid costs', which represent payments due for recovering the costs of the upcoming investment in the grid.

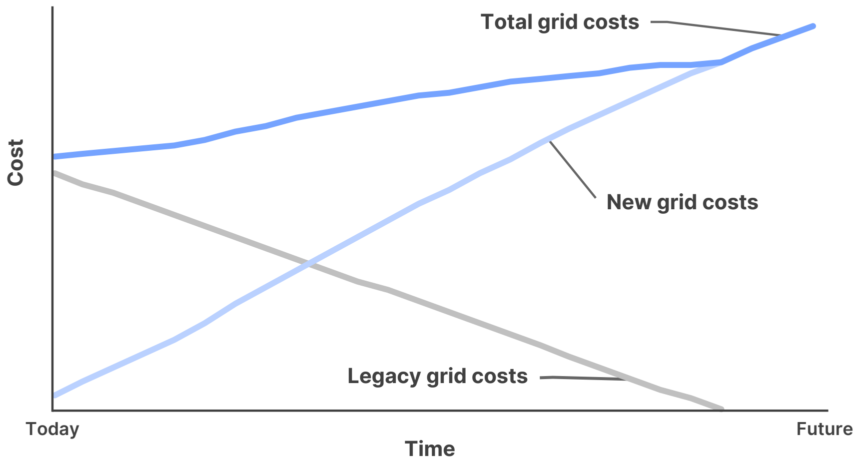
113 Based on recent levels of total transmission and distribution network charges, current legacy grid costs are estimated at around EUR 29 to EUR 35 per MWh[66]. These legacy grid costs will go down over the next decades as historic investment is progressively paid off. While ACER does not have information on the trajectory of asset depreciation, a conservative estimate could be that these legacy grid costs would reduce by a quarter every decade[67].

114 While legacy grid costs reduce, new grid costs build up, accumulating in gradually rising total grid costs, as depicted in a stylised way in Figure 8. Assuming an investment pace for the next decades that is twice the historic investment pace, the total grid costs might stabilise at a 60% increase compared to legacy grid costs in 2022 (depicted in Figure 9), up to nearly twice the legacy grid costs in 2022, depending on the level of investment.

66 Based on approximate total charges for use of the network (approximate allowed revenues) for the whole EU electricity system in 2022, legacy grid costs come down to at least 32 EUR per MWh, at 2022 consumption levels. However, data were not provided for a few countries, as listed in Table A5 in the Annex.

67 Assuming a stable pace of historic investment and an average depreciation time of 40 years, the legacy grid would be half depreciated after two decades, thus halving the costs associated with those legacy assets.

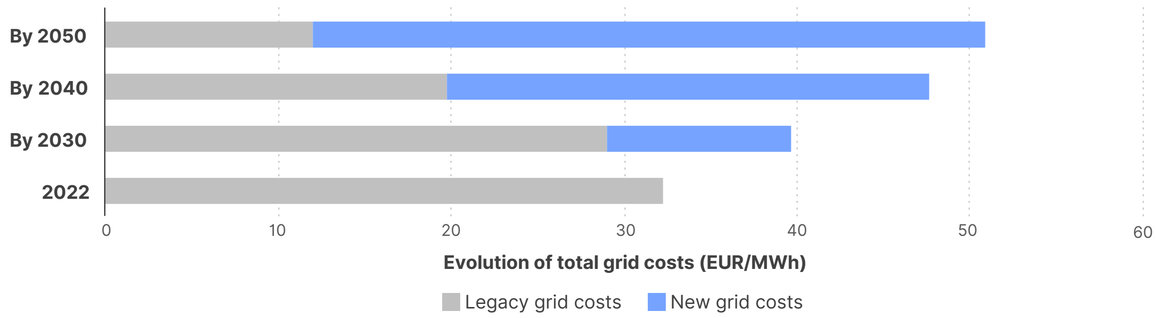
Figure 8: Stylised evolution of total grid costs, 'legacy grid costs' and 'new grid costs'



Note: While legacy grid costs go down, new grid costs are expected to accumulate in gradually rising total grid costs.

115 Further analysis in this section focuses on new grid costs as these can still be influenced, whereas the legacy grid costs serve as a point of comparison.

Figure 9: Evolution of total grid costs by 2030, 2040 and 2050



Source: ACER calculation.

Note: The total grid costs by 2030, 2040 and 2050 comprise 'legacy' costs for the historic investment and 'new' costs for the upcoming investment between 2025 and 2050 (based on Ember's investment projections). Consumption levels were based on a REPowerEU scenario[68] for 2030, – extended by ACER for 2040 and 2050, and Eurostat data for 2022 consumption. The numbers give the order of magnitude of rising costs.

116 In Chapter 1, it was emphasised that investment must be based on benefits and identified needs. A key assumption for determining these is the evolution of consumption. When consumption does not evolve as anticipated, the expected investment benefits will not be achieved. Figure 10, on the left, shows the sensitivity of the new grid costs to variation of future consumption, starting from the base case, as shown in Figure 8, and showing a 10% variation upward and downward. A reduction by 10% of consumption compared to the anticipated level drives up new grid costs by about the same percentage. Less shoulders to carry the burden then coincide with missed project benefits that were associated with the higher consumption. The right-hand side of Figure 10 depicts a similar sensitivity for variations of investment costs, emphasising the value of cost-effective investment.

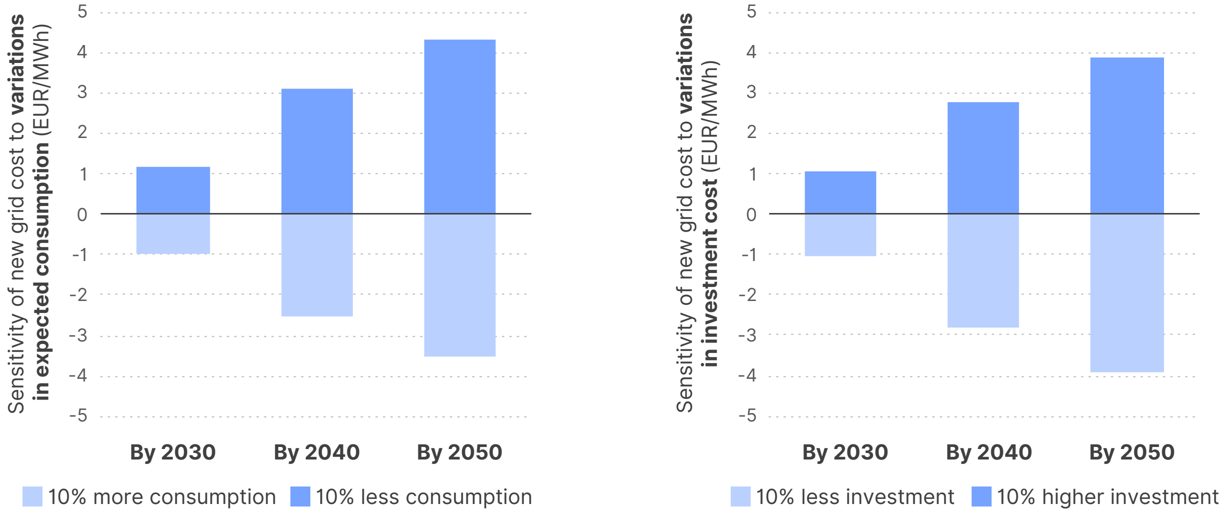
117 As impacts of new grid costs vary with consumption, projections about the evolution of consumption are important. In that light, the draft TYNDP-2024 scenarios[69] project electricity consumption levels substantially above the European Commission's REPowerEU scenario[70] (see Table A2 in the Annex). Overly optimistic projections about consumption may trigger investment based on overestimated capacity needs (as described in Chapter 1) raising grid costs while missing out on any benefits.

68 European Commission, 'Commission Staff Working Document implementing the REPower EU action plan: investment needs, hydrogen accelerator and achieving the bio-methane targets accompanying the document communication from the Commission to the European Parliament, the European Council, the Council, the European Economic and Social Committee and the Committee of the Regions REPowerEU plan', SWD(2022) 230. The document includes a consumption estimate for 2030 only; for 2040 and 2050, a 10% growth of consumption by each decade has been assumed by ACER to establish future consumption levels.

69 ENTSOG, ENTSO-E, *TYNDP 2024 Draft Scenarios Report*, May 2024, https://2024.entsos-tyndp-scenarios.eu/.

70 See note 60.

Figure 10: Sensitivity of new grid costs to variations in consumption (left) and investment (right)



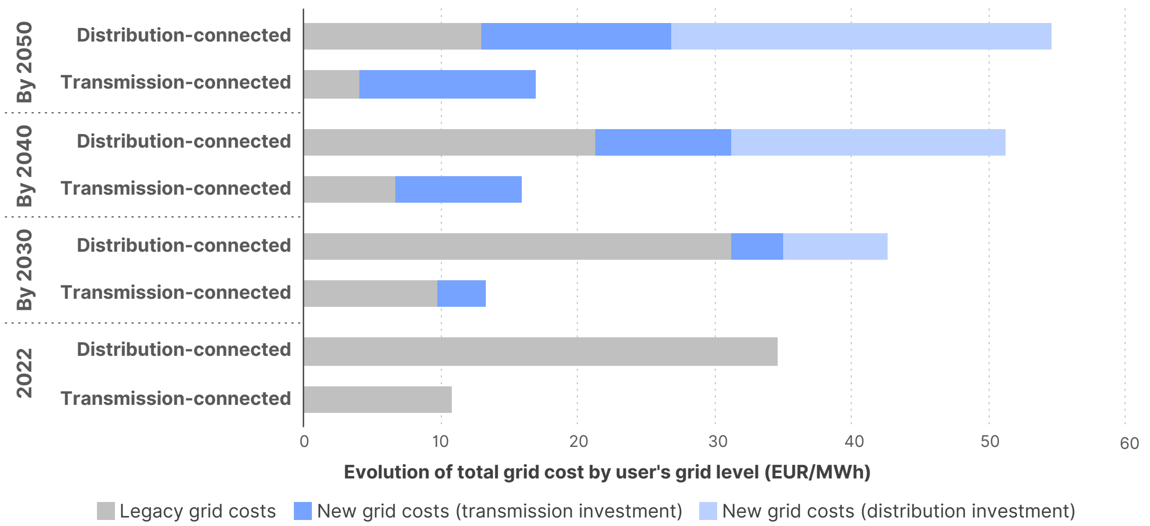
Source: ACER calculations.

Note: A 10% decrease of consumption compared to the base level and a 10% increase of investment drive up new grid costs by about 10%.

118 Distribution-connected consumers, including households, commercial sector and industry, will be more affected by the rising grid costs. About two thirds of upcoming investment would target distribution networks and most of the transmission-level costs are passed on to distribution-connected users as they also benefit from transmission-level investment. Currently, about 90% of transmission costs are passed down to consumers connected to the distribution level[71]. Impacts for transmission-connected industry remain moderate, increasing by about EUR 5 per MWh, as illustrated in Figure 11[72].

119 Effective impacts among distribution-connected users will vary with user habits and with the detailed network tariff designs, as each user must pay for their effective use of the grid.

Figure 11: Evolution of total grid costs by the grid to which consumers are connected



Source: ACER calculations.

Note: Future distribution-level investment accounts for two thirds of investment, while on average 90% of transmission costs are passed down to distribution-connected users (corresponding to the consumption share they represent).

While grid costs for transmission-connected users remain moderate, they face an increase of more than half their 2022 legacy grid costs. Legacy grid costs for distribution-connected users include also costs associated with the transmission level (not depicted).

71 ACER's 2023 Report on Electricity Transmission and Distribution Tariff Methodologies in Europe found that 80% to 90% of transmission-level costs are paid by network users connected to the distribution system (costs are cascaded down as distribution-connected users also use the transmission network). https://www.acer.europa.eu/sites/default/files/documents/Publications/ACER_electricity_network_tariff_report.pdf.

72 To estimate user-group shares of consumption, historic data (see the Annex) was used as the REPowerEU scenario does not provide consumption projections by grid level.

120 Cost impact will also differ between Member States, as investments may appear to be disproportionate to their domestic consumption. Such disproportionate investment may be due to a catching-up effect, when historically less investment has taken place compared to other countries. Larger investment than would be expected (based on market size) could be driven by regional grid capacity needs and benefits, for instance investment in offshore grids that may benefit several Member States and non-EU countries[73].

121 Regardless of any remaining historic investment, by 2050 the RABs of TSOs and DSOs will have increased by about EUR 1500 billion. That value will have to be recovered, and a remuneration paid for it, for the next decades, while possibly adding further investment after 2050 at a pace that cannot be predicted today.

2.2.3. Effects of grid investment on affordability and competitiveness

122 It is undisputed that investment in transmission and distribution grids must happen to support the integration of RES in an energy system on its way to decarbonisation. The findings of Chapter 1 suggest that we need more and faster grid development, targeting identified needs.

Risk for sustaining the EU's competitiveness

123 **The upcoming wave of grid investments carries a great amount of uncertainty**: from uncertainty about the grid needs to determining the cost-efficient projects that address those needs.

- When a need is overestimated and growth of electricity consumption does not reach the anticipated level, the grid bill for users rises due to less shoulders to carry the investment costs (and the investment benefits associated with that consumption are missed). If consumption is 10% lower than anticipated – and investment needs are determined based on anticipated consumption included in the network-planning scenarios, as explained in Section 1.1 – then users will see a roughly 10% raise in their grid bill, as the costs will be spread across the actual consumers.
- When scrutiny of proposed investment is minimised to accelerate infrastructure development, a 10% increase in the investment cost adds about 10% to the grid bill.
- While not depicted, a 1% point increase of the WACC – to make the financing of grid investment more attractive – inflates the additional annual revenues by billions of euros, a cost that goes into the grid bill. If that higher WACC applies to the historic assets, the legacy grid costs will rise as well.

124 **While investment generates benefits, which should exceed costs, containing rising grid costs supports Europe's competitiveness compared to other regions**. Investment that is based on unrealistic assumptions about electricity consumption and generation causes a spiral of rising grid costs that discourages electrification. This further increases costs for actual consumers. Addressing cost spirals by artificially lowering grid bills mainly encourages inefficient electrification and creates more bills for European citizens. Instead, better grid planning should focus on supplying the grids needed to connect realistic future generation and consumption.

125 Grid costs make up an essential part of system costs, but rising grid costs may help reduce (or keep stable) system operation costs when better interconnectivity reduces market prices, increases RES integration and makes the EU less dependent on third countries. In that regard, ACER's report on transmission capacities for cross-zonal trade noted the substantial costs associated with an increased need for congestion management over the past few years alone show a EUR 4 billion bill. Limited grid expansion and rapid adoption of renewables may worsen congestion and increase congestion management costs further[74]. The aggregate effects on total costs of electricity, however, has not been estimated in this report.

73 An attempt was made to calculate impacts by Member State based on Ember's data on NDPs; however, such NDPS are not fully comparable, so the results are not included in this report.

74 See note 5.

Competitiveness and affordability for user groups and Member States

126 **While the upcoming investment impacts Europe's overall competitiveness, those effects have a distributional component**. Distribution-connected users will see higher impacts of the rising grid costs compared to transmission-connected users, which is consistent with investment targeting the different grid levels and the passing on of transmission costs to distribution-connected users benefiting from transmission services. As about two thirds of industry consumption takes place at the distribution level, these impacts may substantially affect the competitiveness of the EU's industry. This in turn may give rise to pressures on regulators and governments towards shifting the network tariff burden from certain consumers to other consumers or to socialise network tariffs via the tax base. In this context, energy regulators call for strong prudence from policymakers as to the possibly detrimental effects of doing so. Moreover, energy regulators find coordinated approaches amongst Member States highly preferable in this regard, compared to what might otherwise become inter-Member-State competition via network tariffs. Network tariffs should be non-discriminatory and cost-reflective; those users that offer a valuable service of flexible grid use could be offered corresponding (lower) tariffs that reflect the costs and value they create for the grid.

127 Looking closer at how Member States may be impacted by the wave of investments, some countries may promote regional investment that goes beyond their national needs and may largely bring regional benefits, including sustainability benefits. In more simple terms, their share in the EU's proposed investment exceeds their respective share in the EU's electricity consumption (as a proxy for market size and national infrastructure needs).

128 Since market integration started, the EU has foreseen a few r**edistribution mechanisms in recognition of cross-border use of electricity grids**.

- The **inter-TSO compensation (ITC) mechanism** is the only systematic EU-level cost sharing mechanism in widespread use, which compensates for part of the costs of cross-zonal trade-relevant grid investments and for transit losses. However, its **budget is small**: in 2021, the total ITC fund amounted to around EUR 365 million of which EUR 100 million contributes to the costs of making infrastructure available and around EUR 265 million to the costs of the incurred transmission losses. In 2022, the total ITC fund amounted to nearly EUR 605 million of which EUR 100 million contributes to the costs of making infrastructure available and almost EUR 505 million to the costs of the incurred transmission losses. The exponential increase is due to the electricity price shock in 2021 affecting the calculation of the values of losses for the purpose of the ITC mechanism.

- In the case of PCIs, **cross-border cost allocation (CBCA)** helps to pay for investment considering the beneficiary countries of the project. As a pragmatic approach, the compensation of a country that suffers a welfare loss by implementing the project, removes a potential barrier for the project's go ahead. **The majority of the CBCA decisions** foresee that the hosting countries will bear the costs of the projects based on the 'territorial principle', i.e. **without any cross-border financial contributions involved**[75]. With an integrated EU energy system, this approach to cost allocation differs strongly from the (regional) benefits from infrastructure. To help unlock the regional benefits of offshore networks, the European Commission issued a guidance on collaborative investment frameworks for offshore energy projects[76].

75 ACER Recommendation 02/2023 on good practices for the treatment of the investment requests including CBCA requests for electricity and gas PCIs. https://www.acer.europa.eu/sites/default/files/documents/Recommendations/ACER_Recommendation_02-2023_CBCA.pdf. See ACER's CBCA monitoring reports, available at: https://www.acer.europa.eu/electricity/infrastructure/projects-common-interest/cross-border-cost-allocation.

76 Commission communication – Guidance on collaborative investment frameworks for offshore energy projects, C(2024) 3998, https://energy.ec.europa.eu/document/download/277e1f8f-8a58-4f84-96ee-b8fe9f723b92_en?filename=C_2024_3998_1_EN_ACT_part1_v5.pdf.

- **Congestion income** that arises from scarcity of cross-zonal capacity makes up another source to finance investments that address congestion. **Around EUR 1.2 billion**, or 8% of the available congestion income (excluding the part used for system operating costs and taxes) is **dedicated to network investment that addresses congestion** in 2022 and 2023, whereas almost double that amount is used for reducing tariffs. The highest amount, around EUR 8.6 billion, is saved in a separate account for network investments to address congestion in the upcoming 10 years[77].

- **Public (including EU) funds** are enough to **cover a margin of the costs**. The CEF fund, which supports PCIs (and PMIs), committed EUR 4 billion to electricity transmission projects (including funding for works and studies) and EUR 410 million to smart grid projects between 2014 and 2024[78]. Other EU funds that are not dedicated to energy in particular include, for instance, cohesion funds and modernisation funds.

129 **Grid cost redistribution mechanisms** may soften cost impacts in Member States that invest in grids with significant regional benefits, but they are limited and may not fully reflect the regional benefits of electricity infrastructure.

Transparency on uncertainties

130 Energy regulators understand they have to approve more investment that is characterised by greater uncertainty and that affects competitiveness and affordability. In this light, it is paramount that project promoters transparently inform regulators about the uncertainty and the project risks to enable regulators to make informed decisions. Grid development based on methodical assessment of grid needs and project benefits helps create more transparency.

2.3. Recommendations to grid developers and regulators for sustaining affordability and competitiveness while accelerating investment

131 Scrutiny of proposed grid investment alongside efficient investment frameworks remain crucial while facing a wave of investment at unprecedented rates.

132 To mitigate the magnitude of investment, TSOs and DSOs should promote energy efficiency across the whole network planning process. There are also efficiency gains to be made by optimising the use of existing grids (reducing grid capacity needs), raising capacity without grid investment – such as through digitalisation and GETs – and efficiently investing in traditional grid buildout.

133 The risk of underutilised investments can also be addressed with strong coordination. TSOs, DSOs, regulators, Member States and generation investors must coordinate and plan their actions in a way that both network and generation investments are completed at approximately the same agreed time.

Regulators to design network tariffs for an optimal use of the grid capacity

134 Current tariff designs should be cost-reflective as well as inciting users to behave in a way that optimises the use of the existing grid capacities and thus reduces needs for additional capacity. Time signals already play a crucial role in optimising grid capacity; locational signals, which are hardly used in Europe today, might further inspire behavioural change in network users with respect to when and where to generate and consume energy, adding flexibility to the energy system and reducing system costs[79]. When reviewing their network tariffs design, regulators should take a forward-looking, efficiency-first approach and include signals that help reduce or postpone grid investment.

77 ACER monitoring report 2022, Use of Congestion Income 2021. https://acer.europa.eu/sites/default/files/documents/Publications/ACER_Congestion_Income_Monitoring_Report_2021.pdf.

78 CINEA public dashboard, https://webgate.ec.europa.eu/dashboard/sense/app/a429734c-ebed-4cf8-afe1-cd9c75f14032/sheet/4c9ea8df-f0f9-4c0d-b26b-99fc0218d9d9/state/analysis, last checked August 2024.

79 See note 62.

Regulators to smarten investment frameworks with a view on making grid enhancing technologies and other non-wire alternatives to traditional grid buildout attractive for TSOs and DSOs

135 There are several existing measures to raise capacity that do not require traditional grid buildout, exist to raise capacity. Examples include GETs and cross-system solutions [80], which rely on capacity issues being addressed by the system that can do it most cost-effectively regardless of where the grid need originated. Such solutions are often faster or less expensive than building transmission and distribution infrastructure.

136 As noted in Section 1.3, to **incentivise grid developers to implement non-wire solutions, Europe needs smarter regulatory frameworks** that experiment with ways to make TSOs and DSOs choose the best solution to raise system capacity, regardless of whether a solution is CAPEX- or OPEX-heavy[81]. ACER's work on infrastructure efficiency and the consultancy on cross-system solutions may serve as a starting point for regulators when innovating their frameworks. Such innovative solutions should be included in the network planning process.

While regulators face approving projects under greater uncertainty, cost scrutiny remains essential to keep rising grid costs manageable

137 **Traditional scrutiny of costs** and setting fair remuneration for TSO and DSO activities **remains necessary** to fairly share the risks between the network operators and society[82]. Any revision of financing parameters to make equity and debt financing more attractive has a cost that is passed on to consumers.

138 While grid costs come to the fore among system costs to deliver energy in Europe, governments and regulators may face pressure to redistribute the burden from one consumer group to another or to socialise them via the tax base. Prudence is needed from policymakers as to the possibly detrimental effects of doing so. Coordinated approaches should be preferred while keeping network tariffs cost reflective and non-discriminatory[83].

139 To address national affordability concerns in a context of regional investments, policymakers and regulators must review the EU regulatory approaches for funding cross-border grid investment. Energy regulators have already committed **to consolidating and improving the current regulatory approaches to better share the cost and benefits of electricity network infrastructure arising from cross-border trade**[84].

Comprehensive monitoring of the local, national and cross-border electricity systems would generate better insights on the effects of investment on affordability and competitiveness

140 ACER emphasises that the calculation of grid costs is based on publicly available data that was sometimes incomplete, often had to be interpolated and extrapolated, and suffered from inconsistencies among data sets. Better monitoring of grid investment and financing conditions at the national level (transmission and distribution) and the European level enables decision makers to act based on better information.

141 Considering how scattered information on grid investment is, and the importance of investment for reaching the EU energy and climate targets, EU legislators might consider enhancing the transparency of such information with a view on monitoring and analysis in support of the EU's policy objectives.

80 Cross-system solutions comprise, for instance, better TSO-DSO coordination to address a capacity need at the right system level, integration of demand response and storage, digitalisation, flexible network access. See: Trinomics, Advancing cross-system solutions to address electricity network challenges, study for ACER, 2024, https://www.acer.europa.eu/sites/default/files/documents/Publications/Consultancy_study_Electricity_Network_Solutions_2024.pdf.

81 See note 49.

82 See note 18.

83 See note 4.

84 See note 4.

3. Conclusions

- **The report concludes that focused development of distribution, transmission and cross-border capacities is essential for a secure, sustainable and competitive EU energy system.**

142 Infrastructure is key to enabling the integration of renewable generation and electrification of energy demand, and to unlocking the benefits of market integration, including a more optimal operation of the EU power system (reducing congestion management costs, redispatching costs and other such costs) and sharing flexibility. These benefits should in principle outweigh the costs of making the required infrastructure investments.

143 ACER finds that grid capacity development shows a 50% gap with identified cross-border grid capacity needs, not addressing needs at some locations. While project implementation timelines are already exceeding 10 years (for cross-border projects), the necessary grid investment for RES integration, electrification and handling the associated higher volatility of the electricity system risks being late.

144 Secondly, while the rate of investment in transmission and distribution grids doubles to achieve decarbonisation and unlock the benefits of market integration, grid costs for consumers are estimated to increase significantly compared to today (based on available information and complemented by ACER in case of missing data and information). Rising grid costs will become a main determinant of total costs of delivering decarbonised energy to EU consumers; keeping them under control is essential for affordability of energy for consumers and global competitiveness of the EU. Not investing also has costs (such as rising costs of congestion management, redispatching and flexibility schemes) that could even be higher than the rise of grid costs.

- **The report formulates recommendations to grid developers (such as TSOs and DSOs), NRAs and EU and Member State authorities; these recommendations aim to promote grid investment that addresses needs and maximises benefits (Section 1.3) while considering affordability and competitiveness (Section 2.3).**

- **ACER highlights that comprehensive monitoring of infrastructure development across local, national and cross-border levels would ensure better tracking of how infrastructure keeps pace with the foreseen decarbonisation trajectory and observed electricity market changes.**

145 This first edition of an infrastructure monitoring report by ACER showed blind spots with respect to the comprehensive monitoring of infrastructure developments. In general, more structured information and data exist at the cross-border level, already monitored by ACER, while data on national transmission- and distribution-grid planning and investment are scattered and not easily available or comparable. However, these grid levels are indispensable and interlocked parts of the comprehensive EU electricity grid, which supports the EU electricity market.

146 ACER compensated for this lack of comprehensive data by making assumptions about missing values or excluding countries from the analysis. Despite these challenges, the numerical findings contained in this report signal the order of magnitude of the issues, while numbers should not be used or quoted without adding this nuance.

Annex: Methodology for cost impact projections

The calculation of cost impact projections serves to report the **order of magnitude of rising grid costs** leveled by consumption forecasts in 2030, 2040 and 2050.

Table A1: Investment need projections

Source	Annual investment	Total investment
ERT	~ EUR 75 billion (mid-point of range in the study)	EUR 1950 billion
Ember	~ EUR 63 billion (until 2030), EUR 85 billion (as of 2030)	EUR 2100 billion
ENTSO-E	~ EUR 96 billion	EUR 2500 billion (based on EUR 834 billion investment in transmission grids)
Eurelectric	~ EUR 100 billion (based on EUR 67 billion investment in distribution grids)	EUR 2600 billion

Source: ACER estimates based on projections by different entities.

Note: When the source projection covered only transmission or only distribution, a relative share of one third for transmission and two thirds for distribution investment was used for estimating the total grid investment.

Calculations in the report are based on the Ember projection unless specified otherwise.

Table A2: EU consumption projections (TWh)

	2030	2040	2050
REPowerEU(1)	2764	3040.7 [3]	3344.8 [3]
TYNDP 2024[2] 'NT+'	3063	3534	
TYNDP 2024 'DE'		3766	4063
TYNDP 2024 'GA'		3368	3616

Sources: [1] European Commission, Commission staff working document implementing the REPower EU action plan: Investment needs, hydrogen accelerator and achieving the bio-methane targets accompanying the document Communication from the Commission to the European Parliament, the European Council, the Council, the European Economic and Social Committee and the Committee of the Regions, REPowerEU Plan, SWD(2022) 230. [2] ENTSO-E and ENTSOG, https://2024.entsos-tyndp-scenarios.eu/. [3] ACER extrapolation, assuming 10% growth of consumption over the decade.

Notes: TYNDP scenarios consumption levels tend to be higher than the Commission scenario. NT+ stands for 'national trends +', DE for 'distributed energy' and GA for 'global ambition'. For comparison, EU consumption in 2023 amounted to 2585.4 TWh. Calculations in the report used the REPowerEU consumption levels extended by ACER for the 2040 and 2050 horizons.

Table A3: Simplified calculation of 'annual allowed revenues' associated with 'new grid costs' to recover investments from 2025 until 2050

Year	Annual investment (bn EUR)	CAPEX cumulative depreciation (bn EUR)	RAB (bn EUR)	Remuneration (RAB × WACC) (bn EUR)	OPEX (2%) (bn EUR)	New 'allowed revenues' (bn EUR)
2025	63.00	1.40	61.60	3.3	0.03	4.82
2030	85.00	8.89	370.11	20.37	0.18	29.43
2040	85.00	27.78	1027.33	56.53	0.56	84.87
2050	85.00	46.67	1495.67	82.31	0.93	129.91

Source: ACER calculation based on the Ember investment projection.

Note: numbers show order of magnitude and should not be considered accurate estimates.

For comparison, total use-of-network charges for most of the EU in 2022 amounted to EUR 72.2 billion (data was incomplete or not provided for Finland, Italy, Malta and Slovakia).

Table A4: Regulatory parameters for simplified calculation of additional annual allowed revenues in Table A3

Parameter	Value used in calculation	Description
Depreciation rate (asset lifetime)	45 years	Time over which an asset is depreciated, lifetimes of around 45 years apply to long-lasting assets like lines, whereas several infrastructure elements have shorter lifetimes
RFR	3.5125%	Risk-free rate, approximated by 10y-bond, EU27 average (Eurostat)
Rm	3.5%	Market premium for equity above RFR
beta	0.69	Asset beta
gearing	0.3	Debt financing over total financing
CoE	0.059275	Cost of equity, RFR + (beta × Rm)
Rd	0.01	Premium above RFR for debt
CoD	0.045125	Cost of debt, RFR + Rd
WACC	0.05503	Weighted average cost of capital, g × CoD + (1 – g) × CoE

Note: Numbers were chosen within the range of observed values for these parameters; they do not represent a concrete example.

Table A5: Total network charges EU Member States for the year 2022

Transmission (EUR)	Distribution (EUR)
20 402 829 506	**51 798 938 216**
Data was not provided for Finland, Italy or Slovakia	Data was not provided for Finland, Italy, Malta or Slovakia

Source: ACER data collection from national regulatory authorities.

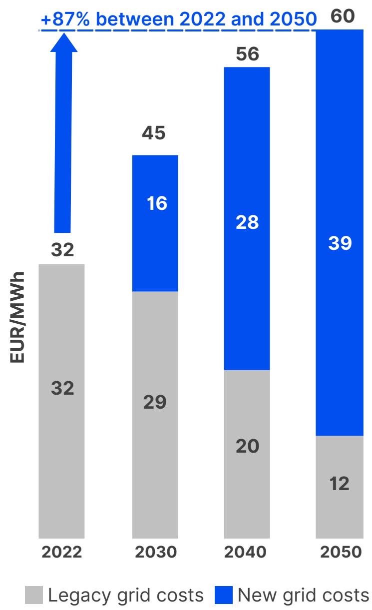
Note: The numbers comprise 'Use of network charges' which include: charges for costs for building, upgrading, maintaining and operating the distribution infrastructure (CAPEX and OPEX), costs for (purchasing) losses, costs for (purchasing) system services, metering costs and costs due to reactive power. Few countries may have reported the transmission costs charged to the DSO in the transmission number and also in the distribution number.

Table A6: Cost and consumption shares of user groups

Parameter	Consumption share	Cost share (considering passing down transmission costs to distribution level consumers)
Households	29%	31%
Commercial	29%	31%
Industry connected to distribution grid	26%	28%
Industry connected to transmission grid	10%	3%
Other	6%	7%

Source: ACER estimates based on Eurostat and the ACER tariff report of 2023. 90% of transmission cost are cascaded down to the distribution level as that is the level where consumption is happening.

Figure A1: Evolution of total grid costs in a high-investment scenario



Source: ACER calculation considering Eurelectric's investment scenario.

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