ACER

European Union Agency for the Cooperation of Energy Regulators

Energy infrastructure development in Europe

2026 Monitoring Report

6 November 2026



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Executive summary

116

electricity and gas EU priority infrastructure projects commissioned since 2013



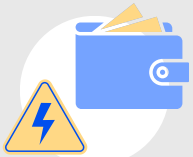
3 times

more annual electricity transmission investment than in 2019, while gas investment remained broadly stable and hydrogen nascent



7 times

rise in electricity congestion income since 2019, most of it is not yet activated



1 Europe's energy system is undergoing a profound transformation, making energy grids central to the EU's energy and industrial strategy. The rapid expansion of renewable electricity generation, the growing electrification of transport, buildings and industry, and the EU's continued efforts to advance decarbonisation and strengthen energy security are reshaping infrastructure needs across the electricity, gas and hydrogen sectors.

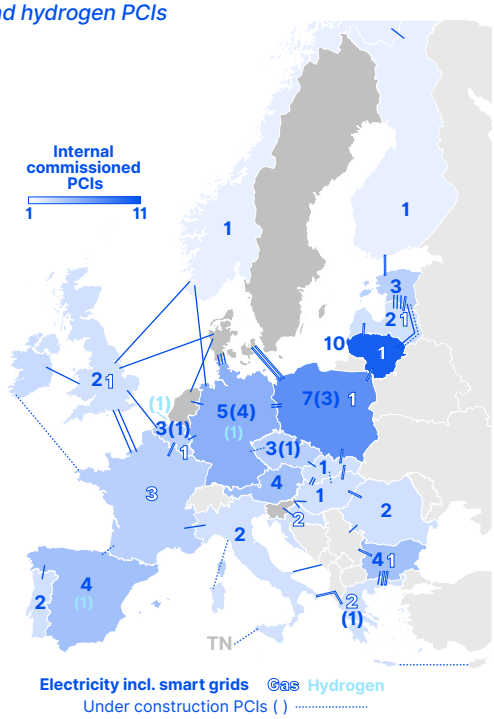
2 The EU has supported the development of cross-border energy projects through the (2013) Regulation on Guidelines for Trans-European Energy Infrastructure (TEN-E Regulation). Since then, 88 electricity and 28 gas Projects of Common Interest (PCIs) and Projects of Mutual Interest (PMIs), in total 116, have been commissioned, contributing to greater EU energy market integration, system resilience and security of supply (Figure I). An additional 18 electricity and 3 hydrogen PCIs are currently under construction. Moreover, cross-zonal capacities may have, in many cases, been increased through non-PCI projects.

3 The Grids action plan, adopted by the European Commission in 2023, sets out further measures to accelerate grid development including through improved planning, permitting and stronger supply chains. It was complemented in 2025 by the Affordable energy action plan, which aims to lower energy costs, mobilise investment and strengthen crisis preparedness. These measures are increasingly relevant in the current context of geopolitical risks, supply disruptions caused by more frequent extreme weather conditions and growing pressure on energy affordability and industrial competitiveness.

4 Against this backdrop, the European Union Agency for the Cooperation of Energy Regulators (ACER) published its first Monitoring Report on grid developments in 2024, focusing on electricity. While retaining its primary focus on electricity infrastructure, this second report broadens its assessment to include gas and hydrogen, reflecting the interdependence and different momentums of these sectors.

116 electricity and gas PCIs developed since the TEN-E Regulation took effect

Figure I. Commissioned and under-construction electricity, gas and hydrogen PCIs



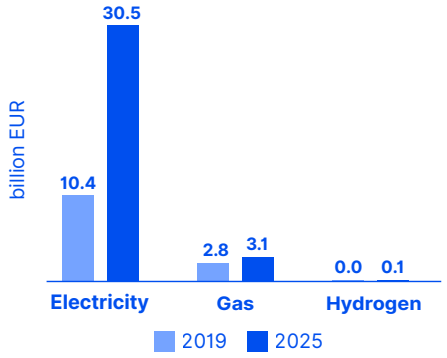
Source: CINEA's PCI-PMI Transparency Platform, ACER study and inputs by NRAs.

Diverging trends and challenges across energy carriers

5 Markedly different development trends are observed across energy carriers (Figure II), reflecting their distinct roles and varying levels of maturity. In line with its pivotal role in the clean energy transition, annual capital expenditure (CAPEX) of EU's electricity transmission nearly tripled between 2019 and 2025, rising by 193% from about EUR 10.4 billion to EUR 30.5 billion. In parallel, annual CAPEX of electricity distribution rose by 51% between 2021 and 2024, from EUR 23.5 billion to EUR 35.3 billion.

Different investment momentums across energy networks

Figure II. Transmission system operators' annual capital expenditure in electricity, gas and hydrogen



Source: ACER data collection from national regulatory authorities (NRAs).

6 Electricity network investment has increased due to higher manufacturing prices,[1] and, predominantly, because of growing demand for connecting new users and electricity exchanges across the system. Renewable deployment and electrification are advancing rapidly: between 2023-2025, installed wind capacity increased by 10% and solar by 19%. On the demand side, publicly available information indicates that the stock of heat pumps, the number of electric vehicles and the capacity of data centre are growing rapidly and have reached approximately 70%, 25% and 44% of their respective 2030 reference levels.

7 Higher capital expenditure alone cannot ensure that infrastructure will keep pace with growing transmission capacity needs. First, despite great progress of Europe's priority projects, delays persist, mainly for permit-granting reasons, leading to increased congestion costs and slow access to cheaper and cleaner generation. Between 9% and 30% of electricity transmission PCIs and PMIs are affected by delays each year (on average 22%) and about 40% PCIs impacted at some point, contributing to an average of 12 years implementation time for these projects.[2] ACER estimates that a one-year delay in delivering electricity transmission PCIs and PMIs results in EUR 4 billion in net economic welfare losses.[3]

8 Second, 'congestion income', which is the revenue from scarce cross-border transmission capacity when electricity prices differ between EU bidding zones due to constraints on the EU power grid, has increased substantially.[4] Compared with 2019, it rose sevenfold in 2025, from EUR 1.3 billion to EUR 9.2 billion.[5] ACER notes that the price differentials driving congestion income simultaneously stem from grid congestion and different generation mixes and demand patterns across bidding zones. Despite the strong increase, ACER finds that around 60%

1 2026 ACER energy infrastructure unit investment cost report estimates that unit investment costs in electricity infrastructure have risen by around 50% from 2018 to 2024.

2 Implementation dates are also notably impacted by project rescheduling (on average 13% of electricity transmission PCIs and PMIs each year) as system needs or investment priorities change.

3 ACER calculates the net socio-economic welfare loss by accounting both for the negative impact of postponed benefits and the positive impact of postponed costs due to one year delay of all electricity transmission PCIs and PMIs on the current Union list.

4 In principle, less constrained grids increase welfare-increasing trade that raises the EU overall welfare. Congestion income can signal potential capacity needs, but does not by itself justify investment, as it captures only part of the benefits of increased interconnection capacity and these benefits must be weighed against investment costs to reduce congestion. Its variability over time also means that congestion income alone may not indicate persistent structural congestion.

5 These figures refer to the congestion income generated in the single day-ahead coupling, calculated as the scheduled commercial exchange multiplied by the price spread on each bidding zone border in the 2026 ACER electricity market integration monitoring report (p. 45). They do not represent the full amount of congestion income, excluding congestion income amounts that may arise from long-term transmission rights and intraday and balancing timeframes.

of the total congestion income available[6] continues to be set aside for later use, amounting to about EUR 12.5 billion in 2025, rather than being reinvested to address cross-border grid constraints or, where those priority objectives are already fulfilled, directed towards tariff reductions.

9 ACER further observes that physical electricity grid congestion remains substantial and costly, and soaring demand for grid connection capacity is lengthening grid connection queues.

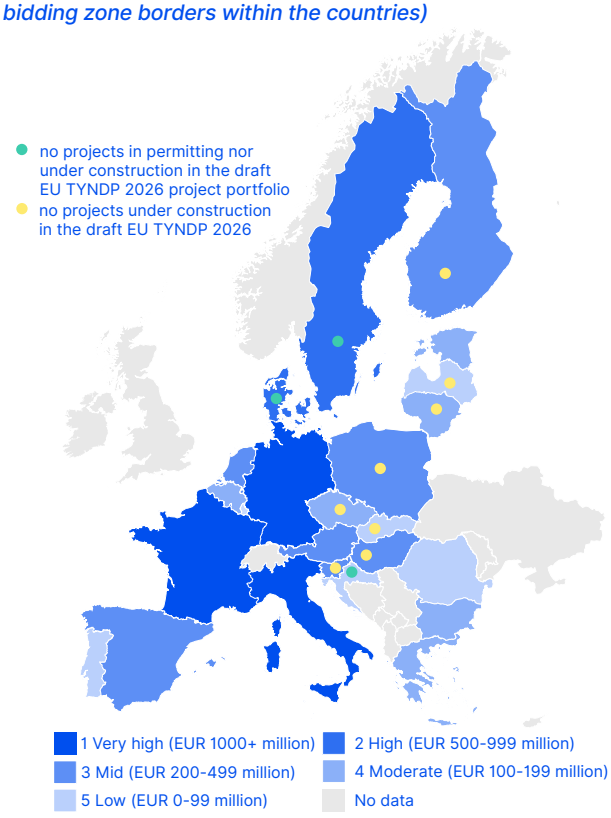
10 Electricity transmission system operators (TSOs) spent EUR 5.4 billion on remedial action in 2025, over 25% more than in 2024. A 2025 study by the European Commission's Joint Research Centre estimates that, under a business-as-usual grid expansion scenario, annual congestion management costs could exceed EUR 100 billion by 2040, around 20 times their current level, while redispatch volumes could increase more than tenfold.

11 In this context, ACER underlines that TSOs are still not fully and consistently meeting the EU's 70% cross-zonal capacity requirement. While fuller implementation would bring extra economic gains, it may also increase the need for remedial actions and related costs unless supported by structural measures such as grid upgrades or bidding zone changes.[7]

12 Soaring demand for grid connection capacity is lengthening grid connection queues. While insufficient infrastructure capacity is a material driver of such queues, there are also multiple reasons for them, which could also include speculative or immature applications. An external study suggests that 1700 GW of renewable energy and hybrid projects were waiting for grid connections across 16 countries as of 2024-2025,[8] more than three times the additional wind and solar capacity estimated to be needed between 2024 and 2030 to reach 2030 targets.

About 40% of EU Member States have no electricity transmission cross-border projects under construction in the EU TYNDP 2026 draft project portfolio; some with significant congestion revenues.

Figure III. Mapping of countries without advanced stage transmission projects in the electricity TYNDP 2026's draft project portfolio and average annual congestion income from 2023-2025 (excluding congestion income collected at bidding zone borders within the countries)



Source: EU TYNDP 2026 draft project portfolio, data on congestion income provided by the NRAs.

13 Data from the draft project portfolio of the 2026 electricity EU-wide ten-year network development plan (EU TYNDP) indicate that approximately 40% of the Member States, including some with significant congestion revenues, have no cross-border projects under construction (see Figure III). Congestion income should not be interpreted as evidence for additional infrastructure needs. However, these findings underline the need to refine the assessment of infrastructure requirements at the national and EU levels and to address project development bottlenecks, for example by improving project acceptance or accelerating permitting procedures.

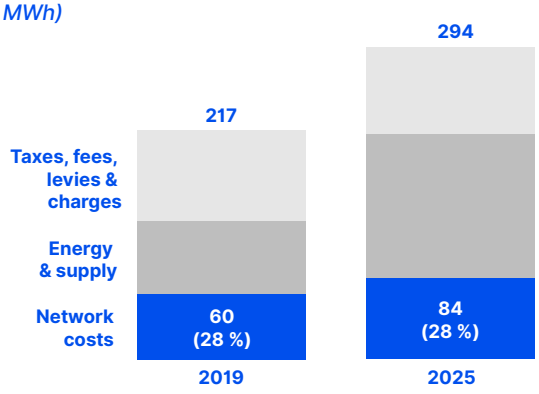
6 Total 'congestion income (CI) available' is calculated as the sum of CI collected at EU-EU borders (including CI generated at internal bidding zones, which may account for significant amounts), CI stored in a separate internal account line from previous years and some applicable country-specific adjustments due to provisional data. Further details are provided in Section 3.3.

7 ACER, Electricity market integration monitoring report, 2026.

8 Beyond Fossil Fuels, E3G, Ember and the Institute for Energy Economics and Financial Analysis, How Europe's grid operators are preparing for the energy transition, 2025 (p. 5).

14 Cross-border relevant investments may also stall due to little or no net benefits in the host countries. Existing EU cost-sharing mechanisms, including inter-TSO compensation (ITC) and cross-border cost allocation (CBCA), help address asymmetries in costs and benefits across countries, but they remain limited in size. The EUR 880 million ITC fund in 2024 represented less than 3% of annual electricity TSO CAPEX and OPEX (operational expenditure) in 2025. At the same time, CBCA led to a very small fraction, only 0.4%, of total electricity and gas investment costs being transferred to non-hosting countries, while around 4% of the total CAPEX from the 13 interconnectors without offshore sections has been transferred across borders since 2013.[9] ACER's recent papers[10] conclude that the existing cost-sharing mechanisms come up short in adequately reaching an equitable sharing of costs and benefits arising from cross-border trade underscoring the need for a comprehensive review of the cost- and benefit-sharing framework.

Figure IV. Average electricity network costs and other electricity price components for households in EU-27 (EUR/MWh)



Source: ACER calculations based on Eurostat dataset nrg_pc_204_c, all bands, nominal unit prices and share of total price.

15 While significant differences are observed across Member States,[11] electricity network costs for EU households increased on average by 40% between 2019 and 2025, from 60 EUR/MWh to 84 EUR/MWh (see Figure IV). They now account for around 28% of the average EU household electricity bill - a share which is likely to increase even further.[12]

16 The challenge in electricity is therefore twofold: ensuring investment keeps pace with system needs while remaining cost-efficient to safeguard EU competitiveness and energy affordability. This requires robust, sufficiently stable and granular methodologies at both the EU and national levels, alongside transparent assessments that prioritise projects delivering the greatest system value.[13]

17 Gas infrastructure follows a different trajectory. Over the past four years, EU gas demand fell significantly, driven by electrification, efficiency gains and industrial contraction following the energy crisis of 2022-2023. In 2025, gas consumption remained 16% below the five-year average (2017–2021) reference period despite a modest 2% year-on-year rebound.[14] In recent years, gas infrastructure investment has focused primarily on maintaining import and transmission capacity to support gas trade and security of supply while enabling renewable and low-carbon gases, providing flexibility to the electricity system and adapting to gas supply changes.[15]

18 Investments reflect the maturity of the sector as the annual CAPEX of gas TSOs in nominal terms rose modestly by 11% from EUR 2.8 billion to EUR 3.1 billion between 2019 and 2025.[16] While Europe's gas infrastructure

9 ACER Report on cross-border cost allocation, 2025.

10 ACER Recommendations and commitments on challenges of the future electricity system, 2024 (p.8); ACER Policy paper on sharing of costs and benefits of electricity network infrastructure arising from cross-border trade, 2026.

11 Eurostat data shows average network costs across EU countries in 2025 spanned from around 34 EUR/MWh (Bulgaria) to 142 EUR/MWh (the Netherlands), a roughly fourfold difference. From 2019 to 2025, trends varied with a slight decline in Italy, Portugal Slovenia to more than a doubling in the Netherlands. See the Retail Dashboard for more details.

12 2024 ACER infrastructure monitoring report estimates that annual grid costs could rise by 50% to 100% by 2050.

13 EU TYNDP 2024 identified 108 GW of additional cross-border network needs by 2040, on top of the 2030 grid. However, caution is required, an average of 1-1.3 GW shifts in network capacity needs for half of EU borders over the two recent TYNDP cycles and occasional mismatch of near-term TYNDP projects and congestion reinforce the importance of robust planning.

14 ACER, Key developments in EU electricity and gas markets, 2026 (p. 46).

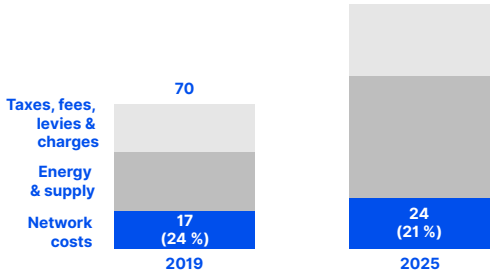
15 ACER monitoring report on decarbonisation of the EU's natural gas market, 2026.

16 While ACER's 2026 Unit investment cost report did not assess gas infrastructure, the broader inflationary environment could partially explain higher infrastructure costs.

proved vital in replacing Russian pipeline supplies and supporting liquefied natural gas (LNG)-based diversification, the long-term challenge is preventing unnecessary network capacity expansion and managing decommissioning while ensuring system resilience and preserving affordability under declining utilisation.

19 As the gas consumer base declines, network tariffs may increase, potentially leading to further decline in consumption. The tariff framework, therefore, increasingly needs to be complemented by regulatory approaches to manage the underlying asset costs. Transmission tariffs have already increased in the EU, on average by 40% between the 2020/2021 and 2024/2025 gas years, which is also reflected in household consumer gas prices (Figure V).

Figure V. Average gas network costs and other gas price components for households in EU-27 (EUR/MWh).



Source: ACER calculations based on Eurostat dataset nrg_pc_202_c, all bands, nominal unit prices and share of total price.

20 Hydrogen infrastructure development remains nascent. Hydrogen demand has developed more slowly than anticipated and its future trajectory remains uncertain. Despite an almost sixfold increase since 2020, EU electrolyser capacity has reached only 490 MW in 2025, underscoring how far it lags behind the 30-58 GW target for 2030.[17] Uncertainty over future supply and demand undermines commercial viability and discourages investment, while cross-border projects spanning multiple transit countries face additional cost-allocation challenges. While regulatory frameworks for planning and investment develop, ACER considers that a gradual approach to hydrogen infrastructure based on realistic demand forecasts and prioritising strategic infrastructure that can support market emergence, is the most appropriate.

21 Hydrogen infrastructure could benefit from a different financing approach from gas and electricity because some hydrogen investment may need to precede the emergence of sufficiently large demand. EU law allows the introduction of inter-temporal cost allocation (ICA) mechanisms, which help prevent excessive tariffs in the early stages of the demand ramp-up, and complementing the regulatory framework with external financing and de-risking measures.[18] These de-risking measures should limit the transfer of demand risk to future network users and provide transparency on the risks transferred to national budgets. So far, only Germany has implemented an ICA mechanism for its planned hydrogen core-network, while Denmark is investigating the implementation of a similar mechanism for its planned backbone.

How to deal with the challenges? Three sets of actions for Europe's energy grids:

22 This report reiterates eight previous ACER recommendations and actions grouped into three set of actions, to help legislators, regulators and system operators manage the grid challenges.

23 ACER underlines that the proposed actions require strong and effective mandates for the regulators, including on system operators' network planning, revenue and network tariff setting, and adequately resourced NRAs and system operators to match their tasks and responsibilities under the energy transition.

I. Maximise the use of existing network capacity through market and system operation rules

1. **Efficiency first:** Maximise the efficient use of the existing network, including - for electricity - through effective demand response frameworks, market-based congestion management that leverages flexibility across transmission and distribution networks, full implementation of the 70% minimum cross-

17 ACER monitoring report on European hydrogen markets, 2026.

18 Article 5 of Regulation (EU) 2024/1789.

zonal capacity requirement,[19] cost-reflective network tariffs[20] and regulatory measures for innovative solutions such as digitalisation and grid-enhancing technologies (GETs), where they can cost-effectively increase the existing network capacity and thereby reduce or defer the need for conventional reinforcement.[21]

II. Efficient grid-build out via robust, integrated and adaptive planning and timely project delivery:

2. **Adequate transparency.** Ensure adequate transparency in network planning, investments and operation by publishing transmission and distribution network development plans (including key project information), transmission and distribution system operators' CAPEX and OPEX estimates, and existing and forecast grid use.[22] (See Sections 2.3 and 3.1.)
3. **Planning scenarios which fit for decision-making.** Provide stable and complementary scenarios for assessing infrastructure needs, grounded in measurable observed trends and projections to achieve a more informed assessment of infrastructure needs and facilitate prioritisation. Enhance needs assessment by increasing granularity beyond the cross-border level towards internal, link identified infrastructure needs and future grid constraints and effectively prioritise among them. Enhance consistency across national planning practices, and systematically adopt scenario building, infrastructure needs identification and cost-benefit analysis of projects in a forward-looking manner.[23] (See Sections 2.2 and 2.3.)
4. **Multi-sectoral planning.** Continue to work towards multi-sectoral planning, encompassing electricity, gas and hydrogen - at the EU and, preferably, national levels - starting with greater consistency in assumptions and methodologies across sectors and a high-level cross-sectoral needs assessment, while gradually moving towards deeper integration.[24] (See Section 2.5.)
5. **Unlocking efficient investments.** Unlock efficient investments by mitigating any CAPEX bias and eliminating rigid expenditure caps lacking adjustment mechanisms. (See Section 2.4.)
6. **Timely investments.** Accelerate confirmed priority investments via enhanced (simpler, more predictable, time-bound) permit granting, early, meaningful public engagement and forward-looking network planning, while carrying out an in-depth regulatory scrutiny of continually rescheduled priority investments.[25] (See Section 2.1.)

III. Addressing shortcomings in cost sharing mechanisms across network users and borders:

7. **Cost recovery across network users.** Adopt forward-looking cost-recovery mechanisms and regulatory asset management alongside evolving network utilisation approaches to allocate costs fairly across users over time.[26] (See Section 3.2.)
8. **Cost sharing across borders.** Further assess and, where necessary, consolidate and improve existing cost and revenue-sharing mechanisms to recognise shared benefits and promote a more system-wide approach to benefit- and cost-sharing.[27] (See Section 1.1.)

19 Article 16(8) of Regulation (EU) 2019/943.

20 See ACER network tariff report, 2025.

21 See ACER DSO revenues report, 2026.

22 Requirements may differ across the sectors; See ACER DSO revenues report, 2026, ACER Opinions No 05/2021 and No 07/2025 on electricity NDPs, ACER Opinion No 17/2026 on gas and hydrogen NDPs.

23 See 2026 ACER DSO revenues report and ACER Opinions No 05/2021 and No 07/2025 on electricity and No 17/2026 gas and hydrogen NDPs.

24 ACER Opinion No 07/2017 on ENTSOs' draft consistent and interlinked electricity and gas market and network model; ACER Opinion No 01/2026 on the integrated model for electricity, gas and hydrogen infrastructure planning.

25 See ACER TEN-E position paper, 2025.

26 This includes several elements: In justified cases revenues partially based on planned expenditure, combined with an ex-post adjustment based on economically efficient real values shall be allowed (See ACER DSO revenues report, 2026); Remuneration schemes should avoid inter-temporal re-distribution of costs by pushing network costs remuneration to the far future unless such re-distribution is justified (e.g. by corresponding network utilisation patterns) (See ACER DSO revenues report, 2026); Include, where relevant, a framework for the phase-out, decommissioning and repurposing of natural gas projects to hydrogen projects (See ACER Opinion No 07/2024 on gas and hydrogen NDPs).

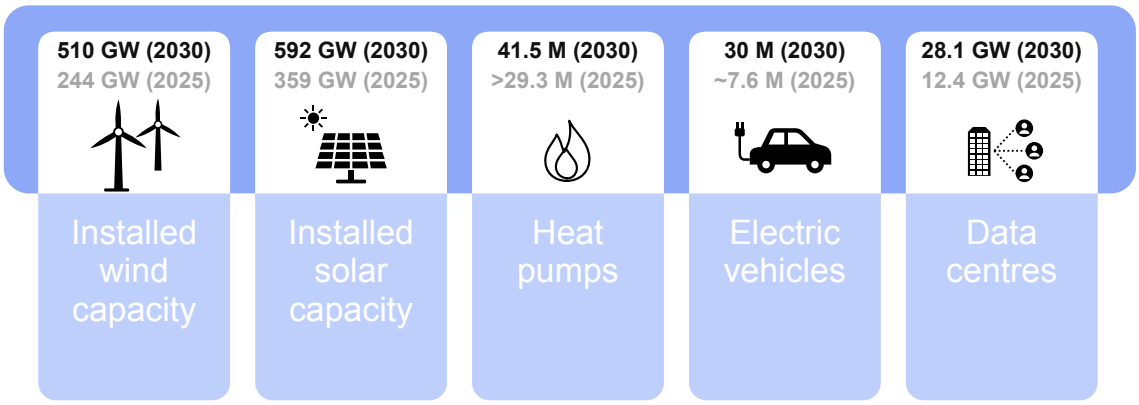
27 ACER Recommendations and commitments on challenges of the future electricity system, 2024 (p.7-8).

Introduction

24 The EU energy system's transformation towards decarbonisation[28] and a secure and integrated internal energy market, is progressing. This transformation encompasses changes in both energy markets and infrastructure which evolve at different speeds. While markets can generally adapt more rapidly to changing patterns of supply and demand, infrastructure typically develops over longer timeframes. This difference in pace is becoming increasingly relevant as renewable generation, electrification and evolving consumption patterns reshape Europe's infrastructure needs.

25 The 2024 ACER infrastructure monitoring report documented progress towards the EU's energy transition targets.[29] The transformation continued to accelerate. EU wind capacity increased by 10% (23 GW), reaching 244 GW in 2025, while solar capacity grew by 19% (99 GW) to 359 GW. These levels represent 48% and 61% of the respective 2030 targets. Heat pump stock exceeded 29.3 million[30] units in 2025, which is about 70% of the 2030 target. The number of electric vehicles reached about 7.6 million, about 25% of the 2030 ambition, while data centres' power capacity stood at about 12.4 GW in 2025, about 44% of the 2030 baseline (see Figure 1).

Figure 1: Integration of renewable energy sources (RES) integration and electrification of demand.



Source: European Commission, 'Implementing the REPower EU action plan', 'Quarterly Report on European Electricity Markets Q4 2025', 'Sustainable and Smart Mobility Strategy' and 'Impact Assessment Report accompanying the proposal for a Cloud and AI Development Act', Eurostat, 'Stock of zero-emission vehicles on 31st December by type of vehicle and type of motor energy', European Heat Pump Association platform, '2026 Heat Pump Market Report'.

26 The combined effects of increased electrification, energy efficiency improvements and reduced industrial activity following the 2022-2023 energy crisis contributed to a 16% decline in EU gas demand in 2025 relative to the 2017–2021 average (see Figure 2).[31] Although gas demand has recently stabilised, with a modest 2% year-on-year rebound to around 340 bcm, further reductions will be needed to align with the Fit-for-55 and REpowerEU trajectories, which require considerably lower gas demand by 2030.[32] In this context, at least 13 Member States have introduced dedicated gas-demand reduction policies.[33]

28 Regulation (EU) 2021/1119 established the EU's objective of climate neutrality by 2050 and sets bindings intermediate targets to reduce net greenhouse gas emissions by at least 55% by 2030 and by 90% by 2040 compared to 1990 levels. The European Commission's REPowerEU Plan (2022) set a binding target for renewables to reach 42.5% of the EU's gross final energy consumption by 2030, with an ambition to reach 45%.

29 ACER Monitoring report on electricity infrastructure development, 2024 (p. 8).

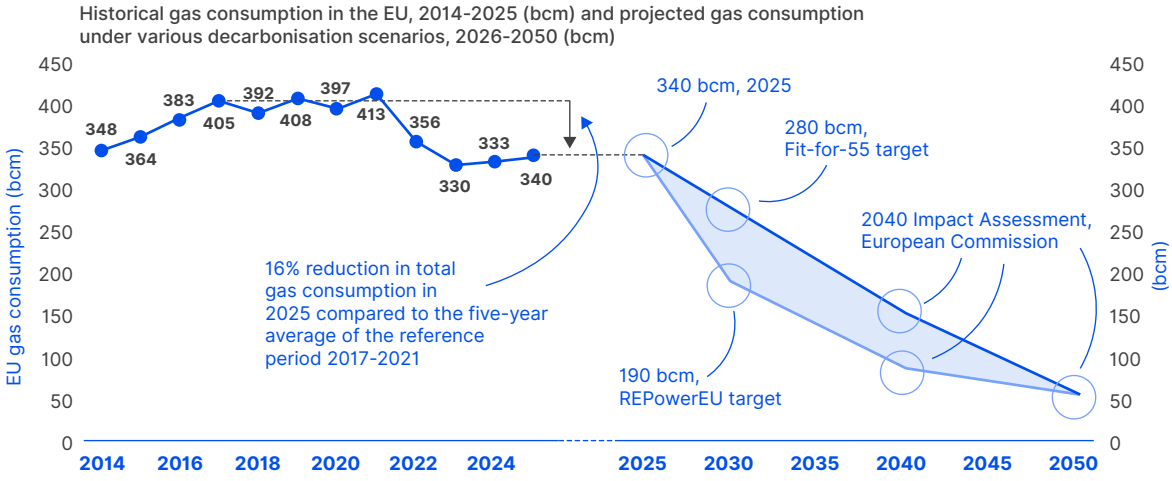
30 The figure includes 21 European countries.

31 ACER Monitoring report on key developments in EU electricity and gas markets, 2026.

32 ACER Monitoring report on decarbonisation of the EU's natural gas market, 2026.

33 ACER No 17/2026 Opinion on gas and hydrogen NDPs.

Figure 2: Historical and projected gas consumption in the EU.



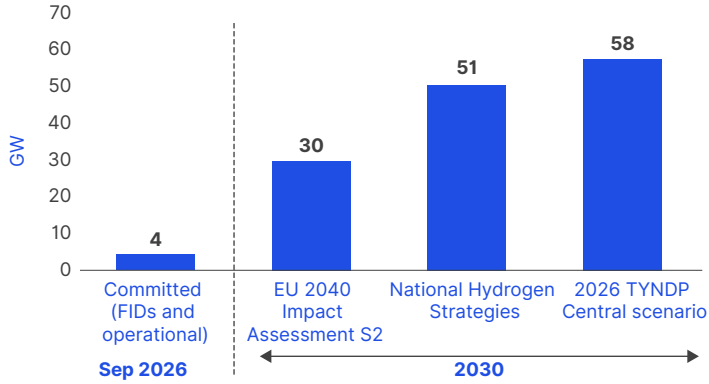
Source: ACER Monitoring report on Decarbonisation of the EU's natural gas market, 2026 (p.14).

Note: Fit-for-55 implies a 32% reduction in natural gas demand compared to 2019, while the most ambitious REPowerEU scenario (without considering the gas savings related to renewable hydrogen targets) projects gas demand 32% below the Fit-for-55 level.

27 In parallel, EU's gas import mix shifted towards LNG:[34] its share rose from 37% (132 bcm) to 47% (146 bcm) between 2022 and 2025, while pipeline gas declined from 63% (224 bcm) to 53% (165 bcm). Over the same period, the geographical composition of gas imports changed, with the United States increasing its share of LNG imports into the EU from 42% (55 bcm) to 58% (84 bcm), and Norway strengthening its position as the largest pipeline supplier, increasing its share from 41% (91 bcm) to 53% (87 bcm).

28 Despite a sixfold increase since 2020, EU electrolyser capacity (in operation) reached only about 0.49 GW in 2025, with an additional 3.5 GW having reached at least a final investment decision, remaining far behind the 30-58 GW targets for 2030, signalling rather limited progress in hydrogen development (see Figure 3).[35]

Figure 3: Electrolyser deployment in EU-27 vs. national strategies and EU scenarios for 2030 (GW).



Source: ACER Monitoring report on European hydrogen markets, 2026.

Note: For details on the EU 2040 Impact Assessment S2 scenario, see Commission Staff working document (2024) on Europe's 2040 climate target and path to climate neutrality by 2050.

34 ACER Analysis of the European LNG market developments, 2026 (p.22).

35 ACER Monitoring report on European hydrogen markets, 2026.

29 Ensuring that grids enable rather than constrain the pace of the energy transition has become a central pillar of the EU's energy and industrial strategy. The European Commission's Grids action plan[36] adopted in November 2023, set out measures to accelerate energy infrastructure development and ensure that sufficient capacity is available to trade and transport energy in line with market needs.[37]

30 ACER provides regular monitoring of European grid developments as part of its mandate under Article 15 of Regulation (EU) 2019/942.[38] Its first report from 2024 focused on electricity networks, including transmission and distribution investment and their cost implications.[39] This second edition maintains a primary focus on electricity infrastructure, while broadening the assessment to include gas and hydrogen, reflecting their interdependence and their different momentums. It reviews key developments over the past two years and provides further deep-dive analysis on three topics: project delays, infrastructure needs and use of congestion income.

31 Europe's energy transition requires sufficient capacity to transport and trade energy across Europe. This can be achieved through the following two complementary means:

- **First, efficient use of the existing network.** This relies on market- and system- operation rules that maximise the utilisation of the existing network. Instruments include, for electricity, demand response, market-based grid congestion management that leverages flexibility across transmission and distribution networks, and the implementation of the 70% minimum cross-zonal capacity requirement; More broadly, they also include network tariffs and regulatory measures for system operators to use the existing network more efficiently.
- **Second, timely and efficient infrastructure development.** This requires robust assessment of infrastructure needs and potential, supported by network planning and investment measures that facilitate that the most efficient (highest value) solutions, whether conventional grid reinforcement or GETs, are pursued and timely delivered.

32 This report assesses infrastructure development based on the input provided by 28 NRAs (all Member States and Norway), between May and September 2026, as along with information presented in previous ACER publications and publicly available sources. While the main report discusses the key findings, challenges and practices in Europe, the Annex provides detailed information on the assessments and national data. Instruments aimed at improving the use of the existing network are mainly addressed in other ACER publications.[40]

33 The rest of this report is structured as follows:

- **Chapter 1** reviews the grid development challenges across the energy carriers;
- **Chapter 2** assesses how to ensure robust investments are delivered timely, examining network planning and project delays in greater detail;
- **Chapter 3** evaluates investment trends and grid financing, while also reviewing the use of congestion income;
- the **Annex** provides detailed data for individual countries and additional figures.

36 European Commission, Grids, the missing link, 2023.

37 Importance of energy infrastructure has since been reinforced through subsequent EU initiatives, including: Clean Industrial Deal, 2025; Affordable energy action plan, 2025; Guidance on anticipatory investments, 2025; the European grids package, 2025; EU Electrification action plan, 2026.

38 The activity is part of ACER's monitoring to assess the barriers to the completion of the internal market for electricity.

39 ACER Monitoring report on electricity infrastructure development, 2024.

40 For example, ACER, Report on network charges, 2025; ACER, DSO revenues report, 2026; ACER, Report on progress of EU electricity wholesale market integration, 2024; ACER, Report on progress of EU electricity wholesale market integration, 2025; ACER, Report on capacity use and booking trends in European natural gas markets, 2025; ACER, Gas congestion report, 2026.

1. Different challenges across the energy sectors

34 Electricity, natural gas and hydrogen networks differ substantially in terms of their maturity and their role in the European energy system. Each energy carrier faces distinct challenges and must adapt to changing demands, technologies and regulatory frameworks. This chapter examines the specific challenges affecting network planning and project implementation in each sector.

1.1. Expanding electricity grid capacity amid affordability concerns

35 Electricity networks are undergoing a fundamental transformation, evolving from passive infrastructure into an active backbone of the decarbonised and integrated energy system. They face several key challenges:

- **Providing sufficient and timely grid capacity.** More capacity is needed to connect new supply and demand and to transport electricity across interconnected grids to where it is most valued. Where grid capacity falls short, connection queues and grid congestion increase.
- **Ensuring system security and resilience.** Secure and resilient system operation remains essential as demand-supply patterns shift and climatic conditions become more challenging.
- **Managing rising network costs.** Significant capacity needs and increasing transit flows with corresponding cost impact are putting increasing pressure on network costs.
- **Addressing efficient allocation of costs and benefits.** While the internal electricity market efficiently distributes the benefits and costs of electricity generation, the costs and benefits of network infrastructure are not yet shared in a comprehensive and efficient manner.[41]

Providing sufficient and timely grid capacity

36 The rapid growth in renewable generation and electrification is driving a rise in grid connection requests. As connection applications outpace available grid capacity and the administrative capacity of existing connection processes, queues for new generation and demand are lengthening (see Case study box 1).

37 Connection delays risk slowing renewable energy integration and electrification. They may also increase system inefficiencies where viable projects cannot connect due to insufficient capacity, while limiting the ability of networks to accommodate future energy system needs.[42]

38 The size of connection queues alone is not a reliable indicator of network constraints; growing connection queues can reflect physical grid constraints, but also immature projects, speculative behaviour by project developers and inefficiencies in connection processes.[43] The traditional first-come, first-served approach to allocating connection capacity is increasingly being reconsidered. The European Commission's guidance on grid connections recognises the need for more effective queue-management and prioritisation mechanisms, including approaches that consider project maturity and system needs. Improved transparency, prioritisation frameworks and better coordination between network users, operators and regulators can support more

41 ACER Paper on challenges of the future electricity system, 2024 (p.8).

42 Refused demand requests due to lack of capacity can contribute to higher levels of renewable curtailment, undermine investor confidence and create wider system inefficiencies, particularly when connection requests are mature and well-founded.

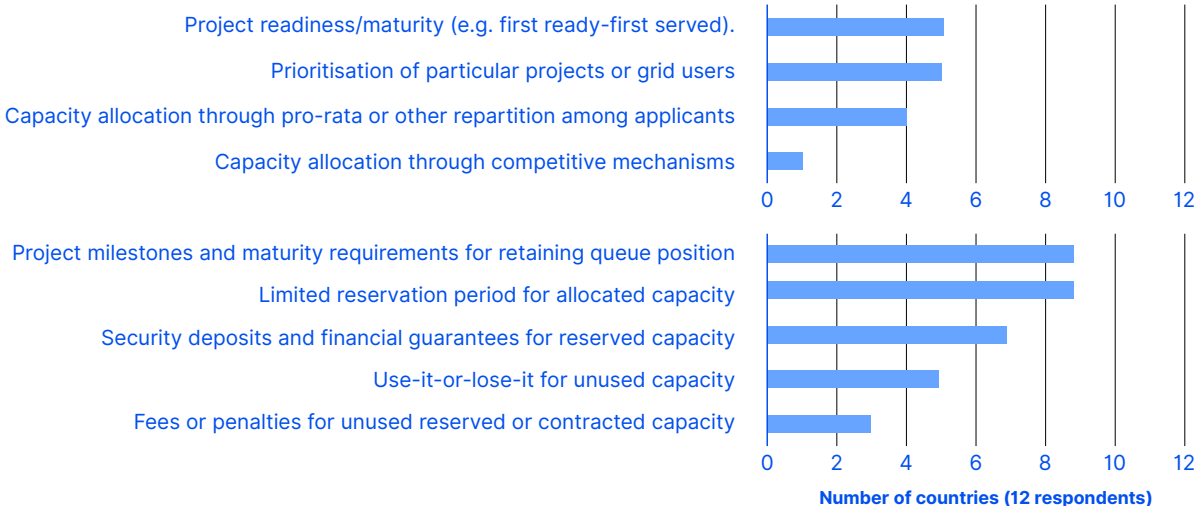
43 Florence School of Regulation, Flexibility and grids: understanding available grid capacity, connection queues and what can be done, 2026.

efficient allocation of available grid capacity.[44]

39 In 2024, ACER stressed that network users should be encouraged to flag their potential future connection requests, including their capacity requirements and planned locations, as early as possible; and coordination, including early exchange of information, amongst future network users, network operators and NRAs should be deployed as a basis to speed-up the regulatory validation of grid investments.[45]

40 As shown in Figure 4, several Member States have introduced measures over the past five years to manage connection queues and/or free up additional connection capacity.[46] For connection-queue management, the most frequent measures are the consideration of project maturity and readiness and prioritisation of particular grid users.[47] The most frequent measures reported for addressing non-progressing requests include loss of queue position if specific project milestones or predefined deadlines are not met and time-limited reservation of allocated connection capacity (with a reservation period varying between 10 days and 3 years).[48]

Figure 4: Measures for connection-queue management (top) and measures for addressing non-progressing requests to free up additional connection capacities (bottom), over the past five years.



Source: ACER's data collection from NRAs.

44 The European Commission's legislative proposal on future-proofing electricity bills of 17 July 2026 aligns with their guidance on grid connections and provides for the prioritisation of grid connections for certain system user categories or users within a specific category, based on objective, transparent and non-discriminatory criteria. According to the proposal, under a new Article 18d of Regulation (EU) 943/2019, the prioritisation of categories of system users or users within a specific category shall be based on criteria that consider the impact of potential projects on solving network congestion as well as the economic, environmental and social benefits.

45 In this regard, consultation of the network planning scenarios (including access to relevant data), the identification of the priorities in addressing reinforcement needs and its means, including wire and non-wire solutions are useful tools. As a concrete example of information exchange, TSOs and DSOs should publish and regularly update country-wide 'hosting capacities' maps, which display the capabilities of the network to integrate (i) new generation and (ii) additional loads. For more information, see ACER and CEER position paper on anticipatory investments, 2024.

46 In 10 out of 12 countries, grid connection queue management rules and principles are established jointly by multiple bodies, including NRAs (8 countries), TSOs (8 countries), DSOs (6 countries), and/or ministries (4 countries). In the 2 remaining countries, it is the sole responsibility of NRA in one country and of the TSO in the other.

47 Sweden treats preferentially projects relieving congestion, Czechia prioritises RES projects, Greece prioritises RES projects with specific characteristics (e.g. inclusion of a storage unit, PPA agreements), whereas Cyprus prioritises self-consumers.

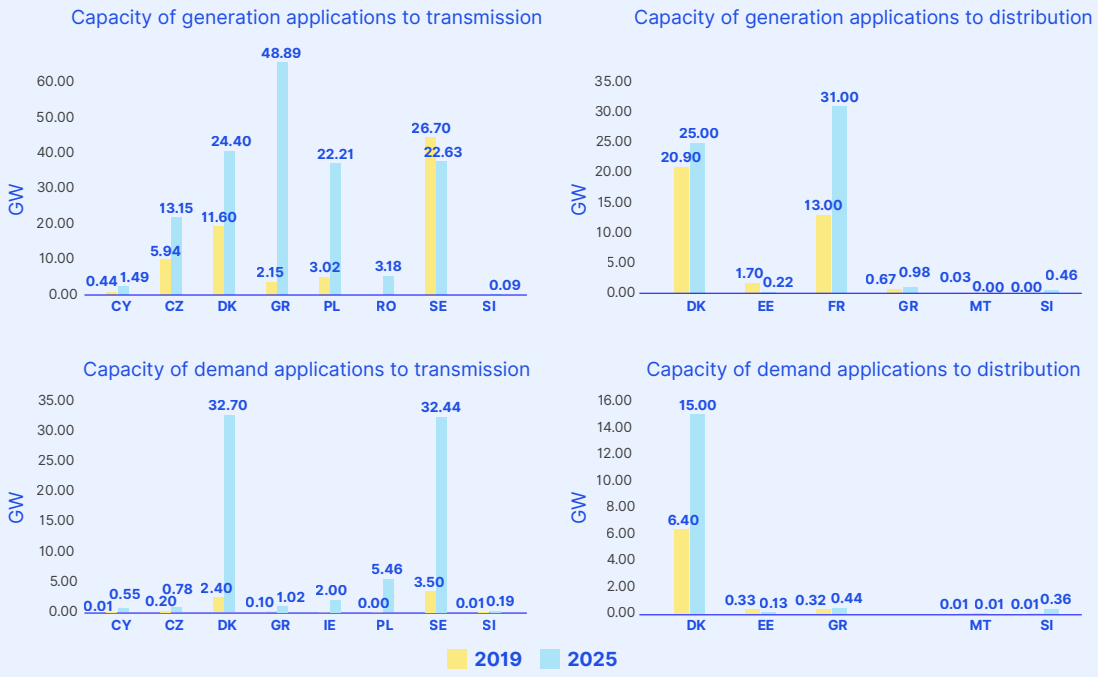
48 Tables 4, 5, and 6 in the Annex provide further details.

Case study box 1: Growing connection pressure

Connection pressures are growing at both the transmission and the distribution level across Europe. External studies identified distribution-level grid connection challenges in at least 15 EU countries in 2025,[49] while transmission-level queues in several countries were estimated to be several times their national peak loads in 2024.[50] Another study estimates that, as of 2024-2025, 1 700 GW of renewable energy and hybrid projects were awaiting grid connections across 16 European countries – more than three times the additional wind and solar capacity estimated to be needed between 2024 and 2030 to reach 2030 targets.[51] The scale of these queues suggests that they may reflect not only physical grid constraints, but also procedural bottlenecks and speculative or immature connection requests.

ACER's analysis of connection requests and queues, based on data made available by NRAs, points to increasing grid-connection demand and highlights the need for more proactive network planning and efficient connection management. Compared to 2019, annual generation and demand connection requests in 2025 increased at both transmission and distribution level in almost all countries for which data are available,[52] leading to significantly longer connection queues, as illustrated in Figure 5, with increases ranging from 20% to more than 2 000%. Refused connection requests also increased, although limited data availability, covering only four countries, prevents broader conclusions from being drawn.[53]

Figure 5: Total capacity in grid connection queues (GW).



Source: ACER data collection from NRAs

Note: Collected data encompasses 20 submissions. Figure 5 includes only countries reporting data for both 2019 and 2025.

49 European Commission, Study on network development planning, tariff structures and connection requests for electricity distribution grids, 2025.

50 Boston Consulting Group, Mind the queue: connection reform for the electricity grid, 2025.

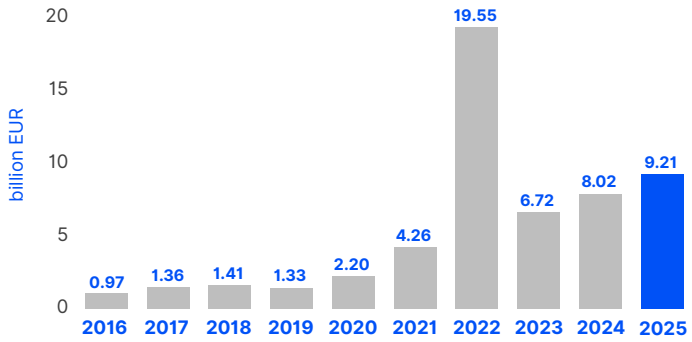
51 Beyond Fossil Fuels, Ember, E3G and the Institute for Energy Economics and Financial Analysis: How Europe's grid operators are preparing for the energy transition, May 2025.

52 This was the case for generation applications at the transmission level in 8 of 9 countries and at the distribution level in 6 of 7 countries, while for demand applications at the transmission level in 9 of 10 countries and at the distribution level in all 5 countries.

53 For additional information, see Tables 1, 2 and 3 in the Annex.

41 The challenge is not only to connect new generation and demand, but also to transmit electricity and to trade it where it is most valued.[54] However, growing congestion on the transmission network are increasingly constraining cross-zonal exchanges, leading to greater reliance on costly congestion management measures. Growing distributed renewable generation and electrification are placing pressure on distribution networks, resulting in local capacity constraints in several Member States.[55]

Figure 6: Congestion income generated in single-day ahead coupling, 2016-2025.



Source: ACER electricity market integration monitoring report, 2026.

42 ACER has observed increasing congestion across the EU electricity system in recent years, as reflected in rising congestion income (Figure 6) and growing volumes and costs of remedial actions. In 2025, EU TSOs spent approximately EUR 5.4 billion on remedial actions, redispatching approximately 70 TWh of electricity.[56] Compared with 2024, this represents an increase of around 16% in volumes and over 25% in costs. In this context, ACER underlines that TSOs are still not fully and consistently meeting the EU's 70% cross-zonal capacity requirement. While fuller implementation would bring extra economic gains, it may also increase the need for remedial actions and related costs unless supported by structural measures such as grid upgrades or bidding zone changes.

43 Looking ahead, the Joint Research Centre's modelling suggests that congestion management needs could increase substantially, with annual redispatch volumes rising to around 800 TWh and yearly congestion managements costs exceeding EUR 100 billion by 2040 under business-as usual grid development and the current bidding zone design.[57] While congestion management and bidding zone reviews also help address congestion, timely network capacity enhancement (including new lines and non-wire alternatives) is an important long-term response to structural congestion and has been identified as a key solution in this regard.[58]

44 Insufficient network capacity can also lead to the curtailment of renewable generation, increasing costs and higher emissions. While some curtailment may be unavoidable or economically efficient, persistent structural curtailment may signal insufficient grid capacity, including where network development has not kept pace with generation deployment due to delays (e.g. in permitting) or planning issues, thereby limiting the timely delivery of these benefits.

54 Efficient cross-zonal electricity trade is a cornerstone of the EU internal electricity market, enabling electricity to flow from lower- to higher-price areas, improving security of supply and supporting renewable energy integration.

55 European Commission, Economic forecasts and financial support for EU member states – macroeconomic and fiscal surveillance and country reports, 2026.

56 ACER, Electricity market integration monitoring report, 2026.

57 Joint Research Centre, Future-proofing the European power market: Redispatch and congestion management, 2024.

58 ACER, Electricity market integration monitoring report, 2025.

45 The increasing share of variable renewable generation is fundamentally changing power system operation and increasing the need for system flexibility.[59] This need is also reflected in increasingly volatile wholesale electricity prices, including more frequent episodes of negative prices.[60] Such price signals underscore the growing value of demand response, electricity storage and flexible generation in balancing supply and demand.

46 Flexibility is relevant not only at the transmission level but also increasingly at the distribution level, where distribution system operators (DSOs) can use local flexibility services as a complement or an alternative to network reinforcement to manage grid congestion or capacity constraints.[61] In this respect, grid digitalisation, advanced monitoring and control technologies, and enhanced coordination between system operators at the transmission and the distribution level are becoming increasingly important for maintaining secure and efficient system operation.[62]

Rising electricity interruptions: ensuring system security and resilience

47 The interconnected European power system offers resilience against sudden shocks, as cross-border connections allow countries to support one another during system disturbances and assist system restoration. This was demonstrated during recent large-scale electricity disruptions, such as the Iberian blackout of April 2025, the Czech transmission system incident of July 2025, and the local outages during summer 2026 heatwaves.[63]

48 Electricity networks are facing growing physical, cyber and climate-related risks. Attacks on energy infrastructure, such as witnessed in Poland, Ukraine or the Baltic Sea, underline the need to strengthen the protection of critical energy infrastructure against physical and cyber threats. Climate change is also creating increased operational challenges for the electricity system. The recent extreme heatwaves, followed by record-low water levels, have reduced the availability of thermal, hydropower and nuclear generation while simultaneously increasing cooling demand. Floods and wildfires pose additional threats to electricity infrastructure. Conversely, the condition of electricity networks can itself contribute to climate-related risks, particularly in areas exposed to wildfires.

49 These developments underline how increasingly variable operational conditions are making it more challenging to maintain the system within secure operating limits. This increases the importance of adequate network capacity, real-time situational awareness, effective protection and restoration procedures and coordinated system operation across borders and across transmission and distribution levels.[64]

59 ACER and the European Environment Agency (EEA) estimated in 2023 that flexibility needs could approximately double by 2030 (ACER and EEA, Flexibility solutions to support a decarbonised and secure EU electricity system, 2023).

60 Since 2020, the average daily gap between the lowest and highest day-ahead electricity prices has increased fivefold. ACER, Key developments in EU electricity and gas markets, 2026 (p. 28).

61 EU DSO Entity's report on distributed flexibility practices (2026) showed that DSOs across several Member States, including France, Italy, the Netherlands, Portugal and Sweden, are already using flexibility services to alleviate local congestion

62 ACER, DSO revenues report, 2026; ACER and CEER guidance on distribution network planning, 2025.

63 ACER also finds that power outage levels averaged less than two hours per customer across the EU in 2024, and none of the assessed outages were due to inadequate electricity supply (ACER Monitoring report on security of EU electricity supply, 2025).

64 Interconnected grids enable electricity and flexibility exchange across areas in increasingly short operational timeframes, while distribution networks can facilitate local flexibility solutions where system needs are location specific. Stronger interconnection enables neighbouring systems to share balancing resources, inertia and reserves, improves frequency stability and allows electricity to flow towards areas experiencing supply shortages or network disturbances. ACER Monitoring report on security of EU electricity supply (2025) identified need to strengthen regional cooperation and coordination on risk preparedness.

Managing rising network costs

50 The 2024 ACER Infrastructure monitoring report highlights that the transition to a decarbonised European energy system will require a major increase in investment in electricity transmission and distribution networks. Industry estimates of EU grid investment needs range from around EUR 75 billion to EUR 100 billion annually between 2025 and 2050, with roughly two thirds required at the distribution level.[65] The increase in grid investment costs is driven by both additional needs for capacity and by rising manufacturing prices.[66]

51 As grid costs become a main driver of overall electricity costs, containing their rise is key for competitiveness. Cost-effective grid investments are indispensable to keeping electricity bills low for households, businesses and industry. Distribution-connected consumers will face the largest burden as, beyond distribution investments, up to 90% of transmission costs are passed on to them because they also benefit from transmission services. Measures to unduly alleviate one user group would increase costs for others and distort the efficiency signals in the network tariffs.

Challenge of asymmetric distribution of costs and benefits

52 Building integrated European electricity markets requires substantial cross-border relevant grid investments.[67] Applying a strict territorial principle to cross-border infrastructure, can disincentivise or even lock-in investments whenever local costs equal or exceed local benefits, despite broader EU gains.

53 Several mechanisms currently aim to address this challenge, including public (EU and national) funding for infrastructure development;[68] the EU-wide ITC mechanism which redistributes costs related to hosting transits;[69] the CBCA mechanism which enables a negotiated sharing of costs of major infrastructure investment across borders based on the expected benefits in the Member States;[70] and the distribution and use of congestion income revenues arising from cross-zonal trade.[71]

54 Some of these mechanisms currently play a relatively small role in infrastructure financing. In 2024, the ITC Fund totalled about EUR 880 million, of which EUR 780 million covered transit losses and EUR 100 million infrastructure availability.[72] This amount together represents less than 3% of TSOs' annual CAPEX and OPEX in 2025. Furthermore, between 2014 and 2024, no investment costs were allocated to non-hosting countries for any electricity project, and less than 6% of the total electricity investment costs (EUR 0.12 billion out of EUR 2.1 billion) were transferred between the hosting countries, deviating from the territorial principle for onshore interconnections.[73]

65 ACER Monitoring report on electricity infrastructure, 2024 (p. 5, 30). The cost figure is consistent with the Commission's estimate that approximately EUR 1.21 trillion will be required in electricity network investment by 2040, split between EUR 730 billion for distribution and EUR 477 billion for transmission infrastructure.

66 ACER Report on energy infrastructure unit investment cost indicators, 2026.

67 In the context of the North Seas Energy Cooperation framework, a separate discussion is ongoing on offshore infrastructure, including recent observations by the North Seas energy regulators.

68 The Connecting Europe Facility (CEF) programme earmarked EUR 5.8 billion to priority energy infrastructure for the 2021–2027 period, with the European Commission proposing a fivefold increase to EUR 29.91 billion for the 2028–2034 period, while over EUR 20 billion was allocated across various initiatives for hydrogen, including the European Hydrogen Bank auctions and the EU Hydrogen Mechanism to connect supply with demand. Broader EU funding channels, such as the Cohesion Fund and Modernisation Fund, also support energy infrastructure, while Member States have additionally launched domestic support schemes.

69 Commission Regulation (EU) No 838/2010 on laying down guidelines relating to the inter-transmission system operator compensation mechanism and a common regulatory approach to transmission charging.

70 ACER Recommendation No 02/2023 on good practices for the treatment of the investment requests.

71 For a detailed assessment of the use of congestion income, see Section 3.3 of this report.

72 CER Report on the implementation of the ITC mechanism, 2025.

73 The calculation is based on ACER data collection from NRAs through CBCA monitoring activity. For offshore sections the allocated amount could not be reliably calculated as the default cost allocation was often not provided (see ACER, CBCA monitoring report, 2025).

55 As pointed out in 2026 ACER Policy Paper on Infrastructure cost sharing,[74] the existing cost and benefit sharing mechanisms currently fall short of fulfilling their objectives. ACER proposed to perform a thorough quantitative evaluation of multiple policy options, put forward by the report without defining a preferred one, and feasibility testing to fine-tune the different design elements of a set of improvement options.

1.2. Gas networks adapting to an evolving role in turbulent times

56 The role of gas networks is changing fundamentally as Europe transitions towards a decarbonised and integrated energy system and faces geopolitical tensions impacting supply patterns. In this context, the EU-level planning is becoming less focused on identifying new cross-border gas projects and more focused on assessing whether the evolving gas system remains adequate, resilient and appropriately sized .[75] The recast Gas Regulation nevertheless retains a biennial EU TYNDP, including network modelling, scenarios, a European supply adequacy outlook, resilience assessment and consideration of repurposing and decommissioning. The key challenges relate to:

- **Maintaining security of supply and resilience under changing supply patterns**;
- **Adapting and financing gas infrastructure under declining utilisation**;
- **Adapting infrastructure and investment approaches to support emerging renewable and low-carbon gases**, while avoiding inefficient investments and managing impacts on tariffs and market integration.

Maintaining security of supply under changing supply patterns

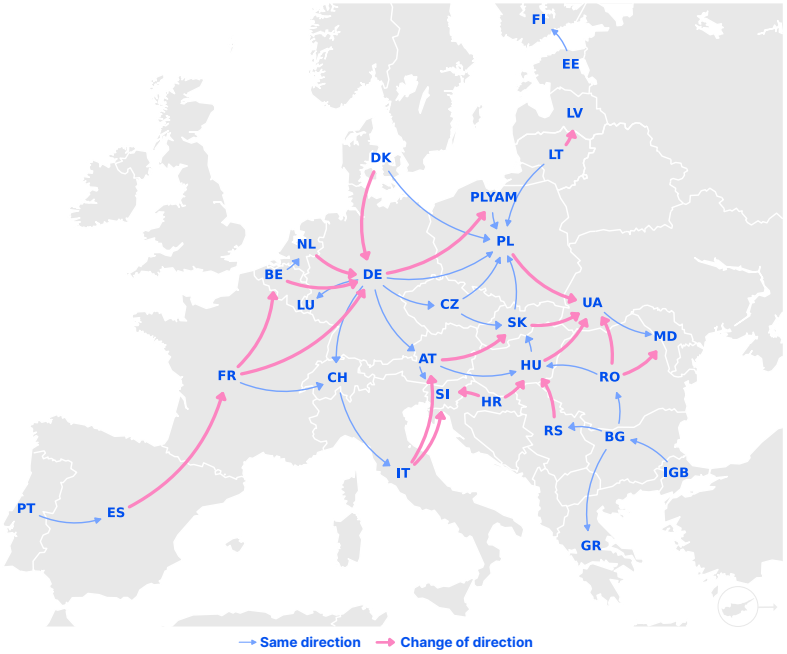
57 Following the 2022-2023 energy crisis, gas infrastructure has demonstrated its importance for security of supply and system flexibility. The reduction in Russian pipeline gas imports following that country's invasion of Ukraine has fundamentally changed European gas supply patterns, exposing vulnerabilities in Europe's previous supply structure.

58 The flexibility of European gas infrastructure enabled a major shift from predominantly east-to-west pipeline flows towards LNG imports arriving through coastal terminals and being transported across the European network, while pipeline imports from Norway further increased. Existing interconnections, reverse-flow capabilities, LNG terminals and underground gas storage, together with coordinated EU measures, allowed Europe to maintain security of supply despite the loss of a significant share of former pipeline imports. Gas price spreads across major EU hubs have generally remained limited, indicating that the internal gas network has continued to facilitate market integration despite these changing flow patterns (see Figure 7).

74 ACER Policy paper on sharing of costs and benefits of electricity network infrastructure arising from cross-border trade, 2026.

75 The TYNDP 2026 methodology already reflects this shift. ENTSOG assesses natural gas and hydrogen jointly through a Dual Gas Model, testing peak demand, called '*Dunkelflaute*', supply and infrastructure disruptions, the impact of gas-network repurposing, and LNG and interconnection diversification.

Figure 7: Change in flow direction at EU gas cross-border interconnection points and with some neighbouring countries (first half of 2021 to second half of 2025)



Source: ACER, Monitoring report on capacity use and booking trends in European natural gas markets, 2025.

Note: Adjusting gas flows proves the resilience of the EU gas system.

59 Nevertheless, the changing supply structure does not eliminate security of supply challenges:

- First, despite the significant reduction in Russian pipeline gas imports since 2022, Russia remains an important supplier of LNG to the EU, accounting for 14% of the total EU LNG imports in 2025,[76] while EU-wide phase-out of Russian natural gas imports will be completed by 2027, subject to different deadlines for LNG and pipeline gas imports.[77]
- Second, Europe's increased reliance on global LNG markets has changed the nature of gas supply and price risks, involving stronger global competition and more volatility in prices and shipping costs,[78] significantly influenced by geopolitical developments affecting major LNG-producing regions, like the current Middle East conflict.[79] Moreover, diversification away from Russian gas has been accompanied by increasing concentration among alternative suppliers: the United States accounted for 58% of EU LNG imports in 2025.

60 ACER's monitoring indicates that the EU should, in principle, be well positioned to manage the phase-out of Russian LNG imports, supported by substantial regasification capacities, strong interconnections and access to diversified global LNG supply sources.[80] As supply routes continue to evolve, resilient infrastructure and well-functioning internal gas markets remain important; LNG terminals and underground storage provide complementary flexibility over different time horizons, while adequate interconnection capacity is necessary to move imported gas from coastal entry points to demand and storage locations, particularly in landlocked and eastern Member States.

76 In 2026, Russian LNG imports are projected to reach around 20 bcm, accounting for over 15% of total EU LNG imports and around 5-6% of total EU gas consumption. (ACER Report on Russian gas imports, 2026).

77 Regulation (EU) 2026/261 sets a stepwise phase out of Russian natural gas imports; the ban on LNG imports takes full effect on 1 January 2027, while pipeline gas imports under existing long-term contracts may be temporarily permitted until 30 September 2027, with a possible extension until 1 November 2027, subject to gas storage conditions.

78 Following the extreme volatility of 2022, European gas prices have stabilised as storage levels recovered, supply sources diversified and demand adjusted. Nevertheless, prices remain above pre-crisis levels and are increasingly influenced by global LNG market dynamics.

79 ACER Analysis of the European LNG market developments, 2026.

80 In 2025, ACER observed 7 countries accounting for between 2% and 58% of the total LNG supply to the EU, while additional countries covered smaller shares. For more information, see ACER's Analysis of the European LNG market developments, 2026.

Adapting and financing gas infrastructure under declining utilisation

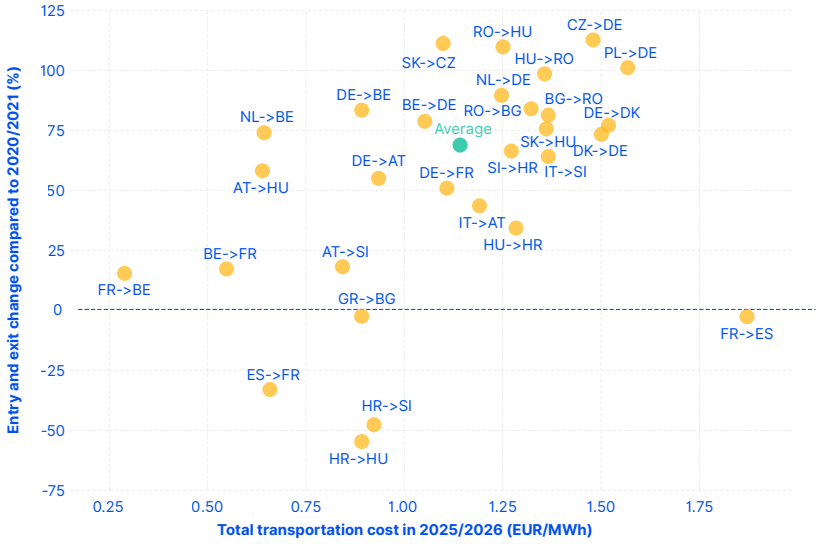
61 European gas infrastructure is facing a difficult transition as renewable energy, energy efficiency and electrification are expected to substantially reduce fossil gas demand. However, as described in Section 2.2 in this report, the pace and geographical distribution of this decline remain uncertain. Infrastructure operators therefore face uncertainty over both the future scale and utilisation of the gas network.

62 Declining gas demand does not imply a proportionate reduction in infrastructure needs. Gas networks continue to provide important functions, including seasonal storage, security of supply during peak demand periods and flexibility for the electricity system during periods of low renewable generation. Some infrastructure may consequently retain substantial system value despite declining average utilisation.[81]

63 At the same time, the decline of Russian pipeline gas and growing reliance on LNG and alternative supply corridors have reduced utilisation along some traditional east-to-west transit routes and increased west-to-east flows. In parts of central and eastern Europe, former transit systems are increasingly serving primarily domestic and regional demand, with implications for transport costs and market integration.

64 These developments are creating a growing economic and regulatory challenge. Gas networks have largely fixed costs, while declining transported volumes and capacity bookings reduce the base over which these costs can be recovered. ACER has observed that lower gas demand and reduced transit flows have contributed to lower capacity bookings and rising cross-border transport costs (see Figure 8). At the same time, infrastructure that provides security-of-supply or flexibility value may need to remain available despite lower utilisation. The key question is therefore to determine which assets should be replaced or extended once they are fully depreciated and which should be removed (either decommissioned or repurposed for use in hydrogen networks) to avoid stranded assets amidst shrinking customer bases.

Figure 8: Relative changes in cross-border capacity reserve prices for yearly products in selected borders.



Source: ACER Key developments in European electricity and gas markets, 2026 (p.48).

81 Gas phase-out is a long-term process rather than an immediate event, as industry, heating, and generation during peak periods or shortages, demand the ongoing operation and maintenance of vital transmission networks.

Adapting infrastructure and investment approaches to support renewable and low-carbon gases

65 The energy transition may also require new investments in the context of declining natural gas demand. For example, 54% of EU biomethane plants are connected to distribution networks, compared with only 18% that are connected to transmission networks.[82] Further deployment may require new connections, network reinforcement and reverse-flow capacity, particularly at the distribution level. Meanwhile, existing infrastructure must continue to be operated safely, including through investment in methane monitoring and mitigation. These needs must be carefully assessed against declining fossil gas demand to avoid inefficient expenditure and stranded assets. Reflecting this shift, the 2022 revision of the TEN-E Regulation has largely redirected EU infrastructure support from conventional natural gas projects towards electricity, hydrogen and CO_2 infrastructure.[83]

1.3. Hydrogen grid development in uncertain markets

66 Hydrogen infrastructure development is at an early stage compared with electricity and gas networks and no new hydrogen pipeline systems connecting industrial sites has entered commercial operation over the last four years based on NRA data.[84] At the same time, the future scale and timing of hydrogen demand, production and trade remain uncertain, despite hydrogen's expected role to contribute to decarbonising hard-to-electrify sectors and supporting energy system flexibility. This creates the following key infrastructure-related challenges:

- **Developing infrastructure under highly uncertain market conditions**; and
- **Managing investment and cost recovery risks, compounded by incomplete regulatory and institutional frameworks**.

Developing infrastructure under highly uncertain market conditions

67 The largest challenge for hydrogen infrastructure development remains the uncertain pace of demand growth. As underlined earlier in this report, renewable hydrogen production and demand continue to develop more slowly than anticipated, while most projects remain dependent on public support. National hydrogen ambitions have already been revised downward in several Member States, while the current rate of market growth remains insufficient to meet EU and national targets.

68 Uncertainty over future hydrogen demand makes it difficult for hydrogen network operators to determine the appropriate timing and scale of network investments, which already contributed to the cancellation or delay of several high-profile projects.[85]

69 Hydrogen infrastructure planning increasingly requires decision-making under conditions of profound uncertainty. Demand trajectories and project pipelines continue to evolve, while differences between infrastructure envisaged at European level and projects reported nationally indicate uncertainty over the scale and timing of future network development (see Figure 9). The limited maturity of the market also means that projected demand can only to a limited extent be tested against firm capacity commitments or established market behaviour.

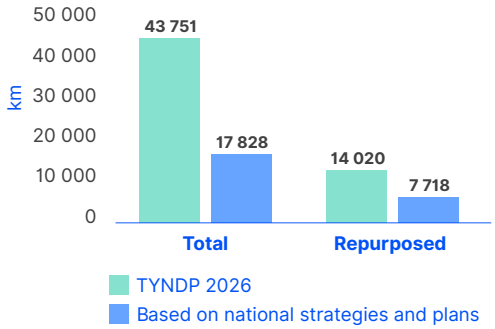
82 ACER Monitoring report on decarbonisation of the EU's natural gas market, 2026.

83 Only two gas projects with derogations were included in the latest PCI/PMI list.

84 ACER Opinion No 17/2026 on gas and hydrogen NDPs.

85 ACER Monitoring report on European hydrogen markets, 2026.

Figure 9: Comparison of planned hydrogen network (km) based on national strategies and plans with TYNDP 2026 hydrogen network projects (October 2025).



Source: ACER, based on information from NRAs and ENTSOG's TYNDP 2026 list of projects.

70 Technical assumptions surrounding future hydrogen infrastructure add another source of uncertainty. Repurposing existing natural gas infrastructure could reduce investment costs, permitting requirements and environmental impacts compared with new-build infrastructure. However, repurposing is not an automatic or universally preferable solution. Decisions require a systematic assessment of technical feasibility, security of supply, economic efficiency and stakeholder impacts to ensure that repurposing delivers greater overall value than alternative infrastructure solutions.[86]

71 Experience also demonstrates that project assumptions can evolve significantly during project development and significantly alter investment needs. For example, changes to the planned development of the Dutch hydrogen backbone, including less extensive repurposing of existing gas pipelines and higher construction costs, have more than doubled the expected investment cost compared to the initial estimate.[87]

72 The development of hydrogen infrastructure requires effective coordination with the electricity system. Electricity network tariffs, grid availability and other electricity-system conditions can materially affect the economics and location of electrolysers and, therefore, where hydrogen supply and infrastructure utilisation emerge. These interdependencies add further uncertainty to both electricity and hydrogen infrastructure needs.

86 ENTSOG and ENNOH, Criteria for natural gas infrastructure repurposing – final report, 2025.

87 ACER Monitoring report on European hydrogen markets, 2025 (p. 37).

Investment and cost recovery risks, compounded by incomplete regulatory and governance frameworks

73 The development of EU hydrogen infrastructure remains dependent on the timely transposition and implementation of the EU legislative framework at Member State level, which has been uneven across the EU and remains incomplete.[88]

74 Significant progress in establishing functioning national hydrogen markets has so far been achieved only in few Member States, including Belgium, Denmark, Germany, the Netherlands and Poland.[89] Most Member States have neither set up a hydrogen network planning framework, designated or certified Hydrogen Network Operator (HNO), nor put in place the corresponding regulatory oversight.[90] In some Member States, regulators already perform these activities despite pending formal transposition, while in others, the absence of a national regulatory framework prevents regulators from assessing hydrogen infrastructure projects. Incomplete implementation and regulatory uncertainty therefore hinder coordinated infrastructure planning across Member States and weaken investment conditions.[91]

75 Developing a European hydrogen market may require significant infrastructure investment to transport hydrogen from supply sites to end users. However, low initial network utilisation could lead to high regulated tariffs for early users, weakening demand and network utilisation.[92] At the same time, extensive investment ahead of credible supply and demand increases the risk of underutilised or stranded assets, with costs potentially being borne by taxpayers, where these risks are covered through public support or guarantees. A key challenge remains balancing the need to enable early infrastructure investment against the risk of network users or public finances bearing the costs of underutilised assets.

88 ACER No 17/2026 Opinion on gas and hydrogen NDPs,.

89 ACER Monitoring report on European hydrogen markets, 2026 (p. 33).

90 ACER No 17/2026 Opinion on gas and hydrogen NDPs identified Poland as the only Member State with a certified and designated HNO in line with Article 71(2) of Directive (EU) 2024/1788, while five additional Member States have designated or certified an HNO, at least provisionally, but not in line with that provision. Transposition of the EU provisions on regulatory oversight of hydrogen NDPs into national law is ongoing in many Member States with only Poland reporting these provisions being mostly transposed.

91 ACER notes that the certification of HNOs under national legislation is a prerequisite for the formal establishment of ENNOH, while national hydrogen network-planning frameworks remain incomplete.

92 While pipeline transport costs are currently expected to represent a relatively small share of delivered hydrogen prices, they could increase significantly if expected network utilisation does not materialise and fixed infrastructure costs must be recovered from fewer users.

2. How to ensure infrastructure is delivered where needed, at the right scale and time

76 As described in Chapter 1, electricity, gas and hydrogen networks face different transition challenges. Electricity networks must expand and modernise rapidly while maintaining system security. Gas networks need to manage declining utilisation, ensure security of supply and adapt to renewable and low-carbon gases. Hydrogen requires building a new value chain across production, transport, storage and end use amid significant uncertainty.

77 As also discussed in Chapter 1, ensuring sufficient capacity to transport and trade energy across Europe requires a combination of the efficient use of existing networks and timely and efficient infrastructure development, and while both are essential to the energy transition, this report focuses on the latter.

78 In this context, Chapter 2 first assesses the progress of priority energy infrastructure projects and the action needed for their timely implementation. It then focuses on network planning,[93] examining how it can become more robust, coordinated and responsive to evolving system needs.

2.1. Timely infrastructure delivery requires faster implementation

79 Delays in network capacity delivery postpone system integration benefits and impose costs on consumers and the energy system (e.g. through higher commodity prices). As an illustration, ACER estimated the impact of a one-year delay in delivering electricity transmission PCIs and PMIs on the existing Union list, accounting only for socio-economic welfare benefits and investment costs, but not for other benefits (e.g. variation of losses, security of supply and sustainability) and other costs (e.g. OPEX). ACER finds that a one-year delay in delivering electricity transmission PCIs and PMIs would result in EUR 4 billion in net economic welfare losses.[94] This reinforces the idea that the causes of delays should be carefully scrutinised and addressed.

80 This section examines the progress of infrastructure delivery limited to Europe's priority projects (i.e. PCIs and PMIs) expected to deliver significant pan-European benefits; the assessment does not account for all pan-EU relevant transmission projects, nor other transmission and distribution projects of national relevance.

81 As shown in Figure 10, ACER finds that 116 projects included in at least one PCI/PMI list since 2013 have been commissioned, of which 88 (76%) are electricity. An additional 18 electricity and 3 hydrogen projects are currently under construction.[95] These figures demonstrate solid infrastructure delivery under the PCI/PMI framework.[96] Most commissioned projects are in the electricity sector, followed by gas, while none have yet been completed in the hydrogen sector. This reflects the recent inclusion of hydrogen projects in the PCI/PMI framework and the early stage of hydrogen infrastructure development.

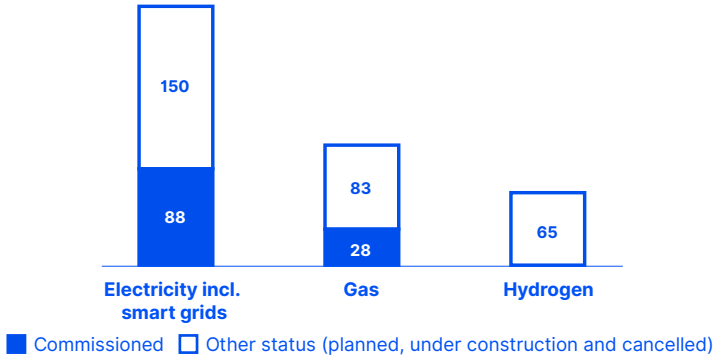
93 Energy network planning identifies the infrastructure needed to ensure the secure and efficient operation of the energy system and support the energy transition. It is based on the development of future supply and demand scenarios, the identification of network needs and the assessment of projects to address those needs. Since each planning step builds on the previous one, uncertainties around assumptions propagate through subsequent planning stages. This is particularly relevant when policy, technology and market developments rapidly evolve and alter infrastructure needs over time.

94 The net socio-economic welfare loss accounts for both the negative impact of postponed benefits and the positive impact of postponed costs due to a one-year delay of all electricity transmission PCIs and PMIs on the current Union list. Projects were assessed using ENTSO-E's TYNDP 2024 project cost-benefit analysis results for 2030 and 2040 under the central policy scenario. The estimated socio-economic welfare benefits totalled EUR 215.7 billion over the 25 years economic lifetime of projects, 4% social discount rate and no residual value, while the inception CAPEX (investment costs) amounts to about EUR 112.3 billion (in 2026 values). Assuming a one-year delay to the commissioning of all projects, the estimated benefits drop to EUR 207.4 billion, and the costs to EUR 107.9 billion (in 2026 values). In this calculation '2026 values' mean real values, i.e. not taking into account inflation, and expressed in 2026 values.

95 According to ACER's 2026 PCI monitoring activity, accounting for two projects reported as 'under construction' that have since been identified as commissioned.

96 The overall number of projects should not be interpreted as a portfolio in which every project is expected to be delivered.

Figure 10: Commissioned electricity, gas and hydrogen PCI/PMIs per category

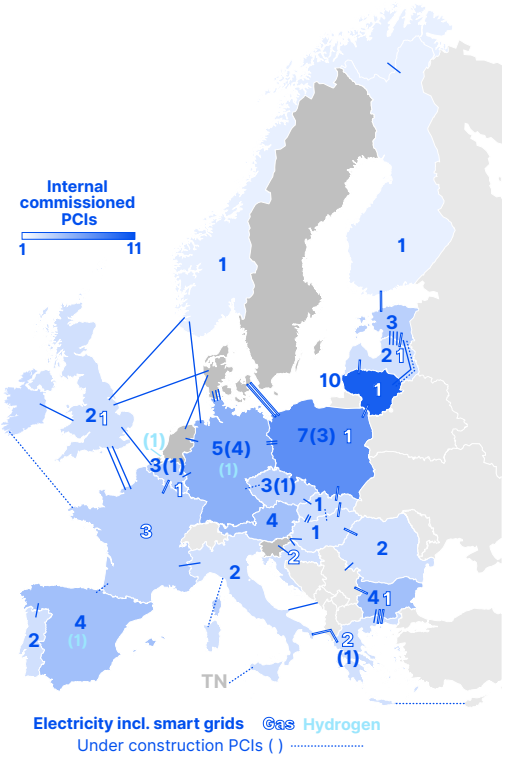


Source: CINEA's PCI-PMI Transparency Platform, ACER study and inputs by NRAs. See also ACER's website.

Note: This analysis covers all PCI/PMIs that have appeared on at least one Union list of PCI/PMIs and have been subject to monitoring by ACER. As projects may be re-clustered, with changes to their codes or scope over time, the analysis uses the most recent clustering and code assigned for each project. Projects included for the first time in the second Union list of PCI/PMIs are excluded, as ACER has not yet monitored them.

82 Geographically, as shown in Figure 11, commissioned projects are spread across a large part of Europe. Electricity projects located in one country ('internal projects') are concentrated mainly in central and eastern Europe and the Baltic region, while interconnections and other projects developed in multiple countries span northern, western, central and south-eastern Europe. Commissioned gas projects are more concentrated in central, eastern and south-eastern Europe. It should be noted that the geographical distribution of commissioned PCIs/PMIs does not reflect all pan-EU relevant infrastructure developments, as participation in the PCI/PMI framework varies across countries and cross-zonal capacities have also been increased through non-PCI projects.

Figure 11: Commissioned and under-construction electricity, gas and hydrogen PCI/PMIs per country



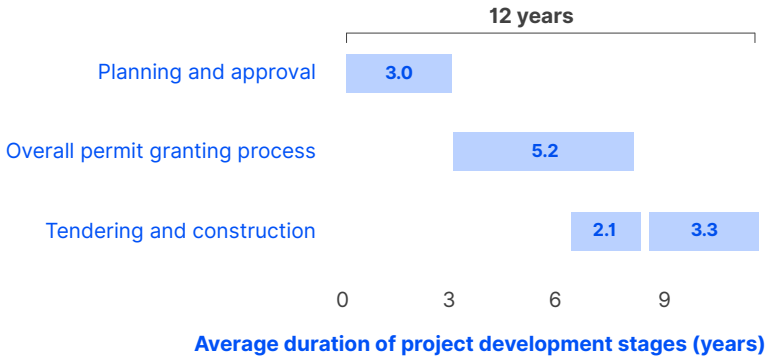
Source: CINEA's PCI-PMI Transparency Platform, ACER's own study and inputs by NRAs.

Note: For the purpose of this visualisation, projects located in a single country are shown as internal projects. Interconnection and other projects developed in multiple countries are represented by lines connecting the respective countries. These lines indicate the geographical attribution of projects in the underlying data and do not necessarily represent physical interconnectors between the countries concerned.

Electricity priority projects often experience repeated postponements

83 Figure 12 illustrates the average duration of the development phases of electricity transmission projects within the overall project implementation timeline, covering the period from the end of the 'under consideration' stage until commissioning. The average implementation time of an electricity transmission project is around 12 years.

Figure 12: Average timeline of electricity transmission projects subject to ACER monitoring since 2020



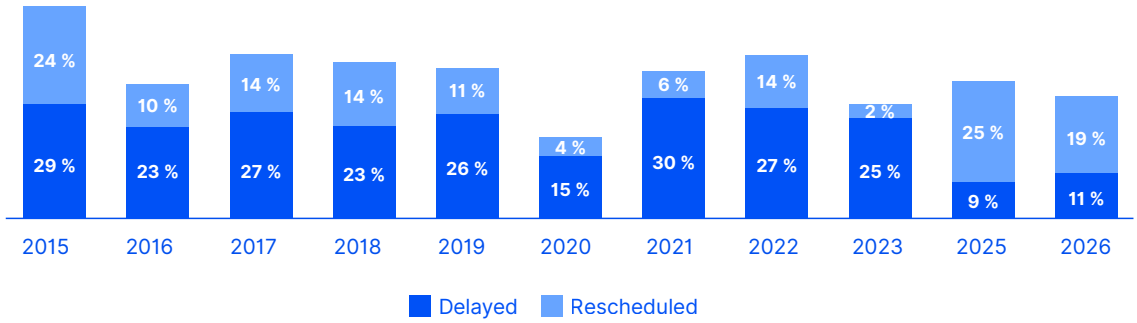
Source: ACER database.

Note: The project implementation phases show estimated dates for pending phases and actual dates for completed milestones. The 'under consideration' phase is not shown as it is not always clearly delineated by the project promoters.

84 Based on annual PCI monitoring data, ACER finds that the expected commissioning dates of electricity transmission PCIs have been repeatedly postponed. ACER notes that many postponements have been caused by project delays due to external reasons beyond project promoters' control (as opposed to voluntary project rescheduling)[97]. More than 40% of electricity PCIs have reported delay at least once[98].

85 As shown in Figure 13, across ACER's annual monitoring cycles, between 9% and 30% (on average 22%) of electricity transmission projects were delayed each year, while 2% to 25% (on average 13%) were rescheduled, highlighting a persistent challenge, affecting a notable share of electricity PCIs and PMIs.

Figure 13: Shares of delayed (beyond TSOs' control) and rescheduled electricity transmission PCIs/PMIs across ACER's monitoring cycles



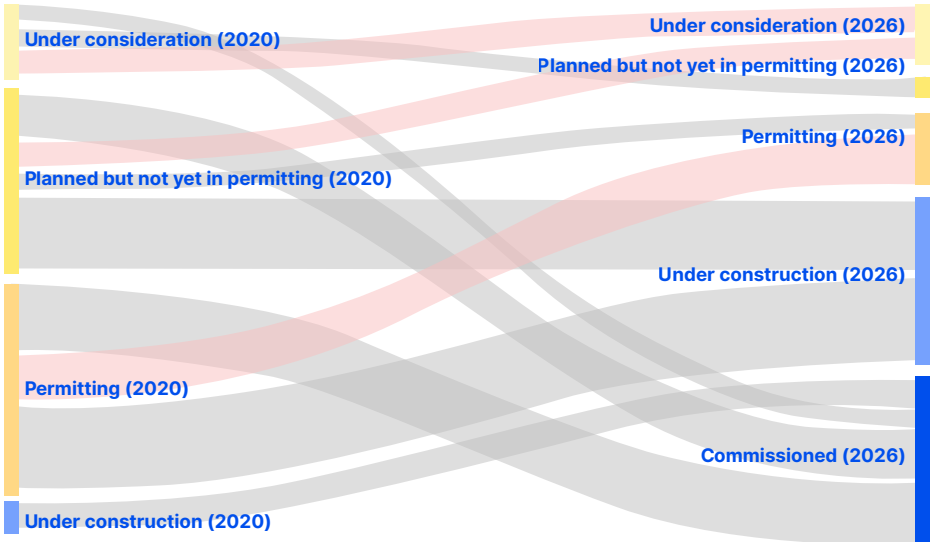
Source: ACER database.

97 When assessing project implementation, ACER distinguishes between project delays and project rescheduling, because they may have different implications for policy and regulatory action. Delays occur when a project remains necessary but cannot be commissioned as planned due to constraints such as permitting, environmental, supply-chain, financing or legislative issues. By contrast, rescheduling reflects a voluntary postponement by the project promoter, typically following changes in system needs, demand forecasts, planning assumptions or investment priorities. Unlike delays, rescheduling generally reflects an adjustment of project timing rather than an implementation failure.

98 Cross-border projects are slightly more likely to report delays, with 45% reporting delays compared to 40% of internal projects, which is in line with their often-higher complexity and the need for coordination across multiple jurisdictions.

86 Permit granting has been consistently identified as the leading cause of delays[99] for electricity transmission projects, with the average permitting duration increasing steadily from less than three years in 2020 to almost four and a half years in 2026. Figure 14, which illustrates change in projects' status between 2020 and 2026, shows that 20% of electricity transmission PCIs have not progressed its status for more than six years, including four projects having remained in the permitting phase.

Figure 14: Evolution of the PCI status of electricity transmission projects between 2020 and 2026



Source: ACER database.

Note: The figure includes the status of the 38 electricity transmission projects that appeared on both the 2019 and 2024 PCI lists and had their annual reports submitted for PCI/PMI monitoring activities in 2020 and 2026.

Hydrogen and gas transmission priority projects are being postponed as well

87 Although it can be evaluated only over a shorter timeframe, as hydrogen projects were only recently added to the Union list, the PCI/PMI monitoring findings underline that delays and rescheduling are also a significant issue for hydrogen infrastructure. About a third (8 out of 25) of transmission projects have experienced delays, 7 (28%) have been rescheduled, while 10 (40%) have maintained their previously expected commissioning timeline. Multiple reasons for postponements are reported by the project promoters, including a lack of financing and guarantee mechanisms to support investments and delays in the transposition of the hydrogen transport framework.

88 Conventional gas infrastructure projects have also historically experienced significant delays and rescheduling but, with few exceptions, have been phased out of the Union list of PCIs/PMIs.[100] The two gas transmission projects that were allowed to retain their PCI status were both reported as rescheduled in the latest ACER monitoring exercise. In the previous exercise, one had been reported as delayed and the other as rescheduled.

Supply-chain issues as a growing concern:

89 Supply chain issues are an increasing barrier to timely project implementation. While ACER's monitoring identified supply chains as being a main cause of delays only for certain high-voltage direct current projects, about two thirds of the NRAs reported supply-chain constraints affecting electricity infrastructure[101]. The most commonly reported issues are long lead times

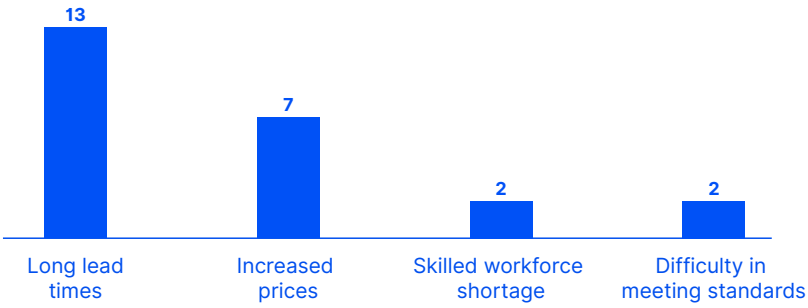
99 Other reasons also include supply chain issues and public acceptance. See also ACER PCI/PMI Monitoring Reports.

100 Under Regulation (EU) 2022/869, conventional natural gas infrastructure is no longer eligible for PCI/PMI status, except for two gas interconnections.

101 See Table 11 in the Annex and ACER and CEER guidance on electricity distribution network planning (2025).

and rising equipment cost (see Figure 15), partially driven by limited manufacturing capacity and uncertainties regarding technical standards – a finding also supported by external studies.[102] As grid-investment needs continue to grow, sudden increases in demand for equipment may create additional supply bottlenecks, meaning that even well-planned projects may face delays when supply chains are constrained. In relation to gas and hydrogen, supply-chain issues, while also reported by some NRAs, seem to be more isolated, which is consistent with gas' maturity and hydrogen's early development stage.

Figure 15: Types of reported supply-chain issues

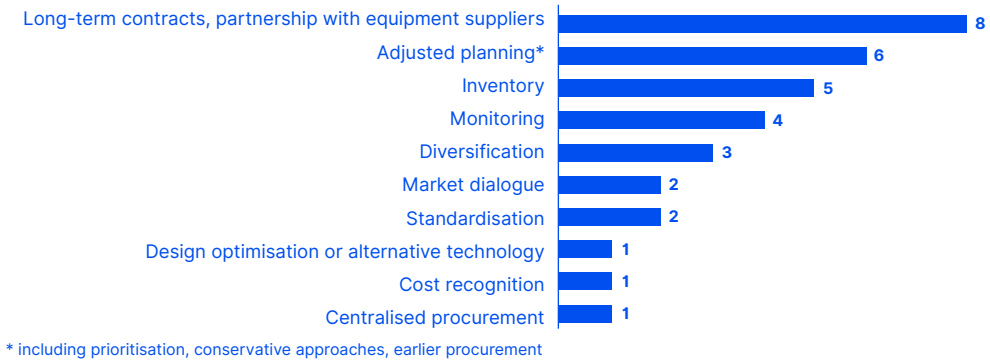


Source: ACER data collection from NRAs.

Note: 16 NRAs reported at least one type of supply chain issue.

90 Recognising supply chain challenges, project promoters and NRAs have introduced several measures to address them (see Figure 16). The most frequently applied tools include long term contracts, adjusted planning, technology inventory and close monitoring.

Figure 16: Measures to overcome supply-chain issues



Source: ACER data collection from NRAs.

Note: 18 NRAs reported measures in place to address supply-chain issues.

91 Timely grid expansion increasingly depends on the availability of key equipment and raw materials.[103] Growing reliance on these supplies creates new strategic dependencies and drives up investment costs, making secure, diversified and sustainable supply chains an integral part of European energy policy.

92 ACER finds that persistent project delays, driven mainly by permitting and supply-chain constraints beyond NRAs' remit, highlight the need for targeted EU-level action, including through the 2025 European grids package.

ACER-proposed actions to address the identified challenges

102 International Energy Agency, Building the future transmission grid, IEA Publications, 2025. This report finds that procurement times for critical grid components, such as power transformers and cables, have nearly doubled since 2021, reflecting strong global demand for transmission infrastructure and constrained manufacturing capacity.

103 For example, copper, aluminium, lithium, nickel, rare earth elements, power electronics and digital equipment.

1. Regulators should actively scrutinise delays and use their powers, where necessary.

NRAs must actively monitor project delays and take timely measures to ensure that the investment is carried out.104 Clear NRAs' approval mandates and forward- looking national development plans (NDPs) ensure market visibility, giving suppliers the certainty needed when planning production capacity and supply-chain investments. To accelerate implementation, NRAs can greenlight pre-construction and permitting activities prior to final construction approval, limiting potential 'sunk costs' to minor upfront expenses if project needs change.

- An EU-wide NRAs' mandate to approve investment in the NDPs would provide a signal of commitment and greater certainty about the future projects pipeline, while forward-looking national development contributes to better visibility of future investment needs.
- NRAs could consider greenlighting a project to progress permit granting and other preconstruction activities, without prejudice to the regulatory approval of the project construction (which comes as soon as the need is confirmed); such an approach would speed up project implementation, while limiting the risks of 'sunk costs' for society to (small) preconstruction costs, in the event the need is never confirmed.[105]

2. Permitting procedures should be accelerated and their performance closely monitored.

- Lengthy permitting procedures remain a major cause of delays and should be addressed through simpler, more predictable and time-bound procedures. The 2025 European grids package proposes a more harmonised EU framework for electricity-grid permitting, including common time limits and streamlined, digital procedures, with the aim of limiting permitting to two years in most cases and three years for the most complex projects. It also strengthens monitoring and reporting of permitting to improve transparency and help identify and address bottlenecks.[106]

3. Accelerated permitting should be complemented by early, meaningful public engagement.

Faster procedures alone may not prevent delays arising from local concerns, opposition or appeals. Project promoters' early and continuous engagement with affected communities and stakeholders can help identify concerns and potential impacts before key decisions are taken, improve project design and build trust. The pact for engagement under the EU grid action plan, co-signed by ACER, seeks to make such engagement more systematic, while the 2026 roadmap towards public engagement plans promotes a more structured approach throughout the project cycle and sharing of good practices.

2.2. Network scenario development needs to balance stability and adaptability

93 Robust scenarios form the foundation of network planning at the EU, national (transmission) and local (distribution) levels. They underpin long-term infrastructure investment decisions and must therefore provide credible and transparent representation of how the energy system could evolve under different assumptions. Scenarios that fail to adequately reflect technological, economic or policy developments can lead to inefficient investments or infrastructure that is either insufficient or underutilised.[107]

104 See Article 51(7) of Directive (EU) 2019/944.

105 ACER and CEER Position on anticipatory investments, ACER and CEER Position on anticipatory investments2024 (p.9)

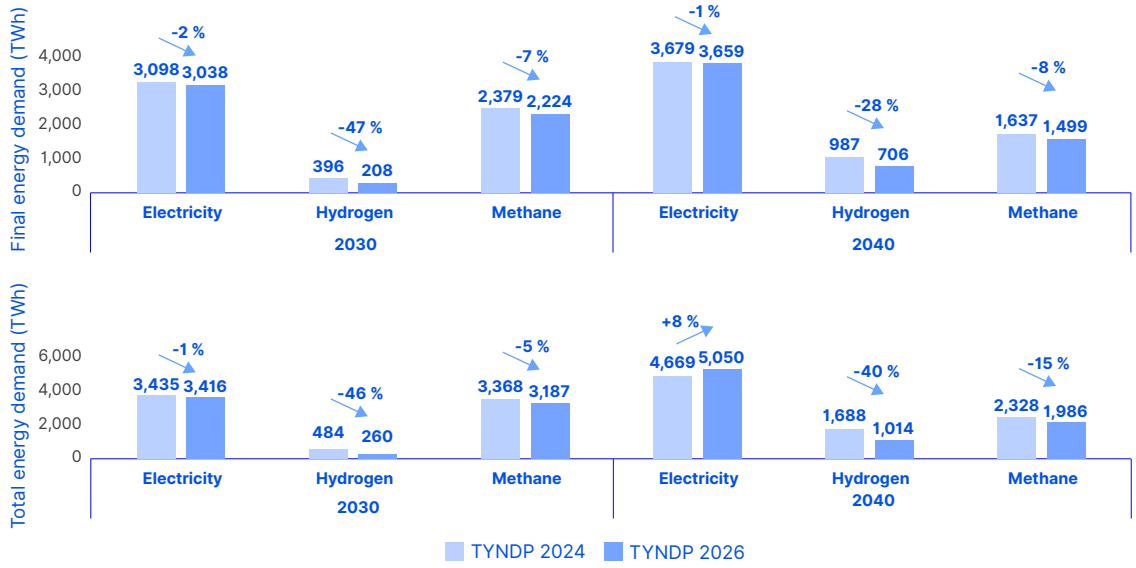
106 European Commission, Proposal for a revised Directive to accelerate permit-granting procedures, 2025.

107 Targeting investments at realistic future consumption is key to avoiding a cost spiralling effect; lower or higher-than-expected demand realisation leads to a significant swing in grid costs, as shown in 2024 ACER Infrastructure monitoring report (p. 6).

94 Scenario-based planning is well established for transmission networks at both the national and EU levels, as all relevant NDPs are based on one or more scenarios. However, its application in electricity distribution network planning remains inconsistent.[108]

95 The input parameter assumptions used in EU TYNDP scenario building show considerable volatility. Compared with the EU TYNDP 2024, the draft EU TYNDP 2026 scenarios project 46% lower hydrogen demand in 2030 and 40% lower in 2040, i.e. nearly halving demand assumptions between the two planning cycles. Methane demand assumptions are also revised downward, by 5% in 2030 and 15% in 2040, while electricity demand assumptions are broadly stable (1% lower) in 2030 and 8% higher in 2040 compared with the previous cycle (see Figure 17).

Figure 17: Energy demand in EU TYNDP 2026 and EU TYNDP 2024 scenarios per sector



Source: ENTSOs' TYNDP 2024 and TYNDP 2026 scenarios data (national trends scenario, 2030 and 2040 horizons).

Note: EU TYNDP 2026 NT scenarios assume less energy demand than EU TYNDP 2024. Final energy demand refers to energy consumed by end users, while total energy demand also includes energy used within the energy system for conversion processes, such as electricity used for hydrogen production or gas used for electricity power generation.

96 The EU-wide trends conceal large differences across Member States in the size and direction of revisions to the end-user demand assumptions between the scenarios of the two TYNDP cycles:[109]

- Despite broadly unchanged EU-wide electricity end-user demand assumptions for 2040, the figures rose substantially in the Netherlands (60 TWh), Spain (51 TWh), Sweden (33 TWh) and Finland (31 TWh), but fell sharply in Germany (-126 TWh).
- For hydrogen, the overall downward revision in 2040 demand assumptions reflects major cuts in some large markets. Assumed hydrogen end-user demand projections fell by around 61 TWh in Poland, 55 TWh in Germany and 49 TWh in France. In nine Member States, hydrogen demand assumptions increased, to the greatest extent in Romania (15 TWh), Sweden (14 TWh) and Slovakia (10 TWh).
- For methane, the downward revisions of EU-wide 2040 demand assumptions are driven by substantial reductions in Germany (-80 TWh), Poland (-27 TWh), Bulgaria (-22 TWh) and Czechia (-20 TWh). The largest upward revisions between the two cycles were recorded for Italy (25 TWh), the Netherlands (13 TWh) and Sweden (6 TWh).

108 ACER Opinion No 07/2025 on electricity NDPs; ACER No 17/2026 Opinion on gas and hydrogen NDPs; ACER and CEER guidance on distribution network planning, 2025.

109 Per-country demand of end users is presented on Figures 1, 2 and 3 in the Annex.

97 Recent developments also highlight demand uncertainties. Despite policy ambitions to accelerate the direct use of electricity, the electrification rate in the EU has remained slow, at around 23% over the past decade, according to a report by the Joint Research Centre.[110] Uncertainty around hydrogen demand is underpinned by 2026 ACER report on hydrogen markets, which finds a significant gap between projected electrolyser deployment and the capacity of committed projects. These developments raise uncertainty as to whether, and at what pace, the electricity demand growth assumed in network planning scenarios will materialise.

98 Overall, ACER's assessment shows substantial revisions in projected electricity, hydrogen and methane demand at the EU level, with even greater variation across Member States. While scenarios are inherently uncertain, factoring in political ambitions without matching them to observable trends or assessed potential carries risks, and may contribute to investments being rescheduled.[111] This highlights the need for network planning that can effectively adapt to new information while retaining a long-term perspective.

99 Beyond the uncertainty over the pace and trajectory of decarbonisation, changes in scenario assumptions may also be triggered by changes in the methodological framework itself. The draft EU TYNDP 2026 is the first planning cycle to apply the concept of a central scenario based on the latest national energy and climate plans, compliant with EU energy and climate targets, complemented by scenario variants, as proposed by ACER's TYNDP scenarios guidelines.

ACER-proposed actions to address the identified challenges

1. EU TYNDP scenario methodologies require further improvement.

ACER's recent Opinion on EU TYNDP 2026 scenarios identifies several areas for improvement regarding the methodological framework governing EU TYNDP scenario development. These include, among others, ensuring that scenarios credibly reflect pathways towards EU climate and energy targets, developing more divergent transition pathways, strengthening consistency in the scenario grid methodology and improving transparency and public scrutiny of the scenario-building process.

2. Scenarios development framework should be stable and grounded in current trends and projections.

ACER welcomes European Commission's 2025 proposal to revise the TEN-E Regulation, underlining the importance of a stable scenario development framework, introducing a central scenario for the EU TYNDPs, as also envisaged in ACER's Scenario Framework Guidelines. ACER recommends complementing this scenario with at least one additional scenario grounded in current trends and projections, which is to be regularly updated, to achieve a more informed assessment of infrastructure needs and facilitate prioritisation.

For hydrogen, given the particularly high level of uncertainty over future supply and demand, the stable scenario framework should be complemented by additional sensitivities testing a broader range of plausible hydrogen market developments. Such sensitivities, to be considered either when developing scenarios or directly as part of the infrastructure needs assessment, should be accounted for at the national and EU levels, to assess the robustness of infrastructure needs under different hydrogen demand and supply trajectories.[112]

110 Joint Research Centre, Overall strategic analysis of clean energy technology in the EU, 2026.

111 Where changing assumptions result in significant changes in identified infrastructure needs across planning cycles, investment decisions often get stalled, particularly where previously identified needs are reduced or no longer materialise. Such uncertainty may contribute to projects being rescheduled to a later date, as presented in Section 2.1 of the report.

112 ACER Opinion No 05/2025 on ENTSOG draft hydrogen infrastructure gaps identification report.

System operators should follow a forward-looking network planning approach, covering a horizon of at least 10 years.[113]

TSO and DSO NDPs and scenarios underpinning them should cover a time horizon of at least 10 years. TSOs should take at least the central EU TYNDP scenario into account when developing national scenarios. Furthermore, DSO should develop their scenarios considering national energy and climate plans and aligning them with scenarios of the relevant TSOs. All scenarios should be publicly available and easily accessible.

2.3. Identifying infrastructure needs in the energy transition

100 Infrastructure needs assessment is central to network planning: It identifies where network capacity is inadequate to meet evolving system needs under different scenarios and underpins the identification and prioritisation of measures to address those needs. Assessments are carried out at both the EU and the national level: EU TYNDPs provide an EU-wide view, while national and regional development plans capture national or regional constraints that the EU-wide assessment may not.

101 This section first compares the national transmission infrastructure needs assessment across the three energy carriers. It then examines the EU-wide electricity needs in greater depth,[114] focusing on how observed congestion relates to network investments and identified infrastructure needs and on how stable these needs are across successive EU TYNDP cycles.

102 When interpreting the relationship between congestion and infrastructure needs, their different time horizons need to be kept in mind. Congestion reflects recent system conditions, whereas identified infrastructure needs are forward-looking, and future congestion patterns may differ from those observed in recent years as the system evolves.

103 For reasons of simplification, the terms 'needs assessment' and 'infrastructure needs assessment' are used interchangeably in this section.

National assessment of transmission infrastructure needs complementing the EU-wide assessment

104 Figure 18 summarises national-level needs assessments for electricity, gas and hydrogen, including their purpose, methods and metrics. Overall, the application of these assessments remains limited and uneven across sectors and countries.[115]

105 Where performed, national electricity needs assessments are typically scenario-based and assess reinforcement options to address bottlenecks. Gas and hydrogen needs assessments often follow a bottom-up approach, building on customer and shipper demand[116], complemented by security-of-supply analysis and considering decarbonisation objectives.[117]

113 ACER and CEER Position on anticipatory investments, March 2024; ACER opinions No 07/2025 and No 05/2021 on electricity and No 17/2026 on gas and hydrogen NDPs; ACER and CEER guidance on distribution network planning, 2025.

114 Equivalent gas and hydrogen analysis was not carried out due to differences in data availability and nature at the EU level.

115 ACER Opinion No 17/2026 on gas and hydrogen NDPs; ACER Opinion No 07/2025 on electricity NDPs.

116 ACER finds increased efforts to understand future hydrogen demand. The use of non-binding market consultations increased from 8 instances in 2024 to 13 in 2026, while a binding hydrogen capacity booking procedure, carried out in Denmark, was reported in ACER's assessment for the first time (ACER Opinion No 17/2026 on gas and hydrogen NDPs).

117 These differences reflect the underlying market structures. While electricity networks facilitate economic exchanges between geographically dispersed supply and demand across Europe, gas networks largely transport externally sourced gas to consumption centres, making supply availability, import capacity and security of supply key planning considerations.

106 Electricity needs are usually expressed as additional transfer capacity at individual borders or specific reinforcement projects in the national planning instruments, while gas and hydrogen needs are generally defined by broader areas or in terms of required flows/capacities. National assessments, except some instances, report technical, project-related or indicative capacities rather than economically optimal targets and rarely use optimisation, unlike the EU TYNDP electricity needs assessment.[118]

107 Infrastructure needs identified at the EU and national levels often differ. About one third of countries with quantified electricity needs identified significant differences between the EU and national results, mainly due to different methodologies, assumptions and benefit definitions. These differences do not necessarily contradict each other; they address different objectives and planning questions, and should therefore be seen as complementary rather than directly comparable.

Figure 18: National approaches to assessing infrastructure needs

	Electricity	Gas	Hydrogen[119]
Implementation rate	53% of countries (including those building on the EU TYNDP identification of system needs)	48% of countries (+ 30% perform related activities without a formal concept or metrics)[120]	26% of countries (+ 17% perform related activities without a formal concept or metrics)
Objective	Relieve congestion, meet interconnection objectives, accommodate demand growth, integrate RES, facilitate cross-border exchange	Meet decarbonisation objectives, enable repurposing, ensure sufficient import capacity	
Typical assessment approach	Scenario-based market and network modelling	Primarily based on bottom-up demand assessments, often complemented by top-down assessments of security of supply, diversification and decarbonisation	
Typical presentation of needs	Additional transfer capacity (often cross-border capacity) or list of specific projects	Specific infrastructure requirements, expected flow/capacity needs or country-wide system requirements (cross-border capacities are often technical, project-related or indicative rather than model-derived 'optimal' target capacities)	

Source: ACER's 2024 and 2026 Opinions on NDPs for electricity, gas and hydrogen and 2026 data collection from NRAs.
Note: The table covers responses from 28 NRAs regarding electricity and 23 regarding gas and hydrogen.

Recent congestion, upcoming investments and future infrastructure needs

108 Congestion income should not be interpreted as evidence of additional infrastructure needs. The appropriate action depends on whether the underlying constraint is persistent and whether it can be addressed more efficiently through operational measures, the optimisation of existing infrastructure or other alternatives. Still, a high level of congestion income signals where additional cross-zonal capacity could reduce price differences and improve system efficiency. In this context, ACER analysed:

- whether project delivery is expected in countries where congestion income indicates

118 The Italian electricity needs assessment assesses economically efficient targets, while other national approaches focus on identifying bottlenecks and assessing specific reinforcement options. For gas and hydrogen, there appear to be no optimisation-based needs assessment approaches.

119 This assessment was conducted before the 5 August 2026 deadline for Member States to transpose Directive (EU) 2024/1788 into national law.

120 The figures relate to the assessment of needs within the network planning process and do not cover additional assessment, such as those arising under the Regulation (EU) 2017/459.

network bottlenecks; and

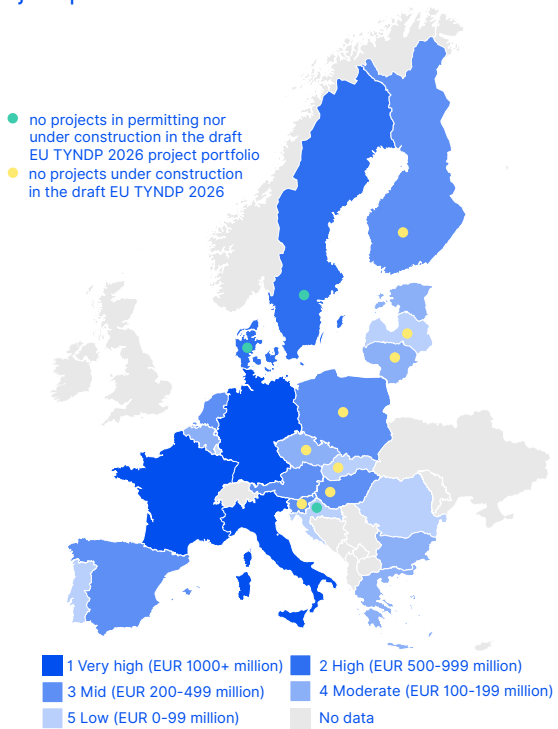
- whether identified infrastructure needs point to additional capacity at borders with persistent congestion.

Short-term response: is project delivery expected where networks are constrained?

109 Figure 19 illustrates the average yearly congestion income collected within the EU in 2023–2025,[121] highlighting Member States where EU TYNDP 2026's draft project portfolio[122] includes no transmission projects in permitting or under construction. It provides an indicative view of where transmission constraints, if persistent, may limit cross-border trade, while additional transmission capacity is not envisaged in the form of additional cross-border investments in the near-term.

110 ACER observes a broad alignment between observed network constraints and the project pipeline, with some notable outliers. According to the EU TYNDP 2026 draft project portfolio, around 40% of Member States have no transmission projects under construction, including some with significant congestion income. While all three Member States with average congestion income above EUR 1 billion have TYNDP projects under construction, neither of the two Member States with average congestion income between EUR 500 million and EUR 1 billion has any project under construction or in permitting in the EU TYNDP. Further, four of the seven Member States with congestion income ranging from EUR 200 million to EUR 500 million have no projects under construction.

Figure 19: Average annual congestion income by Member State from 2023 to 2025 and Member States with no transmission projects under construction or in permitting phase in the EU TYNDP 2026's draft project portfolio



Source: EU TYNDP 2026 draft project portfolio, data on congestion income collected from the NRAs.

Note: The analysis includes Member States that reported congestion income in 2023, 2024 and 2025. Congestion income reported as collected on internal bidding zone borders was excluded from the analysis.

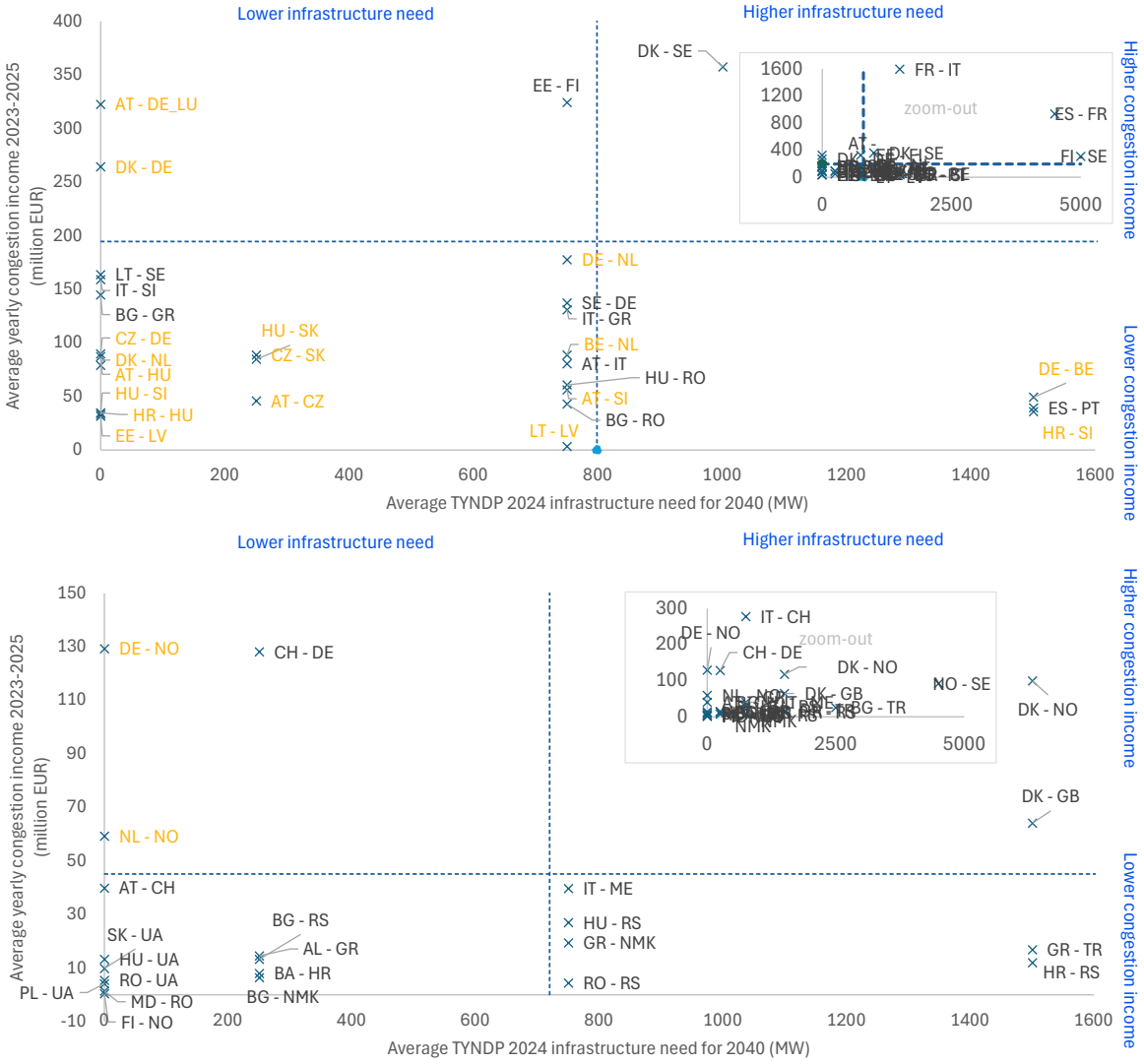
121 The analysis was conducted at an aggregated level (not at the border level), as for around half of the reporting Member States, at least some congestion income collected was not attributed to a specific border.

122 ENTSO-E, TYNDP 2026 draft project portfolio, published on 2 April 2026.

Long-term needs: do infrastructure needs (also) capture today's congestion?

111 In Figure 20, ACER mapped congestion income for 2023–2025 against cross-border electricity infrastructure needs identified in the EU TYNDP 2024 for 2040 to assess whether long-term planning identifies opportunities for additional capacity where persistent congestion has been observed in recent years.[123]

Figure 20: Congestion income and cross-border infrastructure needs identified in the EU TYNDP 2024 for 2040 (upper chart - borders with congestion income reported by both bordering countries; lower chart – borders with congestion income data reported by one bordering country)



Source: EU TYNDP 2024, data on congestion income provided by NRAs.

Note: Dashed lines indicate average congestion income and average infrastructure needs across the presented borders. They divide each figure into four above/below average quadrants. Orange labels indicate potentially underestimated congestion income due to its incomplete border-level allocation.

112 The analysis shows a mixed picture. Out of the 14 borders with above-average congestion income, 8 (about 60%) also show higher network capacity needs. By contrast, 34 out of 44 borders (about 80%) with below-average congestion income also show lower needs. This suggests that less congested borders are more consistently associated with lower identified needs, whereas the relationship is less systematic for more congested borders.

123 As infrastructure needs in the EU TYNDP 2024 are expressed as ranges, representative average range values were derived for the purpose of the comparison. Because congestion income is reported at bidding-zone borders, whereas EU TYNDP needs are primarily reported for country borders, the datasets were harmonised to enable comparison. Further methodological details are provided in the Annex.

113 The absence of a clear correlation between EU TYNDP infrastructure needs and observed congestion does not necessarily mean needs are inadequately captured.[124] Some borders with high congestion may already have planned projects to increase capacity. Some cross-border congestion may stem from internal constraints outside the current EU TYNDP needs assessment's scope. Furthermore, needs can also be driven by RES integration, flexibility, adequacy or resilience requirements, rather than congestion alone.

114 The comparison nevertheless points to need for greater transparency. While the expected impacts of infrastructure investments on congestion and price differentials are considered in the economic welfare assessment, the European Network of Transmission System Operators for Electricity's (ENTSO-E's) infrastructure needs report does not explicitly present these impacts (e.g. at the individual border level).

Stability of identified infrastructure needs across successive planning cycles

115 ACER examined border-specific electricity infrastructure needs reported in EU TYNDP 2022 and 2024 to assess their stability across planning cycles for the 2030 and 2040 horizons.

116 The overall magnitude of identified infrastructure needs is substantial in both. The TYNDP 2022 identified 88 GW of additional cross-border capacity needs by 2040 compared with the expected 2025 grid, while the TYNDP 2024 identified 108 GW compared to the expected 2030 grid.[125] These figures are equivalent to around 70% and 86%, respectively, of today's cross-border capacity.[126]

117 As shown in Figure 21, about half of the borders analysed show no change in identified needs between TYNDP 2022 and TYNDP 2024, indicating relatively stable needs across these planning cycles.[127] Where needs do change, shifts are often substantial at individual borders, with average increases of around 1.3 GW and average decreases of just below 1 GW across both horizons.[128]

124 Recent developments in the gas sector provide a clear illustration; Following exceptionally high gas congestion revenues of EUR 3.7 billion in 2022, during the energy crisis, such revenues fell to around EUR 140 million in 2023 and EUR 139 million in 2024 as demand declined, new infrastructure entered operation and system operation was optimised. Nevertheless, residual congestion remains concentrated at a limited number of highly utilised interconnection points, particularly in Southeast Europe (ACER, Capacity use and booking trends in European natural gas markets, 2025).

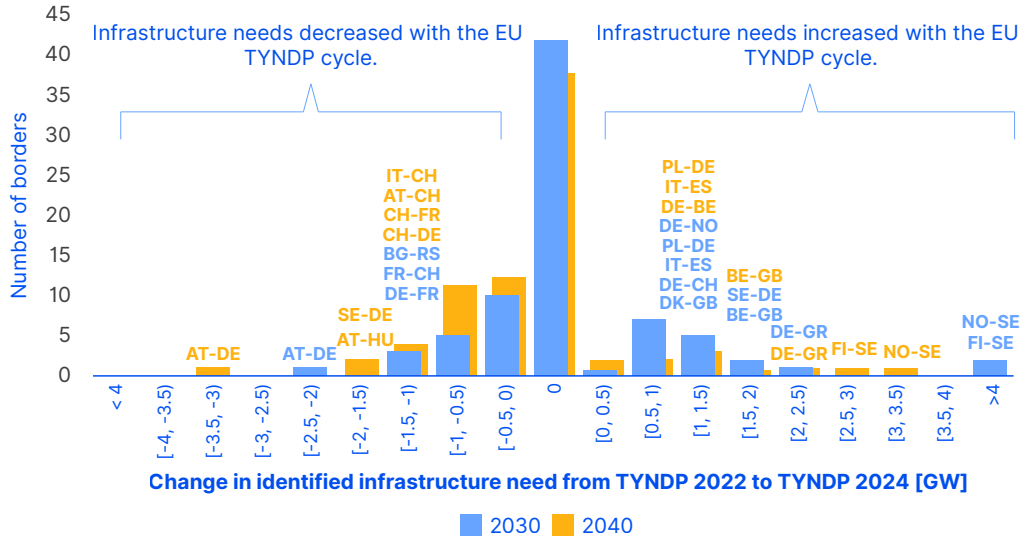
125 These aggregates are not directly comparable, because the two cycles use different starting grids, methodologies and underlying scenarios. Instead, they illustrate the significant scale of needs identified by ENTSO-E.

126 2025 ENTSO-E's Infrastructure gaps report reports 126 GW of total available cross-border transmission capacity in 2025.

127 These findings should be interpreted with caution, as TYNDP 2024 expresses needs as ranges rather than point estimates. These ranges are relatively wide (around 700 MW on average) and the comparison treats needs as unchanged whenever the EU TYNDP 2022 estimate falls within the corresponding EU TYNDP 2024 range.

128 For the 2030 horizon, the identified infrastructure needs increased and decreased at a similar number of borders. For the 2040 horizon, decreases are almost three times more frequent than increases. The largest increases exceeding 3 GW are observed at the Norway-Sweden and Finland-Sweden borders. The largest decreases are observed on the Austria-Germany border.

Figure 21: Infrastructure needs can change substantially between EU TYNDP cycles.



Source: EU TYNDP 2024, EU TYNDP 2022.

Note: Histogram of electricity infrastructure needs change from EU TYNDP 2022 to EU TYNDP 2024 for 2030 and 2040. The analysis covers borders that involve at least one Member State.

118 These changes should be interpreted in the light of differences between the two EU TYNDP cycles. Lower needs may reflect network reinforcements completed between assessments, while different electrification level assumptions, with large differences in the projections for individual Member States[129] and methodological changes[130] may also have affected the results.

119 The scale of the identified needs, their persistence at some borders and their variation at others underline the importance of effective regulatory oversight and prioritisation of investments based on their expected system benefits.

ACER-proposed actions to address identified challenges

1. Scenario-based infrastructure needs assessment should be systematically integrated into national energy network planning and projects in NDPs should be based on its results.[131]

Electricity national assessments should clearly distinguish between national and cross-border needs, supporting consistency and complementarity with EU-level assessments. Cross-zonal relevant projects in NDPs should be clearly linked to identified infrastructure needs among zones. Hydrogen national assessments should consider the outcomes of transparent and structured stakeholder engagement including market consultation and binding capacity bookings, to reflect emerging supply and demand and support a gradual network build-out.

129 See Section 2.2.

130 The EU TYNDP 2024 changed the starting grid approach, allowed offshore corridors to be considered alongside conventional reinforcements, incorporated hydrogen grid considerations into the market model and expressed infrastructure needs as ranges rather than point estimates, limiting direct comparison with previous cycles and interpretative value.

131 ACER Opinion No 17/2026 on gas and hydrogen NDPs; ACER Opinion No 07/2025 on electricity NDPs.

2. EU-wide infrastructure needs assessments should have a sufficiently stable framework[132] and they should be further improved.

ENTSO-E's electricity infrastructure needs assessment should be more transparent and informative to provide adequate investment signals and better support prioritisation[133] of investments, thereby addressing persistent constraints and delivering the greatest system-wide net benefits: (a) ENTSO-E's infrastructure needs reports should more clearly link identified needs to existing and future network constraints, explaining how addressing them is expected to affect congestion and price differentials observed at individual borders; (b) Electricity EU TYNDP and PCI processes should more clearly rank infrastructure gaps[134] according to their urgency and their impact on economic welfare;[135] (c) Electricity infrastructure needs should be presented as point estimates, when they are based on a single assessment;[136] (d) ENTSO-E's electricity infrastructure needs assessment should assess grid constraints with higher granularity.[137] An optimisation process (network expansion) should be considered to determine where optimal hydrogen cross-border capacities are needed. After optimal hydrogen network capacity needs are identified, the benefits of addressing these needs should be demonstrated.[138]

3. Effective regulatory scrutiny should ensure that investment decisions focus on well-substantiated needs that deliver the greatest system benefits.

NRAs should have powers and responsibilities to approve and amend transmission NDPs, challenge underlying assumptions, scrutinise identified infrastructure needs and priorities, and assess whether proposed projects adequately address them.[139] NRAs should also be given strong oversight of electricity distribution network development, including scrutiny powers over distribution network development plans (DNDPs) and, where DSOs are exempted from the obligation of preparing them, at least the authority to request relevant information and take necessary action.[140]

4. NDPs should provide a comprehensive and well-substantiated portfolio of projects addressing identified infrastructure needs.

Electricity NDPs should include non-TSO projects, subject to appropriate NRA assessments, to provide a robust basis for the EU TYNDP.[141] For gas and hydrogen NDPs, Member States should ensure the timely implementation of the requirements of the Directive (EU) 2024/1788, including among others, key decarbonisation projects, such as gas infrastructure decommissioning, hydrogen repurposing of gas infrastructure and biomethane integration. Gas NDPs should identify capacities that are still needed and those that are to be adapted, repurposed or progressively decommissioned,[142] and assess the appropriate timing of such action, considering the costs.

132 While methodologies should improve where this leads to better assessment, the framework should be sufficiently stable to distinguish actual changes in system needs from those resulting from methodological changes, providing a consistent basis for prioritisation and comparison across planning cycles.

133 Prioritisation is becoming increasingly important given the magnitude of identified needs, their persistence at some borders and changes at others, along with constraints on simultaneous infrastructure development (e.g. supply chain issues).

134 Infrastructure gap corresponds to the network capacity shortfall between the identified infrastructure needs and the capacity provided by existing and planned infrastructure projects.

135 This can be achieved, for example, by assessing the welfare loss magnitude and the rate at which they accumulate over time.

136 Presenting the identified infrastructure needs as ranges, as in ENTSO-E's EU TYNDP 2024, is of limited interpretative value unless the ranges reflect variation across multiple assessments, such as different scenarios.

137 The current focus on national borders is insufficient to provide adequate investment signals. See ACER Opinion No 4/2025 on the draft ENTSO-E TYNDP 2024 and infrastructure gaps identification report.

138 See ACER Opinion No 05/2025 on ENTSOG's draft hydrogen infrastructure gaps identification report.

139 This includes, inter alia, that the Member States should ensure timely and effective transposition and implementation of Directive (EU) 2024/1788 requirements for NRA oversight, approval and amendment of NDPs under Articles 55 and 78. See also ACER Opinion No 17/2026 on gas and hydrogen NDPs.

140 NRAs should also monitor the implementation of DNDPs and provide guidance on DNDPs at the national level, including, for example, a template and a set of requirements that all DNDPs are expected to meet. See also ACER and CEER guidance on distribution network planning, 2025.

141 ACER Opinion No 5/2021 on electricity NDPs.

142 In certain instances, future capacity needs may also entail gas capacity expansion, for example for security-of-supply reasons.

5. Transparent and inclusive network planning should support stakeholders' visibility of network development and effective contribution to the planning process.[143]

Draft NDPs and DNDPs should be subject to public consultation. Where appropriate, stakeholders should be consulted on the key building blocks of network planning, including scenarios, infrastructure needs assessments and cost-benefit analyses. Market consultations should be used to assess future hydrogen demand, and their results should inform the relevant NDPs.

NDPs and DNDPs should be published,[144] including key project information, as specified in relevant, previously issued ACER recommendations, as applicable to the respective sector.[145] Planned projects in electricity NDPs with cross-border and/or cross-zonal relevance should be flagged explicitly, by providing the relevant cross-border or cross-zonal capacity increase.

Electricity system operators should regularly monitor the current utilisation of the grid and forecast future utilisation through relevant studies and simulation. They should share information about existing and forecast spare capacity and the location of heavily congested areas and update it regularly.[146]

2.4. Grid enhancing technologies help meet network capacity needs efficiently

120 To meet future network capacity needs efficiently, the existing network should be used to its full potential before additional infrastructure is developed. This principle is strengthened in the proposed revision of the TEN-E Regulation requiring non-wire solutions to be considered with priority in network planning.

121 Grid-enhancing technologies (GETs) are part of such solutions,[147] allowing operators to increase the capacity, efficiency and controllability of existing infrastructure, enabling increased efficiency in system operation, capacity calculation and network planning.

122 In its Electricity 2026 report, the International Energy Agency compared a range of solutions for increasing grid capacity, with widely differing capacity gains and implementation times. Among GETs with short lead times (up to three years), dynamic line rating (DLR) offered particularly large gains, typically bringing 20-30%[148] more capacity than static ratings for around 90% of the year. Even larger potential gains were identified in ACER's recent assessment of electricity price spikes in South-East Europe which found that DLR could increase available capacity in capacity calculation by more than 50%.[149]

143 See ACER Opinion No 5/2021 and ACER Opinion No 7/2025 on electricity NDPs; ACER Opinion No 17/2026 on gas and hydrogen NDPs; ACER and CEER Guidance on distribution network planning, 2025; ACER DSO revenues report, 2026.

144 Beyond the NDP itself, all formal acts on the NDP, as applicable in each country (e.g. decisions, opinion, consistency analysis, monitoring), the stakeholders' comments on NDP public consultation and information about the treatment of comments should be published. See ACER Opinion No 05/2021 on electricity NDPs.

145 Requirements may differ across the sectors. See ACER Opinion No 7/2025 on electricity NDPs; ACER Opinion No 17/2026 on gas and hydrogen NDPs; ACER and CEER guidance on distribution network planning, 2025.

146 See also ACER DSO revenues report, 2026.

147 While GETs often provide faster or less costly alternatives to traditional network reinforcement, not all are low-CAPEX or strictly non-wire solutions. Some technologies, such as flexible AC transmission system devices (FACTS) or phase-shifting transformers (PSTs), may require significant investment, while others, such as high-temperature low-sag (HTLS) conductors, increase the transfer capacity of existing lines without requiring new transmission corridors.

148 The Czech NRA reported up to 30% capacity gains of the DLR.

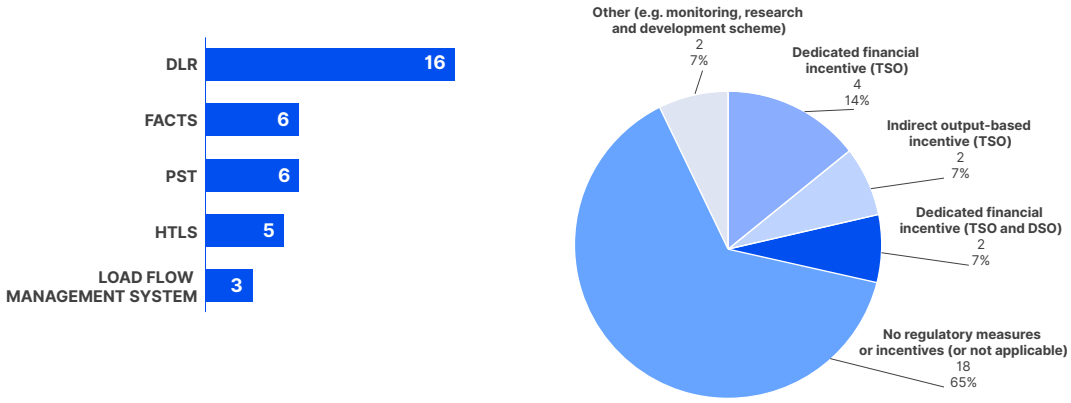
149 This assessment also revealed uneven uptake of DLR across TSOs and across different uses. While some TSOs apply dynamic ratings extensively, others continue to rely largely on static or seasonal ratings. Furthermore, operational deployment of DLR is not always followed by its integration into capacity calculation and ACER considered (in particular for the central and southeast Europe) that, once GETs are deployed and used in the real-time process, the additional capacity they provide should, where appropriate, be reflected in capacity calculation.

123 GETs appear to be widely used in network planning (see Figure 22). About 80% of responding NRAs report that GETs are considered in national planning. In almost all of these cases, TSOs include some GET projects in their NDPs. DLR was the most frequently reported lower-CAPEX technology, although its short lead time sometimes limits its inclusion in the NDP. ACER welcomes that some TSOs go further by incorporating capacity gains from relatively lower-CAPEX GETs directly into planning assumptions, for example by reflecting the capacity gains from high-temperature-low-sag (HTLS) conductors or DLR.

124 At the EU level, investment-intensive GETs such as phase shifting transformers (PSTs) or flexible AC transmission system devices (FACTS) are generally included in the EU TYNDP as projects and reflected in planning assumptions. However, the capacity gains from relatively low-CAPEX GETs do not yet appear to be considered in the EU TYNDP. Where the capacity of such technologies are not included, this can result in wrongly estimated infrastructure needs.

125 Specific regulatory incentives or measures for the deployment of GETs remain limited across the EU. Around two-thirds of the NRAs report no measures to encourage TSOs to develop and use GETs. Where measures exist, they are mainly financial incentives, in some instances combined with output-based incentives or other measures. To support greater uptake, ACER recently proposed a set of transmission performance indicators to monitor the application of GETs.[150]

Figure 22: Inclusion of GETs (as projects) in TSO's NDPs (left) and use of regulatory measures or incentives to develop and use GETs or more broadly non-CAPEX solutions (right)



Source: ACER's data collection from NRAs.

ACER-proposed actions to address the identified challenges

1. ACER welcomes the European Commission's proposal to give priority consideration to non-wire solutions in network planning[151].

In this context, electricity TSOs and ENTSO-E should systematically consider GETs in their respective network planning processes and prioritise where they can cost-effectively increase the capacity of existing infrastructure and reduce or defer the need for conventional reinforcement. In particular: (1) the capacity gains from GETs should be reflected in planning, so that future needs consider the capacity unlocked from existing infrastructure; (2) the needs assessment should distinguish between needs that can be addressed through more efficient use of the existing network and those that require additional other conventional infrastructure; (3) GETs should be included as projects in electricity NDPs, where meaningful in view of their deployment lead times.

150 ACER, Smart grid output key performance indicators for electricity transmissionACER's Smart grid output KPIs for electricity transmission, 2026.

151 European Commission, Proposed revision of the TEN-E Regulation, 2025.

2. Regulators should ensure regulatory frameworks with appropriate incentives for TSOs to deploy and use, where appropriate, cost-effective GETs.

CAPEX–OPEX neutrality should be strengthened to ensure that system operators are financially indifferent between alternative solutions and select the most efficient technical and operational measures.152 Where NRAs identify a CAPEX-bias in the regulatory framework, they should address it through appropriate measures which may include output-based approaches.[153]

Application of rigid (non-adjustable) CAPEX, OPEX and/or TOTEX caps made irrespective of the value of additional investment would bring to society should be avoided. Possibility of ex-ante or ex-post adjustments154 should be allowed in justified cases.[155]

2.5. Growing interdependence requires closer cooperation among system operators

126 As the EU advances with decarbonisation, interdependencies between electricity, gas and hydrogen are growing, with investment needs in each sector increasingly influenced by developments in the others.[156] Cross-sectoral coordination and EU-wide optimisation in infrastructure investment could deliver hundreds of billions of euro in savings over a 20-year period, according to an external study.[157]

127 Coordinated planning relies on aligned scenarios and national needs assessments as well as systematic consideration of innovative solutions and non-wire alternatives alongside conventional reinforcement. Recent ACER assessments show that the current level of cross-sectorial planning remains limited, focusing mainly on joint scenario development.[158]

128 At the EU level, efforts towards greater cross-sectoral integration are expected to be reflected in the development of the interlinked model as requested by Regulation (EU) 2022/869. However, despite some progress, ACER found the level of cross-sectoral consistency and integration in the EU infrastructure planning, including input data and methodologies, limited, and the EU interlinked modelling framework providing a modest basis for cross-sectoral considerations in the TYNDPs.[159]

152 In their previous reports, ACER and CEER stressed that CAPEX-bias is a common drawback of traditional cost-based regulation, whereby CAPEX is remunerated more favourably than OPEX. ACER Position on incentivising smart investments to improve the efficient use of electricity transmission assets, 2021; CEER Report on incentives in regulatory frameworks with a focus on OPEX/CAPEX neutrality, 2025.

153 ACER and CEER identified the following approaches or a mix of them to address CAPEX-bias in electricity grid investments: TOTEX-based approaches including partial OPEX capitalisation; an efficiency requirement for CAPEX (in addition to existing ones for OPEX) or TOTEX; TOTEX benchmarking for the identification of efficiently incurred cost; output-based regulation, including shared cost-saving mechanisms, with caps on reward/ penalty levels.

154 The adjustments should be set carefully (e.g. after cost evaluation, including benchmarking of the set of indicators) to avoid burdening network users with the risk of inaccurate cost forecasts, especially concerning proven technologies.

155 ACER DSO revenues report, 2026.

156 For example, since electricity is needed to produce hydrogen, while hydrogen can provide storage and flexibility to the electricity system, coordinated development can deliver efficiency gains, whereas uncoordinated development risks stranded assets. Similarly, the premature decommissioning of gas infrastructure without adequate substitution of its energy and security-of-supply functions could undermine security of supply.

157 Agora Europe, Designing energy infrastructure for a climate-neutral Europe, 2025 (p. 16).

158 EU TYNDP scenarios are jointly developed for electricity, gas and hydrogen since 2018. Similar approaches at national level remain uneven. In Denmark, Germany, Italy, Lithuania, the Netherlands and Spain, gas and electricity TSOs jointly develop at least some scenarios for the electricity and gas sectors, typically also covering hydrogen. In Belgium, the joint scenario exercise is driven by the electricity TSO and the HNO, also coordinating with the gas TSO. Austria, France, Hungary and Romania reported joint scenarios for gas and hydrogen network planning, but not for electricity planning. There is currently no integrated electricity-gas-hydrogen network development plan at EU or national level and the EU law includes no such requirement. A coordinated long-term plan for electricity, gas and hydrogen is planned to be introduced in United Kingdom in 2028, with the underlying methodology already approved by Ofgem. See ACER Opinion No 17/2026 on gas and hydrogen NDPs; ACER Opinion No 01/2026 on the integrated model for electricity, gas and hydrogen infrastructure planning.

159 While further constraining the comparability and reliability of findings across different reports. See ACER Opinion No 01/2026 on the integrated model for electricity, gas and hydrogen infrastructure planning.

129 Recent ACER assessments show that coordination and alignment within the energy carrier sector's planning are improving but remain uneven across sectors and Member States. Transmission networks are typically planned via a single NDP prepared for each of the electricity and gas sectors.[160] Coordination at the distribution level is generally less advanced, with most DSOs preparing individual plans and cooperating rather in the scenario development process, data exchange and joint assessments. Coordination between TSOs and DSOs exists in most Member States, particularly in electricity, although more integrated approaches remain limited.[161]

130 Alignment between EU-wide and national planning has gradually been strengthening through greater consistency in frequency and methodologies. However, practices vary and further alignment is still needed in planning cycles, scenarios, project assessment, transparency and coordination among network operators.[162] ACER welcomes that ENTSO-E and EU DSO Entity recently launched a TSO-DSO cooperation platform and issued a planning collaboration report.

ACER-proposed actions to address the identified challenges

1. System operators should closely coordinate across planning levels to support timely and cost-effective infrastructure development[163].

This includes better alignment of national NDPs with the EU TYNDP in terms of timing (i.e. biennial cycle), methodologies and data[164], and closer TSO-DSO and DSO-DSO coordination at the national level. Such alignment and coordination ensure that investment decisions are based on robust, up-to-date and consistent information.

2. Transmission infrastructure development in the EU should evolve towards multi-sectoral planning, encompassing electricity, gas and hydrogen at EU and, preferably, national levels[165].

ACER promotes further work towards multi-sectoral planning, encompassing electricity, gas and hydrogen — at the EU and, preferably, at national levels — starting with greater consistency in assumptions and methodologies across sectors, and a high-level cross-sectoral needs assessment, while gradually moving towards deeper integration. At the national level, stronger coordination in scenarios, needs assessments and investment decisions is needed where developments in one sector significantly affect another. At the EU level, integration should be more ambitious, as parallel and loosely coordinated sectoral models should progressively develop into a more coherent and systematically interlinked modelling framework[166].

160 Exceptions are Austria (electricity) and France (gas), where two TSOs prepare separate NDPs.

161 See ACER Opinion No 07/2025 on electricity NDPs (annex); ACER Opinion No 17/2026 on gas and hydrogen NDPs, (annex); ACER and CEER guidance on electricity distribution network planning, 2025 (annex); ACER, DSO revenues report, 2026.

162 In this context, timely and effective transposition and implementation of the relevant requirements of Directive (EU) 2024/1788 are key, in particular for gas and hydrogen network planning.

163 See ACER Opinion No 17/2026 on gas and hydrogen NDPs; ACER Opinion No 07/2025 on electricity NDPs ; ACER and CEER Guidance on distribution network planning, 2025; ACER DSO revenues report, 2026.

164 Achieving this alignment requires improvements to the EU TYNDP process, particularly the timely development of scenarios.

165 ACER and CEER, Position paper on challenges of the future electricity system, 2024; ACER Opinion No 01/2026 on the integrated model for electricity, gas and hydrogen infrastructure planning.

166 Including transmission infrastructure, along with storage facilities, LNG and electrolysers.

2.6. Planning outputs should be up to date

131 ACER has repeatedly observed delays in key EU TYNDP-related deliverables. Since 2018, EU TYNDP scenarios and the draft electricity and gas EU TYNDPs have been increasingly delayed, by an average of 3 months and 9 months, respectively.[167] Within-the-two-year EU TYNDP cycle to complete scenarios, system needs assessment and projects' cost-benefit analysis within the legally required time frames, and the sequential nature of the planning process adds to overall delays. At the same time, they also point to the growing complexity of the planning process and the need to focus methodological improvements on areas that provide the greatest added value.

132 Delays in the EU TYNDP planning process can undermine the timeliness and quality of PCI/PMI selection by reducing the time available for stakeholder consultation on cost-benefit analysis results and regulatory scrutiny. Furthermore, project information is already, on average, 16 months old when the draft EU TYNDP is published, increasing the risk that project selection is based on outdated information. Timely EU TYNDP delivery is therefore essential for meaningful stakeholder engagement, sound investment decisions and an effective PCI/PMI selection process.

133 Delays may also negatively affect national NDPs, as TSOs and NRAs often rely on EU TYNDP results.

ACER proposed actions to address the identified challenges

1. EU TYNDP planning outputs should be kept up to date and delivered on time.[168]

A more flexible EU TYNDP process, decoupling infrastructure needs identification and project-specific cost benefit analysis, could support timely delivery of key assessments reflecting more up-to-date scenarios and project information, while ensuring methodological developments.

2. The legal framework should strike a better balance between ensuring the regular availability of the EU TYNDP and allowing sufficient time for a robust and proportionate planning process.

167 The longest delay was observed for the gas draft EU TYNDP 2024, at 13 months. More detailed information on the timelines of key EU TYNDP deliverables is available in Table 1 in the Annex.

168 ACER Position on improving and simplifying the legal framework on European grids, 2025.

3. How to ensure affordable grid financing

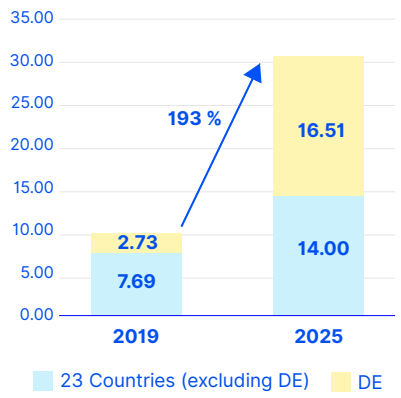
3.1. Different investment cost trends across the energy carriers

134 This chapter explores the changes of annual investment costs across the energy carriers between 2019 and 2025. The values refer to total capital expenditures (CAPEX); extending beyond network developments. Since the analysis is limited to two selected years, these findings on individual countries may not translate to any trend and year-by-year results could show some volatility due to country specific circumstances (e.g. lack of large capital investments in a particular year). Given substantial differences in the size and characteristics of national energy systems, absolute investment levels should not be interpreted as a measure of investment intensity.

Electricity investments are ramping up

135 As shown in Figure 23, the ramp up of investment is already ongoing. ACER finds that compared with 2019, the annual capital expenditures of TSOs increased by 193% in 2025 (from about EUR 10.4 billion to about EUR 30.5 billion, with more than EUR 13 billion increase in Germany alone), and a further increase is expected in 2030 based on the data available to NRAs.[169] Earlier, ACER had found similar results for DSO capital expenditures, which experienced a 51% increase (from about EUR 23.5 billion to EUR 35.3 billion) in 2024 compared to 2021.[170]

Figure 23: Annual total electricity TSO capital expenditures covering 24 countries (billion EUR).



Source: ACER data collection from NRAs.

Note: for some countries, 2024 CAPEX data were used as proxies for 2025 CAPEX data.

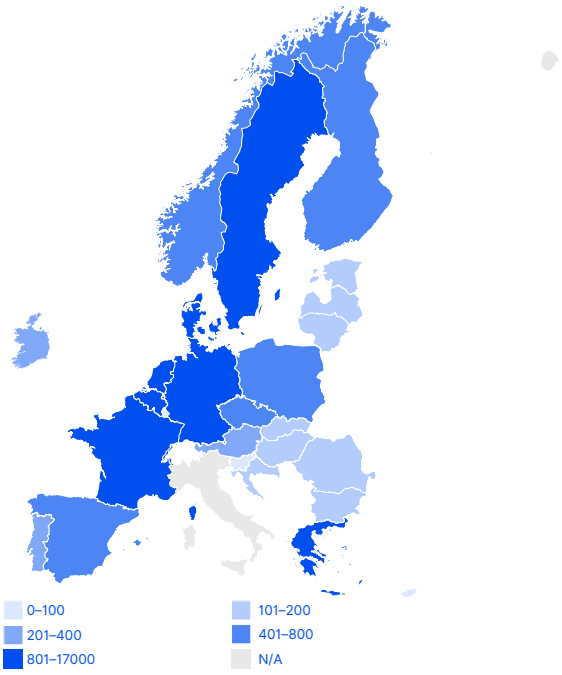
136 Figure 24 shows total electricity CAPEX by country in 2025. While the normalisation of these figures was not applied in this report, the figure highlights that electricity investments are placing considerable pressure on electricity costs in Europe, although its extent differs across countries and regions.[171]

169 For more than third of the countries, TSOs' expected investment costs in 2030 are not available.

170 ACER, DSO revenues report, 2026

171 Of the 26 countries for which data is available, 8 (31%) invested more than EUR 0.5 billion. Within this group, 5 countries exceeded EUR 1 billion of capital expenditures: Greece (EUR 1.0 billion), Belgium (EUR 1.4 billion), the Netherlands (EUR 2 billion), France (EUR 3.0 billion), and Germany (EUR 16.5 billion). The remaining 18 countries (69%), most of them in central-eastern Europe, invested less than EUR 0.5 billion, with 6 of these 18 countries in the EUR 350–500 million range.

Figure 24: Total electricity TSO CAPEX (investment) in 2025 per country (million EUR).



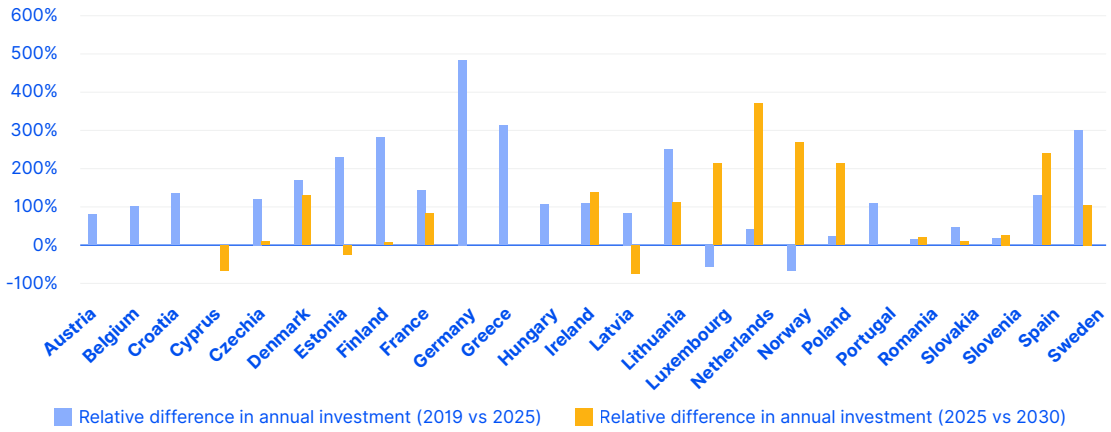
Source: ACER data collection from NRAs.

Note: For some countries, 2024 CAPEX data were used as proxies for the 2025 CAPEX data.

137 Figure 25 shows that about 90% of the countries (22 out of 24) experienced an increase in annual investment in 2025 compared to 2019 (a 155% increase on average), with the highest increase in Germany, Greece, and Sweden (505%, 327%, and 310% respectively). Annual investment decreased in Luxembourg and Norway,[172] by 59% and 69%, respectively.

138 When looking ahead, a similar trend is observed; 15 out of 18 countries (83%) estimate higher investment in 2030 than in 2025 (on average by 134%). The Netherlands expects the largest increase, with investment projected to reach almost five times its 2025 level. Estonia, Latvia and Cyprus are the only Member States projecting a decrease. ACER underlines that these estimates should be assessed with caution, given the repeated delays to and rescheduling of transmission projects, highlighted in the previous chapter.

Figure 25: Annual electricity TSO CAPEX (investment) differences in relative terms (2019 and 2025; 2025 and 2030).



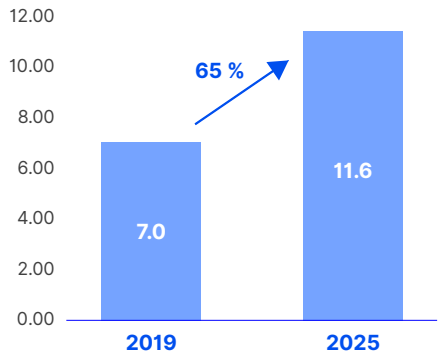
Source: ACER data collection from NRAs.

Note: For some countries, 2024 CAPEX data were used as proxies for the 2025 CAPEX data.

172 For Norway, 2019 marked a year of high investment levels due to the ongoing construction of two high-voltage direct current submarine power interconnectors, i.e. Nordlink to Germany and North Sea Link to the United Kingdom. The numbers reported are capitalised investments.

139 As illustrated in Figure 26, the annual total electricity grid operational expenditures (OPEX), i.e. costs of maintaining and operating the network, including losses and system services, rose by 65% between 2019 and 2025, from EUR 7.0 billion in 2019 to EUR 11.6 billion. This growth trend occurred in 19 out of 21 countries. Luxembourg recorded a more than threefold increase, followed by Ireland, the Netherlands, Lithuania and Sweden where OPEX more than doubled. The two exceptions are Austria and Cyprus, where OPEX decreased by approximately one third and less than one fifth respectively.

Figure 26: Annual total electricity TSO operating expenditures covering 21 countries (billion EUR).

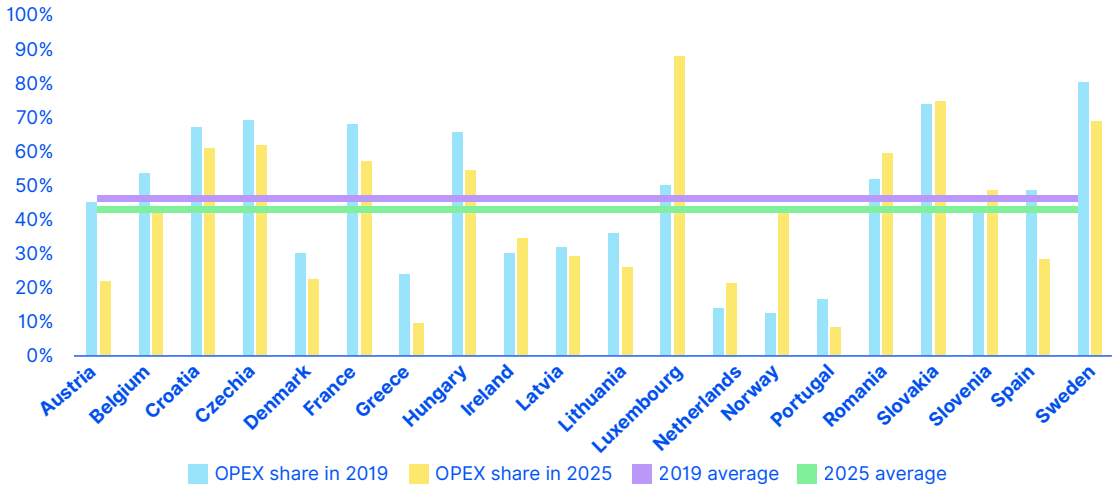


Source: ACER data collection from NRAs.

Note: For some countries, 2024 OPEX data were used as proxies for the 2025 OPEX data.

140 The aggregated CAPEX and OPEX split across 20 countries (where both CAPEX and OPEX figures were provided for both years) remained constant between 2019 and 2025, with the OPEX share of total expenditures marginally decreasing from 50% in 2019 to 47% in 2025. However, as shown in Figure 27, significant differences emerge at the country level. In 11 out of 20 countries, the change in the OPEX share did not exceed 20%, while in the remaining 9 countries, changes ranged from a 57% decrease to a 237% increase.

Figure 27: Share of OPEX within total electricity TSO expenditure in 2019 and 2025 per country and EU average (%).



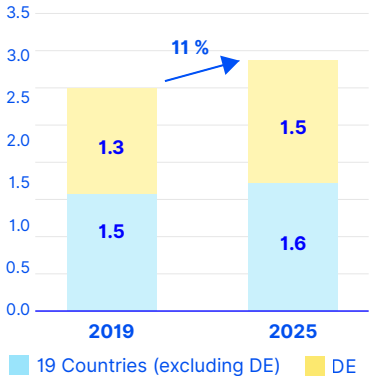
Source: ACER data collection from NRAs.

Note: For some countries, 2024 data were used as proxies for the 2025 data.

Gas TSO investments remain broadly stable

141 Gas investments present a remarkably different picture compared to electricity. As shown in Figure 28, annual gas TSO capital expenditures across 20 EU countries increased by 11% between 2019 and 2025, from about EUR 2.8 billion to over EUR 3.1 billion. Available NRA data suggest a further moderate increase by 2030, although projections are available for only 12 countries (see Annex).

Figure 28: Annual total gas TSO capital expenditures covering 20 countries (billion EUR).

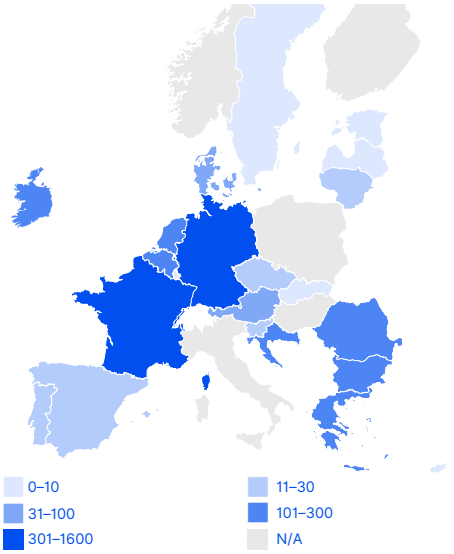


Source: ACER data collection from NRAs.

Note: For some countries, 2024 CAPEX data were used as proxies for the 2025 CAPEX data.

142 Figure 29 shows TSO CAPEX by country in 2025. Investment is highly concentrated, with Germany accounting for about half of total reported investment at EUR 1.5 billion, followed by France (EUR 0.4 billion), Belgium and Romania (around EUR 0.2 billion each), while the remaining 16 countries reported lower investment activity.

Figure 29: Total gas TSO CAPEX (investment) in 2025 per country (million EUR).

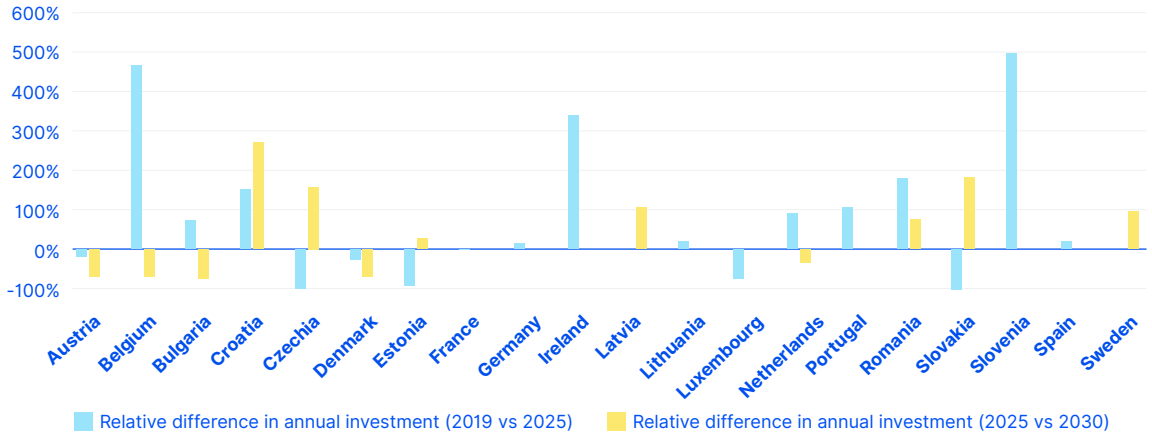


Source: ACER data collection from NRAs.

Note: For some countries 2024 CAPEX data were used as proxies for the 2025 CAPEX data.

143 As shown in Figure 30, developments at the national level are more heterogeneous than the aggregate trend suggests. Between 2019 and 2025, annual investment increased in most countries (12 of the 20) countries, with Slovenia, Belgium and Ireland recording the largest increases albeit from comparatively low starting levels. Investment remained constant in one country and decreased in seven. The outlook to 2030 is more mixed. Seven out of 12 countries project an increase compared to 2025, with the largest relative rise (more than threefold) expected in Croatia, while five countries project a decline.

Figure 30: Annual gas TSO CAPEX (investment) differences in relative terms (2019 vs 2025; 2025 vs 2030).



Source: ACER data collection from NRAs.

Note: For some countries, 2024 CAPEX data were used as proxies for the 2025 CAPEX data.

Hydrogen investments are still at an early stage

144 Hydrogen infrastructure remained the smallest investment category and experienced only very localised growth. The current hydrogen developments seem to focus on exporting renewable generated hydrogen to Germany, including the Nordic-Baltic corridor, West-to-East (from Denmark, the Netherlands and Belgium) and South-to-North (from Spain via France and from Tunesia via Italy and Austria). However, these plans have not been realised yet.

145 Based on NRA data, no investments in regulated hydrogen infrastructure were recorded in 2019. In 2025, only Belgium and Spain reported investments of about EUR 80 million and EUR 10 million, respectively. More recently, hydrogen investments have also been commissioned or are underway in Germany and the Netherlands.

146 Looking ahead, four countries provided estimates for regulated hydrogen investments up to 2030. Austria and Denmark project annual investment of just under EUR 200 million per year up to 2030, followed by Sweden at around EUR 100 million and Estonia EUR 3 million.[173]

Conclusions on investment trends

147 The comparison of annual CAPEX across electricity, gas and hydrogen infrastructure reveals distinct investment trends in Europe, reflecting different underlying drivers and maturity:

- The strong increase in annual electricity TSO and DSO CAPEX across Europe reflects the key role of electricity networks in the decarbonisation of the European energy system. It is driven by the rapid expansion of renewable electricity generation, growing electrification, the need to upgrade ageing networks and expand cross-border interconnections and rising equipment and manufacturing costs, as highlighted in ACER's 2026 unit investment cost report[174] and other sector studies.[175]

173 Denmark reported one investment of EUR 930 million in the 2026–2030 period, aiming to develop the first Danish transmission infrastructure.

174 ACER's 2026 assessment on unit investment costs revealed that infrastructure costs across most infrastructure categories have increased significantly faster than inflation over the past decade. Since 2018, annual costs increases have exceeded inflation by more than 6% on average. Overall, costs appear to have risen by around 50% from 2018 to 2024, with some components, such as high-voltage direct current converters, likely experiencing even steeper cost increases. The dominant cost component in traditional network expansion projects is typically installation and civil works, accounting for between one half and three quarters of total investment costs, while materials and manufacturing account for about one quarter (ACER, Energy infrastructure unit investment cost indicators, 2026).

175 2025 IEA Report on building the future transmission grid indicates a 75% increase of price of power transformers since 2019.

- The more modest increase observed in annual gas TSO CAPEX reflects the maturity of gas networks in Europe and suggests that investment needs are not widespread across Europe. Instead, investment is increasingly shaped by specific needs to adapt the gas system to a changing security-of-supply reality and the evolving role of natural gas in decarbonising the energy system, as described in Section 1.
- Hydrogen CAPEX remained marginal and very localised, with investments focused on the early deployment of dedicated hydrogen pipelines, import infrastructure and the conversion of selected gas assets to support future hydrogen transport.

148 **Transparency on investment trends is key.** ACER notes that in some countries data on annual CAPEX and OPEX were not available to the NRAs. For hydrogen infrastructure, this may reflect the lack of relevant NRA mandates.[176] Regulation (EU) 2024/1789 introduced new transparency requirements including the publication of OPEX and CAPEX and the composition of the TSO's regulatory asset base.

ACER proposed actions to address the identified challenges:

1. Information on capital and operational expenditures is essential

Information on actual annual CAPEX and OPEX and their forecasts on system level support informed decision-making by policymakers, legislators, NRAs and manufacturers. They also help assess whether legislative and regulatory frameworks remain appropriate and anticipate network tariff impacts.

TSOs and DSOs should strive to provide estimations of the network costs, including CAPEX and OPEX, for at least the next five years,[177] where possible separately per each year, and make this information publicly available.

3.2. Observations on impacts on grid costs

149 As presented briefly in Section 1, the energy transition creates different cost-recovery challenges in different sectors. These include cost pressures from rising investment volumes or a declining use base, along with questions around sharing costs and risks between countries, current and future users and, where relevant, taxpayers. This section examines these impacts in more detail and recalls some action to address them.

Financing electricity grids puts increasing pressure on network charges

150 While increasing electricity demand mitigates the impact,[178] the investment wave in electricity inevitably puts upward pressure on network tariffs and, ultimately, electricity costs for consumers and industry. Based on sector estimates for expected grid investment, grid costs for consumers are projected to rise by 50-100% by 2050 relative to current levels under different investments scenario.[179]

151 As shown, in Figure 31, network costs are already a substantial component of electricity bills. Between 2023 and 2025, they increased by 14% for households and 38% for industry, reaching 29% and 12% of their respective electricity bills in 2025. These shares are expected to increase further as network investment accelerates.

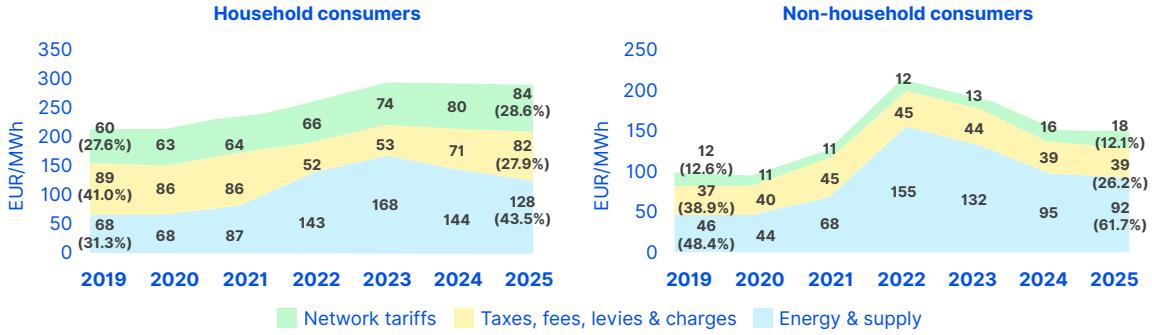
176 ACER Opinion No 17/2026 on gas and hydrogen NDPs.

177 Alignments with the regulatory periods and/or network planning horizons may be considered when setting the time horizon for the required cost estimations. Some requirements may differ across the sectors, including due to applicable EU legislation.

178 This is, higher consumption helps absorb rising grid costs and can keep unit tariff increases down.

179 ACER, Electricity infrastructure development to support a competitive and sustainable energy system, 2024 (p.5).

Figure 31: Breakdown of the weighted average final electricity bill for households and industrial consumers in the EU-27 between 2019 and 2025.



Source: Eurostat data on electricity prices components for household consumers.

Recovering gas network costs becomes more challenging as utilisation declines

152 Gas network infrastructure has historically been designed to accommodate substantial cross-border flows bringing remote gas to European consumption centres. In recent years, network development served multiple objectives (i.e. increasing capacity, either in new cross-border connections or to accommodate changing flows, increasing security of supply, and maintaining system capacity in the context of an aging network). Cost recovery from national and cross-border users occurs by charging tariffs for the use of the gas system at points where gas enters or exits.

153 Cost sharing between countries happened through CBCA; its relevance for gas infrastructure is declining rapidly as new unabated natural gas infrastructure has been phased out of the TEN-E framework (Regulation (EU) 2022/869). However, like electricity, most of the CBCA decisions for gas have been based on the 'territorial principle', i.e. without much redistribution of costs based on benefits.[180]

154 ITC mechanisms are rare in gas; where they are in place they enable redistributing costs among TSOs where some TSOs can't recover their costs directly by means of tariffs, e.g. multiple TSOs within a single entry-exit zone.[181]

155 Despite network investment being stable and mature, gas tariffs in the EU are experiencing upward pressure, increasing on average by 40% between gas year 2020/2021 and gas year 2024/2025 (see Figure 32). This upward pressure stems from reduced gas consumption (down by 16% in 2025 compared to the pre-crisis average) alongside changing supply and transport patterns (e.g. rising eastward flows and reduced capacity use for westbound flows from Russia).[182] Both reduced consumption and decreased utilisation affected Member States unevenly, with systems built for the purpose of transporting large volumes of gas from Russia being particularly impacted.

180 Based on the ACER's CBCA monitoring (2025), between 2014 and 2024, CAPEX transfers to non-hosting countries were included in three gas CBCA decisions, amounting to a total of around EUR 120 million. In addition, ACER, based on CBCA data, estimates about EUR 55 million was transferred between hosting countries, deviating from the territorial principle, representing 2% of the total CAPEX of EUR 2.8 billion for gas interconnections without offshore section.

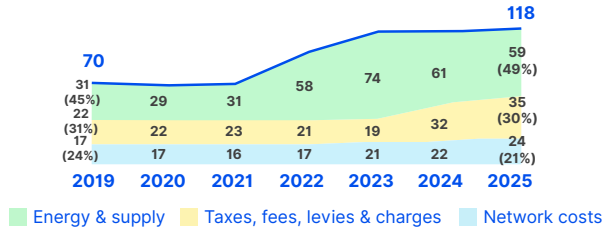
181 The NRAs of Estonia, Finland and Latvia agreed to strengthen their cooperation by creating the FinEstLat market, which became operational on 1 January 2020 and has a single natural gas transmission entry-exit system with specific characteristics.

182 ACER, Key developments in EU electricity and gas markets, 2026 (p. 14); ACER, Key developments in European gas wholesale markets Gas winter season 2025-2026, 2026 (p. 30).

156 The reduction of gas consumption impacts the consumer base to recover costs. The average use of gas networks is expected to decline further as final consumption decreases, in line with decarbonisation efforts, and despite the gradual increase of low-carbon gases, and this will lead to a reduction in capacity bookings. The changing import patterns impact the proportions of the costs recovered at when supplying end-users and when transporting gas across networks. This is relevant as some cross-border infrastructure had been developed with the objective of recovering these costs when transporting gas across borders. The changes in supply and transport patters may lead to these costs being born by domestic end-users.

157 The extent to which gas infrastructure is used, including its repurposed parts to support the emerging hydrogen market, will influence the long-term evolution of tariffs. At the same time, challenges remain in ensuring gas network adequacy for a shrinking gas sector that may still be required to meet power peak demand periods.[183] This could be even more challenging in cases where despite annual demand decreasing in a Member State, the increasing peak demand due to electrification requires additional investment. Recovering a fair share of the network costs from peak-only network users booking short-term capacity also poses a new challenge for regulators.

Figure 32: Evolution of household gas price components across EU-27, 2019 and 2025 (EUR/MWh).



Source: ACER calculations based on Eurostat dataset nrg_pc_202_c, all bands, nominal unit prices and share of total price.

158 The transition therefore raises a broader question about how the costs of maintaining an adequate and resilient gas network should be distributed between current and remaining future users as utilisation declines. ACER's earlier study on the future regulation of natural gas networks explored different approaches to managing stranded-cost and cost-recovery risks, including their allocation between network operators, network users and public budgets184. While the study does not represent an ACER position on a preferred model, the underlying issue becomes increasingly relevant where fewer users may otherwise have to bear the residual costs of infrastructure built for substantially higher levels of use.

159 Regulators have several instruments that can help manage the costs of maintaining, adapting, repurposing or decommissioning gas infrastructure and allocating them between network users. Besides the tariff structures, robust regulatory scrutiny185 helps to focus on justified and efficient infrastructure investment while cost and cost-efficiency comparisons[186] increase transparency and promote efficient and decarbonised gas systems. ACER has been tasked to complete an efficiency comparison (AEC) of gas TSOs under Article 19 of Regulation (EU) 2024/1789. The AEC will be used to provide efficiency scores across TSOs, which NRAs should take into account when setting the revenue regulation of TSOs. In addition, it will measure the existing practice across TSOs to replace and extend the asset lives of fully depreciated assets as well as to remove assets from the networks (i.e. decommissioning or repurposing). Over time, the benchmark will allow assessing the response of TSOs to changes in demand and network utilisation, identifying best practices.

183 ACER, Key developments in EU electricity and gas markets, 2026 (p.48).

184 See Study on the Future regulatory decisions on natural gas: repurposing, decommissioning and reinvestments, 2022.

185 ACER's review of gas and hydrogen NDPs showed that NRA scrutiny can materially affect investment decisions. For example, in Germany the review led to rejection of individual projects and to an amendment request.

186 See ACER efficiency comparison of EU gas TSOs and Article 3 of Regulation (EU) 2024/1787 on the reduction of methane emissions in the energy sector.

Hydrogen infrastructure

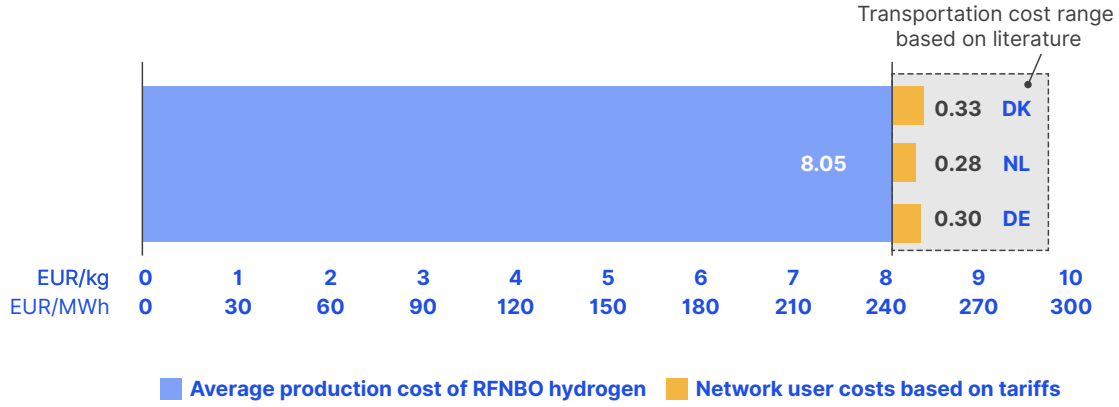
160 Hydrogen requires a different financing approach because infrastructure investment may precede the emergence of a sufficiently large network-user base. Financing frameworks therefore need to address two related questions: how cross-border infrastructure costs, benefits and their risks should be allocated between countries, and how infrastructure costs and their risks should be distributed between early and future users.

161 An effective regulatory framework must strike a careful balance between supporting justified early infrastructure and long-term sustainability. Firstly, it means enabling financing for early-stage projects without imposing disproportionate costs on initial users, which could otherwise stifle demand. At the same time, the framework must preserve strong incentives for efficient investment. Lastly, it must mitigate the transfer of underutilisation risk to future network users or public finances.

162 Early national approaches illustrate how different instruments can be combined[187] to provide some predictability to early network users. Nevertheless, future tariff levels remain sensitive to actual costs and utilisation. In Figure 33, the regulated or ramp-up tariffs for hydrogen in Denmark, Germany and the Netherlands appear modest compared to total delivery costs. They also fall at the lower end of estimated pipeline transport costs (EUR 0.1–1.8/kg).[188]

163 However, the tariff levels may need to be adjusted if expected demand and network utilisation do not materialise.

Figure 33: Hydrogen transportation tariffs in Denmark, Germany and the Netherlands compared with the levelized cost of renewable hydrogen (EUR/kg and EUR/MWh).



Source: ACER Monitoring report on European hydrogen markets, 2025 (p. 55).

Note: The depicted network user costs are estimations of a combined entry and exit capacity tariff in each country calculated for an assumed capacity factor of 5,000 hours.

164 The emerging EU framework combines ex-ante CBCA with transitional tariff flexibility. The framework additionally foresees the option to remove tariffs at interconnection points, accompanying this measure with an ITC:

- Entry–exit tariffs: Under Regulation (EU) 2024/1789, hydrogen networks will operate as entry-exit systems, becoming mandatory default structures by 1 January 2033. At cross-border interconnection points, NRAs may decide to set zero network access tariffs or offer discounts during the transition period up to 31 December 2032 to stimulate market roll-out.

187 In Denmark, the framework combines revenue-cap regulation and an inter-temporal cost allocation model with state-backed operating support of up to EUR 1.4 billion over 30 years and long-term capacity commitments from prospective network users. Germany has similarly introduced a ramp-up tariff based on inter-temporal cost allocation, while the Netherlands has established a uniform network tariff until 2033. ACER's Hydrogen Market Monitoring Report (2025) notes that the Dutch NRA has warned that revised cost estimates and demand assumptions could imply a more than tenfold tariff increase in the absence of additional measures such as State-backed inter-temporal cost allocation. See ACM's Market report on hydrogen transport tariffs from the perspective of the hydrogen market, 2025.

188 ACER Report on European hydrogen markets, 2025.

- CBCA: Hydrogen infrastructure benefits from a dual CBCA regime governed by Article 16 of Regulation (EU) 2022/869 for PCIs/PMIs and complemented by Article 59 of Directive (EU) 2024/1788 for non-PCI interconnectors or zero-tariff cross-border points. ACER's monitoring recorded one formal hydrogen CBCA decision[189] to date due to the early stage of market development.
- Negotiated financial compensation scheme: Where no tariffs are charged at cross-border points, Article 59 of Directive (EU) 2024/1788 requires hydrogen network operators (from 1 January 2033) to negotiate a financial compensation system for cross-border infrastructure.

165 To prevent prohibitive initial tariffs for early adopters, Member States may allow inter-temporal cost allocation (ICA),[190] transferring early capital costs to future user bases, and using state support and guarantees. Spreading cost recovery over time can reduce the burden on early users but does not eliminate utilisation risk: where expected future demand does not materialise, remaining costs still need to be recovered. Depending on the investment framework this risk will be allocated to users, network operators or, where guarantees are provided, public budgets.

166 Further EU-level de-risking options are now being explored[191]. A joint European Network of Network Operators for Hydrogen (ENNOH) and European Network of Transmission System Operators for Gas (ENTSOG) report on de-risking hydrogen infrastructure examines several mechanisms. It proposes, among other options, an ICA-based mechanism combined with a European guarantee and an alternative based on long-term capacity bookings through a European special-purpose vehicle. While these proposals provide useful input into the policy discussion, they require careful assessment of their added value, the contribution to market development and the risk they transfer to public budgets.

ACER proposed actions to address the identified challenges

1. Cost impact of the investment ramp up in electricity grids can be contained.

The cost impact of the increasing investments in electricity grids can be mitigated through better planning and stronger scrutiny of investment decisions. When an investment need is overestimated and the consumption growth falls short of the anticipated level, the grid bill for users rises due to fewer users to share the investment costs (and the investment benefits associated with that consumption are missed). Similarly, insufficient scrutiny of project costs can translate directly into higher network bills for consumers.

Cost-recovery mechanisms and regulatory asset management should be forward-looking alongside evolving network utilisation approaches to allocate costs fairly across users over time:[192] (1) In justified cases revenues partially based on planned expenditure, combined with an ex-post adjustment based on economically efficient real values should be allowed. (2) Remuneration schemes should avoid inter-temporal re-distribution of costs by pushing network costs remuneration to the far future unless such re-distribution is justified (e.g. by corresponding network utilisation patterns).

189 It pertains to the Hydrogen interconnector Denmark-Germany (ACER Monitoring report on European hydrogen markets, 2026.)

190 ICA transfers costs over time to be recovered when demand materialises. The financing gap due to this cost transfer (imposing higher risk of stranded assets due to very high demand uncertainty) are in most cases mainly funded by governments. Transit countries are not willing to take on this risk as their projects rely on demand in other countries and those countries are not willing to overtake this risk as they can't control how the infrastructure is managed (costs, operation, etc.). For example, the German KfW which finances ICA only cover domestic network costs and are not able to include any cost from a CBCA.

191 ENNOH and ENTSOG, De-Risking Options for EU Hydrogen Infrastructure, 2026.

192 ACER, DSO revenues report, 2026

2. Gas network cost recovery require a structured and adaptive framework.

To sustain adequate gas system capacity amid a declining user base, it is critical that costs are recovered through a structured and adaptive framework. This requires efficient asset management, where strategies such as extending the service life of fully depreciated assets, repurposing or decommissioning of underused infrastructure, and making targeted investments – such as replacing ageing assets, facilitating biomethane integration, and reducing methane emissions – play a central role. At the same time, any adjustments to cost-recovery mechanisms, including capacity tariffs, must be designed to manage user costs fairly, ensuring equitable burden-sharing while safeguarding the system's financial stability.

3. Gradual approach to hydrogen infrastructure is the most appropriate.

A gradual approach to hydrogen infrastructure, based on realistic demand forecasts, prioritising strategic infrastructure projects that can support market emergence, is most appropriate. Hydrogen infrastructure financing requires complementary, carefully designed mechanisms addressing both the geographical allocation of cross-border infrastructure costs and risks and their distribution between early and future users. Existing national approaches demonstrate the potential of ICA,[193] regulated ramp-up tariffs, state guarantees and long-term bookings, while possible additional EU-level de-risking mechanisms remain under assessment. Any instrument to facilitate infrastructure investment should limit the transfer of utilisation risk to future network users. In addition, these mechanisms should provide transparency on the risks transferred to national budgets.

Member States should progress with the transposition of the amended Renewable Energy Directive into the national legislation to ensure regulatory certainty and accelerate market development as well as of the Hydrogen and Decarbonised Gas Market package to facilitate proper planning and deployment of infrastructure and the creation of a well-functioning hydrogen market.[194]

3.3. Use of congestion income

167 This section reviews the evolution of the total congestion income available in the EU and its allocation to the different objectives. The EU total congestion income covers 23 Member States, as Cyprus, Ireland, Luxembourg and Malta have no congestion income collected at EU borders in their territory.

168 Congestion income (CI) arising from a scarcity of cross-zonal capacity is an important source of financing for investments that address congestion. Under Article 19(2) of Regulation (EU) 2019/943, revenues resulting from the allocation of cross-zonal capacity shall be used to fulfil specific objectives ('priority objectives'[195]):

> (a) guaranteeing the actual availability of the allocated capacity, including firmness compensation;
>
> (b) maintaining or increasing cross-zonal capacities through optimisation of the usage of existing interconnectors by means of coordinated remedial action, where applicable, or covering costs resulting from network investment that is relevant to reducing interconnector congestion; or

193 ACER Recommendation No 02/2025 on inter-temporal cost allocation for hydrogen networks and its annex provides practical advice to support the roll-out of hydrogen networks and ensure fair cost-sharing over the long term; identifies key investment risks in hydrogen infrastructure and suggests ways to address them; it offers high-level guidance on designing fair and effective ICA mechanisms to support the development of the hydrogen market and emphasises that ICA should be carefully designed and form part of a broader financing and risk-mitigation framework.

194 ACER Report on European hydrogen markets, 2025.

195 The use of congestion income in accordance with these objectives is subject to a methodology proposed by the TSOs (the UCI methodology), which was approved by ACER in December 2020. See ACER Decision No 38/2020 on the methodology for the use of congestion and its Annexes.

(c) compensation of offshore renewable electricity generators affected by reduced access to interconnected markets.[196]

169 For the analysis, the total 'congestion income available' is calculated as the sum of the following categories, as reported by each NRA to ACER:

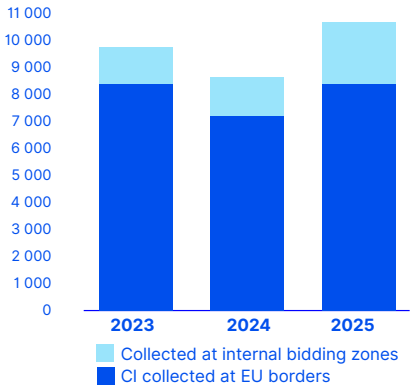
- 'CI collected': CI generated at EU–EU borders including amounts generated at internal bidding zones (which can account for high figures). The CI collected arises from allocating capacity in the single day-ahead, intraday and balancing frames and from long-term transmission rights.
- 'CI stored in a separate internal account line': Amounts of CI generated at EU–EU or internal bidding zones borders from previous years that were not used and were thus stored in a separate internal account line for future use (account balance at the beginning of the reporting year). The CI stored in a separate internal account line may be overstated in some countries, as it includes CI generated across all borders where it was not possible to distinguish between EU–EU and EU-non-EU borders.
- 'Adjustment': Applicable country-specific adjustments due to provisional data.

Congestion income is experiencing growth

170 Congestion income generated in the single day-ahead market in 2025 is almost seven times as high as it was in 2019, rising from EUR 1.33 billion to EUR 9.21 billion.[197] A similar upward trend is observed for total congestion income available, although this evolution should be interpreted in the context of changes to the congestion income reporting recommendation in 2022[198] and the exceptionally high levels recorded during the 2022–2023 energy crisis, which have been carried over in the internal accounts in subsequent years.

171 In 2025, congestion income collected in the EU increased by 24% compared with 2024. Figure 34 presents its evolution, distinguishing between amounts generated at EU borders and those at internal bidding zone borders. Figure 35 provides a closer look at congestion income collected at the six bidding zone borders where the cumulative amounts collected exceeded or neared EUR 1 billion over the past three years.

Figure 34: Evolution of congestion income (CI) collected at the EU level, 2023-2025 (million EUR).



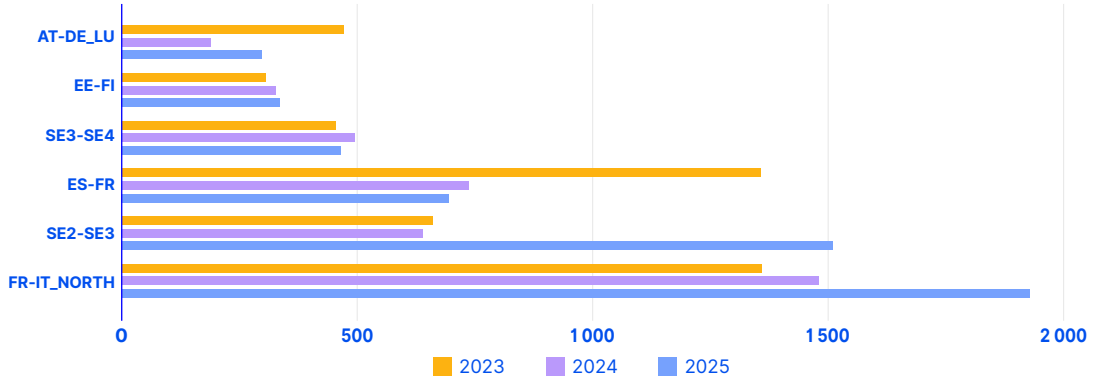
Source: ACER data collection from NRAs.

196 Article 19(2)(c) refers to compensating offshore renewable electricity generation plant operators in an offshore bidding zone directly connected to two or more bidding zones where access to interconnected markets has been reduced in such a way that it results in the offshore renewable electricity generation plant operator not being able to export its electricity generation capability to the market and, where relevant, in a corresponding price decrease in the offshore bidding zone compared to without-capacity reductions.

197 These figures refer to the congestion income generated in the single day-ahead coupling, calculated as the scheduled commercial exchange multiplied by the price spread on each bigging zone border in the 2026 ACER electricity market integration monitoring report (p. 45). They do not represent the full amount of congestion income, excluding congestion income amounts that may arise from long-term transmission rights and intraday and balancing timeframes.

198 ACER Recommendation No 01/2020 on NRAs reporting on the use of congestion income was updated by ACER Recommendation No 01/2022.

Figure 35: EU bidding zone borders with highest congestion income (CI) collected, 2023–2025 (million EUR).

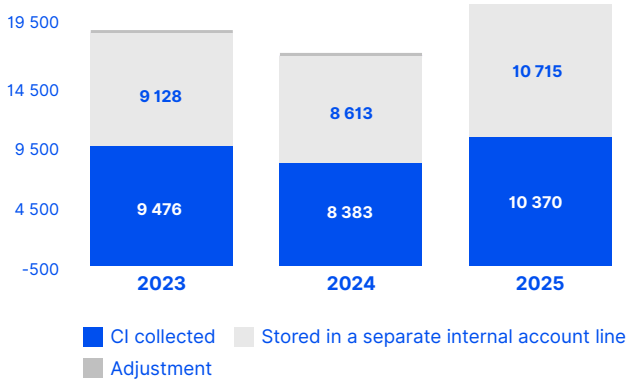


Source: ACER data collection from NRAs.

Notes: CI collected at each bidding zone border was calculated for each year by summing the reported CI collected for that border by each Member State. In some Member States (FR, DE, PL, IT, SI, AT, HR, LV, BE, NL, HU, SK, LT, CZ, FI), part of the CI collected could not be attributed to a specific bidding zone border and thus these (frequently limited) amounts have been excluded from the analysis. For further details, see Table 8 in the Annex.

172 CI stored in a separate internal account line rose by approximately 24% year-on-year, from EUR 8.61 billion to EUR 10.71 billion. Combined with the CI collected, this increase contributed to an overall rise in the total CI available at the EU level. As illustrated in Figure 36, the total CI available in the EU climbed to EUR 21.08 billion, a near 24% increase compared with 2024.

Figure 36: Evolution of congestion income (CI) available at the EU level, 2023–2025 (million EUR).

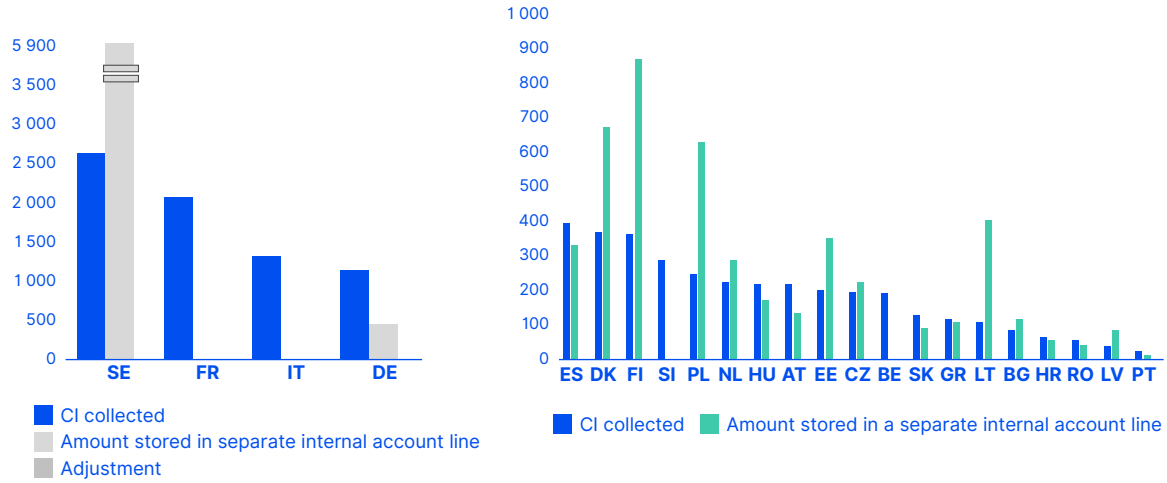


Source: ACER data collection from NRAs.

Notes: The figure represents the total CI available at the EU level calculated by summing the CI collected and the CI stored in a separate internal account line at the beginning of the year in each Member State. Where applicable, Member State-specific adjustments due to provisional data have been taken into account. Congestion income stored in a separate internal account may include amounts from non-EU borders. In these cases, a distinction between congestion income originating at EU–EU borders and congestion income at non-EU borders was not possible. Further details are provided in Table 12 of the Annex.

173 At the Member State level, the data reveals significant disparities in the CI amounts. As shown in Figure 37, in 2025, Sweden, France, Italy and Germany recorded the highest CI collected, each exceeding EUR 1 billion and collectively accounting for around 68% of the EU total. In contrast, Portugal, Latvia, Romania and Croatia each collected less than EUR 60 million, collectively accounting for around 1.5% of the EU total.

Figure 37: Congestion income (CI) available in 2025 by Member State (million EUR).



Source: ACER data collection from NRAs.

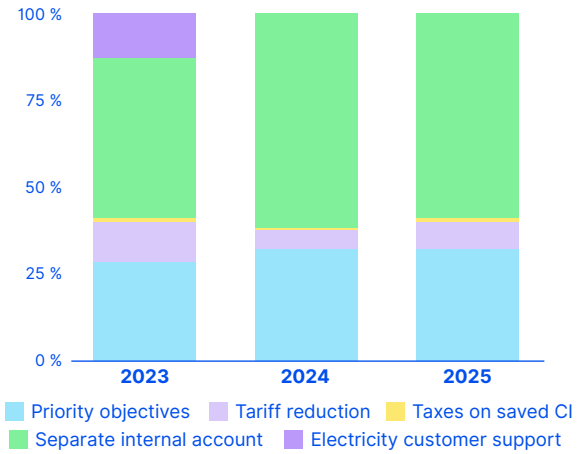
Notes: 'CI collected' refers to CI collected at EU–EU borders, including internal bidding zones, which can account for high figures. The data are presented in two charts to facilitate visualisation; the scales differ by an order of magnitude. For Finland, Sweden and Denmark, CI stored in separate internal accounts at the beginning of 2025 includes all borders, as EU–EU and non-EU amounts could not be distinguished. For Sweden, CI collected excludes amounts allocated to Baltic Cable AB.

174 CI stored in separate internal accounts at the beginning of 2025 accounted for more than half of the CI available in 10 out of 23 Member States. The highest amounts of CI stored were found in Sweden, Finland, Denmark[199], and Poland. In Belgium, France, Italy and Slovenia, no CI was stored in separate internal account lines at the beginning of 2025.

Use of congestion income in the EU: expenditures and carry-over

175 At the EU level, the use of congestion income in 2025 remained broadly unchanged compared with 2024 (see Figure 38). Most congestion income remained in separate internal accounts (around EUR 12.46 billion), while 32% was spent on priority objectives (EUR 6.79 billion) and 8% was used to reduce tariffs (EUR 1.69 billion).

Figure 38: Expenditure and carry-over evolution at the EU level (%).



Source: ACER data collection from NRAs.

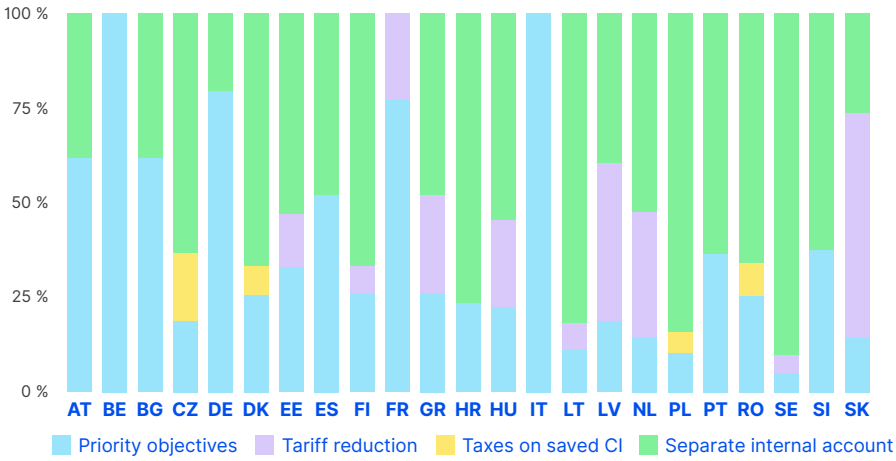
Note: For the reporting of data for year 2025, the 'Surplus CI spent for electricity customer support' was removed from the data collection as the derogation introduced pursuant to Article 9 of Council Regulation (EU) 2022/1854 on an emergency intervention to address high energy prices is no longer in application. The aggregate amounts also include Member States whose expenditure figures incorporate CI generated across all borders, as it was not possible to distinguish CI from EU–EU borders (for example, Finland, Sweden and Denmark in 2025).

199 The amount stored in a separate internal account line reported in Sweden, Finland and Denmark includes CI from all, not only EU–EU, borders, as a distinction between EU–EU and non-EU borders was not possible.

176 Figure 39 presents how CI available was used and carried over by category and Member State in 2025. In half of the Member States, the majority of CI available was stored in separate internal accounts – accounting for over 80% of total expenditures in Sweden, Poland and Lithuania.

177 Around 30% of Member States (7 out of 23) allocated more than half of their CI available to priority objectives. Belgium and Italy allocated 100% of their CI to these priorities, followed by Germany and France, which allocated around 80%. Around 48% of Member States (11 out of 23) used CI for tariff reduction, with Slovenia (62%) and Slovakia (59%) recording the highest shares.

Figure 39: Expenditure and carry-over breakdown in 2025 per Member State (%).

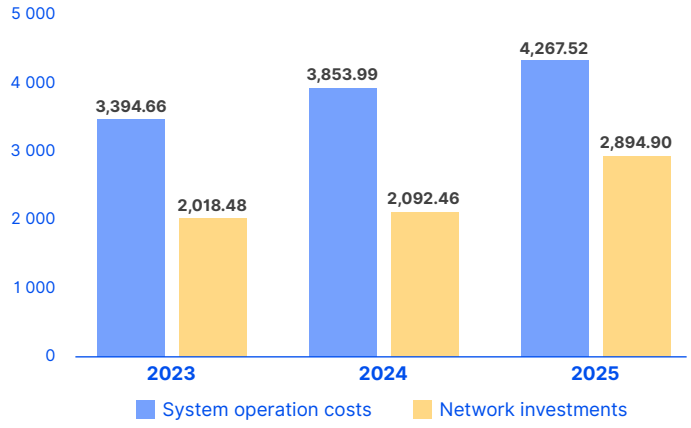


Source: ACER data collection from NRAs.

Notes: For the reporting of data for year 2025, the 'Surplus CI spent for electricity customer support' was removed from the data as the derogation introduced pursuant to Article 9 of Council Regulation (EU) 2022/1854 on an emergency intervention to address high energy prices is no longer in application. In Sweden, Finland and Denmark the expenditure amounts include congestion income generated from all borders as distinguishing CI only from EU–EU borders was not possible. CI allocated to Baltic Cable AB is not included in these figures.

178 To fulfil the priority objectives (a) and (b) of Article 19 (2) of Regulation (EU) 2019/943, TSOs shall allocate CI to one or more cost categories specified in the use of congestion income (UCI) methodology[200]. This methodology groups costs into 'system operation costs' and 'costs resulting from network investments that are relevant to congestion'. As illustrated in Figure 40, expenditure on priority objectives has risen in recent years. System operation costs remain the largest expenditure category, increasing modestly in 2025, by 11% compared with 2024. In contrast, expenditure on costs resulting from network investments grew significantly, rising by 38%.

Figure 40: Evolution of priority objectives expenditure (million EUR).



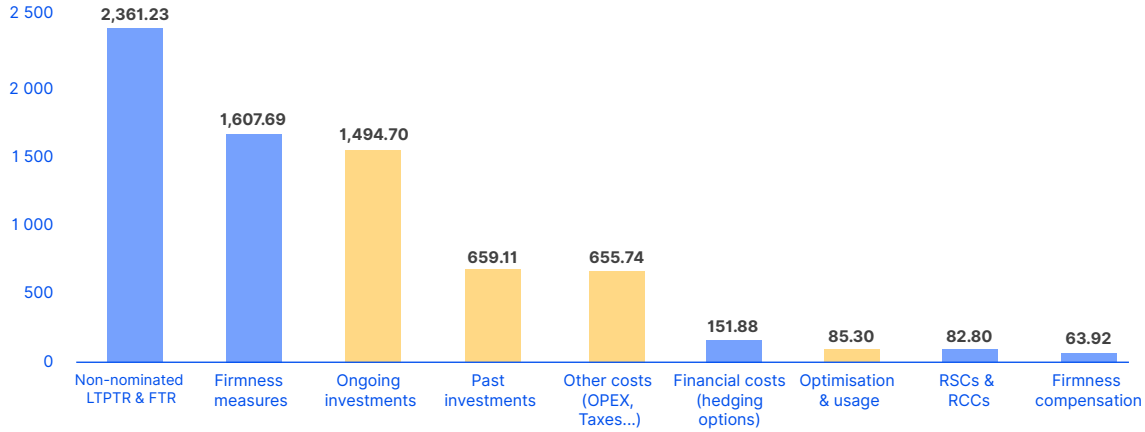
Source: ACER data collection from NRAs.

Notes: The cost categories have been calculated following the classification of cost categories for contributions to priority objectives set out in Article 3 of the UCI methodology in accordance with Article 19(4) of Regulation (EU) 2019/943. The total amounts are overestimated, as they include Member States whose expenditure figures cover CI generated at all borders, where it was not possible to distinguish CI derived from EU–EU borders only.

200 ACER Decision No 38/2020 on the methodology for the use of congestion income.

179 At the aggregate level, the distribution of expenditure across cost categories in 2025 remained largely consistent with that observed in previous years. As shown in Figure 41, the largest share of CI was allocated to the remuneration of non-nominated long-term physical transmission rights and financial transmission rights (EUR 2 361 million), firmness measures (EUR 1 608 million), and ongoing investments (EUR 1 495 million).

Figure 41: EU expenditure on priority objectives by detailed cost category, 2025 (million EUR).



Source: ACER data collection from NRAs.

Notes: Each column represents a cost category under the UCI methodology that contributes to fulfilling priority objectives (a) and (b) of Article 19 of Regulation (EU) 2019/943. The blue columns indicate costs associated with system operation, whereas the orange columns indicate network investment costs relevant to reduce congestion. See also note to Figure 40 regarding overstatement of total amounts. Further details are provided in Table 17 and 18 of the Annex.

Conclusions on congestion income

180 In 2025, the total CI collected at the EU level reached EUR 10.37 billion, marking a 24% year-on-year increase. Just four Member States, Sweden, France, Italy and Germany, accounted for approximately 68% of this total, indicating higher levels of congestion. Similarly, CI stored in a separate internal account line at the beginning of the year grew from EUR 8.6 billion to EUR 10.72 billion.

181 Approximately 60% of available CI was stored in a separate internal account, about 32% was spent on priority objectives and about 8% was used for tariff reduction. The continued accumulation of CI in separate internal accounts is noteworthy and merits consideration, particularly at a time when electricity investment needs are accelerating alongside rising network tariffs. Improved infrastructure needs identification facilitates the assessment of the fulfilment of priority objectives and the release of CI to reduce network tariffs.

ACER proposed actions to address the identified challenges

Use congestion income

Increased interconnection capacities between Member States and bidding zones are crucial to meet the EU's increasingly ambitious energy objectives and to successfully address the challenges highlighted in this report. Considering the above, ACER urges all NRAs to expand cross-zonal capacities where most needed and beneficial. Available congestion income that is no longer required for network capacity expansion or other priority objectives, as these have been adequately fulfilled, could be allocated to reducing network tariffs.

4. Conclusion

182 **Investments have different momentums across energy networks.** ACER finds that Europe is increasing investment in electricity networks, while gas network investment remains relatively stable and hydrogen infrastructure development remains at an early development stage.

183 **Timely infrastructure delivery requires faster implementation and robust planning.** ACER observes that investment is not always delivered in a sufficiently timely, coordinated and efficient manner to meet evolving system needs. This creates twin risks: investment in projects that do not adequately respond to future system needs may lead to inefficient capital allocation, higher network costs and negative impacts on affordability and competitiveness, while delayed investment can slow decarbonisation, increase congestion and limit market integration.

- Efficient infrastructure development should be based on scenarios that meet the EU's policy targets as well as on realistic and regularly updated demand and generation deployment assumptions. Network planning frameworks should systematically assess flexibility solutions, storage, innovative technologies and non-wire alternatives alongside conventional reinforcement. They should recognise anticipatory investments where these are justified by expected future needs and supported by appropriate risk-mitigation measures. Permitting, infrastructure project acceptance and supply chain barriers that delay infrastructure delivery should be addressed.
- While not the focus of this Report, the efficiency-first principle remains essential for balancing infrastructure costs with the need for sufficient network capacity. This requires optimising the use of existing infrastructure before expanding it. Flexibility solutions, demand response and grid-enhancing technologies can contribute to meeting the system needs more cost-effectively than traditional network expansion.

184 **Managing network charges is key across all energy networks.** ACER finds that cost recovery should follow cautious approaches to manage cost impacts and safeguard affordability of energy services.

- Network reinforcement costs should be borne by the users in whose interest they are incurred and allocated based on the expected infrastructure use over its lifetime. While mechanisms such as ICA can help avoid excessive charges for early users, any redistribution of costs to future generations of network users should be carefully justified, particularly in a high-interest-rate environment.
- Regulatory frameworks should facilitate efficient grid use and infrastructure development. They should strengthen CAPEX–OPEX neutrality so that system operators remain financially indifferent between alternative solutions, selecting the most cost-efficient (highest value) technical and operational measures.

185 **Continuous monitoring of grid planning, project implementation and investment trends remains essential to align infrastructure development with the evolving needs and energy transition uncertainties, while maximising value for consumers and society.**

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