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Upgrading Europe's electricity grid is about more than just money

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Executive summary

ELECTRICITY NETWORK INVESTMENT is essential for the energy transition, with annual investments of tens of billions of euros required across Europe. Network companies are already investing such amounts and delivering efficient grid investments requires more than additional money.

ASSESSING INFRASTRUCTURE NEEDS is the first step in grid investment. At local, national and European Union levels, network development planning is determined by policy choices and can greatly affect the efficiency of investments. Coordinated grid planning is crucial to set the right incentives for the efficient development of the European electricity system. An EU independent system operator could assume responsibility for network planning by providing regular, independent assessment of efficient network investment needs from a holistic European perspective.

ALTHOUGH SIGNIFICANT CAPITAL expenditure is undoubtedly necessary, network regulation should encourage network companies to invest in the most-efficient solutions. Current regulatory approaches may favour traditional capital expenditure, leading to system inefficiencies and higher-than-necessary consumer costs.

CROSS-BORDER ELECTRICITY TRANSMISSION infrastructure is critical to integrate renewables into the electricity system at scale and reduce costs for European consumers. But such projects are often not built or are delayed because those that decide on and pay for the infrastructure are not necessarily those that benefit from it. A European fund could smooth negotiations between parties and accelerate the physical interconnection of the European electricity system.

FAIRLY RECOVERING THE COSTS of grid investments from consumers is vital to maintain public support for the energy transition. National funds could smooth out cost impacts over time, keeping electricity affordable throughout the energy transition.

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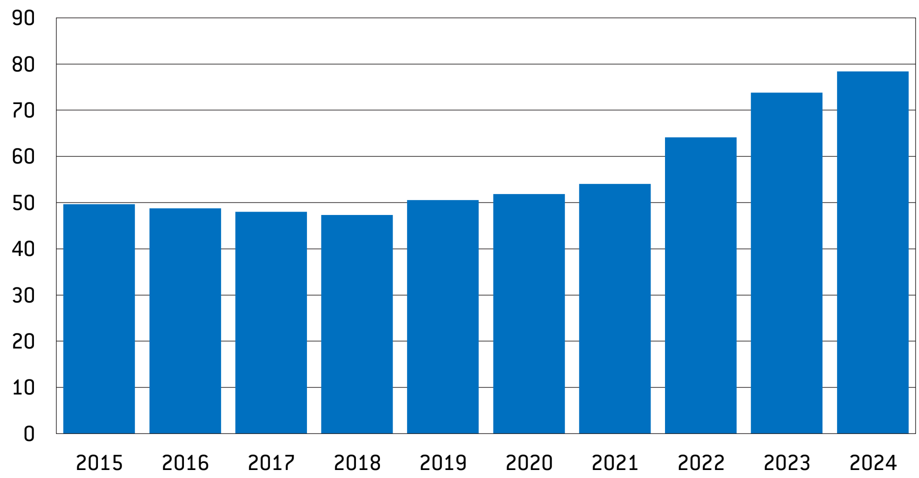
1 Why are electricity network investments required?

The European Union's transition to clean energy will require a major expansion of electricity networks to facilitate increased demand as buildings, transport and industry are electrified. To integrate electricity from renewable sources, new grid connections, both cross-border and within country, will be needed, especially because much of Europe's renewable energy potential is located far from industrial and population centres.

Electricity networks also need a quality upgrade. Electricity systems need more flexibility to adapt to the intermittent nature of renewables. Flexibility can be enhanced through more interconnection capacity[1], enabling increased cross-border trading of electricity in Europe. More cross-border electricity trade will lead to convergence of electricity prices in EU countries, reducing average prices and price volatility. At local level, upgraded networks are needed to handle decentralised clean-energy technologies such as solar photovoltaics, batteries and electric vehicles, many of which both consume electricity and inject it back into grid. Additionally, as Europe has some of the world's oldest electricity grids, many of the assets currently in use require direct replacement or maintenance and enhancement through the integration of digital technologies.

It will cost tens of billions of euros per year in the EU to move to a clean and secure energy system (European Commission, 2023a). While financing such investment is by no means straightforward, network companies' current investments are already of the same order of magnitude and it should be possible to sustain this level of investment, given a stable regulatory environment (Figure 1). Thus, delivering the grid for the clean economy of the future is a question of more than just money. Many policy choices must be made to ensure that each euro spent on the electricity network provides maximum benefit for consumers.

Figure 1: European transmission and distribution network investments, 2015-2024, € billions



Source: Bruegel based on IEA (2024). Note: Europe includes the EU and Albania, Belarus, Bosnia and Herzegovina, North Macedonia, Gibraltar, Iceland, Israel, Kosovo, Montenegro, Norway, Serbia, Switzerland, Republic of Moldova, Turkey, Ukraine and the United Kingdom. Given the 16 non-EU countries, the total figures are not suitable for direct comparison with the investment needs in Table 1. Increased investment levels may reflect not only additional infrastructure but also higher costs related to supply chain constraints or borrowing.

1 Interconnection capacity refers to cross-border cables that allow electricity trade between neighbouring countries.

First, setting the right market rules to improve the usage of already-built grid infrastructure can save money and time[2]. Second, identifying the right investments is crucial. Third, policy should support network companies in financing their investments. Fourth, network regulation should be designed to incentivise innovative, cost-efficient solutions. Fifth, fairly recovering the costs of grid investments from consumers is essential to maintain public support for the energy transition[3].

This policy brief evaluates these major European policy challenges for grid development. In section 2 we outline the key aspects of the electricity network sector, followed in section 3 by an overview of investment needs. Section 4 addresses policy challenges in financing grid investments, while section 5 examines issues with current network regulation. Section 6 sets out recommendations: a new EU institution for operating and planning the European electricity system (section 6.1); more and better targeted European grid funding to accelerate cross-border electricity infrastructure deployment (section 6.2); and national funds to help distribute costs of grid investments over time (section 6.3).

2 The European electricity-network sector

The European electricity network has two layers: high-voltage transmission grids transporting electricity over longer distances, and medium-to-low-voltage distribution grids connecting most grid users to the wider system. Transmission cables connect at more than a thousand nodes (where three or more lines come together and typically connect to the distribution layer) and there are many millions of connection points in the distribution networks.

The transmission grids of most neighbouring European countries are interconnected. There are 30 transmission system operators (TSOs)[4] in the EU and several thousand distribution system operators (DSOs). Electricity-distribution grids account for most electricity-grid infrastructure and this is reflected in asset values. For example, the grid operated by the largest French DSO, ENEDIS, is worth €54 billion, while the asset base of French TSO RTE is €17 billion (S&P Global Ratings, 2024). The returns earned by TSOs and DSOs and their investment incentives are determined by national regulators, with each EU country taking a distinct regulatory approach.

2.1 The distribution layer

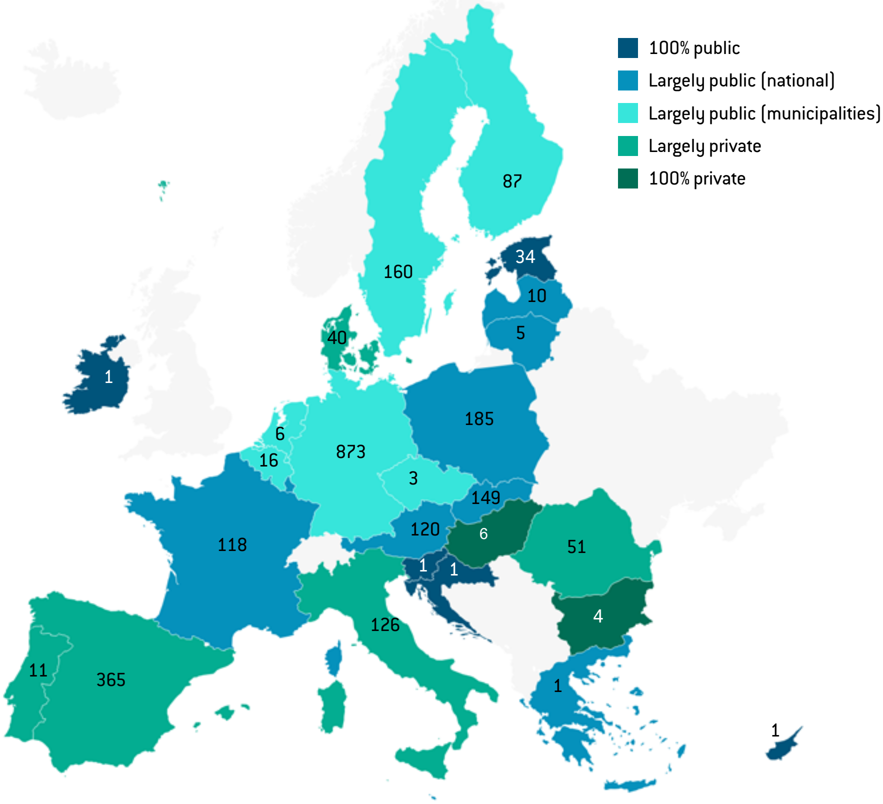
Approximately two thirds of new grid investments will occur on the distribution level (see section 3). The role of the distribution grid and the responsibilities of DSOs are changing fundamentally. In addition to their historical role of owning, operating and investing in the distribution network, DSOs are now required to provide the equipment, including smart meters and local storage, for management of flows of electricity to and from consumers who use their own energy resources to store electricity and inject it into the grid.

2 This includes electricity market design choices, such as efficient locational price signals for generation, storage and demand installations, and consumer-pricing schemes that incentivise efficient demand-side behaviour.

3 Another issue is permitting of infrastructure, which should be accelerated to enable timely upgrades. This topic, however, is beyond the scope of this paper. See Banet and Donati (2024) for a detailed treatment of the implementation challenges with speeding up renewable energy permitting in Europe.

4 Most EU countries have one state-owned TSO, although Germany has four and Austria has two, making a total of 30 TSOs across the EU.

Figure 2: DSO ownership and number of DSOs per country

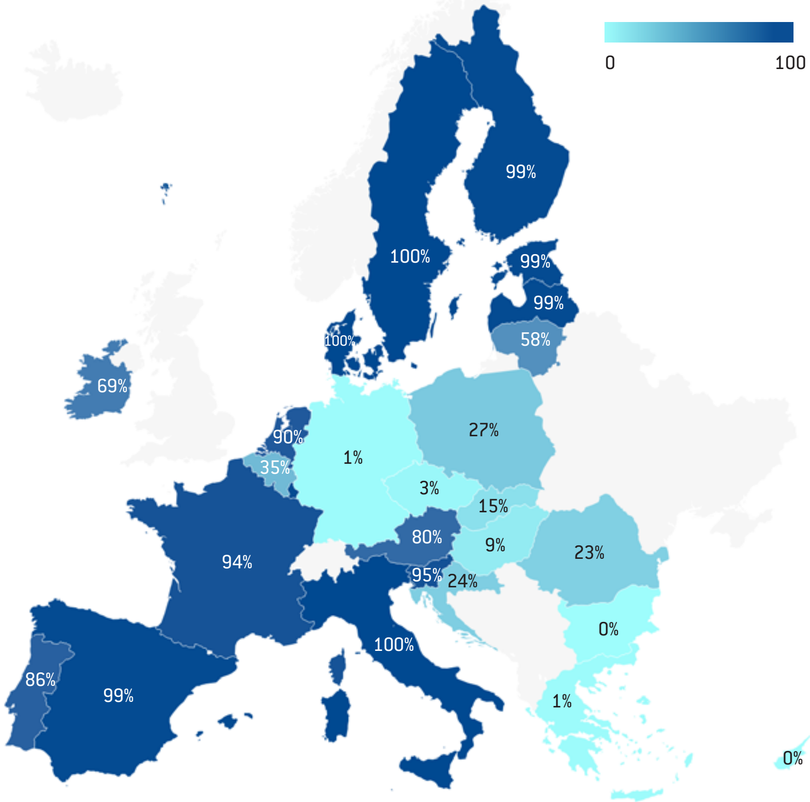


Source: Bruegel and E3G based on CEER. Note: Not labelled are Luxembourg (5) and Malta (1).

Depending on the country, DSOs range from a single publicly owned company covering the entire grid to hundreds of largely privately owned entities (Figure 2). The technological sophistication of distribution grids in different countries varies widely. Some countries have already completed their smart-meter rollouts (a key enabling technology for activating consumers), while others have yet to begin (Figure 3). Much of the required distribution-layer investment will also involve technologies that are currently at early stage[5]. Regulatory schemes to incentivise DSOs to efficiently operate and invest in their systems also vary by country (CEER, 2024). Thus, local variation is a defining characteristic of the distribution layer, making it difficult to target European funds efficiently to appropriate projects, or to develop effective harmonised EU-level rules.

5 For example, local peer-to-peer trading platforms for distributed energy resources, the operation of community energy schemes and new network monitoring approaches.

Figure 3: Share of final consumers with a smart meter in 2023



Source: Bruegel based on ACER (2024). Note: Not labelled are Luxembourg (99 percent) and Malta (93 percent).

2.2 The transmission layer

The role of the TSO in the transmission layer of the electricity network is in many ways analogous to that of the DSO on the distribution layer, although there are some significant differences. TSOs are legally responsible for operating, maintaining and developing their respective transmission systems and their interconnections with neighbouring systems. Cross-border electricity infrastructure is mostly owned and operated by TSOs. Moreover, TSOs perform some public-authority functions, such as setting rules for energy-system participants and holding responsibility for maintaining their system's security of supply and long-term reliability[6]. While European TSOs have more in common than DSOs, how they are regulated by their governments still varies by country (Box 1).

Box 1: Network regulation models

Network companies are local monopolies. Network companies submit investment plans and consumer tariffs to regulatory authorities for approval. To protect their customers, their tariffs are regulated, most commonly by the national regulator setting a maximum allowed revenue for a set period depending on costs, investments and acceptable rates of return (a revenue-cap model). Cost-plus, price-cap and hybrid models are also used by some regulators. Furthermore, depending on the country, operational expenses and capital expenses are treated differently, eligible cost of capital for DSOs are calculated differently and incentives for specific purposes such as quality of service, digitalisation or climate resilience are included in different ways (CEER, 2024).

6 Under Directive (EU) 2019/944 of 5 June 2019 on common rules for the internal market for electricity.

2.3 Cross-border infrastructure

Interconnection is vital for European energy security, decarbonisation and cost reduction

Cross-border transmission infrastructure, typically called interconnectors, allow for electricity to be traded between neighbouring countries. Interconnection is vital for European energy security, decarbonisation and cost reduction (Zachmann *et al*, 2024). Interconnectors are typically built and owned by the adjacent national TSOs, although private companies are occasionally involved, and interconnector owners can earn substantial revenues from arbitrage between electricity price zones (amounting to €16 billion in 2022 when EU country price differences widened during the energy crisis; ACER, 2023a). The split of investment costs between co-owners varies by project (ACER, 2023b). For interconnection projects and offshore grids involving several countries, complex cost-sharing mechanisms have been proposed by the European Commission and others (European Commission, 2024a; Trinomics, 2023).

All things being equal, a new interconnector will lead to more harmonised prices in neighbouring countries, raising prices in one country (leading to gains for the producers) and reducing them in the other (leading to benefits for the consumers)[7]. The total welfare benefits of an interconnector can be very sizeable. However, because of the challenges of fairly distributing these benefits, such welfare-enhancing projects are often delayed or not developed at all. It took six years, for example, to reach an agreement on cost sharing for a subsea interconnector between France and Spain[8]. An interconnector between Sweden and Germany was rejected on the basis that it would raise Swedish power prices[9].

2.4 European coordination

The lack of substantial spillovers means there is relatively little cross-border DSO coordination in the EU[10]. TSO coordination, however, has a long history and its main body – the European Network of Transmission System Operators for Electricity (ENTSO-E)[11] – plays a major role in organising the operation and design of the European transmission system.

Every two years, ENTSO-E publishes a ten-year network development plan (TYNDP), in which the value of projects already proposed by TSOs is assessed using a standardised cost-benefit analysis methodology, though new projects are not proposed. Identifying projects with significant European benefit – so-called Projects of Common Interest (PCIs) – is done under the Trans-European Energy Networks (TEN-E) Regulation (Regulation (EU) 2022/869). Regional decision-making groups across Europe, each composed of national government representatives, the relevant TSOs, the European Union Agency for the Cooperation of Energy Regulators (ACER) and ENTSO-E, select PCIs against criteria such as their contribution to sustainability and electricity-market integration. PCIs receive European funding from the Connecting Europe Facility – Energy (CEF-E).

7 Depending on the generation mix and demand profile in the linked countries it might be that electricity is sent in one direction for many hours and in the other direction during other hours.

8 Euractiv with Reuters, 'France, Spain announce breakthrough in undersea power link', *Euractiv*, 3 March 2022, https://www.euractiv.com/section/electricity/news/france-spain-announce-breakthrough-in-undersea-power-link/.

9 *Reuters*, 'Swedish government says no to new power cable to Germany', 14 June 2022, https://www.reuters.com/business/energy/swedish-government-says-no-new-power-cable-germany-2024-06-14/.

10 To promote cooperation at DSO level and align with TSO processes, the EU DSO entity was established by Regulation (EU) 2019/943 of 5 June 2019 on the internal market for electricity

11 ENTSO-E has 40 TSO members, including some outside the EU.

3 Assessing investment needs

The exact investment volumes needed to prepare Europe's electricity networks for net-zero carbon emissions are highly uncertain. The electricity network is just one part, though central, of a complex energy system, including generation, storage and demand, with substitutability and complementarity between technologies and even other energy sectors, such as heating. Additional cables are not always the best answer, as network issues can also be addressed by improved system operation, additional storage capacity or encouraging consumers to shift consumption to hours with less demand and more abundant supply.

Overall, a substantial and sustained increase in grid investment would be highly beneficial. Based on a review of studies, we estimate Europe's total annual investment needs up to 2030 to be €65 billion to €100 billion (Table 1). The top end of the range is based on Eurelectric's (2024a) expectation of a maximum distribution grid investment of €67 billion and assumes that transmission investment needs are approximately half the distribution investments.

Table 1: Assessments of European grid investment needs (€ billions)

Study	Publication year	Period assessed	Annual distribution investments	Annual transmission investments	Annual interconnection investments	Total annual investment needs	Estimated cumulative investments to 2030
TYNDP 2024 Infrastructure Gaps Report (ENTSO-E, 2025)	2025	2025-2030			5		
Eurelectric (2024a)	2024	2025-2050	55-67			55-67	402*
European Roundtable for Industry (ERT, 2024)	2024	2021-2030	39	24	2	65	650
Goldman Sachs (2024)	2024	2024-2033	50	30		80	480**
European Commission's REPowerEU modelling (European Commission, 2023b)	2022	2022-2030				73	584

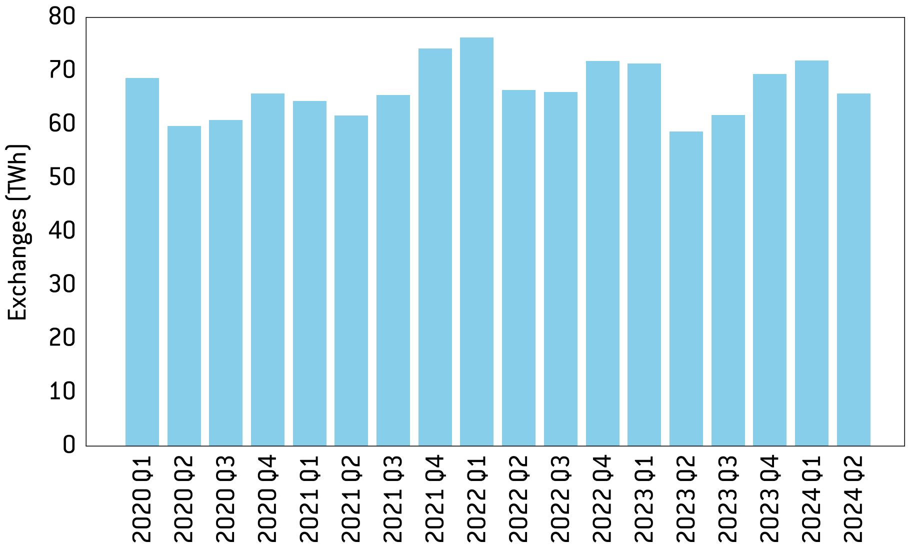
Source: Bruegel. Note: * Eurelectric (2024a) covers only distribution system investments and includes Norway in its estimates. **Goldman Sachs (2024) includes EU and UK in its investment needs. Direct comparison between studies is complicated by the fact that many studies explore different time periods, are based on different scenarios, or focus exclusively on certain layers of the electricity network. The widely reported figure of €584 billion by 2030 cited in the EU Grids Action Plan (European Commission, 2023a) is based on European Commission internal REPowerEU modelling from 2022.

A general takeaway from Table 1 is that most investment will take place on the distribution layer. Investment needs between countries differ significantly. Eurelectric (2024a) indicated that Germany will need to invest over three times as much as France in its distribution grid on average until 2050. In its assessment of the 2040 climate target, the European Commission (2024b) modelled between €79 billion and €96 billion of investments from 2031-2040, while ENTSO-E (2023) also expect cross-border investment needs to increase after 2030, indicating that grid investment will continue to be a challenge post-2030.

For our purposes, unless otherwise stated, investment needs are assumed to refer only to transmission and distribution, as interconnection and offshore grid needs are typically not specified. ENTSO-E (2025) increased their estimate of cross-border investment needs from €2 billion/year up to 2030 (ENTSO-E, 2023) to €5 billion/year. Furthermore, ENTSO-E expects investment needs to increase to €6 billion/year up to 2040, and to as much as €13 billion/year up to 2050. The lack of alternative, independent and comprehensive assessment of cross-border and offshore network needs is a glaring absence in the available analyses.

Comprehensive data on cross-border capacities available for electricity trade is also scarce. The available information indicates that cross-border commercial exchanges across major European borders have not increased significantly for many years, suggesting that new capacity is not being added (Figure 4). Massive price differentials between countries during the energy crisis showed substantial limitations in the available cross-border capacity (Dimopoulos *et al*, 2023).

Figure 4: Scheduled day-ahead commercial electricity exchanges, 2020-2024



Source: Bruegel based on ENTSO-E's Transparency Platform. Note: Selected borders were chosen based on data availability. The annex lists the borders included.

4 Electricity network financing options

The volume of capital required to enhance and expand the European electricity network is substantial, but not prohibitively large. An annual investment of €80 billion would correspond to 0.5 percent of 2023 EU GDP[12]. For context, between 2015 and 2020, France, Germany, Italy, Spain and Poland together invested an average of €25 billion annually in rail networks[13]. Eurelectric (2024) noted that their call for distribution grid annual investment of €55 billion to €67 billion is less than half of what the EU spent on fossil-fuel imports in 2022.

Given a stable regulatory framework, TSOs should have the capacity to finance this investment; financing should thus not be the main obstacle to upgrading Europe's grid. However, there are some specific financing challenges on the distribution level. While large DSOs can comfortably attract the required finance, many DSOs are much smaller and may struggle to access the investment finance needed, meaning they could benefit from national public

12 Based on a GDP of €17 trillion, Eurostat.

13 Based on OECD data.

financing. However, our focus is on the EU-level policy. We make the case that the distribution layer should be primarily a national policy issue.

4.1 Public vs. private financing

Public financing can come from either national or EU sources. At EU level, the main options are the European Investment Bank (EIB), which typically provides loans, and common EU funds, which provides grants to projects. The EIB invests in energy infrastructure, with €4 billion invested in domestic electricity networks (EIB, 2023a). The EIB also provided loans totalling €3.5 billion for cross-border electricity infrastructure from 2010 to 2022, covering 40 percent of these projects' total investment costs (EIB, 2023b). The European Bank for Reconstruction and Development (EBRD) also provides financing for transmission and distribution projects in the former communist countries that joined the EU in 2004 and after, and in Greece.

The primary EU fund for energy infrastructure is the Connecting Europe Facility – Energy (CEF-E). CEF-E is providing €5.8 billion to the energy sector from 2021 to 2027. The Cohesion Fund, the EU's investment fund that addresses socio-economic disparities, also disburses money to some national electricity-network projects. Additionally, the Modernisation Fund, which is financed with revenues from the EU emissions trading system (ETS), supports energy network investments in 13 lower-income EU countries.

National public financing for grids can come from development banks that offer long-term support for energy infrastructure projects. Another national-level option is to finance grid investments directly from national budgets, with governments providing loans or grants to network companies.

For private financing, grid companies can choose to raise funds via debt or equity. Larger companies, such as TSOs, can raise money on capital markets through bond issuance, while smaller firms might have to rely on typically more expensive bank loans. The greater the perceived risk of a grid company and the more it is already leveraged (high debt, little equity), the more expensive and difficult debt financing can become, to the point where it is necessary to increase equity. In a notable example of equity financing, in May 2024, National Grid (the UK's TSO) promoted the largest rights issuance in the UK since 2009, aiming to raise £7 billion for significant grid expansion[14].

4.2 Mapping financing options to investment needs

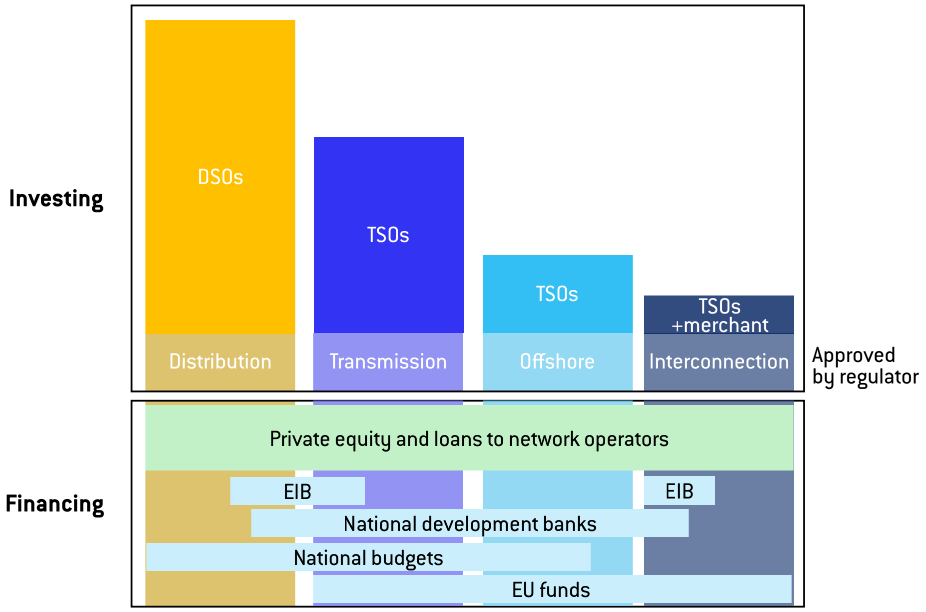
The different investment needs across distribution, transmission, offshore and interconnection are each better suited to specific financing structures (Figure 5). However, in terms of EU financing at the distribution level, determining the European public benefit is difficult. Fair sharing of EU funding between complex and very different distribution-grid investments across Europe would be bureaucratically arduous and unlikely to lead to efficient outcomes. Furthermore, the primary obstacles for distribution-grid investments are not access to public funding, but regulatory issues (section 5). The distribution grid is therefore not a suitable option for EU funding.

Given a stable regulatory framework, TSOs should be able to raise much of the funds they need from private sources, although national public financing may help accelerate or safeguard investments in some cases[15]. Interconnection projects typically involve a combination of joint public financing between the two partnering countries, EU funding through the CEF-E facility or, in some cases, private project financing (so-called 'merchant' investments).

14 Aby Jose Koilparambil and Yadarisa Shabong 'National Grid to raise $9 billion in biggest UK rights issue since 2009', *Reuters*, 23 May 2024, https://www.reuters.com/world/uk/uks-national-grid-raise-about-9-bln-via-rights-issue-2024-05-23/.

15 For example, the Dutch state provided TenneT, the TSO for the Netherlands and part of Germany, with a €25 billion loan facility to safeguard its grid investment plans. See TenneT press release of 12 January 2024, 'TenneT to receive €25 billion loan from the Dutch State to facilitate electricity grid expansion', https://www.tennet.eu/news/tennet-receive-eu25-billion-loan-dutch-state-facilitate-electricity-grid-expansion.

Figure 5: Grid investment needs and financing options



Source: Bruegel. Note: the height of the columns corresponding to each investment type approximately scale to the estimated annual investment need based on the studies in Table 1.

4.3 Policy issues with financing

The primary policy challenge involved in mobilising tens of billions of euros in investment annually is identifying how public financing can appropriately complement the large volumes of ongoing private finance in the network sector. The types of projects that receive public support (especially EU support) should depend on the capacity of the project developer to finance their investment privately, the degree to which regulatory obstacles impede that capacity to finance and the benefits for EU citizens of the projects. The level of public financing will only amount to a fraction of the total investment need, meaning it should be targeted to deliver maximum additional public benefit.

European capital market fragmentation is an entrenched problem. Insufficient liquidity in European capital markets could drive major network operators to raise money in the United States, introducing currency risk and adding further costs. Capital-market reform and harmonisation would reduce the need to raise finance outside the euro area, removing currency risk, and would mean firms could access more risk-tolerant investors, thus reducing the cost of capital on average. Countries on the European periphery would benefit most.

5 Is the regulatory regime fit for purpose?

5.1 Planning efficient grid investments is challenging

Because of the way electricity flows, changes to a single line often affect many other elements of the system. As discussed in section 3, there is the potential for significant substitutability between the network and other energy-system components. With perfect knowledge and perfect foresight, centralised models might be able to calculate an optimal set-up. Yet future electricity demand and supply at each connection point is uncertain because climatic, economic and other developments can change energy consumption. Consequently, the optimal network investments and their costs are not known *ex ante*.

Investors in additional electricity demand, supply or network assets face significant commercial risks if one of the other segments is not in place in time. To avoid this risk derailing the transition, the EU in 2024 introduced the concept of 'anticipatory investment' (Regulation (EU) 2024/1747), or network infrastructure built to facilitate expected electricity demand assuming the EU meets its long-term climate targets. However, investments made on the basis of as-yet unconfirmed generation and demand risk becoming sunk costs. More information exchange between network operators and regulators is needed to ensure that long-term, anticipatory projects provide maximum value (ACER and CEER, 2024b). For efficient investment, thousands of stakeholders would have to share private information truthfully and incentivise the network operator to design appropriate cost-efficient solutions. Unfortunately, misaligned incentives between different electricity-system stakeholders may inhibit essential information exchange. National regulatory authorities have significantly less information than the companies they regulate. Accordingly, regulators find it hard to assess and challenge the investment proposals and rate-of-return demands of grid companies.

The interests of TSOs do not necessarily imply social-welfare maximisation. TSOs might prefer less interconnection to reduce internal redispatch costs and operational complexity, while maintaining arbitrage revenues and limiting uncertainty. Moreover, national (often public) TSOs might be encouraged by politics and regulators to not relinquish 'sovereignty' over the national energy mix, or to protect consumers against rising prices in exporting countries.

Network-company engineers may seek to overbuild the network to remove the risk of any outages. Accountants might support this approach, as it would add to the asset base on which the firm receives a regulated return. If the regulated return on capital is equal across grid companies, those with lower capital costs might have a much greater incentive to invest than those that struggle to attract capital. Furthermore, electricity networks are natural monopolies with no direct competition and so, in theory, could overcharge consumers for the service they provide. Consequently, EU and national rules determine that network companies' returns are regulated (Box 1).

Current regulatory approaches may favour investments in standard capital assets rather than innovative operational solutions**.** Since large-scale grid expansion has not been necessary until now, network regulation in Europe has focused on constraining network companies from overbuilding, in order to shield consumers from unnecessary costs. However, this can still incentivise capital spending over operational expenditure if firms receive a rate of return above the cost of capital (Averch and Johnson, 1962). While huge capital investment in physical grid expansion is evidently needed, regulation must ensure that these investments are efficient and incorporate innovative and efficient solutions (Weisman, 2024). Many of the innovative solutions in electricity networks, related to digitalisation and developing the smart grid, rely on an increase in operational spending. These innovations could be crowded out if the regulatory framework has a capital expenditure bias (Brunekreeft, 2023).

5.2 Experimenting with regulatory innovation

Adding key performance indicators to the regulatory framework – such as bonuses for speedy connections of new users, maximising existing grid efficiency or penalties for outages – is a potential solution to incentivise network companies to better prioritise their investments and operations[16]. However, such indicators are difficult to define and may unintentionally lead to misallocations. Certain projects selected for their political value (eg an interconnector between friendly countries) may not be the priority if viewed from a European system perspective.

Further reforms to the regulated returns of network companies could include total expenditure ('totex') regulation and benefit-based remuneration. With totex regulation, the regulator

16 The European Union Agency for the Cooperation of Energy Regulators (ACER) and the Council of European Energy Regulators (CEER) have consulted on how best to incorporate 'smart-grid' performance indicators in network company regulatory frameworks (ACER and CEER, 2024c).

pre-defines a ratio between the revenues allowed to cover operational expenditures and capital expenditures. In theory, totex regulation removes biases towards capital expenditure and should incentivise network companies to choose the most-efficient solution available. However, it can be complex to forecast costs accurately over a given regulatory period, with the regulator needing strong analytical capacity to assess the appropriate ratio. Pototschnig and Rossetto (2024) set out a new remuneration approach in which the regulatory authorities would identify the system needs to be addressed and define the standard way to address such a need (eg through building new physical grid capacity). If the network company can identify a more-efficient way of addressing the needs, they receive an incentive payment equal to a share of the difference between the allowed revenues for the standard approach and the costs of the more innovative solution.

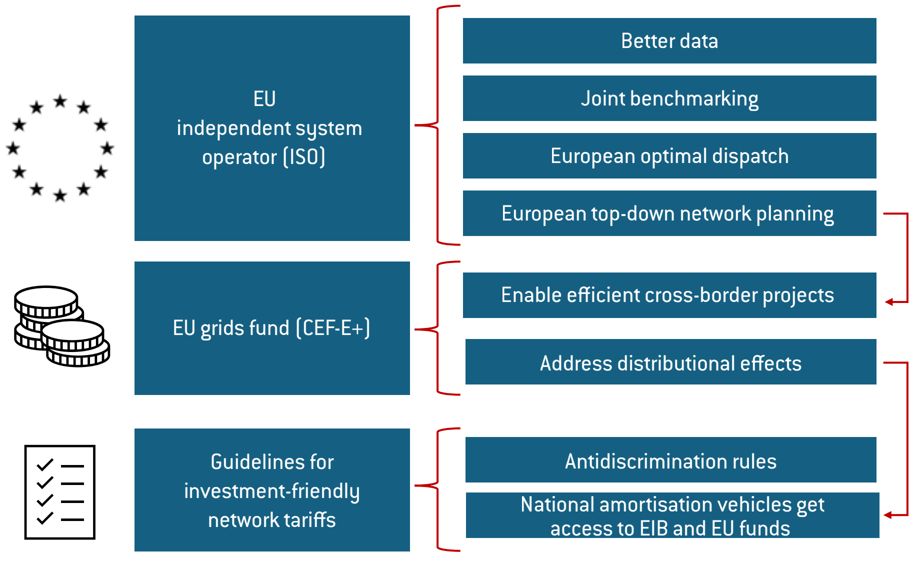
European network planning (TYNDP, see section 2) is a bottom-up process in which TSOs feed their national plans and individual projects into a European proposal that serves as the basis for an official European plan. Unbiased, transparent system planning is imperative as identifying the optimal cross-border infrastructure is strategically important for reducing energy costs in Europe. We discuss how network planning reform could be implemented in the next section. Improving the underlying EU legislation, the TEN-E regulation, is another option for improving grid planning[17].

6 Recommendations

Building electricity network infrastructure involves an extensive process of **planning**, **regulatory** approval, **financing** and **cost recovery**. We recommend three actions (Figure 6) to improve these processes:

- Establish a new institution to operate and plan the European electricity system (section 6.1)
- Expand and better target existing EU funds (section 6.2)
- Harmonise rules for smoothing out consumer grid tariffs (section 6.3).

Figure 6: Policy recommendations



Source: Bruegel.

17 For a detailed discussion of the TEN-E regulation and its potential reform, see Sikow-Magny (2024).

6.1 Better planning and operation through an independent electricity system operator

Several of the misaligned incentives discussed in section 5 would be removed from the network-planning process if a European independent system operator (EU ISO) were established. This would help with transparent information availability and exchange, while reducing regulatory bias towards capital-intensive investments and the predominance of national interests over European benefit. Furthermore, an EU ISO would simplify the operation of an interconnected European system, leading to efficiency gains by maximising the benefit of the existing network and thus reducing future investment needs.

An EU independent system operator would simplify the operation of an interconnected European system, leading to efficiency gains

The EU ISO would be responsible for operating the interconnected European electricity transmission network from a central point and would be responsible for reliable electricity supply. Ownership of the grids by national grid companies could still be retained[18] and national control centres could serve as a backup for national system operation in case of EU-level issues. To complement industry-led planning, the EU ISO would carry out pan-European needs assessments of network capacity and associated investments, based on a standardised, transparent methodology. The needs assessment could explicitly include a scenario aligned with the EU's climate targets[19].

In this institutional framework, the selection of Projects of Common Interest (section 2.4) would be based on the independent needs assessment. National TSOs would still formulate their own network development plans and submit them to their national regulatory authorities for approval, but industry-planned transmission projects could then be benchmarked against this independent assessment in terms of their social-welfare benefits, also highlighting potentially beneficial connections not taken into account by industry[20]. Political support at the highest level in Europe would be required to deliver this deep institutional reform.

A second-best solution would be to carry out transparent, independent top-down system planning through a different European body, such as ACER. To make progress towards more efficient operation of the interconnected European system, the EU could encourage a move towards jointly optimised regional system operation. In general, more transparent, publicly available modelling and data on the European grid and the planned projects would allow independent assessment of project value. Given the complexity of this novel task, managing grid expansion should be designed as a learning process. Continuously and consistently collecting data on investments and the costs and outcomes of different regulatory approaches will allow policymakers to evaluate what works and adjust policy to continuously improve the governance and planning system.

6.2 A European grid fund to close the funding gap for beneficial projects

As individual market players worry about becoming relatively worse off because of imperfect cost-sharing, or because of the risks of losing out from electricity trade, they will lobby to slow down the buildout of critical cross-border infrastructure. A well-targeted European fund could resolve this by closing the funding gap for welfare-enhancing transmission projects, providing side payments to involved parties to smooth negotiations and compensate losers and lowering the cost of capital. For this the Connecting Europe Facility – Energy (CEF-E) should be expanded and targeted to cross-border projects for which cost-allocation obstacles hold up completion (section 2).

Many cross-border electricity transmission projects might provide a social benefit that exceeds the cost of the project. However, project costs cannot easily be recovered only from

18 Such a separation between ownership and operation is well established in significant parts of the US, and has been introduced in the UK.

19 In many cases national network development plans are misaligned with national policy targets and the associated grid investment needs (Cremona and Rosslowe, 2024).

20 In a similar vein, ACER proposed improving the planning process through full transparency of the infrastructure assessment, including a multi-sectoral approach, and introduction of a complementary EU planning approach to the bottom up TYNDP approach, in order to identify regional infrastructure solutions (ACER and CEER, 2024a).

the network users that benefit from it, which may be spread across two or more countries. To realise such projects, EU funding can close the gap between the project's cost and the realistic level of cost recovery from network users. Using EU funds for strategic electricity network investments can reduce overall costs, as the average cost of capital will be lower with the addition of European financing. A fully interconnected European electricity system is a European public good and thus spending in this area of funds raised through European borrowing would be justified.

CEF-E was established in 2014 for these reasons. However, CEF-E suffers from the problem of project selection directly involving the TSOs, the potential owners of the infrastructure (section 5). More funding for CEF-E to ensure completion of all the welfare-enhancing projects in the EU, and better selection of those projects (section 6), is required to maximise the impact of such public financing. The use of the CEF-E could be extended to also smooth out distributional issues involved in cross-border projects (price changes that can disadvantage some end-users though the overall project is welfare-enhancing) by partially compensating the losers from specific projects for their higher costs or their lost revenues (see section 6.3.2 for a proposal on how such compensation could be achieved).

ENTSO-E (2025) calculated that cross-border electricity investment needs could reach €13 billion per year by 2050, yet current CEF-E funding for electricity infrastructure amounts to less than €100 million per project and less than €1 billion per year[21]. To provide sufficient funds to accelerate infrastructure deployment and also compensate losers from electricity trade, CEF-E funding should at least be tripled – and could benefit from being up to ten times larger.

Challenges remain in using EU funds for such projects. EU funding might not overcome diverging economic and political interests in EU countries that would otherwise be ideal candidates for more interconnection capacity, or this source of financing may even be blocked for that reason. Furthermore, selecting projects is difficult and requires mobilising substantial analytical capacity and navigating complex bureaucracy. Independently assessing the transmission grid investment needs, as discussed in section 6, would complement an EU fund and help to efficiently and fairly target public money to appropriate projects.

6.3 Preventing network tariff escalation

After projects are planned, financed and built, the network costs must be recovered (Figure 7). Network costs can be a substantial part of final consumer bills: in 2023, network costs accounted for 25 percent of the average EU household's electricity costs[22]. Given that network operation costs could also increase substantially in the transition[23] total network costs in Europe are likely to rise significantly. Without state intervention, these increasing costs will have to be recovered from network users. In the best case, the increase in electricity demand during the transition will ensure that per-unit tariffs stay in check. In the worst case, however, increases in per-unit tariffs will slow electrification, limiting the base from which network costs can be recovered, leading to even higher per-unit tariffs.

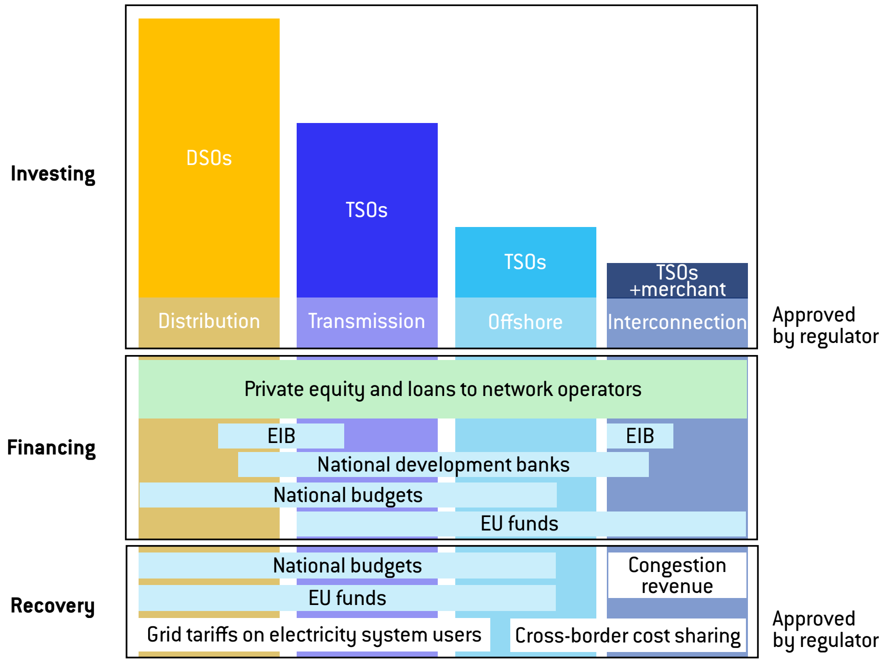
National funds could be utilised to smooth the cost-recovery impacts on consumers of large network investments, while reducing cost of capital for network companies. EU guidelines for such funds can ensure that the national instruments are compliant with state-aid rules.

21 60 percent of CEF-E funds have been allocated to electricity projects, with 20 percent going to each of hydrogen and CO2 storage infrastructure. See European Commission press release of 20 January 2025, 'EU invests over €1.2 billion in cross-border infrastructure contributing to build our Energy Union and to boost competitiveness', https://ec.europa.eu/commission/presscorner/detail/en/ip_25_377.

22 Based on Eurostat, including taxes and levies.

23 According to Thomassen *et al* (2024), redispatch cost in the worst scenario might increase from €5 billion in 2022 to more than €100 billion in 2040.

Figure 7: Estimated investment needs, financing options, and cost recovery sources



Source: Bruegel. Note: the height of the columns corresponding to each investment type approximately scale to the estimated annual investment need based on the studies in Table 1.

6.3.1 Consumer costs depend on regulation and demand

The typical cost-recovery process starts with a network company making an investment, the value of which is added to its regulatory asset base (RAB – the valuation of the assets owned by the firm). Simultaneously, the annual depreciation of the firm's assets is subtracted from the RAB. The firm is then permitted to receive revenue each year equal to: (1) compensation for the cost of capital of its RAB; (2) the annual depreciation; and (3) compensation for specific other expenses and incentives. All elements are the result of sophisticated and complex design and accounting rules, developed over years by national regulators with input from national stakeholders. By design, (1) and (2) should cover the costs associated with the network investment, which is the associated cost of capital. The level of the return is divided by the expected electricity demand, deriving a tariff level that can be applied to various market participants according to their consumption.

Within this process, the core variables determining the final consumer cost in each year are the capital expenditure, the weighted average cost of capital (WACC), electricity demand, the rate of depreciation and the asset lifespan.

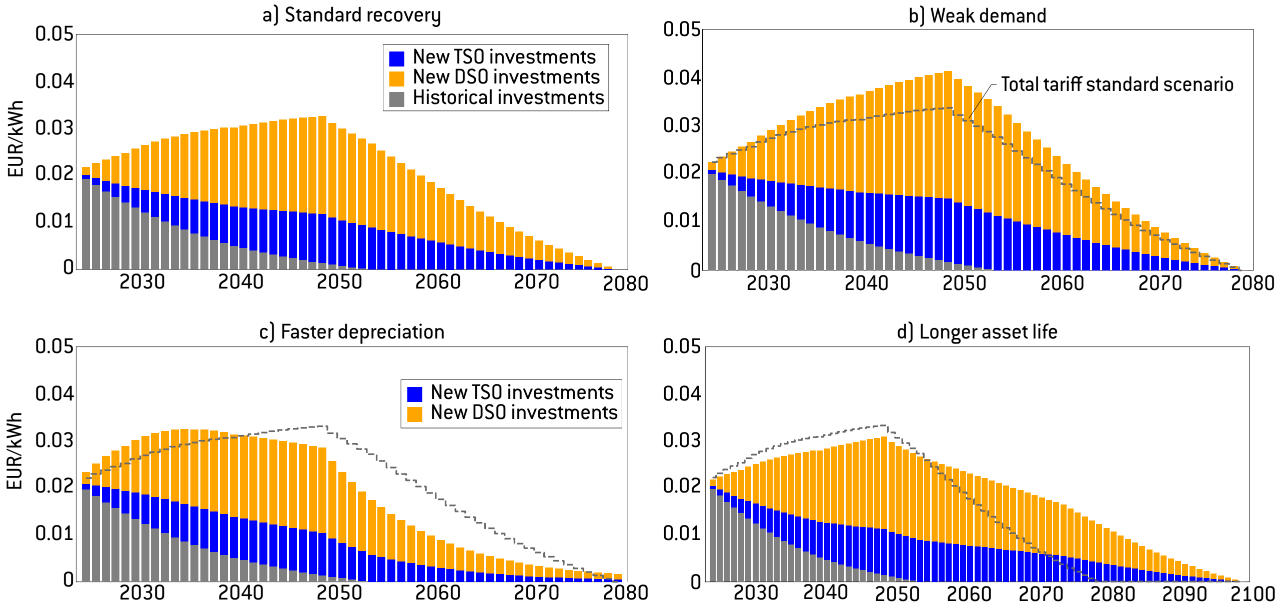
Figure 8 shows possible increases in network costs for consumers associated with the grid investment wave in different cost-recovery scenarios. We assume historical investment levels of €30 billion/year for 1995-2024[24], the costs of which are still being recovered from consumers as the assets are depreciated. The right side of each figure shows the value of the variables determining the cost-recovery scenario.

In panel A, the 'standard' approach, electricity demand is assumed to grow in line with the European Commission's 2040 impact assessment (European Commission, 2024b), remaining flat after 2050. The depreciation is done linearly, with the same level of depreciation in each year over the asset lifetime. In this setting, network costs increase each year up to 2050[25], at which point we, for better illustration, set new grid investments to zero and hence grid costs

24 Exact investment figures for the EU over this period are not available but would not materially alter the analysis above.
25 ACER (2024) reached a similar conclusion.

start to fall. In the standard approach, we estimate the total additional EU consumer costs from the planned network investments over 2025-2080 to be €3.5 trillion[26].

Figure 8: Illustrated average grid tariffs for different cost-recovery approaches



Parameter		Scenario A	Scenario B	Scenario C	Scenario D
Asset life in years		30	30	30	50
WACC		5%	5%	4.50%	5%
Electricity demand (TWh)	2025	2500	2500	2500	2500
	2030	2800	2700	2800	2800
	2040	3600	3100	3600	3600
	2050	4000	3200	4000	4000
New TSO investments (€ billions)	2025-2030	120	120	120	120
	2030-2040	290	290	290	290
	2040-2050	270	270	270	270
New DSO investments (€ billions)	2025-2030	250	250	250	250
	2030-2040	580	580	580	580
	2040-2050	530	530	530	530
Total consumer cost due to new investments (€ billions)		**3500**	**3500**	**2900**	**4600**

Source: Bruegel.

Weak electricity demand growth (panel B) would increase these costs on per-kWh basis, though absolute costs would remain the same. Regulatory approaches that reduce the cost of capital could benefit consumers, but to reduce the cost of capital, regulators would need to reduce the risk for investors. Lower risk could be achieved by providing returns early in the asset life, for example by accelerating the rate of depreciation. Panel C shows the impact of depreciating the asset value faster and reducing the cost of capital from 5 percent to 4.5 percent. Overall consumer costs across 2025-2080 would be nearly 20 percent lower in such a scenario (€2.9 trillion compared to €3.5 trillion), although costs would be higher in the earlier years.

26 Approximately €64 billion/year, expressed in 2025 euros.

The converse is also true. Policymakers might want to stretch out the asset life in the regulatory framework, meaning that the annual costs are lower. However, because network companies earn a return on their RAB, which would remain higher for longer, the overall cost for consumers would increase if such an approach is taken, and the impact on annual tariffs may not be significant (Figure 8, panel D).

6.3.2 Smoothing consumer costs through national funds

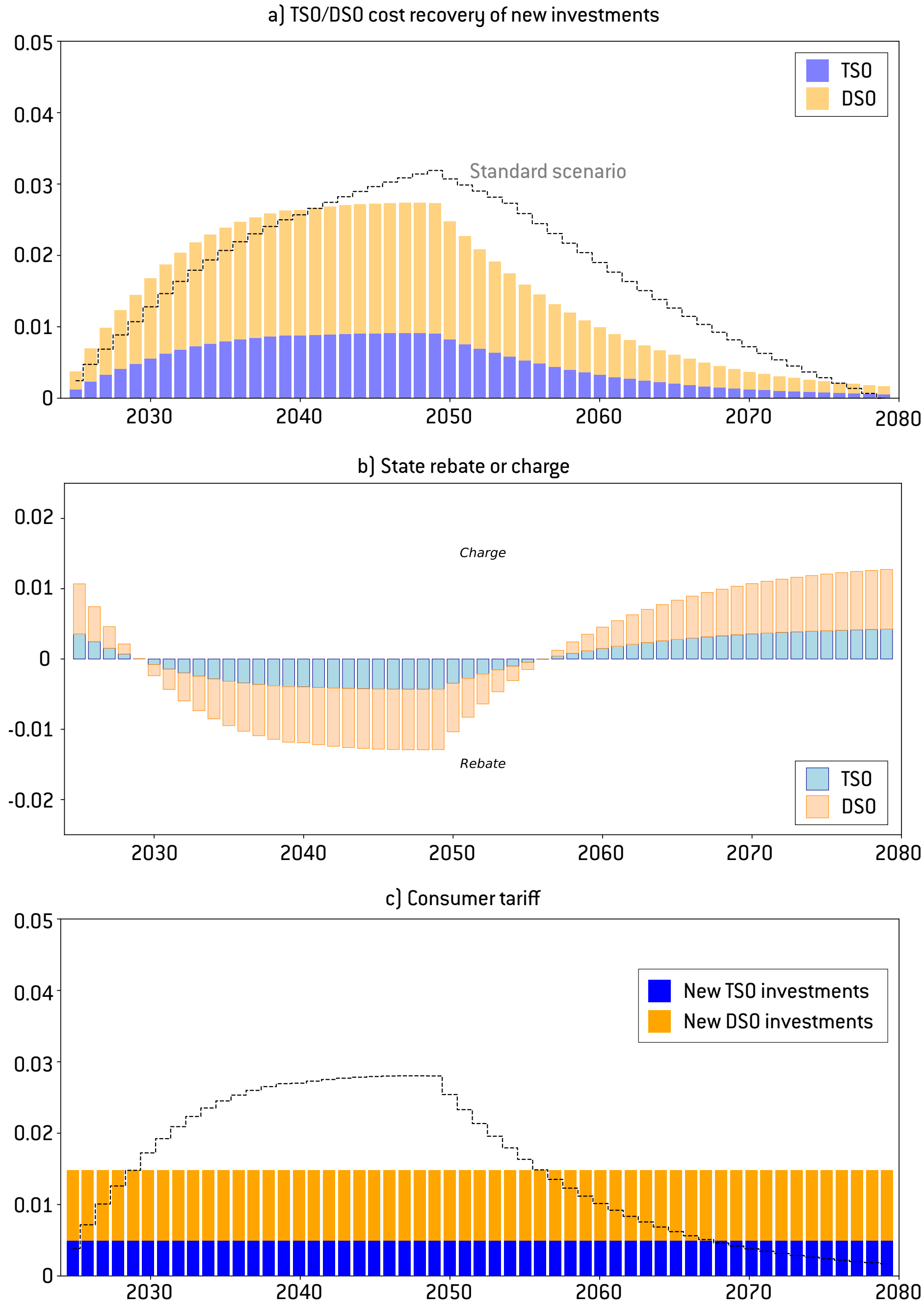
A grid built today will provide value for decades; it makes sense to not put all of the costs on today's consumers and taxpayers

A grid built today will provide value for many decades, with many benefits accruing when the transition to clean electricity is in its later stages, especially if grid investments are made in anticipation of future demand growth. It thus makes sense to not put all of the costs of new infrastructure on today's consumers and taxpayers, but to use financing tools to spread out the cost over time. National public funds could enable faster depreciation for investors while avoiding price spikes for consumers by taking on costs in the early years of the recovery period and then charging consumers for incurred costs in later years (a so-called amortisation vehicle). Such an instrument could be cost neutral over its lifetime.

As national amortisation vehicles would protect consumers from price spikes in the early years of the grid investment wave, network companies could plan for faster depreciation, thereby potentially reducing the cost of capital compared to a baseline scenario. Returns would be higher for network companies in the early years but overall costs of the investment for consumers would be lower. Amortisation vehicles could then provide a rebate to consumers in the early years of the asset life. In the later years of the cost-recovery period, the state would add additional charges to consumer tariffs to recover those costs, making the fund cost-neutral. The result would be an annual consumer cost profile smoothed out over time. Overall consumer costs would be lower because of the reduced cost of capital associated with faster depreciation.

To illustrate what could be achieved with such an instrument, we modelled an amortisation vehicle in a context of grid tariffs for all grid levels remaining flat over the lifetime of €2 trillion of investment. As expected, such a design would lead to massive liabilities in the amortisation vehicle accounts at the point immediately before costs are recovered from consumers (approximately €800 billion across in the EU in 2055 according to our simulations). These liabilities are dependent on the covered grid levels (excluding DSO tariffs would slash them by about two-thirds, for example), electricity demand growth and the efficiency of grid buildout, each of which would lower the exposure of the fund substantially. Moreover, alternative cost profiles could be designed that do not reduce consumer costs so significantly during the peak years, thus reducing the maximum fund liability.

Figure 9: Impact of a state amortisation vehicle on consumer tariffs



Source: Bruegel.

However, if an amortisation vehicle led to inefficient grid investments, for example by triggering overbuilding, the national budget and consumers would ultimately bear the cost. A scenario could emerge in which a fund takes on significant costs in the early years when network investments are being made, but it becomes politically infeasible to recover these costs from consumers in later years, for example if electricity demand is lower than expected. Unfair state aid might also be a risk, with countries with greater public resources using such an amortisation vehicle to reduce energy costs and attract investment.

Rules should be set to reduce such risks. Anti-discrimination rules for network tariffs, under which countries would not be permitted to reduce network costs for industrial consumers that compete on the European single market, would reduce the risk of the amortisation vehicle being used for state aid. To encourage harmonisation in network tariff design, the EU should develop guidelines for investment-friendly network tariffs. The EU could propose a standard model for consumer tariffs and their reduction through national amortisation vehicles, which would serve as a reference when assessing national schemes, encouraging convergence through easing state-aid clearance when national systems align. The target model should include provisions on transparency, non-discrimination, and size and time limits on amortisation vehicles. To temporarily buy support for increasing cross-border investments that go beyond national interests, the EU funding discussed in section 6.2 could inject money into national amortisation vehicles.

In practical terms, amortisation vehicles could be owned by public companies such as TSOs. To avoid incurring public debt, the European Investment Bank could provide loans to the amortisation vehicle's management entity. Something similar has been done in Germany for developing the hydrogen network, with the national development bank providing a substantial loan to a state amortisation vehicle (de Zeeuw, 2024).

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Annex

Cross-border electricity exchanges included in Figure 4

Exporter	Importer	Exporter	Importer
AT	CZ	FR	DE
AT	DE	FR	ES
AT	HU	FR	IT
AT	IT	HR	HU
AT	SI	HU	AT
BE	FR	HU	HR
CZ	AT	IT	AT
CZ	DE	IT	FR
DE	AT	LT	LV
DE	CZ	LT	PL
DE	DK	LT	SE
DE	FR	LU	DE
DE	LU	LV	EE
DE	NL	LV	LT
DE	PL	NL	DE
DK	DE	PL	DE
EE	FI	PL	LT
EE	LV	PT	ES
ES	FR	SE	DK
ES	PT	SE	FI
FI	EE	SE	LT
FI	SE	SI	AT
FR	BE		