cerre Centre on Regulation in Europe



ELECTRICITY SYSTEM PLANNING AND GRID INVESTMENTS IN EUROPE

November 2026

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1. Introduction

This issue paper explores how Europe can accelerate the roll-out of electricity transmission networks. It draws on existing literature and discussions at the CERRE Regulatory Lab held in Brussels on 1 October 2026 under the Chatham House Rule.

Accelerating grid investment is needed to reach decarbonisation goals at low cost, improve security of supply and support strategic autonomy (COM(2025) 1005). This requires coordination among regulated transmission system operators (TSOs), generators and consumers, regulators and governments, not only at national but also at European level, as many of these coordination needs have an increasingly international dimension. Interconnections can lower system costs by linking regions with different renewable resources and production patterns over time. Large-scale offshore wind development involving hybrid interconnectors and, in future, more integrated offshore grids will require close coordination among the countries involved. Accelerating grid investment also requires improving the planning process, strengthening commitments to planning decisions and adapting network regulation. Uncertainty about future demand and generation makes planning and investment decisions more difficult.

The proposed European Grids Package would give the Commission a larger role in European network planning by making it responsible for developing a central scenario. The scenario would be used in project cost-benefit analyses, whose published results would show how benefits are distributed across countries (COM(2025) 1006, Arts. 11(1) and 14(13)). National network development plans would have to be based on scenarios consistent with the central scenario (COM(2025) 1007, Art. 40a(2)(c)). As of October 2026, the Council and the European Parliament have not adopted the proposal.

Improving planning is not enough: a plan tends to guide investment only if governments and market participants commit to it, also across borders, and if it remains reasonably stable from one planning cycle to the next. Such commitments also require rules, agreed in advance, on who bears the costs when outcomes differ from the plan.

Network regulation may also need to adapt. Increasingly, TSOs share the planning role with Member States, generators, regulators and European institutions, and under the proposal the Commission would set the central scenario. Yet TSOs still need to raise the capital for these investments and may bear financial risks created by decisions they do not control. TSOs are being asked to make larger bets than in the past: investments increasingly use newer technologies and depend on specific generation projects rather than on predictable demand growth.

This paper discusses some of these key issues and identifies trade-offs under three themes:

1. **How should Europe identify future transmission needs and coordinate network planning across Member States?** This includes how national, regional and European planning processes should interact (balancing granular technical details at country level and European coherence and system-wide optimisation) and how national preferences and EU-wide objectives can be reflected (balancing national energy mix versus European-wide strategic autonomy, security of supply and cross-sectoral interactions).

2. **How should plans be translated into commitments: who should guarantee implementation, and who should bear the risks when outcomes differ from the plan?** This includes commitments by governments and market participants, also across borders, and ex-ante rules for deviations from the plan.

3. **How should regulation support timely network investment when future generation and demand remain uncertain?** This includes how risk should be divided among TSOs, market participants and governments.

2. Problem Definition

Even if all cross-border transmission projects currently under development are completed, the resulting capacity remains below the level ENTSO-E estimates is needed to minimise system costs in 2040. Europe had 126 GW of cross-border transmission capacity in 2025, and projects under construction or at an advanced stage should bring this to 161 GW by 2030. Taking that 2030 grid as the starting point, ENTSO-E finds that a further 108 GW of cross-border capacity by 2040 would be required to minimise the total costs of Europe's electricity system. Building it would require about EUR 6 billion a year of investment until 2040, against welfare gains of about EUR 14 billion a year (ENTSO-E, 2025b). However, projects actually planned for after 2030 add only 80 GW, leaving a gap of 28 GW (ENTSO-E, 2025b), while 66 of the 105 projects monitored by the European Union Agency for the Cooperation of Energy Regulators (ACER) are behind their first reported commissioning date (ACER, 2024).

Coordinating transmission investment with decisions about generation, storage and consumption is difficult because those decisions are decentralised and market-based, while network planning and investment are centralised and regulated. This split follows from unbundling, which separated competitive wholesale and supply markets from regulated networks (Directive (EU) 2019/944, as amended, recitals 67 and 68).

Network planning must also be coordinated with government decisions affecting the generation mix and the speed of electrification. Governments influence how much generation is built and where, through technology-specific support schemes and auctions for seabed rights (Pollitt et al., 2022). Roques and Finon (2017) describe this combination of market decisions and government support as a hybrid market regime. Joskow (2022) expects a partial return to government planning, through long-term contracts and government-mandated procurement. On the demand side, national policies affect how quickly heat pumps and electric vehicles are adopted. Credible government commitments can make future generation and demand easier to anticipate.

Planning remains fragmented across National Energy and Climate Plans (NECPs), even though renewable generation, flexibility and cross-border trade increasingly affect network needs beyond national borders (Roth et al., 2026). On paper, national and European plans rarely contradict each other: almost all reporting Member States use the European scenarios directly or take them into account (ACER, 2025a). In practice, they differ in what they assume and in the analysis behind them. For 2030, the sum of the NECPs projects considerably less electricity demand than the Commission's EU Reference Scenario 2020, which in turn projects less than ENTSO-E; the exercises date from different years, and the national plans together fall short of the EU targets that ENTSO-E's 2030 scenario is built to meet (Roth et al., 2026; ENTSO-E, 2025b). National approaches to identifying needs also vary: in around half of the reporting Member States, the TSO conducts a formal needs identification study; in eight, it does not; and consistency checks of national plans against the European plan have not led any reporting regulator to take action (ACER, 2025a).

Cross-border and national networks cannot be assessed separately. The cross-border reinforcements that ENTSO-E finds beneficial on half of Europe's borders require strong reinforcement of national internal grids (ENTSO-E, 2025b). The benefits of such lines are also unevenly distributed across countries and uncertain in advance. They depend strongly on demand growth and on generation

capacity decisions in each country: a change in nuclear capacity, for example, can materially affect cross-border price differences and therefore the value of an interconnector. Whether countries can share these risks depends on whether the effects offset each other across borders or move in the same direction (Serrien et al., 2026).

Efficient network investment decisions therefore depend on assumptions about where and when generation and demand will develop, and which flexibility resources will be available. TSOs share the planning role with other actors. Member States set energy policy and targets and decide on the availability of sites. National regulatory authorities scrutinise national network plans and set tariffs. ENTSO-E draws up the Union-wide ten-year network development plan and its scenarios (jointly with ENTSOG, its gas counterpart). ACER sets framework guidelines with criteria for how these scenarios are developed, consulted on and published, gives opinions on the European plan and on the consistency of national plans with it, and decides on cross-border cost allocation when national regulators cannot agree. The Commission approves the scenarios, adopts the list of projects of common interest agreed with the Member States, and provides funding (Regulation (EU) 2022/869, Arts. 3, 12 and 16; Regulation (EU) 2019/943, Art. 48; ACER, 2025a). Generators and other project promoters decide on generation investment, and consumers invest in electric vehicles, rooftop solar, batteries and flexibility, while paying for the networks through tariffs. Because these decisions are taken by different actors, at different levels and on different timescales, aligning network investment with generation and demand is difficult. Depending on the regulatory framework, TSOs may therefore bear financial risks created by decisions they neither control nor can fully predict.

This issue paper will consider how planning should be coordinated (Theme 1), which commitments are needed to support investment (Theme 2), and how regulation should allocate risk (Theme 3). The paper concentrates on transmission network investment and its coordination with generation and consumption, including demand response. It does not discuss distribution planning, where the planning issues are mainly national, nor permitting and supply chains, which the Grids Package addresses through separate measures (COM(2025) 1007 for permitting; COM(2025) 1005, pp. 5-6 for supply chains).

3. Planning and Coordination

The first question is whether existing bottom-up planning processes need to be complemented by more top-down planning at EU or regional level, given the coordination needs created by renewable generation, cross-border interdependence and concerns about European resilience.

There are different understandings of what planning involves. For policymakers, it may mean targets for specific technologies or the choice of an energy mix. In a policy impact assessment, it may mean estimating how a proposed support mechanism, such as an electric vehicle subsidy, would affect investment and consumption against a baseline reflecting existing policies. For TSOs, it may mean planning the route of a network asset, choosing technologies and sizing the investment.

Network planning today starts bottom-up, from national energy and climate policy. In their **National Energy and Climate Plans (NECPs)**, Member States set out objectives and policies for the five dimensions of the Energy Union: decarbonisation, energy efficiency, energy security, the internal energy market, and research, innovation and competitiveness. A new plan is due every ten years, with an update halfway, and progress reports every two years; the current plans cover 2021 to 2030, were submitted in 2019 and updated in 2024 (Regulation (EU) 2018/1999, recital 2 and Arts. 3, 14 and 17). TSOs prepare **national network development plans (NDPs)** based on existing and forecast supply and demand (Directive (EU) 2019/944, Art. 51(1)). Most national scenarios are aligned with the NECPs, but there is no harmonised method for developing them, and national planning cycles range from one to six years. Almost all Member States also use the European TYNDP scenarios in their national plans, either directly or alongside their own, although those European scenarios are themselves largely built from national data (ACER, 2025a). Most national plans use cost-benefit analysis: some countries apply it only to cross-border projects, and in some, a project with a negative result can still be included (ACER, 2025a).

At European level, ENTSO-E drafts the **Union-wide ten-year network development plan (TYNDP)** every two years, building on national investment plans (Regulation (EU) 2019/943, Art. 48; Roth et al., 2026). It starts from energy-system scenarios developed jointly by ENTSO-E and ENTSOG. The central **National Trends** scenario is in line with national policies, including the NECPs, and is built from demand and generation figures collected from the TSOs: these quantities are fixed inputs, not the result of a model (ENTSO-E, 2025c). Two further scenarios, Distributed Energy and Global Ambition, explore different futures for 2040 and 2050 and act as stress tests. They fix demand but let a model choose part of the generation, flexibility and network investment. They reflect the requirement that European scenarios look ahead to 2050, for which Member States have no detailed plans (ENTSO-E, 2025c; Regulation (EU) 2022/869, Art. 12). A **system needs study** then takes generation, demand and flexibility assets from the National Trends scenario for 2030 and 2040 as given, and can only invest in cross-border transmission and storage from a list of candidates, to minimise total system costs. Its results are expressed per border, not per project. The two other scenarios serve as a check: for 2040 they show even higher needs. The costs of the internal reinforcements needed for these cross-border increases are included as estimates, but national networks are not modelled in detail (ENTSO-E, 2025b).

Project promoters, mostly TSOs but also third parties, then submit concrete projects, with a specific location and estimated costs (ENTSO-E, 2025a). A **project cost-benefit analysis** evaluates each project

individually: it compares a reference network with and without the project, with generation capacities and annual demand fixed, and reports indicators such as socio-economic welfare, emissions, renewable integration and security of supply (Willems et al., 2025). Because projects are assessed one at a time, the method can miss projects that complement or substitute for each other (Willems et al., 2025). The analysis is repeated for several scenarios: in the 2024 edition, National Trends for 2030 and 2040, with market indicators also for Distributed Energy 2040; no project is assessed for 2050 (ENTSO-E, 2025a).

Projects in the TYNDP whose benefits outweigh their costs can become a **project of common interest (PCI)**, on the EU list of priority cross-border projects (Regulation (EU) 2022/869, Art. 4(1)). Member States and the Commission select PCIs by consensus in regional groups, host Member States must approve projects on their territory, and the Commission adopts the Union list (Regulation (EU) 2022/869, Art. 3 and Annex III). Selection therefore combines an economic assessment with political agreement. PCI status gives priority in permitting and access to EU funding (Willems et al., 2025).

For mature PCIs, promoters can request a **cross-border cost allocation**. The national regulators concerned decide jointly how investment costs are shared between TSOs; if they cannot agree within six months, ACER decides (Regulation (EU) 2022/869, Art. 16). In practice, costs are often allocated by territory or split equally (Willems et al., 2025). About one-third of the decisions taken between 2014 and 2024 contain a mechanism, agreed in advance, for adjustment if assumptions change, mostly when costs change (ACER, 2025b).

Most transmission investment is **financed** by the TSOs and recovered through network tariffs, after congestion income and other charges (Regulation (EU) 2022/869, Art. 16(1)). PCIs can also apply for EU grants from the Connecting Europe Facility, for studies and works (Regulation (EU) 2022/869, Art. 18).

Several weaknesses follow from this process. Because generation, demand and flexibility are assumed to be fixed inputs to the network planning process, the process is not designed to show whether building generation or flexibility in a different place would be cheaper than building lines (Willems et al., 2025). Because projects are assessed one at a time against a reference network, projects that only pay off together may each look unattractive; two projects that substitute for each other may both look attractive; and projects already in the reference network are favoured over alternatives (Willems et al., 2025). And because selection and cost allocation require agreement between Member States, a project with overall net benefits can be blocked by a country that expects higher prices or tariffs without sufficient benefit. Territorial or equal cost splits do not follow where the benefits fall, so a country can end up paying more than it gains (Willems et al., 2025; SWD(2025) 2000).

The Grids Package would move the development of the central scenario from ENTSO-E and ENTSOG to the Commission, supported by the Joint Research Centre (COM(2025) 1006, Art. 11 and financial statement). The scenario would cover electricity, hydrogen and natural gas, be consistent with EU energy and climate targets, extend to at least 2050, include sensitivity analyses, be renewed at least every four years, and have its input and output data published. ENTSO-E, ENTSOG, the hydrogen network operators' association and Member States would supply the data, and the Commission could ask ACER to verify them, together with national regulators (COM(2025) 1006, Art. 11). ENTSO-E would continue to carry out the system needs study and the project cost-benefit analysis, but both would have to be consistent with this scenario, including its assumptions on flexibility (COM(2025) 1006,

Arts. 12 and 14). The Council would also invite Member States to verify national assumptions (ST 10746/2026, Art. 11). The European Parliament's industry committee wants updates every two years instead of four, and a second scenario based on actual progress in supply and demand, next to the Commission's scenario consistent with EU targets; this second scenario would likely be less ambitious (A10-0231/2026, Art. 11).

Open issues include the following:

How should EU-wide scenarios and models be linked to more detailed regional planning and bottom-up distribution planning? The growing European dimension of network planning calls for more top-down coordination of data, assumptions and planning cycles. This does not require a detailed EU-wide investment plan or a single model: shared scenarios and open data would allow competing models to be compared. Distribution planning depends on local information about connections, congestion and flexibility, and requires bottom-up models and coordination between DSOs and TSOs. A single top-down process cannot replace those local assessments. At regional level, offshore grids may require more detailed joint planning of specific investments.

Should EU-level scenarios make policy measures more explicit? Europe is not a planned economy. Consumers respond to prices and policies when buying electric vehicles and deciding when to charge them; those decisions affect demand and flexibility. A network study that takes future demand and flexibility as fixed inputs cannot examine these responses or their links with transport. It may therefore be useful for some EU-level scenarios to specify policy measures and use cross-sector models to estimate the resulting demand and flexibility.

How do we integrate national choices about the energy mix and European objectives with respect to strategic autonomy in the scenario and model development?

4. Commitment and Risk Allocation across Borders

The second question is how plans should be translated into commitments, and who should bear the risks when outcomes differ from the plan, in the context of an investment whose impacts cross borders between Member States.

A commitment here means a promise to stick to an investment or policy choice, on which a cross-border line relies, such as generation or storage in a given location, or a reinforcement of a national grid. Such commitments may make planning more reliable, because they reduce uncertainty about future generation and demand (Willems et al., 2025). Yet commitments can also lock in policy choices that new information would justify revising, or induce parties to make irreversible investments before useful information becomes available.

In an integrated electricity system like the EU's, the net benefits of an investment may depend on what other countries do after it is built: their energy mix, their use of the line and their investments in complementary national grids (Willems et al., 2025). For offshore interconnectors in the North Sea, decisions on generation capacity are among the main drivers of a project's value (Serrien et al., 2026). If these decisions are not part of the agreement, a country can lose out once its investment is made. This is a hold-up problem, and agreeing in advance what happens after such changes can reduce the risk of hold-up (Willems et al., 2025). Some changes cannot easily be ruled out by contract, typically because Member States keep the right to choose their energy mix, or because developments were not foreseen. The agreement could set compensation in advance: a country would remain free to change its energy mix, but would compensate the TSO if this reduced the need for the line (Willems et al., 2025). Within a country, such commitments can be organised through contracts between network operators and generators, backed by government guarantees; across countries, they require coordination between Member States, through the EU, or both (Willems et al., 2025).

CERRE's earlier work proposes two types of commitment (Willems et al., 2025). The first is an agreement between Member States. It would commit them to their national generation and demand scenarios, including the timing, technology and location of generation, and to the complementary network investments on which the benefit assessment is based (Willems et al., 2025). A paper from the Florence School of Regulation similarly proposes that Member States commit to targets for their future generation mix and its location (Sikow-Magny, 2025). The closest existing instrument is the non-binding agreement in which Member States set goals for offshore renewable generation in each sea basin (Regulation (EU) 2022/869, Art. 14(1)). According to the Commission, these goals and the offshore network plans based on them have not yet led to the identification and realisation of concrete cooperation projects (SWD(2025) 2000). Across borders, EU energy law provides no compensation mechanism of this kind, so it would require a voluntary agreement between Member States. If it were introduced in EU law, it would have to be reconciled with Article 194(2) TFEU, which preserves a Member State's right to choose between energy sources and to determine the general structure of its energy supply (Willems et al., 2025; TFEU, Article 194(2)).

The second type uses contracts to establish specific financial rights and obligations, rather than relying solely on general regulatory rules. A government could buy a financial transmission corridor to an

offshore wind location: a long-term financial transmission right, for which it pays a fixed fee in return for a share of the congestion rents on the line. The TSO obtains more certain revenue, but bears the risk of not delivering the line on time; for causes outside its responsibility, such as permitting delays, some risk sharing would be needed (Willems et al., 2025).

Open issues include the following:

How large is the risk of hold-up in network investments with cross-border benefits? A country may be reluctant to invest if it fears that, once costs are sunk, it will lose bargaining power and be unable to recover an adequate share of the costs from other countries. Anecdotal evidence from the discussion suggests that cross-border effects may be significant, arising from generation and consumption decisions as well as internal network reinforcements.

Should Member States commit to their generation mix and production locations, and should they pay compensation for deviations? A firm commitment to a generation mix is often not possible, because investment and production also depend on decisions by firms, electricity demand and market prices. Governments nevertheless control decisions that affect the mix, such as nuclear phase-outs, support for offshore wind and permitting. Where changes in these policies reduce the value of network investments in other countries, compensation might be justified. Commitments need not specify the generation mix. They could concern interconnection targets, such as the current 15% target, and, in future, specified levels of flexibility and reliability, drawing on the approach used for reliability standards under capacity-mechanism rules. Agreements could specify these commitments and the compensation due if they are not met.

Besides Member States, should TSOs also make commitments, for example on the timing and location of their investments? Investments included in national network development plans (NDPs) are binding in some countries but indicative in many others (ACER Opinion 07/2025, para. 43). Workshop examples suggest that repeated delays can occur despite investment obligations. Under the ITO regime, regulators must intervene when qualifying planned investments are not delivered, with tendering among their options. Many countries have extended these provisions to other TSOs (Directive (EU) 2019/944, Art. 51(7); CEER, 2025, pp. 13 and 24). Should these enforcement procedures be applied more widely, and are they sufficient to secure timely delivery?

Should network users make binding commitments to the timing and location of their investments? Network operators may invest in capacity for projects that are subsequently delayed or abandoned. The workshop discussed upfront payments towards connection and reinforcement costs, offset against later charges, as a way to obtain a partial commitment from developers. Such payments could serve a similar purpose to a completion bond. In Great Britain, generators pay a cancellation charge if they terminate their agreement to connect to the transmission network or reduce the capacity they have booked. They secure this charge with a bond, a letter of credit or a cash deposit (National Energy System Operator, 2026; CUSC Section 15).

5. Regulation of Network Investments

The third question is how regulation should support timely network investment when future generation and demand are highly uncertain.

Some network investments are larger bets than in the past. Their value may hinge on a single outcome, such as whether an offshore wind farm gets built. If it does not, the asset may remain underused. For a large project, the loss may be difficult to offset through the TSO's other investments. Such projects may also use new technologies, such as offshore high-voltage direct current (HVDC) links (Pollitt et al., 2024). They are irreversible and have long lead times: transmission projects can take more than a decade to build (C/2025/3179). The use of new technologies can make costs harder to compare with those of other projects under incentive regulation. Their optimal timing and size are also harder to judge, as it is difficult to judge in advance how much 'learning by doing' may reduce the costs of later investments based on similar technology. Under some types of regulation, large network investments also expose the TSO to more risk. For example, where remuneration depends on how much an asset is used, operators may be more reluctant to carry out a large project since it will carry more risk (ACER & CEER, 2024).

Investments made in advance of large changes to generation or demand are often called anticipatory investments, although all network investments anticipate future needs to some degree. The term appears in EU legislation but is not explicitly defined (C/2025/3179). [1] The Commission and ENTSO-E propose adjusted regulatory treatment for anticipatory investments. They recommend that regulators assess and approve such investments in advance and not penalise TSOs solely because use later turns out lower than expected (C/2025/3179; ENTSO-E, 2024). The Commission asks that benchmarking take anticipatory investment into account, while ENTSO-E would rule out benchmarking of underused assets (C/2025/3179; ENTSO-E, 2024). Benchmarking is a method some regulators use to determine the revenue network operators may recover through tariffs. It compares operators' costs and performance to assess efficiency. An anticipatory investment may appear inefficient if expected demand does not materialise or arrives later than forecast. ACER and CEER, the Council of European Energy Regulators, are wary of the impact on tariffs (ACER & CEER, 2024). They propose to allow permitting to start early but to only approve construction once the need is confirmed. They also propose better information on available network capacity and future connection requests, and regulatory approval of the investments in transmission plans, not only of their costs (ACER & CEER, 2024).

Economic theory offers some guidance on when to make anticipatory investments and how to regulate them. Real options theory analyses the optimal timing of irreversible investments when demand is uncertain and waiting reveals more information. It shows that a positive net present value today is not enough to justify investing immediately. The value of waiting must be weighed against the cost of leaving early demand for the line unserved. The regulatory test should therefore compare

[1] Banet (2026, p.244) defines anticipatory investments as "*an investment, by a private or public entity, that goes beyond the immediate needs of the initial user's development. These investments are not needed for committed projects, but they can address near-future needs*" stressing the intertemporal character and the possibility that the investment might remain unused. Banet, C. (2026), 'Regulating Anticipatory Investments in Electricity Grids: The Example of Hybrid Offshore Wind Grid Solutions', in P. Delimatsis and G. Monti (eds.), *EU Law and Regulatory Spaces: Essays in Honour of Leigh Hancher* (Hart Publishing), pp. 241–256.

the expected net present value of building now with that of delaying the decision until more is known about demand, including the possibility of not building the line (Willems & Zwart, 2018). Long project lead times, however, may require an earlier investment decision (C/2025/3179).

Exposing TSOs to risk may improve efficiency when they can influence outcomes or predict them better than regulators. If TSOs have better information about future network demand, de-risking them with specific anticipatory regulatory measures might not be optimal. Specific regulatory treatment for anticipatory investments may be more justified when demand risk arises from government policies or lumpy generation investments. There, the extra risk has little incentive effect, but it raises the cost of capital and may delay investment (Pollitt et al., 2024). Part of this risk is created by governments, through poor planning or a lack of commitment. Reducing it may bring investment forward.

In practice, the regulation of anticipatory investments may need fine-tuning, because the two extremes may be too crude. Guaranteed full cost recovery makes investment risk-free for the TSO (ACER, 2026), but may lead to overinvestment (Willems and Zwart, 2018). Incentive regulation may lead TSOs to postpone investment in long-lived assets (Willems and Zwart, 2018). Some regulators therefore keep approved investments outside efficiency targets or already allow a return on capital during construction (CEER, 2026; ACER & CEER, 2024). The Commission (C/2025/3179) also mentions state loans repaid according to use.

Open issues include the following:

How can the cost efficiency of anticipatory investments be assessed? Before an anticipatory investment is confirmed, expected demand growth and the risks around it should be made explicit. Afterwards, costs and utilisation should be assessed against those expectations and risks, rather than treating underuse alone as evidence of inefficiency.

Who bears the risks of network investments under existing regulation? A TSO's shareholders' exposure depends on the regulatory framework. A risk associated with an investment is not necessarily a financial risk for the TSO that undertakes it. Network users often bear the residual costs of network investments through tariffs unless specific rules allocate them elsewhere.

Which risks need to be distinguished? Four types of risk should be considered: delivery risk, where infrastructure arrives late and planning goals are not achieved; cost escalation risk, for example from higher equipment prices or unexpected ground conditions when laying underground cables; stranding risk, where assets remain underused because expected generation or demand does not materialise, such as when an offshore wind farm is not built; and regulatory risk, for example where allowed returns do not keep pace with rising financing costs or rules for cost recovery change after investment.

Which of these risks should be shifted from network users to TSO shareholders? Under cost-plus regulation, network users often bear most investment costs and risks. Incentive regulation shifts some of these risks to shareholders to encourage better decisions, particularly where the TSO controls outcomes or has better information. This may raise the cost of capital, but the aim is for efficiency gains to outweigh the additional financing costs. ***Delivery risk*** could be shifted towards shareholders through penalties for late completion. ***Cost escalation risk*** could be shared: procurement and construction management are partly within the TSO's control, while equipment-price increases or unexpected ground conditions may be harder to manage. ***Stranding risk*** could remain with network

users for a large project built in response to an agreed national plan. ***Regulatory risk*** should be reduced through clear rules and credible commitments on remuneration, cost recovery and risk allocation; otherwise, it may undermine the efficiency gains from shifting the other risks.

Should bilateral contracts shift more stranding risk to network users? Where network investment serves a particular wind farm or data centre, upfront connection payments or cancellation charges could make that user bear part of the stranded costs if its project is delayed or abandoned, reducing the costs passed to other network users. Such commitments could be reciprocal, with the network operator also committing to a connection date. Regulation could encourage stronger financial commitments from generators and large electricity users.

6. References

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