European electricity infrastructure in the energy transition age

Finanziato dall'Unione europea NextGenerationEU
Ministero dell'Università e della Ricerca
Italiadomani PIANO NAZIONALE DI RIPRESA E RESILIENZA
NEST NETWORK FOR ENERGY SUSTAINABLE TRANSITION
INTESA SANPAOLO

Disclaimers

NEST - Network for Energy Sustainable Transition - is an extended public-private partnership project selected by the MUR (Ministry of University and Research). This document is part of the activities carried out by Intesa Sanpaolo within the project funded by the European Union - NextGenerationEU - National Recovery and Resilience Plan (PNRR) - Mission 4 Component 2 Investment 1.3 - Notice No. 341 of 15.03.2022 of the Ministry of University and Research (MUR). NEST envisages the participation of 24 partners including universities, public and private research centres and companies, distributed throughout the country and focused on the macro scientific areas in which the research project is developed. Intesa Sanpaolo is one of the founding members and partner companies involved in the project.

Present document is not exhaustive and it is to be considered as a working progress paper.

This document is for informational purposes only and does not in any way constitute an offer, solicitation, promotion or invitation to buy or sell products or services. All content is provided for informational purposes only.

oxera

European electricity infrastructure in the energy transition age

—

Prepared for Intesa Sanpaolo S.p.A. and FortyEight Brussels

December 2025

Finanziato dall'Unione europea
NextGenerationEU

Ministero dell'Università e della Ricerca

Italiadomani
PIANO NAZIONALE DI RIPRESA E RESILIENZA

NEST
NETWORK FOR ENERGY SUSTAINABLE TRANSITION

INTESA SANPAOLO

Contents

Oxera Consulting LLP is a Limited Liability Partnership under English law, registered in England with registration number OC392464 and registered office at the following address: Park Central, 40/41 Park End Street, Oxford, OX1 1JD, United Kingdom, with an additional office in located at 200 Aldersgate, 14th Floor, London, EC1A 4HD, United Kingdom. Oxera has the following branches: in Belgium with number 0651 990 151, registered office in: Spectrum, Boulevard Bischoffsheim 12-21, 1000 Brussels, Belgium; in Italy with REA number RM – 1530473, registered office in: Via delle Quattro Fontane 15, 00187 Rome, Italy, with an additional office located at Piazzale Biancamano 8, 20121 Milan, Italy; and in Spain, with CIF number W0306516F, registered office in: LOOM Azca, Plaza Pablo Ruiz Picasso 11, Planta 1, 28020 Madrid, Spain.

Figures and Tables

Executive summary

Europe's energy transition stands at a critical juncture. Facilitating this transition and meeting the EU's ambitious energy and climate targets for 2030, in line with the Fit for 55 targets, and the net zero commitment by 2050 of the European Climate Law, will require large-scale deployment of renewable energy sources (RES) alongside strategic and complementary investments across a wide set of technologies and infrastructures, including electricity grids, electricity storage and demand-side flexibility.

This study, commissioned by Intesa Sanpaolo S.p.A. and FortyEight Brussels assesses how different investment pathways—with varying interconnection capacity and flexible resources availability—can reshape the European electricity system's costs, reliability, and decarbonisation trajectory over the 2030–40 period.

To support informed decision-making, the study employs the BID3 European electricity market model developed by AFRY Management Consulting S.r.l. to assess the implications of four stylised scenarios, which vary two key parameters: the costs for BESS (reflecting different levels of flexible resources availability) and the interconnection capacity across bidding zones (representing different degrees of system planning coordination).

While the study has a European scope, covering the EU-27, expanding to EU-30 (also including Norway, Switzerland and the United Kingdom) where data availability allows to do so, it discusses the key findings and also provides deep-dives for the focus countries, i.e. France, Germany, Italy and Spain—countries that together represent over 57% of EU electricity demand and exhibit diverse regulatory and market structures.

Comparing AFRY's BID3 model results across the four scenarios provides insights into the trade-offs and synergies between transmission coordination and distributed flexibility deployment. At a high level, model results show the following.

Demand flexibility is foundational. The expected evolution (and level of flexibility) of electricity demand plays a key role in ensuring a competitive, affordable and resilient electricity system. The type of demand matters as much as the quantity. Under the Baseline scenario, flexible decarbonised demand enables a 33% reduction in wholesale electricity prices between 2030 and 2040 (reaching €48.5/MWh for the focus countries). Instead, sensitivity analysis shows that without additional flexible decarbonised demand, no price reductions would be achieved by 2040, with wholesale prices consistently remaining around €70/MWh in the focus countries. This derives from the fact that flexible decarbonised demand better aligns itself with renewable generation. It therefore increases consumption in periods of surplus solar and wind, deepening the value of these resources, supporting additional RES build-out and reducing reliance on gas-fired generation.

EU and member state policy is key to ensure these projected benefits are actually realised. According to ENTSO-E's Ten-Year National Development Plan 2024 (TYNDP 2024) scenarios, which form the starting point for the modelling exercise, demand is projected to undergo unprecedented growth (+56% between 2024 and 2040 in the four focus countries), despite it remained essentially flat over the previous two decades. Therefore, policy measures are likely to be needed to stimulate the required change. This will likely require state resources, with associated implications, including the need for state aid approval and potential challenges in terms of ensuring the level playing field within the EU.

Interconnection and storage are complements, not substitutes. Additional (and coordinated) investments in interconnection capacity and BESS serve different purposes and support one another. While taken forward on its own, more interconnections perform better than more flexibility, the combination of the two policy levers (enhanced interconnections, and increased adoption of BESS and flexibility more broadly) achieves the greater benefits, making the Full Policy scenario the preferred outcome. While BESS excels at providing short-duration flexibility, it cannot fully replace dispatchable thermal generation for addressing extended periods of low renewable availability (e.g., the Cheaper BESS scenario still requires 15GW of new gas-fired capacity to come online between 2030 and 2040). Instead, based on the modelling results, no new gas-fired capacity is needed in the scenarios with higher cross-border interconnection capacity (Enhanced NTCs and Full Policy scenarios).

Cross-border coordination could deliver benefits. While greater interconnection across bidding zones generally brings positive benefits, these are often unevenly distributed on the two sides of a new interconnector. This can slow down the buildout of new interconnection capacity, even where it would bring additional benefits. Therefore, greater centralised decision making and appropriate compensation mechanisms may be required to facilitate the planned investments.

The cost structure changes radically. While historically a large proportion of total system costs were variable—fuel, CO_2 and operating expenses (OPEX)—towards 2040 capital expenditures (CAPEX) are projected to become more prevalent across the modelled scenarios (all of which characterised by high RES-penetration and flexible decarbonised demand). Overall, total system costs over the period 2030–40 are broadly comparable across the four scenarios, but their composition differs significantly. In particular, while the expansion of interconnection, BESS and generation assets requires considerably higher investments in long-lived assets, it also reduces the variable costs to operate the system (e.g. lower commodity and fuel costs for thermal plants), which instead are a 'recurring expenditure'. Moreover, a lower share of variable generation costs also means that the system will be less exposed to fuel price volatility and external shocks (all else equal).

The OPEX to CAPEX shift has implications for financing, risk allocation and consumer prices. First, with the large volume of CAPEX required, the cost of capital becomes one of the single largest determinants of consumer prices. Therefore, stability and predictability of regulatory and policy frameworks influence perceived risks and required returns, more directly impacting affordability. Secondly, increased CAPEX intensity also exposes consumers to asset costs, with supply-chain constraints and the cost of construction materials affecting the delivered cost of the transition for consumers.

Moreover, as a greater share of total system costs becomes 'fixed', it is key that demand grows in line with the expectations. Otherwise, if projected demand growth does not materialise, a (relatively) smaller set of consumers will bear the costs and therefore end-user costs are likely to remain higher, raising affordability and competitiveness concerns. At the same time, flexible demand can play a key role as it could allow the system to be dimensioned below its peak. In this respect, the sequencing of demand growth is also relevant, as expanding more flexible demand first could alleviate some bottlenecks (e.g. for grid expansion that takes time) and contribute to reducing costs for expanding generation and network capacity.

Lower wholesale electricity prices increase missing money. Lower wholesale prices mean that generation, storage and interconnection assets can recover a smaller share of their total costs through market revenues alone. Notably, the Full Policy scenario exhibits the highest missing money among all scenarios, reflecting the fact that it achieves the greatest reductions in wholesale prices, while CAPEX requirements are substantial and rising. Missing money will require policy measures to overcome the gap through appropriately designed support mechanisms, including for example RES support schemes, storage remuneration and capacity mechanisms which are likely to evolve rather than disappear.

Overall, model results show that the Full Policy scenario, combining the two policy levers assessed in this study, delivers the best outcomes—but only under a policy framework capable of delivering grids, flexibility, (flexible decarbonised) demand growth and stable investment conditions.

While the modelling analysis provides valuable insights into infrastructure investment trade-offs, it is important to acknowledge some limitations to ensure appropriate interpretation of the results. First, scenario findings are sensitive to the starting point and associated (non-neutral) assumptions, e.g., different demand pathways would materially change capacity needs and price dynamics. Moreover, the BID3 model operates on a zonal basis and does not capture intra-zonal or distribution-level constraints. Finally, the modelling exercise reflects a least-cost optimisation (from a system perspective) which may not be achieved by market forces and price signals alone, so market outcomes could differ from the results of this optimisation process.

1 Introduction

Europe's energy transition stands at a critical juncture. Facilitating this transition and meeting the EU's ambitious energy and climate targets for 2030, in line with the Fit for 55 targets,[1] and the net zero commitment by 2050 of the European Climate Law,[2] will require more than just large-scale deployment of renewable energy sources (RES). It also requires strategic and complementary investments across a wide set of technologies and infrastructures.

The development of a resilient and decarbonised electricity system demands a coordinated approach. This includes scaling up low-carbon installed capacity; investing in flexible resources, such as electricity storage; maintaining in operation a certain number of gas-fired plants; and expanding electricity networks. These investments are not optional extras—they are essential enablers to integrate renewables effectively into the grid, ensure system stability and help to avoid bottlenecks that could slow down the pace of the transition. Moreover, demand-side flexibility offers additional benefits, enhancing the security and adequacy of the future electricity system, while contributing to containing overall system costs (e.g. by smoothing peak demand) and better utilising RES assets (e.g. by absorbing excess supply and reducing RES curtailment).

This study addresses a critical question for European policymakers and investors: how do different investment pathways shape the speed, cost, and resilience of our electricity system transformation?

Commissioned by Intesa Sanpaolo S.p.A. and FortyEight Brussels, this study focuses specifically on the relative implications of allocating more or fewer resources to certain technologies, in particular battery energy storage systems (BESS) and electricity grids (with a specific focus on interconnectors connecting different bidding zones). Understanding these trade-offs is crucial for assessing how investment choices affect both the pace and cost-efficiency of Europe's energy transition.

[1] See European Commission (2023), 'Commission welcomes completion of key 'Fit for 55' legislation, putting EU on track to exceed 2030 targets', Press release, 9 October. See also European Council, Council of the European Union, 'Fit for 55' (accessed 5 November 2025).

[2] Official Journal of the European Union (2021), REGULATION (EU) 2021/1119 OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL of 30 June 2021 establishing the framework for achieving climate neutrality and amending Regulations (EC) No 401/2009 and (EU) 2018/1999 ('European Climate Law'), 9 July.

To support informed decision-making, this study employs a European electricity market model (specifically the BID3 model developed by AFRY Management Consulting S.r.l.) to assess the implications of investing (more or less resources) in different technologies. The focus is on four stylised scenarios, which depict different potential pathways for the European electricity system. These scenarios vary two key parameters: the costs for BESS (reflecting different levels of flexible resources availability) and the interconnection capacity across bidding zones (representing different degrees of system planning coordination). This scenario-based approach enables robust assessment of system-wide effects under different investment strategies and policy frameworks.

This study has a European scope, covering the EU-27, expanding to EU-30 (EU member states, plus Norway, Switzerland and the United Kingdom) where data availability allows to do so. While the analysis and the modelling exercise have been carried out at the European level, this study discusses the key findings and **also provides deep-dives for the focus countries, i.e. France, Germany, Italy and Spain, offering country-specific insights for national policymakers and market participants**.

The remainder of this study is structured as follows.

- Section 2 provides an overview of today's European electricity system and discusses the recent evolution of system costs and overall 'inefficiencies' in the EU-27, as well as key drivers of today's electricity prices in the EU.
- Section 3 discusses the challenges ahead in light of the profound changes expected in the European electricity system to achieve climate and energy goals.
- Section 4 describes the methodology and the analytical framework we adopted for the electricity market modelling analysis. The analysis was developed to test potential tools that could contribute to reduce wholesale costs during the transition towards a decarbonised electricity system.
- Section 5 provides an overview of the four scenarios modelled as part of the analysis.
- Section 6 presents key model results from the electricity market modelling exercise.
- Section 7 concludes by summarising the key findings of our analysis and discusses policy implications.

2 The overall context: today's electricity system

Overall, the transition is a market-wide effort that requires significant investments at all levels of the energy value chain for a variety of different assets, each of which is confronted with specific market failures and challenges.

Decarbonising Europe's electricity system, however, is not simply about adding renewable capacity. A major challenge is that **significant investments in new and traditional technologies**—i.e. RES, low-carbon flexibility sources (including storage for supply-side flexibility and demand response for demand-side management) and electricity networks—**are needed in a coordinated way**. When one element lags, it can represent a bottleneck for the others and the entire system, delaying the transition and increasing costs. **This interdependency makes investment incentives, timing, and sequencing critical policy considerations**.

In order to properly and effectively deal with this challenge, **policy analysis will require statistically reliable data covering all the key aspects of the European energy system**. However, currently many critical variables of the European energy system remain inadequately measured or reported. Certain data are either not collected or lack recent updates; existing information is gathered at the national level, without easy comparability across Europe; and inconsistencies persist among different data providers and subsequent releases. Without comprehensive and harmonised data collection, the European energy transition risks being guided by assumptions rather than solid empirical analysis, potentially leading to suboptimal policy choices.

Renewable capacity has grown significantly since 2000,[3] with wind and solar leading the transformation of Europe's electricity mix. This growth reflects successful policy incentives (e.g. several RES support schemes), technology costs reductions in terms of levelised cost of energy (LCOE) and increased investments.

However, this renewable surge has exposed critical gaps. **The expansion of Europe's electricity grids has often failed to keep pace with new RES installations.** Around 30% of all Projects of Common Interest (PCIs),

[3] Oxera analysis based on IRENA, 'What are the latest global trends in renewable energy?' (accessed 28 October 2025).

which represent major cross-border infrastructure works designated as European priorities, have experienced significant delays.[4] Since electricity networks, both at transmission and distribution level, play a key role in enabling the integration of a growing share of RES into the system, they are instrumental to achieve a decarbonised electricity system. An infrastructure deficit could have serious consequences: as highlighted in the Draghi report, an insufficient deployment of grids globally would limit the uptake of renewables, increase emissions and result in twice as much gas and coal use by 2050.[5]

Similarly, while battery storage capacity is growing, utility-scale deployment has often been slower than RES growth. As highlighted by the European Union Agency for the Cooperation of Energy Regulators (ACER), regulatory bottlenecks and barriers—including unclear market participation rules, inadequate incentives to provide flexibility and muted price signals, restrictive qualification requirements for providing certain services to the system, and lengthy administrative processes—are holding back the full potential of energy storage, demand-side response and distributed resources.[6] These regulatory challenges risk constraining system flexibility at a time when it is increasingly needed.

The remainder of this section provides an overview of today's European electricity grids and expands on the current situation of the EU-27 electricity system with a particular focus on system costs and overall 'inefficiencies'. Finally, it concludes by summarising our key findings on retail electricity bills in the EU-27, and provides a breakdown of electricity prices for domestic consumers until 2024.

2.1 A brief overview of today's electricity grids

Having established that grid infrastructure is falling behind renewable deployment, this section examines the current state of network investment across Europe. Understanding these investment patterns is essential context for assessing how different investment scenarios may reshape the electricity system and impact overall transition costs.

Electricity grids are key enablers of RES integration and play a critical role in connecting supply and consumption centres. While distribution networks are key to transport electricity within a country or between

[4] ACER (2024), 'Transmission capacities for cross-zonal trade of electricity and congestion management in the EU. 2024 Market Monitoring Report', 3 July, p. 49.
[5] Draghi (2024), 'The future of European competitiveness. Part B | In-depth analysis and recommendations', September, p. 15.
[6] ACER (2023), 'Demand response and other distributed energy resources: what barriers are holding them back? 2023 Market Monitoring Report', 19 December.

market areas and in linking production sites with demand, transmission networks and interconnections increase market integration, enabling RES (and, more broadly, power) to be shared across wider regions and allowing additional gains from cross-border trade to be realised.[7]

According to the latest data reported by ACER, total network charges in the EU member states amounted to around €20.4bn for transmission networks and €51.8bn for distribution networks in 2022.[8] These figures refer to so-called use of network charges, charged to consumers to ensure that regulated (efficient) costs incurred by network operators are recovered, i.e. capital and operating expenditures (CAPEX and OPEX), metering costs, costs associated to losses, reactive power and those for purchasing system services. Based on ACER's calculations, total grid costs amounted to €32/MWh in 2022.[9]

Given limited data availability on EU electricity grids and their underlying costs, especially from common sources that would allow a like-for-like comparison, the following section provides a deep dive on key metrics of transmission system operators (TSOs) in the four focus countries of this study, i.e. France, Germany, Italy and Spain—countries that together represent over 57% of EU electricity demand[10] and exhibit diverse regulatory and market structures.

A key metric of grid investments is the regulatory asset base (RAB), which reflects the current value of assets managed by grid operators. Specifically, the RAB reflects the stock of all investments carried out by a network operator (and allowed by the regulator for tariff purposes) and not yet depreciated.

Figure 2.1 shows that **investments in transmission grids** and, in turn, the RAB of several European TSOs, **have been steadily increasing in recent years**, with an acceleration observed from 2021–22 onwards. This increase likely reflects multiple factors: growing renewable capacity requiring grid reinforcement, post-COVID recovery investment programmes, and heightened energy security concerns following the

---

[7] See, for example, Oxera (2019), '[Smarter incentives for transmission system operators. Volume 2](#)', 6 December, section 2.1. See also Oxera (2020), '[La roadmap per la riforma dei mercati elettrici: prospettive e sfide per l'Italia](#)', November, pp. 22, 46–49.

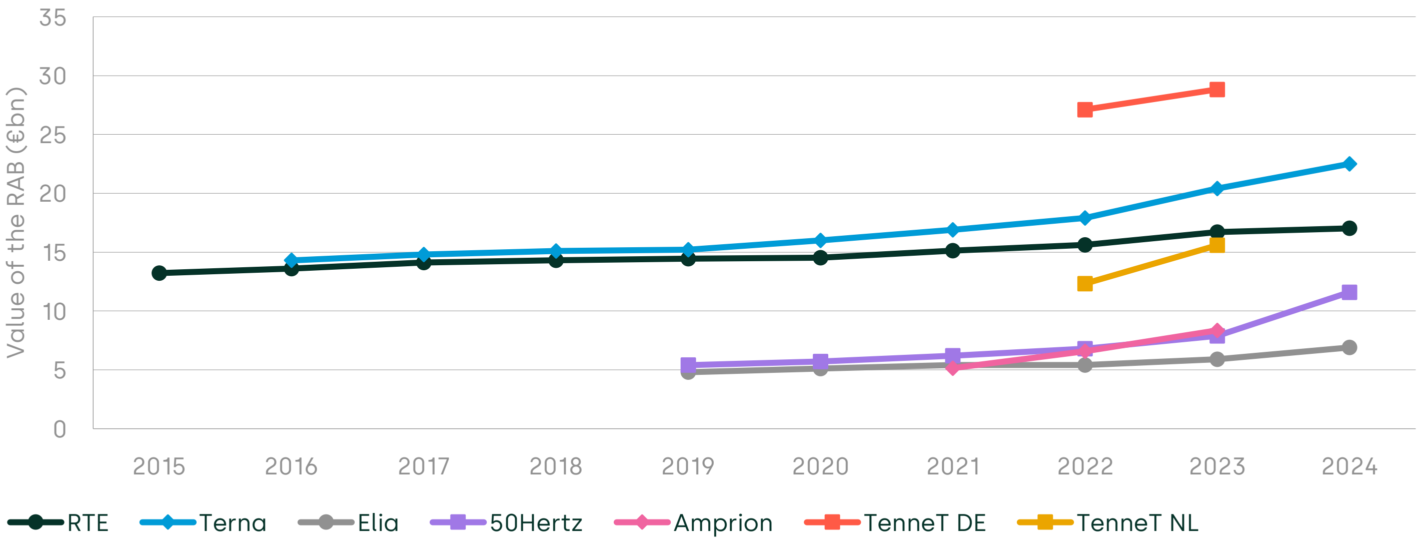
[8] Based on ACER's report, no data was provided for Finland, Italy and Slovakia (for both transmission and distribution network charges) as well as for Malta (for distribution network charges). Moreover, according to ACER, some countries 'may have reported the transmission costs charged to the DSO [distribution system operator] in the transmission number and also in the distribution number'. See ACER (2024), '[Electricity infrastructure development to support a competitive and sustainable energy system. 2024 Monitoring Report](#)', 16 December, p. 41.

[9] Ibid.

[10] Oxera analysis based on [EMBER](#) and Eurostat data ([nrg_cb_e](#) dataset, Final consumption) for 2024 (accessed 6 November 2025).

Ukraine conflict. However, as discussed earlier, even this accelerated investment may be insufficient to prevent grid bottlenecks from constraining renewable integration in the coming decade.

Figure 2.1 RAB growth of selected European TSOs



Note: Data refers to the closing RAB (values at the end of the year). Prices are in nominal terms.
Source: Oxera analysis based on RTE, Terna (2014–20, 2021–22, 2023, 2024), Elia/50Hertz (2019, 2020, 2021, 2022, 2023, 2024), Amprion (2021, 2022–23), TenneT (DE) and TenneT (NL) data (accessed 30 October 2025, respectively).

While increased investments in the transmission grid represent a common feature, the **data reveals large discrepancies when comparing network length and the associated RAB values in the focus countries**.

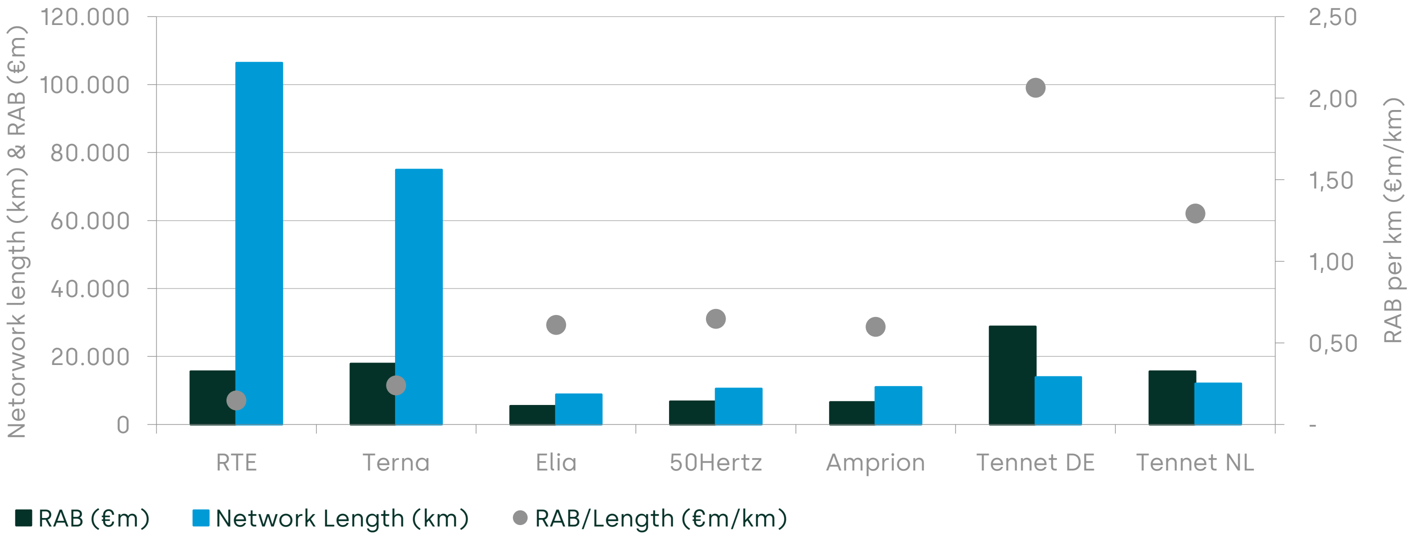
As of 2022, France's RTE operates the longest transmission network at over 100,000 km, yet holds a relatively moderate RAB of around €15.6bn. Italy's Terna manages a somewhat shorter grid (around 75,000 km) but has a higher RAB of nearly €18bn. In contrast, the Belgian TSO Elia and German TSOs 50Hertz and Amprion oversee a smaller network (each running for around 9,000–11,000 km), with a RAB of approximately €5.4–€6.8bn.[11] Meanwhile, based on 2023 data, in Germany and the Netherlands, TenneT operates at higher RAB levels (respectively around

[11] It is worth noting that Elia and 50Hertz RAB values have grown substantially in more recent years, reaching €6.9bn and €11.6bn in 2024.

€29bn and €15.6bn) and similarly smaller network lengths (around 14,000 km and 12,000 km, respectively).

These **differences are also evident when comparing the RAB per kilometre of network length,** as shown in Figure 2.2. While RTE and Terna both operate relatively large networks and feature comparatively low RAB-per-km figures, German and Belgian TSOs (Elia, 50Hertz and Amprion) service smaller areas but feature higher RAB-per-km figures based on 2022 data. TenneT records the highest RAB per km, at around €1.3m/km in the Netherlands and exceeding €2m/km in Germany.[12]

Figure 2.2 Ratio of RAB to network length across TSOs in selected European countries (2022)



Note: For TenneT the ratio is computed on 2023 data, as the breakdown of network length between Germany and the Netherlands is not available for 2022.
Source: Oxera analysis based on RTE (network length and RAB), Terna (network length and RAB), Elia/50Hertz (network length and RAB), Amprion (network length and RAB), TenneT DE and TenneT NL (plus RAB) data (accessed 30 October 2025, respectively).

Variations in RAB-per-km figures between countries could be driven by multiple factors. For example:

- Geographical and technical factors play a significant role. Differences in the prevalence of above-ground and below-ground infrastructure and onshore and offshore grid coverage

[12] Comparison based on 2022 data, except for TenneT, for which 2023 data are used.

may have substantial implications for the costs of constructing and operating the infrastructure.

- The configuration of the serviced area (mountainous vs plain territories; urban vs rural areas; and network density) may also have an impact on costs to build and operate the network.
- Network age and technology create significant variations. For example, older networks with lower (i.e. largely depreciated) asset values may service similar areas to those as newer networks while operating at much lower RAB levels.
- Different regulatory approaches to asset valuation, cost capitalisation, depreciation schedules, allowed rates of return, and treatment of investment incentives can produce different RAB outcomes for otherwise comparable infrastructure.

The range of possible explanations means that a thorough and detailed analysis would be required to identify the drivers of differences in RAB-per-km. **Specific investment levels depend on country-specific circumstances, policy priorities, and system requirements**. However, understanding these drivers is essential for assessing whether current investment trajectories are sufficient and how investment resources might be allocated most efficiently across different technologies and infrastructure types.

2.2 System costs and the overall 'inefficiencies' of today's EU-27 electricity system

This section describes the current system costs and the overall 'inefficiencies' of the EU-27 electricity system based on historical data (largely from 2023 or 2024, depending on data availability). The evolution of balancing and redispatching costs, negative prices, RES curtailment and costs associated to measures aimed at ensuring the adequacy of the electricity system are discussed in turn below.

2.2.1 Balancing and redispatching costs (and volumes)

As renewable energy penetration increases across the EU, grid constraints are forcing system operators to intervene more frequently to preserve system stability and security (so-called 'remedial actions').

Specifically, remedial actions are triggered to ensure that voltage and power flows in the system are within the predefined operating ranges.[13] While some of these measures do not entail any operating costs (e.g. changes in grid topology or the use of phase-shifting transformers),

[13] Remedial actions are 'measures taken by TSOs to address violations of security limits after the market gate closure time'. ACER (2024), 'Transmission capacities for cross-zonal trade of electricity and congestion management in the EU. 2024 Market Monitoring Report', 3 July, p. 49, para. 171.

others involve actively adjusting market outcomes to ensure that the system operates securely—actions that carry significant costs (e.g. redispatching and countertrading).

Remedial action costs are an important consideration as they are ultimately passed on to electricity consumers. More fundamentally, increasing volumes of remedial actions signal infrastructure bottlenecks that constrain renewable integration, raise concerns on the secure operation of the system, and increase overall system costs—precisely the challenges that this study seeks to address.

Box 2.1 Understanding costly remedial actions

Redispatching refers to the adjustment of the output of a particular generation or consumption unit activated by the system operator, either increasing or decreasing electricity production, load pattern, or both, in order to change physical flows in the electricity system, to resolve grid congestions or otherwise ensure secure electricity supply.[14]

When the physical network is unable to transport electricity as planned due to constraints, redispatching is one of the tools used to reconfigure the original generation schedule and alleviate bottlenecks. This process is essential in preventing voltage control issues, network congestions/overloads and localised imbalances, but it also comes with significant financial and efficiency costs.[15]

Countertrading indicates 'a cross-zonal exchange initiated by system operators between two bidding zones to relieve physical congestion'.[16] This is a congestion-management measure that involves compensating generators or consumers in other bidding zones for adjusting their output or demand to alleviate physical congestions between two bidding zones, where the precise generation or load pattern alteration is not predefined.[17] Countertrading is a market-based solution, as the cheapest bid is selected irrespective of the geographical location within the bidding zone.[18]

Curtailment is the controlled reduction of electricity generation from renewable energy sources by the system operator when supply exceeds demand or the grid lacks the capacity to accommodate additional output, resulting in inefficient outcomes where demand has to be met by higher cost or carbon-intensive generation.

Source: Oxera analysis based on ACER, ENTSO-E and the broader EU electricy market design principles.

The financial burden of grid congestion is substantial and growing. Based on the latest data reported by ACER, **the overall volumes of costly remedial actions activated in the EU and Norway in 2024 amounted to 60 TWh**—a 5% increase from 2023, including both redispatching and countertrading, at a total cost of €4.3bn.[19] These costs are ultimately borne by electricity consumers through electricity tariffs.

As shown in Figure 2.3, the need for congestion management,[20] and specifically redispatching actions, appears to be strongly concentrated in a certain number of countries, suggesting that these reflect national circumstances: in 2023, Germany alone accounted for over 54% of all redispatching volumes in the EU-27, followed by Spain (24%) and Poland (19%).[21]

[14] Specifically, redispatching 'means a measure, including curtailment, that is activated by one or more transmission system operators or distribution system operators by altering the generation, load pattern, or both, in order to change physical flows in the electricity system and relieve a physical congestion or otherwise ensure system security'. See Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity (recast), Article 2.

[15] See, for example, CEER (2021), 'Redispatching arrangements in Europe against the background of the Clean Energy Package requirements', CEER Report, 21 December.

[16] Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity (recast), Article 2.

[17] THEMA Consulting Group (2020), 'Redispatch and Countertrade Costs. The Impact of German Bidding Zones. Final Report', January, p. 7.

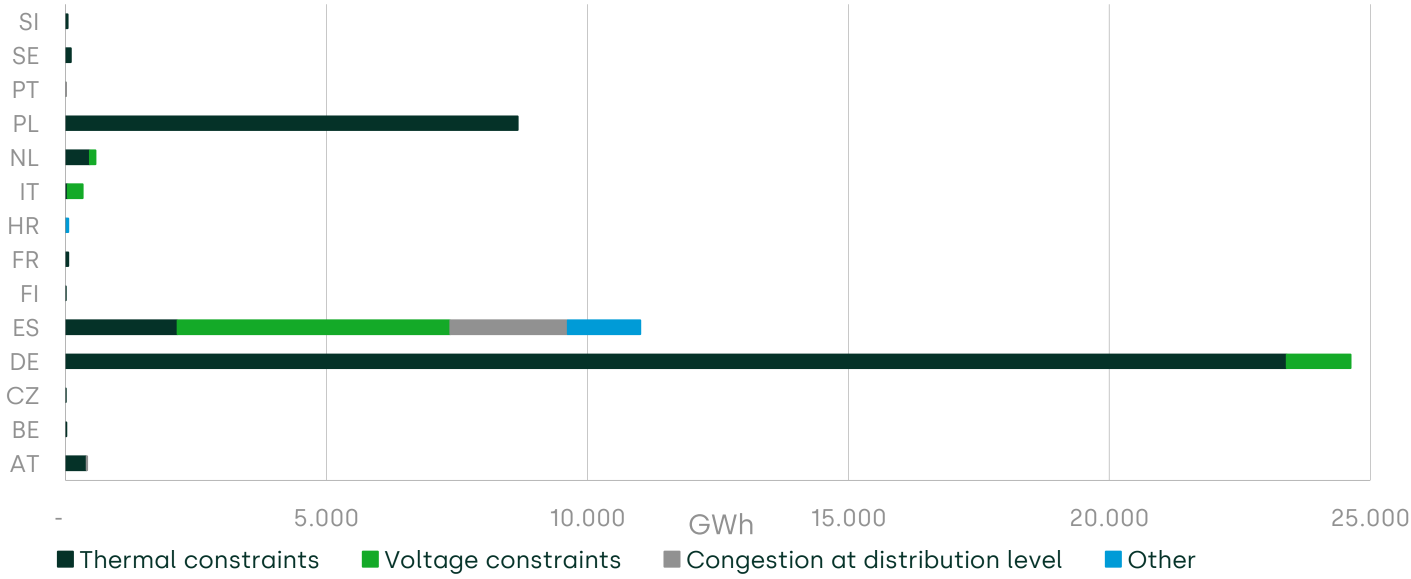
[18] See, for example, ENTSO-E (2020), 'Explanatory document to the coordinated redispatching and countertrading methodology for Capacity Calculation Region Hansa in accordance with Article 35 of the Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing a Guideline on Capacity Allocation and Congestion Management', 3 December, p. 4.

[19] ACER (2025), 'Transmission capacities for cross-zonal trade of electricity and congestion management in the EU 2025. Monitoring Report', 5 September, pp. 56–57.

[20] Congestion management refers to the set of measures and strategies used to prevent or alleviate bottlenecks in electricity grids, ensuring the efficient and reliable operation of the power system.

[21] Oxera analysis based on ACER data (data item 565), accessed 31 October 2025.

Figure 2.3 Redispatching volumes by country (2023)



Note: Member state-level data on total upward and downward redispatching volumes by underlying reason, with a focus on the EU-27. Member states with zero redispatching volumes reported in the dataset published by ACER are not shown in the chart. Based on ACER's report, no data were available on the breakdown of redispatching volumes by underlying cause for Greece and Ireland.
Source: Oxera analysis based on ACER data (data item 565), accessed 31 October 2025.

While more recent data with a similar level of granularity do not appear to be available, a recent report from ACER confirms this geographic concentration: 53% of congestion management costs in 2024 corresponded to member states in central Europe, with Spain recording the second-highest share of remedial actions over total electricity demand, followed by Poland and Germany.[22]

As for the underlying causes, based on the latest data available, thermal constraints[23] drive the vast majority of redispatching actions, accounting for more than 75% of all volumes activated in the EU-27 in 2023, followed by voltage constraints (around 15% of total volumes). Distribution-level congestions and other factors make up the rest. While this picture holds true both for the EU-27 and the individual member states, Spain represents a notable exception, as voltage constraints accounted for around 50% of redispatching volumes in 2023.[24] The

[22] ACER (2025), 'Transmission capacities for cross-zonal trade of electricity and congestion management in the EU. 2025 Monitoring Report', 5 September, p. 57.
[23] Thermal constraints refer to limits on the volume of power that can be allowed to flow through grid infrastructure to avoid damage from overheating.
[24] While absolute values are significantly lower compared to Spain, in 2023, voltage constraints represented around 85% of all redispatching volume also in Italy. Oxera analysis based on ACER data (data item 565), accessed 31 October 2025.

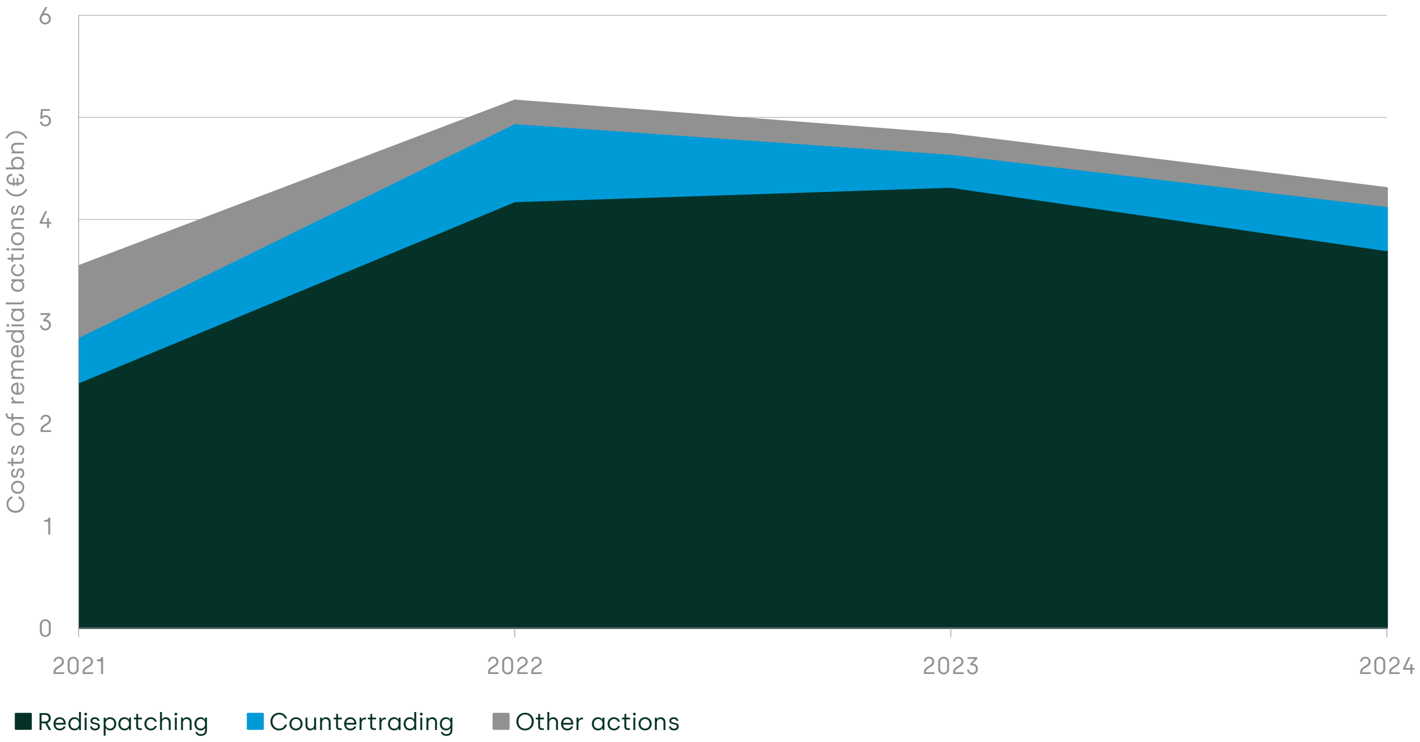
peculiarity of Spain is also confirmed by more recent information reported by ACER for 2024.[25]

Fossil-based generators currently dominate redispatching actions, but this is changing as curtailment has increased more recently. In 2023, around 64% of all redispatching volumes in the EU-27 relied on fossil-based generators, while RES and hydropower plants were affected by upwards or downwards redispatching actions for only 22% and 6% of total volumes, respectively.[26] However, ACER data for 2024 highlights 'a growing trend in the need for congestion management involving renewable energy technologies, mainly in the form of downward regulation or curtailment',[27] with over 10 TWh of RES production curtailed in the EU because of grid congestions.

A closer examination of overall costs, as illustrated in Figure 2.4 below, shows that redispatching is the main driver behind the total costs of remedial actions—which have almost doubled between 2021 and 2022–23—while countertrading continues to account for a small share of the total costs, albeit with a peak in 2022.

[25] ACER (2025), 'Transmission capacities for cross-zonal trade of electricity and congestion management in the EU. 2025 Monitoring Report', 5 September, p. 56.
[26] Oxera analysis based on ACER data (data item 565), accessed in 31 October 2025.
[27] ACER (2025), 'Transmission capacities for cross-zonal trade of electricity and congestion management in the EU. 2025 Monitoring Report', 5 September, p. 58.

Figure 2.4 Costs of remedial actions in the EU and Norway, 2021–24 (€bn)



Note: Evolution of the costs of remedial actions in the EU and Norway. According to ACER's report, 2021 data for Spain was not available, so it is not included in the figure, while Ireland only reported volumes of countertrading (not redispatching).
Source: Oxera analysis based on ACER data (data item 822), accessed 31 October 2025.

Among the four focus countries, Germany shows the highest congestion management costs. According to ENTSO-E's Transparency Platform data for 2024, Germany's redispatching costs reached approximately €1.9bn, with countertrading adding another €98m. For the same year, France and Italy show relatively lower costs of congestion management (based on the data available on the ENTSO-E Transparency Platform), while no data is reported for Spain.[28]

As highlighted by ACER, this trend of increasing costs and volumes of remedial actions in Germany, specifically redispatching actions, is driven by three main factors: the rapid penetration of RES in the German

[28] Oxera analysis based on ENTSO-E Transparency Platform data for 2024, 'Cost of congestion management'. For Spain, the ENTSO-E Transparency Platform currently reports congestion management costs of zero for all months of 2024 (accessed 6 November 2025).

power system, the increasing minimum cross-zonal capacity requirement, and the limited pace of grid reinforcement.[29]

2.2.2 Negative prices and RES curtailment

The growing shares of RES connected to the grid are introducing new challenges by inherently changing the way electricity is produced as well as how the whole electricity system operates. The remedial action costs discussed previously reflect one consequence of grid constraints and insufficient flexible and/or dispatchable resources. This section examines two other consequences: negative electricity prices and renewable energy curtailment.

Both phenomena stem from the same fundamental issue: RES generation is typically intermittent, geographically distributed, and with profiles that do not necessarily align with demand. **Periods of intense renewable output may not coincide with peak demand and therefore result in overgeneration**, pulling wholesale electricity prices close to or below zero (where the producers pay consumers to take electricity) and/or forcing system operators to curtail renewable energy generation. Curtailment is particularly frequent when transmission constraints arise—these may force system operators to act even in cases where generation does not exceed demand on a system-wide level.

These are not merely technical curiosities—they represent significant economic inefficiencies and reveal where infrastructure, market design, and flexibility sources are finding it difficult to keep pace with renewable deployment and the evolution of demand.

Negative prices typically occur when high RES generation coincides with low demand or periods of sustained RES production. In these situations, some inflexible power producers, as could be the case of thermal plants, including coal and gas-fired units as well as nuclear reactors, opt to continue generating electricity—even at a financial loss—rather than shutting down their production (e.g. due to long ramp-up/ramp-down timings that would prevent a certain asset from being available in more 'profitable' hours if turned down).[30]

Market design and support schemes features can exacerbate the issue. Some RES producers may also continue generating when market prices turn negative when they benefit from support schemes that remunerate

[29] ACER (2024), 'Transmission capacities for cross-zonal trade of electricity and congestion management in the EU. 2024 Market Monitoring Report', 3 July, p. 51, para. 178.
[30] See, for example, ACER (2022), 'ACER Market Monitoring Report 2020 – Electricity Wholesale Market Volume', 12 January, p. 38.

the output they inject in the grid regardless of wholesale market prices, meaning that their net revenues remain positive despite negative wholesale prices. As this behaviour exacerbates situations of oversupply, more recent RES support schemes include provisions according to which the subsidy is not granted when wholesale prices are zero or negative for a prolonged period of time.[31]

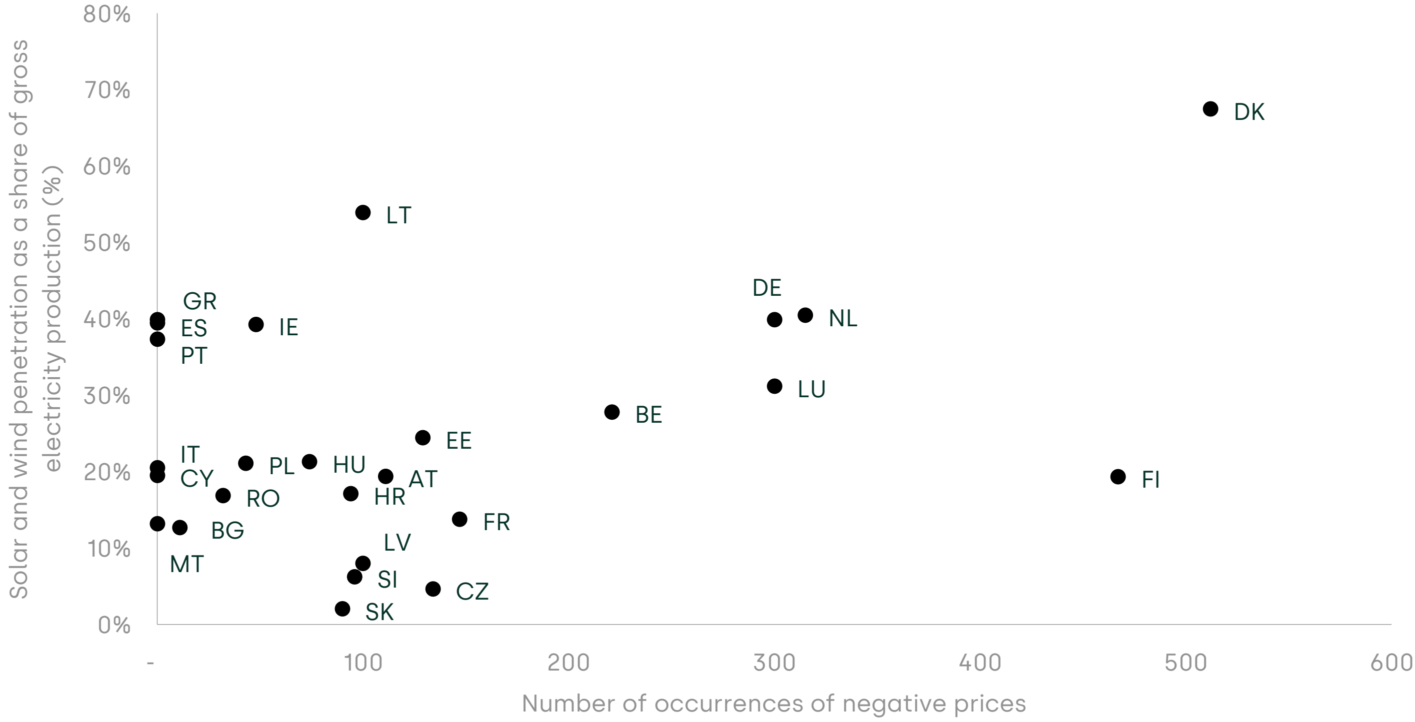
The frequency of negative prices has surged. In 2023 and 2024, electricity prices in day-ahead markets fell below zero hundreds of times across multiple EU member states. On such occasions, producers are effectively paying off-takers to absorb the oversupply. **These episodes are critical indicators of both system stress and limited market flexibility** (e.g. insufficient storage, demand-side response, or cross-border trading capacity). However, not all EU countries experienced negative prices due to differences in market structures and design, pricing rules, and generation mix.[32]

The relationship between variable RES penetration and negative prices is complex. Indeed, as shown in Figure 2.5 below, the relationship between variable RES penetration (computed as the share of energy from solar photovoltaic, solar thermal and wind sources in gross electricity production, based on Eurostat data) and the frequency of negative prices is slightly U-shaped, but not particularly clear. At lower levels of negative price occurrences, variable RES penetration exhibits a varied influence. However, as the frequency of negative prices increases, there is a clearer trend that suggests that higher variable RES penetration could contribute to this phenomenon. Nonetheless, the relationship is relatively weak, suggesting that other factors also play a role, such as:

- the electricity mix of the different countries (including the contribution of solar vs onshore and offshore wind);
- the availability of storage capacity;
- weather conditions;
- the design of RES support schemes;
- the level of interconnection.

[31] For more details see, for example, von Bebenburg, C., Mikovic, P., Robins, N., Vitelli, R. (2024), 'Incentivising behavioural changes: Subsidies vs regulation', Concurrences N° 2-2024, May.
[32] Negative day-ahead prices occurred for the first time in Spain and Portugal in 2024, while Italy has not experienced negative prices yet also due to price regulation (until recently negative bids were not allowed in the day-ahead market).

Figure 2.5 Number of hours with negative day-ahead prices compared to solar and wind penetration (2023)



Note: Solar and wind penetration derived by Eurostat data as the share of gross electricity production from solar photovoltaic, solar thermal and wind sources in gross electricity production. Sweden has been removed from the dataset (22% solar and wind penetration as a share of gross electricity production and a total of 1,665 hours with negative prices across the four bidding zones).
Source: Oxera analysis based on ACER data (data item 570) and Eurostat data on electricity production by type of fuel (nrg_bal_peh dataset, Total gross electricity production, Solar PV, Solar thermal, Wind), accessed 6 November 2025.

For example, among the focus countries, Germany and Spain display similarly high solar and wind penetration as a share of gross electricity production in 2023 (40% and 39%, respectively), but differ significantly in the frequency of hours with negative day-ahead prices.

Across Germany, Spain and France, the occurrences of zero and negative day-ahead prices increased by around 200% from 2023 to 2024.[33] In 2024, Spain recorded negative price-hours for the first time since 2015 (while some instances of zero day-ahead prices also occurred in 2023).

[33] Oxera analysis based on ENTSO-E Transparency Platform, 'Energy Prices' for France and Spain and SMARD data for Germany (accessed 5 November 2025).

Italy represents a unique case, as by design it has not yet recorded negative prices in its day-ahead market. Historically, the day-ahead market included a price floor of 0 €/MWh, i.e. market players could only submit bids with positive prices, effectively preventing the occurrence of negative electricity prices.[34] However, a recent regulatory reform has aligned Italian price limits with harmonised EU ones.[35] At the same time, zero day-ahead price occurrences have been increasing in Italy as well, particularly in southern regions and islands.[36]

If price signals are insufficient for the system to remain in balance, system operators may resort to curtailment.

While high RES penetration can contribute to curtailment, other factors such as grid constraints, market design, and energy storage capacity also play a crucial role in determining the level of curtailment across different countries (and bidding zones). Unlike negative pricing, which occurs across a broader range of markets, curtailment is primarily a system management tool, implemented as a last resort to resolve local grid constraints or balancing challenges.

Curtailment is geographically concentrated. ACER data shows that in 2023 RES curtailment was largely concentrated in a limited number of countries, with several member states not experiencing any curtailment. Germany dominates EU curtailment volumes, recording over 10,000 GWh of RES curtailment (corresponding to 4.4% of its RES generation) in 2023,[37] surpassing all other member states combined. A major contributing factor is Germany's heavy reliance on wind power, an inherently variable source, which accounted for 61% of its total RES generation in 2023.[38]

Spain followed with around 1,000 GWh (corresponding to 1.2% of total RES generation),[39] largely driven by wind and solar production in certain regions.[40] France and Italy also reported notable levels of curtailment, though at lower volumes.

[34] Oxera (2020), 'La roadmap per la riforma dei mercati elettrici: prospettive e sfide per l'Italia' November.
[35] The technical price limits (harmonised maximum and minimum clearing prices) are defined in accordance with the CACM Regulation. See Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing guidelines on capacity allocation and congestion management.
[36] Oxera analysis based on GME data (accessed 29 October 2025).
[37] Oxera analysis based on ACER data (data item 567), accessed 31 October 2025.
[38] IEA, 'Germany - Renewable electricity generation' (accessed 30 October 2025).
[39] Oxera analysis based on ACER data (data item 567), accessed 31 October 2025.
[40] Red Eléctrica, 'Generación total' (accessed 30 October 2025).

Data for 2024 confirms this picture, with **Germany recording the highest curtailment rate (around 3% of RES generation), followed by Spain (1.4%), France (1.1%), Finland (0.9%) and Italy (0.6%).**[41]

A key insight from ACER data is that **curtailment remains a geographically concentrated issue**, affecting significantly only a small number of the member states. This suggest that **curtailment does not appear to be necessarily correlated with RES penetration**, but rather driven by country-specific structural and infrastructural factors. Some countries with high renewable shares alongside low (or no) curtailment, such as Denmark, exhibit relatively strong grid management, strong interconnections with neighbouring countries, and significant investments in system flexibility.[42] Conversely, countries with more moderate RES penetration but higher curtailment, such as Spain and Italy, suggest the influence of structural and infrastructural factors on curtailment levels.[43]

Curtailing RES output can impose substantial system costs because of the double expense of paying RES generators to reduce output while also paying other units to replace the curtailed volumes. According to ACER, in 2023 these costs amounted to €580m in Germany, €20m in Italy, €2.2m in France and €0.78m in Spain.[44]

2.2.3 Adequacy of the system and security of electricity supply

The previous section considered the significant costs from grid congestion, redispatching and curtailment. This section examines the growing challenges in maintaining reliable electricity supply.

Near-zero marginal costs of generation enable RES technologies to crowd-out more expensive dispatchable capacity (frequently thermal generation) which sits lower in the merit order. **As RES penetration increases, historical suppliers of reserve capacity and ancillary services (i.e. thermal plants) find it increasingly uneconomical to operate**. This therefore poses a challenge for the adequacy and security of the electricity system.

Moreover, unlike dispatchable plants that generate predictable output, given its intermittency, RES generation is forecasted with uncertainty.

[41] ACER (2025), 'Transmission capacities for cross-zonal trade of electricity and congestion management in the EU. 2025 Monitoring Report', 5 September, p. 59.
[42] Agora Energiewende (2023), 'Variable Renewable Energy Grid Integration', p. 2.
[43] See, for example, IEA (2021), 'Spain 2021. Energy Policy Review', p. 105; IEA (2023), 'Italy 2023. Energy Policy Review', pp. 121 and 127.
[44] ACER (2024), 'Country Sheets: Monitoring Data 2023', 5 December, pp. 16–17, 21, 33. ACER does not provide information on how these costs are computed.

This requires that systems operators procure higher reserve margins to hedge against deviations of in-feeds from scheduled outputs at the time of delivery. In turn, this increases the need for flexible and dispatchable backup capacity precisely as market revenues for such capacity decline.

Increasing RES penetration therefore requires other dispatchable, flexible and low-carbon capacity, e.g. storage capacity, including BESS, demand-side response contributions and interconnection capacity. Moreover, gas-fired plants, capable to rapidly ramp up when needed, also remain key as the system decarbonises and other flexible and low-carbon sources expand. However, electricity markets often do not provide sufficient incentives to invest in these technologies, e.g. because expected prices may not guarantee an appropriate remuneration to these assets (as discussed in more detail in section 3).

Capacity remuneration mechanisms (CRMs), described in more detail in Box 2.2, are one of the tools frequently used to ensure that firm capacity remains available when needed.

Box 2.2 How capacity remuneration mechanisms (CRMs) work

CRMs represent a specific form of subsidies that are used to ensure the adequacy of the electricity system and to incentivise the development of storage capacity and other flexibility sources.

When a CRM is established, selected generators (and consumption units) receive a 'capacity payment' (in €/kW) for their availability, which is additional to the revenues achieved in the wholesale markets. In other words, the CRM provides an additional revenue stream for firm capacity to make it economical for these generators/technologies to remain (or come) online. In turn, supported units are required to offer their capacity in the wholesale market.

Since CRMs imply the use of state resources, they qualify as state aid and therefore require an approval from the European Commission to be introduced.

Source: Oxera based on various sources.

While CRMs are a proved tool to maintain security of supply and protect system operators from the possibility of persistently high future costs for reserve procurement, procuring reserve as a separate product may impose higher costs on system operators in the short term.

In light of the growing need for member states to strike a balance between the decarbonisation and security of supply objectives, several member states introduced a CRM (e.g. France and Italy) and others are considering/planning to do so (e.g. Germany and Spain).[45] Moreover, the 2024 market design reform made CRMs a more structural element of the EU electricity market, overcoming their previous role as a last resort

[45] ACER (2024), 'Security of EU electricity supply. 2024 Monitoring report', 16 December, p. 18. See also European Commission, 'Consultation on Spanish market reform plan' (accessed 30 October 2025).

measure for member states to ensure the adequacy of their electricity system.[46]

The scale of capacity support is substantial and growing. During the period 2022–24, more than 170GW of capacity have been supported through CRMs in the EU, with total supported capacity reaching 178GW in 2024, up from 125GW in 2020.[47]

Meanwhile, total costs for capacity remuneration mechanisms in the EU have risen even faster than capacity volumes, from €2.6bn in 2020 to €7.4bn in 2023—a 40% increase from 2022 to 2023. However, according to ACER projections, the costs of EU capacity mechanism in 2024 are expected to be lower (around €6.5bn).[48]

The €7.4bn spent on capacity mechanisms in 2023 exceeds the annual costs of redispatching and congestion management actions (€4.3bn). Together, these represent over €11.5bn annually spent managing system stress and reliability challenges.

Overall, the evidence points to growing needs (and associated costs) for system operators to resort to remedial actions, more frequent zero and negative price episodes and curtailment—signalling the challenges associated with the profound change of the electricity system.

2.3 Key drivers of today's electricity prices

The system costs and inefficiencies discussed in section 2.2 are ultimately passed on to end consumers through increases in final electricity bills.[49]

At a high level, electricity bills depend on three macro-components (discussed in more detail in Box 2.3):

- 'energy and supply', related to wholesale electricity costs—which in turn depend on a variety of factors, including the national electricity mix—and supply margins of retailers;

[46] Official Journal of the European Union (2024), 'REGULATION (EU) 2024/1747 OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL of 13 June 2024 amending Regulations (EU) 2019/942 and (EU) 2019/943 as regards improving the Union's electricity market design', 26 June.
[47] ACER (2024), 'Security of EU electricity supply. 2024 Monitoring Report', 16 December, pp. 19–20.
[48] Ibid. Based on the information reported by ACER, while in 2023 costs increased across all market-wide capacity mechanisms, higher costs of the French scheme were one of the primary drivers of this significant growth. In particular, in France, the reduced availability of the nuclear fleet tightened supply volumes, pushing up capacity prices of procured capacity.
[49] Prices faced by domestic and industrial consumers tend to differ; this section focuses on prices charged to the former.

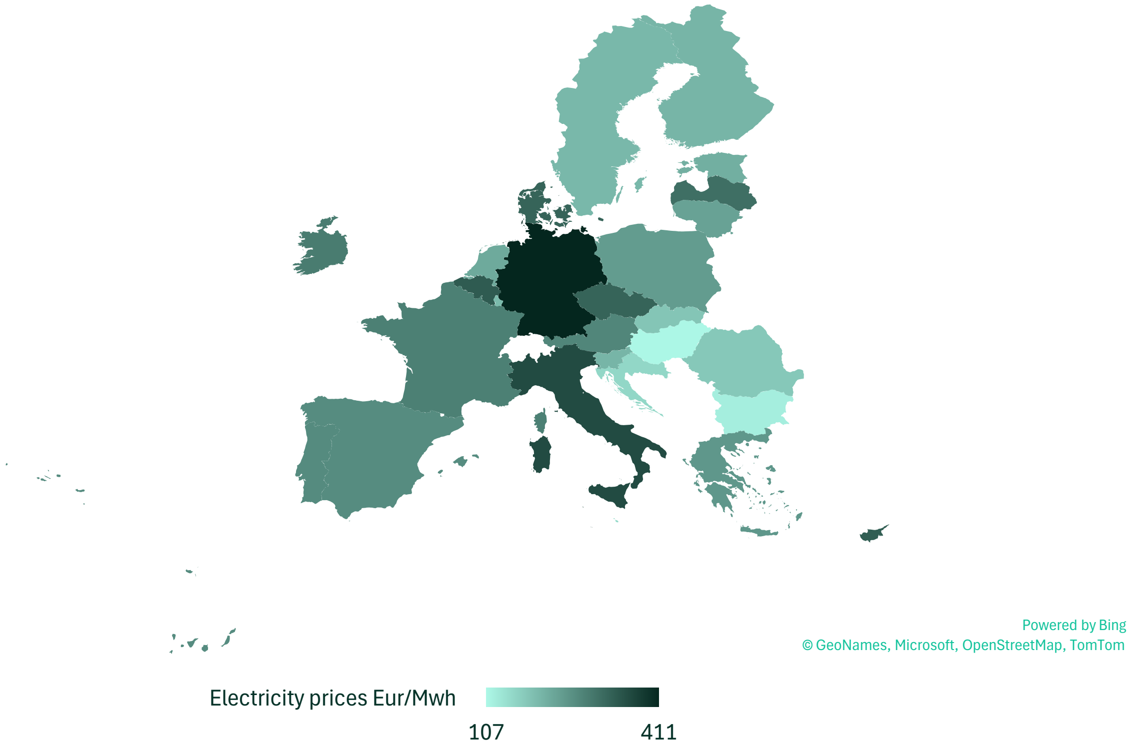
- ‘network costs’, related to the costs of transmitting and distributing power from production sites to consumers;
- ‘taxes, levies and other charges’, that largely vary between countries and include components such as VAT, taxes, and the costs of support schemes for RES and other generation/consumption technologies.

Electricity prices are sensitive to a number of factors, including underlying fuel costs (including CO2 costs from the emission trading system), but also the national electricity mix, network costs, the costs of incentive mechanisms and support schemes (e.g. RES support schemes) and the level of taxation (e.g. value-added tax, or VAT, and other taxes and levies).[50] Prices can also be affected by the broader macroeconomic and geopolitical context as well as extreme weather events.

As can be seen from Figure 2.6, Eurostat data for 2024 show a wide dispersion across member states, from roughly €100–€150/MWh to more than €400/MWh—with the highest prices recorded in Germany, Italy and Belgium, and the lowest in Hungary and Bulgaria. The EU-27 average stood at €289/MWh, heavily influenced by these extremes.[51]

[50] European Commission (2025), ‘Energy prices and costs in Europe’ (accessed 30 October 2025).
[51] Oxera analysis based on Eurostat data (nrg_pc_204_c dataset), accessed 16 October 2025.

Figure 2.6 Map of electricity prices for household consumers in 2024 (€/MWh)



Note: Figures based on Eurostat data on electricity prices for domestic consumers ('all bands') in 2024 in the EU-27. 'all bands' figures are available on Eurostat website and represent the single national electricity prices, computed as a weighted average of all household consumers bands.
Source: Oxera analysis based on Eurostat data (nrg_pc_204_c dataset), accessed 16 October 2025.

Since 2019, electricity prices for household consumers have risen in the EU, but not as much as wholesale prices. Specifically, the peak observed in 2022 for wholesale electricity prices has been smoother for retail prices, as other components (e.g. network costs and taxes/levies) also play a role in the overall level of electricity bills.

Moreover, **the speed and magnitude through which wholesale costs are passed through to consumers differ across member states and depend on a variety of factors** such as lags through which wholesale costs are reflected in retail prices, network charging principles, market design arrangements (e.g. different shares of low-carbon power subject to long-term agreements, liquidity of forwards markets and protection mechanisms in place to, at least partially, shield consumers from price volatility and/or price spikes) and different levels of taxes and levies recovered through electricity bills. Other factors include variations in contract-length structures (e.g. fixed- or variable-price contracts) and retailers' procurement strategies (such as long-term contracts and price hedging) as well as differences in mitigation measures (e.g. national interventions to deal with high prices in 2022–23).[52]

[52] See, for example, European Commission, '[Energy prices and costs in Europe]' (accessed 30 October 2025).

Box 2.3 Understanding the key components behind electricity tariffs

Energy and supply component. This reflects the underlying costs of the electricity consumed by the specific consumer, which largely depend on fuel costs (e.g. commodity prices for gas and coal and emission allowances for carbon-intensive generators) and the investment costs for generation capacity. This represents the most volatile component, responding to commodity market conditions and seasonal renewable output variations.

Network costs. They correspond to the allowed revenues set by regulators for network operators, covering the costs of grid investments and maintenance activities (i.e. both CAPEX and OPEX).

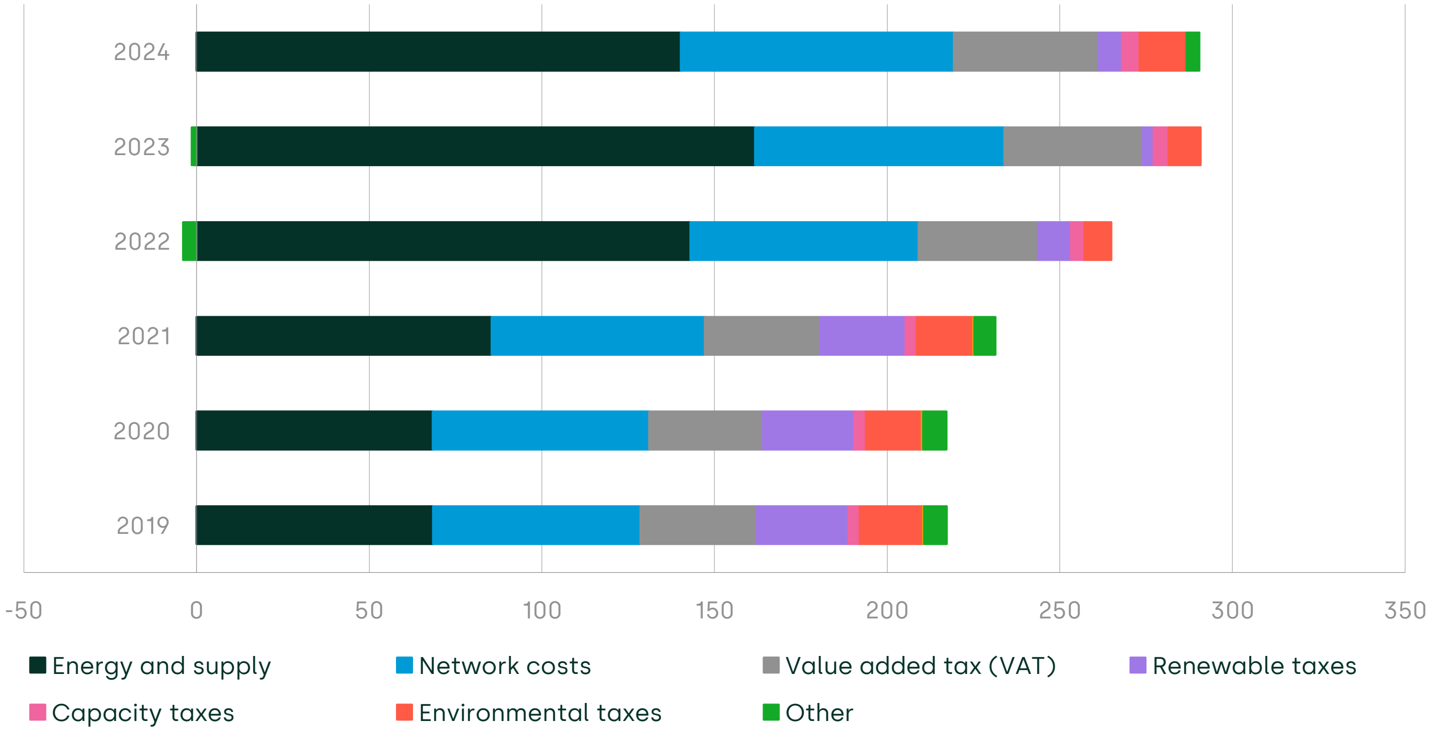
Taxes, levies and other charges. They largely vary between countries and include components such as:

- **VAT**;
- **renewable taxes**, to cover the costs of support schemes for RES capacity expansion, energy efficiency and combined heat and power generation. These costs are typically recovered either through electricity bills or general taxation (or a combination of both), but the precise methodologies differ between countries and consumer types;
- **capacity taxes**, to recover the costs related to CRMs, energy security and generation adequacy measures;
- **environmental taxes**, charged on emissions of CO_2 or other greenhouse gases (GHG), generally related to air quality and other environmental purposes;
- **nuclear taxes**, capturing various charges related to the nuclear sector, including nuclear decommissioning, inspections and fees for nuclear installations;
- allowances corresponding to each of the above, that act to reduce the final tariff.

Source: Oxera based on various sources, including Eurostat.

An overview of the contribution of each of these components to electricity prices paid by domestic consumers in the EU-27 and their evolution between 2019 and 2024 is provided in Figure 2.7.

Figure 2.7 Electricity price components in the EU-27 over 2019–24 (€/MWh)



Note: Figure based on Eurostat data on electricity prices for domestic consumers ('all bands') in 2019–24 in the EU-27 member states. 'all bands' figures are available on Eurostat website and represent the single national electricity prices, computed as a weighted average of all household consumers bands.
Source: Oxera analysis based on Eurostat data (nrg_pc_204_c dataset), accessed 16 October 2025.

The share of the **energy and supply component** increased sharply in 2022, due to high gas prices, accounting for around 56% of electricity bills in 2023, compared to about 37% in 2021, reflecting the spike in wholesale electricity and gas prices.

Network costs remained relatively stable in recent years, representing approximately 25–30% of overall electricity tariffs between 2019 and 2024. As the green transition proceeds, the significant grid investments required to accommodate the planned RES buildout are expected to have substantial impacts on network charges in Europe.[53] For example, according to ACER estimates, total grid costs in a high-investment scenario could rise from €32/MWh in 2022 to €60/MWh in 2050.[54]

Taxes, levies and other charges, instead, declined significantly in 2022 and 2023, reflecting emergency measures adopted by several member states to mitigate price increases.

While these trends represent a shared feature across the EU, individual components vary widely across member states. For example, differences in the costs of energy and supply are driven by a number of factors, including differences in the underlying generation mix, the level of interconnection capacity, grid bottlenecks and price arrangements for generation capacity (e.g. amount of capacity subject to contract-for-difference mechanisms or other long-term contracts).

Similarly, network costs also differ significantly across the EU, but the magnitude of this variation is lower—e.g. €122/MWh in Germany, €82/MWh in Spain, €66/MWh in France and €62/MWh in Italy for 2024.[55] Based on the latest data for 2023, distribution costs accounted for the bulk of network costs in the majority of member states, but there are differences also in the relative weight of transmission and distribution costs.[56]

[53] See, for example, European Commission (2024), 'The future of European Competitiveness: Part B | In-depth analysis and recommendation', September, p. 21. See also ACER (2024), 'Electricity infrastructure development to support a competitive and sustainable energy system. 2024 Monitoring Report', 16 December, p. 41.
[54] Ibid., p. 41.
[55] Oxera analysis based on Eurostat data (nrg_pc_204_c dataset), accessed 16 October 2025.
[56] Eurostat, 'Electricity price statistics' (accessed 30 October 2025).

3 The challenges ahead

Achieving Europe's decarbonisation and climate goals will require a significant transformation of the European electricity system over the next two decades.

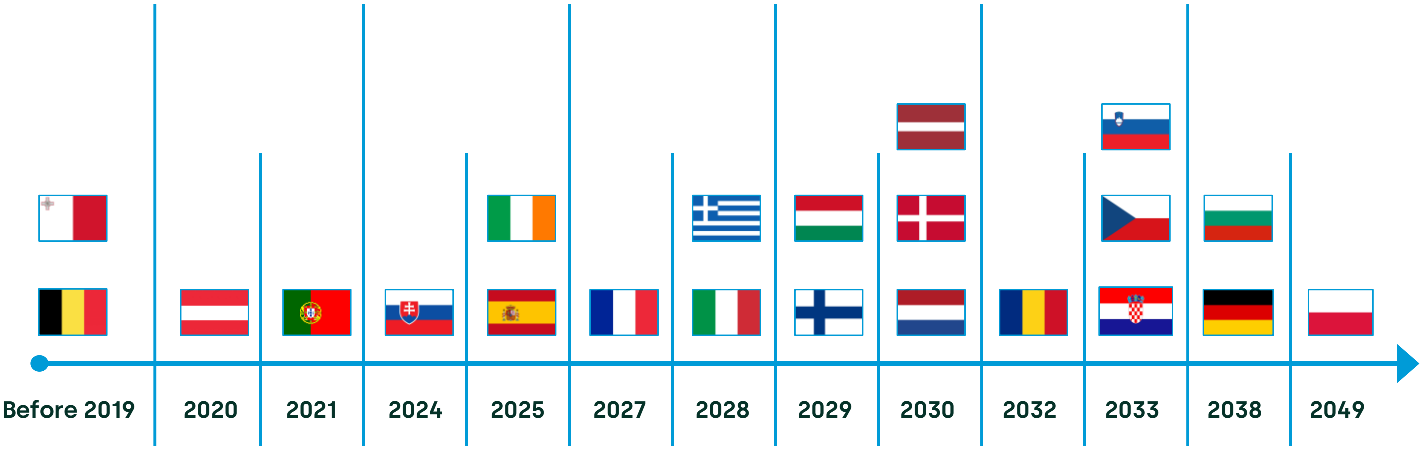
This section examines three transformation challenges: (i) phasing out fossil fuel generation while maintaining adequacy, (ii) integrating renewable capacity into the system, and (iii) accommodating substantial demand growth from electrification. Individually, these challenges would place stress on the current system, but together, they would require coordinated investment across generation, networks, storage and flexibility resources.

3.1 Fossil fuels phase-out

The energy transition will entail a gradual phase-out of fossil fuels, in particular coal and lignite, a process already ongoing. This phase-out is both necessary for decarbonisaition and creates significant adequacy challenges, particularly in countries where grid constraints already limit renewable integration.

Several member states have already set clear timelines for phasing out coal and lignite, as summarised in Figure 3.1. While some countries have already completed their coal phase-outs, others aim to complete the process by 2030. Only a limited number of member states foresee the continued reliance on coal for power generation beyond 2030.

Figure 3.1 Coal phase-out plans for countries in the EU-27



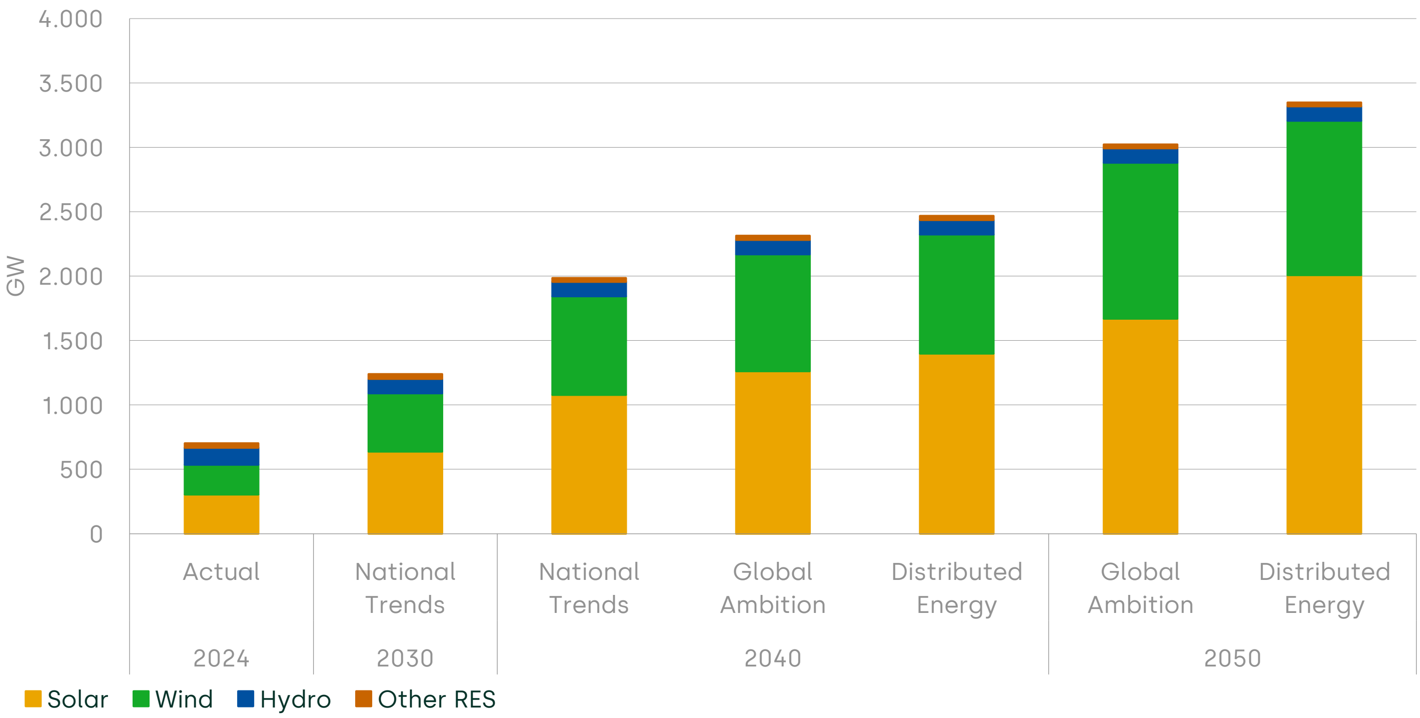
Note: Luxembourg and Lithuania currently do not have any coal-fired power plant in their electricity mix. Based on the latest information, Italy is planning to complete the coal phase-out by January 2026, with the exception of Sardinia, where the phase-out is expected by 2028.[57] As for the Netherlands, the coal phase-out is expected by early 2030, in line with a ban on using coal for electricity production from 2030 onwards. According to the German National Energy and Climate Plan (NECP), the political goal remains phasing out coal, ideally by 2030. The respective NECP does not specify a phase-out date for: Estonia (although the International Energy Agency confirms that the country has updated its 2030 ambitions and set more stringent energy policy targets, including a 100% renewable electricity goal by 2030),[58] Sweden (although the NECP states that the government will work to take measures to phase out the use of coal in order to contribute to the Swedish climate neutrality target for 2045)[59] and Cyprus (although the European Commission's assessment of the NECP confirms that the power sector in Cyprus is largely coal-free).[60]
Source: Oxera analysis based on the latest NECPs, updated by the different member states between 2023 and 2025.

3.2 Renewable expansion

In parallel to thermal retirement, the rapid expansion of RES to comply with the ambitious decarbonisation goals is expected to significantly change the generation mix. As shown in Figure 3.2, according to ENTSO-E's Ten-Year National Development Plan 2024 (TYNDP 2024) scenarios, total installed RES capacity is expected to more than double by 2040 compared to 2024 levels, driven primarily by solar and wind expansion.

[57] Terna (2025), 'Rapporto Adeguatezza Italia 2024', 28 February, p. 27.
[58] IEA (2023), 'Estonia 2023. Energy Policy Review', November, p. 9.
[59] Swedish Ministry of Climate and Enterprise (2024), 'Sweden's updated National Energy and Climate Plan 2021–2030', June, p. 15.
[60] European Commission (2023), 'Commission Staff Working Document. Assessment of the draft updated National Energy and Climate Plan of Cyprus. SWD(2923) 910 final', p. 11.

Figure 3.2 Actual and projected RES installed capacity in the EU-27 (GW)



Source: Oxera analysis based on EMBER data for 2024 and TYNDP 2024 from 2030 onwards (accessed 14 October 2025).

As shown in section 2, **today's electricity system is already facing growing operational challenges and cost pressures, pointing to the need for a structural change as the system evolves towards a decarbonised mix**. With coal and lignite being phased out, in several countries, the system will lose an important share of dispatchable capacity. At the same time, as mentioned in section 2.2, the rapid expansion of RES will exert economic pressure on thermal generators, given the merit order effect, according to which units with lower costs are dispatched first.

As RES penetration increases, thermal plants will be dispatched less frequently, **and face declining revenues, hence potentially being unable to recover their fixed costs through the market**. Unless other mechanisms are in place to ensure their profitability, e.g. a CRM, this effect could reduce the amount of dispatchable generation available, i.e. those plants that can ramp up and down at short notice to respond to sudden changes in demand, needed to balance the system.

Moreover, in a decarbonised electricity system, **with RES frequently representing the marginal technology, wholesale prices are often likely to be reduced to their marginal costs (near zero), resulting in price**

cannibalisation, which also limits the potential for RES plants to recover their CAPEX. Especially when combined with the threat of regulatory interventions to mitigate high prices or price volatility, this can also lead to the so-called 'missing money' problem, that could prevent a sufficient expansion of 'firm' and 'flexible' capacity.[61]

An increasing expansion of RES further affects the way the system operates. **RES generation is variable and its production is geographically distributed, often located far from consumption centres**. Compared with traditional thermal plants, RES units are more frequently connected at the distribution level, resulting in a limited visibility over their output for the system operators.

At the same time, with more RES connected to the grid, **residual load patterns**[62] **change during the day**: in certain hours, residual load will become much lower than today or even negative, e.g. during the central hours of the day, when solar production is higher and over-production may occur. The more electricity production exceeds demand, the stronger and more frequent the corrective measures reported in section 2 will need to be. Additionally, when storage capacity is insufficient, RES can result in a steeper load curve towards the evening, when solar output decreases and demand is typically increasing.

Consequently, maintaining system adequacy and security in a similar context will require new sources of flexibility and low-carbon capacity, such as BESS, demand-side response, electricity interconnectors and retaining a certain share of gas-fired capacity.

Overall, **this transformation marks a shift from a system dominated by dispatchable fossil-fuel generation to one increasingly reliant on distributed and intermitted renewable energy sources, supported by a portfolio of flexibility solutions**.

3.3 Demand growth

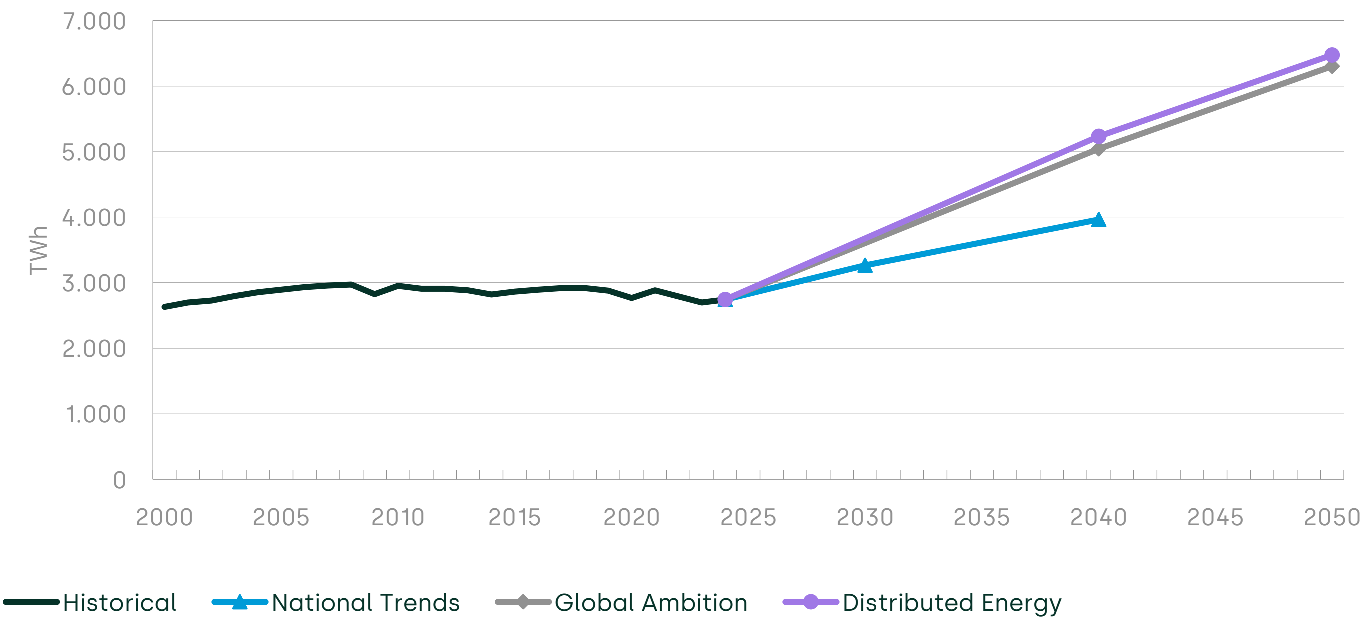
Another key component of the equation to ensure that the system is 'in balance' in real time is demand. According to several forecasts, including ENTSO-E's TYNDP 2024 scenarios, **EU electricity demand is set to increase significantly in the coming years**—around 19% by 2030 and more than 130% by 2050 compared to 2024 levels, as shown in Figure

[61] See, for example, Oxera (2020), 'La roadmap per la riforma dei mercati elettrici: prospettive e sfide per l'Italia', November, section 1.3.3.
[62] Residual load (or residual demand) refers to net demand after accounting for intermittent generation produced at a local level.

3.3. This growth reflects the ongoing electrification of end-use sectors, such as transport, heating and industry.[63]

However, the pace and scale of demand growth remains uncertain. A wide range of projections from different sources show significant discrepancies in expected demand levels, highlighting the impact of different assumptions. Even focusing the attention to TYNDP 2024 only, the spread between demand projections across ENTSO-E's scenarios is substantial: by 2040, the National Trends scenario foresees a 45% increase in demand compared to 2024, while Distributed Energy projects an increase of about 91%. On the contrary, other sources forecast a more moderate evolution of demand, for example ACER has in some instances assumed a 1% year-on-year growth rate from 2030 to 2050.[64]

Figure 3.3 Historical and projected electricity demand in the EU-27 according to TYNDP 2024 (TWh)



Note: For demand projections, the chart does not include electricity consumption from pumped hydro storage and BESS units. It therefore reflects native demand, demand from electric vehicles (EVs) and electricity consumption from electrolysers.
Source: Oxera analysis based on EMBER data for historical data until 2024 and TYNDP 2024 projections from 2030 onwards (accessed 14 October 2025).

[63] See ENTSO-E and ENTSOG (2024), 'TYNDP 2024. Scenario Results', section 'Electricity demand'.
[64] See, for example, Eurelectric (2025), 'ACER overestimates network costs for consumers towards 2050 – says Eurelectric', 2 April, accessed 30 October 2025.

This uncertainty poses significant risks for both consumers, operators and investors. Since the electricity system is dimensioned to meet peak demand, **if projected demand growth does not actually materialise there is a risk of 'over-dimensioning' the system**—a case in which generation and network capacity would exceed actual needs. Conversely, a lower-than-projected demand could result in infrastructural assets being underutilised or even stranded, undermining operators' and investors' financial sustainability. **Moreover, this would result in higher costs being recovered over a smaller consumer base**, ultimately making the system more expensive for final consumers, with a risk of hampering the electrification process and the path towards a net zero economy.

3.4 The coordination imperative

Given the wide uncertainty and associated risks**, effective coordination among all the actors of the electricity system will be essential in managing the energy transition, ensuring that the expansion of generation, network and flexibility resources evolves in line with actual demand**. Better coordination between consumers, network operators, players responsible for generation and storage, and potentially aggregators and other flexibility providers, would contribute to minimising inefficient investments and supporting a more balanced, cost-effective transition.

In this context, **demand-side flexibility will also play a critical role in supporting a cost-efficient transition**. As renewable generation increases and the system becomes more dependent on variable sources, part of the adjustment will need to come from the demand side. Flexible consumption allows electricity demand to adjust dynamically to market and system conditions, shifting consumption away from periods of scarcity or high prices and towards hours of abundant renewable generation. This helps balance supply and demand more efficiently and contributes to making the system more resilient.[65]

More broadly, **demand-side flexibility helps with smoothing demand profiles, reducing system peaks and alleviating network congestions**. In this sense, at times, flexibility can represent a tool to defer or reduce investments in generation and grid capacity, e.g. in line with the 'flex first' approach that guided the RIIO-ED2 price control in the United Kingdom. However, more recently, given the current state of the energy transition, Ofgem considered that this approach would be inappropriate for the next price control, RIIO-ED3, highlighting the role of flexibility not

[65] See, for example, 4E TCP (2025), 'Overview of flexibility platforms', 9 February, section 2.3.

as a substitute for grid reinforcement, but as a lever to support and smooth the pace of network expansion. In this view, flexibility remains critical to manage system intermittency and local network issues, but should not be used to avoid building network investments that will be required to accommodate demand growth.[66]

The level of flexibility embedded in the demand also has implications on the design of the required electricity system as sectors with largely baseload demand require firm capacity to ensure security of supply, whereas load-following or flexible demand can be more easily paired with variable renewables, enhancing overall system efficiency.[67] In this way, **greater demand-side participation not only supports the integration of RES, but also contributes to making the transition more cost effective**.

3.5 The cost challenge

A critical policy challenge is ensuring that the profound transformation of the electricity system described in this section does not increase wholesale costs, but rather contributes to reducing them, while preserving system security and achieving the decarbonisation goals. To achieve this, it will be essential to ensure that the lower costs of RES are more directly passed on to final consumers.

Until now, wholesale electricity prices have largely been driven by gas-fired generation—which has often been the marginal technology in the merit order across Europe—meaning that consumers have only partially benefited from the declining costs of renewables. Going forward, as RES are expected to increasingly set the market price, there will be greater potential for their lower costs to translate into lower wholesale prices.

As also highlighted in the European Commission's Affordable Energy Action Plan, several complementary instruments can facilitate this transition, such as long-term power purchase agreements and contract-for-difference schemes for RES, as well as by expanding grids and interconnectors and increasing system flexibility with storage and demand-side response. [68] Together, if timely and effectively implemented, these measures can contribute to an energy transition

[66] Ofgem (2025), 'ED3 Framework Decision', 30 April, pp. 61–62.
[67] See, for example, CIRED (2024), 'Network Planning and System Design With Flexibility', March, pp. 11–12.
[68] European Commission (2025), COM(2025) 79 final, 'Communication from the Commission to the European Parliament, the Council, the European Economic and Social Committee and the Committee of the Regions Action Plan for Affordable Energy. COM(2025) 79 final', 26 February.

that delivers both the decarbonisation of the economy and lower electricity costs for consumers.

3.6 Testing pathways: the role of modelling

Understanding which investment combinations can manage this transition in a cost-effective manner requires rigorous system-wide analysis. The interplay between renewable deployment, grid expansion, storage capacity, demand growth and flexibility resources creates complex trade-offs that cannot be resolved through partial analysis.

This study, therefore, **uses an electricity market model to assess how different investment pathways perform across a number of metrics. The modelling exercise specifically examines the role of BESS and expanded interconnections in delivering system-wide benefits**.

4 Modelling methodology and analytical framework

This section provides an overview of the modelling methodology and analytical framework used to assess how different investment pathways—varying battery storage deployment, distributed flexibility adoption and interconnection capacity—affect system costs, wholesale prices and operational efficiency across Europe.

The analysis employs the BID3 electricity market model developed by AFRY Management Consulting S.r.l. (AFRY) to simulate four alternative scenarios to assess the impact of expanded interconnection capacity and greater availability of flexible resources on wholesale prices and total system costs. BID3 is an optimisation model with an objective to minimise total system costs subject to certain technical and operational constraints.

While the market modelling exercise covers the entire pan-European region, a more detailed analysis of the modelling results has been carried out for France, Germany, Italy and Spain, as the focus countries for this study.

4.1 Modelling methodology

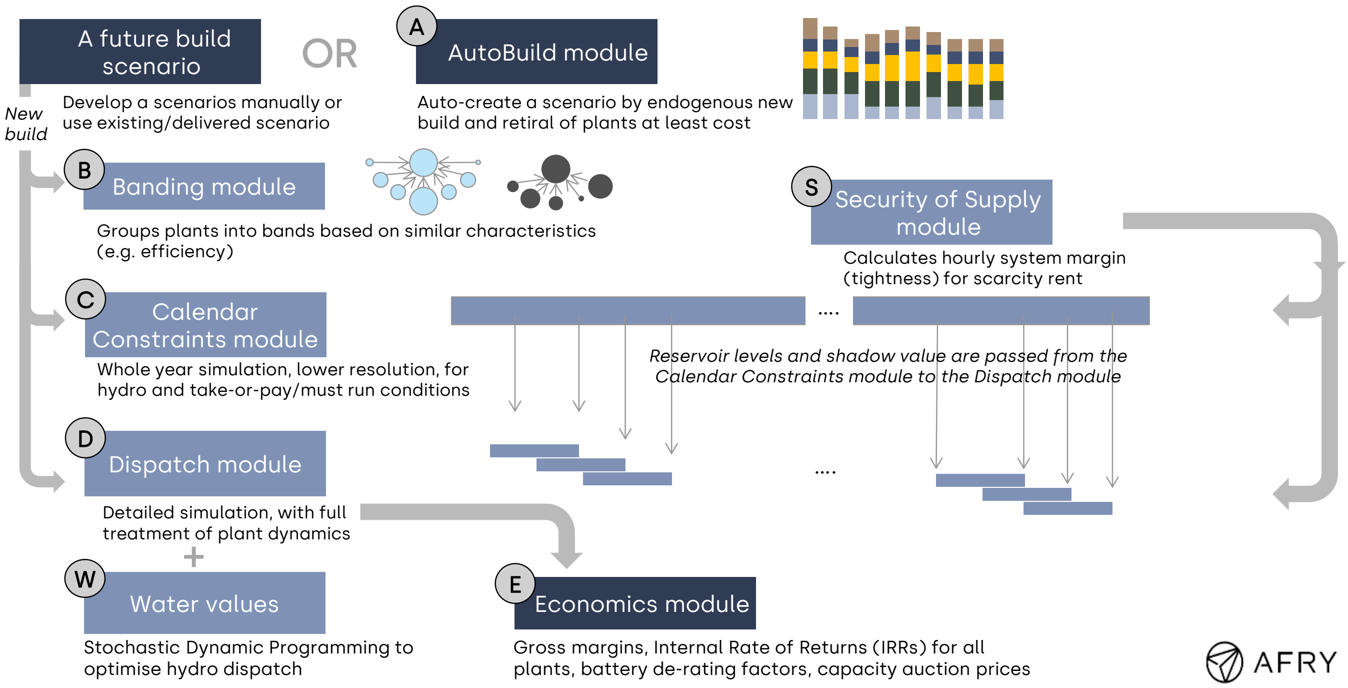
The BID3 electricity market model developed by AFRY simulates electricity market dispatch and pricing under realistic operational and economic constraints.

At its core, **BID3 uses advanced mathematical optimisation techniques to solve unit commitment and economic dispatch problems across interconnected power systems** and therefore replicates how electricity markets operate under real-world constraints. The model is designed to capture the interplay between generation assets (including storage units), transmission networks and market rules, enabling users to forecast prices, assess capacity evolution and evaluate system reliability over both short-term and long-term horizons.

The model operates on a zonal basis and incorporates a highly granular representation of power plants, renewable resources and interconnectors. It accounts for operational constraints such as ramp rates, minimum up and down times and fuel limitations, while also modelling intermittent renewable generation such as wind and solar with detailed profiles. Additionally, the model incorporates information on storage facilities (e.g. batteries and pumped hydro storage), with assumptions on efficiencies and reservoir sizes, as well as demand-side response mechanisms. The model also considers interconnectors and their capacities.

BID3 is structured into a series of interconnected modules, each responsible for a specific stage of the modelling process, as summarised in Figure 4.1. These modules work together to move from long-term capacity planning and constraint handling to short-term dispatch optimisation.

Figure 4.1 The seven integrated modules behind BID3



Source: Oxera and AFRY.

At the heart of this architecture is the 'dispatch module', which performs the detailed hourly optimisation of generation, storage and interconnector flows under all relevant constraints. Specifically, this module solves the unit commitment and economic dispatch problem across the modelled time horizon, co-optimising generation, reserves and interconnector flows under all operational and network constraints.

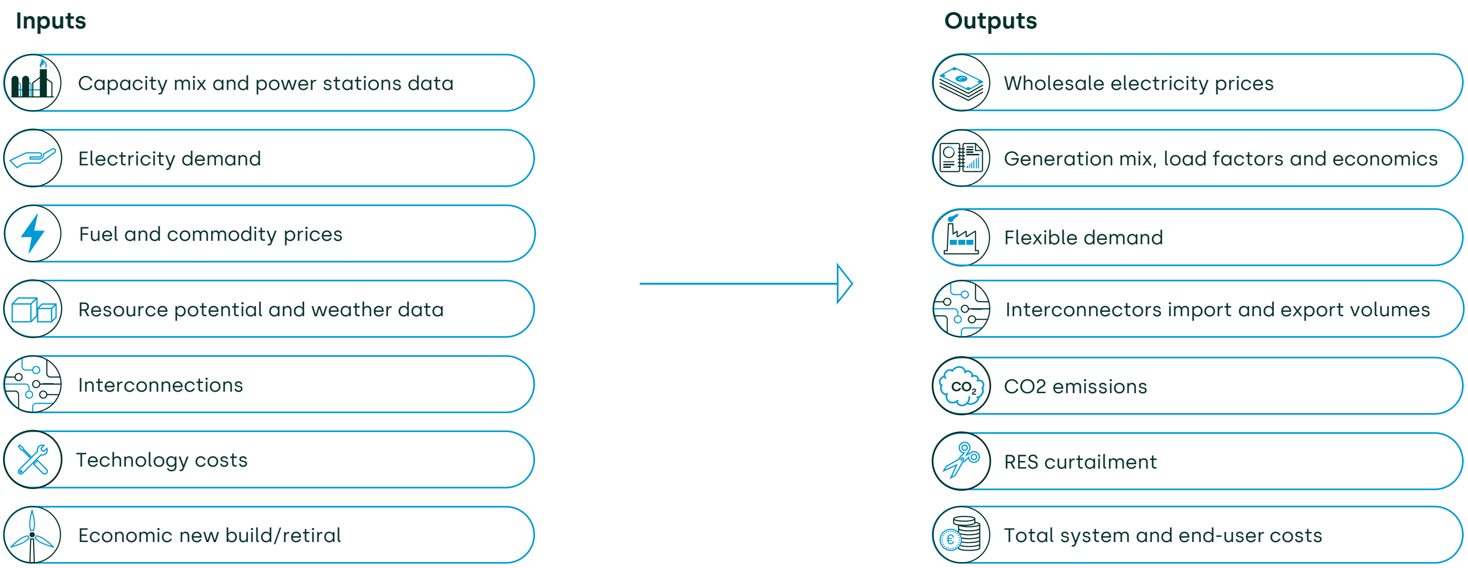
Other modules, such as 'auto build', 'banding' and 'constraints', provide inputs and boundary conditions that shape the outcomes of the dispatch module, ensuring consistency between long-term planning and operational simulation.

The auto build module (AutoBuild) in BID3 is designed to endogenously determine the optimal future configuration of the power system under a given scenario. Rather than relying on exogenous assumptions about which plants will be built or retired, **AutoBuild uses a least-cost optimisation approach to decide on new-build investments, retirements and mothballing of generation assets**. The module uses iterative optimisation techniques to converge on a capacity mix that minimises total system costs over the planning horizon. This functionality enables advanced long-term scenario analysis, as it allows the model to dynamically respond to changes in demand, fuel prices, technology costs and policy constraints, rather than being locked into static capacity assumptions.

One of the key features of AutoBuild is its ability to co-optimise across multiple infrastructure layers. It does not limit itself to power plants; it can also include endogenous investment in interconnectors, transmission grid reinforcements, as well as hydrogen production, storage and transmission capacity.

The main inputs and outputs of the electricity market model used for the analysis are summarised in Figure 4.2.

Figure 4.2 Key inputs and outputs of the electricity market model



Source: Oxera and AFRY.

4.2 Geographic coverage

The modelling covers the entire pan-European region, capturing the interconnected nature of European power markets and enabling realistic assessment of cross-border electricity flows, price formation, and capacity sharing opportunities. The analysis covers 36 market areas: Albania, Austria, Belgium, Bosnia and Herzegovina, Bulgaria, Croatia, Cyprus, the Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Latvia, Lithuania, Luxembourg, Malta, Montenegro, the Netherlands, Northern Ireland, Norway, Poland, Portugal, Republic of Moldova, Romania, Serbia, Slovakia, Slovenia, Spain, Sweden, Switzerland and the United Kingdom.

In line with the zonal configuration of the model, each country is represented by one or more bidding zones, reflecting the specific market structure currently in place. For example, Italy consists of seven bidding zones, Denmark of two zones and Sweden of four zones.

As anticipated, **while the optimisation is carried out for the entire pan-European region, a more detailed analysis of the modelling results has been carried out for France, Germany, Italy and Spain**, identified as focus countries for this study. These markets were chosen as they represent some of the largest power systems in Europe, with diverse generation mixes, significant cross-border interconnections and a central role in price formation across the continent. These markets have been examined in greater depth to provide clearer insights into price formation, generation patterns and cross-border dynamics.

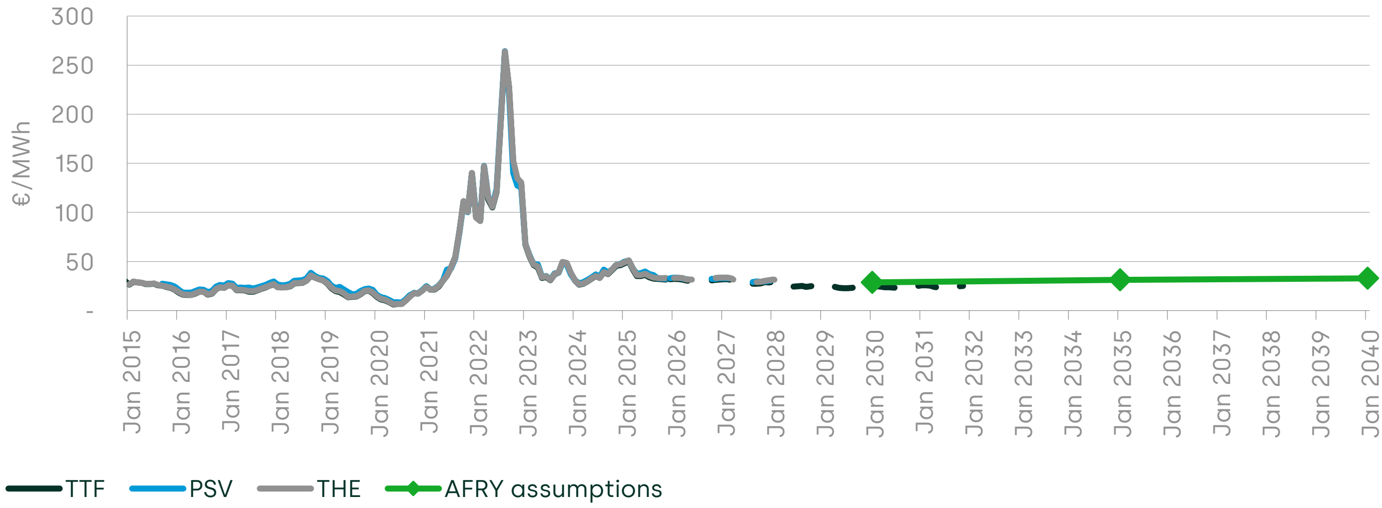
4.3 Key assumptions

4.3.1 Fuel and commodity prices

Fuel and carbon prices represent an important input for thermal power plants. At a high level, the electricity market model relies on ENTSO-E's TYNDP 2024 assumptions for nuclear and lignite fuel costs, while assumptions for other technologies, specifically natural gas, coal and CO2, reflect more recent market evidence and are based on the analysis of future prices, market drivers and trends.

Figure 4.3 displays historical and forecasted natural gas prices from 2015 to 2040. After a period of relative stability with prices around €20–€30/MWh and a marked reduction to around €10/MWh in 2020, gas prices rose sharply between 2021 and 2022, with peaks above €250/MWh due to a combination of supply and demand factors, following the gradual reductions of gas exports from Russia, coinciding with the lifting of COVID-19 restrictions. The upward pressure on gas prices continued following the start of the conflict in Ukraine and in light of a tight gas market.

Figure 4.3 Gas price assumptions (€/MWh)



Note: Prices are in EUR 2025 terms. TTF indicates the Title Transfer Facility, the main European gas hub; PSV the *Punto di Scambio Virtuale*, the Italian gas hub; THE indicates Trading Hub Europe, the German gas hub.
Source: Oxera analysis based on Bloomberg data for TTF, PSV and THE indices (month-ahead futures for historical data and physical forward contracts from December 2025 onwards) and AFRY assumptions from 2030 onwards.

Natural gas price projections reflect an equilibrium averaging approximately at €30/MWh over the 2030–40 period, based on the following assumptions.

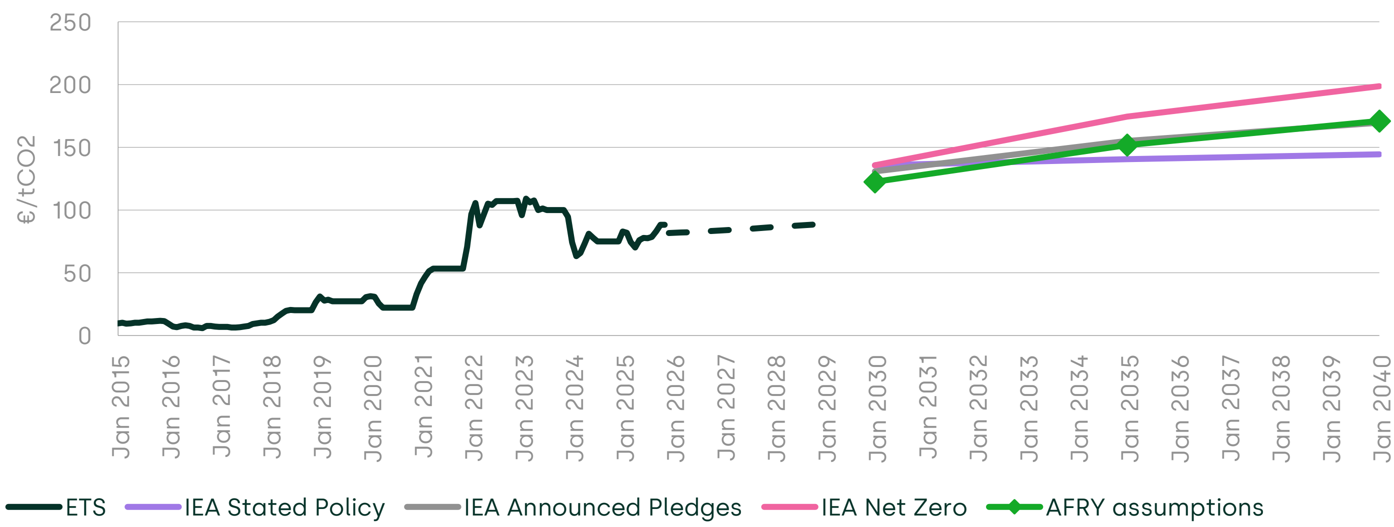
- Global gas demand is projected to remain broadly stable during the modelled horizon, as rising demand in growing economies is broadly offset by the decline in mature markets driven by the expansion of renewable sources and improvements in energy efficiency.
- Declining European gas reserves are expected to be counteracted by stable and then declining demand alongside additional liquified natural gas (LNG) supply.
- Oil-indexed pricing is expected to decline, therefore, oil is projected to have only a minor influence on hub prices by 2030. Instead, US LNG imports are forecasted to typically be the marginal source in Europe.

Carbon prices set by the EU Emissions Trading System (EU ETS) also play a central role in shaping the future of the European electricity system. As shown in Figure 4.4, CO_2 prices were relatively low in 2020, remaining below €30/tCO_2, but rapidly increased to over €90/tCO_2 by 2022 and reaching peaks of more than €100/tCO_2 in 2023.

Over the coming decades, carbon prices are expected to continue rising, with the pace and extent that will depend on future EU policies. Specifically, for this study, **CO2 prices are assumed to increase significantly from €122.5/tCO2 in 2030 to €171/tCO2 in 2040 (+40%),**[69] **due to a combination of ongoing tightening of the EU ETS allowances cap and higher abatement costs**, as the carbon price is determined by the marginal cost of the abatement source required to meet the demand for carbon allowances.

In particular, these assumptions reflect the more ambitious decarbonisation goals behind the 2023 revision of the ETS Directive, according to which the EU ETS cap is set to reduce emissions by 62% by 2030, compared to 2005 levels. Beyond 2030, a continuous tightening of the emissions cap is assumed, with a path consistent with a 100% emissions reduction by 2050.

Figure 4.4 CO2 price assumptions (€/tCO2)



Note: Prices are in EUR 2025 terms.
Source: Oxera analysis based on Bloomberg data for historical prices (front-year data), ICE EUA futures for projected prices from December 2025 to December 2028, IEA scenarios for projections from 2030 to 2040 and AFRY assumptions from 2030 onwards.

4.3.2 Demand evolution and RES availability

Assumptions on electricity demand are derived from the ENTSO-E's TYNDP 2024 scenarios for the respective years, based on the 'National

[69] Values are expressed in EUR 2025 terms.

Trends' scenario (NT scenario) for 2030 and on the 'Global Ambition' scenario (GA scenario) for 2035 and 2040, reflecting the so-called 'native demand' and 'electric vehicles' (EV) components, with EV representing a minor share of the total.[70]

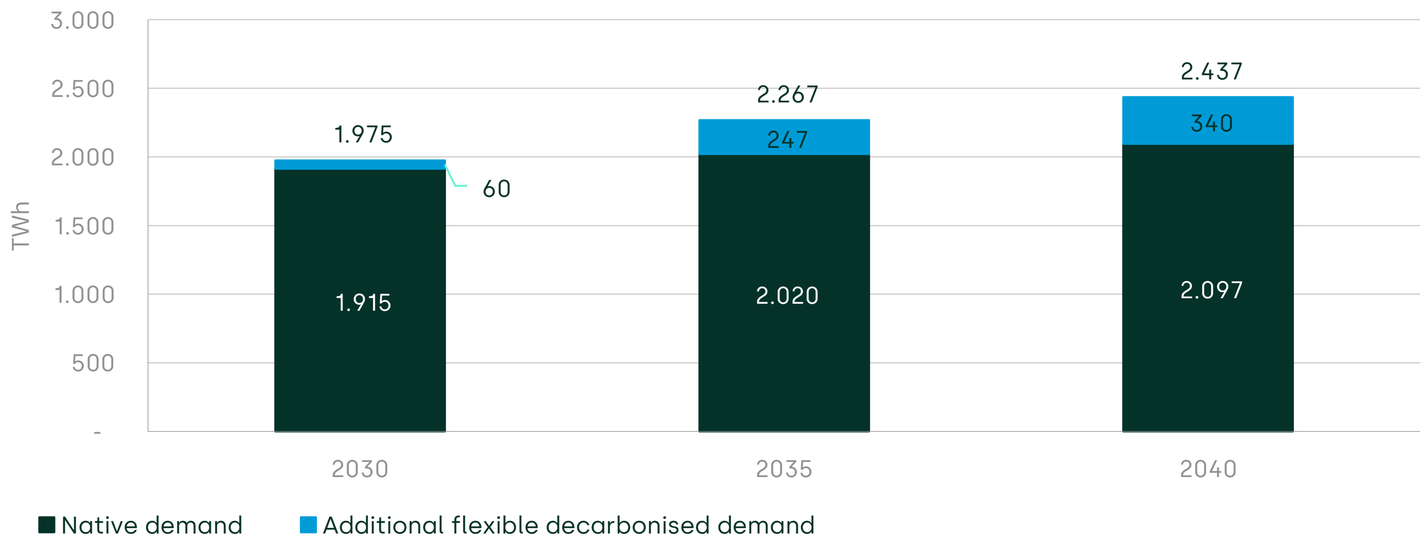
According to the TYNDP methodology, these assumptions are based on an analysis of the annual final demand for each energy carrier, derived from a sectoral assessment conducted for every member state. The annual electricity demand in each sector is then converted into hourly profiles for modelling purposes.[71]

In line with the TYNDP 2024 methodology that specifically accounts for electricity demand from electrolysers, **in addition to the 'native' and 'EV' components, a flexible decarbonised demand element has been introduced to account for sources that specifically require green energy**. This component reflects a degree of flexibility in how this demand can be met. The final resulting electricity demand that was assumed as input in all scenarios for the four focus countries is illustrated in Figure 4.5 below.

[70] Using the climate year 2009.

[71] For further details, see ENTSO-E and ENTSOG (2025), 'TYNDP 2024 Scenarios Methodology Report', January.

Figure 4.5 Projected demand evolution in the four focus countries 2030–40 (TWh)



Note: The focus countries are France, Germany, Italy and Spain. Native demand does not include electricity consumption from pumped hydro storage and BESS units, which is an output of the electricity market model (rather than an input).
Source: Oxera and AFRY analysis based on ENTSO-E's TYNDP 2024 scenarios.

Moreover, an indirect form of electricity demand, not captured in Figure 4.5 above, which represents an output of the modelling simulations is the electricity consumption from pumped hydro storage and BESS units. In other words, the amount of electricity used for these purposes is a result of the simulation, rather than a predefined input. This consumption is essentially a demand on the system that arises from the operation of the storage facilities themselves, making it an indirect form of electricity demand, which is an output of the modelling process.

For the native demand and EV components, hourly timeseries to effectively simulate hourly fluctuations in demand are taken from the ENTSO-E's TYNDP 2024 database. Similarly, RES availability assumptions are derived from the ENTSO-E's TYNDP 2024 scenarios by using the corresponding RES resource availability profiles and applying them into the BID3 market model.

For the additional flexible decarbonised demand, hourly profiles have been determined through separate simulations of consumption units with inherent flexibility (i.e. ability to defer or shift demand) and responsiveness to price signals. As a result, these units selectively consume electricity during periods of low-cost renewable generation, creating a demand profile that reflects both low-price incentives and system-level flexibility.

4.3.3 Generation and storage capacities

Assumptions on generation and storage capacities are derived from ENTSO-E's TYNDP 2024 scenarios as follows.

- Using the NT scenario as a starting point for 2030.
- Deriving the expected evolution of generation and storage capacities for 2035 and 2040 from the GA scenario, with the exception of the technologies that were the object of capacity optimisation through AutoBuild as illustrated in section 5—namely, BESS, solar photovoltaic (solar PV), onshore wind and offshore wind, Combined Cycle Gas Turbine (CCGT) plants and interconnectors.

More details on the capacity optimisation process and differences across scenarios are provided in section 5.

Generation units are grouped by technology and fuel type in each bidding zone, following the same categorisation as defined in the ENTSO-E's TYNDP 2024 scenarios.

The majority of techno-economic parameters used for the different technologies are derived from the ENTSO-E's TYNDP 2024 scenarios. The TYNDP 2024 Scenarios Methodology Report references external datasets and studies for technical parameters such as efficiencies, heat rates and other plant characteristics.[72] In particular, no must-run constraints have been applied to thermal units, in line with the TYNDP 2024 methodology, which considers such constraints an obstacle to system flexibility and decarbonisation.

For any parameters not covered in the TYNDP 2024 scenarios, or those specific to BID3 modelling, standard AFRY assumptions have been applied.

Build-out constraints have been applied to some of the technologies subject to the AutoBuild optimisation as follows.

- For RES, total maximum build-out was capped by ENTSO-E's TYNDP 2024 GA values in each year/bidding zone (based on the observation that the GA scenario already represents an ambitious trajectory for RES deployment and a realistic outlook should not exceed this benchmark).

[72] ENTSO-E and ENTSOG (2025), 'TYNDP 2024 Scenarios Methodology Report', January.

- For BESS, total maximum build-out was capped by ENTSO-E's TYNDP 2024 GA values in each year/bidding zone (to maintain coherence with RES deployment).
- For CCGTs, total maximum build-out in each year/bidding zone reflects AFRY's standard assumptions (to account for technical and practical constraints on the pace at which new CCGT capacity can be deployed in each zone).

4.3.4 Net transfer capacities and grids

The model relies on assumptions on the net transfer capacities (NTCs) between two markets (i.e. bidding zones) in order to depict the current and future limitations that the electricity grid puts on European electricity flows.

For 2030, the assumptions on the NTCs across the different bidding zones are derived from ENTSO-E's TYNDP 2024 NT scenario. **For 2035 and 2040, additional interconnection capacity was introduced in the relevant scenarios** (e.g. in the 'Enhanced NTCs' scenario) beyond the values assumed for 2030, using the AutoBuild module, which optimises potential expansions. The optimisation is based on both economic and system adequacy considerations, by confronting the marginal benefit of relieving congestions between zones against the capital and operational costs of the new interconnection capacity.

The list of candidate lines that could be expanded as part of the optimisation process with AutoBuild, including technical specifications such as length (km), type (e.g. AC/DC lines)[73] and installation environment (overhead, underground or undersea lines) is taken from ENTSO-E's official projects list.

More details on the interconnection capacity optimisation process and differences across scenarios are provided in section 5.

As BID3 is a zonal model, it does not reflect any constraints within each bidding zone, under the assumption that transmission capacity within a zone is infinite/always available as needed. **Similarly, the distribution grid is not captured, so constraints at the distribution level are not mapped**.

[73] AC/DC indicates alternating current and direct current lines, respectively.

4.3.5 Investment and dispatch

Additional generation capacities are added to the existing power plants (as assumed in 2030 based on ENTSO-E's TYNDP 2024 NT scenario) by the model as required.

More precisely, AutoBuild chooses from a **set of expansion candidates**, such that demand and reserves are met while also minimising overall system operating and capital costs. The expansion candidates considered are gas plants, i.e. CCGTs, solar PV, onshore and offshore wind, as well as BESS and, in certain scenarios, interconnection capacity.

RES CAPEX assumptions are derived from AFRY's 2025 Q2 Central scenario, ensuring consistency with BESS cost assumptions (i.e. ensuring that RES costs and deployment determine the correct investment signals for the economics of BESS, and vice versa). In particular, costs for solar generation are assumed to decline following a reduction in the price of modules, driven by efficiency gains and production upscaling and competition, whereas costs of wind generation are assumed to decline more slowly, with increased scaling and maturing supply chains.

CCGT CAPEX assumptions are derived from AFRY's 2025 Q2 Central scenario. Short-term costs are forecasted to be higher, in line with the impact of commodity prices, whereas medium-term prices are expected to return to a business-as-usual view, remaining stable for the rest of the modelled period.

BESS CAPEX assumptions are derived from an analysis of recent market values, with future cost reductions applied according to the learning rate defined in AFRY's 2025 Q2 Central scenario (driven by the upscaling of battery pack production). As discussed in more detail in sections 5.3 and 5.4, these assumptions have been revised downwards for the Cheaper BESS and Full Policy scenarios, to reflect greater availability of flexibility sources.

Cost assumptions for interconnectors are based on the North Sea Power Hub study, specifically the techno-economic dataset provided in the 'Pathway Databook_v11' file.[74] This source includes detailed parameters for High Voltage Direct Current (HVDC) and High Voltage Alternating Current (HVAC) transmission lines, covering investment costs per kilometre, converter station costs and variations by

[74] North Sea Wind Power Hub datasets, 'Pathway 2.0 Techno-economic data' (accessed 30 September 2025).

technology type (AC vs. DC), voltage level and installation environment (overhead, underground or subsea). These values have been assumed to reflect realistic engineering and market benchmarks for 2030–50 deployments.

5 The analytical framework: modelled scenarios

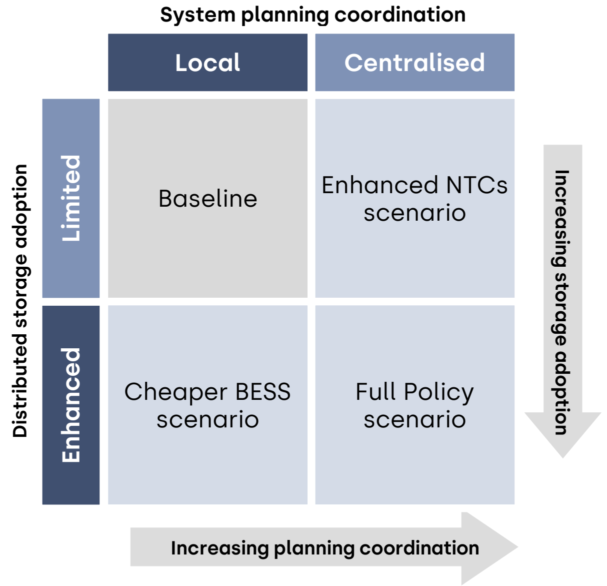
As part of this study, a set of scenarios was developed to explore varying degrees of system planning coordination (reflected as higher/lower interconnection capacity available across bidding zones) **and distributed storage integration** (reflected as higher/lower costs for new BESS). The aim is to illustrate the potential benefits of different policy objectives that could be promoted and implemented at the EU level, by quantifying and comparing their impacts.

Specifically, this study assessed four scenarios, summarised in Figure 5.1 and discussed in more detail below:

- **Baseline**, using ENTSO-E's TYNDP 2024 NT scenario as a starting point for 2030;
- **Enhanced NTCs**, reflecting a higher degree of system planning coordination, with NTCs optimised at the European level for 2035 and 2040;
- **Cheaper BESS**, reflecting an improved integration of distributed flexibility sources, assuming a reduction of CAPEX and OPEX figures for BESS units;
- **Full Policy**, combining the key features of the 'Enhanced NTCs' and 'Cheaper BESS' scenarios.

Figure 5.1 Overview of the modelled scenarios

Scenario matrix



Scenario description

Baseline	– Starting from TYNDP 2024 NT for 2030, GA for 2035 and 2040 – NTCs evolution from TYNDP 2024 (i.e. disjointed national grid plans) – Capacity mix (BESS, RES, CCGT) re-optimised for 2035 and 2040
Enhanced NTCs	– NTCs are optimised at European level for 2035 and 2040 – Consequently, capacity mix (BESS, RES, CCGT) is re-optimised
Cheaper BESS	– Improved adoption of distributed storage considering, as a proxy, a 25-40% CAPEX reduction for BESS and -20% OPEX reduction – NTCs evolution from TYNDP 2024 as for the Baseline scenario – Capacity mix (BESS, RES, CCGT) re-optimised for 2035 and 2040
Full Policy	– Improved adoption of distributed storage assumed as for the Enhanced NTCs scenario – NTCs are optimised at European level for 2035 and 2040 – Consequently, capacity mix (BESS, RES, CCGT) is re-optimised

Notes: NT indicates ENTSO-E's TYNDP 2024 National Trends scenario; GA indicates ENTSO-E's TYNDP 2024 Global Ambition scenario.
Source: Oxera and AFRY.

5.1 Baseline scenario

The Baseline scenario represents a closer to 'business-as-usual' scenario capturing the forward-looking evolution of today's electricity system based on ENTSO-E's TYNDP 2024, specifically building on the NT scenario for 2030 and the GA scenario for subsequent years until 2040. To reflect a more business-as-usual evolution, a number of adjustments were made to the TYNDP 2024 scenarios.

- More 'innovative' technologies at early deployment stages, such as carbon capture and storage and hydrogen-fired generators, have been removed from the baseline. While these technologies may play important roles in long-term decarbonisation, their commercial viability, deployment pace, and economic competitiveness remain uncertain. As the study focuses on the pathways towards 2040, removing them from the baseline ensures the scenario reflects technologies with established deployment pathways and proven economics.
- The assumed level of BESS has been revised to align with NT 2030 figures.
- As anticipated, for 2035 and 2040, AutoBuild defines the optimal level of investment for solar PV, onshore and offshore wind, BESS and CCGTs, with caps on RES expansion in line with GA levels. The dispatch module then provides the optimal unit commitment

and economic dispatch plan for the different snapshot years (2030, 2035 and 2040).

The optimisation for 2035 and 2040 was performed through AutoBuild (instead of directly adopting ENTSO-E's TYNDP 2024 GA scenario), to ensure that the Baseline scenario is coherent from both an economic and system security perspective. This approach is intended to represent a more business-as-usual trajectory, rather than entirely relying on ENTSO-E scenarios.

5.2 Enhanced NTCs scenario

The Enhanced NTCs scenario considers the value of ambitious cross-border transmission coordination, optimising interconnection capacity expansion to maximise European system efficiency while maintaining the same battery storage cost assumptions as the Baseline.

Building on the 2030 NTCs levels from ENTSO-E's TYNDP 2024 NT scenario**, AutoBuild expands NTCs on the most congested borders. Then, the long-term optimisation process of AutoBuild is used to define an economical buildout plan for generation and storage units, starting from these expanded NTCs for 2035 and 2040**. Similarly to the Baseline scenario, the dispatch module provides the optimal unit commitment and economic dispatch plan for the different snapshot years.

The rationale behind this scenario, which involves optimising the NTCs, is to simulate policy and regulatory measures involving enhanced coordination among national TSOs. Such a policy would aim to improve cross-border system efficiency, by possibly strengthening security of supply and reducing overall system costs.

The optimisation process of the NTCs is based on both economic and system adequacy considerations, by calculating the marginal benefit of relieving congestion between zones against the capital and operational costs of adding additional capacity to the available lines. If the expected reduction in system costs (measured as a combination of wholesale prices, generation costs and curtailment), combined with improved security of supply, outweighs the investment cost, additional transfer capacity is added to each optimised line.

Since interconnector capacity was subject to optimisation, a re-optimisation of the installed capacities was also carried out for the technologies previously optimised in the Baseline scenario (BESS, RES and CCGTs), since changes in the system configuration can be expected to alter investment signals and overall plant economics, making a recalibration essential to ensure consistency within each scenario.

5.3 Cheaper BESS scenario

This reflects a scenario with more 'favourable' assumptions for batteries and other storage technologies, such as significantly lower capital costs and/or improved performance for these technologies. In particular, for this scenario, NTCs are assumed to remain unchanged compared to the Baseline scenario, but CAPEX for batteries is assumed to be significantly lower.

Specifically, 'standard' CAPEX assumptions for BESS, used for the Baseline and Enhanced NTCs scenarios, have been revised downwards, lowering Baseline values by 25% in 2030 and 40% in 2040, with linear interpolation for intermediate years. Furthermore, OPEX assumptions in these scenarios were reduced by 20% compared to the Baseline.

Based on these updated assumptions, AutoBuild is used to define an economical buildout plan for generation and storage units, which is then followed by the dispatch module to derive the short-term optimisation of the unit commitment and economic dispatch plan for the snapshot years.

While the Cheaper BESS scenario is implemented in the model via reduced BESS CAPEX and OPEX parameters, this scenario is not primarily about utility-scale battery technology becoming cheaper through manufacturing improvements alone. Rather, **the cost reduction for BESS is a modelling proxy for a policy and regulatory environment in which distributed storage and flexibility are widely integrated and system-level access to flexibility has a reduced cost**.

In such an environment, a significant share of the system's storage/flexibility is provided by distributed, cross-sector assets—e.g. industrial steam or hot-water boilers with thermal inertia, refrigerated warehouses and building HVAC and broader demand-side response resources. Given that these assets are often installed and justified by non-electricity use cases, much of their capital cost is borne outside the power system, so the incremental cost of unlocking their flexibility for grid services (through controls, aggregation and market access) is materially lower than building new, dedicated utility-scale batteries.

The scenario therefore reflects a shift in the composition of storage/flexibility (more distributed and behind-the-meter, often cross-sector) and in the costs incurred to access it (lower due to policy

and digitalisation), rather than a pure technology cost reduction for utility-scale batteries.

5.4 Fully Policy scenario

The Full Policy scenario combines the features of the Enhanced NTCs and Cheaper BESS scenarios to represent a policy environment where regulatory measures are fully leveraged—both to strengthen TSO coordination for grid development and to accelerate the integration of distributed flexibility and storage.

As in the Enhanced NTCs scenario, the model starts from the ENTSO-E's TYNDP 2024 2030 NT scenario values and optimises the evolution of interconnector capacity for 2035 and 2040. This optimisation also triggers a recalibration of the generation mix (including BESS, RES and CCGTs) to reflect the altered investment signals and system economics.

In parallel, consistent with the Cheaper BESS scenario, lower cost assumptions for BESS are applied as a proxy for a situation where part of the system's flexibility costs are absorbed outside the electricity sector (through distributed resources such as industrial thermal systems, refrigeration and demand-side response). This combined approach allows the scenario to quantify the potential benefits of coordinated infrastructure planning and deeper flexibility integration under a comprehensive policy framework.

5.5 Overview of the key features of the scenarios

An overview of the capacity mix resulting from the optimisation process performed with AutoBuild for each of the modelled scenarios is provided in Table 5.1 and Figure 5.2. A more in-depth analysis is provided in section 6.3.

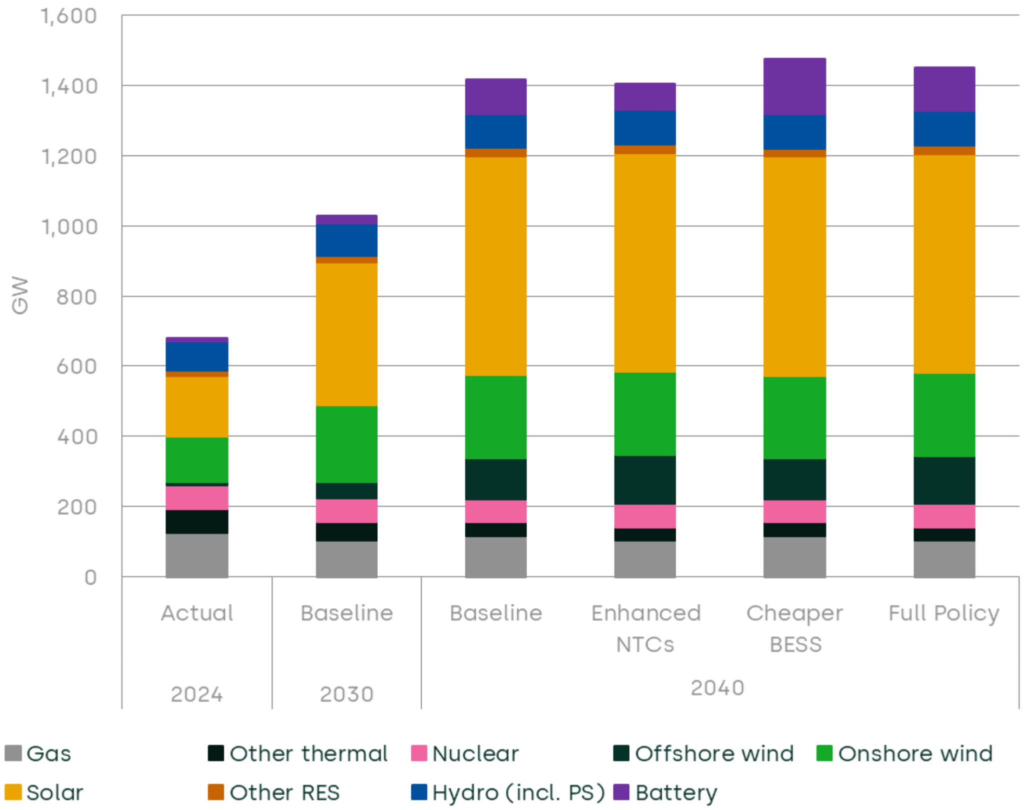
Table 5.1 Breakdown of actual and projected installed capacity across scenarios (GW)

	2024	2030	2035				2040			
	Actual	Baseline	Baseline	Enhanced NTCs	Cheaper BESS	Full Policy	Baseline	Enhanced NTCs	Cheaper BESS	Full Policy
Battery	9	21	58	40	75	55	97	73	155	124
Offshore wind	10	46	84	92	83	88	114	141	114	137
Onshore wind	128	220	237	236	236	237	237	236	236	236
Solar	173	405	533	541	542	542	623	623	623	623
Hydro (incl. PS)	81	93	96	96	96	96	98	98	98	98
Gas	124	103	118	103	118	103	118	103	118	103
Other RES	17	19	23	23	23	23	24	24	24	24
Nuclear	69	67	65	65	65	65	66	66	66	66
Other thermal	68	54	35	35	35	35	39	39	39	39
Interconnections		100	111	153	111	153	116	162	116	164

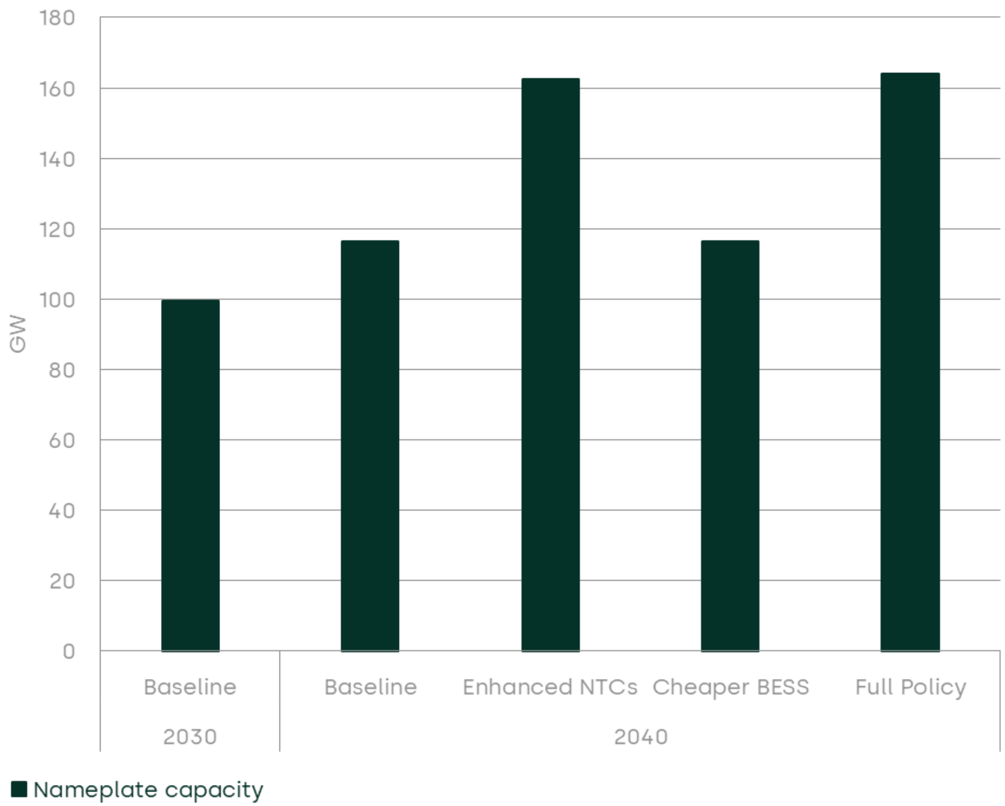
Note: Focus countries (France, Germany, Italy and Spain). PS indicates hydro pumped storage.
Source: Oxera analysis based on Terna, RTE (generation technologies and batteries), REE, SMARD and Bundesnetzagentur data for 2024 (accessed 14 November 2025) and AFRY model results from 2030 onwards.

Figure 5.2 Current and projected installed capacity and interconnectors' nameplate capacity across scenarios in 2030 and 2040 (GW)

Installed capacity (GW)



Interconnectors' nameplate capacity (GW)



Note: Focus countries (France, Germany, Italy and Spain).
Oxera analysis based on Terna, RTE (generation technologies and batteries), REE, SMARD and Bundesnetzagentur data for 2024 (accessed 14 November 2025) and AFRY model results from 2030 onwards.

5.6 Concluding remarks

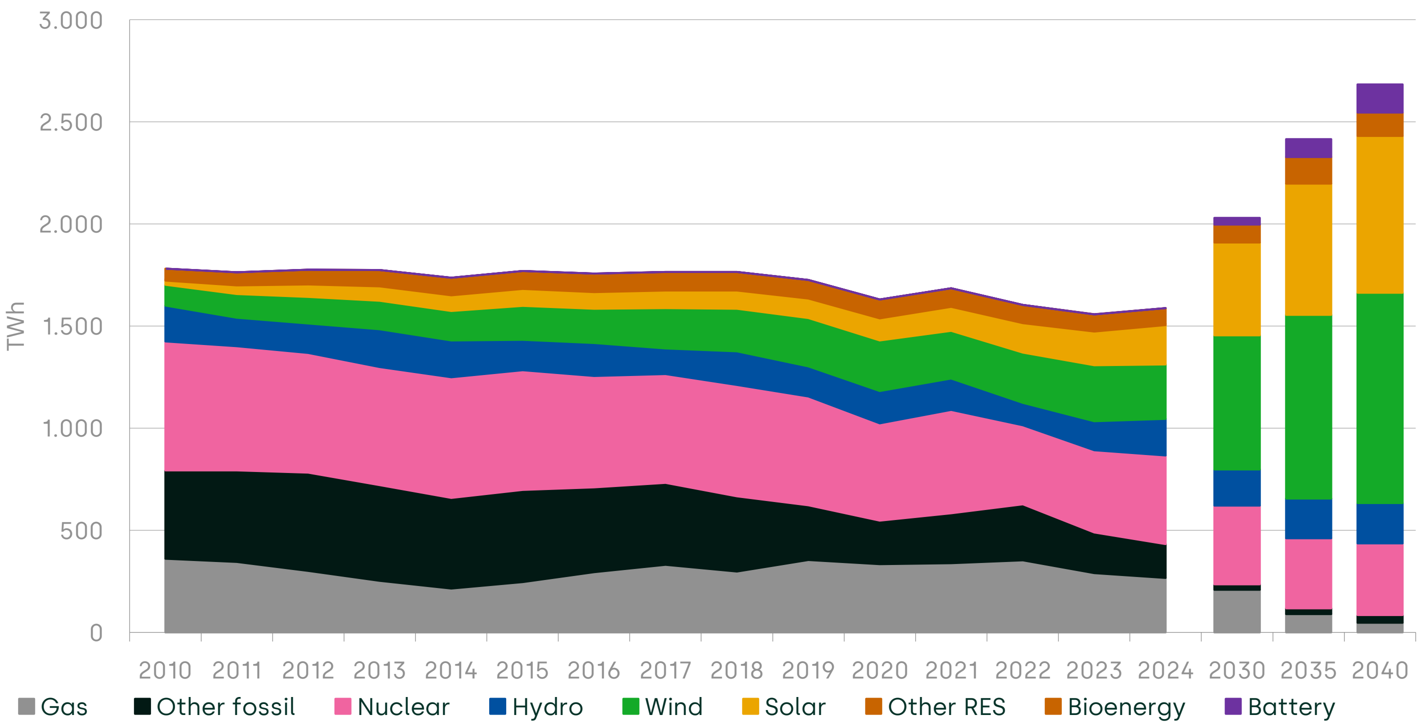
While the four scenarios build on ENTSO-E's TYNDP 2024, it is important to acknowledge both the value and limitations of this starting point. The TYNDP scenarios represent an official set of projections providing a valuable common reference point. However, TYNDP scenarios inevitably reflect the views of their primary developers—European TSOs.

At the same time, it is worth noting that TYNDP 2024 assumes an evolution of the European electricity system that substantially differs from the evolution experienced in recent years, implying that even the Baseline scenario assumes marked and ambitious changes compared to current trends. For example, TYNDP 2024 projects a substantial growth of demand (as seen in section 3), largely reflecting new electricity consumption from electrolysers, which in turn drives the expansion of generation capacity to meet this higher load.

For example, restricting the analysis of the four focus countries, according to ENTSO-E's TYNDP 2024 GA scenario, electricity production is expected to reach around 2,600 TWh in 2040, increasing by more than 60% from around 1,600 TWh in 2024.[75] As shown in Figure 5.3 and discussed in more detail in section 6, this is also reflected in the modelling results.

[75] Oxera analysis based on EMBER data for 2024 and TYNDP 2024 from 2030 onwards (accessed 6 November 2025). For projected values from 2030 onwards, demand figures do not include electricity consumption from pumped hydro storage and BESS units.

Figure 5.3 Historical and projected generation volumes for the focus countries, Baseline scenario (TWh)



Note: Focus countries (France, Germany, Italy and Spain).
Source: Oxera analysis based on EMBER data for 2024 (accessed 6 November 2025) and AFRY model results from 2030 onwards.

Specifically, not only is generation set to increase in line with a significantly higher load, but the capacity and generation mix will also evolve substantially, largely driven by variable RES, while gas-fired generation declines significantly. Looking at the Baseline scenario, wind and solar power are projected to account for more than 65% of total generation in 2040, with nuclear representing slightly less than 15% and CCGTs less than 2% (around 50 TWh).

While these figures depict a picture significantly different from today's electricity systems in the focus countries, it is worth noting that the changes implied by the modelled scenarios are, at least partially, less marked than those assumed in the ENTSO-E's TYNDP 2024 GA scenario. In particular, as the optimisation process for all scenarios results in a smaller expansion of RES capacity in the focus countries compared to the GA scenario, variable RES generation is also lower (around 1,900 TWh in the Full Policy scenario, the scenario with highest RES generation, compared to around 2,250 TWh in the GA scenario, in 2040) while gas-fired generation is slightly higher (35 TWh in the Full Policy scenario, or 48 TWh for the Baseline, compared to 9 TWh in the GA scenario, in 2040).

6 Key model results

The modelling analysis reveals how different investment pathways—varying interconnection capacity and flexible resources availability—can reshape the European electricity system's costs, reliability, and decarbonisation trajectory. Comparing AFRY's BID3 model results across the four scenarios provides insights into the trade-offs and synergies between transmission coordination and distributed flexibility deployment.

At a high level, the modelling exercise shows the following.

- **Demand flexibility is foundational: the expected evolution (and level of flexibility) of electricity demand plays a key role in ensuring a competitive, affordable and resilient electricity system**.
- **Interconnection and storage are complements, not substitutes: additional (and coordinated) investments in interconnection capacity and BESS could be considered complementary, as they serve different purposes and support one another.** The Full Policy scenario demonstrates that combining both approaches delivers greater benefits than either policy in isolation.
- **The cost structure fundamentally transforms**: across every scenario (all of which have high RES-penetration), **the cost structure of the electricity system is expected to change significantly, transitioning from a largely OPEX-based to a predominantly CAPEX-based system**. This transition has profound implications for financing, risk allocation, and consumer prices.

Specifically, flexible demand proves essential for realising the economic benefits of renewable expansion. Sensitivity analysis shows that without **additional flexible decarbonised demand**, no price reductions would be achieved by 2040, with wholesale prices consistently remaining around €70/MWh in the focus countries. In contrast, each of the modelled scenarios, all of which incorporate a growing share of flexible decarbonised demand, result in wholesale price reductions, which ultimately translate in savings for consumers.

Since flexible demand is more easily ‘coupled’ with RES generation profiles, a (flexible) demand increase drives a greater expansion of RES, which in turn more frequently displace gas-fired plants as the marginal technology and result in lower wholesale prices. Moreover, given the significant demand growth projected in ENTSO-E’s TYNDP 2024 scenarios and reflected in the BID3 model, the capacity mix also changes significantly, largely driven by lower cost RES. In light of these two factors, wholesale electricity prices are expected not only to decrease on average but also to become less volatile over the modelled horizon, strengthening the resilience of the system against future shocks on gas prices (if the expansion of flexible decarbonised demand materialises).

As for the respective **roles of interconnections and flexibility resources**, while battery storage addresses the temporal dimension of renewable variability, effectively absorbing excess RES production and reducing total curtailment, the expansion of cross-border interconnections facilitates RES integration by contributing to market integration, smoothing out weather patterns across regions and, more broadly, integrating diverse generation mixes and demand patterns across countries and bidding zones.

At the same time, while BESS excels at providing short-duration flexibility, it cannot fully replace dispatchable thermal generation for addressing extended periods of low renewable availability, as shown in the Cheaper BESS scenario, which still requires 15GW of new CCGT capacity to come online between 2030 and 2040. Instead, based on the modelling results, the Enhanced NTCs and Full Policy scenarios, characterised by higher cross-border interconnection capacity, do not require any additional gas-fired capacity.

The new configurations of the electricity mix projected in the modelled scenarios result in **significant changes in the composition of total system costs**. In particular, while the expansion of interconnection, BESS and generation assets requires considerably higher investments (i.e. higher CAPEX and fixed costs), it also reduces the variable costs to operate the system (particularly lower commodity and fuel costs, as thermal plants produce less electricity and run for a more limited number of hours).

Overall, total system costs over the period 2030–40 are broadly comparable across the four scenarios, but the composition of these costs differ. Specifically, the Enhanced NTCs and Full Policy scenarios are characterised by lower variable generation costs, despite higher investments in interconnection capacity, BESS and RES. This difference is significant, as the variable generation costs are a ‘recurring expenditure’ that will need to be incurred in subsequent years as well (without new investments), whereas investments in generation, BESS and interconnection capacity will continue to be operational and deliver in the following years. Moreover, a higher share of variable generation costs, as in the Baseline and Cheaper BESS scenarios, also means that the system will retain a higher exposure to fuel price volatility and external shocks (all else equal).

At the same time, the modelling results show that an electricity system with more interconnection capacity and flexible resources available also delivers other benefits:

- the Full Policy scenario achieves the lowest CO2 emissions, with emission intensity expected to fall to around 5 gCO2eq/kWh by 2040, a 99% reduction compared to 1990 levels;
- when more interconnection capacity is available, the number of safe hours (i.e. those in which at least 10% of electricity generated is dispatchable) increases compared to the Baseline;
- lower gas consumptions, as achieved in the modelled scenarios, also strengthens EU's strategic independence.

Finally**, it is worth noting that results are sensitive to the starting point (ENTSO-E's TYNDP 2024 scenarios) and different demand paths would materially change capacity needs and price dynamics. Moreover, as the BID3 model operates on a zonal basis, it does not capture intra-zonal or distribution-level constraints** (e.g. local/within-zone bottlenecks) that could affect the system outcomes and costs for consumers. Finally, the modelling exercise reflects a least-cost optimisation (from a system perspective) which may not be achieved by market forces and price signals alone, so market outcomes could differ from the results of this optimisation process.

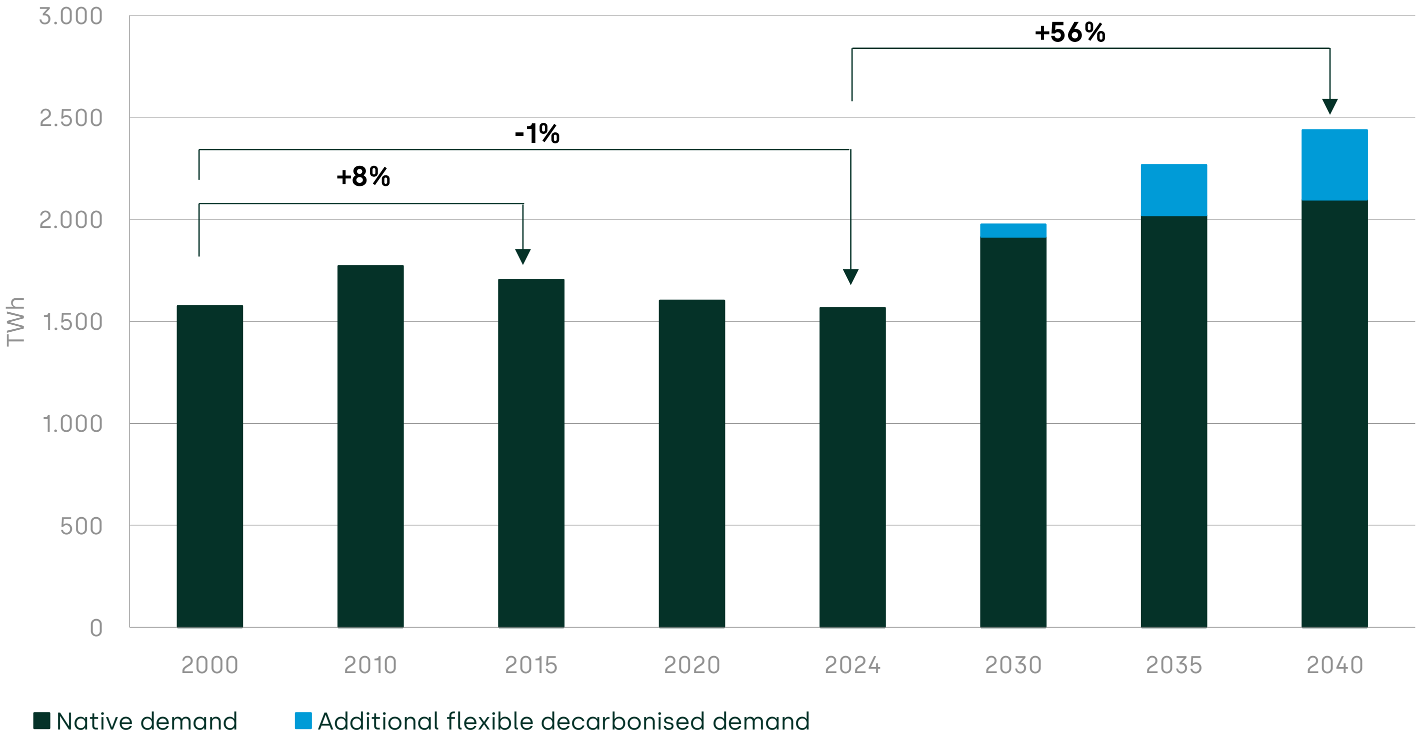
The modelling results and key findings of this study are discussed in more detail in the remainder of this section. Unless otherwise specified, results refer to the four focus countries.

6.1 The role of demand in the end-users cost evolution

The evolution of electricity demand, both in terms of the magnitude of its growth and composition, plays a key role in influencing the competitiveness of the European economies and affordability of electricity prices. Indeed, **the way in which electricity demand evolves fundamentally shapes system outcomes, influencing infrastructure requirements, wholesale prices and ultimately end-user costs**.

The magnitude of the expected demand increase assumed in TYNDP 2024 is unprecedented in the EU history, driven by the widespread electrification of end-use sectors, such as transport, heating and industry, as well as the emergence of new industrial uses. Figure 6.1 illustrates this trajectory: from 2024 to 2040, electricity demand in the focus countries is projected to grow by a striking 56%—a significant increase considering that demand in 2024 remains largely unchanged from 2000 values. The increase in flexible decarbonised demand is particularly pronounced, rising from 60 TWh in 2030 to a projected 247 TWh in 2035 (+313%) and 340 TWh in 2040 (+468% compared to 2030).

Figure 6.1 Historical and projected demand growth (TWh)



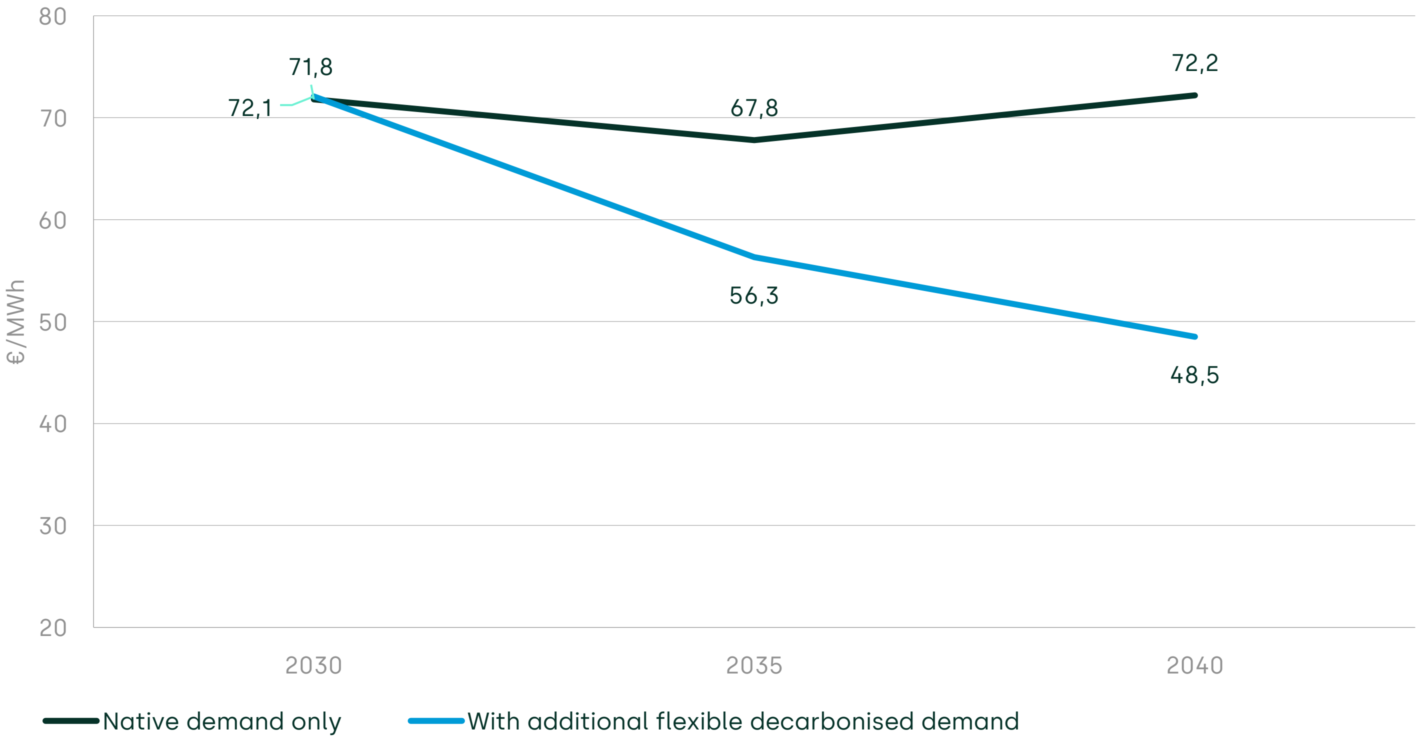
Note: Focus countries (France, Germany, Italy and Spain). From 2030 onwards, demand figures from ENTSO-E's TYNDP 2024 do not include electricity consumption from pumped hydro storage and BESS units, which is an output of the electricity market model.
Source: Oxera analysis based on EMBER data for 2024 (accessed 14 October 2025) and AFRY model results from 2030 onwards.

As anticipated, **the evolution of end-user costs is significantly affected by the projected evolution of the electricity demand. Not only is it key that demand grows, such that system costs are spread over broader electricity volumes (with impact on unit costs), but the type of demand growing matters as much as its scale**. In particular, the growth of flexible decarbonised demand can boost wholesale price reductions, as Figure 6.2 shows. However, **without the additional flexible decarbonised demand considered in all model scenarios, wholesale prices would remain stable in the long run in the Baseline scenario**.

The additional flexible decarbonised demand, as considered in all modelled scenarios, enables a 33% reduction of wholesale electricity prices between 2030 and 2040 in the Baseline scenario, with even larger reductions achieved in the alternative scenarios considered. In the Baseline scenario, in 2040, wholesale prices reach around €48.5/MWh, compared to around €72/MWh in 2030.

Alternatively, **assuming the absence of this flexible decarbonised demand** (with a 'native demand only' sensitivity, as in Figure 6.2), **no price reductions would be achieved by 2040, with wholesale prices consistently remaining around €70/MWh**, with implications in terms of the competitiveness of the European economies and costs borne by European consumers.

Figure 6.2 Evolution of wholesale prices in the Baseline scenario compared to a 'native demand only' sensitivity (€/MWh)



Note: Focus countries (France, Germany, Italy and Spain). Prices are reported in EUR 2025 terms.
Source: Oxera analysis based on AFRY model results.

The same findings also hold true when considering the EU-30, with average wholesale prices reaching €46/MWh in 2040 under the Baseline scenario, compared to around €65/MWh under the 'native demand only' sensitivity.[76] In other words, without the additional flexible decarbonised demand expansion, wholesale prices are expected to remain higher. This highlights how sensitive the results are to projected demand growth assumptions.

6.2 Impact on consumers: wholesale costs and total system costs

This study also examines the impact on consumers through the analysis of the expected evolution of wholesale prices, end-user costs and total system costs across the different scenarios.

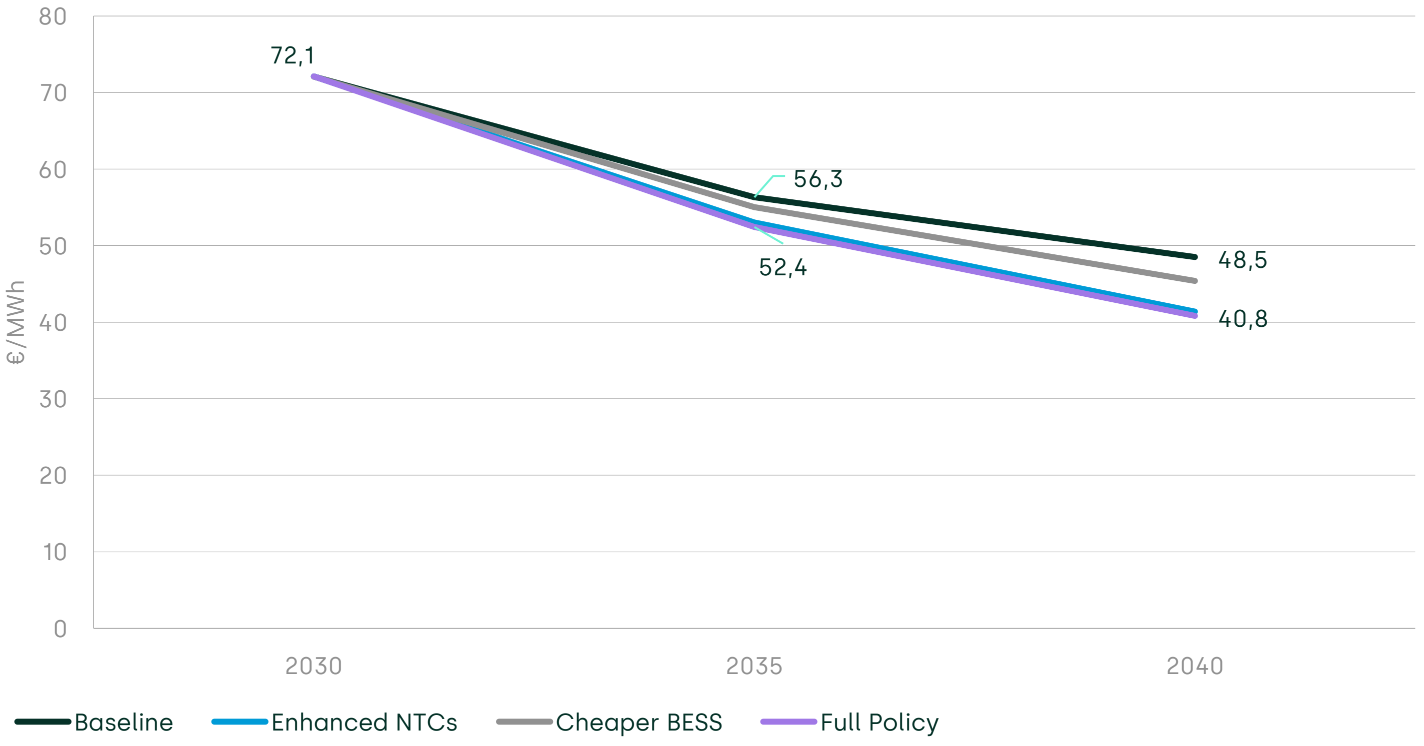
As discussed in the previous section, results and wholesale prices are particularly sensitive to the projected evolution of electricity demand. To allow comparisons across the four modelled scenarios, demand assumptions are fixed and common to all scenarios.

This methodological approach allows the analysis to answer the following policy question: given a particular demand trajectory, which combination of interconnection and storage investment delivers the lowest costs and prices for consumers?

Based on the assumed evolution of demand, **wholesale electricity prices decrease across all countries in all scenarios compared to the Baseline scenario. The largest driver behind the different price reductions across scenarios is the expansion of interconnections across bidding zones**, as the most significant reductions in wholesale prices are achieved in the Enhanced NTCs and Full Policy scenarios, as illustrated in Figure 6.3. By 2040, the Full Policy scenario achieves wholesale prices of €40.8/MWh, a 16% reduction compared to the Baseline and a 43% reduction compared to 2030 price levels.

[76] Oxera and AFRY analysis based on AFRY model results.

Figure 6.3 Average wholesale electricity prices (€/MWh)



Note: Focus countries (France, Germany, Italy and Spain). Prices are reported in EUR 2025 terms.
Source: Oxera analysis based on AFRY model results.

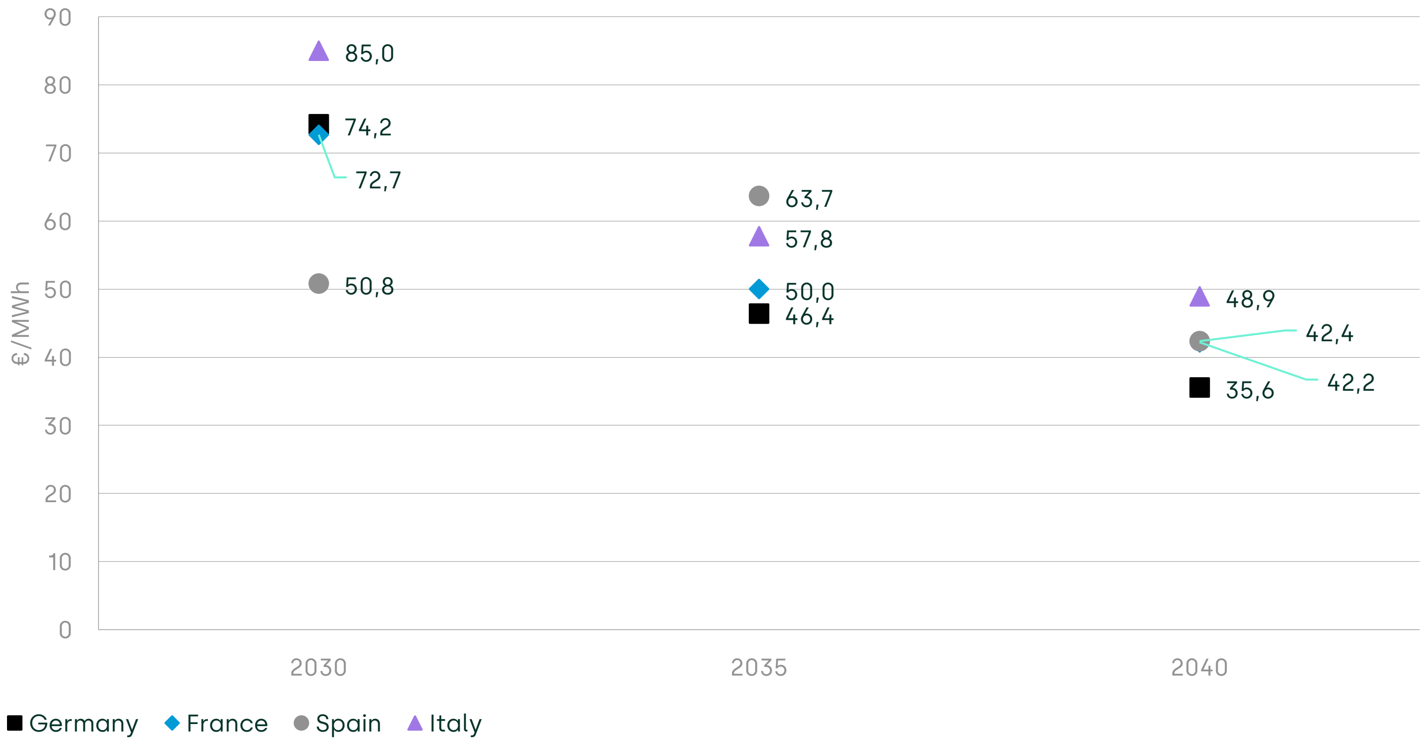
While wholesale prices consistently decrease in all the focus countries, the speed and extent of the reduction differ among them. In particular, the different evolutions are broadly consistent across scenarios and largely reflect the key features of the respective electricity mixes.

Figure 6.4 highlights several country-specific dynamics, and a gradual convergence over time under the Full Policy scenario.

- In 2030, Spain is the cheapest market due to abundant RES generation and nuclear power, while Italy remains the most expensive market due to higher gas dependence.
- In 2035, Spain's prices rise temporarily following the completion of the nuclear phase-out.
- By 2040, prices tend to converge more as additional RES and storage capacity are integrated and enhanced interconnections smooth out generation and demand patterns across regions—although Italy continues to record slightly higher average prices, reflecting the more prominent role of gas plants as the marginal technology, particularly in certain bidding zones. For example, in the Full Policy scenario, CCGT plants set the price in around 3%

of the hours in Italy-North and 0.7% in Italy-South,[77] compared to less than 0.5% in the other focus countries.

Figure 6.4 Wholesale electricity prices across countries, Full Policy scenario (€/MWh)



Note: Prices are reported in EUR 2025 terms.
Source: Oxera analysis based on AFRY model results.

Moreover, the modelling results show that enhanced interconnection capacity improves price convergence in neighbouring countries. Specifically, when comparing the dispersion of wholesale prices in the focus countries across scenarios, the Full Policy scenario shows the lowest values, with the spread between the highest and lowest priced zones decreasing to €16.6/MWh in 2040, compared to €20.3/MWh in the Baseline for the same year and €38.5/MWh in 2030. A good example is the France-Spain differential, which is €22/MWh in 2030 and where prices effectively fully converged by 2040 in the Full Policy and Cheaper BESS scenarios.

[77] In the other Italian bidding zones, price-setting figures of gas-fired plants are broadly comparable (or lower, e.g. in Sicily) with those in the other focus countries.

Wholesale electricity prices are predicted not only to decrease on average but also to become less volatile over the modelled horizon. Over time, the role of gas as the marginal technology declines, as gas-fired plants are expected to be the price setting technology in a shrinking share of hours (around 73% in 2030, falling to 24% by 2040).[78] Therefore, going forward, gas price fluctuations are expected to be less directly reflected into wholesale electricity prices.

A sensitivity analysis shows that **in 2040, a +€50/MWh shock on gas prices is only partially passed through to electricity wholesale prices**: under the Baseline scenario, up to 55% of the shock is absorbed by system resilience rather than reflected in wholesale prices. A more detailed discussion of the declining role of gas plants as the marginal units in the focus countries, as well as an assessment of how price setting technologies evolve across countries and over time, is provided in section 6.4.

To understand whether the benefits to consumers from declining and less volatile wholesale prices are offset by increased costs elsewhere in the electricity system, this study has also assessed the evolution of the end-user costs across scenarios (more details on this metric are provided in Box 6.1).

[78] While gas-fired plants will be price setting in a significantly smaller share of hours (as discussed above and in section 6.4), in some of the hours, they will still play a role as the reference technology also for other plants, e.g. BESS.

Box 6.1 Understanding the definition of end-user costs

This metric is calculated as the sum of the following three components.

- **Wholesale electricity value**, obtained by multiplying total demand by the wholesale price.
- **Missing money for new generation and storage capacity commissioned after 2025**, calculated as the share of total costs that a certain asset is not able to recover through market revenues. This is computed as the sum of the levelised CAPEX plus OPEX of these assets, minus their gross margin (i.e. total revenues less variable generation costs). In other words, these are the costs that would need to be covered 'outside of the market', e.g. through specific support schemes as those for renewables, storage or CRMs.
- **Missing money for new interconnection capacity commissioned after 2025**, calculated as levelised CAPEX plus OPEX, minus the congestion rents earned by these assets.

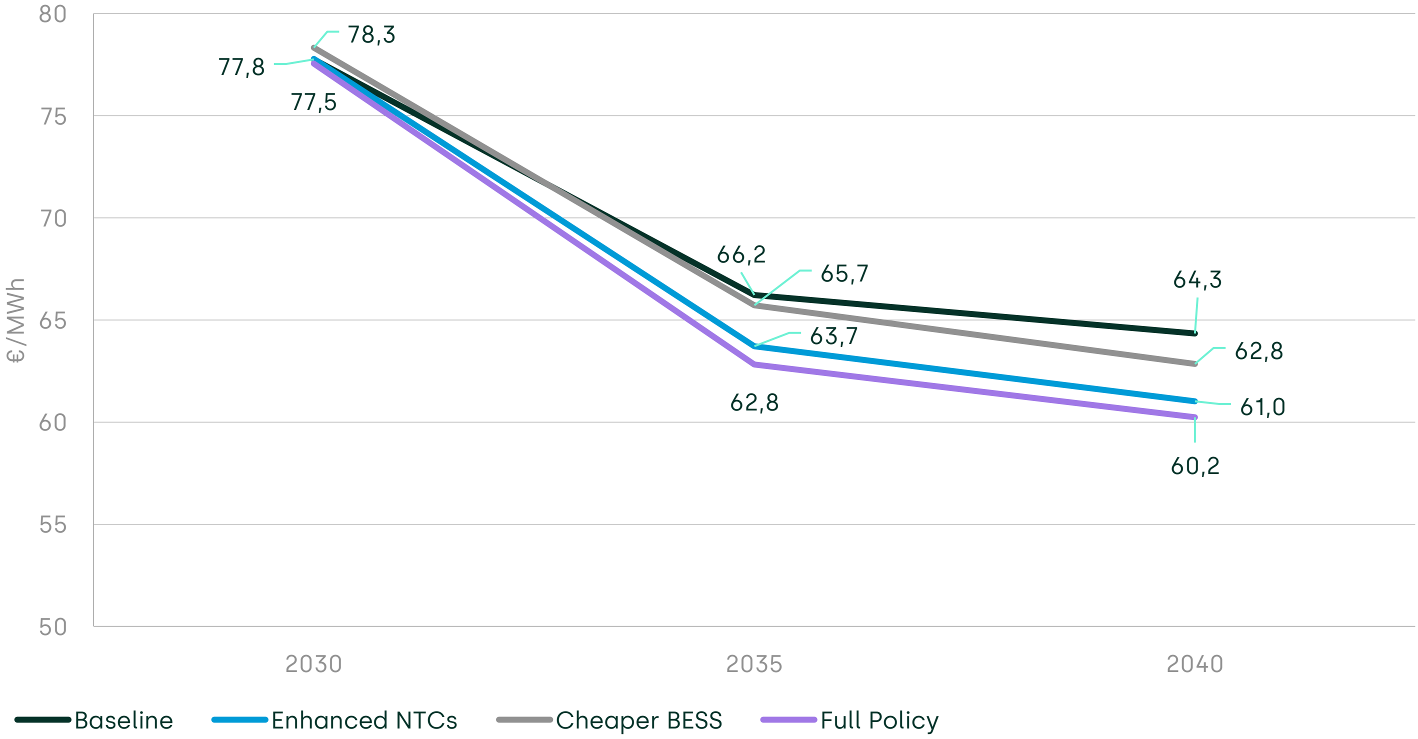
Source: Oxera and AFRY.

Although this indicator does not capture every element ultimately passed through to end-users (such as taxes or ancillary charges), it provides a robust basis for comparing scenarios in differential terms and evaluating the relative economic impact of alternative policy and investment pathways.

As illustrated in Figure 6.5, **enhanced interconnections and increased storage deployment deliver superior outcomes in terms of end-user costs compared to the Baseline scenario**: the Enhanced NTCs scenario achieves €61.0/MWh by 2040—a 22% reduction compared to 2030—while the Cheaper BESS scenario reaches €62.8/MWh, a 20% reduction. Most significantly, **the Full Policy scenario, combining enhanced interconnections and cheaper BESS, delivers the lowest end-user costs at €60.2/MWh by 2040, representing a 22% reduction versus 2030 levels (and -6% against the Baseline scenario in 2040), showing that the**

coordinated deployment of both technologies achieves better outcomes for consumers.[79]

Figure 6.5 Unit end-user costs (€/MWh)



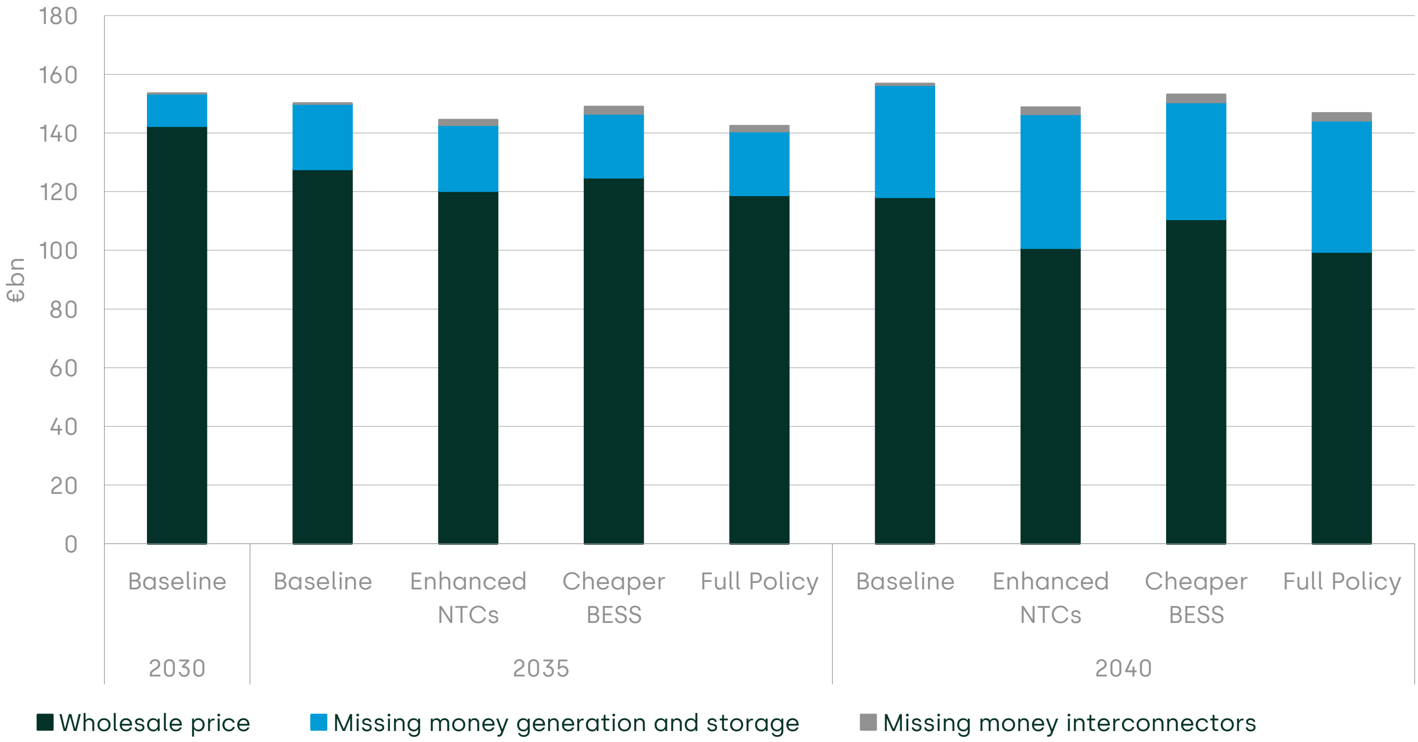
Note: Focus countries (France, Germany, Italy and Spain). Costs are reported in EUR 2025 terms. Investments before 2025 are treated as sunk costs, so their associated CAPEX is not captured in the calculation.
Source: Oxera analysis based on AFRY model results.

In absolute terms, total end-user costs shown in Figure 6.6 reach €146.8bn in the Full Policy scenario by 2040, compared to €156.8bn in the Baseline scenario—a saving of €10bn, outperforming both the Enhanced NTCs (€148.7bn) and Cheaper BESS (€153.1bn) scenarios. **These savings are primarily driven by wholesale price reductions, which more than offset the increased missing money associated to new infrastructure.**[80]

[79] Investments before 2025 are treated as sunk costs, so their associated CAPEX is not captured in the calculation.
[80] The missing money component increases as lower wholesale prices imply that generation and interconnection assets can recover a smaller share of their total costs through market prices. Investments before 2025 are treated as sunk costs, so their associated CAPEX is not captured in the calculation.

Notably, the Full Policy scenario exhibits the highest missing money among all scenarios, reflecting the fact that it achieves the greatest reductions in wholesale prices. Lower wholesale prices mean that generation, storage and interconnection assets can recover a smaller share of their total costs through market revenues alone. This implies that support schemes for RES and BESS, as well as capacity markets, will likely continue to be needed. However, despite higher missing money, the Full Policy scenario delivers the lowest total end-user costs.

Figure 6.6 Total end-user costs (€bn)



Note: Focus countries (France, Germany, Italy and Spain). Costs are reported in EUR 2025 terms. Investments before 2025 are treated as sunk costs, so their associated CAPEX is not captured in the calculation. For simplicity, for 2030, the figure only shows total end-user costs for the Baseline scenario, but these slightly differ across scenarios.
Source: Oxera analysis based on AFRY model results.

This study has also assessed the evolution of total system costs, which represent the overall economic burden of operating and expanding the electricity system and is defined as the sum of:

- variable generation costs, including fuel expenses, CO2 costs and other generation-related variable costs, all expressed per MWh of output;

- OPEX for generation, storage and interconnection assets, including fixed operations and maintenance and personnel costs;
- cumulative[81] levelised CAPEX[82] for new-build generation, storage and interconnection capacity. This reflects the total capital charges associated to the recovery of all investments made from 2025 until the specific year under assessment.

The composition and evolution of total system costs provide further insights on how consumer outcomes change based on the system's costs structure and investment dynamics. Moreover, the total system costs metric helps to verify that these trends are coherent with the ones observed for end-user costs.[83]

When considering the cumulative total system costs over the 2030–40 period, the scenarios show modest differences, with €1,153bn in the Baseline scenario, €1,157bn in the Enhanced NTCs scenario, €1,148bn in the Cheaper BESS scenario, and €1,152bn in the Full Policy scenario.

While the aggregate figures remain similar across the scenarios, the composition of these costs is important for the long-term affordability of the system. **Variable generation costs are projected to be lower in the alternative scenarios compared to the Baseline scenario.** In the Full Policy scenario, cumulative variable generation costs over 2030–40 amount to €223bn, compared to €242bn in the Baseline—a reduction of approximately 8%. This higher share of current expenses in the Baseline scenario means that the system will continue to sustain these operational costs into the future beyond 2040 (unless new investments are carried out), also maintaining a higher exposure to fuel price volatility and external shocks. **In contrast, cumulative CAPEX and fixed costs increase in the Enhanced NTCs and Full Policy scenarios compared to the Baseline**, in light of the investments in new interconnection, BESS

[81] Cumulative means that at each milestone year (2030, 2035, 2040), the value reflects the remuneration of investments made since 2025. For example, the 2035 figure includes all investments from 2025 onwards, while the 2040 figure includes all investments up to that year. This approach ensures that the cost metric accounts for the ongoing financial obligations associated with past capacity additions.
[82] Levelised CAPEX refers to spreading the capital cost over the asset's lifetime using a discount factor. For this study, generation plants were assumed to have a 20-year lifetime with an 8% discount rate, while interconnectors were modelled with a 40-year lifetime and a 6% discount rate. Consequently, the annualised CAPEX component in each year represents the portion of cumulative investments that must be recovered in that year under these assumptions.
[83] The analysis of the total system cost metric is particularly relevant because the scenarios were modelled with additional degrees of freedom (e.g. interconnector optimisation, flexibility integration) and the optimisation algorithm uses an objective function analogous to the total system costs, as defined above. Therefore, a reduction in this metric was mathematically expected and served as a consistency check to ensure that the modelled assumptions translated into measurable system-wide economic benefits.

and generation assets. However, these higher capital costs correspond to the deployment of assets that will continue to deliver value also beyond 2040.

This shift in the total system costs composition represents a fundamental transition from a largely OPEX-based to a predominantly CAPEX-based system. This transition, coupled with enhanced interconnection capacity and greater system flexibility through BESS, is a key driver in mitigating electricity price volatility. **In a system less reliant on fluctuating fuel prices, with more interconnections and more flexibility, the impact of a gas shock on electricity prices will be lower than in the current and past configuration**.

6.3 Evolution of capacity and generation mix across different scenarios

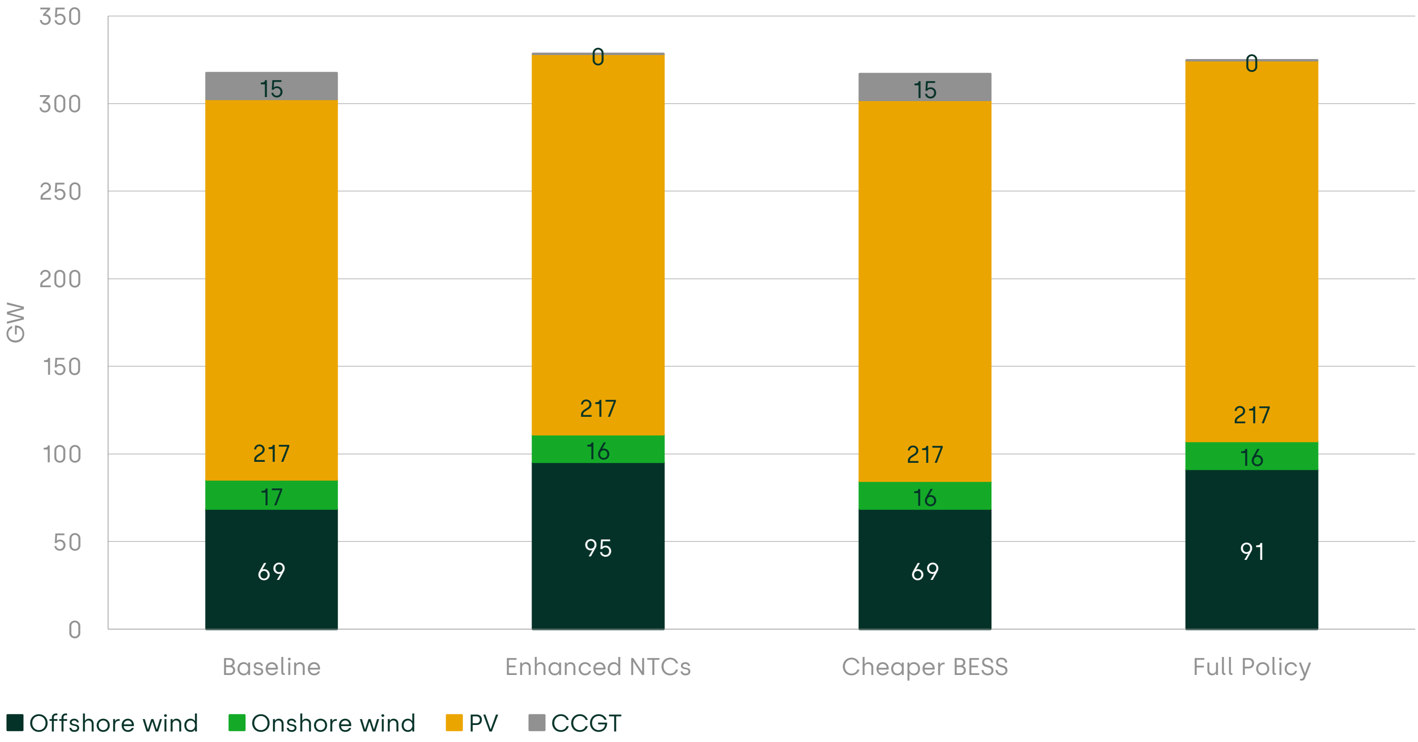
The transition to a decarbonised electricity system entails fundamental shifts in both installed capacity and generation mix across all modelled scenarios. The scale of investment required is substantial, but the composition of that investment—which technologies are deployed, in what quantities, and when—varies significantly depending on interconnection and storage policy choices.

Figure 6.7 illustrates the substantial new capacity buildup required during the 2030–40 period, with all scenarios adding significant renewable generation capacity: new offshore wind capacity ranges from 69GW (Baseline and BESS scenarios) to more than 90GW (Enhanced NTCs and Full Policy scenarios) and new solar PV capacity reaches 217GW.

A critical distinction emerges in new dispatchable thermal capacity requirements across scenarios, revealing one of the most important policy-relevant findings of the analysis:

- Enhanced NTCs and Full Policy scenarios avoid new gas capacity entirely. According to the least-cost optimisation, these scenarios, characterised by enhanced cross-border interconnection infrastructure, do not require any new gas-fired CCGT capacity beyond plants already committed or operational by 2030.
- Baseline and Cheaper BESS scenarios require 15 GW of new CCGT capacity to ensure system adequacy.

Figure 6.7 New generation capacity buildup in the 2030–40 period (GW)



Note: Focus countries (France, Germany, Italy and Spain).
Source: Oxera analysis based on AFRY model results.

The timing of capacity investments reveals relevant differences across the scenarios. Figure 6.7 illustrates the evolution of new capacity buildup differences versus the Baseline, showing how investment pathways vary across scenarios over the 2030–40 period. In the Enhanced NTCs scenario, interconnection capacity exceeds the Baseline by around 41GW in 2035, reaching a difference of roughly 46GW in 2040, while BESS deployment remains lower than the Baseline for the whole period.

The enhanced cross-border interconnections in the Enhanced NTCs scenario allow substantially higher offshore wind installation, reaching approximately 27GW above Baseline levels by 2040. **Greater interconnection capacity reduces the need for domestic storage while enabling higher renewable deployment**.

The Cheaper BESS scenario presents a different investment pathway: while interconnection capacity remains unchanged compared to the Baseline, it is characterised by a particularly significant BESS expansion, deploying approximately 58GW more battery capacity than the Baseline by 2040. This, however, does not enable the same level of offshore wind expansion seen in the Enhanced NTCs scenario and notably requires new CCGT capacity to be built to maintain system adequacy.

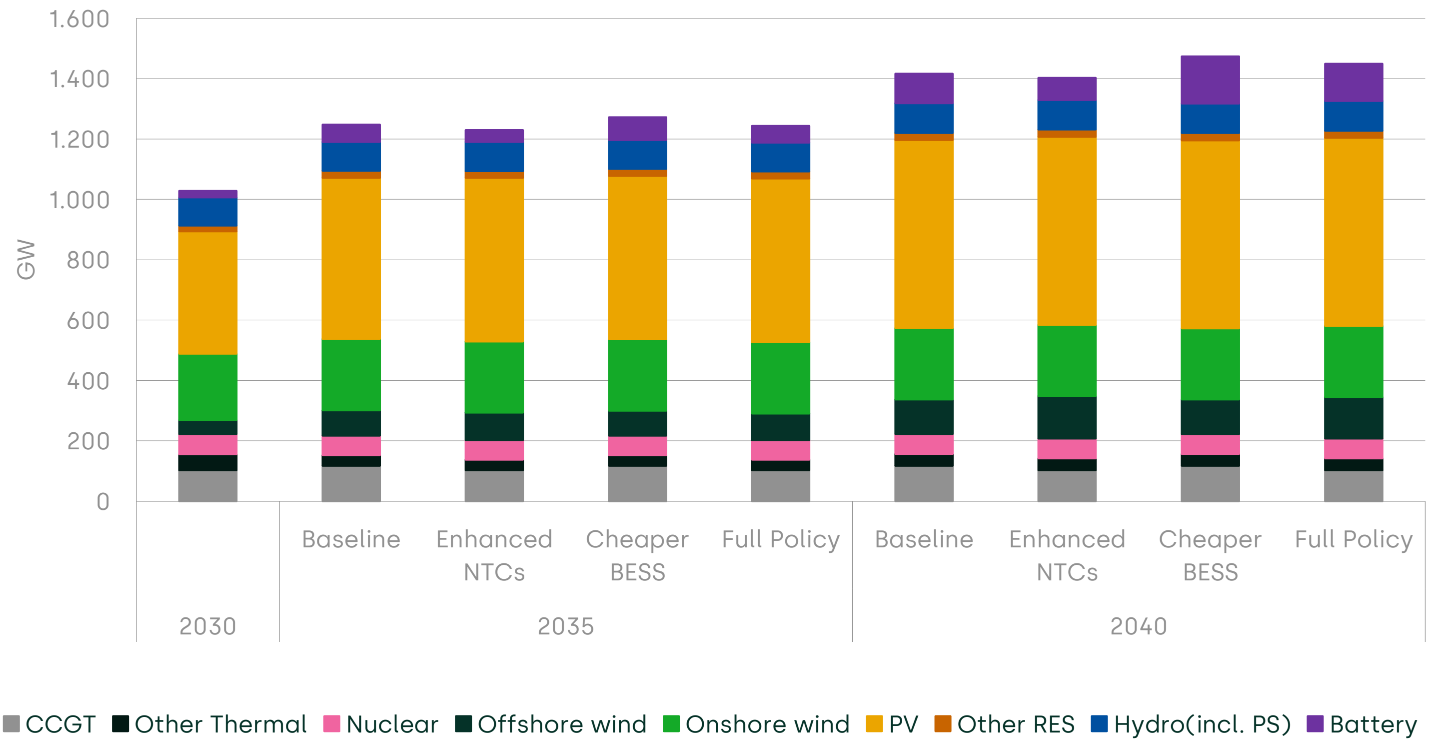
The Full Policy scenario combines both the deployment of 47GW of additional interconnection capacity and more than 26GW additional BESS compared to the Baseline by 2040, while also supporting increased offshore wind deployment similar to the Enhanced NTCs scenario.

Figure 6.8 Additional capacity buildup compared to the Baseline scenario (GW)

Note: Focus countries (France, Germany, Italy and Spain).
Source: Oxera analysis based on AFRY model results.

At an aggregate level, the capacity mix undergoes substantial transformation between 2030 and 2040 across all scenarios, reflecting the structural changes required for decarbonisation. As Figure 6.9 shows, by 2040, renewable technologies—particularly wind and solar—dominate the capacity portfolio, while thermal capacity declines but remains part of the mix in order to guarantee system adequacy.

Figure 6.9 Installed capacity (GW)



Note: Focus countries (France, Germany, Italy and Spain). PS indicates hydro pumped storage.
Source: Oxera analysis based on AFRY model results.

A deep dive on the specificities of the national capacity mix highlights some structural differences that remain across all scenarios even in 2040. Table 6.1 shows the capacity mix by country in 2040 under the Full Policy scenario, highlighting persistent national differences. **Italy maintains a higher proportion of gas-fired plants, Germany heavily relies on RES, with the highest share represented by wind capacity, France retains substantial nuclear capacity, while Spain combines significant solar and onshore wind capacity**.

This heterogeneity in national generation mixes—reflecting different generation resources, demand patterns and, somehow, historical features and energy policy choices—is precisely what makes enhanced interconnections so valuable. **The combination of markets with diverse supply and demand characteristics through robust cross-border interconnections allows the system to smooth out generation and demand patterns**. This diversity mitigates the risk of simultaneous overgeneration that would occur if all countries had identical capacity mixes, improving overall system efficiency.

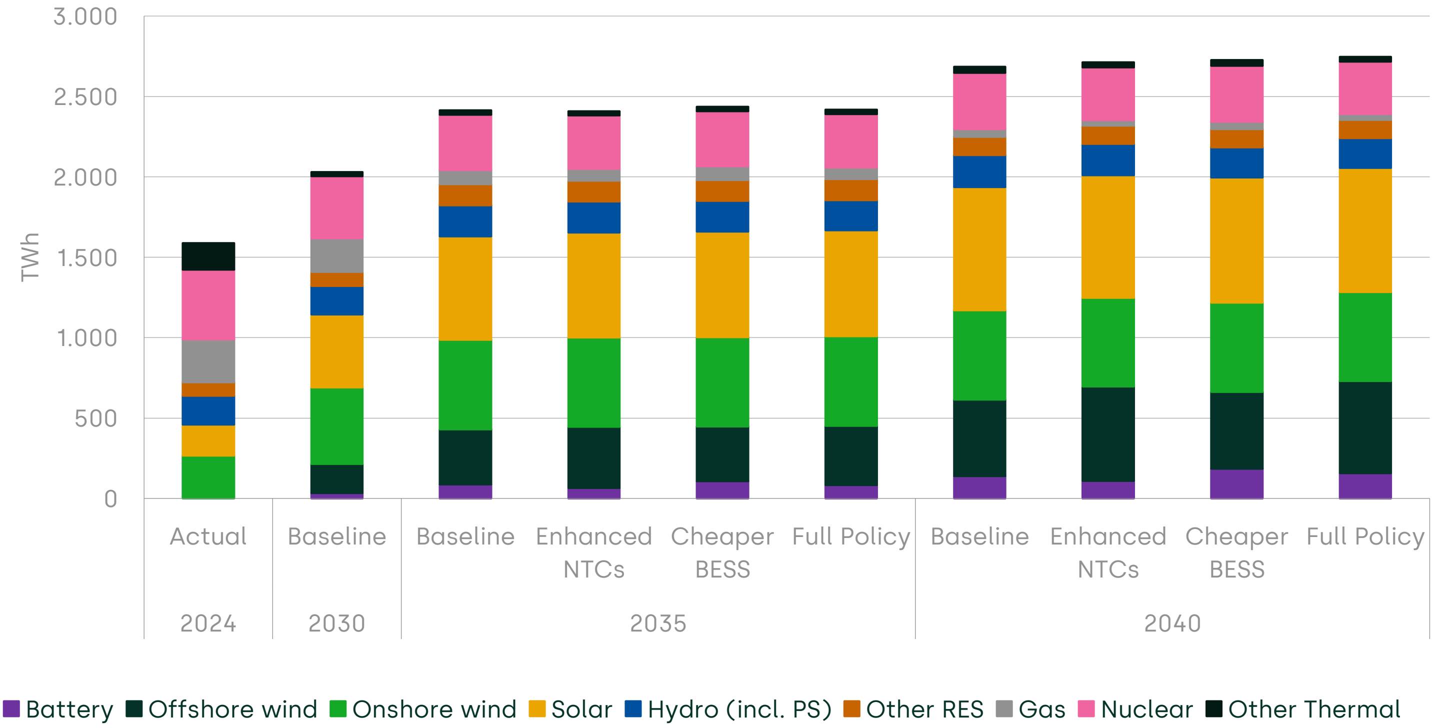
Table 6.1 Comparison of capacity mix in 2024 and 2040, Full Policy scenario (%)

	Italy		France		Germany		Spain	
	2024	2040	2024	2040	2024	2040	2024	2040
Battery	4	18	1	6	1	2	-	13
Onshore wind	9	5	15	11	24	21	25	24
Offshore wind	-	2	1	1	3	23	-	1
Solar	26	48	16	43	30	40	27	42
Hydro (incl. PS)	17	8	16	10	6	3	13	9
Other RES	3	2	1	1	4	1	1	3
Gas	34	14	8	4	14	5	21	7
Nuclear	-	-	39	23	-	-	5	-
Other thermal	6	2	3	1	18	5	7	1

Note: PS indicates hydro pumped storage.
Source: Oxera analysis based on Terna, RTE (generation technologies and batteries), REE, SMARD and Bundesnetzagentur data for 2024 (accessed 14 November 2025) and AFRY model results for 2040 onwards.

The differences in capacity are reflected in generation outcomes. Figure 6.10 shows the evolution of the generation mix across scenarios, highlighting the transition from a system more reliant on thermal generation to one heavily based on renewables, with a remaining share of nuclear (in France).

Figure 6.10 Generation mix (TWh)



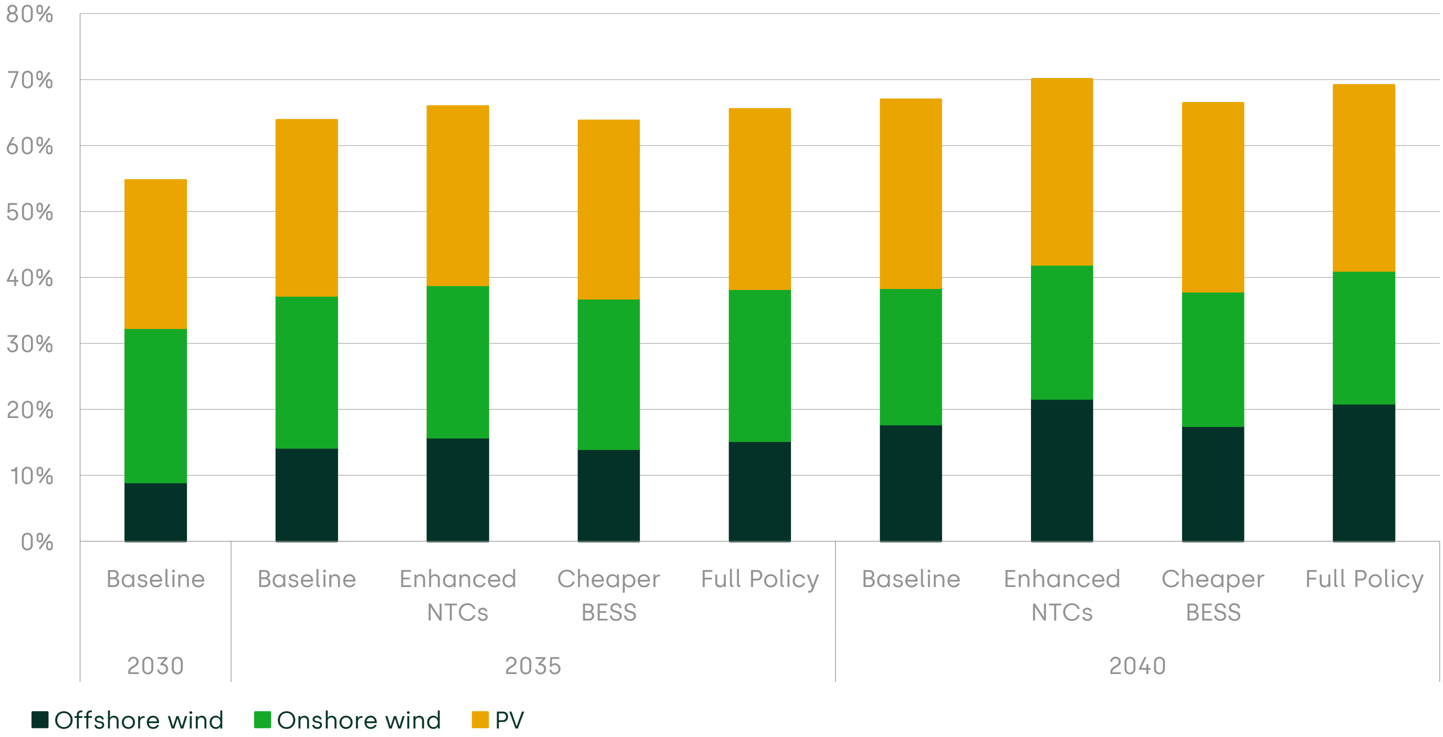
Note: Focus countries (France, Germany, Italy and Spain). PS indicates hydro pumped storage. For 2024, the distinction between onshore and offshore wind is not available from EMBER data. For 2024, 'Other RES' includes bioenergy and other renewables, while 'Other Thermal' includes coal and other fossil.
Source: Oxera analysis based on EMBER data for 2024 (accessed 6 November 2025) and AFRY model results from 2030 onwards.

6.4 RES penetration, RES curtailment and the role of different technologies

The increasing penetration of RES in the energy mix transforms the electricity system's dynamics, creating both opportunities (lower-cost, zero-carbon generation) and challenges (variability, higher curtailment, integration complexities). The modelling reveals how different infrastructure investments address these challenges through complementary but distinct mechanisms.

The share of renewable generation over total electricity production increases progressively across scenarios. The most substantial growth is observed in the Enhanced NTCs scenario, where RES penetration reaches 66% in 2035 and 70% in 2040, closely followed by the Full Policy scenario with a 69% penetration in 2040. As highlighted in the previous sections, **the most relevant driver of RES integration is the expansion of electricity interconnections**. Indeed, increased cross-border interconnections create a larger integrated market that can more effectively exploit renewable generation, by enabling excess renewable production in one country to be exported to neighbouring systems.

Figure 6.11 Variable RES penetration (% of generation)



Note: Focus countries (France, Germany, Italy and Spain).
Source: Oxera analysis based on AFRY model results.

The growth of renewable capacity presents challenges in terms of curtailment, which follows different trajectories across scenarios. **Despite investments in grid infrastructure and flexibility resources, curtailment levels consistently rise over time, as RES capacity increases**.

The Enhanced NTCs scenario, despite presenting higher interconnection capacity compared to the Baseline, experiences curtailment rising to around 70 TWh by 2040—higher than the Baseline's 54 TWh (also in light of the higher RES capacity installed in the Enhanced NTCs scenario). In contrast, the Cheaper BESS scenario—with cheaper CAPEX enabling the deployment of a total of 155GW of BESS by 2040—achieves the strongest curtailment reduction, bringing total curtailment down to 41 TWh, a 25% reduction compared to the Baseline. However, it is worth noting that the Cheaper BESS scenario has a RES capacity installed broadly identical to the Baseline, but smaller than the Enhanced NTCs and Full Policy scenarios.

These findings indicate that **storage is more effective than grid enhancement alone in reducing curtailment**. **In other words, expanded interconnections are more effective in integrating RES, expanding their penetration, and strengthening market integration. On the contrary, BESS perform better at absorbing excess RES production, reducing total curtailment (all else equal).** The Full Policy scenario, by combining both measures, achieves the lowest curtailment in 2035 and achieves curtailment levels close to the Baseline in 2040, despite higher RES capacity in both years.

Figure 6.12 RES curtailment (TWh)

Note: Focus countries (France, Germany, Italy and Spain).
Source: Oxera analysis based on AFRY model results.

Geographically, curtailment is highly concentrated in countries with the highest RES penetration. Germany consistently represents the largest contributor, similarly to what has been observed in recent years—accounting for approximately half of total curtailment volumes in 2035, and more than half in 2040 across all scenarios—possibly due to very high wind integration in the generation mix. Spain is the second largest contributor—representing about a third of volumes in 2040—reflecting its strong solar and wind growth. Overall, results highlight that BESS provides the most direct lever for curtailment reduction.

While battery storage addresses the temporal dimension of renewable variability, grid expansion facilitates RES integration by smoothing out weather and demand patterns across regions, as well as strengthening market integration, contributing to a higher resilience of the interconnected system. Overall, model results show that cross-border electricity flows increase substantially over time across all scenarios, with the most significant growth observed in the Enhanced NTCs and Full Policy scenarios, which feature enhanced interconnection infrastructure.

In the Full Policy scenario, key flows increase markedly by 2040. The Germany-Netherlands interconnector—experiencing the largest nameplate capacity expansion, from 5GW in 2030 to 14GW in 2035—carries around 44 TWh (35% utilisation compared to 23% in 2030). Meanwhile, the Germany-France interconnector, almost doubled to 9.8GW nameplate capacity, reaching a utilisation rate of 52%. Germany's enhanced interconnections—resulting in more than 250 TWh export flows by 2040—enable its significant offshore wind capacity to serve a broader European demand.

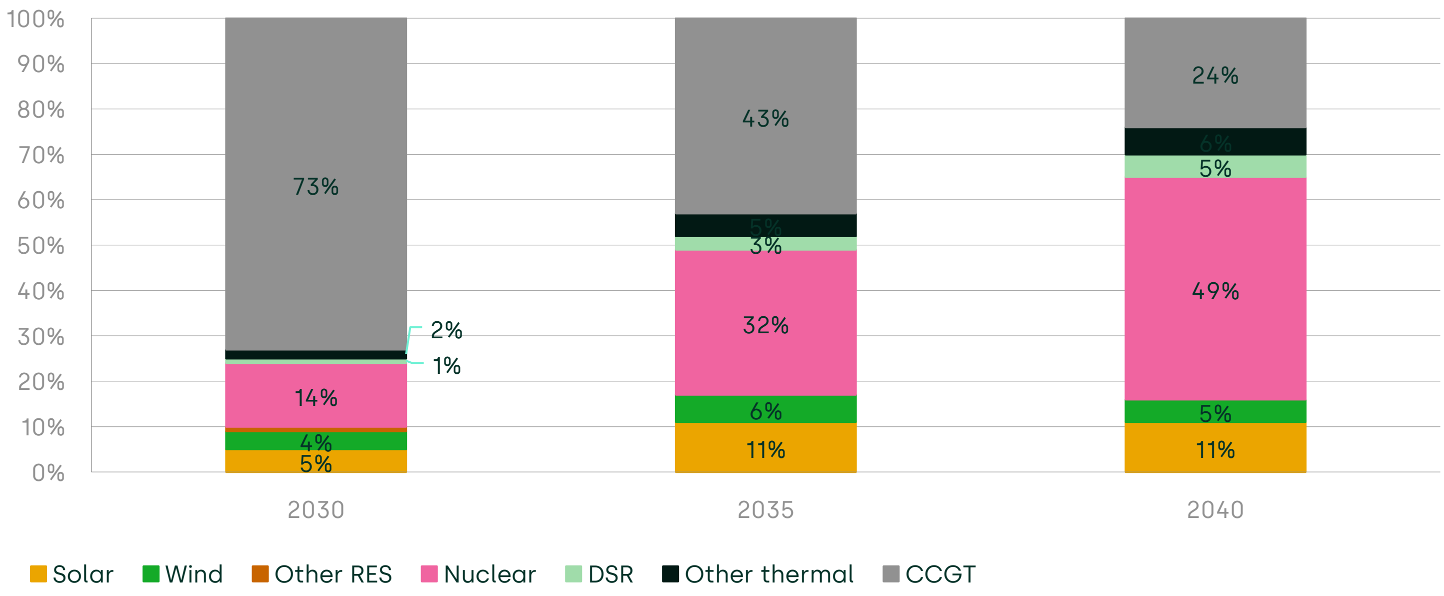
Flows on the France-Spain interconnector, expanded to around 12GW nameplate capacity in 2035, reach 43 TWh (41% utilisation) from France to Spain and around 28 TWh (26% utilisation) in the opposite direction in 2040, showing the complementarity between French nuclear and Spanish RES generation. Another relevant nameplate capacity expansion is projected on the France-United Kingdom interconnector, whose nameplate capacity expanded to 10.6GW in 2040 (+5GW compared to 2030). The Enhanced NTCs scenario presents similar dynamics and magnitudes, with slightly bigger and earlier expansions on nameplate capacities.

The relatively high utilisation factors in the Enhanced NTCs and Full Policy scenarios confirm that the enhanced interconnection infrastructure is being effectively deployed, allowing for reductions in system variability by smoothing out weather patterns across countries. **It is worth noting, however, that the 'load factor' of internal (transmission) lines or distribution lines is not captured by the model**.

The expanding role of interconnections and storage in managing renewable variability raises questions about the future role of gas-fired generation. Despite the rapid growth of renewables, gas remains crucial for system adequacy and backup purposes.

By 2040, CCGT generation declines sharply, to between 35 and 48 TWh across scenarios compared to 209 TWh in 2030 and 266 TWh in 2024 (according to EMBER data),[84] as renewable resources progressively displace thermal generation. Based on a simplified (and aggregate) calculation, the average load factor of CCGT plants across all scenarios falls to around 4–5% by 2040, compared to 26% in 2030.[85] As illustrated in Figure 6.13, in the Baseline scenario, in 2040, CCGTs are the price setting technology in only around 24% of hours, compared with 73% in 2030.[86] However, the role of gas is heterogeneous across countries, as already evident from the differences in the capacity mix, retaining a more relevant role in Italy than in the other focus countries.

Figure 6.13 Price setting technologies, Baseline scenario (%)



Note: Focus countries (France, Germany, Italy and Spain).
Source: Oxera analysis based on AFRY model results.

[84] Oxera analysis based on EMBER data for 2024 (accessed 6 November 2025) and AFRY model results from 2030 onwards.
[85] The average load factor is calculated as total CCGT production divided by theoretical maximum production, assuming that plants are unavailable approximately 10% of the time due to maintenance and unplanned outages.
[86] These figures refer to the role of gas-fired generation as price setting technology rather than price setting units, as also other units may 'anchor' their bids to those of CCGT plants (e.g. BESS).

At the same time, **the model results show that some gas capacity needs to be retained to ensure security of supply**. In line with what is observed for the Baseline, in the Cheaper BESS scenario, despite the significant deployment of BESS, about 15GW of new CCGT capacity is required by 2035, showing that **while BESS excels at providing short-duration flexibility, it cannot fully replace dispatchable thermal generation for addressing extended periods of low renewable availability**.

Conversely, when cross-border interconnection capacity is expanded (as in the Enhanced NTCs and Full Policy scenarios), according to the model results, **adequacy requirements are met without additional gas-fired capacity**. It is worth noting that BID3 is a zonal model, so does not capture congestions within a bidding zone or at the distribution level. Similarly, the electricity market model simulation is focused on the day-ahead market, so all the intricacies of ancillary services provision and redispatching markets are not captured. More granular simulations, as those performed at a nodal level and over shorter time horizons, could therefore lead to different results in this respect.[87]

Finally, BID3 performs a least-cost optimisation under certain constraints, however, its outcomes may differ from those resulting from market dynamics. This is mainly because (i) some of these outcomes may not be achieved by market forces and price signals alone and (ii) in practice, trade-offs may be more complex, including constraints to reflect all objectives at stake (including security and adequacy of the system, resilience, etc.).

6.5 Contribution towards decarbonisation efforts

Although decarbonisation is not the primary focus of the scenarios, the modelling results show that the different projected evolutions of the electricity system in the focus countries also support decarbonisation objectives, with Enhanced NTCs and Full Policy scenarios achieving the deepest decarbonisation through their higher renewable penetration and smaller reliance on gas-fired generation.

By 2040, total CO2 emissions from electricity generation are projected to fall to 18.4m tonnes in the Baseline scenario, a 78% reduction

[87] For example, the last European Resource Adequacy Assessment (ERAA) published by ENTSO-E, ERAA 2024, highlights adequacy risks that could arise from the closure of gas-fired generators that are likely to become economically non-viable by 2030. At the same time, ERAA 2024 modelling 'suggests that over 50 GW of new fossil gas flexible capacity would be beneficial given anticipated high scarcity prices, though these are expected to occur infrequently in 2035. This capacity would help ensure adequacy during peak times or low RES infeed'. See ENTSO-E (2025), 'European Resource Adequacy Assessment. 2024 Edition. ACER's approved and amended version (August 2025)', August, p. 7.

compared to 2030 levels. The alternative scenarios achieve even greater reductions: the Enhanced NTCs and Full Policy scenarios reduce emissions to about 14m tonnes by 2040 (25–26% lower than the Baseline), representing an 83–84% reduction relative to 2030.

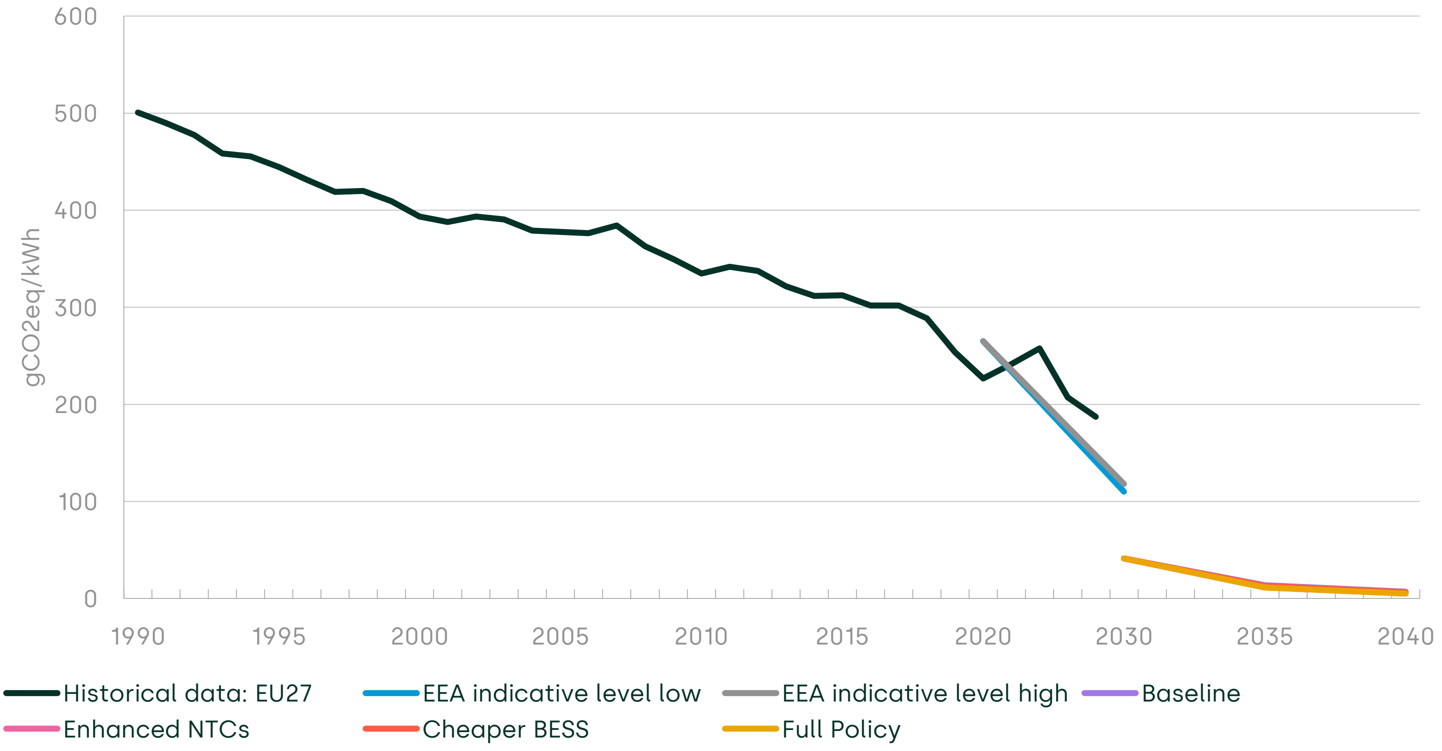
Another useful metric is GHG emission intensity—defined as the ratio of CO2-equivalent emissions from public electricity generation and gross electricity production, expressed in gCO2eq/kWh. Figure 6.14 illustrates the evolution of GHG emission intensity in the electricity generation sector for the EU-27 from 1990 to 2040. The chart combines historical data for the period 1990–2023, forecasts ('indicative intensity levels' that would be consistent with the EU's climate targets) from the European Environment Agency (EEA) for 2020 and 2030,[88] and projections from the model for the focus countries for 2030–40.

The historical data shows a continuous decline in the emission intensity. Between 2020 and 2030, the EEA projects a sharper decline, with the emission intensity of the EU-27 power sector expected to be in the range of 110–120 gCO2eq/kWh. **From 2030 onwards, the model projects a much lower emission intensity in the focus countries: the emission intensity is expected to fall to around 5–7 gCO2eq/kWh by 2040, a 99% reduction compared to 1990 levels**—exceeding the EU's 2040 climate target of a 90% reduction compared to 1990 levels.[89]

[88] European Environment Agency (2024), 'Greenhouse gas emission intensity of electricity generation in Europe', 6 November (accessed 6 November 2025).

[89] The European Commission has recommended reducing the EU's GHG emissions by 90% by 2040 compared to 1990 levels. It is worth noting that the EU target is economy-wide, covering all GHG emissions across all sectors and all member states, whereas the 99% reduction figure in the analysis refers specifically to CO2 emissions from electricity generation in the four focus countries. See, for example, European Commission, '2040 climate target' (accessed 6 November 2025). See also European Council, Council of the European Union (2025), '2040 climate target: Council agrees its position on a 90% emissions reduction', 5 November.

Figure 6.14 Emission intensity of electricity generation (gCO2eq/kWh)



Note: Projections from 2030 onwards refer to the focus countries (France, Germany, Italy and Spain). The AFRY model only covers CO2 emissions. EEA values for 2020 and 2030 represent 'indicative intensity levels' that would be consistent with the EU's climate targets.
Source: Oxera analysis based on EEA historical data and indicative levels for the period 1990–2030 for the EU-27 and AFRY model results for the focus countries from 2030 onwards. European Environment Agency (2024), 'Greenhouse gas emission intensity of electricity generation in Europe', 6 November (accessed 6 November 2025).

6.6 Other benefits

Beyond climate benefits and cost reductions, as part of this study, a set of indicators to assess elements related to strategic independence and trade balance has also been developed.

Enhanced interconnections significantly improve system reliability in high-RES penetration scenarios. Safe hours[90] are higher in the medium and long run when more interconnection capacity is available: the Enhanced NTCs and Full Policy scenarios present a share of safe hours of 83% and 82% respectively in 2040, as shown in Table 6.2.

[90] Safe hours are defined as hours in which dispatchable generation, including the contribution from interconnectors, represents at least 10% of the overall local generation (in a certain market area).

Table 6.2 Safe hours (%)

	2030	2035	2040
Baseline	94%	78%	76%
Enhanced NTCs	94%	83%	83%
Cheaper BESS	94%	78%	75%
Full Policy	94%	82%	82%

Note: Focus countries (France, Germany, Italy and Spain).
Source: Oxera analysis based on AFRY model results.

The modelling results show that enhanced interconnections and more flexible resource availability would also come with additional benefits. In particular**, the reduced gas consumption achieved in the modelled scenarios also strengthens the EU's strategic independence**. Given that the EU imports the majority of the natural gas it consumes, any reduction in gas use for power generation directly translates into lower gas imports, improving its commercial balance by reducing reliance on external suppliers. **Over the 2030–40 period, cumulative gas consumption in the Full Policy scenario decreases by approximately 20 billion cubic meters (bcm) compared to the Baseline scenario, improving the EU's resilience to trade and geopolitical risks**.[91]

Furthermore, because scenarios such as Enhanced NTCs, Cheaper BESS, and Full Policy lead to different generation, storage, and interconnection capacity mixes, this study has also analysed how their evolution affects reliance on technologies that need to be imported from outside Europe. For example, technologies such as photovoltaic panels and BESS are predominantly manufactured in Asia, meaning their deployment requires imports. Conversely, other technologies—such as wind turbines, CCGTs and interconnectors—are also produced within European supply chains.

Therefore, **any evolution in the capacity mix that increases the share of technologies manufactured locally contributes to improving Europe's trade balance and reducing strategic vulnerabilities**. Based on the model results, in the Enhanced NTCs scenario, about €328bn (74%) of total cumulative CAPEX of new build infrastructure over the period 2030–40 is retained within European supply chains—compared to 66% achieved in the Baseline scenario—driven primarily by €203bn in offshore wind, which, together with onshore wind and interconnections, has been assumed to be entirely manufactured in Europe. The Full Policy scenario

[91] Oxera analysis based on AFRY model results.

achieves a similar outcome, with around €320bn (72%) of local (European) investments. This shift reinforces Europe's clean-energy supply chains and strengthens its strategic independence in key technologies.

The analysis thus provides valuable insight into how policy-driven scenarios can influence not only system economics and security, but also Europe's industrial competitiveness and energy sovereignty.

6.7 Some limitations: the importance of data and uniformity across Europe and the scope of the modelling exercise

While the modelling analysis provides valuable insights into infrastructure investment trade-offs, some limitation must be acknowledged to ensure appropriate interpretation of the results. These limitation relate to foundational scenario assumptions, data availability and harmonisation across Europe, and the inherent constraints of the modelling approach employed.

The entire analysis uses as its starting point ENTSO-E's TYNDP 2024 scenarios, which provide a recognised, common baseline but also embed ambitious assumptions on demand growth, technology trajectories and projected system evolution. **Results should therefore be read as conditional on those inputs**.

Scenario findings are sensitive to the starting point: different demand pathways would materially change capacity needs and price dynamics. For example, a flatter demand profile would imply lower renewable buildout requirements and different investment signals, with implications on wholesale prices and associated costs. Fuel and carbon price trajectories are also uncertain and can affect variable costs and wholesale prices.

Moreover, data across European countries remain uneven in terms of harmonisation and granularity, so the modelling necessarily relies on assumptions where complete, consistent, comparable datasets are unavailable.

The BID3 model operates on a zonal basis and does not capture intra-zonal or distribution-level constraints, meaning local bottlenecks, curtailment patterns and internal line utilisation may diverge from modelled outcomes. **Similarly, the electricity market model simulation is focused on the day-ahead market, so the details behind ancillary services provision and redispatching markets are not captured**. More granular simulations, as those performed at a nodal level and over shorter time horizons could therefore lead to different results.

Finally, BID3 performs a least-cost optimisation (from a system perspective) under certain constraints, however, market outcomes could differ for a number of reasons, including different and more stringent constraints, to reflect different objectives and resulting trade-offs. Moreover, as the electricity system reflects the interactions of a variety of different players, some of the outcomes resulting from a least-cost optimisation process may not be achieved by market forces and price signals alone.

For these reasons, the findings should be read as comparative and scenario-dependent rather than precise forecasts. They demonstrate how enhanced grids and flexibility reduce costs and volatility relative to the chosen baseline, while acknowledging that the baseline itself embodies non-neutral assumptions.

7 Conclusions and policy implications

The modelling analysis reveals how different infrastructure investment pathways—varying cross-border interconnection capacity, flexibility sources and battery storage deployment—reshape the European electricity system's costs, reliability, and decarbonisation trajectory over the 2030–40 transformation period. This concluding section considers key findings and policy implications for European and national decision-makers navigating the complex investment challenges identified throughout this study.

7.1 Some findings are consistent across the scenarios

Certain fundamental trends emerge consistently across the modelled scenarios, reflecting the profound transformation that the European electricity system is expected to experience regardless of which specific infrastructure investment pathway materialises.

Electricity **demand is projected to undergo unprecedented growth**. In the four focus countries, demand is projected to increase by 56% between 2024 and 2040, reaching 2,437 TWh—an extraordinary expansion considering that EU electricity demand remained essentially flat over the previous two decades. The growth, in line with ENTSO-E's TYNDP 2024 scenarios, is driven by **the widespread electrification of end-use sectors, such as transport, heating and industrial production, as well as the emergence of flexible decarbonised demand**, which is projected to increase from 60 TWh in 2030 to 340 TWh in 2040—a nearly six-fold increase.

This increased demand **offers efficiency benefits**, as assets are more effectively utilised, but nevertheless large increases in generation (in particular RES, but also BESS) as well as grid investment are required.

Overall, **all technologies are expected to play essential but evolving roles**. No single technology dominates the future electricity system; rather, diverse technologies serve complementary functions with significant shifting utilisation patterns.

Gas-fired generation retains a crucial role in ensuring the security and adequacy of the system, even as its utilisation falls. Across all scenarios, CCGT average load factors are projected to fall to 4–5% by 2040, compared to 26% in 2030, and gas-fired plants are expected to be the price setting technology far less often (e.g. for the Baseline scenario around 73% in 2030, falling to 24% by 2040).[92] This, in turn, implies that market revenues may not be enough to cover the costs of gas-fired generation, raising questions on their sustainability.

RES and low-carbon sources are needed to achieve the ambitious decarbonisation goals, with RES capacity expected to more than double between 2024 and 2040. This deployment offers substantial cost benefits (renewable generation at near-zero marginal cost displaces more expensive gas-fired generation) and decarbonisation benefits (emission intensity reduction). However, challenges persist around system integration, curtailment during high-output periods, price cannibalisation, and the 'missing money' problem.

Finally, **both BESS and grids can bring benefits on several levels**. On the one hand, they bring benefits in terms of decarbonisation, allowing for better RES integration—with variable RES representing around 66–70% of total generation by 2040—as well as delivering lower emissions, with emission intensity expected to fall to around 5–7 gCO2eq/kWh by 2040, a 99% reduction compared to 1990 levels. On the other hand, the **deployment of BESS and enhancement of interconnections deliver lower end-user costs**, although the mix of new generation varies by scenario.

One of the most prominent implications is the transformation of the cost structure of the electricity system, **transitioning from a largely OPEX-based to a predominantly CAPEX-based system**.

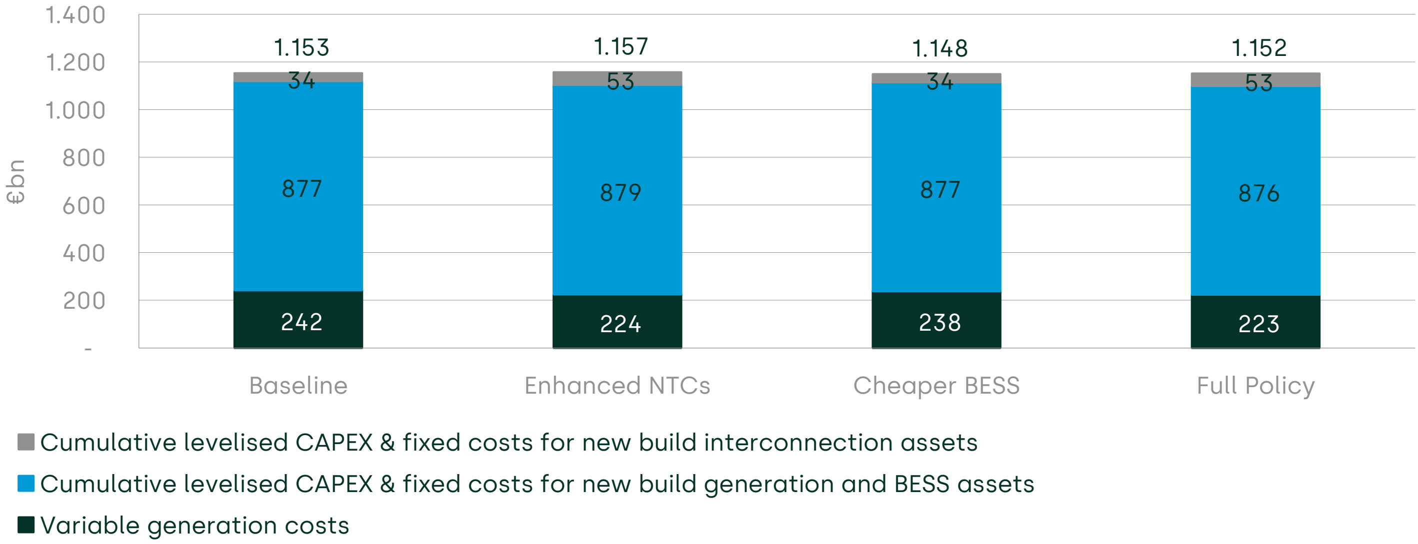
This transformation delivers important benefits. When fuel costs dominate system expenses, electricity costs directly track volatile global commodity markets, exposed to geopolitical disruptions beyond European control. A CAPEX-dominated system with fixed infrastructure costs is inherently more stable and predictable. The 2022 gas prices crisis illustrates the vulnerability that a similar cost structure transformation helps address.

Furthermore, CAPEX-intensive renewable and storage assets, using or leveraging domestically available resources, contribute to reducing the dependence on imported fuels from geopolitically unstable regions, strengthening strategic autonomy.

[92] While gas-fired plants will be price setting in a significantly smaller share of hours (as discussed in section 6.4), in some of the hours, they will still play a role as the reference technology also for other plants, e.g. BESS.

However, this transition to a CAPEX-based system also creates challenges, as it naturally entails **substantial combined investment in generation, storage and grid infrastructure**. Cumulative levelised CAPEX and fixed costs for new build generation, storage and interconnection assets for the period 2030–40 range from €910bn to €932bn across scenarios, as shown in Figure 7.1. As a result, the future electricity system will be influenced more by CAPEX unit costs and by the cost of capital.

Figure 7.1 Cumulative total system costs over the period 2030–40 (€bn)



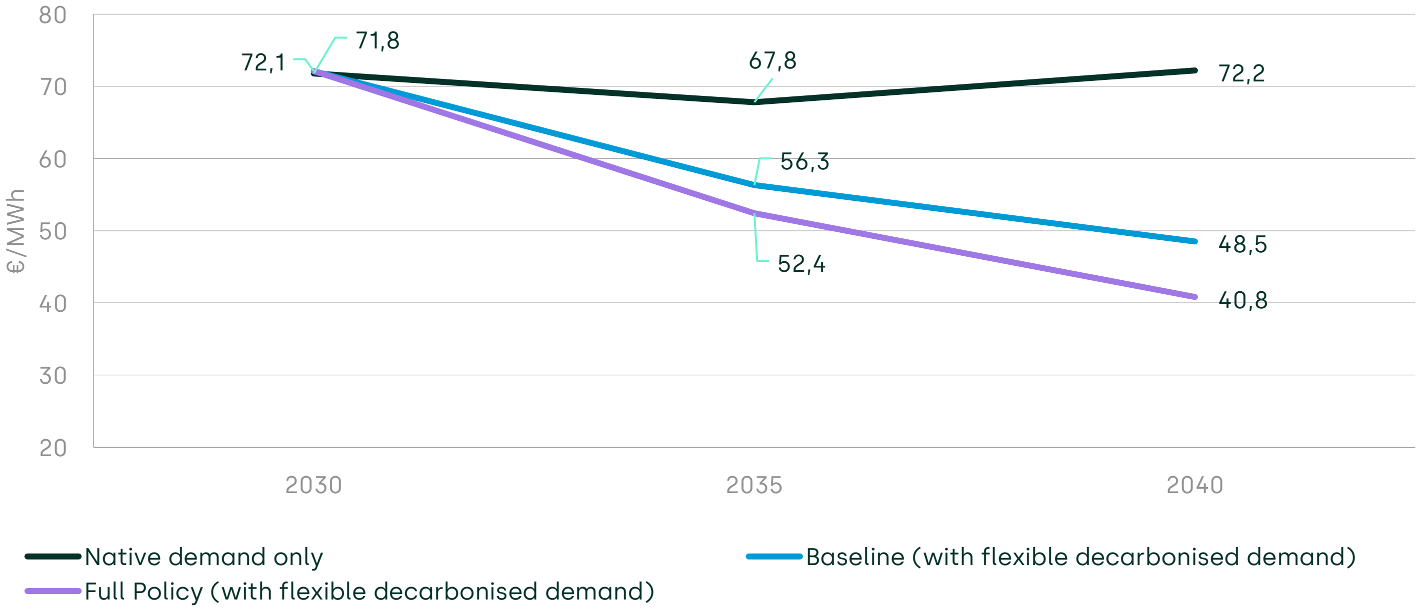
Note: Focus countries (France, Germany, Italy and Spain). Costs are reported in EUR 2025 terms. The cumulative levelised CAPEX component refers to new generation, BESS and interconnection assets built from 2025 onwards. Investments before 2025 are treated as sunk costs, so their associated CAPEX is not captured in the calculation.
Source: Oxera analysis based on AFRY model results.

At the same time, given that a greater share of costs will become 'fixed', **flexible demand can play a key role as it could allow the system to be dimensioned below its peak,** as this demand can contribute to reduce the hourly peak and/or to shift consumption to other hours. Moreover, **it is key that demand actually grows compared to today's levels to ensure that all assets are consistently/sufficiently used** (i.e. with low curtailment rates and good utilisation of grid assets) and that costs can be spread over a sufficiently large base of consumers/demand. In this respect, **the sequencing of demand growth is also relevant, as expanding more flexible demand first could alleviate some bottlenecks** (e.g. for grid expansion that takes time) and contribute to reducing costs for expanding generation and network capacity.

If a greater share of total system costs becomes 'fixed', it is **key that demand grows in line with the expectations to avoid affordability issues**. Indeed, if projected demand growth does not materialise, a (relatively) smaller set of consumers will bear the costs and therefore end-user costs are likely to remain higher. Specifically, sensitivity analysis shows that without additional flexible decarbonised demand, no price reductions would be achieved by 2040, with wholesale prices consistently remaining around €70/MWh in the focus countries.

This finding elevates demand-side policies to equal importance with supply-side renewable deployment and infrastructure investment. The energy transition cannot succeed through supply-side transformation alone.

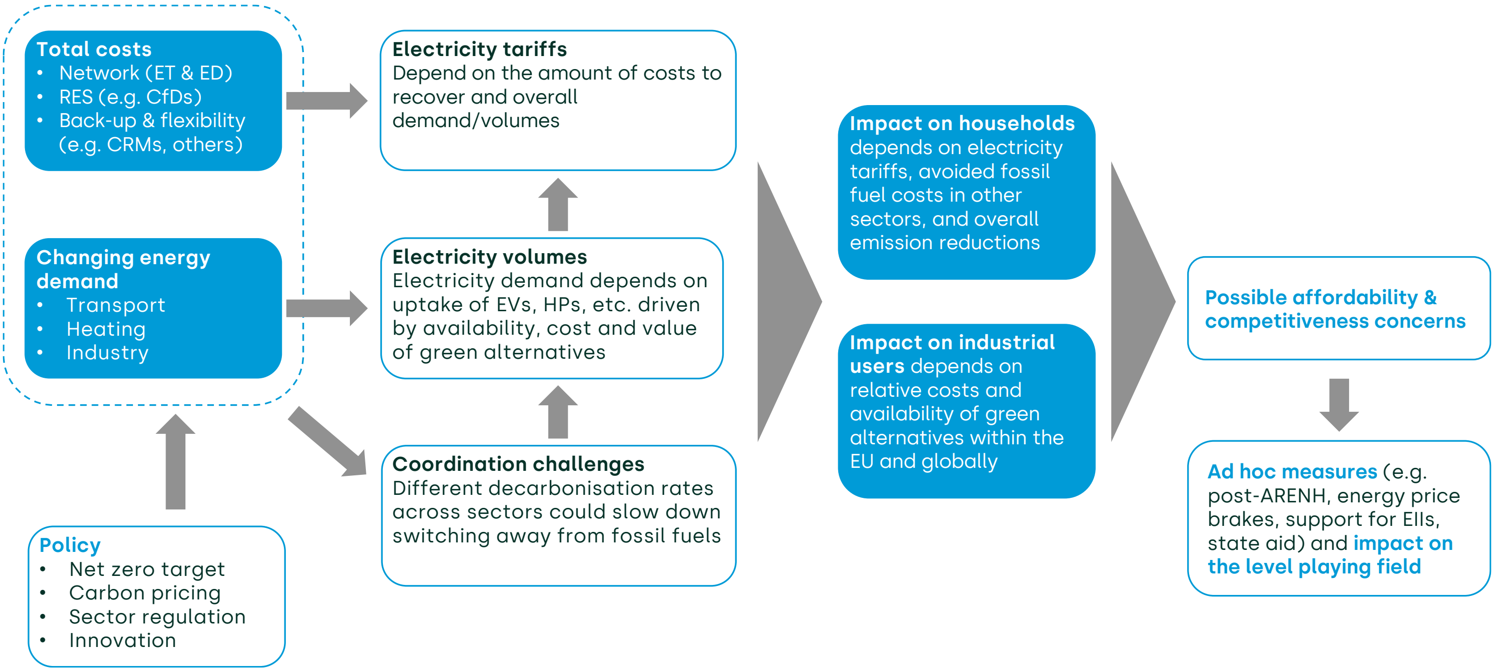
Figure 7.2 Wholesale prices evolution, Baseline and Full Policy scenarios compared to a 'native demand only' sensitivity (€/MWh)



Note: Focus countries (France, Germany, Italy and Spain). Prices are reported in EUR 2025 terms.
Source: Oxera analysis based on AFRY model results.

Electricity tariffs will largely depend on the interaction between total system costs and electricity demand, creating coordination challenges with potentially important affordability and competitiveness concerns if not managed effectively.

Figure 7.3 Electricity tariffs and the broader competitiveness discussion



Note: ET indicates electricity transmission; ED indicates electricity distribution; CfDs indicate contract-for-difference mechanisms; HPs indicate heat pumps; ARENH indicates 'Accès Régulé à l'Électricité Nucléaire Historique' (Regulated Access to Incumbent Nuclear Electricity), the mechanism introduced in France in 2010 and requesting EDF (the sole nuclear electricity producer in France) to sell a certain portion of its electricity production from nuclear power to its competitors in the downstream (retail) market, upon request by those competitors; EIIs indicates energy-intensive industries.
Source: Oxera.

7.2 Key differences across scenarios

While certain fundamental trends emerge consistently, there are important differences between the modelled scenarios—differences that carry significant implications for costs, system configuration, and policy priorities. Overall, the modelling results show that, when taken forward on its own, more interconnection performs better than more flexibility. However, **the combination of the two policy levers (enhanced interconnections and increased adoption of BESS and flexibility more broadly) achieves the greater benefits, making the Full Policy scenario the preferred outcome**.

First, in terms of the type of investment entailed by each scenario, while all scenarios add significant renewable generation capacity, **offshore**

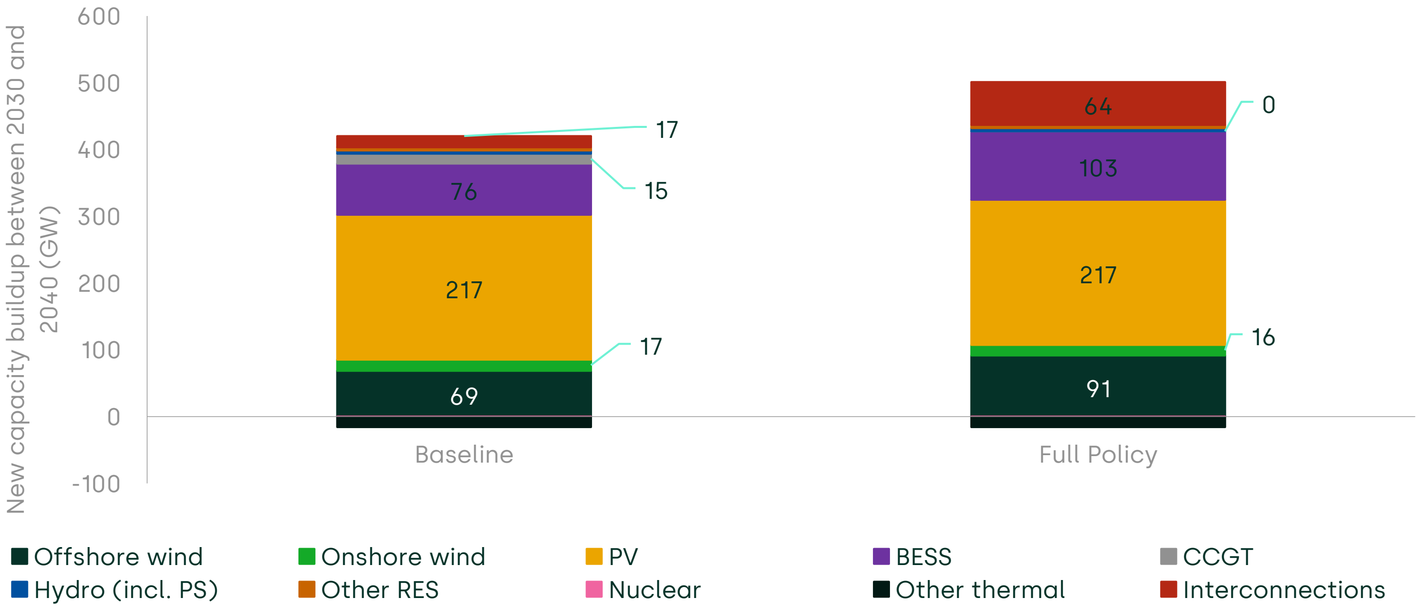
wind shows the greatest variability, with the Full Policy scenario deploying approximately 27GW more offshore capacity than the Baseline by 2040. **A critical difference across scenarios is the need for new thermal generation capacity**: the Full Policy scenario (similarly to the Enhanced NTCs scenario), with enhanced interconnection infrastructure, avoids the need for new gas-fired CCGT capacity entirely, while the Baseline and Cheaper BESS scenarios require 15GW of new CCGT to come online to ensure the adequacy of the system.

The **trade-offs between investment in generation or storage and investment in network infrastructure** represent another relevant distinction. The Full Policy scenario, by combining enhanced interconnection with cheaper BESS assumptions, deploys 47GW of additional interconnection compared to the Baseline by 2040. Critically, despite higher interconnection and RES investment, the Full Policy scenario delivers lower end-user costs—by 2040, unit end-user costs in the Full Policy scenario are 6% lower than in the Baseline.

Moreover, in the Full Policy scenario an even larger share of these costs is represented by CAPEX compared to the Baseline. The higher interconnection, BESS and generation CAPEX represents investment in assets that will continue to deliver value beyond 2040, while simultaneously reducing ongoing variable generation costs. By enabling more efficient cross-border flows and strengthening market integration, enhanced interconnections, coupled with BESS, reduce reliance on gas-fired generation and its associated variable costs. In contrast, once interconnectors are built, they facilitate flows with minimal OPEX. As a result, lower costs from the Full Policy and Enhanced NTCs scenarios would be expected to persist, and be more attractive from a long-run cost-benefit analysis (CBA) perspective.

The buildout of new generation, BESS and interconnection capacity between 2030 and 2040 in the Baseline and Full Policy scenarios is summarised in Figure 7.4, while the evolution of end-user costs is set out in Table 7.1.

Figure 7.4 New capacity buildout between 2030 and 2040 (GW)



Note: Focus countries (France, Germany, Italy and Spain). PS indicates hydro pumped storage.
Source: Oxera analysis based on AFRY model results.

Table 7.1 Projected evolution of unit end-user costs (€/MWh)

	2030	2035	2040
Baseline	77.8	66.2	64.3
Enhanced NTCs	77.8	63.7	61.0
Cheaper BESS	78.3	65.7	62.8
Full Policy	77.5	62.8	60.2

Note: Costs are reported in EUR 2025 terms. The focus countries are France, Germany, Italy and Spain. Investments before 2025 are treated as sunk costs, so their associated CAPEX is not captured in the calculation.
Source: Oxera analysis based on AFRY model results.

Overall, AFRY's BID3 model results show that:

- overall, all scenarios achieve substantial costs reductions over the 2030-40 period;
- scenarios with enhanced interconnection capacity (Enhanced NTCs and Full Policy scenarios) amplify cost reductions;
- the infrastructure investment advantage grows over time (gaps across the scenarios widens from minimal differences in 2030 to a gap of around €4/MWh in 2040).

The scenario comparison shows that infrastructure investment coordination is not merely necessary for decarbonisation but economically beneficial for consumers through lower long-run costs despite higher upfront capital requirements.

7.3 The role of policymakers and regulators

Based on the main results of the modelling exercise, policy priorities should be targeted at (i) ensuring the conditions required for the positive areas of commonality across the scenarios, including structural demand growth, and (ii) specifically addressing delivery of greater interconnector and flexibility capacity, given the attractiveness of the Full Policy scenario across costs, emissions, reliability and strategic independence.

Policymakers and regulators will have a significant influence on the conditions required to deliver the Full Policy options. We highlight below several specific considerations.

Cost of capital and regulatory/policy risks. With the large volume of CAPEX required (€570bn cumulative levelised CAPEX and €358bn of fixed costs over the period 2030–40 under the Full Policy scenario), a major consumer cost driver will be the required return on investment. Every percentage point difference in weighted average cost of capital (WACC) translates to significant differences in total costs. Perceived uncertainty around regulatory and policy support is seen by investors as a critical risk that increases required returns. For example, recent failed offshore wind tenders in the United Kingdom and Denmark, demonstrate that investors are sensitive to the risk profile and available returns for RES investments.[93] Stable and predictable regulatory frameworks, the potential role of public co-financing and guarantees, as well as revenue-certainty mechanism can all play a role in reducing the cost of capital.

CAPEX costs. Increased CAPEX intensity also exposes consumers to asset costs. Model results show that significant investments will be needed in the alternative scenarios to unlock the potential of RES, BESS

[93] For example, in the United Kingdom, as part of the Allocation Round 5 (AR5), no offshore wind capacity was procured. See, for example, Department for Energy Security and Net Zero (2023), 'Contracts for Difference (CfD) Allocation Round 5: results', 8 September. See also Low Carbon Contract Company (2024), 'Auction outcomes' (accessed 6 November 2025). Similarly, in 2024, a tender for offshore wind launched by Denmark did not record any bid. See, for example, Reuters (2024), 'Denmark disappointed after offshore wind tender draws no bids', 5 December. See also Wind Europe, 'No offshore bids in Denmark – disappointing but sadly not surprising' (accessed 6 November 2025).

and interconnections, but these CAPEX forecasts have significant uncertainty. In particular, there are risks around supply chain constraints, costs due to tariffs, global commodity prices for construction materials, etc. Policymakers can mitigate risks through industrial policy measures and careful calibration of tariff impacts, e.g. with instruments such as supply chain diversification, policies accommodating for cost pressures, antidumping tariffs).

Demand profiles. EU and member state policy will affect the evolution of native demand, and more so the electrification of heat, transport and industry will determine the growth pathway of total electricity demand. Likewise, broader industrial and energy policy will affect the evolution of flexible demand, whose impact on wholesale prices is discussed in detail in section 6.1.

As electricity demand in the focus countries and, more generally, in the EU, has been broadly stable since 2000, policy measures are likely to be needed to stimulate the required change. This will likely require state resources, with associated implications, including the need for state aid approval, and potential challenges in terms of ensuring the level playing field within the EU (e.g. as countries with more fiscal space may have more flexibility in supporting demand).

Project planning and consents. In addition to new RES and BESS assets, this is a major issue for interconnector projects in particular. As well as traditional planning issues, the net benefits of projects are likely to be unequally distributed across zonal/national borders, and may have negative effects in some areas. For example, while greater interconnection across bidding zones generally brings positive benefits, these are not evenly distributed on the two sides of a new interconnector.[94]

This uneven distribution of welfare gains across bidding zones (and ultimately countries) can slow down the buildout of new interconnection capacity, even where it would bring additional benefits. Greater centralised decision making and appropriate compensation mechanisms may be required to facilitate the planned investments.

[94] In particular, when there is a price differential between two markets, trading would lead to net welfare gains—if transaction costs are lower than the benefits from the trade. However, the higher priced zone will experience lower wholesale prices (all else equal), as it can import (more) power from the cheaper bidding zone. Instead, when greater interconnection capacity is available, the lower priced bidding zone will be exporting more power to the higher priced zone, so wholesale prices are expected to increase.

Potential tools that would be helpful to further explore include: a more centralised approach to grid planning across the EU; potential compensation mechanisms to share the costs and benefits of these investments; and a unified methodology to quantify the costs and benefits of cross-border interconnection projects on a consistent basis, potentially contributing to more uniform cost allocation between the countries/TSOs involved.

Missing money. For greater interconnection, generation assets and BESS, 'missing money' increases in the Full Policy scenario (as discussed in section 6.2), as lower wholesale prices reduce market revenues while capital expenditure requirements rise. In other words, market revenues will not be sufficient for these assets to cover their costs and the gap ('missing money') increases over time, as wholesale prices (so associated market revenues) decline. Specifically, in this scenario, the cumulative missing money estimated for the focus countries over the period 2030–40 will increase to around €250n for new generation and BESS assets and around €15bn for new interconnection assets.[95]

Therefore, missing money will require policy to overcome the gap through appropriately designed support mechanisms. As this affects all types of assets (although differently), as wholesale prices are projected to be lower in the Full Policy scenario, different tools may require further assessment, including RES support schemes, mechanisms for BESS and storage capacity (e.g. the new Italian scheme 'MACSE')[96] and CRMs.

While missing money would need to be covered 'outside' the electricity system through ad hoc support schemes, electricity consumers could—in principle—also play a role in reducing this amount, e.g. through power purchase agreements (PPAs), with consumers supporting the development of new generation (and potentially storage) assets. However, according to the model results from the Full Policy scenario, consumers may lack incentives to do so. Since wholesale prices are set to decline from 2030 to 2040 in this scenario, consumers may not want to commit to a higher price through long-term PPAs. The interactions between demand and supply and, in particular, the incentives in place

[95] Oxera analysis based on AFRY model results. Investments before 2025 are treated as sunk costs, so their associated CAPEX is not captured in the calculation.

[96] MACSE indicates the so-called '*Mercato a Termine degli Stoccaggi*', the new Italian scheme to support the development of new centralised electricity storage systems. See, for example, European Commission (2023), 'Commission approves €17.7 billion Italian State aid scheme to support development of centralised electricity storage system', 21 December. See also Terna, 'Mercato a termine degli stoccaggi (MACSE)', accessed 6 November 2025.

for demand to support the development of new generation and BESS assets would require further assessment and consideration.

7.4 A roadmap for policy action

The modelling analysis shows that Europe is not facing a choice between infrastructure investment and affordability, but between strategic investment that reduces long-run costs and under-investment that perpetuates inefficiencies.

Key policy insights emerge from this study:

- greater coordination in infrastructure development delivers consumer value;
- interconnection between bidding zones contributes to integrating broader market areas with diverse generation mixes and demand patterns and facilitates RES integration; as such it should be prioritised;
- demand-side policies are as critical as supply-side, as the growth of flexible decarbonised demand is key to reduce wholesale prices;
- coordination across policy domains is critical, as the energy system is more and more integrated across vectors and sub-sectors (e.g. for demand) and certain policy levers could support one another (e.g. interconnection and storage are complements rather than substitutes);
- upfront investment, where supported by evidence on the benefits it can deliver, is economically rational.

The path forward requires ambitious but achievable action. However, event if the Full Policy scenario do not involve deploying breakthrough technologies, coordinated policy approaches on different areas and specific measures to stimulate (flexible decarbonised) demand growth are needed to realise the estimated benefits.

Contact

Alfredo Macchiati
Partner
+39 06 90258083
alfredo.macchiati@oxera.com

oxera.com

European electricity infrastructure in the energy transition age

—

FortyEight Brussels: Policy conclusions

December 2025

Finanziato dall'Unione europea NextGenerationEU
Ministero dell'Università e della Ricerca
Italiadomani PIANO NAZIONALE DI RIPRESA E RESILIENZA
NEST NETWORK FOR ENERGY SUSTAINABLE TRANSITION
INTESA SANPAOLO

FortyEight Brussels: Policy conclusions

The modelling results indicate that EU policy should focus on: (i) maintaining the enabling conditions that are robust across scenarios—most notably structural growth in electricity demand; and (ii) closing the delivery gap for interconnection and system flexibility, given that the Full Policy scenario performs strongly on overall cost, emissions, security of supply and strategic autonomy.

Policymakers and regulators will materially shape the feasibility of the Full Policy pathway. A central finding is the value of a more coordinated, EU-level system approach. This implies a clear responsibility for EU institutions to strengthen common tools and procedures that improve consistency across national approaches—particularly in network planning, permitting and the availability and comparability of data. During this study, material differences were observed in Member State disclosures, including unit costs for network buildout, limited transparency on expected versus realised redispatch costs and inconsistent assumptions on the cost of capital. The forthcoming Grids Package (announced for December 2025) is expected to address elements of these issues, including by strengthening central responsibilities for planning and modelling at European Commission level in the context of the Trans-European Networks for Energy framework. In our view, this would represent a meaningful step towards greater coherence.

EU Policy implications – specific areas for consideration

Cost of capital and regulatory/policy risk.

- The investment volumes implied by the Full Policy scenario are substantial (approximately €570bn of cumulative levelised CAPEX and €358bn of fixed costs over 2030–40). As a result, a key driver of consumer outcomes is the required return on investment. Small changes in the weighted average cost of capital (WACC) translate into material differences in system costs. Investors price regulatory and policy uncertainty directly into required returns; the experience of recent offshore wind tenders in the United Kingdom and Denmark illustrates sensitivity to risk allocation and remuneration. More stable and predictable frameworks, selective public co-financing and guarantees, and revenue-stabilisation mechanisms can all contribute to reducing the cost of capital. The EU's climate and energy policy framework is also entering a period of recalibration, driven by political realignments, weak growth dynamics, and evolving external trade conditions. Ongoing discussions on the 2040 intermediate target, including proposed adjustments linked to heavy industry and the role of free allowances, highlight this direction of travel. In parallel, the implementation debate on the EU ETS—potentially including changes to the Market Stability Reserve—raises important considerations for policy credibility. Given the ETS' role as the cornerstone of EU climate policy, any perceived dilution of its effectiveness would have system-wide implications and could increase financing costs. The modelling underscores that a CAPEX-led electricity system is a structural consequence of the transition and will therefore require durable, credible policy signals to remain investable.

Capital Expenditure costs.

- A more capital-intensive system increases consumer exposure to asset costs. The model indicates that all scenarios require material investment to unlock renewables, storage (including BESS) and interconnection, but relevant cost forecasts remain uncertain. Key uncertainties include supply-chain constraints, the impact of tariffs, and global commodity prices for construction materials. Policymakers can mitigate these risks through targeted industrial policy, supply-chain diversification, and careful calibration of trade measures (for example, ensuring that trade defence instruments are proportionate and do not inadvertently increase transition costs).
- More broadly, the shift towards stronger domestic-demand-led growth and sustained electrification is relevant to both security of supply and competitiveness. Strengthening conditions for investment—including deeper capital markets and productivity-enhancing reforms—supports a pathway in which electrification reduces exposure to imported energy commodities. The EU's evolving industrial policy agenda, including measures associated with the Clean Industrial Deal Implementation Package, reflects this rebalancing. As an implication of the study results, scenarios with higher system value rely on large-scale deployment of EU-sourced technologies (including cables and grid components, and offshore wind supply chains), which has positive spillovers for European industrial capacity and employment while reducing strategic dependencies.
- The EU is rightfully reshaping its approach to industrial policy with the introduction of the Clean Industrial Deal Implementation Package, including the Industrial Acceleration Act, which will lead to a more balanced approach. While upholding the free trade order, the EU cannot afford to expose itself willingly to predatory trade practices and policies aimed directly at sabotaging its industrial base. We view the recently announced "buy European" clause, which applies to sectors where the Union still has a viable industrial base, as an opportune policy. It is worth noting that both scenario 1 and scenario 3 of the study, respectively focusing on high interconnection and 'full policy', both rely on a largely EU-sourced mix of deployed technology. In this sense, both of these scenarios — the ones with the highest system value — require massive investments in cables and electricity system components, as well as additional offshore wind investments, all of which are sourced from EU industry. This would involve European money for European projects, supporting European jobs and reducing the EU's external, unsustainable dependencies.

Demand profiles.

- EU and Member State policy will influence both 'native' demand and the pace and composition of electrification in heat, transport and industry. In addition, industrial and energy policy will affect the development of flexible demand, which is material to wholesale price dynamics (see section 6.1). In a CAPEX-dominated electricity system—characteristic of high shares of variable renewables—the flexibility of incremental demand is central to cost efficiency. Where costs are driven primarily by fixed expenditure rather than fuel, flexibility improves asset utilisation by shifting consumption towards periods of high renewable output. This increases load factors, reduces curtailment, and limits the need for costly redispatching measures. By distinguishing the 'unavoidable' component of peak demand from the avoidable component, flexibility also supports more efficient infrastructure sizing and raises average utilisation.

- From a network perspective, flexibility can reduce peak stress on transmission and distribution assets, smooth load profiles and alleviate structural congestion. It can therefore defer parts of the grid reinforcement otherwise required to accommodate electrification-driven load growth, and reduce losses and asset wear. In interconnected European grids, flexibility can also support cross-border efficiency by reducing remedial actions and preserving interconnector capacity for market-based exchanges.
- The interaction with redispatch is particularly relevant in the EU, where volumes have risen with renewable deployment and regional congestion. Aligning local consumption with local generation—especially in areas with high renewable penetration and limited export capacity—can reduce both preventive and curative redispatch and lower ancillary cost burdens. In this context, electrification of industrial heat processes that currently rely on gaseous fuels is a material source of potential flexible demand.
- EU policy and market design developments (including the Clean Energy Package, Regulation (EU) 2019/943 and demand response network codes) recognise demand-side flexibility as a cost-effective alternative to network investment. The European Commission's emerging approach to pilot auctions for direct electric heating in industry is therefore of particular importance. The study's conclusions indicate that direct electrification of industrial heat is a 'no-regret' option in system terms. In a capital expenditure (CAPEX)-dominated electricity system, which is characteristic of the European Union's transition towards high shares of variable renewable energy, the flexible nature of additional electricity demand plays a critical role in improving the overall cost performance of the system by optimising the utilisation of generation and network assets. The predominance of capital-intensive technologies in the investment portfolio means system costs are primarily driven by fixed expenditure rather than fuel or operating costs. Flexible demand enables these investments to be amortised more efficiently by shifting consumption towards periods of high renewable output. This increases load factors and reduces the levelised cost of electricity. This temporal alignment mitigates renewable curtailment and limits the need for expensive redispatching measures, which often rely on out-of-merit thermal generation and contribute to higher system operating costs. More broadly, the flexible nature of this additional demand reveals the effective consistency of consumption peaks by exposing the 'unavoidable peak' (which could be defined as the theoretical peak minus the 'avoidable' peak). Exposing the real peak allows for more accurate sizing of infrastructure and a drastic increase in the average load factor.

- From a network perspective, demand flexibility reduces peak load stress on transmission and distribution systems, smoothing load profiles and decreasing structural congestion. By reducing peak flows and redistributing demand spatially where locational signals are present, flexibility can defer substantial grid reinforcement investments that would otherwise be required to accommodate electrification-driven load growth. Lower peak utilisation also reduces the thermal ageing of network assets and cuts resistive losses, further reducing total grid operating expenditure. In meshed European grids, flexibility also supports cross-border efficiency, enabling system operators to manage congestion with fewer remedial actions and preserving interconnector capacities for market-based exchanges, thereby improving market coupling outcomes. The impact on redispatching is particularly significant in the EU context, where redispatch volumes have risen markedly due to the rapid deployment of renewables and regional congestion patterns[1]. Flexible demand can reduce the need for preventive and curative redispatch by better aligning local consumption with local generation, particularly in zones with high renewable penetration and limited export capacity. This reduces the burden on system operators and cuts ancillary service procurement costs while improving overall system security by reducing dependency on fast-ramping thermal assets. In our view, this additional flexible demand essentially results from the electrification of existing gas-based industrial heat generation processes[2].
- EU policy and market design developments, such as the Clean Energy Package, the Electricity Regulation (2019/943) and the demand response network codes, explicitly recognise demand-side flexibility as a cost-efficient alternative to the traditional grid. More specifically, we cannot overstate the importance of the European Commission's new approach to pilot auctions for direct electric heating in industry[3]. The conclusions of this study strongly emphasise that direct electrification of industrial heat is the 'no-regret' option by definition.
- Electricity demand in the focus countries—and in the EU more broadly—has been broadly stable since 2000. Delivering the demand uplift implied by the modelling may therefore require targeted policy support. This may involve public resources, with associated implications including State aid approval processes and potential challenges for the level playing field, given differences in Member States' fiscal capacity. The dedicated chapter on aid for industrial decarbonisation in the Clean Industrial Deal State Aid Guidelines (CISAF) recognises these considerations.

The right price signals and markets arrangement for Flexibility.

A coherent price for flexibility is essential to ensure that consumers and market participants receive clear, reliable signals on when and how to adjust their demand

[1] See for example the EU Joint Research Centre (JRC) paper on Redispatch and Congestion Management (2024)
[2] See, for example, McKinsey and Company, "*Net-zero electrical heat: A turning point in feasibility*"
[3] https://climate.ec.europa.eu/news-other-reads/news/commission-publishes-terms-and-conditions-first-pilot-auction-industrial-heat-decarbonisation-budget-2025-10-10_en

or supply in response to system needs. Without consistent, transparent flexibility pricing, investment in demand response, storage, and smart electrification will remain suboptimal, which undermines the efficient integration of renewable generation.

- Therefore, a supportive *market structure* is required — one that enables active participation by aggregators, rewards fast and accurate responses, and ensures non-discriminatory access to all relevant markets. In this sense, the 2024 Market Design Reform[4] introduces the first foundational elements for a pan-EU flexibility market, via new rules regarding the assessment of flexibility needs by Member States, the possibility for them to introduce flexibility support schemes, and design principles for such schemes, as well as paying attention to peak-shaving products. The effectiveness of the 2024 reform remains to be seen, but it certainly details almost all of the elements required to deepen and ensure the proper functioning of short-term markets.
- Well-designed *network tariffs* that reflect underlying system conditions and transmit the value of flexibility to consumers in a fair and predictable manner are equally important. Tariffs should incentivise transmission and distribution system operators to use flexibility services by developing innovative solutions that optimise the existing grid and procure flexibility services — particularly demand response and storage. To this end, network tariffs should be designed to take into account the operational and capital expenditure of system operators, or an efficient combination of both, enabling them to operate the electricity system cost-efficiently. This would contribute to the cost-effective integration of renewables and enable final customers to recognise the value of flexibility solutions. Together, these elements create the right incentives for households, businesses, and industry to reduce peak load, shift consumption, and make the energy system more resilient, affordable, and efficient, thereby aligning with the EU's decarbonisation objectives. In this sense, the 2025 recommendation[5] On Designing Principles for Network Tariffs effectively highlights the link between tariffs, as carriers of flexibility and locational price signals, and the cost of running the EU electricity system. The document provides a robust assessment of the current situation and a series of valid solutions. Upgrading it from a mere recommendation to a legislative proposal, possibly as part of a wider system fine-tuning package, could be a good idea.
- *Project planning and consents*. Beyond investment in renewables and BESS, the consenting and delivery of interconnector projects is a material constraint. In practice, project net benefits may be unevenly distributed across bidding zones and national borders, and some areas may face localised adverse impacts. While additional interconnection generally delivers aggregate benefits, these are not necessarily symmetric across the two sides of a given link. Where welfare gains are unevenly distributed, delivery can be delayed even when projects are system-positive. More

[4] Directive (EU) 2024/1711 of the European Parliament and of the Council of 13 June 2024
[5] 2025 Commission Notice on Guidelines on future proof network charges for reduced system costs

centralised decision-making, alongside well-designed compensation and cost-allocation arrangements, may be required to accelerate buildout.Tools that warrant further assessment include: a more centralised approach to EU-wide grid planning; compensation mechanisms that share costs and benefits across affected jurisdictions; and a unified methodology for quantifying the costs and benefits of cross-border interconnection projects, to support more consistent and predictable cost allocation across countries and TSOs.

The problem of Missing money.

- For interconnection, generation and BESS, the modelling indicates an increasing 'missing money' challenge under the Full Policy scenario (see section 6.2). Lower wholesale prices reduce merchant revenues at the same time as capital requirements rise, widening the gap between market revenues and total costs. For the focus countries, cumulative missing money over 2030–40 is estimated at around €250bn for new generation and BESS and around €15bn for new interconnection assets.
- Addressing missing money will therefore require policy intervention through appropriately designed support mechanisms. As the issue affects multiple asset classes (albeit differently), a range of instruments may need to be assessed, including renewables support schemes, storage and capacity remuneration mechanisms (CRMs), and targeted schemes for storage (for example, Italy's MACSE).
- In principle, a portion of missing money could also be reduced through private contracting, such as power purchase agreements (PPAs), whereby consumers contribute to the financing of new generation (and potentially storage). However, under the Full Policy scenario, declining wholesale prices from 2030 to 2040 may weaken incentives for consumers to lock in higher long-term prices. The interaction between demand, market prices and long-term contracting therefore merits further analysis, including the conditions under which demand-side actors would support incremental generation and storage investment.

A more regulated system, a less intermediated system.

Identifying a market-based solution to permanent competitive electricity prices is essential not only to preserving the international competitiveness of EU industry, but also to preserving the internal energy market itself. Without a clear path towards a market solution for affordable electricity prices, State Aid measures are destined to spread across the Member States. This is Clearly, a undesirable perspective.

- Firstly, because Member States' support schemes tend to be uncoordinated and focused on supporting national players, usually at the expense of neighbouring ones, there is a risk of unleashing an intra-EU subsidy race.
- Secondly, state aid relies on the fiscal capacity of a Member State to support said schemes, and fiscal capacities vary across Member States, which risks compromising the EU level playing field.
- Thirdly, because State Aid depend on political priorities that can change.

The electricity system profile that emerges from the study is clearly more regulated than the current one. It is a profile in which regulated asset-based (RAB) approaches become the de facto prevailing scenario. However, it is also a system where State Aid measures are significantly less pervasive. This is because the right basket of CAPEX in the right sequence, as suggested by this study, enables a self-sustained reduction in wholesale prices and end-user costs. This, in turn, naturally makes RAB investment bankable, as a sustainable price dynamic eliminates the major financing risk of RAB: that final prices become too expensive, making the capital recovery via tariffs unsustainable.

A roadmap for policy action

The modelling results show that Europe is not faced with a choice between investment and affordability, but rather between strategic, coordinated investment, which reduces long-term costs, and continued underinvestment, which entrenches inefficiencies. The Full Policy scenario shows that, if deployed in the right sequence, timely CAPEX is economically rational and essential to achieving lower wholesale prices, higher system efficiency and greater strategic autonomy.

- A coherent policy roadmap should therefore focus on a limited number of high-impact areas. Firstly, stronger coordination in system planning is indispensable. This could be achieved by aligning national and EU-level modelling, improving data transparency, and progressing the Grids Package reforms, which would help to address long-standing divergences between Member States' assumptions and methodologies.
- Policymakers should prioritise interconnection and complementary flexibility infrastructure, as these investments consistently provide value to consumers and enable the efficient integration of renewables. A more centralised approach to cross-border decision-making, supported by fair compensation mechanisms, would accelerate delivery.
- Flexible, decarbonised demand must become a central system asset. The electrification of industrial heat and other flexible loads would lower wholesale prices, reduce curtailment and improve network utilisation. Targeted support may be needed to stimulate demand growth, with careful consideration of State Aid implications.
- Clear price signals and supportive market structures for flexibility are crucial. While the 2024 Market Design reform provides an initial framework, its success hinges on effective national implementation and the ability of system operators to procure flexibility as a genuine alternative to grid reinforcement.
- Network tariffs must transparently and fairly reflect system needs. Tariff design should incentivise peak shifting, support the procurement of flexibility and enable distribution system operators (DSOs) and transmission system operators (TSOs) to operate the system cost-effectively. Strengthening the 2025 Recommendation into binding guidance could be valuable.
- Proportionate support mechanisms are required to address missing-money challenges, whether for renewables, storage or capacity, without undermining the integrity of the internal market. The emerging system will be more regulated and CAPEX-driven, but should not rely on widespread, uncoordinated state aid.

Overall, Europe’s path forward is ambitious but achievable. The core challenge is institutional rather than technological: the coherent and decisive deployment of existing tools to deliver a resilient, affordable and strategically autonomous electricity system.