THE FUNDAMENTAL DRIVERS OF WHOLESALE ELECTRICITY PRICES IN EUROPE

Report for Europex

17 MARCH 2026

Contents

1 Introduction

1.1 European market integration and market coupling

The EU's internal electricity market is designed to keep costs to a minimum while safeguarding security of supply and supporting decarbonisation. This is achieved by directing electricity from where it is cheapest to generate to where it is most needed, within the limits imposed by cross-zonal transmission constraints.

Since the adoption of the first EU electricity package in 1996, all Member States have been progressively integrated into unified short-term electricity markets through market coupling. These integrated, coupled markets enable near-seamless trading across bidding zones[1] and maximise social welfare[2] through the efficient use of cross-zonal transmission capacity. Their development and operation have been led by power exchanges (PXs), in close collaboration with Transmission System Operators (TSOs).

More broadly, power exchanges facilitate both short- and long-term power trading, enabling efficient price discovery, optimised dispatch and effective risk management.

While the further integration of EU and wider European power markets remains a political and economic mandate, substantial progress has already been achieved, delivering significant welfare gains and significantly enhancing the efficiency of resource allocation across the system.

1.2 Challenges highlighted through the energy crisis and policy responses

During the 2022-2023 energy crisis, both average prices and price volatility in short-term power markets increased across all European bidding zones. This was driven in part by fluctuations in power generation availability at different times – such as limited availability of the nuclear fleet, reduced wind output and lower hydro generation – as well as elevated gas prices, which affected electricity prices via higher costs of gas-fired generation.

In response, certain stakeholders and academics suggested more radical reforms to EU electricity market design. These suggestions included, among other things, moving away from the marginal pricing principle in short-term coupled power markets, under which prices reflect the short-term equilibrium between supply and demand and ensure the efficient utilisation of all cross-zonal capacity through organised short-term markets.

In its 2022 assessment, the European Agency for the Cooperation of Energy Regulators (ACER) concluded that the EU electricity market design was "not to blame" for the crisis and,

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1 A bidding zone is a geographical area in which market participants can exchange electricity without allocating transmission capacity. In Europe, bidding zone borders often equal country borders.

2 Combined producer (sales), consumer (purchase) and transmission system operator (TSO) social welfare surplus.

on the contrary, helped to mitigate its impacts.[3] Consistent with this, the EU Electricity Market Design Reform (EMDR), adopted in 2024, explicitly retained the existing wholesale electricity market design. EU co-legislators did, however, introduce structural reforms aimed at reducing the impact on retail electricity prices of movements in wholesale gas prices, particularly during periods of gas price spikes. These measures included:

- promoting non-fossil fuel sources of power system flexibility;
- encouraging longer-term electricity contracting by retailers and traders; and
- requiring governments to design support mechanisms for low-carbon generation that effectively stabilise the price paid by consumers per MWh of low-carbon or renewable output.

There remains a strong focus on energy prices in the European public debate. Reflecting this, the European Commission presented an Affordable Energy Action Plan in February 2025[4] with a series of proposed measures and initiatives, including a planned White Paper on Deeper EU Electricity Market Integration.

1.3 Scope of the report

In light of these developments at EU level, as well as ongoing discussions at national level, Europex has commissioned Frontier Economics to:

- analyse the drivers of wholesale electricity prices, and in particular price volatility, based on empirical evidence across different timeframes and geographies;
- outline the economic significance of well-functioning electricity markets;
- assess how wholesale price movements affect end-consumer prices; and
- identify policy priorities to maximise the benefits of integrated wholesale power markets while advancing consumer welfare, decarbonisation and security of supply.

1.4 Structure of the report

The rest of this report is structured as follows:

- Section 2 contains a summary of the findings of the report as well as key policy-relevant messages derived from these findings;

3 See, for example ACER's Final Assessment of the EU Wholesale Electricity Market Design, April 2022: https://www.acer.europa.eu/sites/default/files/documents/Publications/Final_Assessment_EU_Wholesale_Electricity_Market_Design.pdf

4 https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX%3A52025DC0079&qid=1741780110418

- Section 3 provides background on wholesale power market functioning and on wholesale and retail power price formation;
- Section 4 sets out evidence regarding the drivers of wholesale power price formation, including the results of our own economic analysis of drivers of power prices and volatility across the EU; and
- Section 5 elaborates on the role of wholesale power markets and European market integration in supporting policy objectives for the electricity sector and draws out corresponding high-level policy priorities.

Further detail is contained in the Annexes to this report:

- Annex A summarises the results of our review of empirical studies of power price drivers in Europe;
- Annex B details the data sources used to support our empirical analysis in Section 4; and
- Annex C contains additional bidding zone-specific regression results from the analysis presented in Section 4.

2 Summary and key policy messages

2.1 Short-term wholesale electricity markets, driven by market fundamentals, support efficient price discovery and security of supply

Spot markets - comprising day-ahead and intraday markets:

- facilitate short-term trading for the physical delivery of electricity;
- provide an organised platform for price discovery, with prices determined by supply and demand fundamentals; and
- support security of supply and help to minimise overall system costs through the price signals they provide.

Short-term electricity prices can be volatile, with rapid price swings around the average value**. This volatility naturally reflects** factors such as the mix of generation technologies, the inherent intermittency of renewable energy and the only partially predictable nature of electricity demand. Such dynamics drive fluctuations in short-term prices which in turn provide essential economic signals to the power system. **These price signals help to maximise social welfare by indicating the** value of incremental energy production or system flexibility in each zone. Short-term wholesale markets therefore play a crucial role in guiding operational decisions, supporting decarbonisation and maintaining security of supply at least cost.

During the energy crisis, electricity spot prices and their volatility increased. Our analysis indicates that these developments were consistent with supply and demand fundamentals. Key factors driving price fluctuations included **movements in gas prices, variations in electricity demand and renewable output,** system **tightness** (i.e. scarcity) and the **influence of conditions in neighbouring markets**.

While eliminating volatility is neither feasible nor necessarily efficient, our findings suggest that policymakers could reduce volatility by enhancing system flexibility. Measures such as improved demand-side response and increased interconnection capacity can play a key role in this regard. As also discussed later, **traded power markets are central to facilitating and incentivising these flexibility solutions**.

Spot wholesale prices are genuinely formed according to the **merit order principle**, under which the cheapest available generation resources are dispatched first. These prices reflect both the short-term marginal costs and the availability of generation assets. As such, the clearing prices (provided by the system marginal price) provide signals for the efficient use of generation, storage, demand response and cross-zonal capacity, ensuring that the lowest-cost resources are used to meet demand.

Spot wholesale price levels and volatility are influenced by multiple factors reflecting real-time system conditions and underlying market fundamentals. These factors interact in real-time and influence the marginal cost of electricity in complex ways. They include the **availability and costs of electricity generation** (including changes in the generation mix, movements in fossil fuel and European Union Allowances (EUA)[5] prices), **demand-side factors** (shaping how much, where, and when electricity is needed), and **cross-zonal capacity**.

Electricity spot prices and their volatility[6] increased significantly during the energy crisis, particularly in 2022. Across Europe, average price and volatility levels have again fallen since their 2022 peaks. However, in most markets all metrics remain somewhat above pre-crisis levels.

The results of our empirical analysis are consistent with the view that electricity prices[7] and price volatility accurately reflect underlying supply and demand fundamentals. We analysed hourly market data from 39 bidding zones in the coupled European power market over the period from October 2018 to December 2024. The findings provide relevant insights[8] into key drivers of power prices and power price volatility. While the specifics vary across bidding zones, the elevated prices and volatility observed during the crisis can largely be explained by temporary factors, including higher and more volatile gas prices and weather-related periods of system tightness impacting the availability of various production assets.

- **Variations in gas prices have a statistically significant impact on electricity prices and electricity price volatility** during periods when gas-fired generation is operating. The estimated impact of gas prices is consistent with the typical conversion efficiency of a marginal gas-fired plant, at around 50%.[9] Given that gas prices and their volatility were also elevated over 2021-23, this is likely to explain a substantial share of the higher electricity price levels and volatility observed during the same period. Higher gas prices and volatility are also likely to have contributed to increases in EUA prices and their volatility, as higher gas prices raise the competitiveness of coal-fired generation and, in turn, demand for emissions allowances. Our estimates suggest that EUA prices also

5 A European Union Allowance permits the holder to emit one tonne of carbon dioxide equivalent (tCO_2e) under the EU Emissions Trading Scheme.

6 As indicated by the standard deviation, which quantitatively describes the average spread of prices around the mean. In this report, we mainly discuss the volatility of (daily average) prices across days and the volatility of within-day (hourly) prices.

7 For simplicity this report focuses on the EU-wide coupled **day-ahead market**, where buyers and sellers trade contracted volumes per bidding zone.

8 Our approach is subject to challenges common to econometric analyses of power prices, including the potential endogeneity of key variables. While we have focussed on variables that are more likely to be exogenous to power prices and have tested the robustness of results to different specifications across alternative specifications, these risks cannot be fully eliminated. In addition, the adoption of a standardised approach across bidding zones may not fully capture specific features of individual local power markets and relies on the quality and completeness of the underlying ENTSO-E data. In light of these limitations, the model results should not be regarded as definitive, but rather as indicative of underlying relationships.

9 A conversion efficiency of 50% means that two energy units of gas are needed to generate one energy unit of electricity.

influence electricity prices, albeit with weaker statistical significance than gas prices. By contrast, we estimate that coal prices play a much smaller and statistically less significant - or insignificant - role in explaining electricity prices and their volatility, with the exception of bidding zones such as Sardinia, where coal-fired generation accounts for a relatively high share of the generation mix.

- **Another important driver of electricity prices and their volatility is residual demand** (which we define as electricity demand not met by the sum of wind, solar and other "non-dispatchable" renewable generation). Changes in residual demand reflect a combination of weather-driven factors - affecting both demand and generation - and consumer behaviour, such as weekday-weekend demand patterns. Our analysis shows that both the level and, separately, the volatility of residual load significantly influence electricity price volatility on average across all bidding zones and in many individual bidding zones. The increasing penetration of renewables has coincided with greater variation in intermittent renewable output, both within and across days, which is reflected in growing volatility of residual demand over time – particularly within-day. Consequently, the expansion of renewable energy sources has likely also contributed to sustained electricity price volatility, even as gas price volatility has fallen since its peak during the energy crisis. Within-day, higher system tightness, that is, higher residual demand, generally also leads to increased volatility.

- **Power price movements are closely linked between neighbouring bidding zones**, with positive and statistically significant cross-border effects on both price levels and volatility. The strength of these effects varies by bidding zone and depends not only on cross-zonal capacity but also on the interaction of supply and demand across bidding zones. Although the precise drivers cannot be fully disentangled in our analysis, gas prices and weather appear to play a key role.

These findings also carry several additional implications:

- As fossil fuels are phased out and as the share of renewables increases, the **proportion of periods in which spot prices are set by fossil fuel generation sources should diminish** over time (however, the influence of fossil fuel generation sources will remain as long as it continues to play a role in the energy mix). The combined effect of marginal pricing, together with increasing shares of low short-run marginal cost renewables, will mean that clearing prices (i.e. the system marginal price) may increasingly differ from the average short-run marginal cost of generation across all production sources.

- **Price volatility can be mitigated through flexibility solutions,** such as expanding interconnections between bidding zones, deploying energy storage solutions and increasing participation of demand-side response. Our econometric analysis reveals regional differences in the responsiveness of electricity prices and electricity price volatility to changes in residual demand. This implies corresponding regional differences in the responsiveness of supply to price signals – that is, differences in system flexibility - which warrant further investigation. As noted earlier, markets play a crucial role in ensuring the efficient operational use of flexible assets, and as we discuss later, efficient short- and long-term markets are also important in supporting investment in flexibility.

- The correlations in prices and volatility observed across many bidding zones largely reflect their **interconnectedness**. This interconnectedness enables generation, demand and storage resources to be used more efficiently across Europe through market coupling, thereby reducing overall system costs across Europe and limiting extreme price spikes in individual zones. Indeed, ACER has estimated[10] that, in the absence of cross-border trade, average EU power price volatility during 2021 would have been several times higher than was observed. Our analysis also identifies some relatively isolated zones, pointing to opportunities for further development of cross-zonal transmission capacity. Market coupling in both day-ahead and intraday markets facilitates efficient flows, helping to reduce local volatility and cross-zonal price divergence. The diverging potentials of renewable energy resources across Europe will mean improved co-ordination of dispatch across borders will continue to be valuable.

The EU's energy system is undergoing profound change as part of the energy transition. Higher levels of volatility in short-term power prices may to some extent be a symptom of the ongoing adjustment process. But this volatility is not an inherent problem. On the contrary, price signals provided by short-term markets are – as we later discuss – an **essential means of supporting the required adjustment through helping to minimise system costs and supporting security of supply.**

10 ACER (2022) “Final Assessment of the EU Wholesale Electricity Market Design”

2.2 Recommendations: Strengthen integrated electricity markets to support an affordable, clean and secure energy system

The transition will require substantial changes to the structure of the European electricity system. Ensuring the required investments are delivered, and that the system operates at least cost, represents a major co-ordination challenge, spanning different levels of the value chain and across geographies.

Traded energy markets play a central, orchestrating role in supporting this system transformation through price mechanisms. Market price signals guide both investment and operational decisions, helping to bring underlying volatility to efficient levels. In addition, well-functioning traded energy markets can help shield consumers from short(er)-term price fluctuations.

Well-functioning markets can be complemented by market-based mechanisms that aim at reducing risks through, for example, providing additional revenue stability. However, such mechanisms should be carefully designed to minimise impacts on efficient price formation and to avoid undermining the accuracy of underlying energy market price signals.

Accordingly, our key policy recommendations are summarised in the figure below.

Figure 1 Overview of recommendations

Limit market-restrictive interventions

- Refrain from measures that distort market functioning.
- Ensure that support mechanisms support efficient operational and investment decisions, do not reduce liquidity or distort price formation and allow, to the greatest extent possible, competition between technologies.
- Remove remaining barriers to the participation of demand-side response (DSR) and other distributed energy resources in wholesale markets.
- Ensure that any regulatory intervention is grounded in thorough impact assessments and meaningful stakeholder consultation, so as to minimise the risk of distortions or unintended consequences.

Preserve effective hedging and risk management in energy markets

- Ensure that economic risk management considerations are systematically and sufficiently considered when evaluating policy changes, such as bidding zone reconfiguration, revisions to support schemes or amendments to commodity trading regulation, to avoid undermining hedging opportunities and market liquidity.

Maximise the benefits of cross-border electricity trade

- Strengthen cross-border trading and optimise the use of available transmission capacity to enhance efficiency and price convergence.
- Extend the Internal Energy Market beyond the EU's borders, including through market coupling with the Energy Community Contracting Parties, Great Britain and Switzerland.
- Carefully assess the risks of ongoing market coupling reforms, particularly in light of innovation, resilience and efficiency.
- Ensure that any further development of Europe's coupled markets is subject to thorough impact assessment and meaningful stakeholder consultation.

Ensure that the broader policy framework enables the essential steering role of spot and derivatives markets

- Maintain a focus on efficient infrastructure planning and regulation, ensuring development is optimised across grid levels, energy carriers and Member States.
- Remove barriers to permitting and streamline approval processes.
- Avoid tariff, levy and tax structures that distort market participants' investment and operational decisions.
- Refrain from distortive retail price regulation; ensure that any regulated or social tariffs are well-targeted while preserving competition and maintaining consumer incentives.

Source: Frontier Economics

2.2.1 Limit market-restrictive interventions

As noted earlier, the clearing prices delivered by **well-functioning short-term markets deliver efficient operational signals - including for flexibility - support security of supply and help to minimise the overall costs of operating the energy system in Europe.**

- For example, during the energy crisis, high gas prices reflected the scarcity of gas supplies in the near term and ensured that available gas supplies were used in sectors in which they were most valued. In the power sector, the combination of high gas and power prices incentivised both reductions in electricity demand and the use of alternatives to gas-fired generation where possible.[11]

- As supply, storage and demand technologies become increasingly diverse and decentralised, there will be increasing benefits from efficient short-term electricity markets that help co-ordinate dispatch and ensure the lowest-cost resources are used.

- Interventions, such as price caps or certain forms of support scheme design, that distort operational choices lead to higher than necessary costs for running the power system. The same applies to restrictions on the participation of decentralised demand-side response, which still faces barriers in several Member States.

Prices and price volatility also provide important signals for investment decisions for new capacity. Higher energy prices over 2021-23 contributed to a tripling of the annual capacity installed of solar PV between 2020 and 2023.[12] Expectations of price volatility should, in principle, drive investment in flexible assets such as electricity storage, which in turn helps to reduce price volatility.

Provided that relevant externalities are internalised in the costs faced by market participants, in a context in which there is heightened attention on affordability of energy, the market would be able to trade off between the cost of investing in additional capacity and the benefit it provides to the system. On the other hand, if relevant externalities are not internalised, policy interventions could potentially be applied to further secure investments in additional renewable and low-carbon capacity and in flexible assets through market-based mechanisms, albeit with caution regarding market functioning and with due regard to the possibility for investment outside of these mechanisms. In particular, such interventions should, to the extent possible, be market-based and clearly focus on technology-neutral tools that do not jeopardise price formation in spot markets. If some types of resources are rewarded more than others or if mechanisms depress peak prices, this risks distorting investment incentives and increasing the cost of achieving energy policy objectives. Depending on their precise design, support mechanisms can also influence parties' incentives to respond to market price signals or their incentives to trade on wholesale markets across different timeframes. The impacts of these design choices on dispatch incentives and on forward liquidity (and, in turn, on the availability of hedging opportunities, which we discuss further below) should also be carefully considered.

Short-term markets – hosted by exchanges – allow market participants to fine-tune their traded positions (for example, where retailers expect their customers to consume more or less energy in comparison to earlier forecasts). This enables an efficient market response to

11 Such incentives would have been dampened by mechanisms such as that introduced by Spain and Portugal during the crisis, which effectively capped the price of gas for use in power generation.

12 https://www.solarpowereurope.org/insights/outlooks/eu-market-outlook-for-solar-power-2024-2028/detail

short-term changes in supply and demand, reducing system balancing costs. Said changes include weather conditions, business needs of customers and more complex seasonal demand patterns that might be more difficult to hedge with standardised forward products (see section 2.2.2). Prices established in the day-ahead market are the primary underlying reference prices for forwards/futures markets.

Policymakers should therefore preserve marginal pricing and market players' exposure to spot price signals. In practice this means policymakers should:

- **Refrain from measures that distort market functioning** and the signals provided by spot market prices, such as price caps or dismantling the uniform pricing mechanism;
- Ensure that support mechanisms for renewable and low-carbon capacity support **efficient operational and investment decisions.** Moreover, support mechanisms should neither reduce liquidity nor distort price formation. Well-designed support mechanisms must allow for competition between technologies to the extent possible and safeguard efficient price signals;
- **Remove remaining barriers to the participation of demand-side response** and other distributed energy sources in wholesale markets, whether through direct access or aggregation. This will provide instruments to respond to price volatility and help dampen its impact; and
- **Ensure any regulatory intervention is grounded in thorough impact assessments and meaningful stakeholder consultation**, to minimise the risk of distortions or unintended consequences.

2.2.2 Support market players' ability to hedge price volatility

Liquid forward markets for electricity allow consumers and producers to manage the extent to which they are exposed to shorter-term price volatility. Long-term markets (such as for forward and futures markets) involve the trade of contracts that are settled over longer time horizons, often months or even years ahead of delivery, and can be either physically or financially settled. These primarily serve market participants' risk management needs in the longer term. Forwards/futures prices tend to be less volatile than spot prices. The latter react to short-term changes in the supply-demand balance, which do not affect the expectation of future prices (the key driver for the price of longer-term products) to the same extent. Where customers have preferences for price stability, liquid forward markets for electricity, such as those hosted by power exchanges, allow retailers (or consumers participating directly in the wholesale market) to "hedge" against spot price volatility and, to a certain extent, price movements over one or several years. This in turn allows retail customers to lock in retail prices in line with wholesale forward prices that prevail at the time retail contracts are signed.

Analysis from ACER shows the “smoothing” effect on customer prices of hedging short-term volatility can be material (based on data in Germany during 2021).[13]

The importance of hedging opportunities is recognised in the Commission’s Action Plan for Affordable Energy.[14] Liquid derivatives markets for power, including those operated by exchanges, can support the efficient pricing of corporate Power Purchase Agreements that can play a role in de-risking investments in clean energy and supporting price stability for consumers.

Policymakers should ensure that economic risk management considerations are systematically and sufficiently considered when evaluating policy changes, such as bidding zone reconfiguration, revisions to support schemes or amendments to commodity trading regulation, to avoid undermining hedging opportunities and market liquidity.

2.2.3 Make the most of cross-border trade

Integration of European power markets brings significant benefits. The cross-zonal trade facilitated by coupled short-term power markets brings significant welfare benefits (estimated by ACER at EUR 34 billion in 2021[15]). As discussed above, ACER also estimated that the EU’s coupled markets have helped to reduce power price volatility in the crisis.

Policymakers should therefore make the most of cross-border power trade:

- **Strengthen cross-border trading and optimise the use of available transmission capacity** to enhance efficiency and price convergence;
- **Extend the Internal Energy Market beyond the EU’s borders**, including through market coupling with the Energy Community Contracting Parties, Great Britain and Switzerland;
- **Carefully assess the risks of ongoing market coupling reforms**, particularly in light of innovation, resilience and efficiency; and
- **Ensure that any further development of Europe’s coupled markets is subject to thorough impact assessment and meaningful stakeholder consultation**.

2.2.4 Ensure the wider policy framework enables the important steering role of spot and forward power markets

Wholesale costs are not the only factor influencing retail prices. While our report is focused on wholesale prices, it is the situation on the retail market that usually triggers political debates. This fact needs to be put into perspective when interventions in the wholesale market

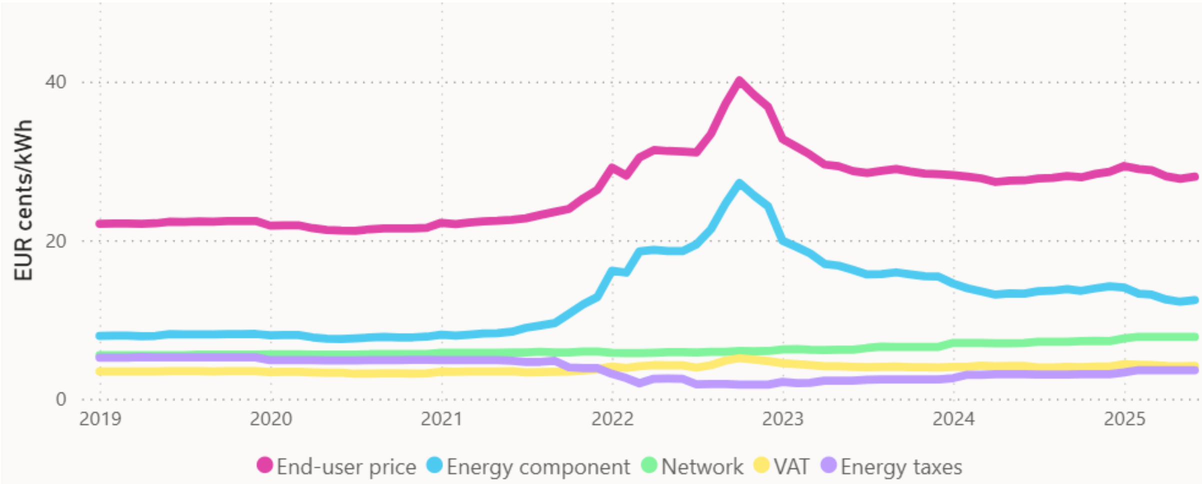
13 See Figure 23 of ACER’s Final Assessment of the EU Wholesale Electricity Market Design, April 2022

14 Action Plan for Affordable Energy (See Action 2).

15 ACER (2022) “Final Assessment of the EU Wholesale Electricity Market Design”

are considered to control retail prices. Data from ACER for 2024 (Figure 2) suggests that – for households across the EU on average – the share of wholesale electricity costs in relation to the final retail electricity price was around 50% in 2024, with network costs and policy costs (i.e., taxes and levies) accounting for the other half. Network costs have risen recently in absolute numbers (but also as a relative share of the retail price) partly due to increased cost of integrating wind and solar PV capacities into the network. As the energy transition progresses, the share of network and policy costs in retail electricity costs is expected to rise further for both households and industry in the EU.

Figure 2 Household electricity prices and their composition (EU)



Source: ACER (2025) Retail electricity and gas markets price dashboard

To address affordability concerns, therefore, **it is important that policymakers do not overly focus on the wholesale component of the retail price, but instead consider the bill as a whole.** This is partly since some components of the retail electricity price (such as energy taxes) bear no direct relation with the underlying costs of electricity supply. The required government revenues could, in principle, be raised through other routes. It is partly also since some components of retail prices are interlinked. These linkages need to be considered if policymakers wish to address the total cost (i.e. wholesale, network, and retail costs) of supply to end-consumers. For example, without sufficient grid investments that facilitate new storage connections and interconnection (between bidding zones) to keep pace with the development of intermittent renewables, price volatility and system costs could be higher than necessary. Similarly, overly **restrictive planning legislation can hold back investments** in new capacity, including in flexible resources that can support system needs and mitigate price volatility.

Decisions on how to recover network costs matter for system efficiency. Appropriate, cost-reflective network tariff design can help reduce system costs, for example, by giving energy users incentives to contain demand at times of system-wide or local peaks. However, poor design of residual cost components of network tariffs can distort incentives in ways that may increase system costs. One such example could be “double” charges (network tariffs applying to both injections and withdrawals from the grid in excess of incremental forward-looking network costs) that risk inefficiently disincentivising investment into energy storage. Careful cost recovery choices can also help ensure that wholesale price signals drive both economic and behavioural incentives at the retail level, strengthening the link between wholesale and retail markets.

Retail price interventions create inefficiencies in electricity markets that may ultimately increase costs elsewhere in the system. While they are intended to protect customers, they can (depending on design) limit exposure to underlying price signals, reducing incentives for flexibility and energy efficiency, and leading to higher system costs. Retail price interventions (e.g. regulated retail prices) also weaken competition.

Policymakers should therefore:

- **Maintain a focus on efficient infrastructure planning and regulation** ensuring that infrastructure development is optimised across levels of the grids, energy carriers and Member States;
- **Remove barriers to permitting and streamline approval processes** for new capacity (generation, storage and network);
- **Avoid tariff, levy and tax structures that distort market participants' investment and operational decisions;** and
- **Refrain from distortive retail price regulation**; ensure that any regulated or social tariffs are well-targeted while preserving competition and maintaining consumer incentives.

3 Background on wholesale and retail price formation

3.1 Retail electricity prices constitute a blend of market-based wholesale electricity costs, retail costs, network costs and policy costs

In the EU, electricity retail prices consist of four main components

Electricity retail prices consist of the following components:

- **Wholesale electricity costs** – these consist of the (typically[16]) market-based purchase price for electricity traded at wholesale level. These electricity costs are driven by wholesale prices that reflect the supply and demand balance at wholesale level for a given delivery period and the geographic region (the "bidding zone").[17] As well as by market fundamentals, wholesale prices are affected by policy, including, notably, the cost of purchasing EUAs (as we later discuss in section 3.2).

- **Retail costs –** these relate to the costs incurred by the retailer, which acts as the contractual partner for the end-consumer, e.g. households or industry. Retail costs typically include costs for risk management performed by the retailer (see section 3.4 for more details), its operating costs (e.g. invoicing), as well as the retailers' margin.

- **Network costs** – these relate to the costs for transmission and distribution of electricity from the geographic point of production (e.g., a power plant or wind park) to the end-consumer (e.g., household or industrial site).[18] Network costs also include the cost of preventive and curative actions that network operators take – e.g., by giving instructions to generators or loads on the system – to avoid overloading the network. Within the EU, network costs are recovered through tariffs, which are regulated and monitored administratively by national or state/provincial regulatory authorities to reflect operation, maintenance, and expansion of transmission and distribution grid infrastructure.

- **Policy costs** – these relate to value-added-tax ("VAT"), energy and environmental taxes, and levies such as those that aim to recover the costs of support schemes (e.g., feed-in tariffs for renewable energy).

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16 In the absence of price regulation at wholesale level.

17 See next sub-sections for more details on wholesale price formation for electricity in the EU and which fundamental drivers affect wholesale price levels and volatility.

18 Network tariffs across the EU typically also include allowances for metering costs (see ACER, 2023, "Report on Electricity Transmission and Distribution Tariff Methodologies in Europe", https://www.acer.europa.eu/sites/default/files/documents/Publications/ACER_electricity_network_tariff_report.pdf), though precise practices vary by country.

Changes in wholesale energy supply costs have been one major driver of recent movements in retail prices

A recent study on behalf of DG ENER has considered the breakdown of retail energy prices across the EU between "energy" costs, "network" costs and "taxes and levies" (i.e. policy costs). Since wholesale costs make up the majority of the "energy" component[19], we use "wholesale" costs as shorthand for "energy" costs in the following discussion.

For **households**, the data shows (Figure 3 below) that, on average across the EU[20], wholesale costs:

- Typically accounted for no more than 40% of the final retail electricity price paid between 2014 and 2021. Network costs, meanwhile, accounted for around a quarter of the final retail energy price. Policy costs (taxes/levies) account for the remaining share of 35-45% each year.

- Policy costs have substantially increased in 2022 and 2023 in both absolute and relative terms compared to previous years in response to the energy crisis, although even then the relative share of electricity wholesale costs on final retail prices remained below 60%.

For the **industrial sector**, the data available in the study on behalf of DG ENER shows (Figure 4 below) for medium-sized enterprises[21] that, on average across the EU, wholesale costs:

- Typically accounted for around 50% between 2014 and 2021 of the final retail electricity price paid. Furthermore, network costs made up for circa 20% of the final retail energy price and policy costs (taxes/levies) accounted for the remaining share of around 30% each year.

- As with households, industrial sector prices have substantially increased in 2022 and 2023 in both absolute and relative terms compared to previous years in response to the energy crisis, although even then the relative share of electricity wholesale costs in final retail prices remained below 80%.

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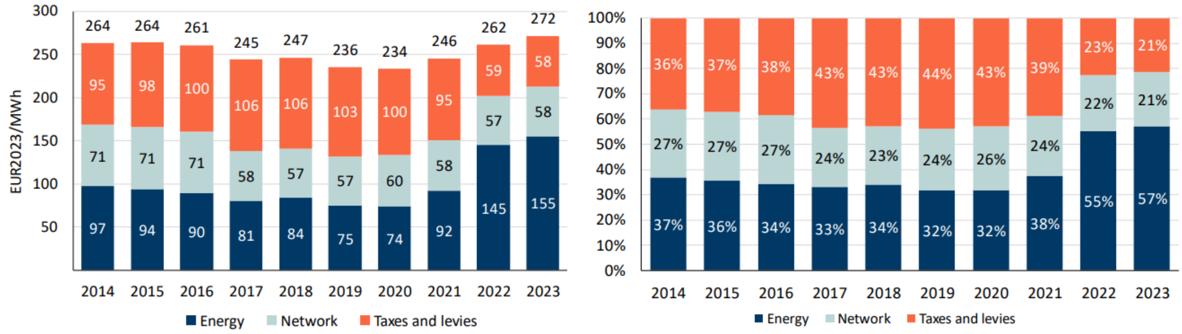
19 The energy cost component in the DG ENER study is based on the "energy and supply" component of the Eurostat retail price data. The latter includes retail costs as well as wholesale costs: https://ec.europa.eu/eurostat/cache/metadata/en/nrg_pc_204_sims.htm

20 While the specific composition of final electricity prices may differ between households and industry across individual EU Member States, the overall structure has remained relatively similar in most countries over the past ten years. However, it is important to note that, particularly during the 2022-2023 energy crisis, Member States adopted different national policy measures which affected the relative importance of the various price components — for example, through significant reductions in taxes and levies. See for example Trinomics on behalf of DG ENER, Study on energy prices and costs – evaluating impacts on households and industry's costs – 2024 edition, page 56 (households) and 63 (industry).

21 This relates to enterprises with an annual consumption of 2,000 to 20,000 MWh/a, which corresponds to the demand from commercial and small industrial electricity users across many sectors of the economy. On EU average, results are similar for very large enterprises and energy-intense industries (70,000 – 150,000 MWh/a consumption) which showed a wholesale electricity cost share of 82% in 2023 (network and taxes/levies each 9%) of the final electricity price paid.

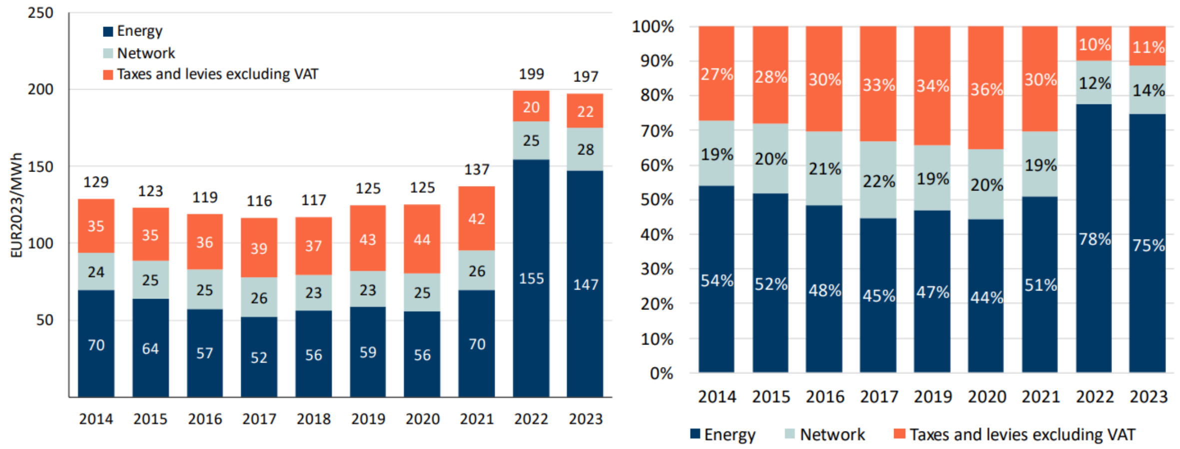
Figure 3 On average across the EU, wholesale electricity costs account for 40-60% of retail electricity prices for households



Source: *Trinomics on behalf of DG ENER, Study on energy prices and costs – evaluating impacts on households and industry's costs – 2024 edition, Figure 18*

Note: *All in EUR 2023/MWh prices; values rounded; data shown relates to DD household band with consumption of 5,000 to 15,000 kWh/a which is the band with highest share in total consumption and therefore considered most representative; prices relate to final electricity prices paid (reflecting subsidisation of electricity costs as part of the category 'taxes and levies').*

Figure 4 On EU average, wholesale electricity costs account for 50-80% of retail electricity prices for industry



Source: *Trinomics on behalf of DG ENER, Study on energy prices and costs – evaluating impacts on households and industry's costs – 2024 edition, Figure 26*

Note: *All in EUR 2023/MWh prices; values rounded; data shown relates to ID industrial end-user prices which corresponds to medium-sized enterprises and is considered as representative for commercial and small industrial electricity users across many sectors of the economy; prices relate to final electricity prices paid (reflecting subsidisation of electricity costs as part of the category 'taxes and levies').*

It is further noticeable that final electricity prices for households have consistently been higher than those for industry. The figures above show that – between 2014 and 2021 – household prices were approximately twice as high as those for industry. Although the absolute price gap narrowed during the energy crisis in 2022-2023, household prices still remained materially above industry price levels - for example, with an average EU final electricity price of EUR

272/MWh for households compared to EUR 197/MWh for industry in 2023. We further note that, while historically (2014-21) the wholesale price component in the price of household customers had been above that of industrial customers (e.g. 92 €/MWh vs 70 €/MWh in 2021), this relationship temporarily reversed during the peak of the energy crisis in 2022 (145 €/MWh vs 155 €/MWh).

The differences between household and industrial retail price levels can be explained by (at least) two main factors:

- **Consumption patterns**: Household demand tends to coincide with overall system demand (e.g., higher consumption in periods with high prices, such as winter and evening hours), leading (typically) to higher wholesale costs; and

- **Lower exposure to policy costs:** Industrial users typically face lower network charges. They also often receive (partial) exemptions from energy taxes and from renewable levies under EU State Aid Rules (though during the energy crisis, some countries also reduced taxes and levies for household customers).

In the EU, network costs and policy costs account for a material share of retail electricity prices

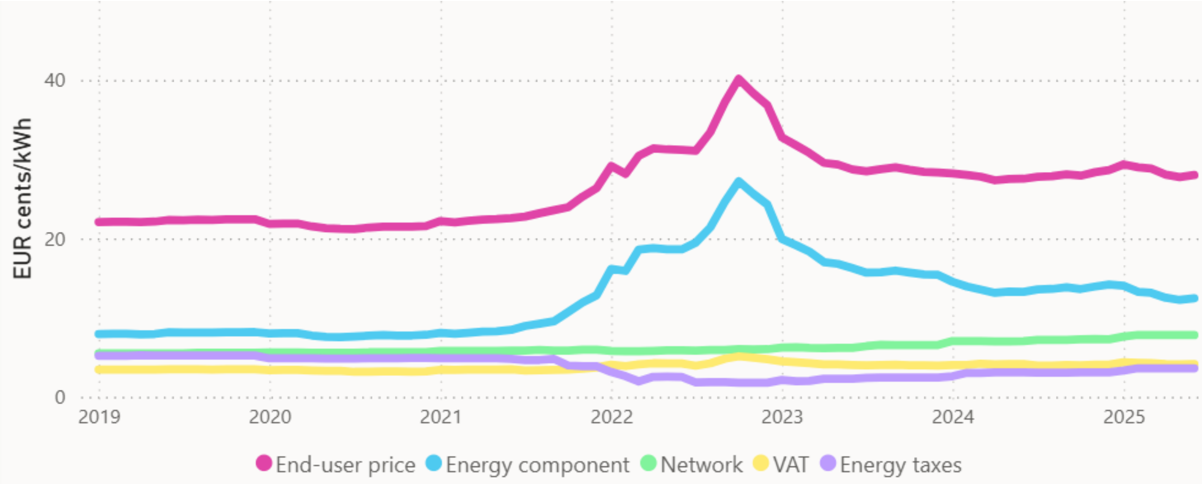
For both households and industry, Figure 4 above shows that final retail electricity prices are materially driven by components other than market-based wholesale electricity costs, namely regulated network charges and policy costs:

- Historically, network charges and policy costs have accounted for at least 60% of the retail electricity price for households (except for during the energy crisis in 2022-2023). Even for industrial consumers, network and policy cost components account for roughly half of the final electricity price prior to the energy crisis.

- During the energy crisis in 2022-2023, network and policy costs accounted for a lower relative share of the final electricity price paid by households and industry, primarily driven by a reduction in policy costs (e.g., temporal reduction of taxes and levies as ‘crisis measures’). This resulted in a share of network and policy costs of slightly above 40% of retail prices for households and 20% for industry in 2022-2023.

Recent data from ACER (Figure 5 below) suggests that – for households on EU average – the share of wholesale electricity costs in relation to the final electricity price paid has already declined from around 60% in 2022-2023 to a level of around 50% in 2024. In turn, this implies that – on EU average – network costs and policy costs together accounted for the other half of the retail electricity prices for households. Indeed, average network costs per unit of consumption have tended to rise in absolute terms over the last year (likely due to increasing costs of integrating wind and solar PV capacities into the network).

Figure 5 In 2024, EU average household electricity prices evenly split between market-based wholesale costs on the one hand, and network charges and policy costs on the other



Source: ACER (2025), Retail Markets Price Dashboard, https://www.acer.europa.eu/media/charts/retail-electricity-and-gas-markets-prices

Network and policy costs could make up a larger share of retail electricity prices in future years

Looking ahead, the share of network and policy costs in retail electricity prices is expected to rise further for both EU households and industry in the context of the energy transition. As Figure 6 below shows:

- Market-based wholesale electricity costs are expected to decline as low or zero variable cost renewable sources (e.g., wind and solar) reduce the frequency at which conventional generation (e.g., gas, coal, nuclear) reliant on fuel inputs and EUAs (see section 3.2 for further details of price formation in wholesale power markets) sets power prices;[22]

- Network costs are expected to rise in aggregate, driven by rising investment needs.[23] At transmission level, investments will be primarily driven by the expansion of renewables capacity, which is typically located more remotely from load compared to conventional generation (this will also tend to lead to higher network costs per unit of consumption, all else equal). Distribution network investment will be driven by growing electricity demand from increased electrification of transport, heating and industrial processes as well as rising small-scale renewable generation, especially solar – embedded in local grids. The

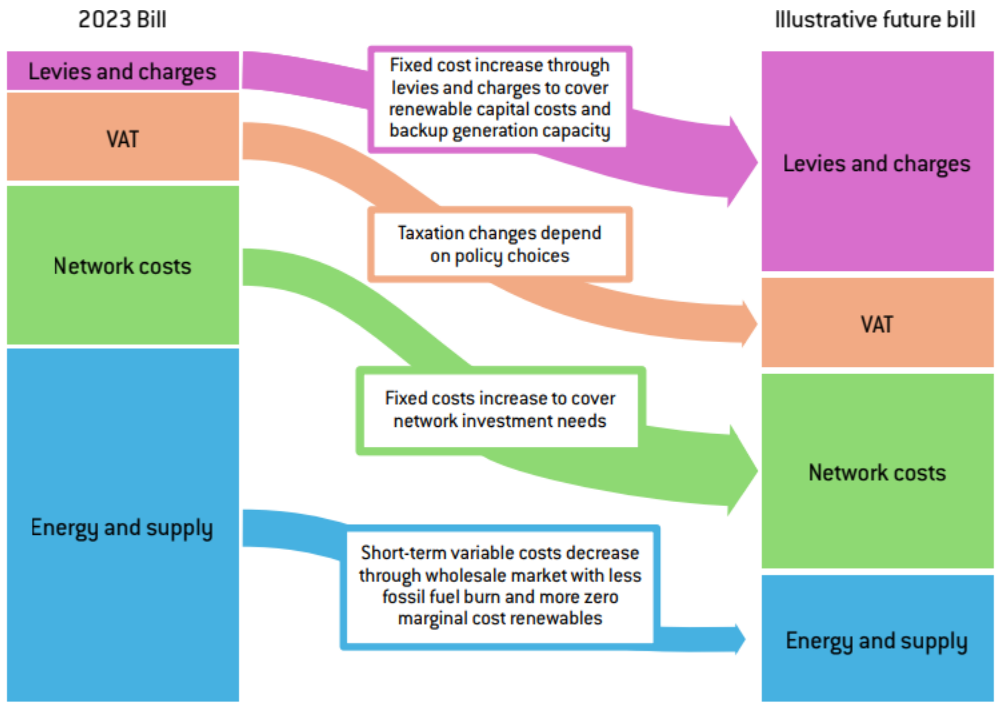
[22] The extent to which wholesale prices decline will depend on the marginal cost (including opportunity cost) of low-carbon flexible technologies (including energy storage, demand response and low-carbon dispatchable power).

[23] According to a review of studies by Bruegel, Europe's total annual grid investment needs are estimated at EUR 65 bn to EUR 100 bn up to 2030 (source). E.ON Energy Playbook analysis investment needs at EUR 83 bn for 2026-2030, EUR 92 bn for 2031-2040, and EUR 59 bn for 2041-2050 (source).

latter also implies that additional network costs will be spread over a wider consumer base – as such, the effect on unit costs is uncertain. A further question relates to the utilisation of the future grid. Average load factors for renewable generation will be lower than that of conventional plants historically, tending to lead to higher unit costs for the grid. However, this effect could be at least partly mitigated by growth in electricity system flexibility; and

- Policy costs (assuming it remains the case they are recovered from electricity prices, rather than through general public budgets) are likely to increase to cover the "out of market" costs associated with deployment of generation and storage via support mechanisms. To the extent that these support mechanisms act to stabilise beneficiaries' wholesale market revenues, the costs recovered from consumers from one period to the next will be negatively correlated with wholesale costs and will partly stabilise retail prices.

Figure 6 Expected changes in EU retail electricity prices under the energy transition, schematic illustration



Source: Bruegel, Decarbonising for competitiveness: four ways to reduce European energy price, Figure 7, *https://www.bruegel.org/sites/default/files/2024-12/PB%2032%202024_0.pdf*

In conclusion, when discussing retail electricity prices, it is crucial to recognise that market-based wholesale electricity costs are a significant component of the final price paid by households and industry. However, they are not the only influencing factor. A large portion of retail prices is driven by network and policy costs.

3.2 Electricity wholesale markets

Efficient electricity wholesale trading requires diverse types of markets

Electricity can be traded across different markets and platforms[24] that differ by:

- lead time before delivery (spot versus long-term);
- settlement (physical or financial);
- the counterparty involved (exchange versus over-the-counter, or “OTC”); and
- degree of regulatory intervention (energy or financial).

The products traded on these markets may also differ by duration of delivery and profile.

- Spot markets cover delivery for intervals of 15 minutes, 1h, blocks of several hours and full days.
- Long-term markets typically cover delivery periods of months, quarters and years. Forward and futures products may distinguish between peak and off-peak periods. Some forward products may be more bespoke in terms of profile.
- Power Purchase Agreements (PPAs) can be viewed as a subset of long-term products traded in wholesale markets. Unlike forward and futures products, they are typically tied to the output or technical capabilities of specific plants. They can also be more bespoke (i.e., less standardised) and may contain arrangements giving either the seller or the buyer some discretion or flexibility over how much electricity they deliver or take-off at different times.

These markets and platforms are to some extent complementary in ensuring that electricity is delivered reliably and efficiently, while allowing participants to balance short-term and longer-term financial and operational[25] risks. In some cases, different platforms and products may be (partly) substitutes for each other (for example, PPAs versus forward or futures products, depending on the duration of the latter).

Spot markets clear close to the time of delivery and cover short-term products

Spot markets are used for short-term trading for the physical delivery of power. Participants in the spot market include, among others:

24 Other mechanisms that support the functioning of electricity markets include balancing markets, imbalance pricing, and congestion management mechanisms.

25 Physical market participants are typically strongly incentivised to balance their portfolios in advance to avoid exposure to imbalance prices. These imbalance prices reflect the cost to system operators of keeping the system balanced and can be significantly higher cost than spot market prices. Imbalance prices also influence spot price formation. For example, the imbalance price faced if participants are short can effectively cap wholesale prices (see footnote 80).

- Predominantly as seller: electricity producers (such as power plants and renewable operators);
- Predominantly as buyers: retailers (who buy electricity on behalf of their customers – typically households or businesses), and large industrial consumers with direct access to the market.

Energy traders may act both as sellers and as buyers in the market. Producers may also act as buyers, e.g. when they have sold more energy forward than they intend to produce on a specific day. In that case they can buy any shortfall or electricity that they do not intend to produce themselves on the spot market. Similarly, retailers or industrial customers may also act as sellers, e.g. if they have over contracted electricity and need to shed some volumes in the spot market.

The two main types of spot markets in Europe are:

- The EU-wide coupled **day-ahead market**, i.e., Single Day-Ahead Coupling (SDAC) where buyers and sellers buy and sell contracted volumes per bidding zone that are then scheduled (e.g. by balancing responsible parties towards TSOs) for delivery on the following day. This is the main reference market for short-term electricity trading. Prices established in this market are the primary underlying reference prices for forwards/futures markets (see below), and the coupled day-ahead market is typically very liquid. This market is organised as a single auction and ensures that a large share of electricity demand is secured in advance with price transparency. The day-ahead market also serves as a benchmark for renewable support schemes and acts as the reference price for the financial settlement of certain swaps and indexed contracts. The coupled SDAC implicit auction closes at noon on the day before delivery, and the results (i.e., 15-min[26] market-clearing prices and volumes) are published around 1300 CET.
- The **Intraday market**, i.e., Single Intraday Coupling (SIDC) where buyers and sellers buy and sell economically contracted volumes per Bidding Zone. It enables the utilisation of cross-zonal capacity, scheduling electricity and capacity volumes for delivery until at minimum 60 minutes before delivery period and, in some bidding zones, up to the start of power deliveries. This allows participants to adjust and fine-tune their positions after the day-ahead market closes and respond to unforeseen changes in supply and demand. The importance of intraday markets has grown in recent years due to the expansion of intermittent renewables, the output of which can be predicted more accurately closer to the real-time of delivery[27] and the coupling of the intraday markets across different geographies. There are two main types of intraday markets:

[26] As of delivery day 1 October 2025. Prior to this, hourly intervals for day-ahead trading were also used in some bidding zones.

[27] See ACER (2023), Progress of EU electricity wholesale market integration – 2023 Market Monitoring Report, p. 23, https://www.acer.europa.eu/sites/default/files/documents/Publications/2023_MMR_Market_Integration.pdf

- Intraday **auctions** are typically held three times throughout the day. Auctions allow participants to rebalance their portfolios after the day-ahead markets close. Auctions serve to concentrate market liquidity into defined auction events.

- **Continuous** Intraday markets operate continuously, allowing participants to trade electricity close to real-time. Continuous trading provides flexibility for participants to respond to real-time changes, such as unexpected outages or fluctuations in renewable energy generation.

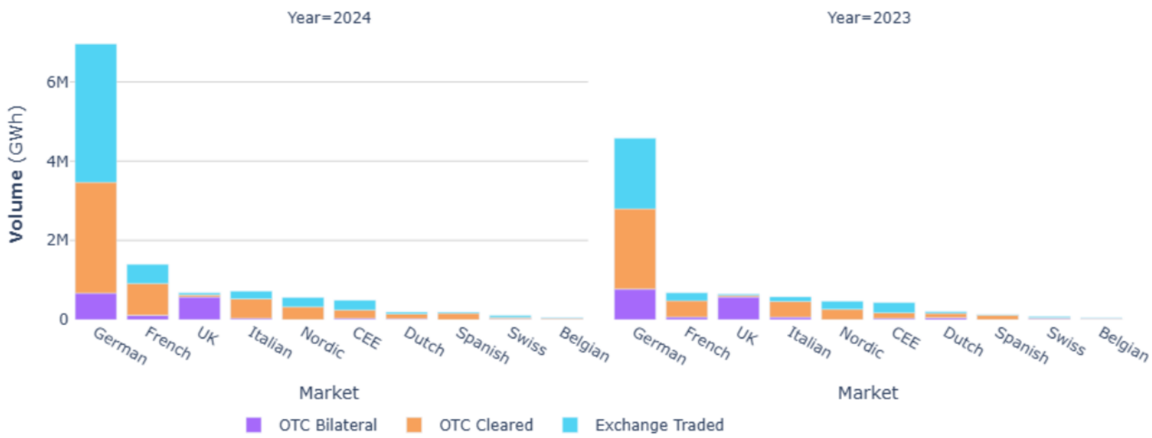
Long-term markets serve to secure deliveries and set prices over longer periods

Long-term markets involve the trade of contracts that are settled over longer time horizons, months or even years ahead of delivery. The value of these contracts depends on an underlying fixed or reference price of the commodity. Derivatives can be traded either on regulated exchanges or OTC between individual parties.

The most relevant products are forwards, futures[28], swaps, and options. These types of contracts allow market participants to manage risks and hedge against price risk and volatility.

Traded volumes of long-term contracts are typically several multiples of consumption (as illustrated in Figure 7 below.

Figure 7 Traded volumes of electricity, selected European power markets



Source: European Commission (2024), "Quarterly report on European Electricity markets" Volume 17 (Q4 2024), Figure 30. DG ENER calculations based on Trayport and London Energy Brokers Association data.

PPAs are long-term contracts between – typically – an electricity generator and a buyer ("offtaker") of electricity – typically a utility or large power user. Their long-term nature may

28 Futures and forwards are both contracts for the future delivery at a fixed price, but futures are traded on regulated exchanges, while forwards are traded over the counter.

(depending on contractual terms such as degree of price stability) may support project financing for generators and price stability for end users.

While spot contracts always imply the physical delivery of the commodity, long-term contracts can be either physically or financially settled. Financially settled contracts do not provide for actual delivery of the underlying physical commodity, but only a settlement of the difference between the contract price and a market reference price (i.e., the spot price).

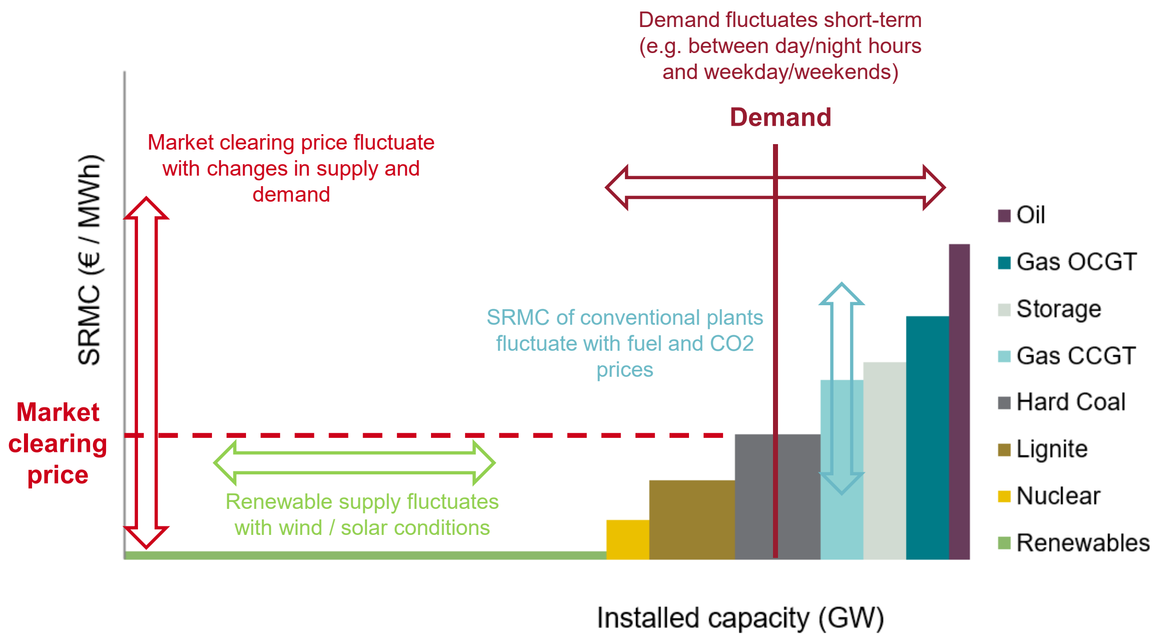
Spot and long-term markets serve distinct purposes in the energy system, but they are closely interlinked, as we discuss later in this section.

European spot market prices are formed with the so-called ‘merit order principle’, ensuring cost-effective dispatch of generation and loads and efficient short-term wholesale electricity pricing

Day-ahead spot markets match electricity supply and demand on a quarter-hourly basis following a pay-as-clear model based on marginal pricing. This is commonly referred to as the “merit order principle”.

In this system, generator supply bids are ranked in ascending order of the short-run marginal cost (“SRMC”) of producing an incremental megawatt-hour (MWh) of electrical energy (Figure 8). The market-clearing price is determined at the point where the aggregated supply curve intersects the demand curve. Generation units with SRMC below the market-clearing price are cleared, while those above it remain idle.

Figure 8 Merit order principle



Source: Frontier Economics

Note: Illustrative example for a market where the technologies above are available, and demand is inelastic to price. There might be power markets where, for example, nuclear is not part of the power mix. The order between conventional plants can change depending on fuel and CO_2 price developments, e.g., coal-fired power plants might have lower SRMC at times of low CO_2 and high gas prices and vice versa

These variable generation costs typically consist of three main components: fuel costs, EUA costs and variable operation and management (O&M) costs. The typical ranking from low to high SRMC would be:

- **Renewables** (wind onshore and offshore, solar PV and run-of-river hydro plants): Once installed, these plants have no significant variable cost. However, as we later discuss (see section 5.1), early vintages of supported renewables may offer their output at negative prices (reflecting the opportunity cost of lost support payments).[29] The availability of wind and solar PV is highly intermittent and can vary from hour to hour.
- **Nuclear power plants**: Without significant fuel tax, nuclear power plants have comparably low SRMC, determined by fuel costs and the power plant's efficiency.
- **Fossil thermal power plants**: Fossil thermal generation units are fired by either lignite, hard coal or gas (or rarely oil products), and their SRMC is determined by the cost of fuel,

[29] Starting with the 2014 Guidelines on State aid for environmental protection and energy 2014-2020, the EU framework has imposed stricter conditions on member state support scheme design. These conditions aim to prevent negative offers from supported renewables, which typically arise when support is paid on the basis of metered output regardless of market conditions.

the cost of EUAs and the respective efficiency of the power plant. The actual order depends mainly on fuel price relations (gas vs. coal) and prices for EUAs.[30]

- **Power storages**: Pumped hydro storages and batteries require electric energy before they can generate electricity at a later point in time. Their SRMC are therefore largely driven by the electricity conversion efficiency and the electricity price itself, both as an input cost and as an opportunity cost of storing energy and producing electricity at a later time.

When the market price exceeds the SRMC of lower-cost generators, the latter units earn a surplus known as "inframarginal rent", which contributes to the recovery of their fixed costs.

In periods of tight supply and/or high demand, spot prices may rise above the marginal generator's SRMC, leading to "scarcity rents" through:

- demand flexibility – if supply is scarce, the market can be cleared by consumers that reduce or shift demand (e.g., energy industry reducing good production) – often at high prices; and/or

- "peak-load pricing" – if supply is scarce and not enough flexible demand is available, some suppliers become pivotal, i.e. demand cannot be met without their capacities. Therefore, in these situations, even in an otherwise perfectly competitive market these suppliers can include a mark-up above short-run marginal costs (contributing to recovery of fixed costs) when setting their price offers because – from a static perspective – these suppliers cannot be replaced by a less costly option.

Scarcity rents reflect real-time system stress and (as we discuss later in Section 5.2) play a role in remunerating the availability of capacity and thereby ensuring incentives for the market to strive for resource adequacy.

Historically, the use of cross-zonal transmission capacities between market areas (or "bidding zones") in continental Europe was auctioned separately for each border. Interconnection was even auctioned separately from the electricity to be transported (referred to as "explicit allocation" of cross-zonal capacity). This led to significant inefficiencies due to:

- a lack of synchronisation between the nomination of cross-zonal flows and network capacity usage on the one hand and national electricity trading on the other;[31] and

- a lack of co-ordination of the calculation and allocation of cross-zonal capacity between different bidding zones in Europe.

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30 Open Cycle Gas turbines (OCGT) and oil-fired power plants have rather low thermal efficiency and, therefore, typically have high SRMC. They cover demand peaks and typically only run a few hundred hours or less per year.

31 Leading, for example, to frequent cross border schedules from high to low price bidding zones, or under-utilisation of the available cross-zonal capacity.

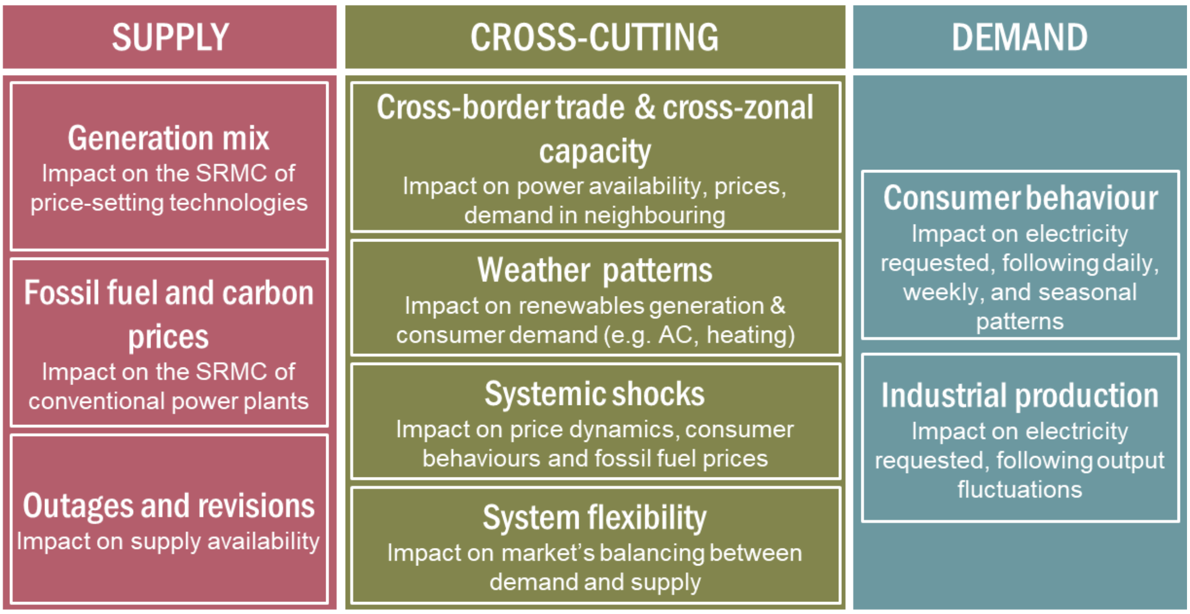
The first issue was subsequently addressed through the synchronised auctioning of cross-zonal transmission capacity and energy or ‘Market Coupling’, through so-called ‘implicit’ auctions, now covering practically all EU countries and being extended to continuous trading. The regime was subsequently refined to address the second issue of co-ordinating the optimal calculation and allocation of cross-zonal capacity across multiple borders, implicitly taking into account the expected flows resulting from the implicit day-ahead auctions and the interdependency of flows between bidding zones (flow-based market coupling, or FBMC). Implementation of FBMC in intraday is still pending. Market coupling takes place at both the day-ahead and intraday timeframes.

Spot market price levels and volatility are influenced by multiple factors reflecting real-time system conditions and market fundamentals

Spot prices in the EU are shaped by a wide range of factors. These factors interact in real-time and influence the marginal cost of electricity in complex ways. These drivers can be broadly categorised into:

- supply-side factors, affecting the availability and costs of electricity generation,
- demand-side factors, shaping how much, where, and when electricity is needed, and
- cross-cutting factors, impacting simultaneously or interactively both ().

Figure 9 Power price drivers



Source: Frontier Economics

On the supply side, the main factors influencing electricity prices are:

- **Generation mix.** The proportion of each technology in the generation mix influences its role in setting the marginal price under the merit order principle. The generation mix also impacts electricity availability. For example, a higher share of intermittent renewable energy can lead to prices being more affected by changes in weather.

- **Fossil fuel and EUA prices**. The SRMC of fossil fuel technologies, such as gas and coal power plants, depends heavily on the underlying fuel price as well as EUA prices. Increases in these input costs feed directly into electricity when these plants are price-setting.

- **Outages**. While planned maintenance tends to take place during periods of expected low electricity demand and prices, unexpected or correlated outages, such as nuclear outages in France in 2022 due to corrosion issues, can tighten supply and trigger price spikes.

On the demand-side, two main factors influence how much electricity is needed:

- **Consumer behaviour**. Electricity demand follows daily, weekly, and seasonal patterns that are (to a degree) predictable. Demand typically peaks around midday and in the evening, is lower on weekends and holidays, and increases in colder and hotter seasons, in particular in markets where electricity is used for heating or cooling.

- **Industrial production**. Industrial activity is a major source of electricity demand. Fluctuations in output, such as during economic downturns or production surges, can significantly influence electricity prices.

Some factors may influence both supply and demand for power, or contribute to more complex system dynamics, including:

- **Cross-zonal trade**. Interconnectors allow electricity to flow across national borders and bidding zones, expanding the pool of available generators in the merit order. This integration allows lower-cost generation from neighbouring regions to meet local demand, leading to stronger price synchronisation, depending also on the level of available cross-zonal transmission capacity.

- **Weather patterns**. Weather affects both sides of the market. On the supply side, renewable output is heavily weather-dependent. On the demand side, temperature fluctuations and light conditions can influence heating, cooling and lighting needs.

- **Systemic shocks**. Major external shocks, such as the COVID-19 pandemic and the recent geopolitical crisis in Europe, can affect both supply (e.g., fossil fuel availability) and demand (e.g., reduced industrial output).

- **System flexibility**. The market's adjustment to variations in supply and demand can influence short-term price signals and can lead to a wider price distribution, depending on the responsiveness of demand, availability of storage, and operational characteristics of generation assets.

The volatility of wholesale electricity prices on the spot market has increased in recent years

The intensity of electricity price volatility varies across periods and across different timeframes.

The phase-out of conventional electricity generation and the growing share of renewables in the generation mix are likely to change the nature of electricity price volatility, from being predominantly influenced by fossil fuel prices to being increasingly influenced by weather. The extent to which volatility changes over time will depend on the development of sources of flexibility, such as storage, demand-side response (DSR), and interconnection. These technologies help smooth out fluctuations by balancing supply and demand over shorter intervals, but their availability and responsiveness currently vary by region or bidding zone and technology.

Trends in power prices and their volatility, and the drivers of this, are analysed further in section 4.

3.3 Wholesale electricity markets for spot and long-term contracts are closely linked but spot prices are typically more volatile

Electricity spot and forward market prices are closely linked, but fulfil different needs of wholesale market participants

Prices of long-term products such as futures and forwards typically reflect the expected future spot price over the delivery period and therefore market participants' view on future demand and supply balance (see previous sub-section on electricity price drivers).[32] Derivative contracts, i.e. futures and forwards, are either financially settled against future spot prices or electricity is delivered physically[33] and would then be valued against the future spot price (mark-to-market), creating a direct connection between spot and derivatives wholesale electricity prices.

In Europe, electricity spot and derivatives markets are therefore closely linked, with the short-term spot market serving as a benchmark for (financial) settlement of derivatives. The spot market reflects real-time electricity prices based on current physical supply and demand dynamics. The derivatives markets allow – among other benefits – participants on the supply (e.g., power plant operators) and demand side (e.g., retailers purchasing electricity) to hedge ("insure") against future price fluctuations by trading contracts such as futures and options

32 Compared to spot prices, derivatives prices typically further include a risk premium (or discount), reflecting market participants risk aversion (e.g., allowing retailers offering fixed electricity tariffs to hedge against spot price spikes), liquidity and transaction costs (e.g., in thinly traded markets with high bid-ask spreads), or wider supply-demand-balance uncertainty (e.g., following from geopolitical events) associated with long-term trading.

33 Forward contracts traded via OTC are always settled physically, whereas futures traded on energy exchanges are commonly settled financially at contract maturity (e.g., difference between the contract price and a reference spot price such as the day-ahead market is settled in cash).

over a longer period (e.g., several years ahead of physical delivery).[34] As a result, movements in the spot market often (but not necessarily) influence expectations and therefore the pricing of derivatives.

Spot prices are typically more volatile than derivatives prices

Spot and derivatives electricity price levels in European power markets often follow similar market trends based on common price drivers. Spot prices, however, are (with few exceptions) significantly more volatile due to their reaction to short-term changes in the supply-demand balance which do not affect the expectation of future prices to the same extent.

To illustrate this, we have analysed German electricity prices for spot and futures over the trading period January 2021 to May 2025 by comparing price levels in absolute terms (EUR/MWh) and price volatility, measured as the standard deviation of prices over a defined period of time.[35] Figure 10 below shows the price levels and 14-day standard deviation for German power (baseload[36]) for the three delivery periods day-ahead (equivalent to the spot market), month-ahead and year-ahead.[37]

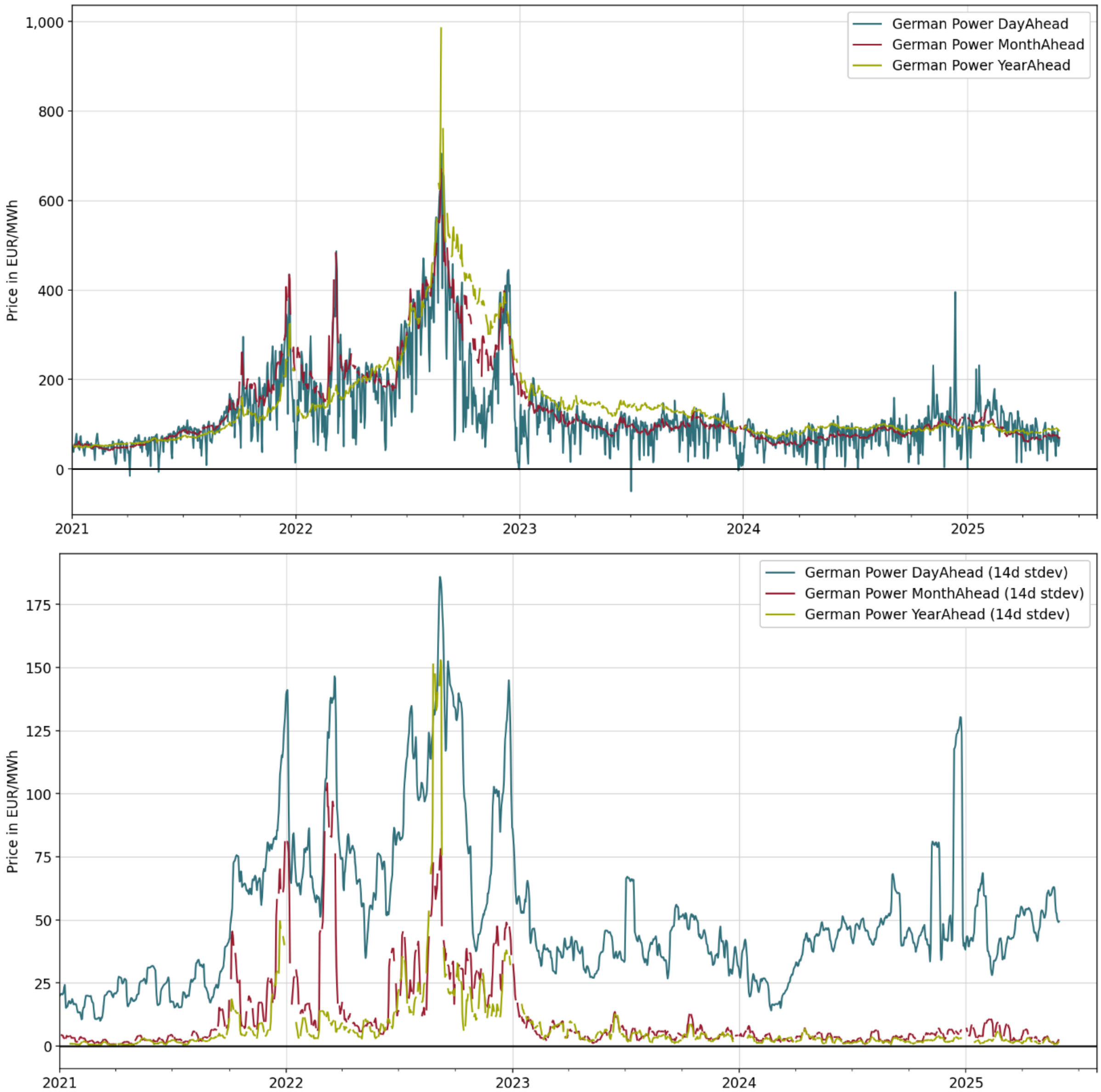
34 Hedging means that buyers/sellers of electricity enter physical or financial contracts that are traded up to several years in advance allowing them to secure stable and predictable prices for a given period of time. In addition to hedging, wholesale market participants further use spot and derivatives markets for risk transformation, price discovery and business diversification, as well as own account trading. See for more details Frontier Economics (2024), “Principles of Energy Market Regulation”, Section 2.1.2, https://cms.energytraderseurope.org/storage/uploads/media/frontier-luther---principles-of-energy-market-regulation-19042024.pdf

35 We primarily rely on standard deviation over the preceding 14 trading days, as is commonly used in the risk assessment of trading positions. See also Halkos et al. (2019), “Using Value-at-Risk for effective energy portfolio risk management”, https://mpra.ub.uni-muenchen.de/91674/1/MPRA_paper_91674.pdf. The period might deviate and can be longer, e.g., 21 days or 30 days. Note that while German price trends will not be reflective of price trends across other European bidding zones, we have selected it for this illustrative case study given the German market is one of the most liquidly traded markets for forwards/futures in Europe. While we have not carried out similar analysis for other bidding zones, we would expect a similar relationship between spot and forward prices elsewhere, for the reasons stated.

36 Baseload is the constant delivery of 1 MWh over the delivery period (day, month, or year).

37 I.e. price for delivery of power over the subsequent calendar year.

Figure 10 Spot and future electricity prices follow similar price trends, but spot prices are more volatile (Germany, January 2021 to May 2025)



Source: Frontier Economics based on the study "Principles of Energy Market Regulation", Section 2.1.3 and Annex B, https://cms.energytraderseurope.org/storage/uploads/media/frontier-luther---principles-of-energy-market-regulation-19042024.pdf; updated using EEX data (Month-Ahead and Year-Ahead prices), and ENSTO-E data (Day-Ahead average daily prices), covering the period January 2024 to May 2025.

Note: Time axis represents trading days. Note that Power futures are only traded on weekdays, which explains the discontinuities in the future price series. The 14-day standard deviation ("14d StDev") is calculated over daily prices of the last 14 days for each trading day. We note that volatility of the prices for these products needs to be compared with caution, as delivery periods differ. For example, the day-ahead price on day D reflects delivery on D+1, while month-ahead and year-ahead contracts reflect delivery in the subsequent month and calendar year, respectively.

Table 1 Summary statistics for spot vs. future prices in the example of Germany, January 2021 to May 2025

German power market	Day-Ahead (in EUR/MWh)				
	2021	2022	2023	2024	2025
Mean	96.8	235.4	95.2	78.5	95
14d StDev	35.1	90.8	41.9	44.4	48.5
	Month-Ahead (in EUR/MWh)				
	2021	2022	2023	2024	2025
Mean	108.9	286.2	104.3	78.6	84.3
14d StDev	9.1	29.7	6	3.7	4
	Year-Ahead (in EUR/MWh)				
	2021	2022	2023	2024	2025
Mean	88.4	298.9	137.5	88.7	88
14d StDev	4.8	21.3	5.2	2.4	1.9

Source: *Frontier Economics based the study „Principles of Energy Market Regulation", Section 2.1.3 and Annex B, https://cms.energytraderseurope.org/storage/uploads/media/frontier-luther---principles-of-energy-market-regulation-19042024.pdf; updated using EEX data (Month-Ahead and Year-Ahead prices), and ENSTO-E data (Day-Ahead prices), covering the period January 2024 to May 2025.*

Note: *The 14-day standard deviation ("14d StDev") is calculated over daily prices of the last 14 days for each trading day; the annual standard deviation ("Annual StDev") is calculated over all daily prices of a calendar year. We note that volatility of the prices for these products needs to be compared with caution, as delivery periods differ. For example, the day-ahead price on day D reflects delivery on D+1, while month-ahead and year-ahead contracts reflect delivery in the subsequent month and calendar year, respectively.*

The comparison of German electricity spot and future products traded between 2021 to 2025 shows two prominent properties:

- **First, spot and future prices follow a common trend**. Spot and future prices rise gradually (top part of Figure 10) – with some intermediate highs – until a sharp increase in August 2022 at the peak of the energy crisis and decline afterwards. Following the August 2022 price peak, we observe a wedge between spot and future markets (futures are priced higher) reflecting limited storability of power in a challenging market environment at the time, which again diminishes in later years (2023-2025).

  The reasons for the joint movement of spot and futures are common factors for short-term and long-term scarcity (e.g., steepness of the merit order curve) and level of SRMC (e.g., the height of the bars in the merit order). For example:

  - Gas prices, which are an input into gas-fired power plants, and which are frequently the price setting technology, are a main driver of power prices.
  - The unavailability of a significant part of the nuclear fleet in summer 2022[38], which due to low variable generation costs sit on the left-hand side of the merit order and run most hours of the year ("baseload"), contributed to shifting price setting to plants with higher variable costs (coal and gas) during the energy crisis.

[38] See ACER (2023), European gas market trends and price drivers - 2023 Market Monitoring Report, page 8, https://www.acer.europa.eu/sites/default/files/documents/Publications/ACER_MMR_2023_Gas_market_trends_price_drivers.pdf

- **Second, spot prices for electricity are usually significantly more volatile than future prices.** Spot prices for power show a pronounced variation around the common trend, with spot prices on individual days reaching zero or even becoming negative. The variation would be even larger for hourly prices compared to the daily baseload prices (which are the average over the 24-hourly prices per day). The large variation in spot prices results in a significantly higher price volatility, measured by the standard deviation, than the monthly and yearly future.[39] This holds for the entire period between January 2021 and May 2025, with the only exception of a brief period in August 2022, when the 14d-standard deviation of the yearly future reached the same – or even slightly higher – levels than the spot price, driven by a few extreme spikes in the German baseload future (almost reaching 1,000 €/MWh) while the spot prices peaked at around 750 €/MWh. The descriptive statistics of the 14-day standard deviation (see Table 1) confirms this finding across all three products in each of the analysed years: the standard deviation of power day-ahead prices between January 2021 and May 2025 is three to twelve times higher than month-ahead prices, while the standard deviation of day-ahead prices in the same period is even four to more than 25 times higher than year-ahead prices.

The reasons for the systematically higher spot price volatility for power lie in a combination of the price drivers and the limited storability of power.

- Spot prices are influenced by a number of short-term drivers, such as short-term power demand and renewable supply (itself driven by weather). The realisation of these drivers changes much more on a daily basis than their expected value for futures periods would. Drivers that market participants consider as short-term will have less of an effect on forward prices. For example, a wind front (which would reduce prices due to high wind availability) does not (significantly) impact the expectations of wind feed-in next year. At the same time, developments which affect the market more fundamentally (e.g., movements in EUA prices) will influence price volatility of day-, month- and year-ahead products in a similar way.

- Due to limited storability of electricity[40], short-term changes in fundamental price drivers (such as a strong wind front for a couple of days at very low spot prices) do not carry over into future periods (next month or year).

- In addition, spot power prices are driven by the weekday/weekend pattern, which introduces a systematic and predictable volatility not reflected in monthly/yearly futures which represent a weighted average of weekend and weekday prices.

[39] We note that volatility of the prices for these products needs to be compared with caution, as delivery periods differ. For example, the day-ahead price on day D reflects delivery on D+1, while month-ahead and year-ahead contracts reflect delivery in the subsequent month and calendar year, respectively.

[40] In a Frontier study in eight European countries, total power storage capacity only sufficed to cover demand for less than 4 hours, see https://www.frontier-economics.com/media/lqqlhwwr/value-of-gas-infrastructure-report.pdf, p. 23.

3.4 The wholesale price component of retail electricity prices typically reflects both spot and forward market developments

Wholesale electricity prices influence retail prices depending on the contractual tariff structure, which in turn is shaped by various factors

As set out in the beginning of this section, wholesale electricity prices account for a large share of retail electricity prices. We have also just discussed that the price of power derivatives tends to be less volatile than that of spot prices. The volatility of retail pricing will therefore depend on the extent to which the wholesale component reflects spot or derivative prices. This, in turn, will depend on:

- **The type of customer and customer preferences** – different types of customers have different preferences for their retail electricity tariff in terms of its duration and the risks they will bear. For instance, retail contracts for household customers are typically for a fixed price (but variable volume) over a given duration (e.g., 12- or 24-month terms, or "evergreen" but with a certain notice period in case of a customer switching), whereas contracts for industrials may be fixed price only for a defined volume and profile which may include some limited and explicitly defined tolerance (with exposure of the customer to short-term price volatility outside of the defined quantity / profile and tolerance).

- **The regulatory framework** – the regulatory framework further impacts the retail tariff structure. For instance, in Spain electricity prices for households are mainly set through the regulated PVPC tariff ("*Precio Voluntario para el Pequeño Consumidor*"), the wholesale component of which reflects hourly prices in the wholesale market. In other markets (such as France) the wholesale component of the regulated retail tariff is indexed to prices of power derivatives. [41]

Retailers apply a hedging strategy that reflects their specific risk aversion and considers internal hedges within their overall portfolio

When procuring electricity on the wholesale market, retailers face different types and levels of spot and derivatives market risk depending on the composition of their individual retail portfolio and the contracts they hold. To manage these market risks effectively, it is industry-standard for retailers to tailor their risk management strategies to their individual requirements and hedge wholesale electricity prices and volumes in line with their portfolio structure and

[41] The PVPC reflects hourly prices in the wholesale market. This tariff is designed to be a dynamic, time-of-use tariff, meaning the price of electricity varies hourly, influencing consumption habits. See also Endesa, (2025), "PVPC. What is the regulated tariff?", https://www.endesa.com/en/blogs/endesa-s-blog/light/pvpc-regulated-tariff

contractual agreements.[42] Amongst other methods, two prominent hedging approaches for retailers include:

- **Back-to-back hedging** – back-to-back hedging involves matching retail sales commitments directly with wholesale electricity purchases to minimise exposure to price fluctuations. By aligning wholesale electricity purchases with customer demand over the agreed delivery period, retailers aim to minimise the risk of market price volatility impacting their margin by locking-in the respective electricity price and volumes for their end-customer in line with their contractual obligations with the respective customer. The approach is often preferred by retailers for individual customers with a large electricity demand or specific consumption pattern (e.g., industrial clients) for which it may be challenging to find alternative end-customers at the contractually agreed prices and volumes.

- **Hedging ladder** – in contrast, the hedging ladder is a layered approach where retailers progressively secure wholesale electricity volumes over time to cover anticipated demand. This strategy spreads risk across different time horizons and market conditions, helping to stabilise costs and protect margins against sudden wholesale price changes. The approach is often used by retailers to manage their existing (and expected) retail portfolio of household customers, especially where customers are not locked into contracts of a defined duration (sometimes labelled “evergreen” contracts) and where retailers need to form expectations of the electricity demand they expect to be serving one and two years in advance.

We provide an example illustrating the mechanisms of the hedging ladder for a retail household portfolio below.

Example: Risk management for a household retail portfolio using the hedging ladder

The key challenge for retailers is that they face volatile wholesale prices but are – at the same time – confronted with strong end-consumer demand (e.g., from households) for largely fixed price contracts (due to strong customer preferences for price stability). Consequently, wholesale electricity market price risk typically sits with retailers as a result of the fixed contracts (typically 12- or 24-month, but also for contracts without a defined duration) they conclude with respective customers.

The common feature of these contracts with fixed price components is that, for such customers, retailers offer fully or partially fixed prices for variable volumes. More specifically, retailers who are then unable to pass on electricity spot market prices to customers, are left with a (mostly) fixed sale price, variable

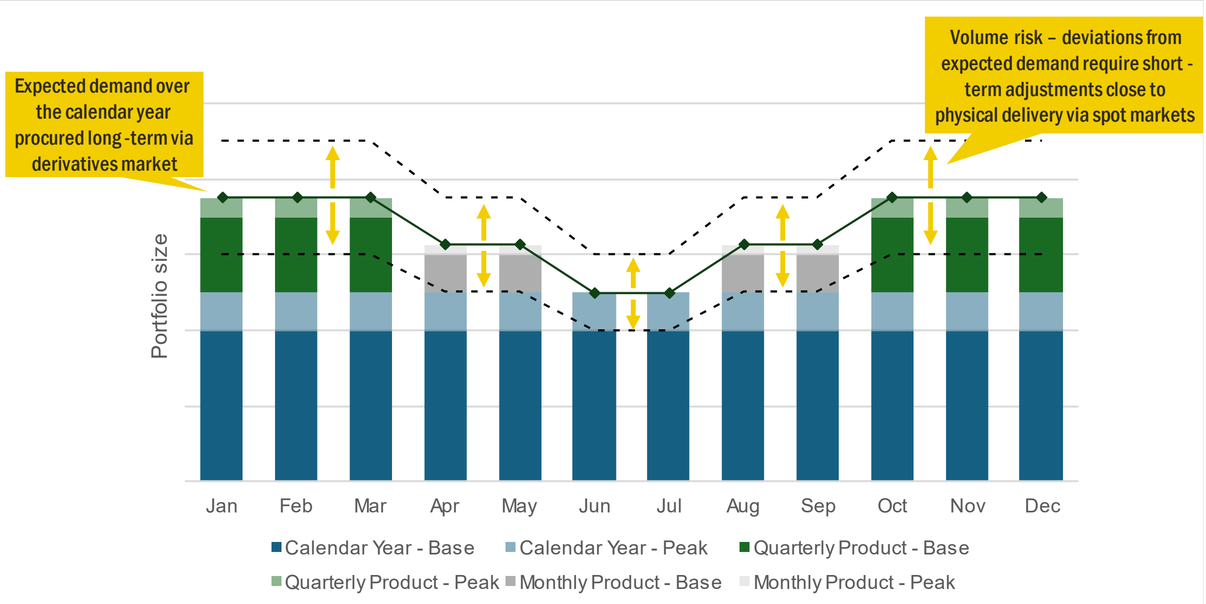
42 Beyond market risk, retailers, similar to other market participants, are typically required to manage cash liquidity and credit risks when trading electricity on a wholesale level. Together with the market risk, credit and cash liquidity risks are typically considered as a ‘risk triangle’ and are balanced out by wholesale market participants as part of their overall risk management strategy. For more details, see Frontier Economics (2024), „Principles of Energy Market Regulation“, Section 2.2, https://cms.energytraderseurope.org/storage/uploads/media/frontier-luther---principles-of-energy-market-regulation-19042024.pdf

input costs and an uncertain volume of demand that will need to be met (see next sub-section on cost pass-on). Further, existing customers may exit these contracts with zero or relatively low exit fees, if they are able to find lower prices elsewhere. Such lack of contractual certainty further increases volume uncertainty for retailers (so-called volume (flexibility) risk).

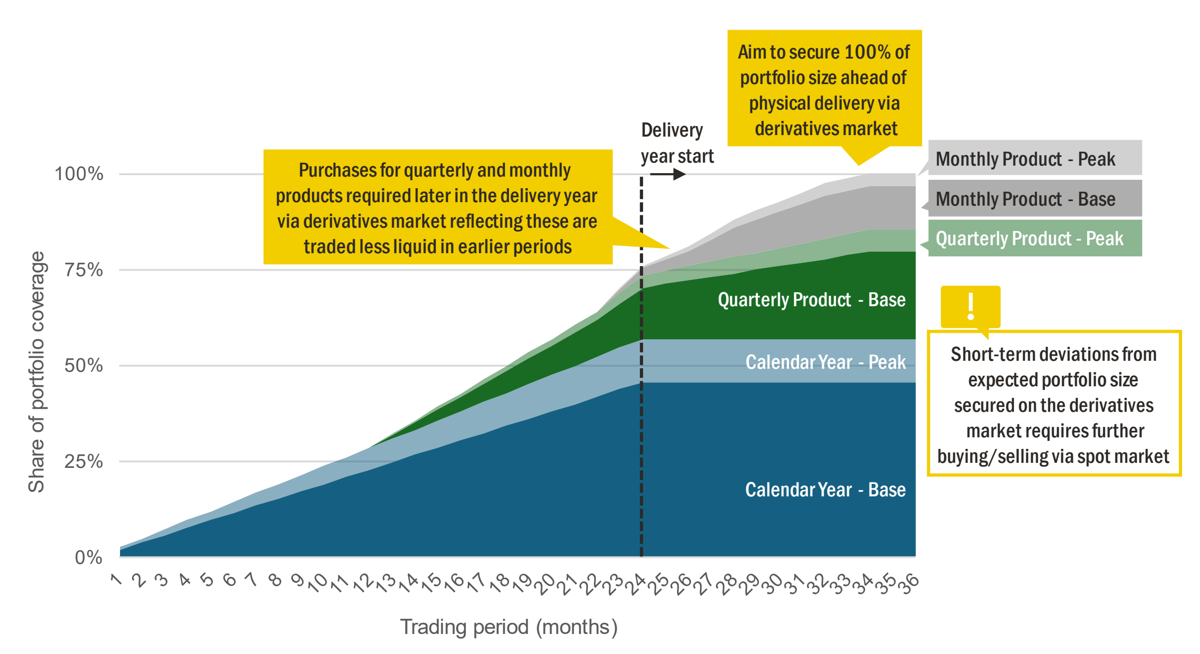
Retailers are therefore exposed to price and volume risk as a result of these contracts and will look to hedge and manage these risks. It is important to understand that:

- In practice, retailers cannot hedge their volume risk perfectly, due to uncertainty about customer demand. Demand levels (e.g., driven by climate conditions) will tend to be positively correlated with wholesale prices, exacerbating the risks faced. Retailers therefore typically manage the market price risk associated with expected volumes by hedging forward in the longer-term on derivatives markets by buying annual, quarterly or monthly products (see figure below).

- Retailers often look to create ladders, e.g. 12 to 24 months ahead of physical delivery, buying fixed-volume derivatives contracts over a specified timeframe to meet expected demand (see schematic illustration below). As there is more certainty in demand closer to real-time, retailers look to fine-tune their positions by buying and selling electricity volumes on derivatives (e.g., years or months before physical delivery) and spot markets (e.g., day-ahead or intraday) subject to the expected change in demand. They further include an allowance for the resulting price risk from spot market trading activity (buying outstanding or selling excessive volumes) in the retail margin.[43]



43 Risk capital is further held by retailers to cover any other risks, such as remaining volume risk, which cannot be efficiently managed through hedging.

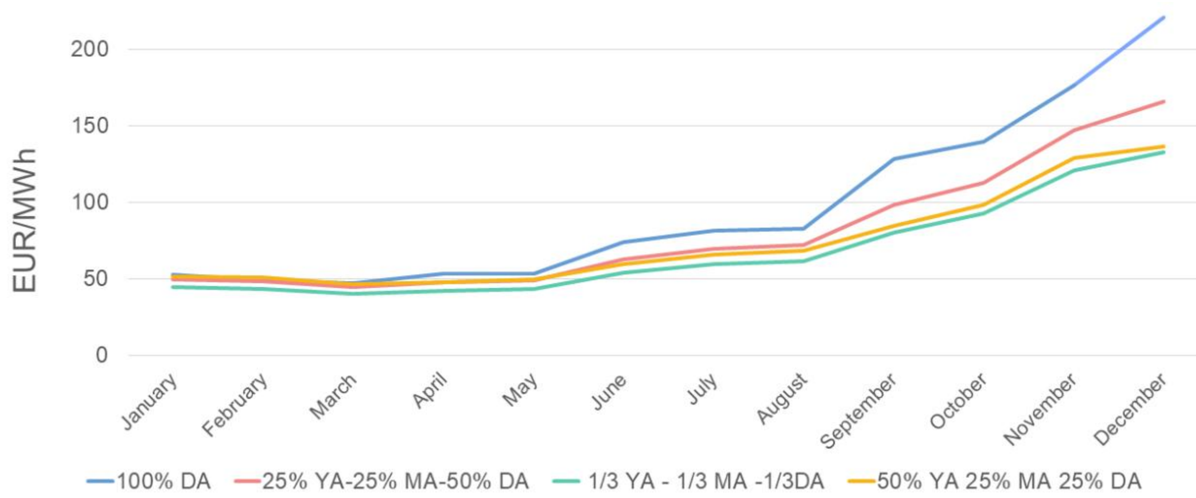


Source: *Frontier Economics*

Note: *Schematic illustration; 24 months purchase ladder ahead of physical delivery; simplified assumption that annual products are traded 24 months, quarterly products 12 months and monthly products 6 months ahead of physical delivery, 100% coverage of expected portfolio size assumed via derivatives market ahead of physical delivery*

In its 2022 assessment of the electricity market design, ACER compared retailer procurement options in Germany in 2021 (Figure 11) - from buying entirely day-ahead to blending in month- and year-ahead contracts. ACER's analysis illustrates how hedging, especially with longer tenors, materially smoothed and delayed the impact of the late 2021 price surge. Without hedging a retailer would have been more directly impacted by rising spot prices (as indicated by the blue curve reflecting 100% procurement based on day-ahead (DA) prices).

Figure 11 Unit procurement costs (EUR/MWh) of a supplier using diverse hedging strategies in the German electricity market in 2021



Source: *Figure 23 of ACER's Final Assessment of the EU Wholesale Electricity Market Design, April 2022*

Customers are not always directly exposed to spot price volatility, though spot price volatility can still affect retail prices

Despite comprehensive risk management strategies such as the aforementioned hedging ladder or back-to-back hedging, a ‘perfect’ hedge is rarely achievable for retailers through exclusively trading on derivatives markets, given that liquidity will tend to pool in standardised products.[44]

As such, even where retailers hedge customer volumes to a large extent, spot prices still directly or indirectly influence the price faced by final customers to some degree. For simplicity, the two extreme cases are considered below, acknowledging that in practice, contract agreements can reflect a mix of both approaches:

- **Low or no pass-on:** When customers do not bear price and/or volume risks, retailers are exposed to spot market volatility. For example, if customers consume more than expected, retailers must purchase additional volumes at potentially higher spot market prices. Retailers typically hold risk capital to cover for this risk, the magnitude of which will depend on the volatility in volumes and prices and the correlation between the two. In a competitive retail market, the efficient cost of holding this risk capital will be reflected in retail prices. This situation best describes pricing to household customers.

- **High or full pass-through:** When retailers can pass wholesale costs from deviations between actual and forecasted demand onto end-customers close to physical delivery, the customers bear the risk of spot market price fluctuations. This model is more common in back-to-back hedging arrangements that include clauses addressing over- or underconsumption, e.g. for large industrial customers. That said, innovative retail offerings for smaller customers are emerging across Europe that (at least partially – for example at times of negative or low prices) expose customers to short-term markets.

To conclude, therefore, volatility in wholesale spot prices does not automatically translate one-for-one into retail price volatility. This is partly since (as discussed in section 3.1) retail prices are a blend of wholesale costs, network costs and policy costs. It is also since (as discussed in this sub-section), the market supports the ability for customers to choose, depending on their risk appetite, their desired level of exposure to shorter-term prices.

[44] This tendency also partly explains the high levels of trading observed in German power products (see Figure 7), compared to levels observed in other European power markets.

4 Evidence regarding the drivers of wholesale price formation in Europe

In this section, building on Section 3.2's conceptual discussion of the drivers of spot power prices and their volatility, we explore how recent developments have manifested in actual market outcomes (sections 4.1 and 4.2), with a focus on the day-ahead market (since it tends to be more in focus in discussions on spot market developments). We also present results from our empirical analysis of volatility dynamics using hourly price, supply and demand data for the period of October 2018 to December 2024 (section 4.3). We finish (section 4.4) by drawing out some policy implications (which we go on to discuss in the next section).

4.1 Developments in price levels

4.1.1 Across Europe, average day-ahead price levels have stabilised since the energy crisis – though trends across bidding zones have not been uniform

In Section 3.3, we explained the historical evolution of electricity wholesale prices through a time series of day-ahead prices in the Germany-Luxembourg bidding zone over 2021-25. We expand on this below.

Figure 12 below presents average spot price levels by calendar year and by bidding zone. It illustrates that, while most bidding zones exhibit similar and synchronised price trends, notable regional differences have emerged in recent years.

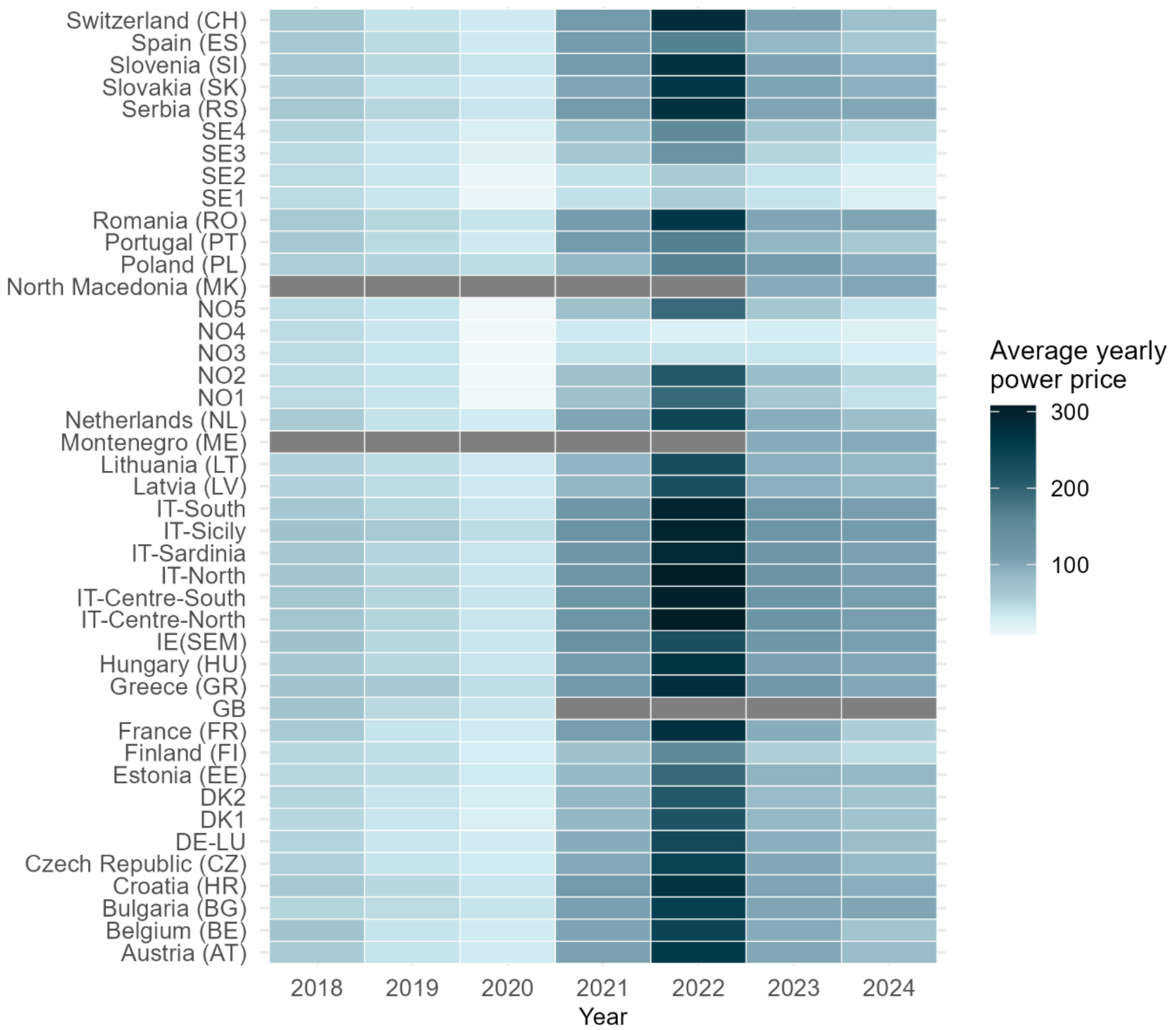
- Day-ahead electricity spot prices remained relatively low and stable from 2018 to 2020, fluctuating mostly between 0 and 60 EUR/MWh in all bidding zones[45].
- In 2020, the economic slowdown during the COVID-19 pandemic, and associated reduced electricity demand and lower gas prices, led to record-low power prices.
- This trend reversed sharply from mid-2021, with electricity prices rising rapidly in mid-2021 and with average prices reaching record highs in late 2022 and early 2023, especially following Russia's invasion of Ukraine.[46] During the European energy crisis, countries such as Italy, Switzerland, Greece, and France experienced some of the highest price levels. In contrast, bidding zones in Norway, Sweden, and Finland generally saw relatively lower price levels.

45 In 86% of all hourly observations across bidding zones between 2018 and 2020, the spot price ranged between 0 and 60 EUR/MWh.

46 Gasparella A., Koolen D., Zucker A. (2023). The Merit Order and Price-Setting Dynamics in European Electricity Markets, European Commission.

- Since then, average spot prices have declined steadily, but they remain above pre-2021 levels across much of the continent.[47] Differences across bidding zones also appeared in the pace of price stabilisation after the crisis. Prices in the Nordic region were generally quicker to return to near-pre-crisis levels. Meanwhile, countries such as Italy, Greece, the Balkan region and Ireland have seen a slower decline in prices and remain well above pre-crisis levels in 2024.

Figure 12 Yearly average of DA spot price levels by Bidding Zone (EUR/MWh)



Source: *Frontier Economics, based on ENTSO-E day-ahead power price data.*

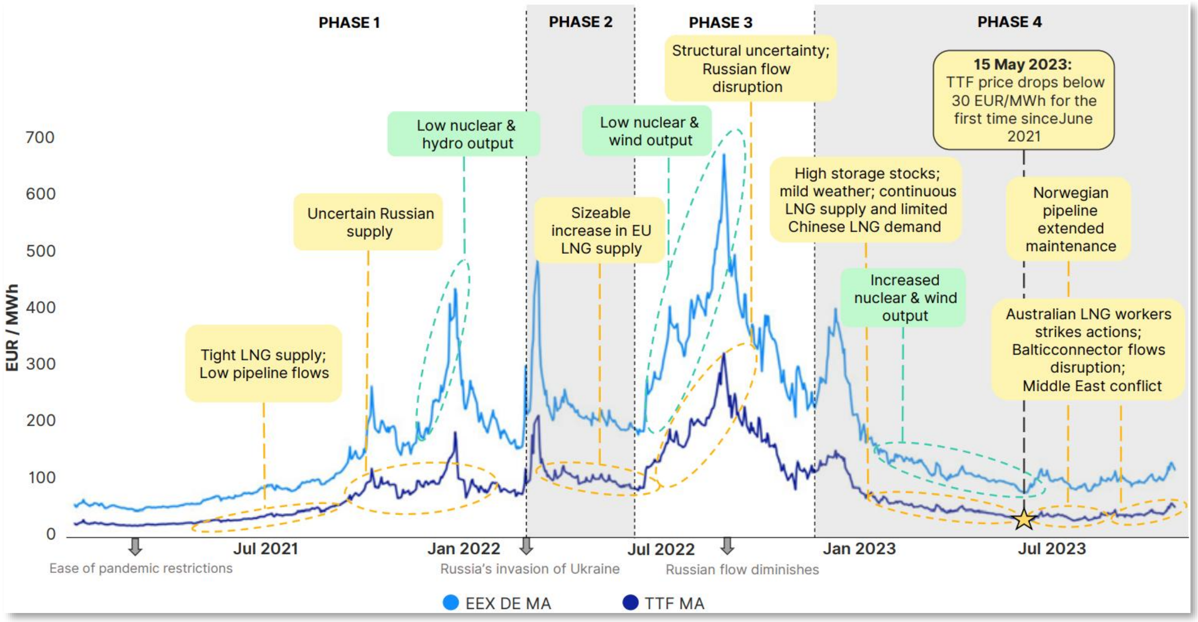
Note: *Yearly average (mean) hourly day-ahead spot prices (EUR/MWh), calculated separately for each bidding zone. Grey colour indicates missing data on the ENTSO-E transparency platform. The figure presents all available bidding zones for transparency. However, some adjustments have been made given the redefining of Italian bidding zones during the period, and not all zones are included in the econometric analysis. Please refer to Annex B for details on data quality and excluded zones.*

47 ACER (2025), Key developments in European electricity and gas markets.

4.1.2 Fluctuations in gas prices and weather patterns have been the driving forces behind these dynamics, though other factors are also important

The evolution of electricity prices across Europe has closely tracked natural gas market developments (Figure 13).

Figure 13 Average monthly DE-LU prices and TTF gas price



Source: ACER (2023), "European gas market trends and price drivers – 2023 Market Monitoring Report", Fig. 1

Note: The Dutch Title Transfer Facility gas hub (TTF) and the German European Energy Exchange (EEX) month-ahead (MA) contract prices are used as benchmarks for gas and power pricing, respectively.

This close relationship is mainly explained by the structure of the electricity market in Europe, in which the market-clearing price is determined largely by the marginal cost of the most expensive resource required to meet demand, typically fossil fuel generation (as discussed in Section 3.2). The price of natural gas therefore has an important role in price developments in the electricity market.

However, the extent to which gas prices influence electricity prices varies considerably:

- **Across bidding zones:** The divergence in power mix within each bidding zone and interconnection capacity between zones helps explain some of the regional disparities in price increases connected to dramatic increases in gas prices. This is reflected in 2022 electricity price levels, which varied widely across bidding zones. As noted by Gasparella et al. (2023)[48], bidding zones with greater reliance on gas-fired generation, such as Italian

[48] Gasparella A., Koolen D., Zucker A. (2023). The Merit Order and Price-Setting Dynamics in European Electricity Markets, European Commission.

zones, experienced higher prices, while zones with more diversified or lower-cost generation mixes, such as those in Sweden, saw lower prices; and

- **Over time:** Figure 13 also illustrates that other factors, such as the availability of nuclear, hydro and wind generation, affect the relationship between gas prices and power prices (by influencing the frequency at which gas-fired generation sets power prices).

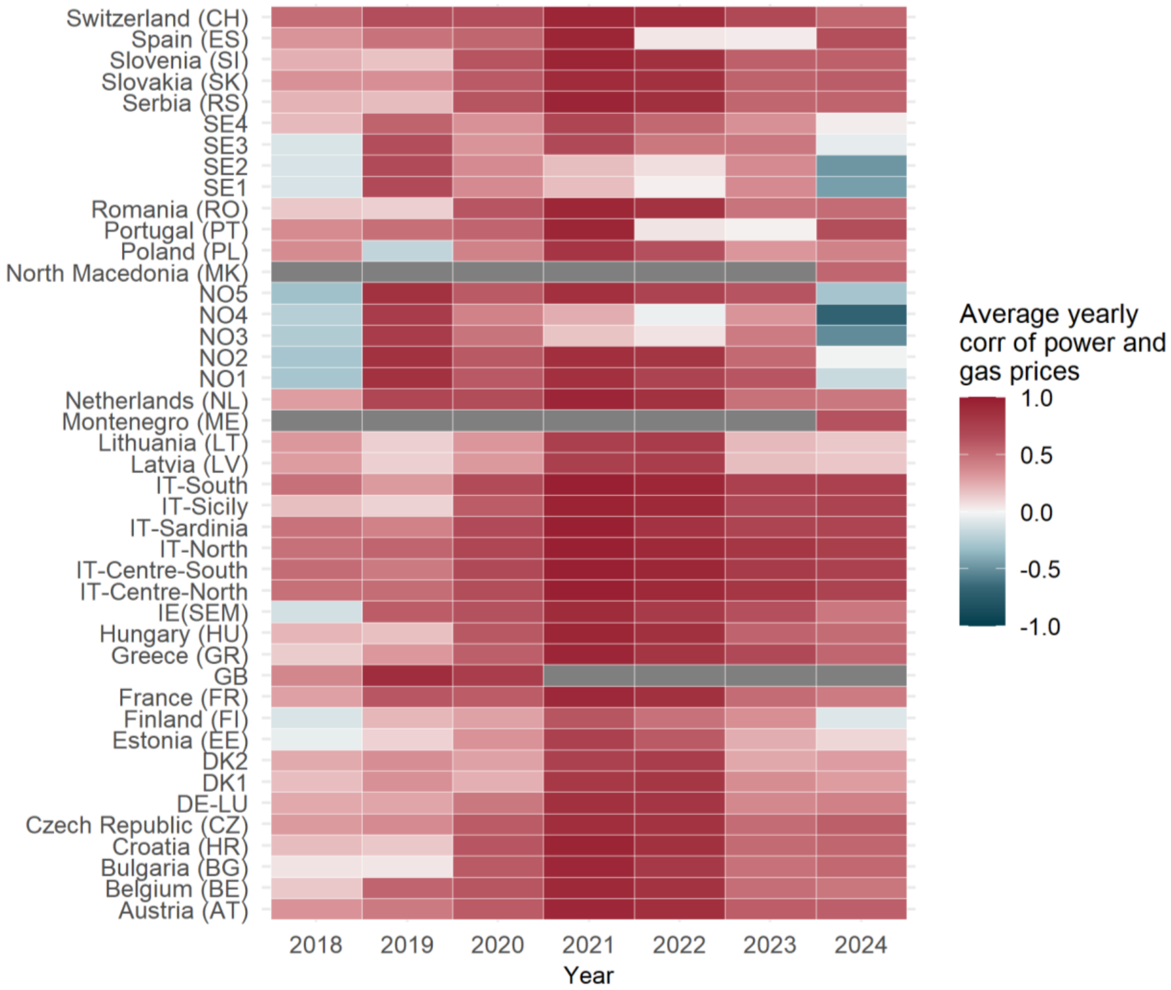
Figure 14 shows the correlation, for each year, between day-ahead gas prices and (daily average) day-ahead power prices in each bidding zone. Figure 14 does not show a causal relationship, and some of the apparent relationship may therefore be “spurious”. However, it is interesting to note that:

- Gas prices and power prices are generally positively correlated. Notable exceptions are:
  - most of the Nordic bidding zones with negative coefficients in some years, reflecting their predominantly hydro, wind and nuclear generation, with very limited fossil thermal output, and power prices therefore largely driven by other factors including non-fossil based output, demand fluctuations and fluctuating availability in cross-zonal capacity between the 12 Nordic bidding zones and towards continental bidding zones;
  - Spain and Portugal over 2022-23: both countries implemented measures[49] that effectively (temporarily) capped the costs of gas-fired power generation (the so-called “Iberian exception”) and, in turn, power prices, which implied a regulation of price volatility (and a decoupling of power prices from European gas prices);
- Correlations between power and gas prices increased over 2021-22 (compared to the earlier period) across most markets[50], including in markets without (significant) local gas-fired generation. Potential explanations could include:
  - reduced availability of wind, hydro and nuclear plants (during 2022), which would have led (other things equal) to more frequent periods in which gas-fired plants set wholesale prices; and
  - the impact of cross-border trade on power price convergence across bidding zones.

49 https://ec.europa.eu/commission/presscorner/detail/it/ip_22_3550

50 Though not in some Norwegian and Swedish bidding zones.

Figure 14 Correlation between daily gas (TTF) and power prices, by calendar year / bidding zone



Source: *Frontier Economics, based on ENTSO-E day-ahead power prices and Bloomberg's Title Transfer Facility (TTF) gas price data.*

Note: *Correlation between daily gas prices and daily average (mean) day-ahead electricity prices, by calendar year and bidding zone. The gas price relates to the delivery at the TTF hub in the Netherlands. As such, the analysis abstracts from regional variations within Europe in wholesale gas prices. However, such variations are generally small compared to movements in overall gas prices. Grey colour indicates missing data on the ENTSO-E transparency platform. The figure presents all available bidding zones for transparency. However, some adjustments have been made given the redefining of Italian bidding zones during the period, and not all zones are included in the econometric analysis. Please refer to Annex B for details on data quality and excluded zones.*

4.2 Developments in price volatility

4.2.1 There are many dimensions to price "volatility"

Before we go on to discuss trends in volatility, it is helpful to first explain the different ways in which observed variation in price-time-series can be characterised.

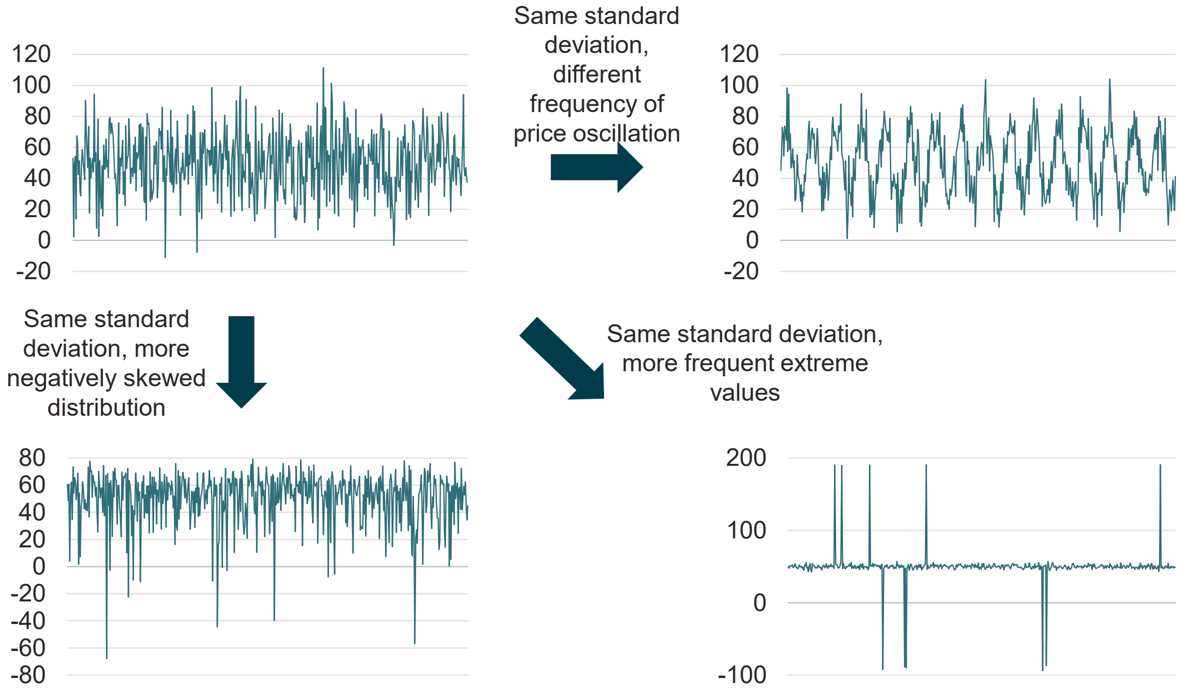
Price volatility is often described by the statistical metric of standard deviation[51], which quantitatively describes the average spread of prices around the mean. While this is a metric we also use, we note that standard deviation alone may obscure important characteristics of the time series.

Figure 15 below illustrates four distinct but equally volatile (in terms of standard deviation) price time series, each also with the same mean (i.e. average) price, but nevertheless exhibiting different properties:

- **Frequency Oscillations:** Two time series may exhibit the same statistical distribution of prices (when ordering prices by levels and ignoring the time sequence in which these prices occur) but exhibit a different frequency of price movements and/or duration of higher/lower price events.
- **Skewness:** Skewness measures the degree of asymmetry in a distribution around its mean. In the illustration below, compared to the series in the top left graph, the distribution in the bottom left graph is biased toward lower (including more frequent negative) prices with occasional steep drops.
- **Kurtosis**: Kurtosis measures the heaviness of the tails of a statistical distribution relative to a normal distribution – in other words, the potential for low probability, high impact events. In the illustration below, compared to the series in the top left graph, the distribution in the bottom right graph exhibits a greater frequency of extreme high prices, with prices otherwise exhibiting lower levels of variation around the mean.

51 Standard deviation is calculated as the square root of the variance, which in turn is equal to the mean of the squared difference between each value in a dataset and the mean (average) of that dataset. It measures the magnitude by which values deviate from their average over a defined period. A low standard deviation indicates that the values tend to be close to the mean of the sample, while a high standard deviation indicates that the values are spread out over a wider range.

Figure 15 Different characteristics of electricity price time series (with identical mean and standard deviation; illustrative)



Source: Frontier Economics
Note: Figures are purely illustrative.

Each of the properties may vary depending on the measurement period. For example, does the analysis consider variation in hourly prices or variation in average price levels (e.g., daily prices)? And over what time window is this variation measured? There is no single correct approach – it will depend on the question of interest. We recommend taking these different dimensions of volatility into account when discussing a concrete case or example.

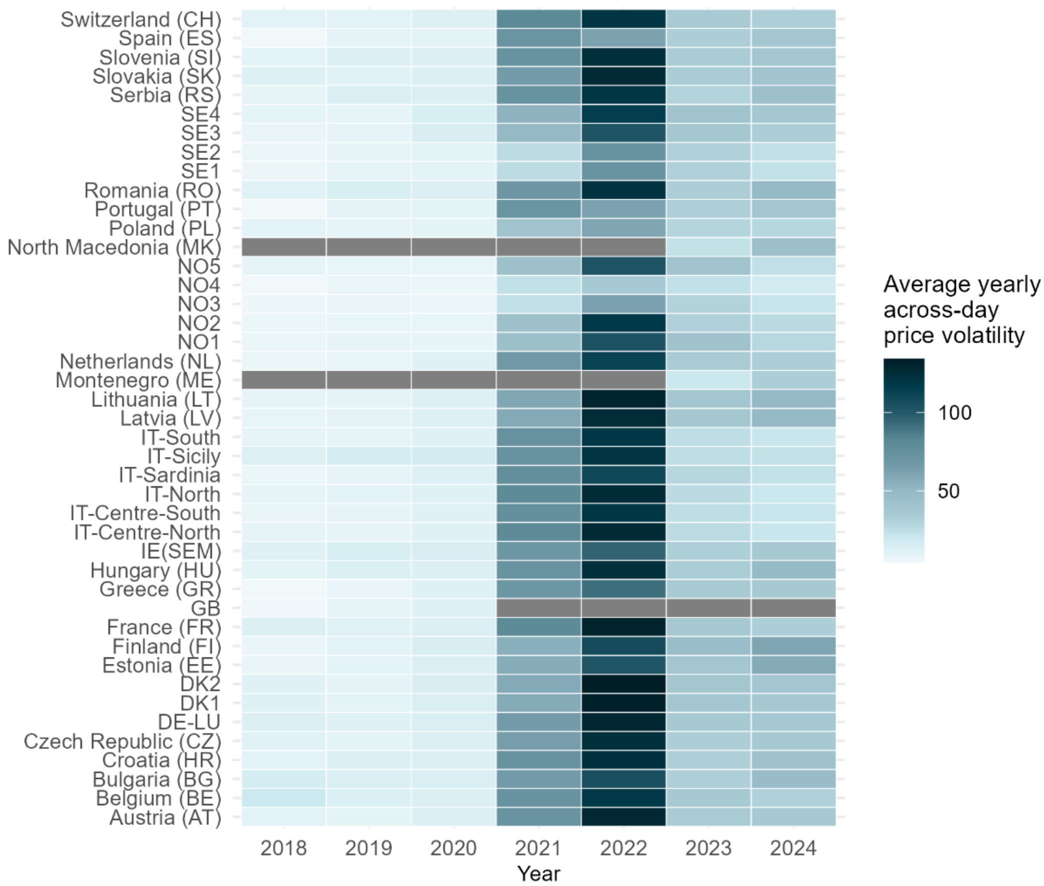
As explained in Section 3.4, while electricity (end) customers will generally be more exposed to changes in longer-term average price levels than they will be to shorter-term movements in spot prices, variation in shorter-term prices may still be relevant (for example, greater variation may affect the risk capital that energy retailers need to hold). In what follows, we mainly discuss variation in (daily average) prices **across days** and **within-day** (hourly) variation in prices. We also briefly comment on the frequency of **price spikes** and increasing instances of **negative wholesale power prices**.

4.2.2 Day-to-day price volatility was higher in 2024 in most bidding zones, compared to before the crisis

Figure 16 shows the standard deviation in the average daily price across each calendar year, by bidding zone. It shows a marked increase in day-to-day price volatility across all bidding zones starting in early 2021 and peaking through 2022. Throughout 2023 and 2024, volatility of daily prices remained significantly above pre-crisis levels.

Looking across regions, during the crisis, some of the Nordic bidding zones exhibited less volatility in daily average prices compared to other European bidding zones. We would expect this to be the case, given material capacity of power storage, in the form of hydropower reservoirs in the Nordics, allowing for a higher potential for inter-temporal price arbitrage, which results in dampened volatility across time.[52] Spain and Portugal are also noticeable for having lower price volatility during the crisis (potentially in part due to power price interventions as noted above). In 2024, some of the Norwegian and Swedish bidding zones remain among those with the lowest volatility, while markets that have seen greatest day-to-day volatility include bidding zones in Finland, the Baltics, Bulgaria and Romania.

Figure 16 Standard deviation of daily average power prices, by calendar year / bidding zone (EUR/MWh)



52 With the corollary that reduced hydropower availability in these markets can be associated with higher price volatility.

Source: Frontier Economics, based on ENTSO-E day-ahead power price data.

Note: Standard deviation of average daily electricity prices (EUR/MWh), calculated separately for each year and bidding zone. Hourly spot prices were first averaged at the day level, and the standard deviation of these daily averages was then calculated for each calendar year. Grey colour indicates missing data on the ENTSO-E transparency platform. The figure presents all available bidding zones for transparency However, some adjustments have been made given the redefining of Italian bidding zones during the period, and not all zones are included in the econometric analysis. Please refer to Annex B for details on data quality and excluded zones.

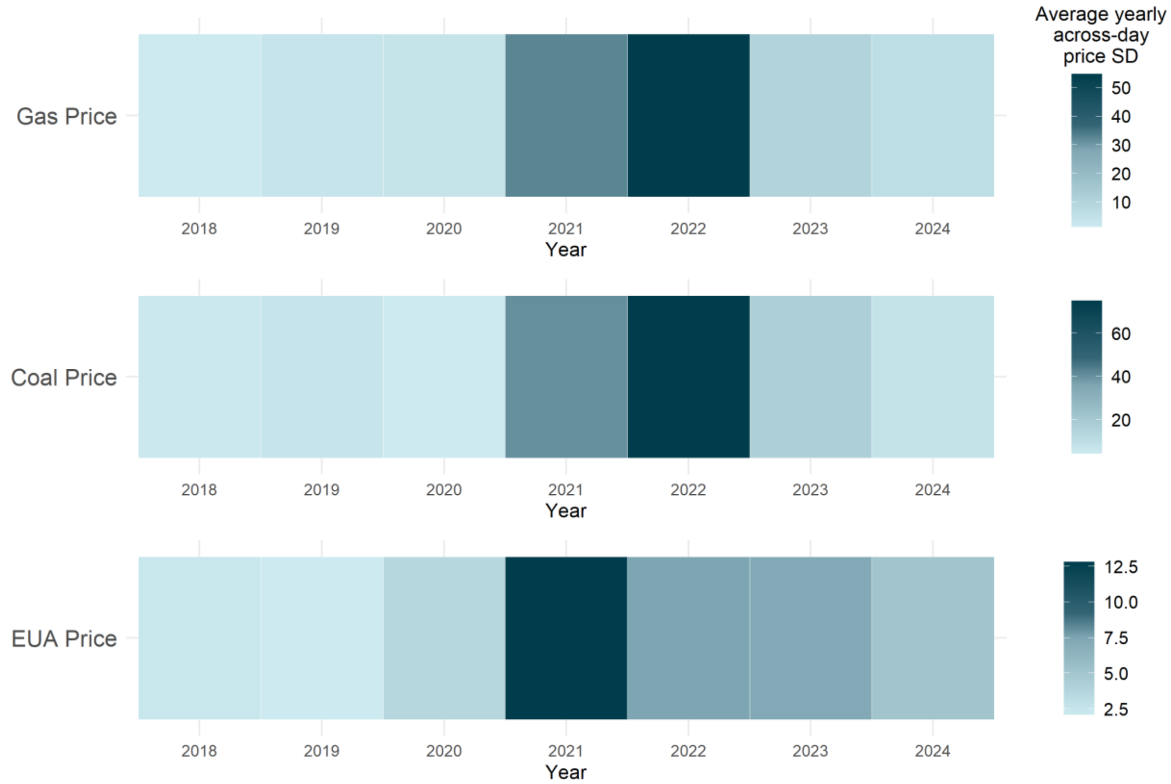
The patterns in power price volatility above are likely to be linked to volatility in commodity prices. As discussed above (see Figure 14), gas and power prices are highly correlated across all bidding zones.

Figure 17 below shows that gas, coal and EUA price volatility all experienced marked variation between 2018 and 2024. Volatility was especially high for gas and coal during the energy crisis in 2021 and 2022, while EUA price volatility also increased in 2021, but to a comparatively more moderate extent, and has shown signs of stabilising since then. While not the focus of this paper, volatility in commodity prices have varying causes and effects. The elevated volatility in gas prices during 2021 and 2022 was largely due to supply shocks.[53] Gas market developments will also have in part affected coal and EUA prices (and volatility) given the possibility (at least in some markets) to substitute gas-fired generation with coal-fired generation.

The timing and scale of these commodity price patterns broadly align with increases in electricity price volatility across EU bidding zones, suggesting a strong link between commodity price instability and power market volatility. However, as is clear from Figure 16, not all bidding zones saw identical increases in power price volatility, suggesting that the extent to which these commodity prices interact with electricity prices may vary between bidding zones and other factors will have been at play in the different bidding zones.

53 While we do not analyse the drivers of gas prices as such in this report, we note that, in addition to some of the fundamental drivers noted in ACER's analysis presented in Figure 13, gas prices (and their volatility) are likely to have been influenced, at least in part, by policy, including gas storage obligations in response to tighter supply in the market, and some unusual storage filling patterns at the outset of the crisis. See https://www.frontier-economics.com/media/awbofa1p/frontier-ockenfels-papier-zu-gasspeicherbefuellung-im-jahr-2025-2025-02-26-stc.pdf (in German)

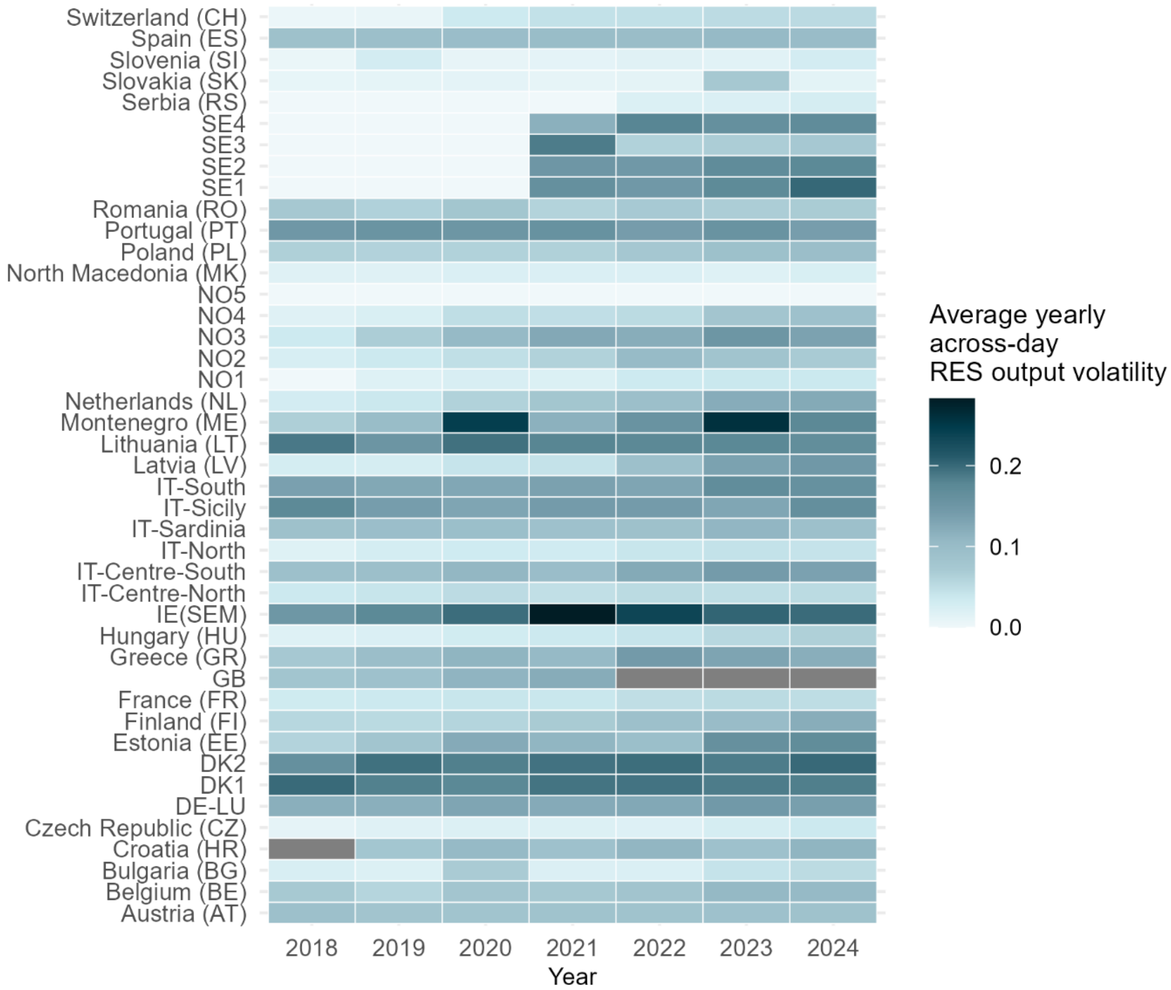
Figure 17 Coefficient of variation of daily average commodity prices, EU-wide by calendar year



Source: Frontier Economics, based on Bloomberg's commodity price data.
Note: Units: gas price: EUR / MWh_th; coal price: USD / tonne; EUA price: EUR / tCO2e.

A key question often discussed is the extent to which the growth in (variable) renewable energy sources (RES; such as wind and solar) has affected price volatility. Figure 18 below shows the standard deviation in the average daily share of (combined) wind and solar output in the generation mix for each calendar year, by bidding zone. In many markets, there has been an increase in the standard deviation of RES output over time, consistent with increasing RES deployment.

Figure 18 Standard deviation of daily average generation share of variable RES, by calendar year / bidding zone



Source: Frontier Economics, based on ENTSO-E generation data.

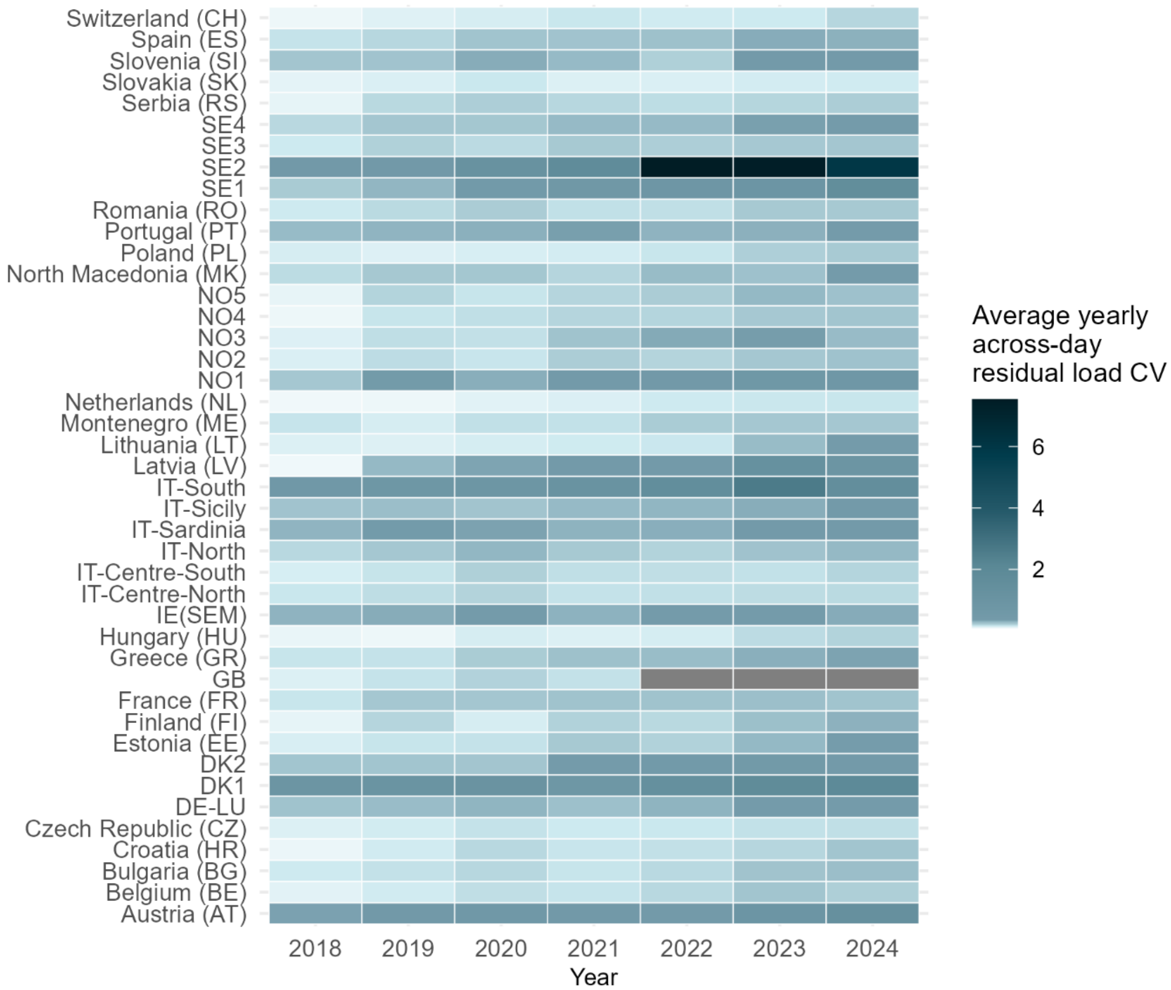
Note: Standard deviation of daily average generation shares from solar, onshore wind, and offshore wind, calculated separately for each bidding zone and calendar year. Hourly RES generation shares were first averaged at the day level, and the standard deviation of these daily averages was then calculated for each calendar year. Grey colour indicates missing data on the ENTSO-E transparency platform. The figure presents all available bidding zones for transparency. However, some adjustments have been made given the redefining of Italian bidding zones during the period, and not all zones are included in the econometric analysis. Please refer to Annex B for details on data quality, excluded zones, and the treatment of Italian bidding zones.

To check the extent to which increasing RES output volatility might be offset by changes in demand, we can consider residual demand (in our case, demand less output from wind, solar and other RES technologies considered "non-dispatchable"[54]).

[54] Including run-of-river hydro.

Figure 19 shows the coefficient of variation[55] in the average daily residual demand, for each calendar year, by bidding zone. Similarly to the pattern in Figure 18, it shows that, across many European bidding zones, volatility in residual demand has increased over time.

Figure 19 Coefficient of variation of daily average residual demand, by calendar year / bidding zone



Source: *Frontier Economics, based on ENTSO-E load and generation data.*

Note: *Residual demand is defined as demand less output from solar, onshore wind, offshore wind and other non-dispatchable RES output. The coefficient of variation for residual demand was calculated as the standard deviation of daily residual demand within each year divided by the corresponding absolute value of the annual mean value. This normalisation allows meaningful comparison of relative volatility across markets of different sizes. Grey colour indicates missing data on the ENTSO-E transparency platform. The figure presents all available bidding zones for transparency. However, some adjustments have been made given the redefining of Italian bidding zones during the period, and not all zones are included in the econometric analysis. Please refer to Annex B for details on data quality, excluded zones, and the treatment of Italian bidding zones.*

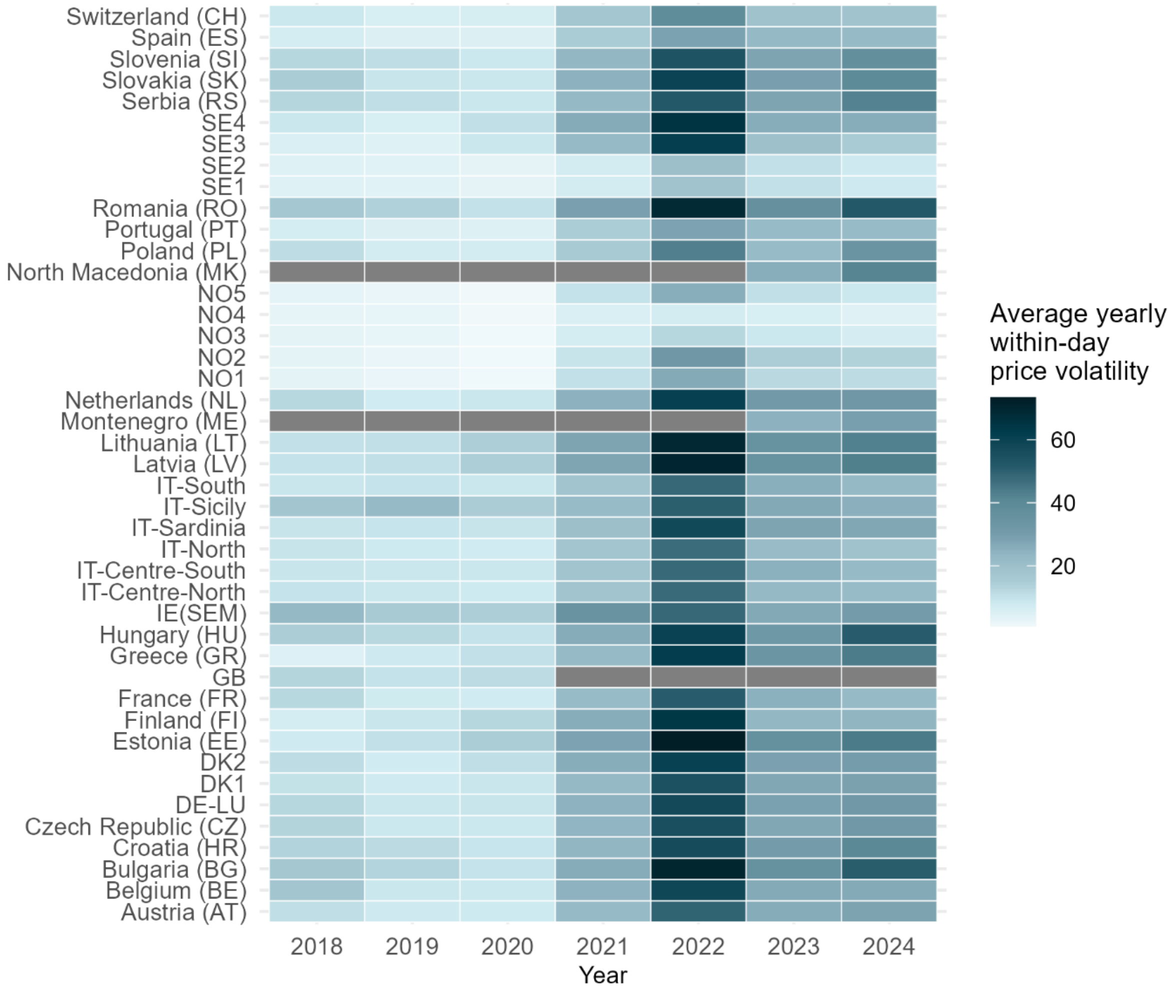
55 The standard deviation normalised by (i.e. divided by) average (i.e. mean) demand.

4.2.3 Within-day price variation has also increased over time

We now examine within-day price variation (i.e. the variation of hourly day-ahead prices). Figure 20 shows the average (across days) in the standard deviation of within-day (hourly) power prices[56], by calendar year and bidding zone. In general, across bidding zones, within-day price volatility has increased over time, with a noticeable peak during the energy crisis. In 2024, within-day price volatility is lowest in certain Norwegian and Swedish bidding zones (again, to be expected given material hydropower capacity), while it was highest in South-Eastern European and Baltic zones.

[56] Day-ahead prices.

Figure 20 Average standard deviation of within-day (hourly) power prices, by calendar year / bidding zone (EUR/MWh)



Source: Frontier Economics, based on ENTSO-E day-ahead power price data.

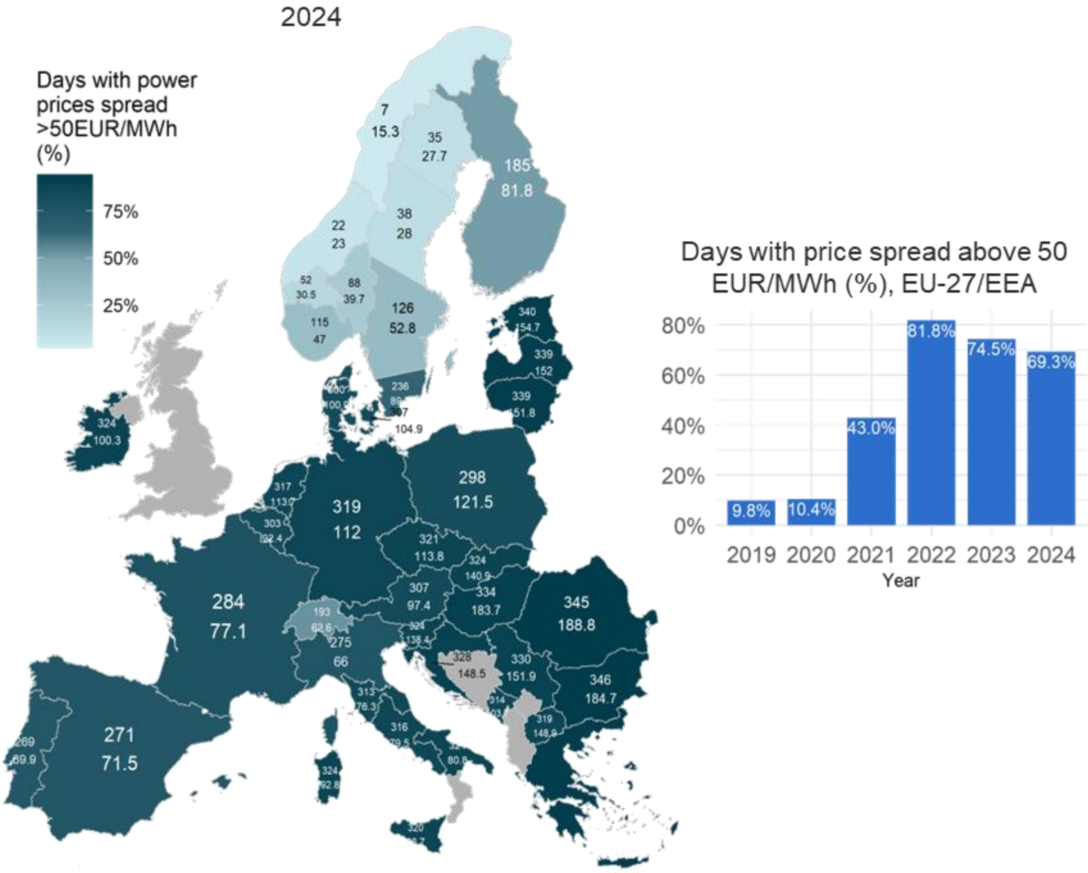
Note: Average standard deviation of hourly day-ahead electricity prices, calculated separately for each calendar year and bidding zone. The standard deviation of hourly day-ahead prices was first calculated for each day, and the average (mean) of these standard deviations was then calculated for each calendar year. Grey colour indicates missing data on the ENTSO-E transparency platform. The figure presents all available bidding zones for transparency. However, some adjustments have been made given the redefining of Italian bidding zones during the period, and not all zones are included in the econometric analysis. Please refer to Annex B for details on data quality and excluded zones.

Similarly, in 2024, daily price ranges exceeding €50/MWh occurred on average on around 70% of days in the EU-27/EEA (Figure 21 below). Such spreads were observed on only about 10% of days in 2019 and 2020.[57] Figure 21 shows a similar regional pattern of within-day variation to that shown in Figure 20.

[57] ACER (2025), Key developments in European electricity and gas markets.

Figure 21 Frequency of within-day price spreads greater than EUR 50/MWh and extent of price spreads

The map on the left shows, for each bidding zone, the number of days with daily electricity prices spread (max-min of hourly prices) above 50 EUR/MWh (upper figure) and the average daily spread in 2024 (lower figure). The graph on the right shows the annual percentage of days where the price spread was above 50 EUR/MWh in the EU-27/EEA (Norway) area from 2019 to 2024.



Source: Frontier Economics based on ENTSO-E day-ahead power price data, based on ACER (2025), Key developments in European electricity and gas markets.

Note: The figure presents all available bidding zones for transparency. However, not all zones are included in the econometric analysis. Please refer to Annex B for details on data quality and excluded zones.

Increasing within-day volatility is likely to reflect both:

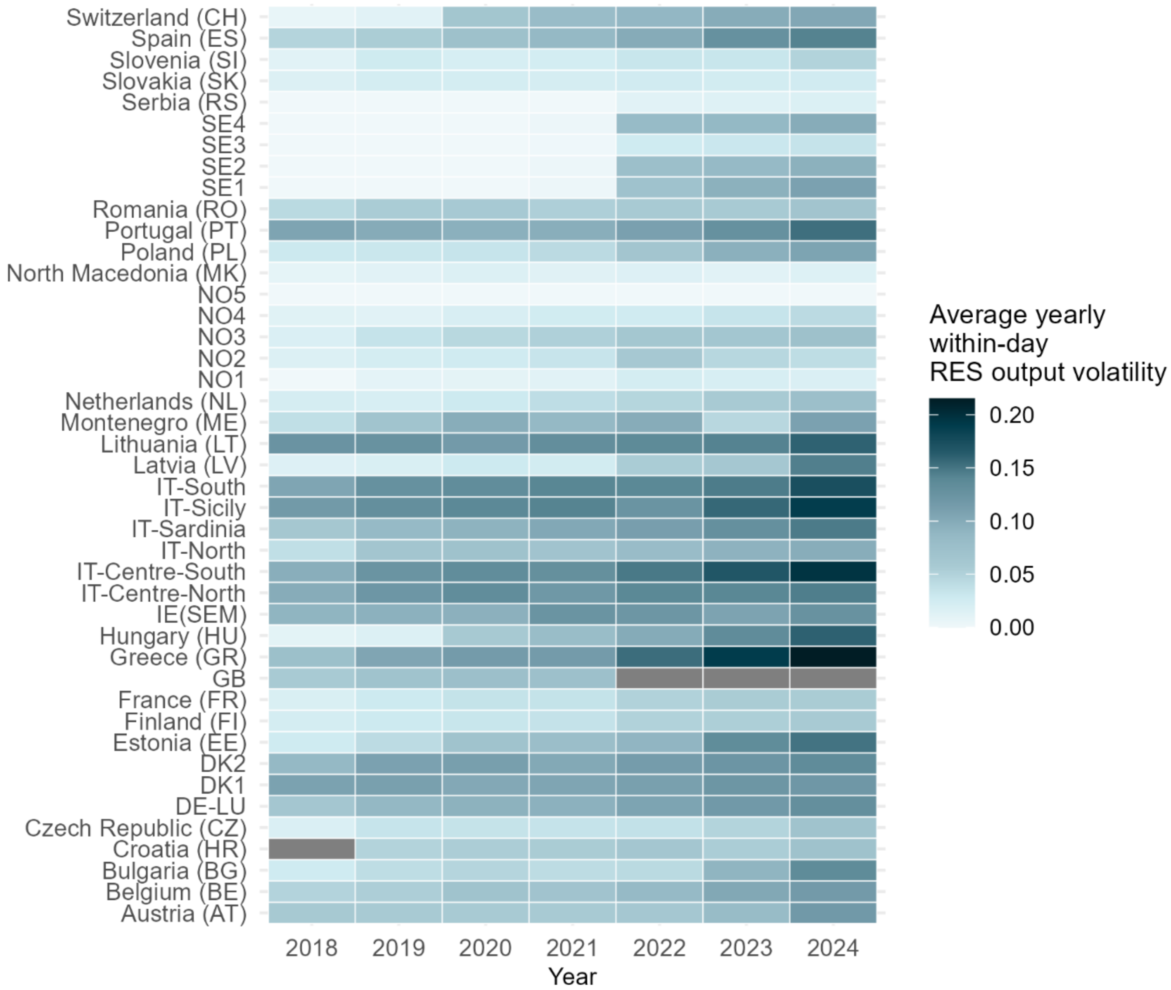
- variations across the course of a day in the extent to which higher marginal cost resources (such as fossil fuel plants) set the price, driven by hourly variations in demand and in output from lower marginal cost resources such as intermittent renewables; and

- changes in relative commodity prices (and in the available mix of capacity) that may affect the "steepness" of the steps in the merit order.[58]

The first of these may have a link with growing RES deployment. Figure 22 shows the average (across days) in the within-day standard deviation of hourly RES generation shares (total for wind and solar). It shows that most bidding zones have seen an increase in average within-day volatility of RES output shares, consistent with increased levels of RES deployment. The markets with the highest (average) volatility in within-day RES output include some of the markets in which we observe the highest within-day electricity price volatility in 2024 (such as Greece and Lithuania) but also include many markets with markedly lower within-day price volatility.

58 The difference between short-run marginal costs of coal- and gas-fired generation before and after the energy crisis has generally between no more than about EUR 10-15/MWh. However, during the crisis, the gap was as large as EUR 400/MWh on certain days. See European electricity prices and costs | Ember

Figure 22 Average standard deviation of within-day RES generation shares, by calendar year / bidding zone

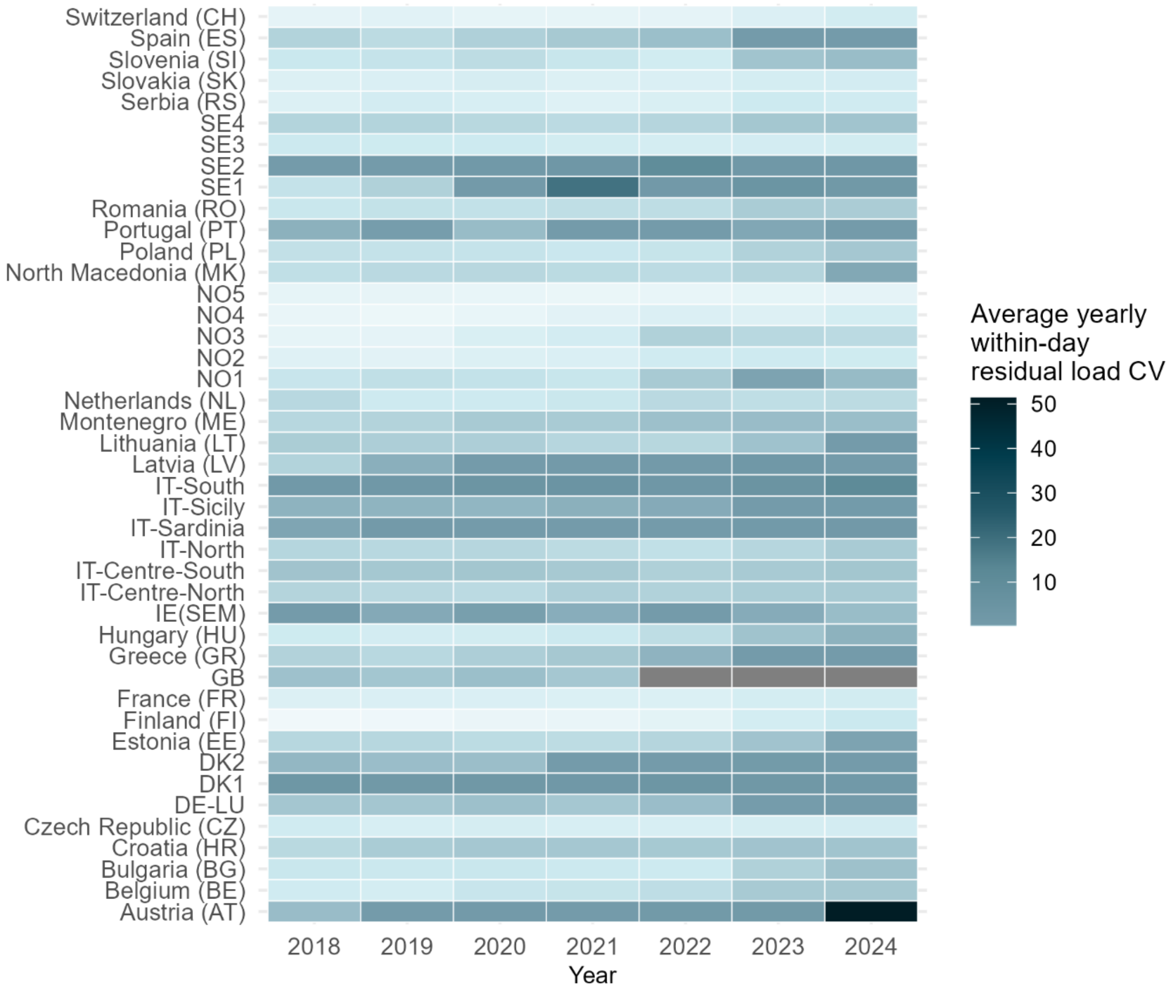


Source: *Frontier Economics, based on ENTSO-E generation data.*

Note: *Average standard deviation of the hourly generation share of wind and solar output in total generation, calculated separately for each calendar year and bidding zone. The standard deviation of hourly generation shares was first calculated for each day, and the average (mean) of these standard deviations was then calculated for each calendar year. Grey colour indicates missing data on the ENTSO-E transparency platform. The figure presents all available bidding zones for transparency. However, some adjustments have been made given the redefining of Italian bidding zones during the period, and not all zones are included in the econometric analysis. Please refer to Annex B for details on data quality, excluded zones, and the treatment of Italian bidding zones.*

Figure 23 shows that growing within-day RES output variation has also translated into growing within-day residual demand variation.

Figure 23 Average coefficient of variation of within-day residual demand, by calendar year / bidding zone



Source: Frontier Economics, based on ENTSO-E load and generation data.

Note: Residual demand is defined as demand less output from solar, onshore wind, offshore wind and other non-dispatchable RES output. The coefficient of variation for residual demand was calculated as the standard deviation of hourly residual demand within each day, divided by the corresponding absolute value of the daily average (mean) value. The average (mean) of these daily coefficients of variation was then taken for each calendar year. This normalisation allows meaningful comparison of relative volatility across markets of different sizes. Grey colour indicates missing data on the ENTSO-E transparency platform. The figure presents all available bidding zones for transparency. However, some adjustments have been made given the redefining of Italian bidding zones during the period, and not all zones are included in the econometric analysis. Please refer to Annex B for details on data quality, excluded zones, and the treatment of Italian bidding zones.

Differences in the in the responsiveness of price volatility to RES volatility will likely relate to differences in the responsiveness of demand or other sources of supply to changes in the (short-term) price (i.e. price “elasticity” of demand and supply). Potential differences in elasticity may be driven by:

- Relative commodity prices that affect the “steepness” of steps in the merit order (as explained above);
- Technical characteristics of individual generators (such as start-up periods and ramp rates);

- The amount of energy storage capacity providing inter-temporal price arbitrage;
- Incentives via market design and/or support schemes that reduce producers' exposure to short-term price signals;
- Incentives or technical ability for consumers to respond to shorter-term price signals.

4.2.4 Increased frequency of price "spikes" and negative prices

As discussed earlier in this sub-section, there are many ways of characterising "extreme" values. One approach can be to define a specific price threshold and then examine either the number of times the threshold is crossed and/or the duration of such events (though the results will be sensitive to the specific threshold or metric used).

Evidence of price spikes – highest during the energy crisis in 2022

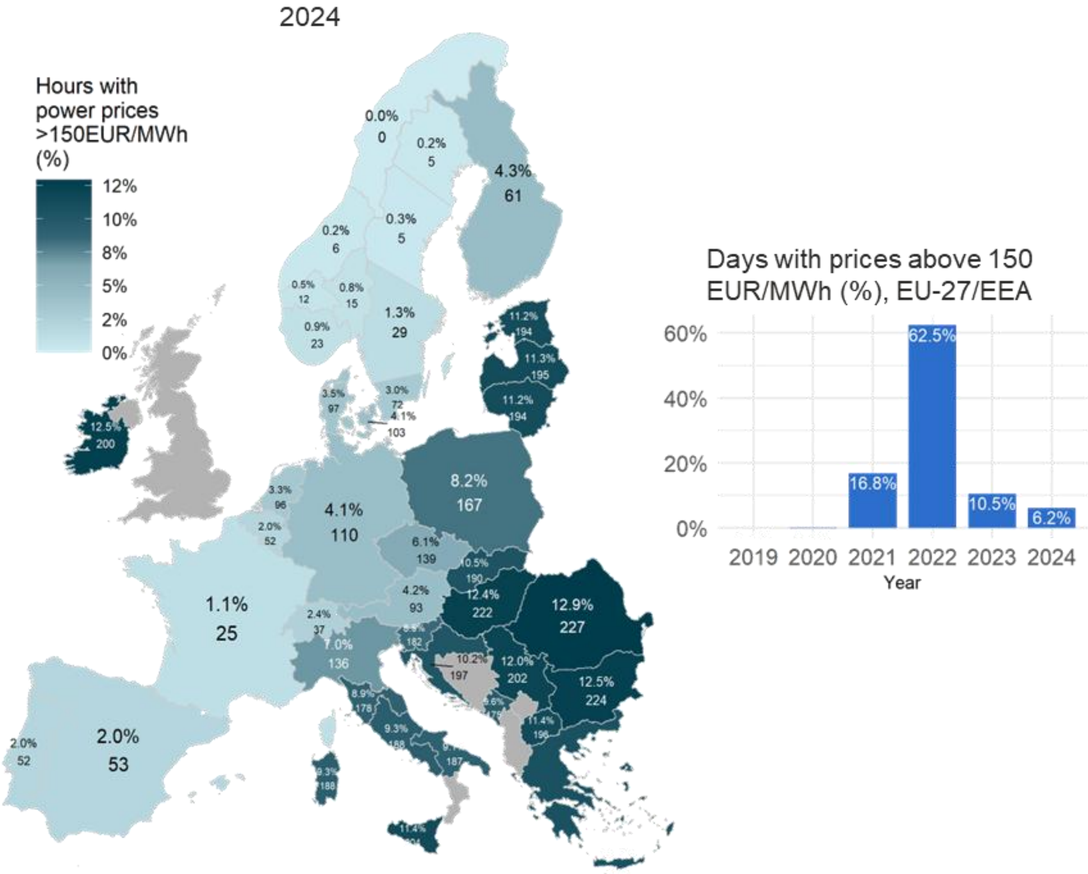
Figure 24 shows the share of hours and number of days each year in which prices were above EUR 150/MWh. The analysis broadly mirrors the trends above in average price levels and volatility.

- **Over time:** In 2024, the share of hours in which prices exceeded EUR 150/MWh is lower than during the energy crisis, but greater than over 2019-2020;

- **Across bidding zones:** During 2024, bidding zones in Iberia, Sweden and Norway have among the lowest instances of prices above 150/MWh, while Baltic and South-Eastern European markets have seen the most frequent episodes of such prices.

Figure 24 Frequency of hourly prices greater than EUR 150/MWh (share of hours in % and number of days)

The map on the left shows, for each bidding zone, the share of hours (upper figure) and number of days (lower figure) with electricity prices above 150 EUR/MWh in 2024. The graph on the right shows the annual percentage of the time when prices were above 150 EUR/MWh in the EU-27/EEA(Norway) area from 2019 to 2024.



Source: Frontier Economics based on ENTSO-E day-ahead power price data, and ACER (2025), Key developments in European electricity and gas markets

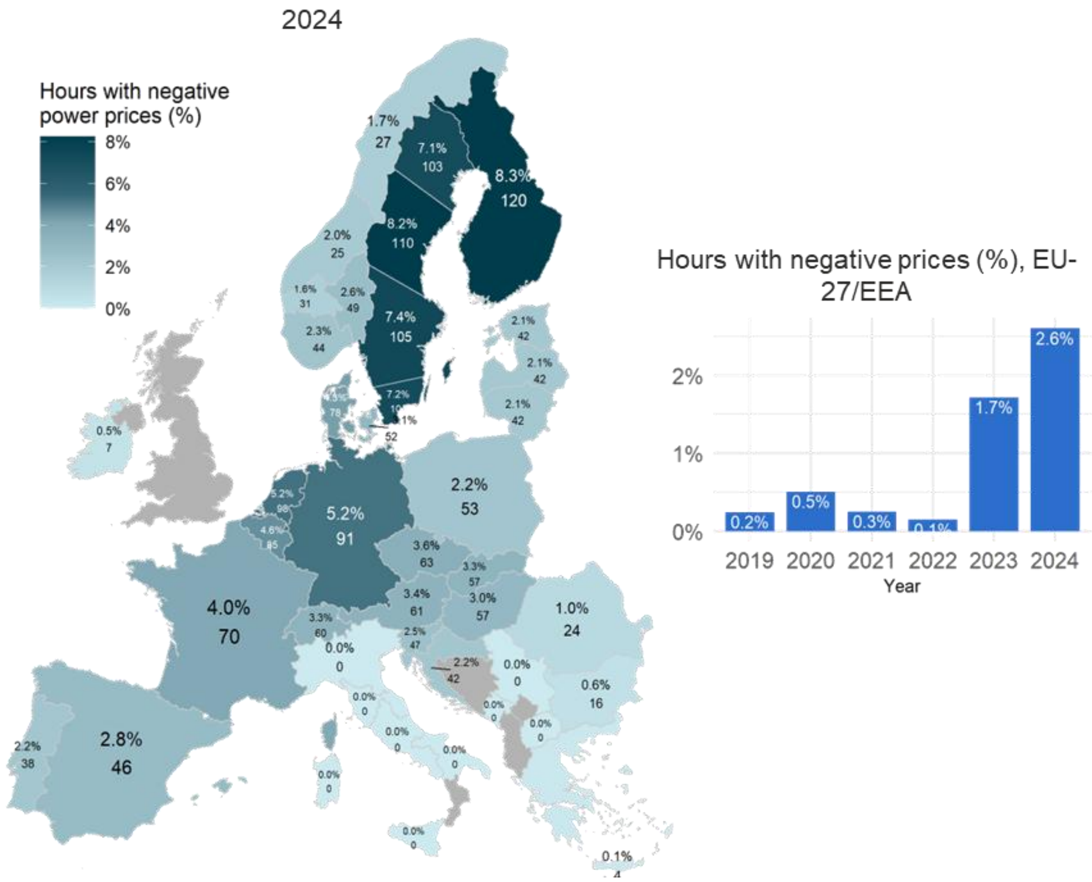
Note: The figure presents all available bidding zones for transparency. However, not all zones are included in the econometric analysis. Please refer to Annex B for details on data quality and excluded zones.

Evidence of negative prices – has continued to grow

Negative wholesale electricity prices have become increasingly frequent in several EU markets. These events typically occur in hours when high solar or wind generation coincides with low electricity demand, so that RES output exceeds electricity demand on the system. Figure 25 shows the share of hours and number of days each year with negative price occurrences. In 2023, occurrences of negative prices in the EU-27/EEA rose to 1.7% (of hours) from negligible levels in previous years and further increased to 2.6% in 2024. The trend is most evident in renewable-heavy bidding zones like Central Western Europe and part of the Nordics (Sweden and Finland).[59]

Figure 25 Frequency of negative hourly prices

The map on the left shows, for each bidding zone, the share of hours (upper figure) and number of days (lower figure) with electricity prices below 0 EUR/MWh in 2024 in each bidding zone. The graph on the right shows the annual percentage of hours when prices were below 0 EUR/MWh across the EU-27/EEA(Norway) area from 2019 to 2024.



Source: *Frontier Economics based on ENTSO-E day-ahead power price data*

Note: *The figure presents all available bidding zones for transparency. However, not all zones are included in the econometric analysis. Please refer to Annex B for details on data quality and excluded zones.*

4.3 Empirical analysis of volatility

While the analysis above highlights some key trends and correlations, it does not disentangle the relative importance of different factors in driving volatility across markets. This is where further empirical analysis can help.

59 Trinomics (2024), Study on Energy Prices and Costs – 2024 Edition, Final Report for the European Commission, & ACER (2025), Key developments in European electricity and gas markets.

A growing body of research has explored the dynamics of electricity price volatility across European markets. Selected studies are summarised in Table 4 at Annex A. The following key themes emerge from this literature:

- Volatility patterns manifest differently across time scales (daily, hourly, and sub-hourly).
- The structure of electricity price volatility in Europe has been shown to change during systemic shocks, such as the COVID-19 pandemic and the energy crisis, with evidence of larger price jumps, slower mean reversion, and regional divergence.
- The impact of renewables on volatility is not linear and appears to vary depending on levels of deployment.
- Variation in prices can be closely correlated across bidding zones, particularly under extreme market conditions. The extent of cross-border price and volatility convergence is influenced by geographic and economic proximity and renewable energy penetration.

We have carried out our own empirical analysis, which builds on and complements the existing literature. The goals of our analysis are to:

- consider how fundamental factors have driven volatility; and
- explore the relative importance of different factors in explaining differences in observed volatility (see above) across European bidding zones.
- The rest of this section discusses our analysis in more detail:
- We first motivate our econometric approach based on a literature review;

We introduce two complementary econometric approaches, a traditional Fixed Effects (FE) model and a more sophisticated model allowing for the synchronous analysis of cross-border effects between bidding zones (Spatial Durbin Model, SDM). We present high-level results from this analysis. More detailed results as well as background analysis on data quality can be found in the Annex.

4.3.1 Our econometric approach assesses key drivers of price levels and volatility

The identification of drivers of price volatility requires identifying the parameters that have a (causal)[60] effect on those variables. To that end, ideally, we would identify a natural experiment to isolate the true causal effect of different drivers of price levels and volatility. However, in practice, this is not feasible. This is because identifying a natural experiment for every potential driver would require distinct, exogenous shocks that isolate each factor independently, which is highly challenging in a complex, interdependent market.

60 Causality should in this context not be understood in the sense of a formal statistical causality, as we are not undertaking strict formal causal inference. Instead, we make use of our domain knowledge on the fundamentals of the electricity market in combination with structural modelling of these markets to apply plausibility checks of causality.

We have therefore opted for an econometric analysis of the relative importance of different drivers (commodity and primary energy prices, demand, interconnection, renewables deployment, etc.) on price volatility.

Such analyses are inherently complex. As illustrated by the wide range of models and methodologies employed in the studies reviewed (see Table 4 at Annex A), no single econometric model or approach can fully capture the multifaceted nature of volatility dynamics. Different econometric approaches offer different strengths and limitations, and each requires trade-offs between interpretability, flexibility, and data requirements. Further, power prices are characterised by significant non-linear relationships.

In this report, we have carried out separate sets of regression analyses (each including one regression per bidding zone), for the dependent variables shown in Figure 26 below. We have considered drivers of price levels as well as price volatility, and we have decomposed volatility into within-day and between-day components.

Figure 26 Dependent variables considered in the analysis

Price levels	Price volatility
▪ Hourly price levels	▪ Standard deviation of hourly prices over a 24-hour rolling window
▪ Daily average price levels (fixed daily intervals)	▪ Standard deviation of daily average prices over a 30-day rolling window

Source: Frontier Economics

For our empirical analysis, we use day-ahead electricity prices from 39 European bidding zones over the period from October 2018 and December 2024.[61] This timeframe captures both pre-crisis market conditions and the more volatile dynamics observed during and after the energy crisis.

Key explanatory variables[62] we have assessed include:

- gas prices (during periods in which gas-fired plants have been operating);
- coal prices (during periods in which coal-fired plants have been operating);
- EUA prices (during periods in which any fossil fuel plants have been operating);

[61] October 2018 was selected as the starting point for the analysis to coincide with the split of the Austrian bidding zone from the Germany-Luxembourg bidding zone, which allowed us to generate consistent time series.

[62] We also control for the volume of energy stored in hydro reservoirs, prices/volatility in previous periods and bidding zone-specific as well as year-specific effects.

- residual demand (measured as demand less wind, solar and other non-dispatchable RES output);
- nuclear output (in bidding zones with nuclear capacity).

In regressions on price levels, we include the levels of explanatory variables. In regressions on the standard deviation of prices, we include the standard deviation of explanatory variables (measured over the same window as the standard deviation of power prices) and the mean value of residual demand (as a proxy for market tightness[63]).

Data is drawn from ENTSO-E (power prices, demand, and generation) and Bloomberg (commodity prices). Further details of the data and sources used are found in the Annex.

4.3.2 We have assessed the robustness of results to alternative approaches

We have used two alternative estimation approaches:

- **Standard Fixed Effects** (FE) regression model – analysing price formation in each of the 39 bidding zones in isolation. This approach uses standard ordinary least squares (OLS) estimation.
- **Spatial Durbin Model** (SDM) - The Spatial Durbin approach allows us to account not only for local market conditions in each bidding zone but also for conditions in neighbouring bidding zones. In our case, we have controlled only for the impacts of prices in neighbouring bidding zones ("direct spillovers" in the econometric literature).[64] This means that for each bidding zone, we analyse that zone together with adjacent bidding zones.

We present results for both the Fixed Effects (FE) and Spatial Durbin Model (SDM). Both approaches yield meaningful and relevant results. The reasons estimates may differ across the two approaches can support a richer understanding of power price dynamics. They should therefore be viewed as complements (rather than as substitutes for each other).

- FE estimates leave open whether (for example) gas price volatility translates into electricity price volatility indigenously, e.g. though the electricity generation merit order in that bidding zone, or whether the effect of gas price volatility (on electricity price volatility) is imported from neighbouring bidding zones.

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63 For a similar reason, we also control for the mean volume of energy stored in hydro reservoirs.

64 The spatial Durbin approach also requires a weighting matrix to be defined that bounds and weights the impact of cross-border effects. Simple versions include a standard 0/1 binary indication of whether two bidding zones are neighbours. We defined weights that proxy for the maximum possible interconnection between two neighbouring bidding zones within a given year by taking the largest annual observed transmission flow between two neighbouring bidding zones. We did not directly include supply and demand variables in the SDM regressions ("indirect spillovers"), to reduce the high levels of multicollinearity they introduced and to guarantee parsimonious modelling.

- SDM allows for a decomposition of cross-border effects and domestic effects. However, there are also some complications associated with the SDM:
  - coefficient estimates of individual explanatory variables need to be viewed together with estimated cross-border effects; they cannot be easily interpreted in isolation;
  - cross-border effects are expressed as one composite effect which is not decomposed by originating bidding zone or underlying drivers in the adjacent zones; and
  - the estimation of cross-border effects may be sensitive to the weightings used (see footnote 64). While we have not investigated this further in this report, this could be a useful area for further analysis.

Overall, the analysis presented in this report involves 320 separate regressions, before accounting for those used in robustness checks (not presented in this report), which we discuss briefly below.

There are common challenges associated with implementing any econometric approach. These challenges, and our approach to addressing them, are summarised in Figure 27 below.

Figure 27 Summary of common issues in econometric analysis and our approach to addressing them

	Description of issue	Our approach
Omitted variable bias	If a relevant explanatory variable is left out of a regression model that is correlated with both the dependent variable and one or more included regressors, coefficient estimates will be biased and inconsistent	We have employed a range of relevant input variables and combinations thereof, subject to data being available in a consistent format across countries
Reverse causality	When an explanatory variable is caused by the outcome variable, we will get biased and inconsistent coefficient estimates	Relevant mainly in the case of hydro as well as import and export volumes, which depend on prices and price spreads We have tested the robustness to inclusion of the variables and tested several instruments
Multi-collinearity	When two or more explanatory variables in a regression model are highly correlated, making it difficult to isolate the individual effects of each variable, leading to less precise estimates	We adopt a simplified specification – excluding different forms (e.g. quadratic) of the same control variable and capacity variables – we found their exclusion had limited impact on our results
Measurement error	If explanatory variables are measured with an error, coefficient estimates will tend to be biased towards zero	Modelling may be affected by underlying data quality We have documented relevant data quality issues
Weak identification	Data provides little information about a given parameter, as we do not observe the full range of possible values in the sample, leading to unreliable estimates	To mitigate this, we have aggregated certain variables (e.g. residual demand rather than including demand and each renewable technology separately)

Source: Frontier Economics

It has not been possible in the scope of this study to resolve all issues completely. However, as noted above, we have assessed the robustness of results to multiple specifications.

Our approach (both in terms of data used and econometric specification) is standardised across bidding zones. While this has some advantages in terms of comparing results across bidding zones, it also involves some trade-offs.

- Some specific local dynamics of price formation may not be completely captured in our analysis. For example, in the case of the Nordics, we have omitted certain variables that may further explain the dynamics of reservoir filling and discharging in hydro-dominated markets (such as precipitation and expectations of future market conditions), but which may only be available from local data sources (as opposed to Europe-wide). A further example includes markets with a higher share of fossil fuel plants that use locally-sourced fuels (such as Bulgaria). The price dynamics of such fuels may not always be well correlated with the fuel prices included in our analysis.
- A key source of consistent data at an hourly resolution on supply and demand across European bidding zones is the ENTSO-E transparency platform. While a full audit of underlying data was not in scope of this project, we have found issues related to data completeness and quality in relation to the ENTSO-E data, which we have documented in Annex B.

While our model findings should therefore not be viewed as definitive, they nevertheless provide important insights into key drivers of prices and price volatility and provide a platform on which policy debate and further analysis could build.

4.3.3 Results of our econometric analysis

We now present the results of our analysis of drivers of:

- price levels; and
- price volatility.

Price levels

We first consider the results of our regressions on hourly and daily average price levels, for both the FE and SDM approaches, when applied across the **full set of bidding zones considered**.

Table 2 below presents the results of our regressions on daily average and hourly price levels, for both the FE and SDM approaches, when applied across the full set of bidding zones considered. The coefficient estimates can be interpreted as average effects of individual drivers across all bidding zones.[65]

- The table presents coefficient estimates with standard errors in parenthesis.
- “p”-values refer to the statistical significance, with a lower “p” value indicating greater statistical significance.
- The lagged dependent variable in the “daily” regression is the average price over the preceding seven days,[66] while in the “hourly” regression it is the average price over the preceding 24-hour period. A coefficient of X means that, for every EUR 1/MWh increase in power prices in previous periods, the power price increases by EUR X/MWh on average.
- Gas price: A coefficient of X means that, for every EUR 1/MWh increase in the gas price (during periods in which gas-fired plants are generating), the power price increases by EUR X/MWh on average.
- Coal price: A coefficient of X means that, for every USD 1/tonne increase in the coal price (during periods in which coal-fired plants are generating), the power price increases by EUR X/MWh on average.
- EUA price: A coefficient of X means that, for every EUR 1/tCO_2 increase in the EUA price (during periods in which fossil-fired plants are generating), the power price increases by EUR X/MWh on average.
- Residual load: A coefficient of X means that, for every 1 percent increase in the residual load, the power price increases by approximately EUR X/MWh on average.
- Nuclear output: A coefficient of X means that, for every 1 percent increase in nuclear output, the power price increases by approximately EUR X/MWh on average.

65 To reflect the difference in size of the bidding zones we use weighted least squares to calculate the averages. The weights used are based on the respective observed demand.

66 Our choice to control for power prices in previous periods is partly on conceptual grounds. One is market fundamentals - intertemporal arbitrage through energy storage may create some interdependency between prices in time periods. Another is "market sentiment", which while difficult to observe may also have an impact on market prices and volatility. Had we not controlled for prices in previous periods, this could therefore have biased our estimates. We also confirmed the presence of stationarity. We have tested the impact of including the lagged dependent variable and of different forms of the lagged dependent variable. Overall, we felt that including the lag of only the previous period (t-1) was likely to lead to the model capturing too much variance. This is why we opted instead to include the average (of either lagged prices or volatility) over a longer period.

Table 2 Regression results with price levels as the dependent variable

	Daily FE	Daily SDM	Hourly FE	Hourly SDM
Lag dependent variable	0.809***	0.543***	0.925***	0.523***
	(0.052)	(0.104)	(0.022)	(0.088)
Gas price	0.372***	0.144	0.113**	-0.204***
	(0.106)	(0.087)	(0.047)	(0.071)
Coal price	0.012	0.002	0.004	-0.002
	(0.016)	(0.021)	(0.007)	(0.022)
EUA price	-0.035	0.007	0.041*	0.062
	(0.076)	(0.045)	(0.024)	(0.042)
Residual load [log]	7.163**	5.945**	9.960***	5.128***
	(2.883)	(2.359)	(3.039)	(1.574)
Nuclear output [log]	-0.347	-0.356*	-0.285**	-0.360
	(0.210)	(0.177)	(0.115)	(0.354)
Spillover		0.399***		0.592***
		(0.074)		(0.075)
Num.Obs.	87396	87396	2102812	2102812
R2	0.879	0.182	0.863	0.193
AIC	852602.5	894363.0	21192381.4	21461252.7
BIC	853090.1	894860.1	21193034.5	21461918.3
Controls	✓	✓	✓	✓

* p < 0.1, ** p < 0.05, *** p < 0.01

Source: *Frontier Economics*

Note: *Additional control variables include stored energy levels as well as bidding zone and year fixed effects. We account for differences in the size of the bidding zones when estimating the average coefficients by using weights derived from the demand levels in the estimation.*
The R-squared statistic reported for the Spatial Durbin model represents a pseudo-R2 and should not be compared to the R2 of the Fixed Effects regression. Likewise, the Akaike Information Criterion (AIC) and the Bayesian Information Criterion (BIC) should not be directly compared across the models, as one is based on the true likelihood and the other on the quasi likelihood.

Key findings include the following:

- **Price levels can be explained through the tightness of the system:** residual load (demand, less wind, solar and other non-dispatchable output) is estimated to have a strong, positive and statistically significant impact, across both FE and SDM approaches and the daily and hourly time horizons (with a one percent increase in residual demand estimated to lead to a EUR 5-10/MWh increase in power prices, other things equal, depending on the precise regression).

- **Effects of gas prices on power prices:** Gas prices are estimated to have a positive and statistically significant impact on price levels under the FE approach (with a higher coefficient estimate for the impact on daily prices). The estimated coefficient in the SDM is not statistically significant for daily prices (and is negative for hourly prices[67]). The lower coefficient estimates for gas prices for SDM, compared to FE, is consistent with gas price shocks being shared across the interconnected bidding zones. The SDM model highlights that at least part of the estimated impact of gas prices on power prices (as evidenced by the results of the FE model) may be associated with cross-border trade.[68] This highlights that cross-border effects depend not only on the availability of cross-zonal capacity but also on the interaction between supply and demand factors across bidding zones.

- **Persistence of power prices across time:** The large, positive, and statistically significant coefficient for price levels in previous periods (i.e. a so-called autoregressive element which we find to be strong across modelling approaches and time horizons) suggests that prices are somewhat sticky. This may be partly explained by fundamentals – energy storage provides some ability to arbitrage power prices across periods. The estimated effect of previous period power prices is lower under SDM, suggesting that the FE estimates may reflect a mix of cross-border effects as well as pure “persistence” of prices.

- **Strong cross-border effects:** The estimated cross-border price effects are positive and strongly statistically significant, highlighting the strong degree of interconnectedness of the system. The lower estimated size of cross-border effects in the daily average prices compared to the hourly prices might indicate that there is more cross-border arbitrage within days than across days.

While the above discussion highlights some general trends across Europe, **drivers also differ by bidding zone**. We have therefore also run each of the regressions separately for each of the 39 bidding zones – allowing us to examine how the sensitivity of power prices to key drivers varies geographically. Figure 28 presents the estimated impact of gas prices on average daily power prices (during periods in which gas-fired plant operate), separated by bidding zone, for the FE approach.

- Gas prices are estimated to have the largest impact on power prices in central European bidding zones, consistent with gas-fired power plants setting the price the majority of time when they are in operation.[69] These bidding zones are also highly interconnected.

- Gas prices are estimated to have lower impacts on power prices (during periods in which gas-fired plants operate) in:

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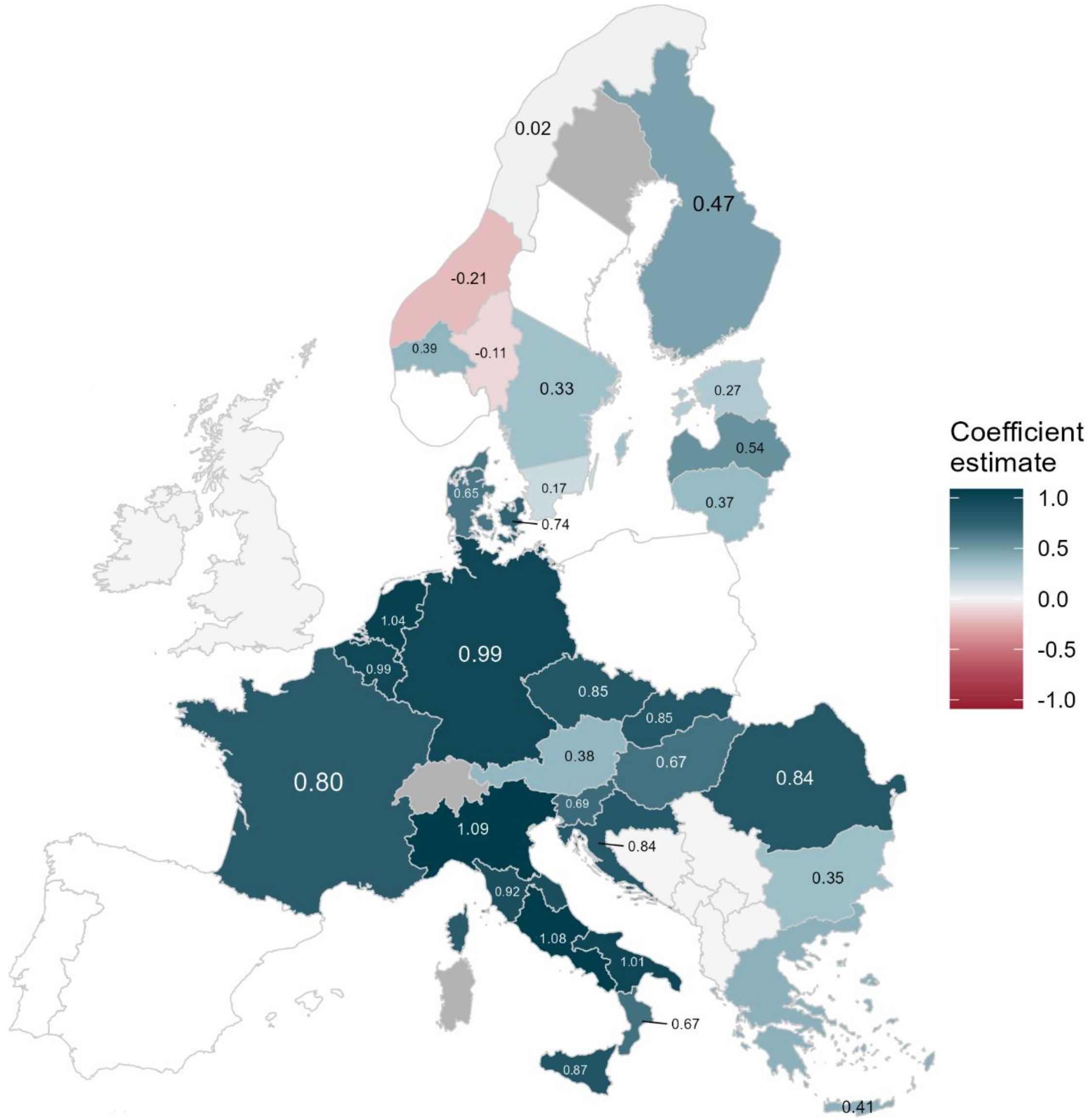
67 As noted earlier, the coefficients on individual cost drivers in the SDM model cannot be meaningfully interpreted in isolation and must be interpreted together with the cross-border effects. These cross-border effects also reflect the dependence of electricity price volatility on gas price volatility.

68 As noted above, the SDM - in the applied form - does not allow the formal decomposition of the cross-border effects.

69 Assuming an efficiency of gas-fired generation of 50%, a coefficient estimate equal to 2 would be consistent with gas-fired plants setting the price all of the time.

- Iberia (although the coefficient estimate is not statistically significant) - consistent with regulatory intervention as discussed earlier;
- Poland: consistent with high shares of coal-fired generation; and
- Nordic bidding zones: consistent with lower shares of gas-fired generation, which are also more likely to be combined heat and power (CHP) units and therefore less likely to be price-setting.

Figure 28 Impact of gas price levels on the level of daily average power prices - estimates by bidding zone (FE estimates)



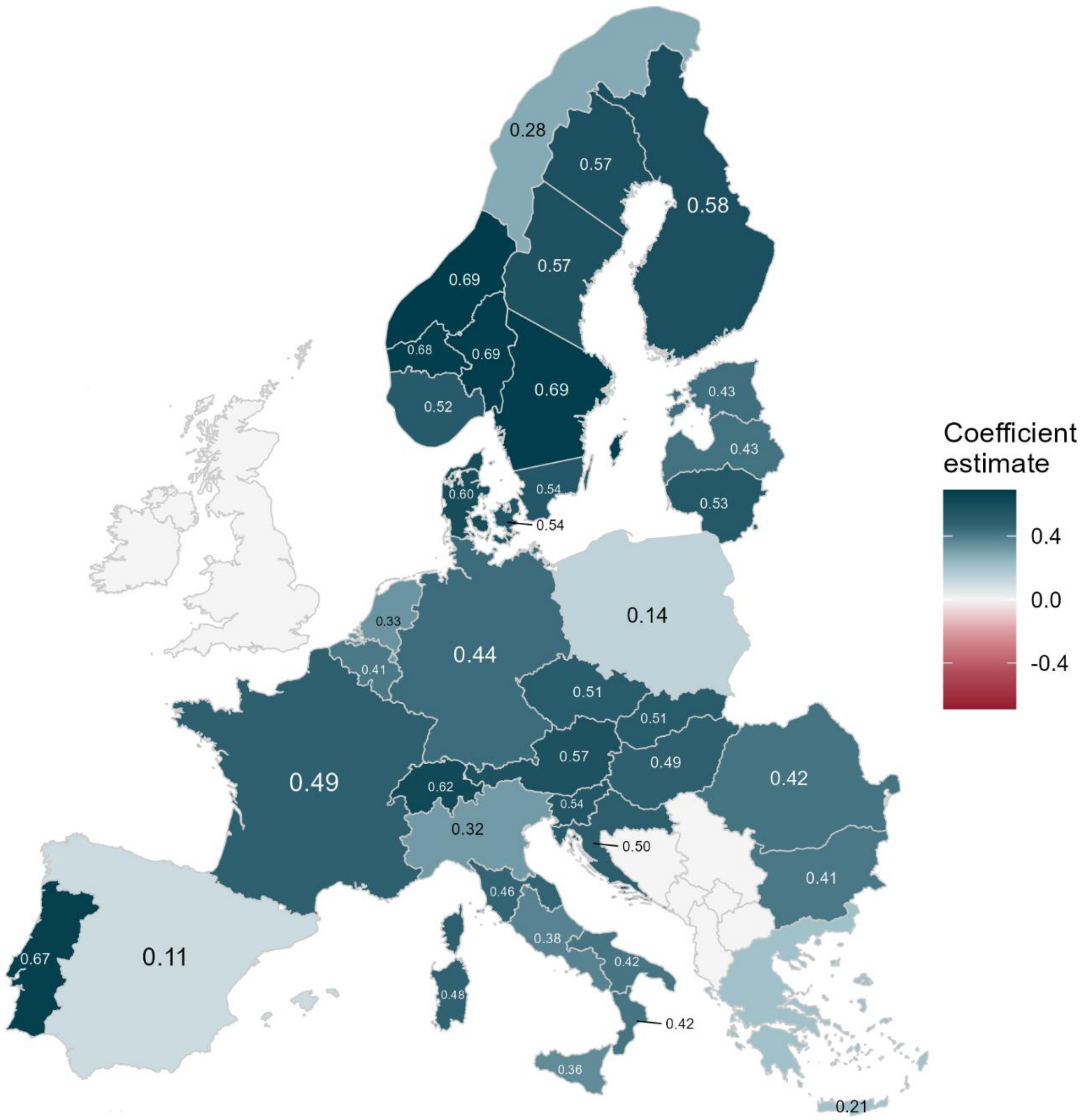
Source: Frontier Economics

Note: An estimated coefficient of X means that a EUR 1/MWh increase in the gas price leads to an EUR X/MWh in the average daily electricity price (holding all else constant). Uncoloured bidding zones are not statistically significant. We were not able to estimate coefficients for the greyed-out zones, either due to high levels of multicollinearity in the variable or due to a lack of variation.

Figure 29 shows the estimated cross-border effect on the level of average daily power prices by bidding zone. As expected, we observe a limited interdependence of power prices with the neighbouring bidding zones for Spain and Poland, while the effect is higher for central European bidding zones and the Nordics. We observe similar patterns of results for cross-border effects across timeframes and for price volatility.[70]

[70] The result for Austria is interesting. It shows a relatively high impact of SDM cross-border effects, while also showing a relatively low FE estimate for the impact of gas prices and being surrounded by bidding zones with higher coefficients for gas prices. This could reflect a low indigenous effect of gas-fired generation and/or cross-border effects linked to factors other than gas-fired generation in neighbouring bidding zones.

Figure 29 Impact of cross-border effects on the level of daily average power prices - estimates by bidding zone (SDM estimates)



Source: Frontier Economics

Note: The coefficients should not be interpreted directly as they represent the effect of a complex composite (including weight multiplication, spatial and temporal lag structures and summations) on power price levels. However, the coefficient can nevertheless be compared across bidding zones.

Price volatility

We first consider the results of our regressions on hourly (within-day[71]) and between-day price volatility (across a 30-day window), for both the FE and SDM approaches, when applied across the **full set of bidding zones considered**.

Table 3 below presents the results of our regressions on between-day and within-day price volatility, for both the FE and SDM approaches, when applied across the full set of bidding zones considered. As above, the coefficient estimates can be interpreted as "average" impacts of individual drivers across all bidding zones.[72]

- The table presents coefficient estimates with standard errors in parenthesis.
- "p"-values refer to the statistical significance, with a lower "p" value indicating greater statistical significance.
- "Between-day" refers to the regression of the standard deviation of daily average day-ahead price levels over a 30-day rolling window, while "within-day" refers to the regression of the standard deviation of hourly day-ahead price levels over a 24-hour rolling window.
- The lagged dependent variable in the "between-day" regression is the standard deviation of daily average price levels over a 365-day rolling window, ending right before the start of the dependent variable rolling window (t – 31 days). The lagged dependent variable in the "within-day" regression is the standard deviation of the hourly price levels over a 168-hour rolling window, ending right before the start of the dependent variable rolling window (t – 25 hours). A coefficient of X means that, for every EUR 1/MWh increase in the standard deviation of power prices in previous periods, the power price standard deviation increases by EUR X/MWh on average.
- Gas price: A coefficient of X means that, for every EUR 1/MWh increase in the gas price standard deviation (during periods in which gas-fired plants are generating), the power price standard deviation increases by EUR X/MWh on average.
- Coal price: A coefficient of X means that, for every USD 1/tonne increase in the coal price standard deviation (during periods in which coal-fired plants are generating), the power price standard deviation increases by EUR X/MWh on average.
- EUA price: A coefficient of X means that, for every EUR 1/tCO_2 increase in the EUA price standard deviation (during periods in which fossil-fired plants are generating), the power price standard deviation increases by EUR X/MWh on average.
- Residual load (mean): A coefficient of X means that, for every 1 percent increase in the residual load average over the rolling window, the power price standard deviation increases by approximately EUR X/MWh on average.
- Residual load (volatility): A coefficient of X means that, for every 1 unit increase in the residual load relative standard deviation, the power price standard deviation increases by approximately EUR X/MWh on average.

71 Or, more precisely, within a rolling 24-hour period.

72 Again, we use weightings based on the observed demand to reflect the difference in size of the bidding zones.

- Nuclear output (volatility): A coefficient of X means that, for every 1 unit increase in the nuclear output relative standard deviation, the power price standard deviation increases by approximately EUR X/MWh on average.

Table 3 Regression results with price volatility as the dependent variable

	Between-day FE	Between-day SDM	Within-day FE	Within-day SDM
Lag dependent variable	0.103***	0.038*	0.512***	0.209***
	(0.017)	(0.020)	(0.043)	(0.059)
Gas price volatility [sd]	1.415***	0.084	0.943***	0.105
	(0.152)	(0.099)	(0.112)	(0.078)
Coal price volatility [sd]	-0.029	-0.019	-0.137***	-0.122
	(0.084)	(0.094)	(0.040)	(0.103)
EUA price volatility [sd]	0.496*	0.207	2.065***	0.670*
	(0.265)	(0.214)	(0.324)	(0.383)
Residual load mean level [log]	8.692***	0.650	2.581**	1.328**
	(2.508)	(1.020)	(0.966)	(0.506)
Residual load volatility [rel sd]	2.097**	0.332	9.143*	5.257*
	(0.863)	(0.360)	(4.927)	(2.816)
Nuclear output volatility [rel sd]	-0.000*	0.000	4.065	1.819
	(0.000)	(0.000)	(3.896)	(1.382)
Spillover		0.925***		0.788***
		(0.056)		(0.087)
Num.Obs.	72264	72264	2096277	2096277
R2	0.702	0.222	0.583	0.143
AIC	604623.7	568279.6	17587568.0	17772170.6
BIC	605110.7	568775.8	17588246.0	17772861.1
Controls	✓	✓	✓	✓

* p < 0.1, ** p < 0.05, *** p < 0.01

Source: *Frontier Economics*

Note: *Additional control variables include stored energy levels as well as bidding zone and year fixed effects.*
We account for differences in the size of the bidding zones when estimating the average coefficients by using weights derived from the demand levels in the estimation.
The R-squared statistic reported for the Spatial Durbin model represents a pseudo-R2 and should not be compared to the R2 of the Fixed Effects regression. Likewise, the Akaike Information Criterion (AIC) and the Bayesian Information Criterion (BIC) should not be directly compared across the models, as one is based on the true likelihood and the other on the quasi likelihood.

Key findings are broadly consistent with the findings of the regressions for price levels and include the following:

- **System tightness affects within-day price volatility:** The average level of observed residual demand (independently of residual demand volatility) is estimated to have a positive, strongly statistically significant, effect on hourly power price volatility across both FE and SDM (though the coefficient estimate for SDM is lower). The impact of average residual demand on between-day power price volatility is also positive and statistically significant under the FE approach – but the corresponding estimate for SDM is not statistically significant. This suggests that the level of (residual) demand is likely to be positively correlated with electricity price volatility in neighbouring bidding zones. This is also consistent with the positive and strongly statistically significant estimate of the impact of price volatility cross-border effects from neighbouring bidding zones under SDM.

- **Variations in residual demand also drive within-day price volatility:** The relative standard deviation of residual demand is estimated to have a positive effect (albeit with weaker statistical significance) on hourly power price volatility across both FE and SDM (though, again, the coefficient estimate for SDM is lower). Increases in within-day residual demand volatility over recent years are therefore likely to have contributed to observed within-day power price volatility. For between-day volatility, volatility in residual demand is estimated to have a significant positive effect only under the FE approach.

- **Effects of gas price volatility:** Gas price volatility is estimated to be an important driver of electricity price volatility both within and across days under FE, suggesting that increased gas price volatility during the crisis has been a major driver of observed power price volatility. At the same time the estimated coefficients for SDM are statistically insignificant. Consistent with the regression results for price levels, this may suggest that the impact on power price volatility of gas price volatility is shared across the interconnected bidding zones (and therefore represented through cross-border effects in our SDM regressions). The FE results suggest that a key driver behind the cross-border effects is in turn variations in gas prices (although again, formally the SDM approach does not formally permit such decomposition of effects). Similar cross-border effects may also be true for EUA and to a lesser extent coal prices.

- **Power price volatility persists over time:** The positive and statistically significant coefficient for price volatility in previous periods (across modelling approaches and time horizons) signals that volatility is persistent. The estimated effect of previous period power volatility is lower under SDM, suggesting that the FE estimates may reflect a mix of cross-border effects as well as pure “persistence” or prices.

- **Strong cross-border effects:** The estimated impact of cross-border effects from neighbouring bidding zones is positive and strongly statistically significant, again highlighting the strong degree of interconnectedness of the system. The estimated size of cross-border effects is higher for between-day volatility than for within-day volatility.

Again, we consider the extent to which **drivers of volatility differ by bidding zone**.

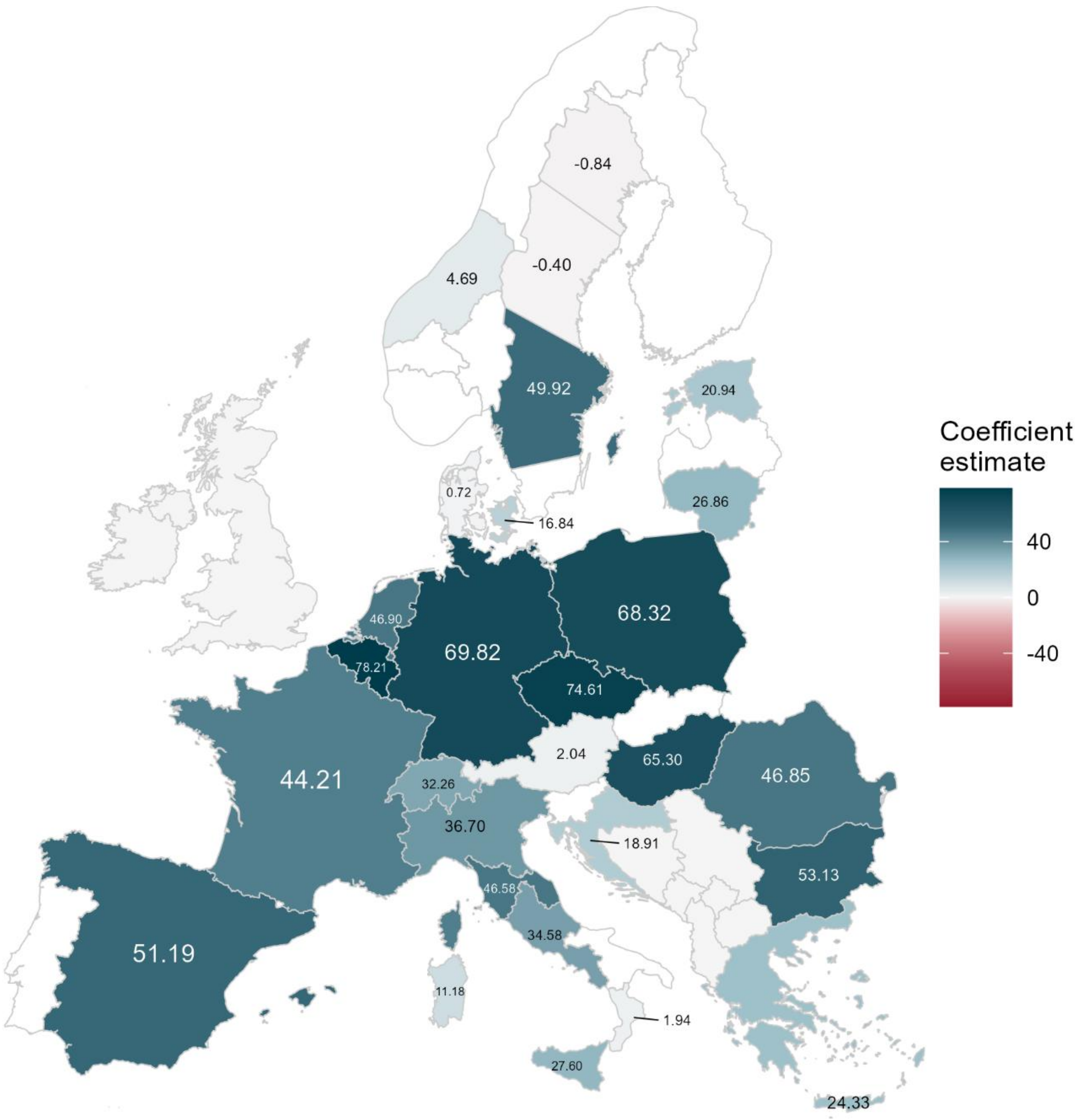
We start with “within-day” power price volatility. As noted in section 4.2.3, a key question is whether increasing RES output volatility (reflected in volatility in residual demand) has had different effects on price volatility across bidding zones. Figure 30 shows the estimated impact of residual demand volatility on hourly power price volatility over a 24-hour rolling window, by bidding zone.

These effects are significantly varied by bidding zone:

- Overall, coefficient estimates tend to be positive – i.e. higher residual demand volatility generally leads to higher price volatility.
- A higher coefficient value means a given variation in residual demand is associated with greater price volatility, and may indicate that the “merit order” or “supply curve” (section 3.2) in the bidding zone in question has a steeper slope.
- Coefficient estimates are particularly low in bidding zones in Northern Sweden and Austria – consistent with more material electricity storage capability (in the form of hydro reservoirs) – allowing for within-day price smoothing.[73]
- Estimates are especially high in Belgium, Czechia, Germany, Hungary and Poland.

[73] Switzerland also has a high amount of hydropower capacity, though has a coefficient as high as France. It may be that the coefficient estimate for Switzerland therefore partly reflects the impacts of cross-border effects linked to trade with neighbouring bidding zones (such as France and Germany), for which it tends to act as a “battery". Regarding Southern Italy, the unexpectedly low coefficient estimate may be in part driven data quality issues (discussed in Annex B).

Figure 30 Impact of residual demand volatility on "within-day" power price volatility - estimates by bidding zone (FE estimates)

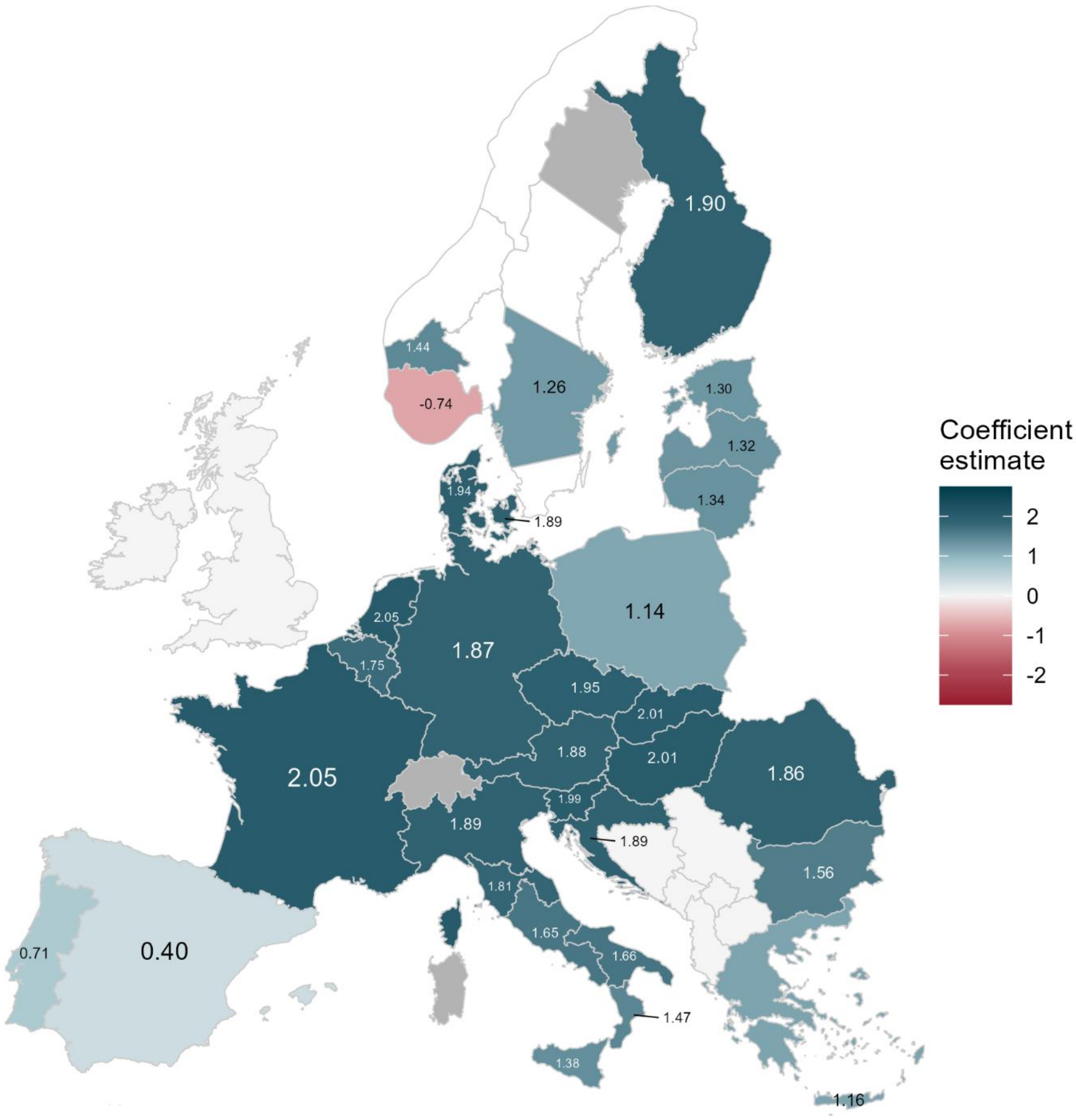


Source: Frontier Economics

Note: A coefficient of X means that a 1 unit increase in the coefficient of variation of residual demand leads to a EUR X/MWh increase in the standard deviation of power prices within a 24-hour window. A 1 unit increase in the coefficient of variation of residual demand is itself equivalent to the standard deviation of residual demand increasing by a level equal to the mean level of residual demand. Uncoloured bidding zones are not statistically significant.

Turning to volatility across days, Figure 31 presents the estimated impact of gas price volatility on power price volatility over a 30-day window (during periods in which gas-fired plant operate), separated by bidding zone, for the FE approach. The results are broadly consistent with the pattern of results for the impacts of gas price levels on power price levels (Figure 28 above) – with gas price volatility being a more significant driver of power price volatility in central European markets.[74]

Figure 31 Impact of gas price volatility on "between-day" power price volatility - estimates by bidding zone (FE estimates)



74 The negative coefficients in some of the Norwegian bidding zones may seem counterintuitive since all else equal, we would expect higher gas price volatility to translate to higher power price volatility if gas-fired plants are price-setting. However, as noted above, Norway has negligible gas-fired generation and most of the capacity is CHP and so unlikely to be price-setting. Note also that only the negative coefficient estimate for zone NO2 is statistically significant.

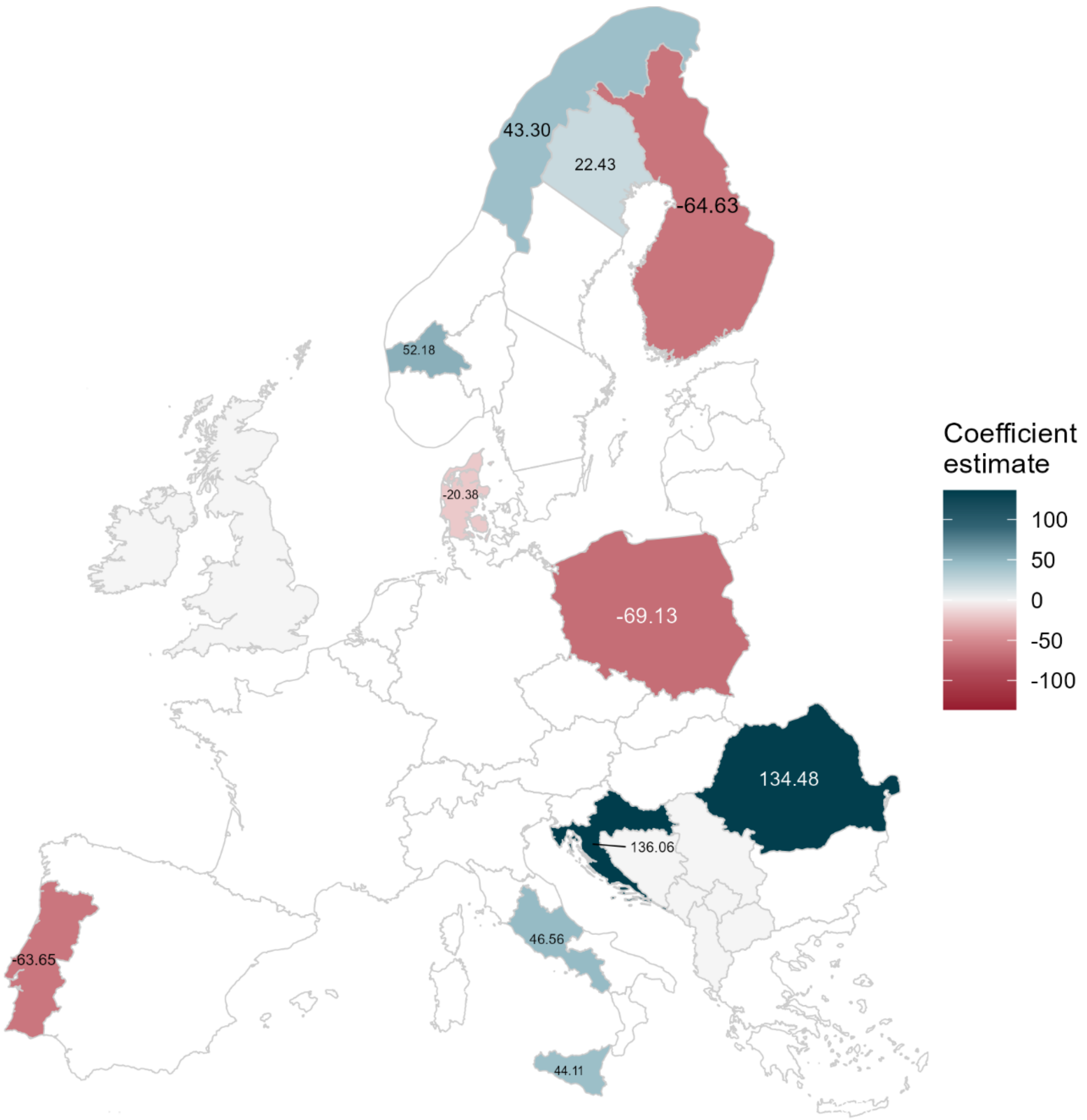
Source: Frontier Economics

Note: A coefficient of X means that a EUR 1/MWh increase in the standard deviation of the gas price leads to a EUR X/MWh increase in the standard deviation of the daily power prices across a 30-day window. Uncoloured bidding zones are not statistically significant. Greyed-out zones were not estimated, primarily due to high multicollinearity.

Figure 32 shows the estimated impact of residual demand volatility on between-day price volatility over a 30-day rolling window, by bidding zone. The patterns are less clear:

- Many coefficient estimates for individual bidding zones are not statistically significant.
- A positive coefficient estimate (as seen, for example, in Croatia and Romania) indicates that greater residual demand volatility is associated with greater power price volatility.
- We observe some negative (and statistically significant) coefficient estimates (meaning that greater residual demand volatility is associated with lower power price volatility) in zone DK1, Finland, Poland and Portugal. This suggests that (compared to periods of lower residual demand volatility) periods of higher residual demand volatility are associated with supply (and imports) being more elastic with respect to price. It also indicates that other factors – including cross-border effects from neighbouring bidding zones (or volatility in nuclear output in Finland’s case) – may be more important than residual demand for explaining volatility across days in relation to respective bidding zones.
- It is also helpful to consider these results together with the impact of average residual demand on power price volatility (Figure 43 at Annex C).

Figure 32 Impact of residual demand volatility on "between-day" power price volatility - estimates by bidding zone (FE estimates)



Source: Frontier Economics

Note: A coefficient of X means that a 1 unit increase in the coefficient of variation of residual demand leads to a EUR X/MWh increase in the standard deviation of power prices over a 30-day window. A 1 unit increase in the coefficient of variation of residual demand is itself equivalent to the standard deviation of residual demand increasing by a level equal to the mean level of residual demand. Uncoloured bidding zones are not statistically significant. We were not able to estimate coefficients for the greyed-out zones, either due to high levels of multicollinearity in the variable or due to a lack of variation.

4.4 Policy implications

While specifics vary between bidding zones, our results are consistent with prices and price volatility being driven by fundamental supply and demand drivers.

- **Variations in gas prices have a statistically significant impact on electricity prices and electricity price volatility** during periods when gas-fired generation operates. The estimated impact of gas prices is consistent with the typical conversion efficiency of a marginal gas-fired plant, at around 50%.[75] Given that gas prices and their volatility were also elevated over 2021-23, this is likely to explain a substantial share of the higher electricity price levels and volatility observed during the same period. Higher gas prices and volatility are also likely to have contributed to increases in EUA prices and their volatility, as higher gas prices raise the competitiveness of coal-fired generation and, in turn, demand for emissions allowances. Our estimates suggest that EUA prices also influence electricity prices, albeit with weaker statistical significance than gas prices. By contrast, coal prices play a much smaller and statistically less significant - or insignificant - role in explaining electricity prices and their volatility, with the exception of bidding zones such as Sardinia, where coal-fired generation accounts for a relatively high share of the generation mix.

- **Another important driver of electricity prices and their volatility is residual demand,** (which we define as electricity demand not met by the sum of wind, solar and other "non-dispatchable" renewable generation). Changes in residual demand reflect a combination of weather-driven factors - affecting both demand and generation - and consumer behaviour, such as weekday-weekend demand patterns. Our analysis shows that both the level and, separately, the volatility of residual load significantly influence electricity price volatility on average across all bidding zones and in many individual bidding zones. The increasing penetration of renewables has coincided with greater variation in intermittent renewable output, both within and across days, which is reflected in growing volatility of residual demand over time – particularly within-day. Consequently, the expansion of renewable energy sources has likely also contributed to sustained electricity price volatility, even as gas price volatility has fallen since its peak during the energy crisis. Within-day, higher system tightness, that is, higher residual demand, generally also leads to increased volatility.

- **Power price movements are closely linked between neighbouring bidding zones**, with positive and statistically significant cross-border effects on both price levels and volatility. The strength of these effects varies by bidding zone and depends not only on cross-zonal capacity but also on the interaction of supply and demand across bidding zones. Although the precise drivers cannot be fully disentangled in our analysis, gas prices and weather appear to play a key role.

These findings also carry several additional implications:

- As fossil fuels are phased out and the share of renewables increases, the **influence of fuel prices** and related geopolitical impacts on electricity prices **will diminish** over time, though it will remain as long as fossil fuel generation continues to play a role in the energy mix.

75 A conversion efficiency of 50% means that two energy units of gas are needed to generate one energy unit of electricity.

- **Price volatility can be mitigated through flexibility solutions,** such as expanding interconnections between bidding zones, deploying energy storage solutions and increasing participation of demand-side response. Our econometric analysis reveals regional differences in the responsiveness of electricity prices and electricity price volatility to changes in residual demand. This implies corresponding regional differences in the responsiveness of supply to price signals – that is, differences in system flexibility - which warrant further investigation. As noted earlier, markets play a crucial role in ensuring the efficient operational use of flexible assets, and as we discuss later, efficient short- and long-term markets are also important in supporting investment in flexibility.

- The correlations in prices and volatility observed across many bidding zones largely reflect their **interconnectedness**. This interconnectedness enables generation, demand and storage resources to be used more efficiently across Europe through market coupling, thereby reducing overall system costs across Europe and limiting extreme price spikes in individual zones. Our analysis also identifies some relatively isolated zones, pointing to opportunities for further development of cross-zonal transmission capacity. Market coupling in both day-ahead and intraday markets facilitates efficient flows, helping to reduce local volatility and cross-zonal price divergence. The diverging potentials of renewable energy resources across Europe will mean improved co-ordination of dispatch across borders will continue to be valuable.

5 The economic role of energy prices, cross-border trade and power exchanges

In this section, we discuss the role of wholesale electricity markets and price signals in supporting EU and national energy policy objectives – in light of our analysis in the previous section - and derive high-level policy priorities.

The objectives of wholesale market design and the wider electricity market framework directly relate to wider energy policy objectives.

- **Efficient operation:** The framework must ensure demand and supply are matched across timeframes and ensure operational security for a given set of generation and network assets. Dispatch should also respect environmental constraints and goals.
- **Sufficient investment:** The framework must ensure sufficient investment in the most efficient combination of resources (supply, demand, storage, network) that ensures decarbonisation, security of supply and flexibility needs are met – across energy carriers.
- **Affordability:** The framework must achieve the above at least cost to consumers.

Given the scale of investments required in the EU electricity sector[76] (even before considering those required elsewhere in the energy sector) this represents an immense co-ordination challenge, across different levels of the value chain (Figure 33) and across geographies. This co-ordination task is also complex given developments such as:

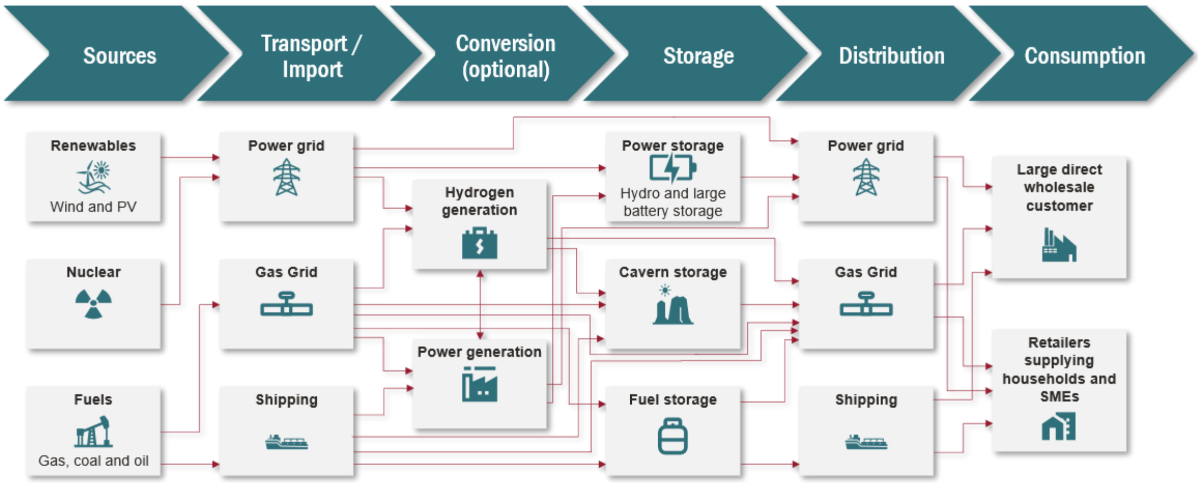
- Global geopolitical crises affecting fossil fuel prices and trade;
- the need for the power sector to adapt to growing amounts of new (and intermittent) renewable generation sources with low or zero marginal costs alongside the retirement of some conventional capacities;
- consequent growing needs for flexibility;
- increasing electrification across energy applications:
  - direct electrification – switch to electricity in applications currently mainly served directly through oil products (e.g., individual mobility) and gas (heating and industrial processes);

[76] Estimates vary by source, but as an indication of the order of magnitude, by 2030, average power generation and grid investment costs for the EU27 are projected to exceed €210 billion (2023 prices) over 2036-40 based on E.ON analysis. See E.ON (2025) "The Energy Playbook", Figure 13. https://www.eon.com/content/dam/eon/eon-com/eon-com-assets/documents/politics/en/eon-the-energy-playbook.pdf

  - indirect electrification – use of derivative products such as green hydrogen in industry and potentially heating and transport applications, making the co-ordination challenge increasingly cross energy vector; and

- increasing decentralisation of power generation (e.g. rooftop solar) and storage (vehicle-to-grid, or "V2G").

Figure 33 Overview of energy value chain



Source: Frontier Economics
Note: Simplified schematic illustration (e.g., excluding biomass and EU ETS)

There are contrasting approaches to achieving the required co-ordination. While there is a necessary role for policymakers, traded energy markets also have an essential role in supporting this co-ordination via price mechanisms and driving necessary investments and operational decisions.

The rest of this section is structured as follows:

- In section 5.1 we set out the role of short-term wholesale markets hosted by market platforms such as power exchanges, in supporting efficient system operation and investment;

- In section 5.2 we discuss the role of derivatives trading and hedging activities, including on power exchanges, play in supporting efficient delivery of energy policy objectives;

- In section 5.3 we set out the case for continued integration of wholesale markets across borders; and

- In section 5.4 we discuss the key areas in which policy and regulatory intervention are required to support efficient markets.

5.1 Competitive and efficient wholesale power markets keep system operation costs to a minimum, and can support the investments required for a secure, low-carbon system

There are significant (and increasing) benefits from efficient short-term electricity markets that help co-ordinate dispatch across an increasingly diverse set of supply, storage and demand technologies

Spot markets are crucial for aligning elastic supply and (less elastic) demand in or close to real-time (as discussed in section 3.2). As also previously described, spot wholesale market prices currently are set on the basis of the merit order principle, on a "pay-as-clear" basis. Spot prices can reflect both the short-term marginal costs and availability of generation resources.

Since competitive spot prices are cost-reflective[77] (in the absence of distortions), they provide signals for efficient use of generation and storage assets, in the sense that the lowest-cost (from a societal perspective[78]) available resources required to meet demand are dispatched.

This is fundamentally no different from price formation in markets for most goods and services, except that spot electricity prices can be relatively volatile from one period to the next for the reasons set out in section 3.2. This volatility serves as an important signal for the operation of (and – as we later discuss - investment into) flexible assets, including hydropower, thermal generation, demand-side response and batteries (in section 5.2 we discuss the role of interconnection between market areas). Besides that, associated commercial risks can be managed, depending on market participants' risk appetite, through hedging (as discussed in section 3.4).

While some stakeholders have called for alternative approaches to setting spot prices (such as on a "pay-as-bid") basis or by capping peak prices, alternative models are unlikely to be as efficient[79] and therefore cannot ultimately be expected to result in gains to consumers.

Interventions such as administrative price caps[80] (other than those arising from the application of competition law) may discourage supply and provision of flexibility (including through

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77 I.e. they reflect the incremental cost of producing power for a given period.

78 Provided that relevant externalities and wider energy system impacts are "internalised" in the costs faced by market participants.

79 In its 2022 assessment of EU market design, ACER sets out why the "pay-as-clear" approach is efficient, compared to "pay-as-bid". See ACER (2022), "ACER's Final Assessment of the EU Wholesale Electricity Market Design", section 3.2. https://www.acer.europa.eu/sites/default/files/documents/Publications/Final_Assessment_EU_Wholesale_Electricity_Market_Design.pdf

80 Even absent explicit price caps, where imbalance prices do not reflect the marginal cost of actions taken by system operators to balance supply and demand within bidding zones (including the value of lost load), this can distort price formation in spot markets. See also footnote 25.

storages), leading to additional challenges in ensuring the secure operation of the system (as well as, as we later discuss, in relation to securing investment).

In theory, the resulting inefficiency from intervening in spot prices could be overcome through adopting a “command-and-control” approach to dispatch. However, this would require administrators to have full information on costs and technical capabilities of an increasingly diverse and decentralised set of resources, which would present an immense challenge.

This is not to argue that there is no room for improvement for spot markets. As described in section 3.2, participants’ short-run marginal costs are sometimes influenced by policy decisions. Where these policies correct for externalities, they contribute to efficient dispatch and to system adequacy.

Nevertheless, policy intervention affecting price formation may distort dispatch. This is the case for certain RES-E support schemes. Some legacy support schemes and feed-in-tariff schemes for smaller-scale RES-E incentivise generation even when electricity wholesale prices are negative (signalling an excess of power generation), and it might have been otherwise efficient for RES-E to self-curtail. Even where support arrangements are designed to avoid payments at periods of negative spot prices as required by EU energy State aid rules since the 2014 EEAG[81], “pay-as-produced” support schemes can nevertheless distort balancing and ancillary services markets (contrary to the requirements of the revised Electricity Regulation as revised by EMDR[82]). This is because the cost of foregoing support payments (during periods of positive spot prices) may reduce incentives for generators to provide downward balancing to system operators.

In addition, while it will not always be economic for consumers to offer their flexibility to wholesale markets (and nor will they always want to), regulatory barriers may inefficiently hold back the potential for demand-side response (including aggregated participation) and other distributed energy resources, such as distributed generation, vehicle-to-grid (V2G) and heat pumps, even where their participation in wholesale markets may be otherwise beneficial (for suppliers) and desirable from a system perspective. For example, in its 2023 market monitoring report[83], ACER has identified several Member States lacking a proper legal framework to allow market access for such sources.

As discussed in Section 3.2, short-term markets – hosted by exchanges – also allow market participants to fine-tune their traded positions in response to, e.g., where retailers expect their customers to consume more or less energy in comparison to earlier forecasts. This enables an efficient market response to short-term changes in supply and demand, including climatic conditions, business needs of customers, and more complex seasonal demand patterns that might be more difficult to hedge with standardised forward products (see below).

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81 https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=planjo:20140620-001, paragraph 124(c).

82 Regulation (EU) 2019/943, Article 19d.

83 ACER (2023) “Demand response and other distributed energy resources: what barriers are holding them back?”.

Wholesale prices provide important signals for investment decisions

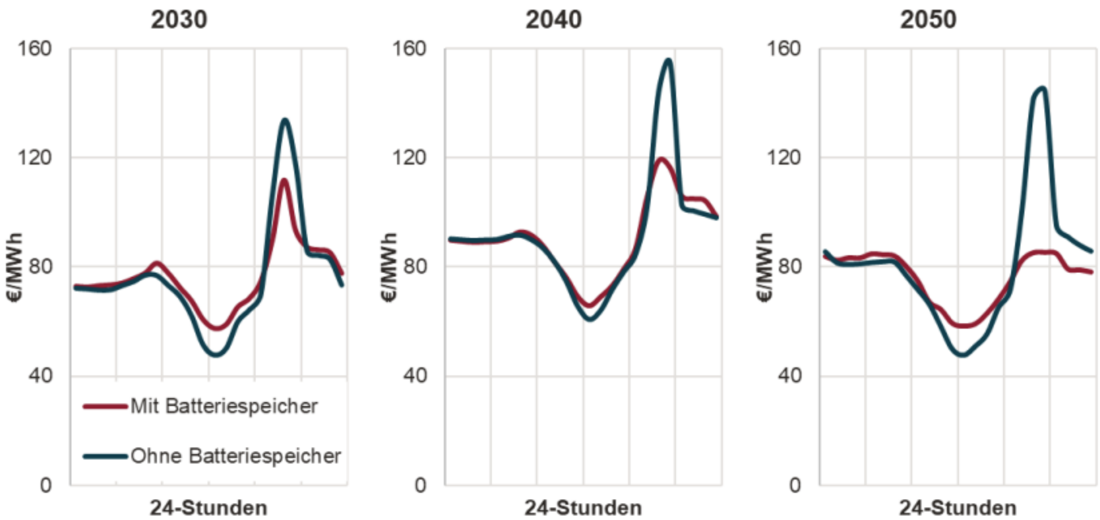
Investment decisions are informed by expectations of future cash flows from prospective investment projects and the investor's required rate of return. Given future cash flows will be subject to uncertainty, many energy investments can be thought of as "real options", with two sources of expected future value:

- **Intrinsic value:** the net present value of expected cash flows. For example, the value of an investment into power storage will partly be driven by the expectation of the typical peak and base wholesale price. The operator of a power storage asset would buy electricity when it is cheap and charge the storage asset, and later sell that electricity when the price is high. The intrinsic value will be the greater, the greater the price spread between the cheapest and the most expensive price hours across the typical charging cycle;

- **Extrinsic value:** the value arising from the option to exploit future periods of higher or more volatile than expected prices. This value is driven by uncertainty and price volatility, as well as the extent of asset flexibility.

This means that price volatility may actually increase the incentive to invest into certain types of electricity assets. If volatility incentivises more investments into flexible supply and storage solutions, then this will tend to lower volatility in the market (Figure 34). Ultimately one would expect an equilibrium in the market where volatility is contained in a way that it no longer triggers significant additional investment into flexible supply and storage sources.

Figure 34 Projected impact of battery storage on daily price movements (Germany)



Source: Frontier Economics (2024) [Der Wert von Großbatteriespeichern im Deutschen Stromsystem]
Note: The red line indicates projected hourly prices with battery storage. The teal line indicates projected hourly prices without battery storage deployed

Investors will ultimately consider all types of available revenue sources in evaluating the commercial viability of investment projects. An entirely wholesale market-driven approach ("energy-only market") to driving investment decisions is, in principle, possible.[84]

- Intrinsic value will depend on the expected extent of inframarginal rent and scarcity rent in spot electricity prices.[85] This in turn will depend on expectations of wholesale prices and participants' expected position in the merit order over time (which in turn will be influenced by changes in fuel costs and EUA pricing) as well as expectations of scarcity;
- Flexible assets may derive further extrinsic value based on price volatility. For example, battery operators can choose when to discharge and capture potential future price spikes and can arbitrage on an ongoing basis between revenues from different services (e.g. ancillary services, wholesale markets); and
- Depending on their risk appetite, investors may seek to hedge these revenue streams (see section 3.3).

In theory, provided relevant externalities (see section 5.4) are addressed, energy-only markets would be capable of driving not only sufficient investment, but also the least-cost mix of technologies (from a societal perspective) required to balance supply and demand and meet system operability needs. Wholesale prices set on the merit order principle will allow operators with lower marginal costs to earn a margin above their variable cost which will contribute to fixed costs, investment costs and a return. Flexible plants will also earn a return from exploiting volatility in electricity prices across different timeframes (including, as noted above, deriving extrinsic value from volatility).

The dynamics of competition, together with free entry and exit of investors, should ensure (over the long run) that market prices are at levels consistent with required investments. In other words, in an energy-only market, in principle[86], participants (in aggregate) make the trade-off between the cost to society of investing in and operating capacity and the associated benefits (in terms of reduced scarcity).

The EMDR saw the introduction into EU internal market legislation of mechanisms to complement the energy-only market. The underlying intent of these mechanisms is, on the one hand, to secure supply and support investments in new generation by stabilising revenues

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84 Revenues from wholesale and ancillary services markets are both relevant.

85 The extent to which the spot price exceeds the generators' SRMC, which contributes to the recovery of fixed costs (see section 3.2).

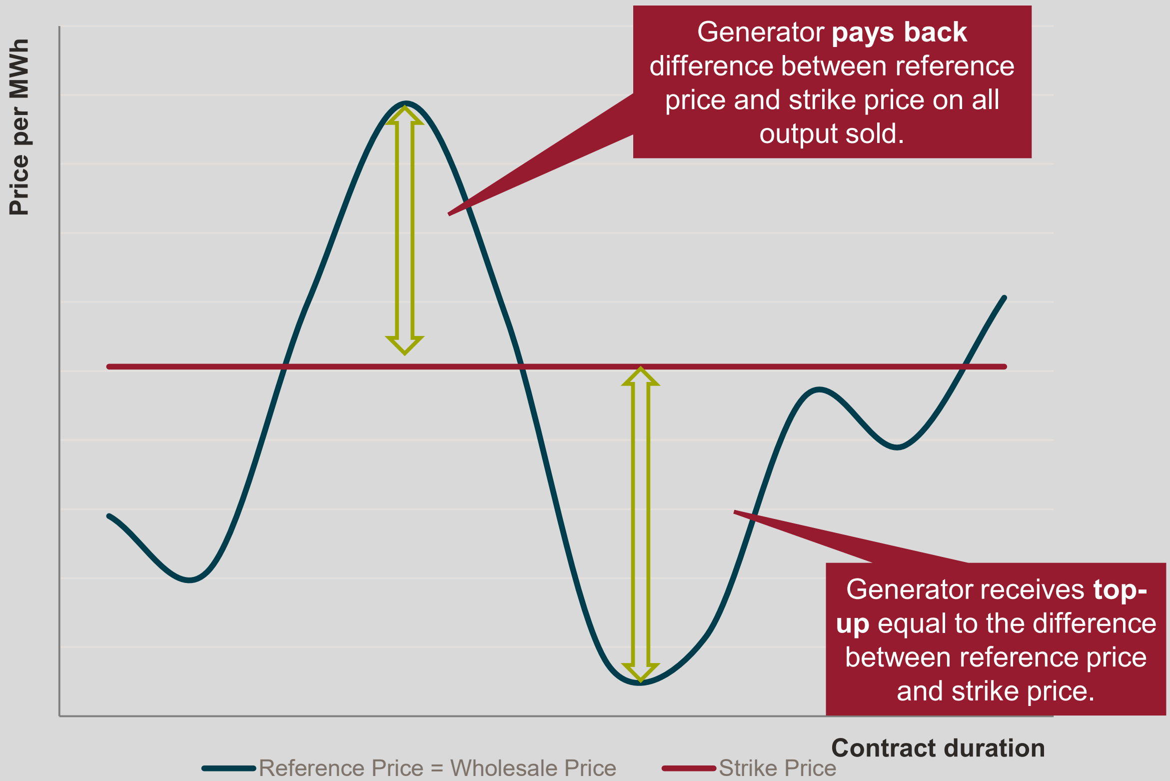
86 For a further discussion, see Perner, Jens, and others, 'Energy Market Design with Capacity Mechanisms', in Leigh Hancher, and others (eds), *Capacity Mechanisms in the EU Energy Markets: Law, Policy, and Economics*, 2nd edn (Oxford, 2022; online edn, Oxford Academic, 19 Jan 2023), https://doi.org/10.1093/oso/9780192849809.003.0005, accessed 4 Nov. 2025

and, on the other, to shield consumers from extreme price peaks. Contracts for difference ("CfDs") are an example of the former (see box below).

Introduction to CfDs

The Electricity Regulation (as amended by the EMDR) defines a (two-way) CfD as meaning "…a contract between a power-generating facility operator and a counterpart, usually a public entity, that provides both minimum remuneration protection and a limit to excess remuneration"

Typically, generators under CfDs (which are typically valid for multiple years, e.g. 15 years) receive top-ups on output sold to the wholesale spot market in hours where the reference price is below the strike price and pay back the difference between the reference price and the strike price in hours when the reference price is above the strike price, as illustrated in the Figure below.



Source: Frontier Economics and Cornwall Insight (2024) "Market signals and renewable investment behaviour: Final Report"

As noted, CfDs are an instrument recognised under EMDR that aim to provide investors with greater confidence on their return on investments. However, when designing CfDs, policymakers should consider the benefit of exposure to underlying wholesale energy market signals and their volatility, and of ensuring that bidding behaviour remains linked to market fundamentals. This can help avoid potential distortions in physical markets, which would otherwise lead to suboptimal or inefficient dispatching. Depending on precise design, mechanisms that reduce investors' exposure to wholesale price risks may also distort investment where there is competition between technologies for support, by masking differences between projects/technologies in terms of the value (both intrinsic and extrinsic[87]) they bring to the system.

In addition, as we go on to discuss in section 5.2, market participants have a natural incentive to hedge their wholesale risks on forward and futures markets. The resulting hedging behaviour, in turn, supports liquidity and reliable forward price signals to suppliers, investors and consumers. Thus, it is important to design CfDs in a way to minimise the potential negative impact on forward markets. In case of a significant use of poorly designed CfDs, this can create difficulties for other market participants to hedge their long-term supply or procurement of electricity in competitive forward markets with shrinking liquidity.

Recommendations: Limit market-restrictive interventions

- Refrain from measures that distort market functioning and the signals provided by spot market prices, such as price caps or dismantling the uniform pricing mechanism
- Ensure that support mechanisms support efficient operational and investment decisions, do not reduce liquidity or distort price formation and allow, to the greatest extent possible, competition between technologies.
- Remove remaining barriers to the participation of DSR and other distributed energy resources in wholesale markets, whether through direct access or aggregation
- Ensure that any regulatory intervention is grounded in thorough impact assessments and meaningful stakeholder consultation, to minimise the risk of distortions or unintended consequences

5.2 Participants will continue to require access to hedging opportunities, including those facilitated by power exchanges

Access to efficient and effective hedging opportunities remains essential for market participants. Trading on well-functioning marketplaces such as power exchanges enables them to continuously manage their exposure to spot price volatility based on their specific business needs. For example, by entering long-term contracts in the derivatives market – months or years ahead of delivery – participants can effectively insure themselves against the

87 For example, price or revenue caps limit exposure to peak prices and/or volatility and therefore reduce the value to investors of developing flexible technologies.

market price risk of short-term spot price swings.[88] We have discussed this earlier with the example of a retail portfolio in section 3.4.

Organised marketplaces such as power exchanges have strong commercial incentives to provide and maintain adequate market liquidity.[89] However, **policy and regulation can contribute to enhancing market liquidity**:

- **Facilitative policy framework** – it is important to ensure that the wider energy policy framework does not unintentionally crowd out demand for or supply of market-based hedging instruments, for example, through administratively set retail price caps (see section 5.4) or flawed designs of policy support mechanisms.

- **Thinking energy and financial regulation together** – energy and financial markets are closely linked, and actions taken in one market affect the other and vice versa. To avoid adverse impacts on market liquidity, a joint view assessing both the physical and financial dimension of energy market regulation is required.[90]

- **Accurate and reliable price signals –** orderly formed market prices convey important information for market participants (e.g., for risk management, investment or dispatch purposes). The regulatory environment for energy trading should therefore ensure orderly price formation through adequate rules on market integrity (e.g., REMIT[91] and MAR[92]).

- **Appropriate bidding zone design** – as hedging requires a sufficiently large set of market participants and counterparties to match supply and demand for risk management solutions (see above), bidding zones need to be appropriately calibrated to facilitate sufficient trading volumes. While more granular bidding zone configurations may support greater efficiency of operational dispatch (depending on what measures are already in place in Member States to manage network congestion within bidding zones), reduced

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88 In its 2023 consultation on the future electricity market design, the European Commission further emphasised the need for sufficient hedging opportunities with increased levels of renewable generation: *"Both consumers and suppliers need effective and efficient forward markets to hedge their price exposure and decrease the dependence on short-term prices"* and "*[t]he rapid deployment of renewable generation over the coming years will increase the need for hedging opportunities due to the expected growing price volatility in the years ahead*." See European Commission (2023), Commission Staff Working Document: Reform of Electricity Market Design, page 36, https://energy.ec.europa.eu/system/files/2023-03/SWD_2023_58_1_EN_autre_document_travail_service_part1_v6.pdf

89 Liquid energy markets allow market participants to buy or sell energy commodities without causing a material change to the price of the product and without incurring material transaction costs. An important feature of a liquid market is the presence of a large number of buyers and sellers willing to transact at all times. Objectives for liquidity include the availability of long-term products for risk hedging, robust reference prices based on real market values and an effective short-term market.

90 See also Frontier Economics (2024), "Principles of Energy Market Regulation", https://cms.energytraderseurope.org/storage/uploads/media/frontier-luther---principles-of-energy-market-regulation-19042024.pdf

91 Regulation (EU) No 1227/2011 of the European Parliament and of the Council of 25 October 2011 on wholesale energy market integrity and transparency, https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32011R1227

92 Regulation (EU) 596/2014 of the European Parliament and the Council of 16 April 2014, https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32014R0596

bidding zone size may adversely affect overall risk management efficiency and effectiveness.

Well-functioning hedging and retail markets can allow end-consumers to choose their preferred level of wholesale price exposure. Irrespective of their selected level of exposure, electricity consumers face useful price signals:

- **Small end-customers** – many small end-customers such as households and small-and-medium enterprises (SMEs) choose to limit their exposure to short-term volatility by entering largely fixed price (but variable) contracts with their retailer, who then procure the electricity for small end-customers on the wholesale market. As we set out in section 3.4 before, even on fixed term contracts, consumers remain exposed to average electricity wholesale prices to some degree.
- **Large direct wholesale customers** – compared to small end-customers, large customers directly active in wholesale markets may be more willing to be more strongly exposed to short-term price movements to support greater operational efficiency (see section 5.1). Even if large direct wholesale customers are fully hedged for a specific volume and time period during a short-term price spike, they are not obliged to consume the hedged electricity. Instead, they face a trade-off between (i) using the electricity at the hedged price to maintain production or (ii) reducing demand and production to sell the hedged position at a profit to wholesale counterparties.

Poorly designed cost recovery charges or interventions in retail pricing (discussed in section 5.4) may reduce consumers' ability to choose and administer their risk exposure. For example, the costs (to be recovered from consumers) associated with payments to generators under two-way contracts for difference (see section 5.1) will be inversely related to the wholesale price. If these costs are recovered from consumers on a one-for-one basis in the exact hours in which they accrue, this will dampen consumers' exposure to short-term wholesale prices (whether consumers prefer it or not).

Recommendations: Supporting market players' ability to hedge price volatility

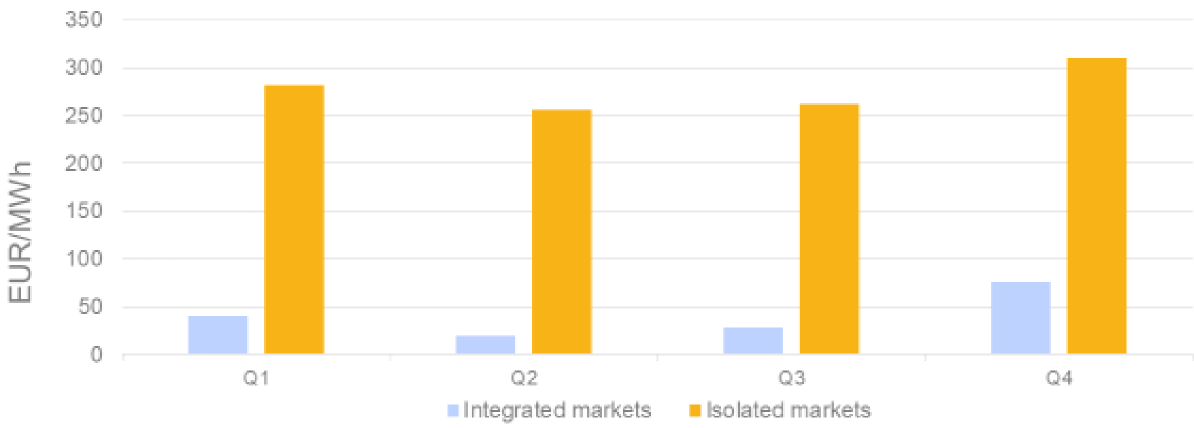
- Ensure that economic risk management considerations are systematically and sufficiently considered when evaluating policy changes, such as bidding zone reconfiguration, revisions to support schemes or amendments to commodity trading regulation, to avoid undermining hedging opportunities and market liquidity

5.3 Harnessing full benefits of the single electricity market (and extending its reach) will help lower costs

Continued integration of EU (and wider European) short-term markets will be crucial

Cross-border trade in the electricity market delivers significant welfare benefits, by ensuring that least-cost resources are used to supply demand in the market (section 5.1). The benefits are significant – estimated by ACER to be worth EUR 34 billion in 2021,[93] compared to a hypothetical counterfactual assuming no cross-border trade between Member States. ACER also estimated that isolation of national markets would have led to spot prices being around seven times more volatile (as measured by the standard deviation) during 2021 than they actually were (Figure 35 below).

Figure 35 Price volatility (EUR/MWh) in integrated and isolated electricity markets in the EU in 2021



Source: *ACER (2022) "Final Assessment of the EU Wholesale Electricity Market Design"*

Note: *Price volatility was calculated as the standard deviation of day-ahead wholesale prices ("integrated markets" = historical prices, "isolated prices" = simulated prices without interconnection capacity) in each of the different EU bidding zones, then averaged across the EU.*

The availability of cross-border capacity and the absence of explicit financial costs of cross-border power trade are clearly important drivers of welfare benefits. But the design of trading arrangements – particularly the operation of market coupling (described in section 3.2) facilitating improved utilisation of cross-border capacity – also contributes to benefits. Of the EUR 34 billion benefits of cross-border trade estimated by ACER (cited above), over EUR 1 billion is attributed to the process of market coupling.[94] The United Kingdom (UK) provides a further case study. Following the UK's withdrawal from the EU, the Great Britain (GB) power market has ceased to be coupled with EU power markets, leading to less efficient utilisation

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93 ACER's Final Assessment of the EU Wholesale Electricity Market Design, pages 21-22. https://www.acer.europa.eu/sites/default/files/documents/Publications/Final_Assessment_EU_Wholesale_Electricity_Market_Design.pdf

94 ACER's Final Assessment of the EU Wholesale Electricity Market Design, page 22.

of available interconnector capacity. Indicative analysis estimates that, during 2021, the value of lost trade may have been in the order of £45 million annually.[95]

It follows that aside from improving the availability of cross-border capacity (including ensuring the optimal allocation of cross-border capacity across market timeframes: day-ahead and intraday), further welfare gains are possible from implementing more efficient trading arrangements with the EU's neighbours, including Switzerland, the UK and Energy Community countries.

The systems and process changes to achieve these gains (and other ongoing reforms to market coupling processes) are being facilitated by co-operation between Nominated Electricity Market Operators (NEMOs)[96], regulators, and TSOs. The Commission is considering possible changes to the governance structures for market coupling operation. In doing so, it will be important that the Commission properly accounts for the risks of transitioning to a radically different governance structure, including potential delays in realising the benefits from planned reforms.

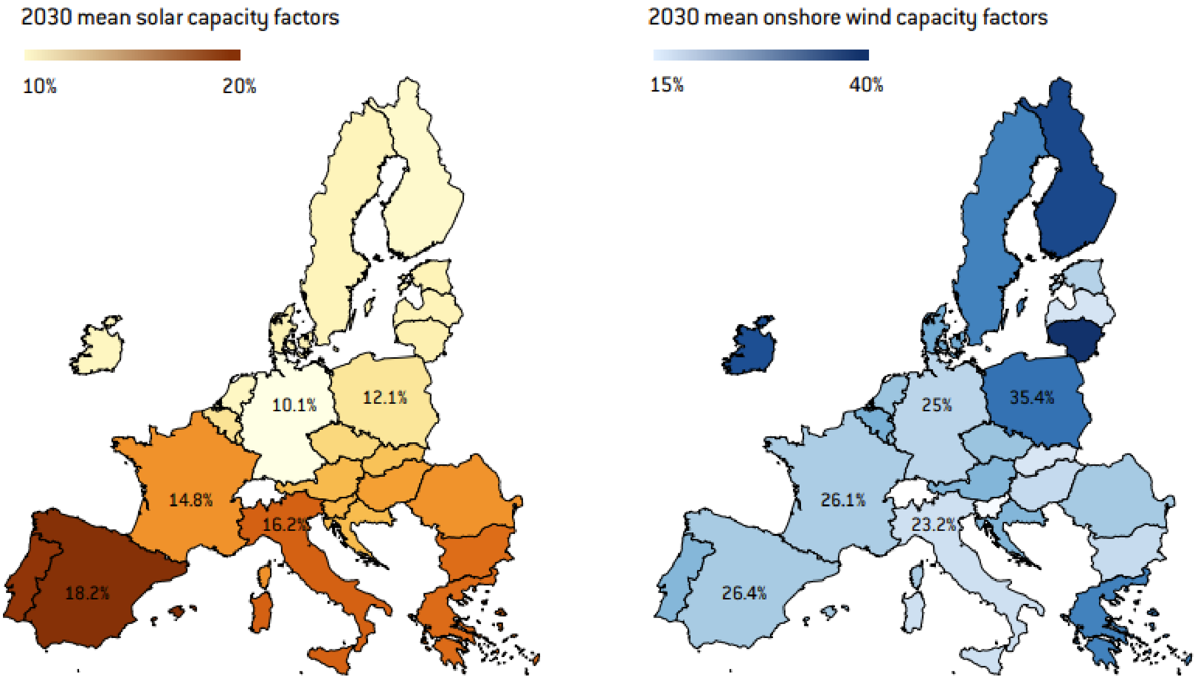
An ambitious view of EU market integration would also promote efficient investment across borders

While EU-wide cost savings from optimising the use of existing resources across borders can be significant (as described above), so can EU-wide savings from optimising the location of investment in new resources, especially given differing natural resource endowments including with solar radiation and wind availability (see Figure 11 below).

95 https://www.frontier-economics.com/uk/en/news-and-insights/articles/article-i8192-brexit-and-interconnectors-a-45m-problem/

96 In many cases, NEMOs are power exchanges.

Figure 36 Solar and wind potential in Europe



Source: Bruegel (2024) "Unity in power, power in unity: why the EU needs more integrated electricity markets" https://www.bruegel.org/system/files/2024-04/PB%2003%202024.pdf

These savings cannot be achieved without cross-border co-ordination in relation to infrastructure planning and regulation (as noted in section 5.4). And given cost savings may geographically be unevenly distributed (indeed, resource-rich regions could see consumers losing out through higher electricity prices from the development of interconnection), realising the required investments in infrastructure may also require strong cross-border cost sharing mechanisms, given the limits to EU level funding. Efficient power markets can support this process too – partly by revealing the value of network capacity – and partly since they (by definition) maximise the combined surplus then available for any sharing between Member States.

Recommendations: Make the most of cross-border trade

- Strengthen cross-border trading and optimise the use of available transmission capacity to enhance efficiency and price convergence
- Extend the Internal Energy Market beyond the EU's borders, including through market coupling with the Energy Community Contracting Parties, Great Britain and Switzerland
- Carefully assess the risks to delivery of ongoing market coupling reforms, particularly in light of innovation, resilience and efficiency
- Ensure that any further development of Europe's coupled markets is subject to thorough impact assessment and meaningful stakeholder consultation

5.4 The wider policy framework has a role in supporting the market

Addressing market imperfections

It is important to recognise that there are some areas of the electricity system where administrative choices will always be required. Indeed, it is important to support the market's role in co-ordinating investment and operational decisions.

- **Addressing externalities**,[97] notably those related to the environmental impacts of energy production, including greenhouse gas (GHG) emissions, air quality and natural environment. For example, in the EU power sector, the EU Emissions Trading Scheme is a key instrument to address GHG emissions, while more localised emissions are further addressed through legislation such as the Industrial Emission Directive at EU level. Best practice benchmarks play a role in both.

- **Network regulation and planning:** Energy network infrastructure is typically a natural monopoly[98] and so is subject to regulation (to mitigate horizontal market power concerns and vertical foreclosure). In addition, the optimal configuration of the physical system involves strategic decisions regarding the placing of energy network infrastructure (the location of which in turn influences the siting of supply and demand). These decisions require a strong role for the public sector in co-ordinating between supply, storage, demand and networks, between levels of the network, and across energy carriers. Network investment partly interacts with security of supply, e.g. because it determines the extent to which capacity reserves can be shared between different jurisdictions or bidding zones. Regions more strongly interconnected through network investment find it easier to benefit from shared resources via market mechanisms.

- **System operation and co-ordination:** Ensuring the real-time operational security of the electricity system is also considered a natural monopoly activity and system operators are also subject to economic regulation;

- **Market power monitoring:** Exercise of market power can reduce both consumer and overall societal welfare. Effective antitrust enforcement and specific energy market abuse legislation (i.e. REMIT[99]) exists to mitigate the associated risks; and

97 Externalities refer to the impacts (positive or negative) that a particular economic activity has on agents outside the market in question. Absent well-defined property rights or policy intervention, such external impacts are not considered by market participants, leading to under-consumption (in the case of positive externalities) or over-consumption (in the case of negative externalities).

98 Natural monopolies are characterised by such high up-front fixed (investment) costs that lead to such significant economies of scale that it will be cheaper for a single firm to serve all demand. In the context of electricity networks, it means that there is limited/no scope for competing network infrastructure.

99 Regulation (EU) No 1227/2011 of the European Parliament and of the Council of 25 October 2011 on wholesale energy market integrity and transparency

- **Financial regulation:** In addition to (physical) energy markets, policymakers have also identified the need for regulatory oversight and intervention in the financial markets where energy derivatives are traded. As energy and financial markets are closely intertwined (actions taken in physical markets affect the other, and vice versa), financial market regulation and energy market regulation need to be aligned (as we have discussed in section 5.2).

- **Permitting:** Overly restrictive planning legislation can hold back investments in new capacity, including in flexible resources that can support system needs and mitigate price volatility.

Policymakers may also wish to intervene to address distributional concerns. The EMDR foresees the use of mechanisms that stabilise revenue streams, potentially reducing the cost of supporting investments in new generation, and that may also contribute to stabilising prices for consumers.

Trade-offs between cost reflectivity and cost recovery

Public and regulatory oversight also applies to the recovery of network (including system operation) and wider policy costs. Considering network and policy costs, the charges that users face serve, in principle, two purposes:

- **Cost reflectivity:** If market participants face the incremental forward-looking costs that they impose on the system (and receive the benefits that they bring), they then should take these costs into account in their investment and operational decisions. This is particularly relevant for network tariff design. Appropriate tariff design can help contain demand peaks (and shift demand to some other periods) so as to lower the utilisation of generation and network assets. This can help avoid or at least delay required capacity expansion (generation and networks).

- **Cost recovery:** Efficiently incurred costs of past investments (and a return on the related investment) do need to be recovered to give investors an incentive to invest in the first place. However, charges that only recover incremental forward-looking costs will not recover irreversibly incurred (i.e. “sunk”) costs, such as those associated with past investments or generation subsidies. As such, authorities also need to consider how to recoup these costs, including how to distribute costs between consumers and across different consumer groups (household, commerce and industry) and whether and how to recover any shortfalls through public budgets. Cost recovery is not intended to encourage a particular form of usage behaviour – so the guiding principles for efficient cost recovery will be the need to avoid distorting behaviour[100] and fairness (while sustaining incentives for efficient investment).

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100 The economist Frank Ramsey developed a theory for optimal commodity taxation in the 1920s. The ‘Ramsey Rule’ is sometimes interpreted as requiring the burden of cost recovery (in our case, levies and sunk network costs) to be

While not the focus of this report, it is important to note that choices in these areas have the potential to significantly affect the costs (see section 3.1) and revenue streams, and resulting signals, that market participants and investors face. Poorly designed network tariffs and broader cost recovery can distort the signals that market participants face (e.g., regarding the flexibility that they demand from the system or that they offer to the system by changing their demand or supply behaviour).

Trade-offs between cost reflectivity and affordability

Policymakers can also intervene more directly in retail pricing, such as through the regulation of (household) retail prices or the introduction of social tariffs to support customers identified as being particularly vulnerable. Whilst such interventions can help to alleviate financial pressure faced by low-income households, they involve trade-offs:

- Between consumer groups, since the cost of such interventions will tend to be borne either by market participants (through reduced profitability) or recovered from other customers. The broader the take-up of social tariffs, or the discount offered, the greater the burden on non-eligible consumer groups; and

- Between the interests of beneficiary consumer groups and overall efficiency. This is partly driven by the extent that such pricing structures dampen the overall cost reflectivity of electricity prices. For example, they may lead to incentives to over-consume electricity and reduced incentives for consumer flexibility. And to the extent that such interventions impose financial constraints on market participants, they may distort competition.

Interventions in retail pricing (going beyond the enforcement of competition law) can also affect retailer hedging behaviour. For example, they may incentivise the trading of certain reference products to the detriment of trading in other products, affecting liquidity available for other market participants.

To the extent still deemed appropriate despite the possibility of less distortive ways of supporting households, such interventions should therefore be carefully designed and targeted.

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shouldered by those least sensitive to changes in prices (i.e. those least likely to respond by changing their consumption or production). This helps to ensure that the resulting production pattern across the economy deviates as little as possible from what is efficient from a societal perspective. For energy-intensive industries exposed to international competition, this provides a rationale for relief from cost-recovery components. Cost recovery charges also have the potential to distort choices between energy carriers, to the extent that they are substitutes for each other.

Recommendations: Ensure the wider policy framework facilitates markets

- Maintain a focus on efficient infrastructure planning and regulation ensuring that infrastructure development is optimised across levels of the grids, energy carriers and Member States
- Remove barriers to permitting and streamline approval processes for new capacity (generation, storage and network)
- Avoid tariff, levy and tax structures that distort market participants' investment and operational decisions
- Refrain from distortive retail price regulation; ensure that any regulated or social tariffs are well-targeted while preserving competition and maintaining consumer incentives

Annex A – Literature on drivers of price volatility

Table 4 overleaf presents a summary of selected empirical studies reviewed on the drivers of power price volatility.

Table 4 Selected recent academic studies on electricity price volatility in European markets

Paper	Area	Time horizon	Methodology	Main findings
Cevik,S., Zhao, Y. (2025). Shocked: Electricity Price Volatility Spillovers in Europe, IMF Working Papers.	24 EU countries	12/14 – 04/24	Investigation of price volatility spillovers across countries, using a VAR framework and a PPML gravity model	Cross-border volatility spillovers dominate the behaviour in national electricity markets in Europe, and bilateral volatility spillovers are influenced by geographic proximity, economic size, and renewable energy shares
Simon, S. N., Anadon, L. (2025). Power price stability and the insurance value of renewable technologies. Nature Energy.	EU countries, UK and CH	Forecasts for 2030	Simulation of European electricity markets for 2030 using Monte Carlo methods to model demand, fuel prices, and weather variability, assessing how different levels of renewable deployment affect annual price volatility and sensitivity to natural gas.	Meeting 2030 renewable targets reduces electricity price volatility and gas sensitivity by around 20–30%, but deeper stabilisation by cutting gas sensitivity requires 30%+ additional renewables.
Stanković, Z.Z., Rajic, M.N., Božić, Z., Milosavljević, P., Păcurar, A., Borzan, C., Păcurar, R., Sabău, E. (2024). The Volatility Dynamics of Prices in the	28 EU countries	01/2018 – 12/2021	Price velocity metrics (e.g. average magnitude of hourly price fluctuations within a day) used to assess short-term electricity price fluctuations, and fixed base	Price volatility was highest on a daily basis during the COVID-19 pandemic, with increasing convergence across markets in volatility patterns.

European Power Markets during the COVID-19 Pandemic Period. Sustainability 2024, 16, 2426.			indices (comparing each year to a reference year) and chain base indices (comparing each year to the previous one) to measure long-term growth and market convergence	
Abadie, L. M., & Chamorro, J. M. (2024). On the Dynamics of Spot Power Prices across Western Europe in Pandemic Times. Energies, 17(14), 3420.	8 EU countries (Western Europe)	04/2020-05/2023	Hourly spot prices modelled using a stochastic process with mean reversion, volatility, discrete jumps and a deterministic seasonal component	Price volatility increased during the crisis period, with larger jumps and slower mean reversion, and showed regional divergence, especially with the Iberian Peninsula decoupling from core EU markets.
Wang, Y., Sbai, S., Wen, F., Sheng, M. (2024). The impact of renewable energy on extreme volatility in wholesale electricity prices: Evidence from OECD countries. Journal of Cleaner Production	32 OECD countries	2015 - 2023	Dynamic panel threshold regression to analyse how different types of renewable energy affect extreme positive and negative volatility	Renewable energy significantly reduces extreme price volatility only after surpassing specific penetration thresholds, with wind, solar, and hydro showing the strongest stabilising effects.
Do, H. T., Nepal, R., Pham, T. H., & Jamasb, T. (2024). Electricity market crisis in Europe and cross-border price effects: A quantile return connectedness	11 EU countries	01/2012-12/2022	Quantile connectedness analysis of daily returns of electricity, natural gas and EUA prices, capturing spillover effects	The COVID-19 pandemic reduced volatility interconnectedness, while Russia’s invasion of Ukraine intensified it, especially

analysis. Economic Modelling.				during extreme market conditions.
Han, C., Hilger, H., Mix, E., Böttcher, P., Reyers, M., Beck, C., Witthaut, D., Rydin Gorjão, L. (2022). Complexity and Persistence of Price Time Series of the European Electricity Spot Market. PRX Energy.	DE, AT	2015-2019	Time series analysis studying price volatility behaviour at different timeframes	Price volatility is strong and consistent at short time scales (under 12 hours), but becomes weaker and less predictable over longer periods. Short-term spikes linked to extreme events and long-term trends shaped by weather.

Source: Frontier Economics.

Note: The literature review presented in this table is not intended to be exhaustive. The selection criteria included a focus on electricity price volatility, empirical analysis using data from European markets, and publication in 2022 or later.

Annex B – Data sources and quality

B.1 Data sources

The dataset is aggregated at an hourly resolution and combines price, generation, load, capacity, and cross-border exchange data to reflect the main drivers of volatility identified in the literature. Table 5 summarises the data used in the analysis and their corresponding sources.

Table 5 Data sources

Variable	Description	Dataset
Prices	Hourly day-ahead prices for each market time unit.	Energy Prices 12.1.D r3, ENTSO-E
Load	Net generation of power by plants, plus net imports and subtracting the absorbed power by energy storage resources.	Actual Total Load 6.1.A, ENTSO-E
Capacity – aggregated	Installed generation capacity for production units with at least 1 MW of capacity, aggregated per production type.	Installed Generation Capacity Aggregated 14.1.A, ENTSO-E
Capacity – Unit-level	Installed generation capacity for production units with at least 100 MW of capacity, per production unit.	Installed Capacity Production Unit 14.1.B, ENTSO-E
Generation	Actual aggregated net generation output per market time unit and production type.	Aggregated Generation Per Type 16.1.B_C, ENTSO-E
Imports / exports	Aggregated scheduled day-ahead commercial exchanges between bidding zones per direction and market time unit.	Commercial Schedules 12.1.F r3, ENTSO-E
Hydropower – energy stored	Aggregated weekly average filling rate of all water reservoirs and hydro storage plants.	Aggregated Filling Rate Of Water Reservoirs And Hydro Storage Plants 16.1.D, ENTSO-E

Outages	Planned and actual unavailability of production units with at least 200 MW of installed capacity. Records changes of 100 MW or more in actual availability.	Unavailability Of Production Units 15.1.C D, ENTSO-E
Gas prices	Daily natural gas day-ahead price in Europe.	TTF DAHD Index, Bloomberg
Coal prices	Daily coal month-ahead price in Europe.	API2 1MON Index, Bloomberg
EUA prices	Daily ICE EUA December Y0 contract values	ICE EUA Futures Index, Bloomberg

Source: Frontier Economics.

Note: All ENTSO-E's datasets are retrieved from the ENTSO-E SFTP (link) between 05/2025 and 06/2025.All Bloomberg's dataset were retrieved from the Bloomberg terminal.

The analysis presented in this report covers 39 bidding zones across Europe, including Austria (AT), Belgium (BE), Bulgaria (BG), Croatia (HR), Czech Republic (CZ), Germany-Luxembourg (DE-LU), two Danish zones (DK1 and DK2), Estonia (EE), Finland (FI), France (FR), Greece (GR), Hungary (HU), seven Italian zones (IT-Calabria, IT-Centre-North, IT-Centre-South, IT-North, IT-Sardinia, IT-Sicily, IT-South), Latvia (LV), Lithuania (LT), five Norwegian zones (NO1 to NO5), the Netherlands (NL), Poland (PL), Portugal (PT), Romania (RO), four Swedish zones (SE1 to SE4), Slovakia (SK), Slovenia (SI), Spain (ES), and Switzerland (CH).

Data quality and completeness

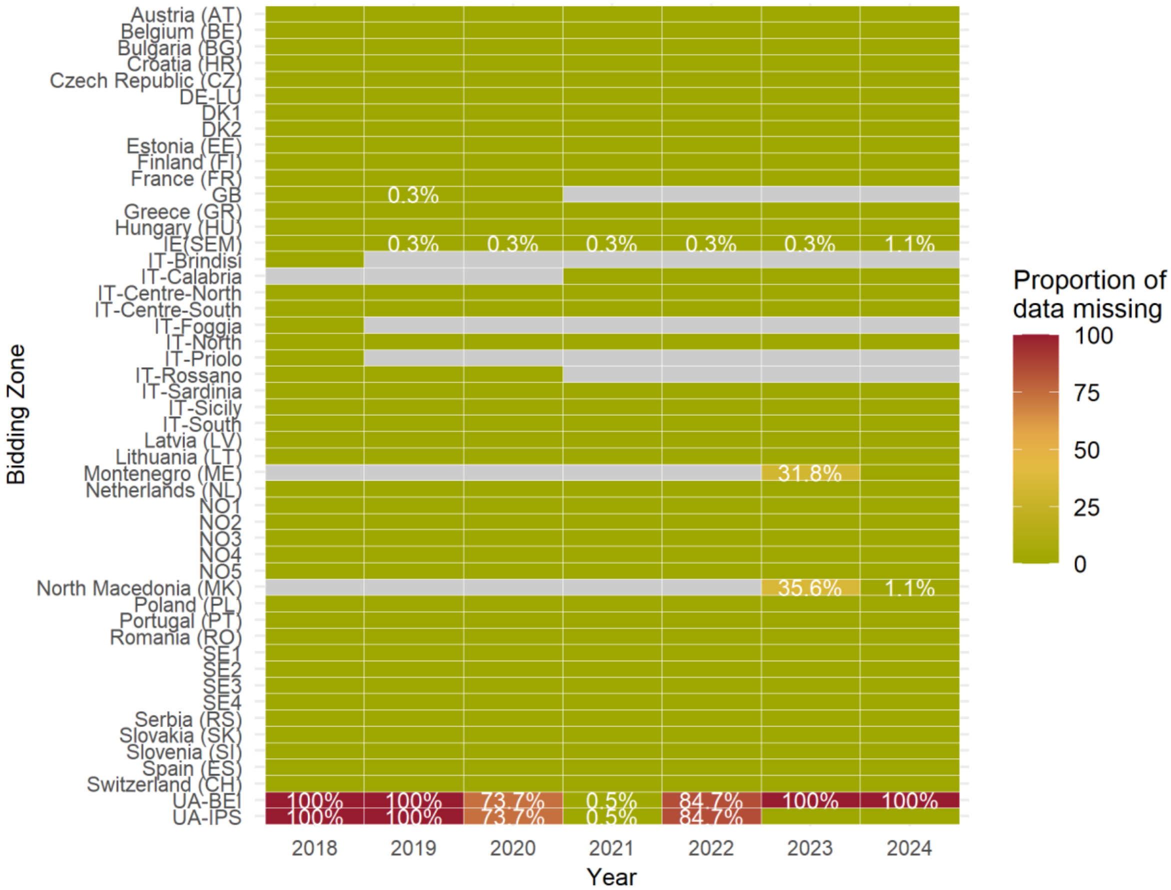
While ENTSO-E provides extensive data coverage in a consistent format across European bidding zones, several data quality and completeness issues remain, which have guided both the cleaning process and the selection of bidding zones for inclusion in our sample. To ensure robust and reliable results, it is essential to work with data that is both complete and of sufficient quality. Some bidding zones available in the ENTSO-E data platform were excluded due to significant data gaps or inconsistencies.

Figure 37 illustrates the extent of missing data for a representative dataset, actual total load, showing the bidding zones excluded from the final dataset due to missing data:[101] Great Britain (GB), Ireland (SEM), Montenegro (ME), North Macedonia (MK), and the two Ukrainian zones (UA-BEI and UA-IPS).[102]

101 While the extent and location of missing observations vary across the ENTSO-E's datasets, load and price data are by far the most complete among all sources. The choice of load as the representative dataset in this figure, therefore, offers a conservative view of overall data availability.

102 See below for a discussion on Italian bidding zones.

Figure 37 Proportion of missing data from ENTSO-E's load dataset by bidding zone (%)



Source: Frontier Economics, based on ENTSO-E's load data.

Note: Grey colour indicates missing data on the ENTSO-E transparency platform.

Beyond missing data, certain datasets required adjustment or cleaning:

- The electricity prices reported in local currencies are converted to EUR using the European Central Bank's historical daily exchange rates.[103]
- From 1 January 2021, Italy redefined its bidding zones, decommissioning four former production hubs (Brindisi, Foggia, Priolo, and Rossano), which reported generation and capacity data but not load. To maintain consistency, we merged these with adjacent zones (e.g., Priolo with Sicily, Foggia and Brindisi with South, Rossano with Calabria). Some regional boundary changes, such as the reassignment of Umbria from Centre-North to Centre-South, remain partially unadjusted and may affect comparability.[104]

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[103] European Central Bank's Euro foreign exchange reference rates (link). If the exchange rate for any specific currency on a given day was unavailable, the most recent available rate from previous days was carried forward.

[104] For additional information on the redefinition of Italian electricity market zones, see Terna (2021), "The new electricity market zones: what you need to know" (link).

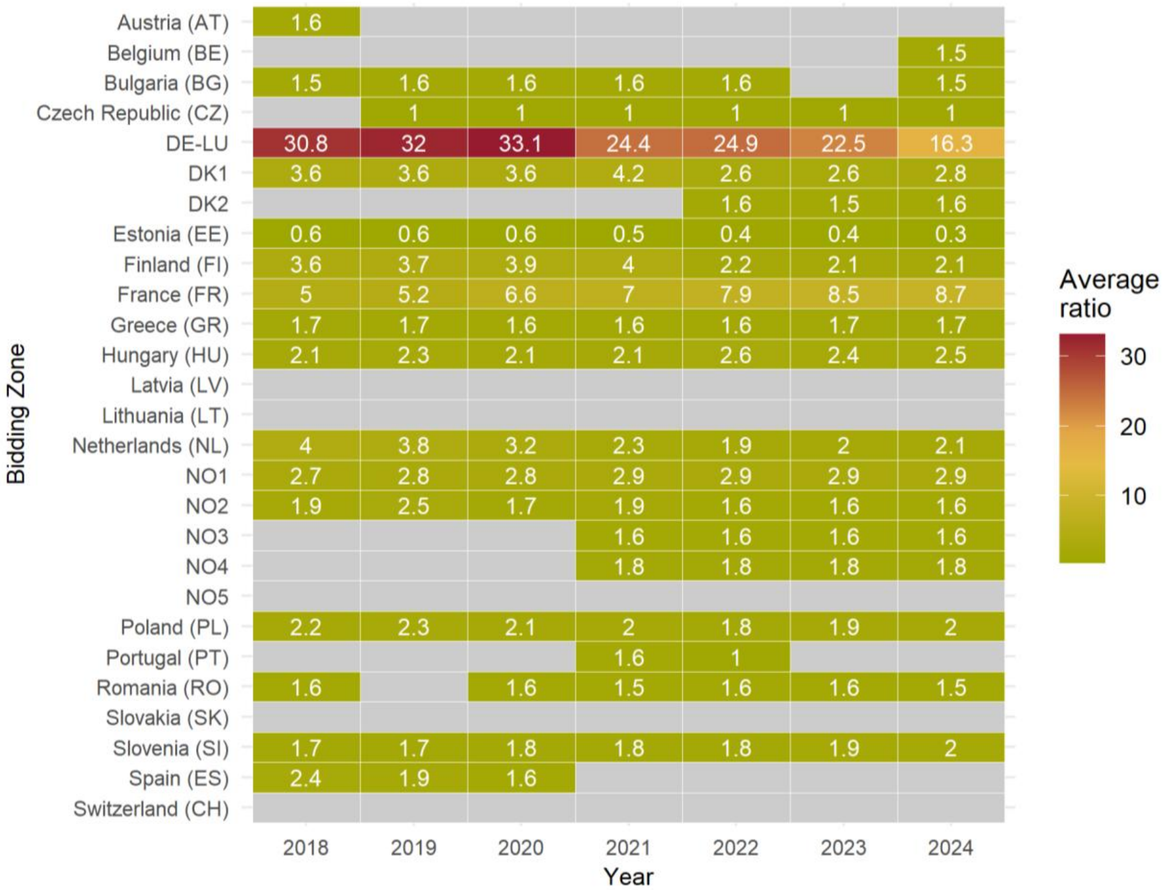
- In the case of hydro storage filling rates, ENTSO-E reports data inconsistently across countries and bidding zones. To address this, we used country-level values to fill gaps at the bidding zone level. In cases where no data was available in either format, we treated the missing values as non-reported and assigned a value of zero. Data for Germany remains missing in both formats, though we understand Member States are only required to report this data to ENTSO-E where hydro accounts for more than 10% of feed-in for this type of generation per year.[105] or bidding zones with more than 30% feed-in of this type of generation per year.

More significant challenges emerged in the generation and capacity datasets:

- The aggregated capacity dataset (14.1.A) reports annual installed generation capacity by production type. Where values are missing, particularly in Italy and Sweden, we supplemented the dataset by aggregating the unit-level dataset (14.1.B). Because aggregate data covers generation units with a capacity of at least 1 MW, it is generally expected to report higher capacity figures than the unit-level ones, covering all units of at least 100 MW. However, notable inconsistencies between the two datasets remain. In some bidding zones (e.g. DE-LU and France), aggregate values were much higher (up to 15 times), while in others (e.g. Estonia), unit-level data exceeded aggregate figures, which is counterintuitive. These inconsistencies, most prominent in solar and wind, remain unexplained but are presented in Figure 38 and Figure 39 below for transparency.

[105] Only bidding zones with more than 30% of feed-in of this type of generation per year are required to report this. For additional information, see ENTSO-E's Transparency Platform (link).

Figure 38 Average ratio of aggregated and unit-level capacity data, by bidding zone

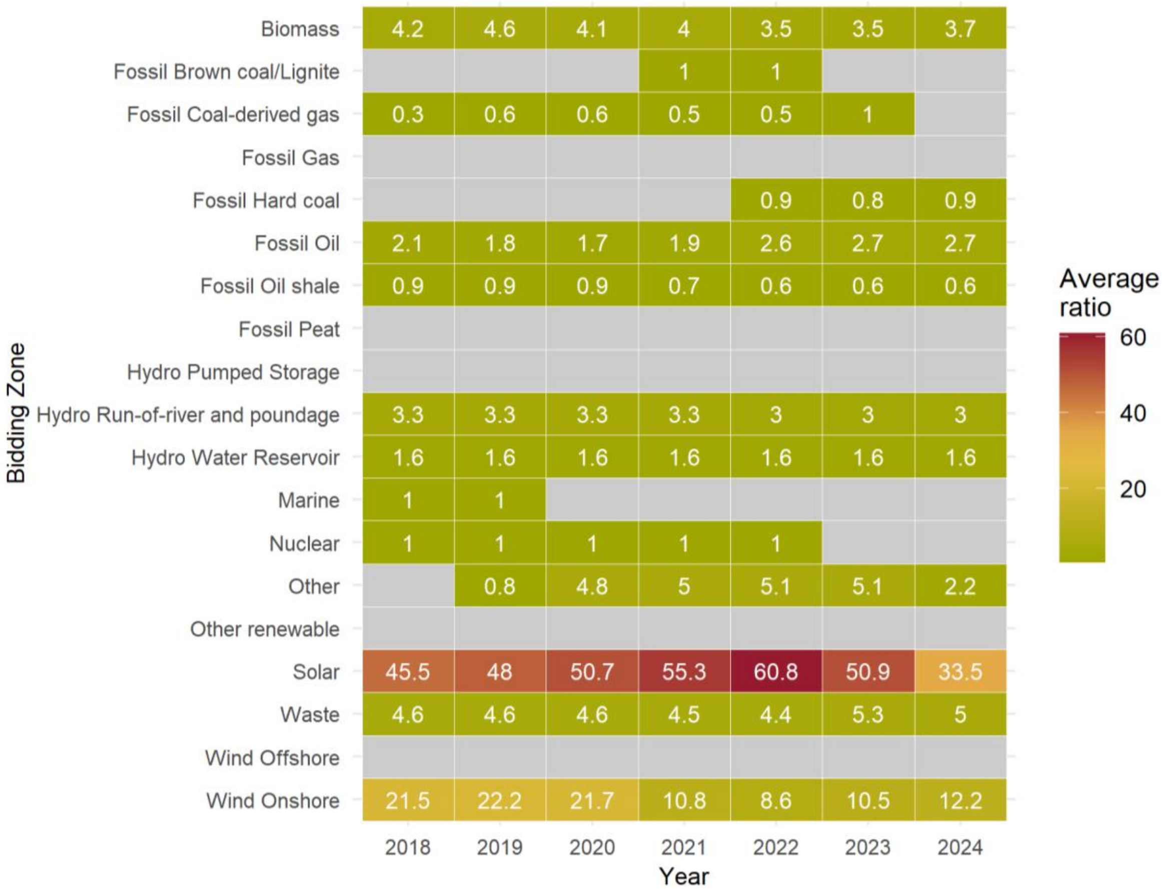


Bidding Zone	2018	2019	2020	2021	2022	2023	2024
Austria (AT)	1.6						
Belgium (BE)							1.5
Bulgaria (BG)	1.5	1.6	1.6	1.6	1.6		1.5
Czech Republic (CZ)		1	1	1	1	1	1
DE-LU	30.8	32	33.1	24.4	24.9	22.5	16.3
DK1	3.6	3.6	3.6	4.2	2.6	2.6	2.8
DK2					1.6	1.5	1.6
Estonia (EE)	0.6	0.6	0.6	0.5	0.4	0.4	0.3
Finland (FI)	3.6	3.7	3.9	4	2.2	2.1	2.1
France (FR)	5	5.2	6.6	7	7.9	8.5	8.7
Greece (GR)	1.7	1.7	1.6	1.6	1.6	1.7	1.7
Hungary (HU)	2.1	2.3	2.1	2.1	2.6	2.4	2.5
Latvia (LV)							
Lithuania (LT)							
Netherlands (NL)	4	3.8	3.2	2.3	1.9	2	2.1
NO1	2.7	2.8	2.8	2.9	2.9	2.9	2.9
NO2	1.9	2.5	1.7	1.9	1.6	1.6	1.6
NO3				1.6	1.6	1.6	1.6
NO4				1.8	1.8	1.8	1.8
NO5							
Poland (PL)	2.2	2.3	2.1	2	1.8	1.9	2
Portugal (PT)				1.6	1		
Romania (RO)	1.6		1.6	1.5	1.6	1.6	1.5
Slovakia (SK)							
Slovenia (SI)	1.7	1.7	1.8	1.8	1.8	1.9	2
Spain (ES)	2.4	1.9	1.6				
Switzerland (CH)							

Source: Frontier Economics, based on ENTSO-E's capacity data (dataset 14.1.A and 14.1.B).

Note: The heatmap reports the ratio of total yearly aggregated capacity (14.1.A) to the unit-level capacity (14.1.B), averaged across production types for each bidding zone and year. Ratios above 1 indicate that the aggregated dataset shows higher capacity than the unit dataset, while ratios below 1 indicate the opposite. Note that the figure represents a simple average across production types, not a capacity-weighted measure. Grey colour indicates cases where the aggregated and unit-level datasets are broadly consistent, i.e. the ratio is between 1 and 1.5.

Figure 39 Average ratio of aggregated and unit-level capacity data, by production type



Source: Frontier Economics, based on ENTSO-E's capacity data (dataset 14.1.A and 14.1.B).

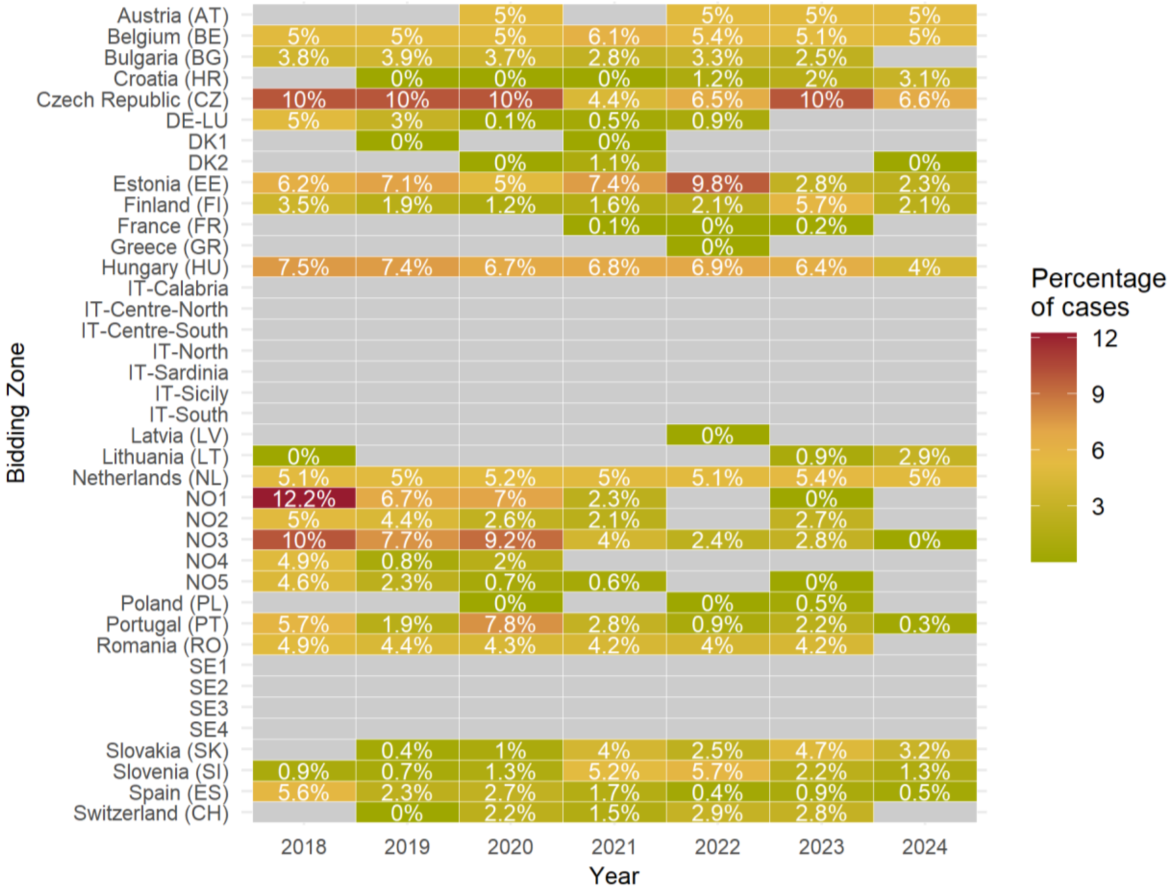
Note: The heatmap reports the ratio of total yearly aggregated capacity (14.1.A) to the unit-level capacity (14.1.B), averaged across bidding zones for each production type and year. Ratios above 1 indicate that the aggregated dataset shows higher capacity than the unit dataset, while ratios below 1 indicate the opposite. Note that the figure represents a simple average across bidding zones, not a capacity-weighted measure. Grey colour indicates cases where the aggregated and unit-level datasets are broadly consistent, i.e. the ratio is between 1 and 1.5.

In several instances, hourly generation exceeds the maximum that would be feasible, given reported installed capacity. This can be partly explained by the two datasets reporting standards: generation is recorded hourly, while capacity is reported annually as a snapshot for the following year. We categorise these cases into two groups based on the extent of the discrepancy:

- Non-extreme cases (generation exceeds maximum implied by capacity by up to 20%); and
- Extreme cases (generation exceeds maximum implied by capacity by more than 20%):

We document the frequency of these cases in Figure 40 and Figure 41 for transparency. We note that some of these cases may be driven by capacity commissioning during the year – though this does not appear to explain all cases.

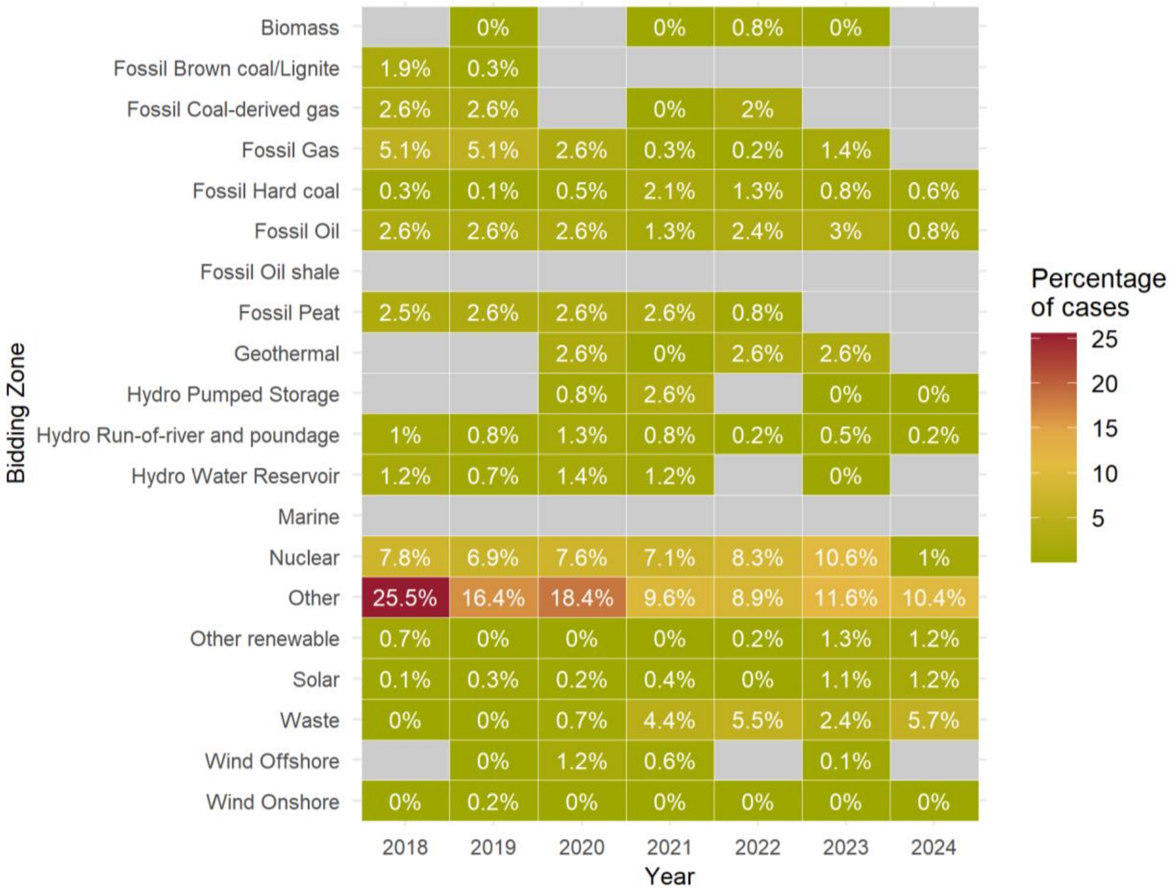
Figure 40 Proportion of cases in which generation exceeds capacity, by bidding zone



Source: Frontier Economic, based on ENTSO-E's capacity data (dataset 14.1.A, 14.1.B and 6.1.A).

Note: Grey colour indicates bidding zones in which no discrepancies were found.

Figure 41 Proportion of cases in which generation exceeds capacity, by production type



Source: Frontier Economics, based on ENTSO-E's capacity data (dataset 14.1.A, 14.1.B and 6.1.A).
Note: Grey colour indicates production types in which no discrepancies were found.

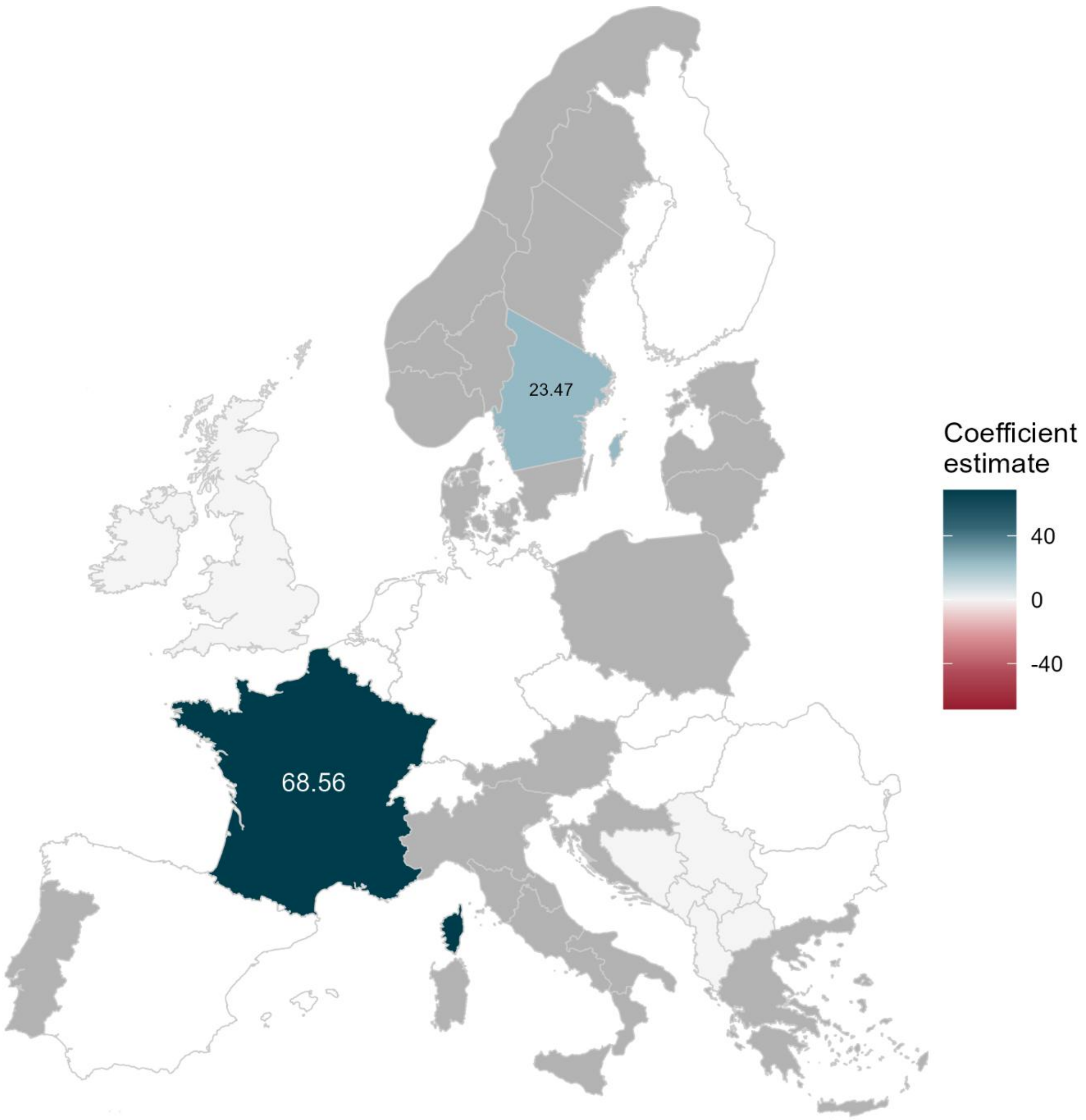
Annex C– Additional bidding zone-specific results

Impact of nuclear output volatility on within-day price volatility

On average across bidding zones, the impact of nuclear output volatility on price volatility was estimated to be small or statistically insignificant across modelling approaches and time horizons (see Table 3 above). This is consistent with nuclear playing a limited role in many bidding zones.

However, again, the effect is not uniform across bidding zones. Figure 42 shows the estimated impact of nuclear output volatility on hourly power price volatility over a 24-hour rolling window, by bidding zone. The effect is particularly pronounced (and statistically significant) for France, the bidding zone with the highest nuclear generation share in Europe.

Figure 42 Impact of nuclear output volatility on “within-day” power price volatility- estimates by bidding zone (FE estimates)



Source: Frontier Economics

Note: A coefficient of X means that a 1 unit increase in the coefficient of variation of nuclear output leads to a EUR X/MWh increase in the standard deviation of the power prices within a 24-hour window. A 1 unit increase in the coefficient of variation of nuclear output is itself equivalent to the standard deviation of nuclear output increasing by a level equal to the mean level of nuclear output. Coefficient estimates for uncoloured bidding zones are not statistically significant. We were not able to estimate coefficients for the greyed-out zones, either due to high levels of multicollinearity in the variable with other included variables or due to a lack of variation.

Impact of average residual demand levels on between-day power price volatility

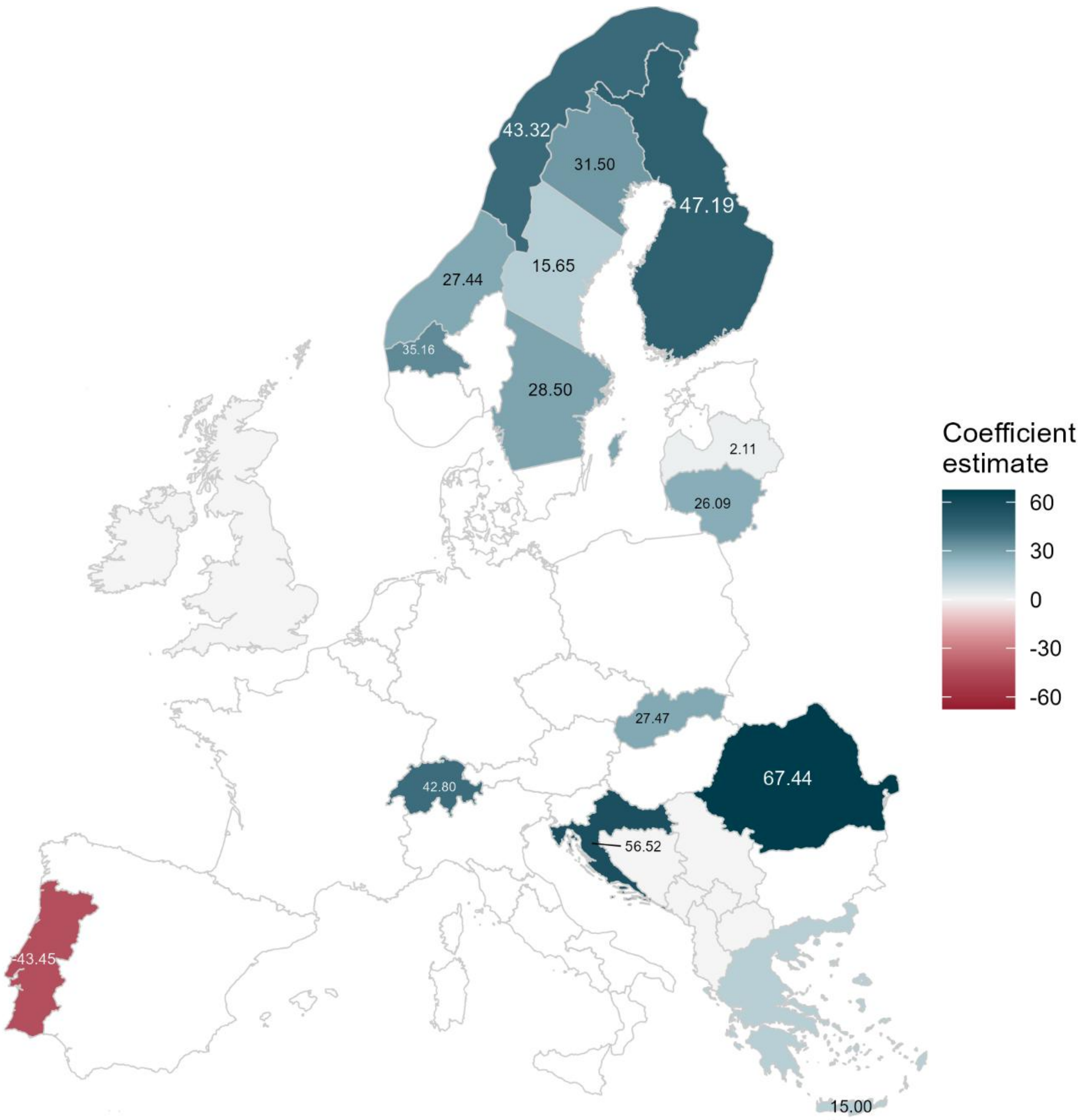
On average across bidding zones, the impact of average residual demand levels on price volatility was estimated to be positive and statistically significant except under SDM for “between-day” volatility (30-day window) (see Table 3 above).

However, again, the effect is not uniform across bidding zones. Figure 43 shows the estimated impact of average residual demand levels on between-day power price volatility over a 30-day rolling window, by bidding zone.

- Across most bidding zones where coefficient estimates are statistically significant, higher residual demand (i.e. a tighter market) is associated with higher price volatility. This is generally to be expected - in periods of very high demand, prices could in principle vary between the marginal cost of the price-setting resource (which might itself be volatile) and the value of lost load (which could be very high).

- Portugal is an interesting exception, with negative coefficient estimates (while the estimate for Spain is not statistically significant). This is consistent with the temporary intervention in Iberia in power prices described earlier. During periods of high residual demand, gas-fired generation is more likely to be setting the price, resulting in a narrower distribution of prices (around the price cap implied by the regulation).

Figure 43 Impact of average residual demand levels on "between-day" power price volatility - estimates by bidding zone (FE estimates)



Source: Frontier Economics

Note: A coefficient of X means that a 1% increase in average residual demand leads to a EUR X/MWh increase in the standard deviation of the daily power prices across a 30-day window. Coefficient estimates for uncoloured bidding zones are not statistically significant.