

MINERVA INVESTMENT MANAGEMENT SOCIETY

Macro Research Division
Research Focus Series - Issue No. 2



The European Energy Pricing Mechanism: A Survey of Theory, Strengths and Limitations*

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October 2026

*The Research Focus series is an initiative of the Macro Research Team of Minerva Investment Management Society. The series provides concise, data-driven analysis of macroeconomic and financial developments, with a particular focus on their policy and market implications.

Abstract

This report examines the European electricity pricing mechanism, its theoretical foundations, and its implications for economic competitiveness. It outlines the institutional structure of European electricity markets and compares uniform and discriminatory pricing mechanisms, highlighting their trade-offs between efficiency, producer payments, and investment incentives. The report then evaluates the European Union’s 2024 electricity market reforms, focusing on short-term market efficiency and long-term contracting through power purchase agreements and contracts for difference. While the reforms address several existing shortcomings, further improvements in market integration, competition, and contract design are needed to reduce price volatility, encourage investment, and strengthen Europe’s resilience to future energy shocks.

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1 Introduction and Motivation

1.1 History and Consequences of High Energy Prices

Following Russia's invasion of Ukraine in 2022, many OECD countries imposed economic sanctions on Russia, primarily targeting the energy sector. These measures contributed to an energy supply shock which, together with the inflationary pressures already generated by the monetary and fiscal expansions adopted in response to the 2020 Covid-19 shock, led to a substantial increase in price levels ([International Monetary Fund, 2022](#); [Giannone and Primiceri, 2024](#)).

In advanced economies, and especially in Europe, the rise in fossil fuel prices was the largest since the 1970s. In the summer of 2022, European natural gas prices peaked at ten times their level of the previous year. By mid-2025, they remained roughly twice their historical average. Even after adjusting for inflation, fossil fuel price forecasts made in early 2026 projected a return to pre-pandemic levels only by 2027 ([Lan et al., 2026](#)).

Retail electricity prices in Europe had historically been about 80% higher than in the United States, but in the years following the crisis they remained two to three times higher ([Draghi, 2024](#)). As of 2024, EU wholesale gas prices were, on average, nearly five times those in the United States, while average EU industrial electricity prices were roughly two and a half times higher ([Heussaff, 2024](#)). Beyond the increase in absolute price levels, volatility also rose steadily, creating uncertainty for both firms and households.

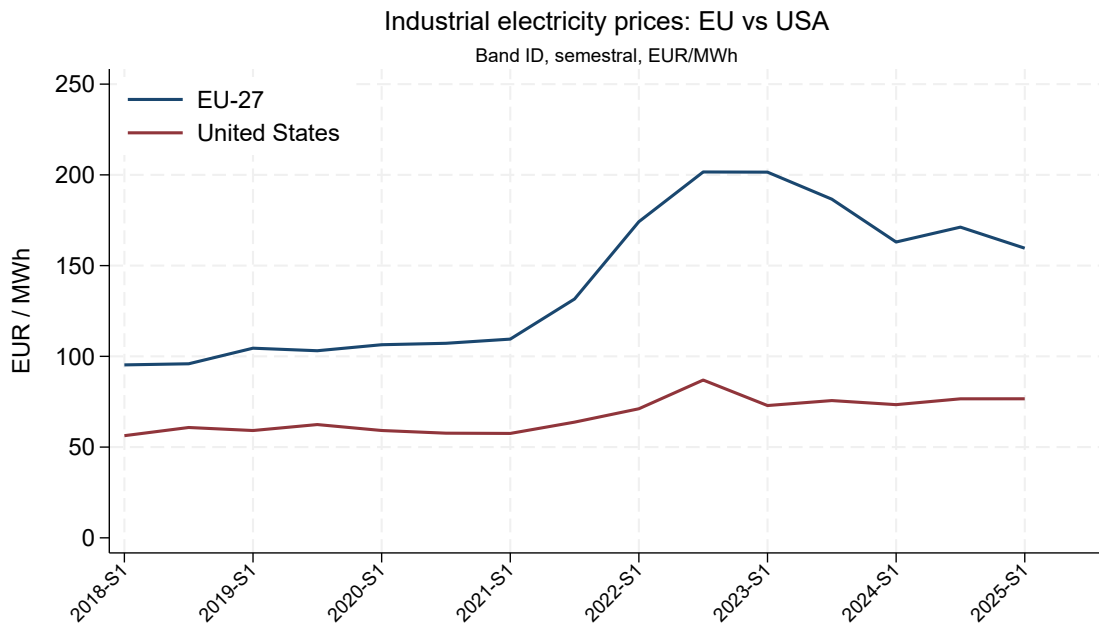


Figure 1.1. Industrial electricity prices: EU-27 vs United States

Sources: Eurostat, US Energy Information Administration, ECB reference exchange rates

These developments posed significant challenges to the EU economic model. Rising input costs have reduced activity in energy-intensive industries, leading to plant closures and temporary shutdowns. In Germany, output in these industries fell by almost 20% relative to pre-war levels, while output in less energy-intensive industries remained broadly stable, partly reflecting firms' energy-efficiency efforts ([Chen et al., 2023](#)).

Beyond the competitiveness concerns associated with higher production costs, the shock also has important implications for labor markets. According to [European Central Bank \(2025\)](#), a 10% increase in electricity prices could reduce employment in the most energy-intensive sectors by 1-2%. These effects are likely to be pronounced in regions with a high concentration of energy-intensive industries, such as southern Germany, the Ruhr area, and Northern Italy, where they may cause long-lasting damage to local labor markets. [Autor et al. \(2016\)](#) show that when a sector contracts sharply in areas where it is geographically concentrated, the resulting job losses are not fully absorbed by other local industries: wages and labor-force participation remain depressed for at least a decade.

The issue is also diverting attention from efforts to promote sustainability. Rising energy prices are perceived as one of the main barriers to investment by 60% of firms ([Draghi, 2024](#)). By narrowing profit margins, reducing economic activity, and increasing uncertainty, energy shocks can weaken investment and productivity, thereby undermining future competitiveness ([Anaya Longaric et al., 2025](#)). Over the past decades, EU growth has relied heavily on exports of high-quality goods rather than on price competitiveness. In this context, persistent underinvestment could erode the EU's competitive edge and increase the risk of de-industrialization or the relocation of production to countries offering higher returns on investment. Even if the shock is not expected to be permanent, its short-term damage to EU potential GDP is projected to reach 0.8% by 2027 ([Lan et al., 2026](#)).

The crisis had distributional consequences, too. Higher energy prices affect households unevenly because lower-income groups devote a larger share of their budget to food and energy. As a result, the energy shock hit the most vulnerable segments of society hardest ([Fabra et al., 2025](#)). Across 18 European economies, households in the lowest income quintile faced an average annual welfare loss of 26.7%, compared with 13.3% for those in the highest quintile ([Cicek et al., 2026](#)). Moreover, many public interventions introduced to cushion the shock were poorly targeted. In 2022, EU countries spent on average 2.5% of GDP on energy-price subsidies, more than 65% of which did not account for income levels. IMF estimates suggest that fully compensating the bottom 40% of households for higher energy costs would have cost only 0.9% of GDP ([International Monetary Fund, 2026a](#)).

More recently, the blockade of the Strait of Hormuz has caused a new disruption in oil and gas supplies. Oil prices have risen by more than 80% since December 2025, exceeding 100 USD per barrel, while gas prices have increased similarly ([European Central Bank, 2026](#)). According to the [International Monetary Fund \(2026b\)](#), global growth would fall to 3.1% in 2026 under a limited-conflict scenario, with a prolonged war causing further disruption. Euro-area growth is projected at only 0.9% in 2026 while headline inflation rises to 2.6%, mainly because of the energy price shock ([European Central Bank, 2026](#)).

Understanding the new crisis and its effects on the energy sector and the EU economy requires examining how energy is priced in Europe. Europe's structural exposure to energy price shocks is well established: the EU relies on imports for 56-60% of its total energy consumption, with import dependence rising to around 90% for natural gas and oil/petroleum products ([Eurostat, 2025a](#)).

1.2 A Role for Market Design

The scale of the price increases observed in Europe cannot be explained by changes in supply and demand alone. The specific design of European energy markets has a

substantial effect on the energy bills faced by households and firms. As [Heussaff \(2024\)](#) points out, energy bills in Europe consist of four main components: the energy cost itself, network charges, taxes, and other levies. Each of these components is influenced by government decisions, which vary widely across countries and contribute to large differences in household electricity prices within the EU.

These policy features suggest that persistently high energy prices in Europe reflect not only supply-demand dynamics, but also market design and inefficiencies. Cross-border restrictions in electricity transmission are a clear example. Such bottlenecks limit price arbitrage, which would otherwise help equalize wholesale prices across member states.

If some of the negative effects of high energy prices stem from institutional inefficiencies rather than from market forces alone, then policy reforms could reduce these costs without relying exclusively on changes in global energy markets. This possibility motivates the present paper. In the next sections, we analyze energy pricing in the EU, focusing on the institutional structure of electricity markets, marginal pricing, and the sources of cross-country differences.

2 Institutional Background

2.1 Day-Ahead Auctions

In the single wholesale electricity market of the European Union, a system of marginal pricing is implemented. All electricity generators receive the same clearing price for the amount of electricity produced per hour, regardless of how much it costs to produce the electricity (European Commission, 2023). The mechanism used to determine this price is the day-ahead auction process, typically conducted by an organization that acts as a Nominated Electricity Market Operator (NEMO). On a daily basis, electricity producers provide bids that include a specification of the lowest possible price at which they would be willing to sell a specified quantity of electricity for each hour of the next calendar day. Similarly, demand bids are submitted by those seeking to purchase electricity. The submissions received from generators are then ranked in ascending order according to their price, and thus form what is known as the merit order. Renewable resources such as wind, solar, and run-of-river hydroelectric facilities have very low variable costs and consequently are first dispatched as they represent the least expensive means of meeting electrical demands. Conversely, fossil-fuel-based production facilities, particularly those burning natural gas, represent the highest cost of production and are generally dispatched last in order to achieve equilibrium between supply and demand. The price bid by the most-expensive generation facility required to clear the market (the marginal plant) determines the single market-wide clearing price paid by all accepted generators for that particular hour (European Parliament, 2023). Figure 2.1 illustrates this auction mechanism using stylized but representative marginal cost values consistent with European market data (Gasparella et al., 2023; European Parliament, 2023). The merit order stacks generation capacity from cheapest to most expensive. The intersection with the vertical demand curve sets the single clearing price paid to all generators, generating infra-marginal rents for lower-cost producers.

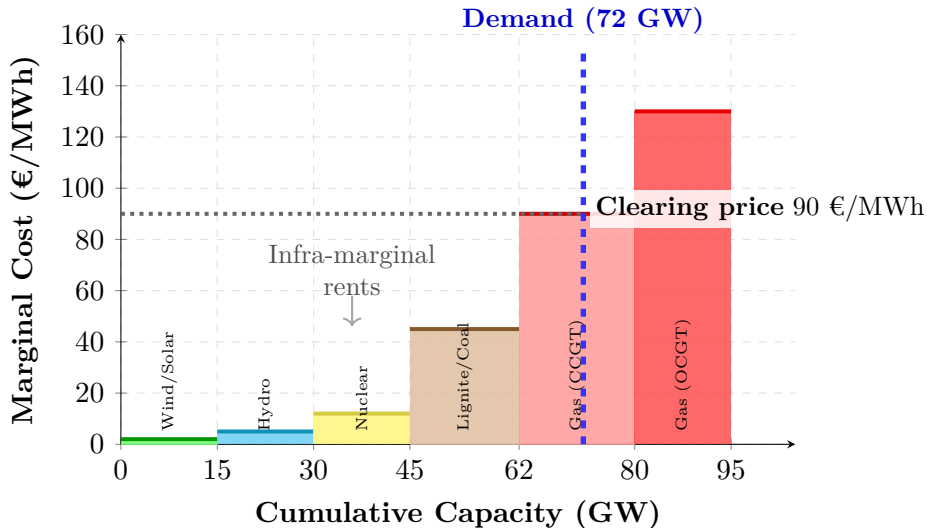


Figure 2.1. Stylized merit order of the day-ahead market clearing mechanism. Marginal cost values are representative of typical 2023 European conditions. All generators receive the single clearing price (90 €/MWh), set by the marginal gas plant. Lower-cost generators earn infra-marginal rents.

As a direct result, all generators, including renewable and nuclear generators, receive the high price set by the marginal gas-fired unit whenever gas becomes the price-determining fuel. The excess revenue generated above the cost of producing electricity is referred to as infra-marginal rent. As evidenced, during the recent energy crisis, natural gas became the marginal plant for approximately 60% of hours across Europe ([Draghi, 2024](#)). Therefore, wholesale electricity prices throughout the continent reached levels significantly higher than the actual production costs associated with most generating units.

There are multiple layers of institutions responsible for regulating these markets. At its core, the European Commission creates an overarching legislative framework through Regulation (EU) 2019/943, which creates a single market for electricity as part of the Clean Energy for All Europeans package. Additionally, ACER develops framework guidelines for legally binding network codes regarding the development and coordination of cross-border electricity transmission systems and markets. Furthermore, ENTSO-E coordinates the operational activities of interconnected grids among member states. While EU-level legislation dictates how wholesale markets should operate domestically, member-state governments retain a considerable degree of autonomy with respect to taxing and providing subsidies for various types of electrical generation, a distinction in jurisdiction that provides a fundamental explanation for why there exist varying prices for electricity across member states.

2.2 How Energy Markets Work More Broadly in Europe

While the day-ahead auction represents the primary interface where electricity prices are determined, it represents just one layer of numerous interfaces through which electricity trade occurs. Forward and futures contracts represent mechanisms whereby generators and large-scale consumers can mitigate risks associated with volatile electricity prices through long-term contracts for deliveries of electricity weeks, months, or years prior to real-time delivery. In addition, intraday contracts represent mechanisms whereby participants may modify their positions as new data becomes available on real-time generation forecasts, a process becoming increasingly important due to increasing penetration rates of variable renewables.

Balancing markets represent another type of contract used to correct discrepancies between planned and actual output or consumption after real-time generation forecasts are finalized. Balancing markets are managed by individual Transmission System Operators (TSOs); however, ENTSO-E and ACER have attempted to develop coordinating structures to harmonize balancing processes across member states through programs such as PICASSO, MARI, and TERRE. Progress toward developing pan-European balancing markets has been limited. For example, as of 2023, only four member state TSOs participated directly in pan-European balancing energy platforms, although additional TSOs joined in early 2024 ([ACER, 2024](#)).

At the structural level, the architecture of the EU’s wholesale electricity markets is based upon a “zonal” system, where there exists a single wholesale price within each designated national bidding zone. Bidding zones mostly correspond to individual member states and do not impose physical trading restrictions within the zone. Interconnector capacities connecting different bidding zones can be allocated through coordinated cross-zone auctions. However, when interconnectors reach maximum capacity, prices between adjacent zones will diverge. A nation with excess inexpensive generating capacity will not be able to export all of it to an adjacent nation with limited generating capacity

and greater demand. Therefore, managing congestion rents and developing sufficient transmission capability for cross-border trade represent fundamental challenges for EU regulators to ensure proper functioning of the single market, and ultimately influence the price differences discussed below.

2.3 Cross-Country Price Differences

While the EU has established a single, integrated electricity market, household electricity prices throughout the EU continue to vary significantly among the various member states. Eurostat data on household electricity prices for the second half of 2024 revealed that Germany had the highest household electricity price at €39.43 per 100 kWh, followed by Denmark (€37.63) and Ireland (€36.99), while Hungary had the lowest price at €10.32 and Bulgaria was second-lowest at €12.17 (Eurostat, 2025b). Figure 2.2 illustrates this disparity. The difference between the most expensive and least expensive EU member states is substantial; the costliest member state pays almost four times as much as the least costly. There are four key structural reasons why EU household electricity prices differ.

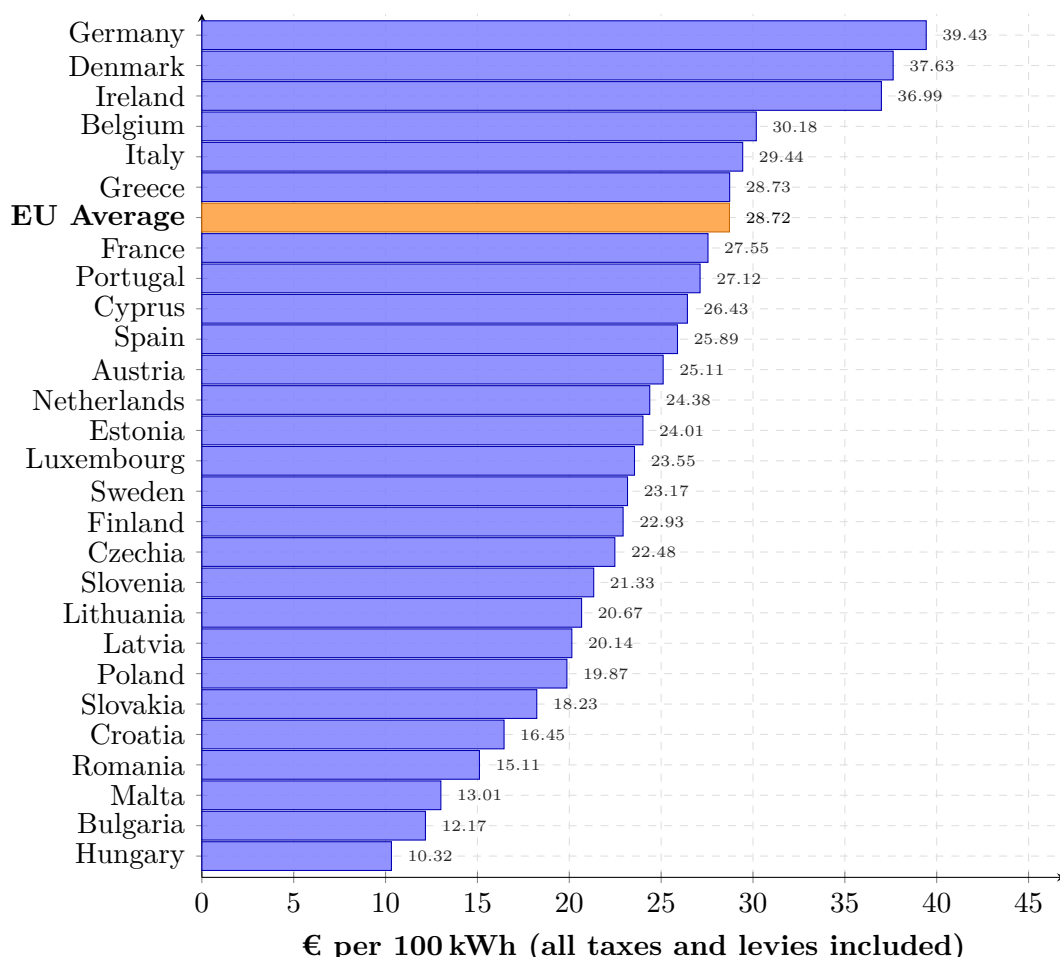


Figure 2.2. Household electricity prices across EU member states, second half of 2024 (€ per 100 kWh, all taxes and levies included). The orange bar represents the EU weighted average (€ 28.72 per 100 kWh). Source: Eurostat (2025b).

Most important of the four from a single-market perspective is the continued inability

of cross-border transmission infrastructure to equalize wholesale prices across EU member states. The internal workings of the single electricity market rely on price arbitrage: surplus inexpensive electricity in one member state should flow to neighboring members with higher-priced electricity until prices converge. Such arbitrage is frequently obstructed by grid congestion. TSOs under EU regulation must make available a minimum of 70 percent of physical transmission capacity for cross-border trade; however, in 2024 TSOs in the Core region achieved an average availability rate of only 54 percent on their most congested corridors, well below the regulatory requirement ([ACER, 2025](#)). Based on analysis conducted by [ACER \(2025\)](#), if TSOs in the Core region complied with EU regulations in 2024 alone, they could have generated at least €580 million in economic benefits through improved efficiency, in addition to €664 million in enhanced consumer welfare via reduced volatility in day-ahead prices. The combined expenditure incurred by TSOs for congestion management totaled €4.3 billion in 2024. The report by [Bruegel \(2023\)](#) illustrates the extent of the market failure. The annual arbitrage potential for a single MW of cross-border transmission capacity between France and Germany during the energy crisis represented hundreds of thousands of euros annually. Thus, the persistence of wholesale price wedges between EU member states is a quantifiable and continuing inefficiency that regulatory action has been unable to resolve.

Subsequently, national taxes and levies are a sizable, non-harmonized component contributing to differing EU household electricity prices. EU member states possess broad autonomy to establish Value Added Tax (VAT) rates applied to electricity, excise duties, and numerous other national levies, many unrelated to energy, such as those supporting public broadcasting ([European Commission, 2023](#)). As indicated by [Eurostat \(2025b\)](#), national taxes and levies comprised approximately 25.1 percent of average EU household electricity expenses in 2024. Additionally, the weight assigned to national taxes and levies varied considerably across nations. Specifically, both Germany and Denmark consistently record the highest retail electricity prices in the EU and impose high levies historically linked to funding renewable energy subsidies and grid investments.

Major differences in network charges, meaning regulated fees used by grid operators to cover the construction, operation, and maintenance of transmission and distribution networks, also exist among EU member states due to variations in grid age, geographical complexity, and requirements for necessary investment in the integration of renewable energy sources. Network charges rose in eighteen EU member states in 2024, resulting in an aggregate 8.9 percent increase in EU-wide network charges compared to the previous year ([Eurostat, 2025b](#)).

Lastly, according to Eurostat, the energy mix is a major contributor to differing electricity prices across EU member states alongside import diversification and environmental protection costs ([Eurostat, 2024](#)). Nations possessing large shares of hydroelectric power, such as Sweden and Austria, or nuclear capacity, such as France, enjoy relatively large quantities of low-marginal-cost generation that structurally depresses their wholesale electricity prices. Conversely, nations heavily reliant on imported natural gas are exposed to global commodity markets, as evidenced by the 2021–2022 energy crisis. [Bruegel \(2024\)](#) indicates that government subsidy programs for particular technologies remain the primary mechanism through which national generation mixes evolve over time, suggesting that decisions made regarding technology subsidies today will translate into varying relative price levels in subsequent decades.

3 Theoretical framework for optimal auction design theory for energy pricing

Besides the policy decision on the promotion of certain electricity generation methods, the way electricity is priced across the continent is an important contributor to high prices, as mentioned in Subsection 1.2. Therefore, the following section will develop a model for electricity pricing and discuss its implications.

3.1 Why energy auction design is a distinct economic problem

The theory of auction design in energy markets cannot be constructed by directly importing standard multi-unit auction models and relabeling bidders as generators. Electricity and renewable procurement markets differ fundamentally from conventional procurement environments because the object being allocated is a physically constrained, network-dependent, and time-sensitive service. As a result, both the value and cost of supply depend on the interaction between market structure, dispatch conditions, and system constraints.

In this setting, electricity auctions can be modeled as strategic multi-unit environments with capacity-constrained firms. Firms are characterized by capacity limits and marginal production costs, and they submit bids indicating the price at which they are willing to supply electricity. Aggregate demand may vary across periods, but in the baseline model its realization is observed by firms before they submit bids, which are subject to an upper bound imposed by the market design. Given realized demand and submitted bids, output is allocated according to a merit-order dispatch rule, in which lower bids are dispatched first subject to capacity constraints. In such an environment, the auction format directly affects equilibrium bidding incentives and the distribution of payments, particularly in states where capacity becomes scarce.

At the same time, short-run pricing cannot be separated from long-run allocation. In renewable energy procurement, auction outcomes determine not only prices but also the spatial distribution of capacity. As shown by [Bichler et al. \(2020\)](#), simple nationwide price-based auctions tend to concentrate projects at the most productive sites, such as those with the highest wind or solar potential. While such allocations minimize awarded remuneration, they can be inefficient from a system perspective because these locations are often remote from demand centers, leading to congestion, redispatch, and network expansion costs.

This implies that optimal auction design in energy pricing is inherently a multi-objective problem. The relevant objective is not limited to minimizing payments or achieving static productive efficiency, but must account for total system cost.

Each of the above-mentioned objectives is affected by the auction mechanism through distinct channels. The pricing rule determines equilibrium bidding behavior and the extraction of scarcity rents, while the allocation rule and bid language determine the spatial configuration of generation capacity and hence system costs. An appropriate theoretical framework must therefore integrate equilibrium behavior, mechanism design, and system constraints.

3.2 Auction mechanism

The auction mechanism defines the strategic environment in which firms interact. It specifies the set of admissible strategies, the allocation rule, and the payment rule. These elements jointly determine how bids translate into quantities and prices.

After observing demand θ , each firm $i \in \mathcal{I}$ submits a bid $b_i \in [0, P]$, where P denotes the exogenous price cap. The vector of bids is denoted by $b = (b_1, \dots, b_N)$. Bids are interpreted as supply offers, indicating the price at which firms are willing to supply electricity up to their capacity.

Given a realization of demand θ , the system operator allocates production according to a merit-order dispatch rule. Firms are ranked in increasing order of bids, and output is assigned sequentially until total demand is satisfied. Formally, the allocation rule determines quantities $q_i(\theta, b) \in [0, k_i]$ such that:

$$\sum_{i \in \mathcal{I}} q_i(\theta, b) = \theta \quad (3.1)$$

and lower bids are dispatched first, subject to capacity constraints.

In the two-firm case, the allocation rule can be expressed explicitly. If $b_i < b_j$, firm i is dispatched first and supplies up to its capacity:

$$q_i(\theta, b) = \min\{\theta, k_i\} \quad (3.2)$$

$$q_j(\theta, b) = \max\{0, \theta - k_i\} \quad (3.3)$$

The allocation rule ensures that production follows the merit order, but the payment received by firms depends on the pricing rule.

Two alternative pricing mechanisms are considered.

Under **uniform pricing**, all accepted units are paid the market-clearing price, defined as the highest accepted bid:

$$p(b) = \max_{i: q_i(\theta, b) > 0} b_i \quad (3.4)$$

Firm i 's profit is therefore:

$$\pi_i^u(\theta, b) = (p(b) - c_i) q_i(\theta, b) \quad (3.5)$$

Under **discriminatory pricing**, each firm is paid its own bid for the quantity it supplies. Profits are given by:

$$\pi_i^d(\theta, b) = (b_i - c_i) q_i(\theta, b) \quad (3.6)$$

The difference between these pricing rules is central. Under uniform pricing, infra-marginal units receive the market-clearing price, which creates incentives to bid above marginal cost when firms expect to remain dispatched. Under discriminatory pricing, firms face a direct trade-off between price and probability of dispatch, since higher bids increase revenue per unit but reduce the likelihood of being selected.

The auction mechanism therefore determines not only the allocation of output, but also the strategic incentives that shape equilibrium bidding behavior. In particular, the interaction between capacity constraints, demand realizations, and the payment rule is the key determinant of price formation.

3.3 Equilibrium structure

Equilibrium is defined as a Nash equilibrium of the bidding game induced by the auction mechanism, conditional on publicly observed demand. Each firm chooses a bidding strategy to maximize profit (or expected profit if its rival mixes), taking the rival's strategy and the realized demand as given.

Let there be two firms $i, j \in \{1, 2\}$, with capacities $k_i, k_j > 0$ and constant marginal costs c_i, c_j . Following [Fabra et al. \(2006\)](#), prices and costs are normalized by subtracting the lower-cost firm's marginal cost, so that $c_i = 0 \leq c_j < P$, where P is the corresponding normalized price cap. Aggregate demand is denoted by $\theta \in (0, k_i + k_j)$, and bids satisfy $b_i, b_j \in [0, P]$. The two-firm formulation is sufficient to characterize the central strategic logic of the model.

Given a bid profile $b = (b_i, b_j)$, the allocation rule is determined by merit-order dispatch. Output allocated to firm i is:

$$q_i(\theta; b) = \begin{cases} \min\{\theta, k_i\}, & \text{if } b_i < b_j, \\ \rho_i \min\{\theta, k_i\} + (1 - \rho_i) \max\{0, \theta - k_j\}, & \text{if } b_i = b_j, \\ \max\{0, \theta - k_j\}, & \text{if } b_i > b_j, \end{cases} \quad (3.7)$$

where ρ_i is the tie-breaking probability: $\rho_i = 1$ if $c_i < c_j$ and $\rho_i = 1/2$ if $c_i = c_j$, as in [Fabra et al. \(2006\)](#).

Under **uniform pricing**, all accepted units are paid the highest accepted bid. Firm i 's profit is therefore

$$\pi_i^u(\theta; b) = \begin{cases} (b_j - c_i) q_i(\theta; b), & \text{if } b_i \leq b_j \text{ and } \theta > k_i, \\ (b_i - c_i) q_i(\theta; b), & \text{otherwise.} \end{cases} \quad (3.8)$$

Under **discriminatory pricing**, firm i is paid its own bid for every accepted unit, so profits are

$$\pi_i^d(\theta; b) = (b_i - c_i) q_i(\theta; b). \quad (3.9)$$

For each observed demand realization θ , firm i solves

$$\max_{b_i \in [0, P]} \mathbb{E}_{b_j | \theta} [\pi_i^f(\theta; b_i, b_j)], \quad f \in \{u, d\}, \quad (3.10)$$

taking the rival's strategy as given. The expectation is over any randomization in the rival's bid, not over the demand realization.

A key result in [Fabra et al. \(2006\)](#) is that the equilibrium structure is organized by a critical demand threshold $\tilde{\theta}$. Under the marginal-cost normalization above, this threshold is

$$\tilde{\theta} = \begin{cases} k_i, & \text{if } k_i \leq \frac{P}{P - c_j} k_j, \\ \frac{P}{P - c_j} k_j, & \text{if } k_i > \frac{P}{P - c_j} k_j. \end{cases} \quad (3.11)$$

This threshold separates two regimes:

Low-demand regime. If $\theta \leq \tilde{\theta}$, [Fabra et al. \(2006\)](#) shows that there is a unique pure-strategy equilibrium in which the highest accepted bid is equal to the marginal cost of the inefficient supplier:

$$p^* = c_j. \quad (3.12)$$

The resulting allocation is cost-efficient, and the equilibrium outcome is the same under uniform and discriminatory pricing.

High-demand regime. If $\theta > \tilde{\theta}$, the market enters a scarcity regime. Residual demand facing firm i is

$$D_i^{res}(\theta) = \theta - k_j. \quad (3.13)$$

If $D_i^{res}(\theta) > 0$, firm i is pivotal.

Under **uniform pricing**, [Fabra et al. \(2006\)](#) shows that pure-strategy equilibria exist in which the highest accepted bid reaches the price cap:

$$p^* = P. \quad (3.14)$$

Under **discriminatory pricing**, no pure-strategy equilibrium exists in the high-demand regime. Instead, firms mix over bids in the interval

$$b_i \in (c_j, P]. \quad (3.15)$$

A key implication is that expected payments satisfy

$$R^d < R^u, \quad (3.16)$$

while the ranking in productive efficiency is ambiguous:

$$C^d \geq C^u. \quad (3.17)$$

Hence, lower expected payments under discriminatory pricing do not necessarily imply lower production costs.

The equilibrium structure is therefore regime-dependent. In the low-demand regime, equilibrium is competitive, pure-strategy, and efficient. In the high-demand regime, scarcity makes firms pivotal, and the pricing rule becomes decisive. Uniform pricing sustains high pure-strategy prices, while discriminatory pricing yields mixed-strategy bidding and lower expected payments, but not necessarily greater efficiency.

3.4 Welfare decomposition

Building on the equilibrium characterization in Subsection 3.3, we now decompose the welfare implications of the auction outcomes into their constituent parts. As noted in Subsection 3.1, the relevant objective for optimal auction design in energy markets is the minimization of total expected system resource cost, which comprises producer costs (generation costs), network congestion and redispatch costs, and capacity expansion or reliability costs. Payments to firms in excess of production costs are producer surplus: they are transfers from electricity buyers to producers, not additional resource costs. For fixed, price-inelastic demand, these transfers do not affect aggregate surplus because gross

consumer benefits are unchanged. The short-run auction outcomes directly influence production costs and payments and, through their effects on bidding incentives and realized dispatch, indirectly shape the other components via long-run investment and locational decisions. Let R^f denote payments to firms and C^f denote generation costs under format $f \in \{u, d\}$, conditional on realized demand and averaged over any equilibrium bid randomization.

In the low-demand regime ($\theta \leq \tilde{\theta}$), the unique pure-strategy equilibrium under both uniform and discriminatory pricing yields the competitive price $p^* = c_j$ (with $c_i \leq c_j$), and efficient dispatch (the lower-cost firm supplies all demand when costs differ). Producer costs are minimized at the first-best level for the realized demand, but total payments need not equal production costs: $R^u = R^d = c_j\theta$, $C^u = C^d = c_i\theta$, and hence $R^f - C^f = (c_j - c_i)\theta > 0$ whenever $c_i < c_j$. Thus, both formats achieve the same welfare outcome in terms of productive efficiency, without a scarcity markup above c_j , while the lower-cost producer still earns inframarginal surplus.

In the high-demand (scarcity) regime ($\theta > \tilde{\theta}$), differences emerge sharply. From the equilibrium structure:

- Under **uniform pricing**, pure-strategy equilibria exist in which the market-clearing price reaches the cap $p^* = P$. Infra-marginal units (including those from the lower-cost firm) receive this high uniform price, generating substantial market power rents. Expected payments satisfy $R^u > R^d$ in general. Productive efficiency is ambiguous: depending on which equilibrium is selected, dispatch may or may not assign output to the lowest-cost available capacity.
- Under **discriminatory pricing**, firms play mixed strategies over bids in $(c_j, P]$, yielding lower expected payments per unit ($R^d < R^u$) because each firm is paid its own bid. However, the randomization implies a positive probability of inefficient dispatch (higher-cost firm dispatched ahead of lower-cost capacity), so $C^d \geq C^u$. Lower payments do not guarantee lower total production costs.

Welfare decomposition for a given demand realization θ and equilibrium can thus be expressed as: Total payments (R^f) = Production costs (C^f) + Producer surplus ($R^f - C^f$). For each realized demand θ , expectations are over any equilibrium mixed strategies; ex ante expected values additionally integrate over the demand distribution $G(\theta)$. Uniform pricing raises payments relative to discriminatory pricing in high-demand states, but the ranking of producer surplus also depends on production costs, which need not be the same across auction formats. Discriminatory pricing lowers payments, albeit potentially at the cost of occasional productive inefficiency. These short-run effects feed into long-run system costs: higher expected rents, when they arise, may encourage more entry or capacity expansion (affecting reliability costs positively), but inefficient locational choices (addressed in Subsection 3.5) can exacerbate network costs.

Numerical illustrations in related analyses (Fabra et al., 2006) suggest that the payment differential $R^u - R^d$ can be substantial in high-demand states, highlighting the trade-off between rent extraction and efficiency. Overall welfare ranking remains parameter-dependent, consistent with the ambiguous productive efficiency comparison $C^d \geq C^u$.

3.5 System-level inefficiency

The preceding analysis treats the auction as allocating a homogeneous good under simplified merit-order dispatch. In reality, electricity is a network-dependent service: generation value and system costs depend critically on where capacity is located relative to demand centers, transmission constraints, and renewable resource availability. Simple price-based auctions (whether uniform or discriminatory) that ignore these spatial dimensions can induce allocations that minimize short-run procurement costs but increase total system costs.

As highlighted in Subsection 3.1, nationwide or zonal auctions without locational signals tend to concentrate renewable projects at sites with the highest capacity factors (e.g., best wind/solar resources). While this minimizes awarded remuneration for a given capacity target, it often places new generation far from load centers.

The resulting inefficiencies include:

- **Congestion and redispatch costs:** Out-of-merit dispatch to relieve transmission constraints, where higher-cost local units are called upon (or distant cheap units are curtailed), raising effective production costs beyond the auction C^f .
- **Network expansion costs:** Accelerated or oversized investment in transmission infrastructure to connect remote generation.
- **Reliability and balancing costs:** Increased need for reserves, storage, or flexible resources due to variability and locational mismatches.

Formally, let the total system cost described in Subsection 3.4 be augmented with a locational penalty term. Suppose the auction awards capacity to firms $i \in I$ at locations ℓ_i , inducing a spatial configuration. The realized system cost includes an additional term $\Gamma(\{\ell_i\}, \theta)$ capturing expected congestion/redispatch given the dispatch rule and network topology. Auction-induced concentration raises $\mathbb{E}[\Gamma]$ relative to a first-best spatial optimum that internalizes network externalities.

In the framework of Subsections 3.2–3.3, the merit-order rule based solely on bids b_i (ignoring location-adjusted costs or shadow prices) decouples the short-run equilibrium from long-run system optimality. Uniform pricing may exacerbate this by sustaining high rents that encourage entry at profitable (but congested) sites, while discriminatory pricing’s lower expected payments may dampen investment but still fail to guide location. Neither format, without additional bid language (e.g., locational marginal pricing components, transmission rights, or differentiated reserve prices), achieves the system optimum. This underscores that auction design in energy markets is inherently multi-objective, requiring integration of mechanism design with network constraints.

3.6 Optimal design problem

The optimal auction design problem consists of choosing the mechanism—defined by the admissible bid language, allocation rule, and payment rule—that minimizes expected total system resource cost described in Subsection 3.4, accounting for the strategic equilibrium behavior induced among capacity-constrained firms. Formally, the designer solves:

$$\min_{\mathcal{M}} \mathbb{E}_{\theta, b^*(\theta; \mathcal{M})} \left[C(\theta, b^*(\theta)) + \Gamma(\{\ell_i(b^*)\}, \theta) + \text{reliability costs} \right]$$

subject to equilibrium best responses conditional on observed demand, individual rationality, and feasibility under network and capacity constraints. Here $\mathcal{M}$ includes uniform vs. discriminatory pricing, but also richer elements such as multi-part bids, locational adjustments, Vickrey-style elements, or hybrid formats. The expectation is over demand and any equilibrium bid mixing; Γ denotes incremental network and redispatch costs not already included in C . If the designer also wishes to limit procurement expenditure R , it should be included as a distinct objective or explicitly weighted term. Since $C + (R - C) = R$, treating that sum as total social resource cost would incorrectly count a transfer to producers as an additional resource cost. Where multiple equilibria exist, as in the high-demand uniform-price auction, a mechanism comparison also requires an equilibrium-selection assumption.

From Subsections 3.3–3.5, neither pure uniform nor discriminatory pricing is universally optimal. Uniform pricing sustains high scarcity rents and can support certain efficient equilibria in high-demand states but inflates payments and may encourage poor locational choices. Discriminatory pricing reduces expected payments and can mitigate some rent extraction but risks productive inefficiency through mixing and offers weaker investment signals. The ranking depends on demand volatility (frequency of $\theta > \tilde{\theta}$), cost/capacity asymmetry, network topology, and the weight placed on different cost components.

An ideal mechanism would:

- Achieve productive efficiency (merit-order dispatch by true system costs, including locational marginal costs),
- Limit excessive scarcity-related payments without distorting entry or location,
- Provide transparent locational signals to align private investment incentives with system-wide optimality,
- Balance short-run dispatch efficiency with long-run capacity adequacy.

Extensions beyond the basic model—e.g., multi-step bids, demand elasticity, repeated interactions, or combinatorial bidding for transmission-constrained zones—can improve performance. In line with Fabra et al. (2006), the choice between uniform and discriminatory is ultimately empirical, hinging on market specifics; more generally, hybrid or pay-as-clear with locational adders (or full locational marginal pricing) often better approximates the system optimum. Future work should characterize mechanisms that explicitly incorporate network constraints into the bid language and allocation rule, moving toward a fully integrated mechanism design approach for energy markets.

3.7 Comparison with the European electricity auction framework

The institutional discussion developed in this section draws primarily on the analysis of European electricity market design presented by Ocker and Jaenisch (2020), particularly regarding intraday auctions, continuous trading, and cross-border market integration.

3.7.1 European electricity auctions as a hybrid market structure

This section compares the theoretical framework developed above with the actual organization of European electricity markets. While the model presented in Subsections 3.1–3.6 is

intentionally stylized, many of its core mechanisms correspond closely to the institutional structure of European electricity auctions. In particular, European electricity markets rely on centralized auction clearing, merit-order dispatch, uniform pricing, and increasingly integrated cross-border allocation mechanisms.

However, the European system differs from the baseline theoretical model in one important respect: it combines auction-based allocation with continuous intraday trading. According to [Ocker and Jaenisch \(2020\)](#), most European short-term electricity markets consist of a sequential structure involving day-ahead auctions followed by intraday continuous trading markets. This creates a hybrid mechanism in which prices are determined partly through centralized clearing and partly through decentralized bilateral adjustment.

The coexistence of auctions and continuous trading reflects a trade-off between allocation efficiency and information efficiency. Intraday continuous markets allow participants to react immediately to updated information regarding renewable generation, demand conditions, and balancing needs. By contrast, auction mechanisms aggregate bids at a single clearing moment and therefore improve liquidity and static allocation efficiency. The European market architecture can therefore be interpreted as an institutional response to the same economic tensions identified in the theoretical framework above.

3.7.2 Uniform pricing and scarcity rents in European markets

European electricity auctions predominantly employ uniform pricing, or pay-as-clear settlement, in which all accepted units receive the market-clearing price. This corresponds directly to the uniform-price mechanism analyzed in Subsection 3.2 and implies that the equilibrium logic developed in Subsection 3.3 has immediate institutional relevance.

Under normal demand conditions, competitive pressure limits the ability of firms to bid significantly above marginal cost. However, as aggregate demand approaches available capacity, firms may become pivotal suppliers. In such states, the equilibrium predictions of [Fabra et al. \(2006\)](#) become particularly important. Uniform pricing allows scarcity rents to emerge because infra-marginal units receive the marginal accepted bid. Consequently, high-demand states can generate equilibrium prices substantially above marginal production costs.

The European framework implicitly accepts this logic. Scarcity pricing is not treated as a market failure per se, but rather as part of the incentive structure required to sustain investment and reliability. At the same time, this creates political and regulatory tension, particularly during periods of extreme price volatility, because the resulting payments may significantly exceed underlying generation costs.

3.7.3 Cross-border integration and network constraints

A central development in European electricity market design has been the increasing integration of cross-border intraday auctions and coordinated market coupling mechanisms. The introduction of the Single Intraday Coupling (SIDC) framework and cross-border intraday auctions reflects a transition toward a more integrated allocation system across European bidding zones.

This evolution is closely related to the system-level considerations emphasized in Subsection 3.5. Electricity cannot be treated as a spatially homogeneous commodity because transmission constraints, congestion, and redispatch costs fundamentally affect the efficiency of allocation outcomes. [Ocker and Jaenisch \(2020\)](#) explicitly note that

efficient usage of cross-zonal transmission capacity becomes increasingly important as renewable penetration rises.

The European move toward coordinated intraday auctions therefore reflects recognition that electricity auction design is fundamentally a network-constrained optimization problem. In theoretical terms, actual market design increasingly attempts to internalize components of the system cost term

$$\Gamma(\{\ell_i\}, \theta), \tag{3.18}$$

introduced in Subsection 3.5. Congestion management, cross-border capacity allocation, and coordinated dispatch are all mechanisms aimed at reducing the divergence between privately optimal bidding behavior and system-wide efficiency.

3.7.4 Limitations of the current European design

Despite increasing market integration, the current European framework remains only partially aligned with the system-optimal mechanism implied by the theoretical model developed above. Existing auction systems primarily optimize short-run market clearing and price formation rather than total expected system cost.

In particular, most European auction mechanisms still rely predominantly on price-based clearing rules without fully incorporating locational externalities, network expansion costs, or long-run reliability effects into the bid language itself. As emphasized by [Bichler et al. \(2020\)](#), such mechanisms may produce privately efficient bidding outcomes while simultaneously generating inefficient spatial distributions of generation capacity.

Moreover, the coexistence of continuous trading and multiple intraday auction stages may fragment liquidity across trading venues and create additional strategic complexity for market participants. The European framework therefore illustrates the broader theoretical point developed throughout this paper: optimal electricity auction design cannot be reduced to a simple comparison between uniform and discriminatory pricing rules. Instead, efficient market design requires the joint integration of strategic bidding incentives, network constraints, congestion management, and long-run investment coordination.

The gradual evolution of European electricity markets toward coordinated cross-border auctions can thus be interpreted as a movement from pure price-based market clearing toward a more system-oriented mechanism design framework.

4 2024 EU market reforms

In 2024, the European Union adopted Directive 2024/1711 and Regulation 2024/1747 to reform its electricity market following the shock to European energy markets caused by the war in Ukraine. As outlined in Section 1 of this report, energy prices rose sharply for both households and non-household consumers in the European Union as a result of the Russian invasion and subsequent Western sanctions. As previously outlined, the rise in energy prices is partly due to the way electricity is priced in Europe. Therefore, the European Commission introduced a reform proposal that would change how European energy markets operate. This proposal culminated in Directive 2024/1711 and Regulation 2024/1747.

While the Directive is mostly focused on reforming state aid, emergency measures that Member States can deploy in an energy crisis, addressing the struggles facing the energy grid, and micro-level reforms on the consumer side, like fixed-term contract availability or energy sharing, the Regulation is a comprehensive set of new rules covering most aspects of the electricity market. With these reforms, European legislators aim to achieve lower prices for all consumers, including industrial users of electricity, less volatile energy prices in the long term, and promotion of clean generation technologies, which are all key for future competitiveness, as also laid out by the Draghi report in 2024 ([European Parliament and Council of the European Union, 2024b,a](#); [Draghi, 2024](#)).

It is important to note that a complete assessment of electricity pricing reform must distinguish between wholesale energy costs and the other components of final consumer bills. Final electricity prices include the cost of supplying energy, network charges, levies for renewables or capacity mechanisms, VAT, and other taxes. These components are governed by different decision-makers: EU rules largely shape wholesale-market design, while national regulators and governments determine many network charges, levies, and taxes. Therefore, reforms to wholesale market design, PPAs, and CfDs may lower price volatility and improve investment incentives, but final consumer prices will also depend on how fixed system costs and taxes are allocated ([Heussaff et al., 2025](#)). The scope of this report is to discuss the implemented reforms in the electricity wholesale market and to evaluate them, while suggesting a few areas for further reform.

In this section, the new rules governing the short- and long-term electricity markets, as introduced by Regulation 2024/1747, are outlined before their in-depth analysis in Section 5. The Regulation includes measures related to the energy grid and other areas that are not discussed in this report, as it focuses on general energy pricing rather than emergency measures or transmission systems in Europe.

4.1 Reforms in the short-term electricity market

The European Parliament and Council identify short-term markets as a key tool to achieve well-functioning, liquid, and efficient short-term markets. To achieve this, Regulation 2024/1747 introduces three key measures:

1. The closure of trading is moved closer to real-time / the time of delivery, as this ensures the participation of more variable energy generators in the short-term market. This is explicitly aimed at renewables like solar and wind, as these technologies have differing production based on weather conditions; thus, due to decreased need to forecast production, generators are exposed to less risk of not being able to deliver ([European Parliament and Council of the European Union, 2024b](#)).

2. Additionally, to further encourage the participation of variable renewable energy technologies in the short-term market, all nominated electricity market operators (NEMOs) are mandated to submit their full order books to the single EU coupling platforms. The goal of this measure is to prevent liquidity leakage and market fragmentation ([European Parliament and Council of the European Union, 2024b](#)).
3. A final but important item in the reform is lowering the minimum bid size to facilitate participation by small-scale renewable producers, helping manage storage and demand response ([European Parliament and Council of the European Union, 2024b](#)).

4.2 Reforms in the long-term electricity market

While short-term reforms are a key part of the package, the focus is on changing the long-term energy market to achieve long-term price stability and support the EU's previously identified climate goals. The Regulation includes measures to strengthen forward markets and facilitate their expansion as tools for hedging long-term price risk. It also promotes long-term power purchase agreements (PPAs) and treats their promotion as a key to achieving the aims of the reforms. The changes include measures to support the creation of a market for PPAs, to help SMEs access the PPA market, and to provide risk mitigation for PPAs.

Additionally, the Regulation also lays out two-way contracts for difference (CfDs) as a requirement for certain new capacities, as a tool for states to use in public support schemes for constructing new low-carbon generation capacity. However, for private projects, using CfDs is voluntary.

Moreover, as a potential supporting mechanism, the reforms introduce a new concept, virtual hubs, that would serve as a reference price zone across multiple bidding areas. These could be especially helpful when using CfDs as a contracting mechanism ([European Parliament and Council of the European Union, 2024b](#)).

5 Analysis of the EU reforms

In this section, we evaluate the reforms implemented by the European Union and, where deemed insufficient, propose further reforms. This section follows the same structure as Section 4: first, it discusses short-term market reforms, followed by a longer discussion of the EU’s long-term market reforms.

5.1 Short-term market reforms

Both Fabra (2023) and Ambec et al. (2025) highlight the importance of short-term markets in the future electricity market framework. Both papers agree that, in the short term, the cheapest electricity sources should be called upon to meet demand, and, as Fabra highlights, short-term markets let generators incorporate changing electricity costs and availability, improving efficiency. Similarly, Ambec et al. (2025) write that short-term markets provide an important price signal to generators, contributing to the efficient market Fabra describes, where flexible assets shift their demand/supply across time to when they are more / less valuable.

This also implies that both papers agree that the EU, rightly so, focuses on the creation of liquid and competitive short-term electricity markets (Ambec et al., 2025; Fabra, 2023). However, Fabra (2023) believes the (at the time) proposal does not go far enough to ensure short-run markets are liquid. The paper argues that to achieve sufficient market liquidity, the EU should adopt a market structure similar to that of New Zealand, Singapore, or Australia, known as the *mandatory gross pool*. In this market structure, all generators are free to enter into financial contracts with third parties, but participation is mandatory for all demand and supply units in the short-term market. Although the adopted reform package includes mandatory reporting of orders for all NEMOs, it may fall short of ensuring the liquidity required for the short-term market to function as intended without the implementation of the reform proposed by Fabra.

Furthermore, Fabra (2023) proposes banning generators from submitting portfolio bids in the short-term market and instead requiring them to submit separate bids for each plant. In Fabra’s view, this would increase the competitiveness of short-term markets. It would allow smaller operators to remain competitive, which the EU clearly sees as desirable, as evidenced by the lowering of minimum bids; however, the final adopted reform package lacks such a clause.

In the vein of competitiveness, Ambec et al. (2025) introduce two further reforms that go beyond the 2024 package and could reduce incumbent manipulation in the short-term wholesale market. The first of these reforms, the opening of electricity markets to international competition, mainly with European neighbors through the development of cross-border transmission links, is embraced by both papers on the reforms as an important objective. They also argue for supporting and implementing a strong, liquid forward market, as it would help limit the market power of dominant operators and provide a means for market participants to hedge against difficulties.

5.2 Long-term market reforms

The most critical part of the European electricity market in need of major reforms is long-term contracting. Currently, long-term contracting is possible through either power purchase agreements (PPAs) between two independent parties or two-way contracts for difference (CfDs).

While the European Union’s reforms passed in Regulation 2024/1747 mainly advocate for PPAs to be used as the default long-term contracting tool between incumbent electricity producers and third parties, and to use CfDs only for the establishment of new publicly supported zero-carbon plants, [Fabra \(2023\)](#) calls for a more widespread use of CfDs in the case of zero-carbon electricity generators. For more traditional power plants, the paper advocates regulator-organized central auctions to achieve equitable and efficient long-run investment. Fabra believes these centrally organized auctions are necessary because the regulator could internalize factors such as security of supply, flexibility, learning-by-doing, and potential complementarities across technologies. Additionally, an important regulatory step in Fabra’s proposed contracts would be to impose marginal caps to ensure generators do not earn excessive profits during periods of high energy prices.

[Ambec et al. \(2025\)](#) do not criticize the use of PPAs as much as Fabra does, but they highlight an important issue with standardized PPAs, as EU Regulation 2024/1747 calls for. They believe standardized PPAs provide insufficient flexibility for contract design. On the other extreme, the EU Regulation states that the current framework of bespoke contracts needs to become more uniform in order to increase the use of PPAs. Also, the case of Exeltium cited by Ambec et al. shows that competition regulation is a key challenge that must be addressed with a more widespread use of PPAs.

Regarding CfDs, both Fabra and Ambec et al. are critical of the EU’s approach, although for very different reasons. [Fabra \(2023\)](#) proposes broader adoption of CfDs, while [Ambec et al. \(2025\)](#) argue that the EU’s CfD design can lead to the significant side effect of zero or negative prices. Therefore, the EU should reconsider the current implementation of CfDs.

Ambec et al. criticize the form of CfDs adopted by the EU reform, in which payment is conditional on the actual delivery of electricity, a mechanism the authors call ‘c-CfD’. They argue that this condition transforms CfDs into guaranteed feed-in tariffs, which pay the same amount to a producer regardless of market conditions. As a result, it incentivizes production when production costs are below the CfD strike price, while symmetrically disincentivizing production when the strike price is below production costs. This phenomenon is exactly what transforms ‘c-CfDs’ into guaranteed feed-in tariffs.

Compared with European Union reforms, [Fabra \(2023\)](#) advocates a significant expansion of CfD use in the European energy market. The paper proposes several CfD types for different situations. It describes a system in which all renewables, including existing ones, would participate in state auctions conducted by the central regulator, which collectively purchases electricity from the generators. As the paper states, a central regulator could internalize a larger share of objectives than a profit-oriented firm. Additionally, auctions would preserve the competition between firms. The proposed structure of PPAs and CfDs by Fabra can be seen in Figure 5.1.

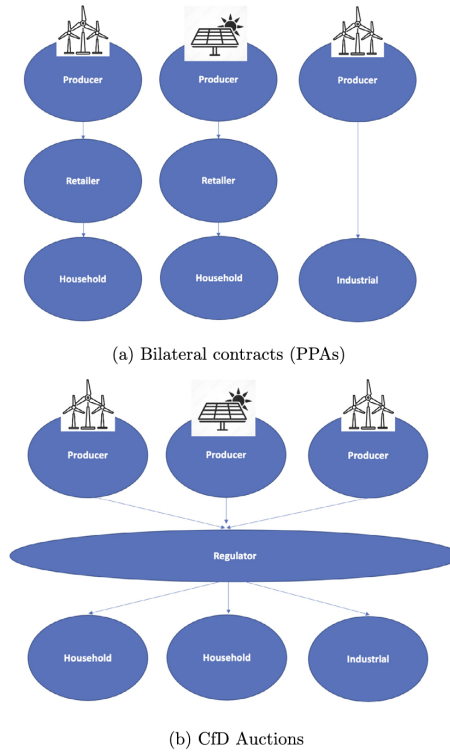


Figure 5.1. *Mechanisms for long-term contracting.*

Note. From [Fabra \(2023, Fig. 4, p. 5\)](#).

[Bichler et al. \(2020\)](#) show that auctions can help regulators internalize the location choices of renewable energy projects. Thus, reinforcing the claims of [Fabra](#) by showing that it is possible for a regulator to internalize different objectives, besides price, in the design of an auction, with only a small increase in price. As [Fabra \(2023\)](#) writes, if the regulator has enough information, auctions can indeed be a good form of allocating energy-generating capacity while internalizing different objectives of policymakers in the energy market; thus providing a new way to implement policy objectives in the energy market, and potentially leading to lower prices in the long term.

A final important consideration when designing long-term contracts is to avoid creating an expectation among participants in the energy market of state bailouts in the event of solvency problems. As [Ambec et al. \(2025\)](#) explain, the fact that political pressure ex-post on the difficulties of energy generators can create an expectation of state bailouts is a major issue ex-ante. Their solution is to mandate ex-ante hedging/insurance, which they explain ideally would occur in a forward market, which ties back to the importance of creating a liquid forward market, as explained in Subsection 5.1.

Taken together, the proposed reforms can be evaluated using three criteria derived from the theoretical framework in Section 3: productive efficiency, the allocation of price risk, and incentives for long-term investment. In the short term, greater market integration and liquidity can strengthen competition and promote efficient dispatch ([Fabra, 2023](#)). In the long term, PPAs and CfDs can reduce exposure to wholesale price volatility and encourage investment by providing greater revenue certainty ([Fabra, 2023](#); [Ambec et al., 2025](#)).

However, as [Ambec et al. \(2025\)](#) note, the effectiveness of these instruments depends on their design, since contracts that distort production incentives may undermine short-run efficiency. These considerations suggest that the positions of [Fabra \(2023\)](#) and [Ambec et al. \(2025\)](#) are not necessarily contradictory: while expanding long-term contracting may be desirable, its benefits depend on preserving efficient market signals and avoiding unintended distortions. Consequently, the optimal reform should combine competitive short-term markets with long-term contracting mechanisms that reduce price risk, support investment, and account for broader system costs, including network-related inefficiencies ([Bichler et al., 2020](#)).

6 Conclusion

While the 2024 reforms address several shortcomings in the design of the European electricity market, they may not be sufficient to protect consumers and firms from future energy crises. Importantly, market design reforms cannot eliminate external supply shocks, such as the disruption to natural gas markets following Russia’s invasion of Ukraine in 2022. Instead, their primary objective should be to increase the resilience of the European electricity system by reducing price volatility, limiting the transmission of wholesale price shocks to final consumers, and strengthening long-term investment incentives. In this context, the wider adoption of long-term contracting mechanisms, including PPAs and appropriately designed CfDs, alongside greater market integration and competition, could help mitigate the economic consequences of future energy shocks. Further reforms should therefore focus not on preventing external shocks themselves, but on reducing Europe’s vulnerability to them.

In the short term, some price reductions may come not from market-design reform but from changes in taxation. Reducing VAT or excise duties on electricity can immediately lower final consumer prices, although this does not reduce the underlying cost of the electricity system. Instead, it shifts costs to public budgets, future taxpayers, or other areas of taxation as analyzed in [Heussaff et al. \(2025\)](#). These insights highlight the need for wholesale electricity market reforms to achieve lower prices in the long term, not just short-term reductions during crises at the expense of public budgets and long-term taxpayers.

In the current geopolitical climate, with a new energy crisis looming due to the closure of the Strait of Hormuz, EU-wide reforms are more important than ever to mitigate the economic consequences of future energy crises. As mentioned in Section 1, European electricity prices are significantly higher than those in other regions, e.g., the United States. Furthermore, crises over the past 5 years could significantly increase volatility, potentially halting investment across the continent.

Therefore, it is essential that European policymakers both in Brussels and National capitals revisit energy market reforms because if the continent wants to regain its competitiveness and transform its economy to be carbon neutral, it must introduce major reforms and make significant investments, which might be painful in the short term for taxpayers but, in the long term, will help ensure the continent’s future in the global landscape.

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