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REFORMING EU ELECTRICITY MARKET DESIGN: PPAS, CFDS, AND LONG-TERM SIGNALS FOR A RENEWABLE-DOMINATED SYSTEM

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Glossary

Power Purchase Agreement (PPA): A long-term bilateral contract between an electricity generator and a buyer (corporate or utility). It defines the price, volume, and delivery profile of electricity over time. PPAs can be physical (energy delivered through the grid) or financial/virtual (cash-settled against a market reference).

Contract for Difference (CfD): A financial contract between a producer and a counterparty (often public), fixing a strike price per MWh. If the market price falls below the strike, the producer receives the difference; if it rises above, the producer pays back the surplus. This contractual structure is also known as “two-way CfD”.

Basis risk: difference between the price at which a contract settles or hedges (e.g. hub or zonal forward, CfD reference) and the actual price realized at the delivery node or asset (or in the buyer’s retail bill). In Europe, this typically refers to hub vs bidding-zone differences and, de facto, intra-zonal congestion.

PPA profiles: **baseload** (seller delivers, either physically or financially, a flat hourly profile, with constant price); **peakload** (seller delivers, either physically or financially, a flat hourly profile, with higher prices during peak hours of demand); **pay-as-produced** (PaP, buyer takes the actual production profile, e.g., solar day curve or wind variability); **sleeved** (balancing, grid settlement, and billing are handled by a retailer – the "sleeve” – who sits between the generator and the customer).

Levelized Cost of Energy (**LCOE**): present value of lifetime costs divided by lifetime MWh. A cost metric, not a value metric.

Guarantees of Origin (**GOs**): electronic certificates proving that 1 MWh of electricity was generated from a specified renewable source. Used for claims (scope-2 accounting), not a hedge against price risk.

Buyer (or **offtaker**): the entity purchasing electricity (or financial exposure) under a PPA.

Executive Abstract

The energy crisis of 2022–2023 marked a turning point for European electricity markets. It exposed how tightly power prices remain linked to gas, how market volatility can destabilize investment, and how fragmented national responses can undermine the integrity of the internal energy market. In the wake of that shock, the European Union has placed electricity-market reform at the center of its Clean Industrial Deal, coupling decarbonization with competitiveness and energy security. The 2024 Electricity Market Design (EMD) reform and forthcoming guidance on Contracts for Difference (CfDs) and Power Purchase Agreements (PPAs) aim to ensure that long-term investment signals coexist with short-run market efficiency. Yet implementation will determine success: translating legislative intent into market outcomes requires sound economic design and clear institutional coordination.

This report was prepared to support that process. It analyzes how PPAs and CfDs can jointly mobilize private and public capital while preserving efficient dispatch and price discovery. Drawing on academic research, EU policy documents, and empirical evidence from different countries, the study provides a structured framework for reform. It links economic theory on incomplete markets and risk allocation to the operational experience of regulators, utilities, and corporate buyers. The analysis proceeds from the recognition that volatility in high-renewable systems is not an anomaly but a structural feature, one that must be managed through institutional innovation rather than suppressed through ad hoc interventions.

Why this matters now - The EU's decarbonization trajectory implies that by 2030, over two thirds of installed capacity will be variable renewable energy (VRE). In such systems, wholesale prices fluctuate widely, forward liquidity remains thin, and the cost of capital becomes the dominant driver of electricity costs. Efficient long-term contracting is therefore essential to channel investment and hedge risk. PPAs and CfDs are the two main tools available, but they serve different purposes and rely on different institutional logics. PPAs are decentralized, market-based hedges that reveal the system value of renewable generation and mobilize private demand. CfDs are centralized public instruments that stabilize revenues and lower financing costs for projects competing in auctions. Designing them to coexist rather than compete is the central policy challenge.

Italy offers a particularly relevant test case. The country faces one of the highest wholesale price volatilities in Europe, widespread transmission constraints, and a corporate sector dominated by small and medium-sized enterprises (SMEs) with constrained access to credit. At the same time, Italy's policy architecture – anchored in the *Gestore dei Mercati Energetici* (GME), the *Gestore dei Servizi Energetici* (GSE), and multiple public stakeholders, like Consip (*Concessionaria Servizi Informativi Pubblici*) which runs most of the electricity procurement for public administrations – provides a unique institutional base for innovation. Recent initiatives such as the *Mercato PPA*, the FER-X CfD scheme, and the ongoing pilots of guarantee programs under the Clean Industrial Deal can be leveraged to build a complete long-term market.

Analytical framework – After a brief introduction (Section 1) and an overview of the available evidence on the EU electricity markets and PPAs (Section 2), Section 3 develops the theoretical foundation of this study. It reviews how the rise of VRE changes system stability (reliability constraints), price formation (volatility and scarcity pricing), and risk allocation (shifting between producers, consumers, and the public sector). The analysis shows that efficient long-term contracting must: (i) preserve marginal-cost dispatch in the short run; (ii) provide credible, bankable signals in the long run; (iii) allocate risks to those best able to bear them.

From this framework, four policy options emerge to strengthen Europe's and Italy's long-term electricity markets.

1. Reducing information and valuation asymmetries - Information gaps remain a major barrier to PPA expansion. Buyers and sellers face uncertainty about future prices, profile risk, and credit exposure. The report recommends a coordinated EU–national initiative to standardize and disseminate pricing, credit, and performance information. This includes:

- establishing open data platforms and anonymized PPA registries;
- supporting transparent modeling tools for shape and volume risk (e.g. the hybrid statistical–fundamental models proposed by Qorbanian, Löhndorf and Wozabal, 2025);
- developing standard clause libraries for bankable PPAs;
- aligning strike prices and benchmarks with more sophisticated valuation schemes than the LCOE, such as those including economic considerations ("ECOE-based valuations").

Reducing information asymmetry is the lowest-cost, highest-impact lever: it shortens negotiation times, compresses bid spreads and facilitates participation of smaller buyers without fiscal cost.

2. Expanding public guarantees and credit access - Credit risk is now a widely recognized bottleneck for corporate PPAs. SMEs and mid-caps, which form the backbone of European (and Italian) industry, rarely meet investment-grade thresholds. The report recommends scaling and integrating public guarantees, like the ongoing European Investment Bank counter-guarantee pilot (€500 million) with national schemes. For instance, in Italy that role could be done by the GSE, but also by CDP in ways like those adopted by its French equivalent. Guarantees should be partial, risk-based, and additional, to make them sustainable for public finances and to avoid inducing moral-hazard behavior.

At national level, the Mercato PPA provides a practical platform to test such guarantees. The report proposes reforms to the current system that include:

- broaden contract types including standardized VRE profiles;
- eliminating daily mark-to-market margining in favor of fixed collateral levels (8–10% of contract value);
- extending access to non–investment-grade firms with proportionate guarantees.

Together, these measures would expand market liquidity while maintaining fiscal prudence and aligning with EU State-aid rules under the Clean Industrial Deal.

3. Mobilising public demand for PPAs - Public administrations are among the largest electricity consumers. For instance, in Italy their annual energy expenditure exceeds €12 billion, with electricity accounting for slightly more than half of the total. Channeling even 15–20% of that demand into long-term renewable PPAs could transform market liquidity. The report outlines two complementary avenues:

- Direct procurement, through aggregated Consip or regional tenders for multi-year renewable PPAs, with Consip or GSE acting as central counterparty;
- Indirect uptake, by awarding extra points in tenders under the Most Economically Advantageous Tender (MEAT) criterion to suppliers that source a significant share of their electricity from renewable PPAs.

These measures would use public procurement strategically to anchor renewable investment, while the forthcoming revision of the EU procurement directives (2026) offers an opportunity to explicitly recognize PPAs as eligible long-term contracts within the project-finance framework. Additional benefits include the coherence of the proposed options with the achievement of the green transition goals and the potential simplifications in the permitting stage of new plant developments where the offtaker is the same local administration involved in the authorization process.

4. Refining CfD auction design for coexistence with PPAs - The next frontier is to design CfD auctions that complement, rather than crowd out, corporate PPAs. The report reviews the Chilean model, which integrates demand-based settlements and locational pricing to balance efficiency and bankability. While the optimal EU–Italian design is still under discussion, the report identifies four areas for experimentation in the next auction cycles:

- testing demand-indexed or proxy-generation CfDs that better align remuneration with the temporal value of electricity;
- defining PPA reservation quotas within CfD-supported projects to ensure public and private contracts coexist without crowd-out;
- evaluating zonal or nodal reference prices to reduce basis-risk exposure and reflect locational system value;
- establishing transparent, predictable auction and revenue-allocation rules, ensuring that CfD proceeds and obligations are handled automatically and consistently.

Conclusion - The report concludes that completing long-term electricity markets is essential for Europe's clean energy transition. Short-run markets should remain the arena for efficient dispatch and price discovery; long-run contracts must ensure investment certainty and fair risk allocation. For Italy, this means transforming the Mercato PPA and FER-X into complementary pillars of a unified framework – where information transparency, targeted guarantees, public demand, and hybrid auctions work together to deliver both stability and competition.

1. Introduction

The energy crisis of 2022–2023 exposed structural vulnerabilities in the EU electricity market, particularly the tight coupling of power and gas prices under marginal pricing and the proliferation of uncoordinated national interventions. These dynamics have raised questions about the ability of existing market mechanisms to ensure both short-term efficiency and long-term investment adequacy.

In response, the European Commission has launched a series of initiatives under the Clean Industrial Deal – including the newly released guidance on Contracts for Difference (CfDs) and Power Purchase Agreements (PPAs) – to recalibrate the market framework and improve resilience.

This study examines how PPAs and CfDs can enhance risk allocation and investment certainty while preserving market efficiency. Using a conceptual and policy-focused approach, it integrates insights from the economic literature on market design and incomplete markets with evidence from EU consultations and emerging country experiences. The objective is to provide a structured analytical basis for reform options, linking academic reasoning to the practical challenges of implementing the EU's electricity market reform and national decarbonization strategies.

The report is structured in four parts. Section 2 outlines the empirical and policy context, tracing how the gas shock evolved into structural volatility and how the EU's policy framework – through RED III and the 2024 Electricity Market Design reform – is shaping the current PPA and CfD landscape. Section 3 develops the theoretical framework, drawing on economic literature to examine how market design, price signals, and risk allocation interact in high-renewable systems. Section 4 translates these insights into policy options for strengthening long-term electricity markets in Europe and Italy: improving information and valuation tools, scaling public guarantees, leveraging public demand, and refining CfD auction design. The study concludes by highlighting the conditions under which these instruments can coexist to deliver investment certainty while preserving efficient market signals.

2. Empirical & Policy Context

2.1 From Gas Shock to Structural Volatility: energy in EU after 2020

Before the crisis, EU wholesale electricity and gas prices were comparatively stable. Day-ahead power typically averaged €40–60/MWh, while the Dutch TTF gas hub often traded below €20/MWh (even dipping under €10/MWh in 2020). Cross-country variation was significant: for instance, industrial gas prices in Italy hovered around €30/MWh.[1]

[1] The numbers references in this subsection are from multiple sources. The main source regarding electricity prices is the ENTSO-E Transparency Platform, while for PPAs the main source is Pexapark. Additional sources include: (i) Prices of natural gas for industry in Italy, Statista; (ii) the report "Il costo dell'energia in Italia e in Europa, analisi e andamento" Report ECR Group.

In the second half of 2021, a rebound in demand after the COVID-19 slowdown, coupled with rigid supply and low storage levels, pushed TTF above €100/MWh by year-end. Electricity prices followed through marginal coupling. The low storage levels (especially in Germany) have been associated with the prelude of Russia's invasion of Ukraine in February 2022. The latter triggered an energy "super-cycle": TTF peaked near €300/MWh in August 2022, and wholesale power broadly tracked it wherever gas set the marginal bid. In Italy, the *Prezzo Unico Nazionale* (PUN) climbed from about €250/MWh in June 2022 to over €400/MWh in August, yielding a 2022 annual average above €300/MWh – among the highest in the EU. ACER described the surge in day-ahead power prices as "guided by record natural gas prices".

In response, EU institutions and governments deployed a series of emergency measures.

- The EU introduced an *inframarginal revenue cap* (generally €180/MWh) on low-cost generation, with excess revenues redirected to consumer relief.
- In December 2022, energy ministers adopted the TTF *market-correction mechanism*: a dynamic cap activating if the front-month TTF exceeded €180/MWh for three days and was €35/MWh above an LNG reference. Although never triggered, it helped stabilize expectations.
- Several Member States introduced local measures. For instance, Spain and Portugal implemented the *Iberian exception* (*tope al gas*), capping the gas input used for power generation. The measure sharply reduced spot prices: 2022 wholesale average in Spain fell to around €167/MWh, while its adjustment cost was charged only to wholesale indexed customers. The export exemption – allowing French imports to benefit without sharing costs – raised cross-border equity concerns. As gas prices normalized, the mechanism became inactive and ended in May 2023.

A mild 2022-2023 winter, demand-reduction policies, and rapid diversification of supply (especially LNG) helped defuse the worst outcomes. EU gas consumption fell about 18 % between August 2022 and May 2024 compared with the previous five-year average; the average EU border gas price dropped to roughly €41/MWh in 2023 (from €101/MWh in 2022), and TTF stabilized within €30–40/MWh by year-end. Yet the new baseline remains well above pre-2021 levels.

Volatility also persisted, no longer driven mainly by gas, but by the interaction of high renewable shares with grid bottlenecks and Europe's simplified zonal market design, which prices congestion between bidding zones but not within them. EU-wide redispatch costs reached about €5.2 billion in 2022 (+46 % y/y), with nearly 50 TWh of redispatch activated, revealing deepening spatial imbalances and basis risk.

At the same time, many markets experienced an increasing number of zero or negative-price hours (Figure 1), and over 12 TWh of renewable generation were curtailed in 2023 due to congestion. These phenomena hit EU countries asymmetrically (as visible in Figure 2) and have a clear cyclicality during the year (Figure 3).

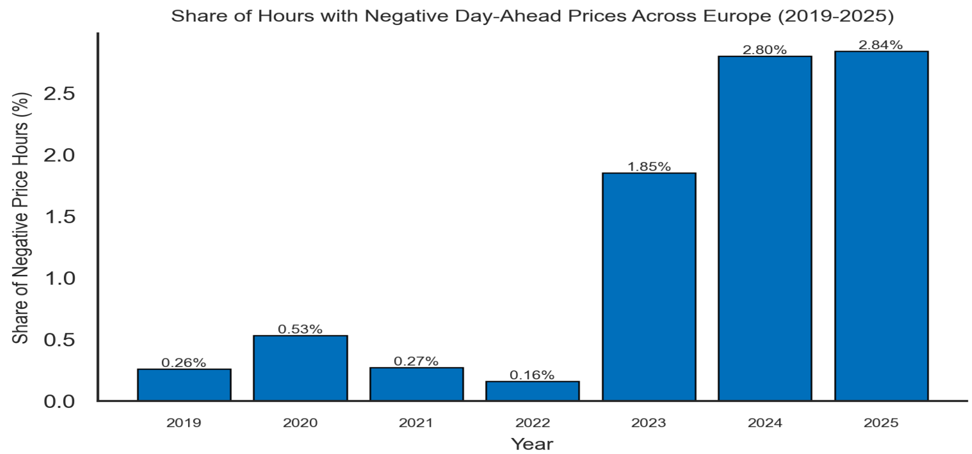


Figure 1: Total negative day-ahead price hours across all EU price zones in the sample period. Own elaboration from ENTSO-E data.

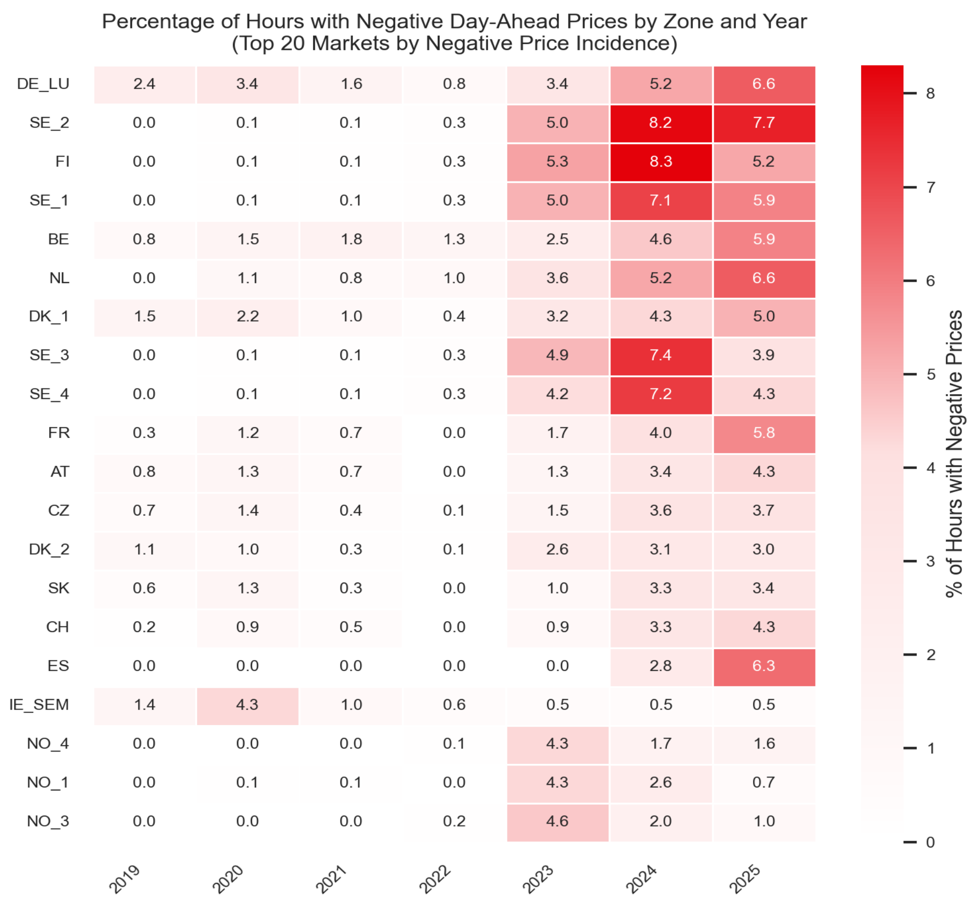


Figure 2: Percentage of hours with negative day-ahead prices by zone and year in the top 20 markets by negative price incidence, which are indeed the ones with mature renewables penetration. "IE-SEM" refers to the Eire-Northern Ireland Integrated Single Electricity Market. Own elaboration from ENTSO-E data.

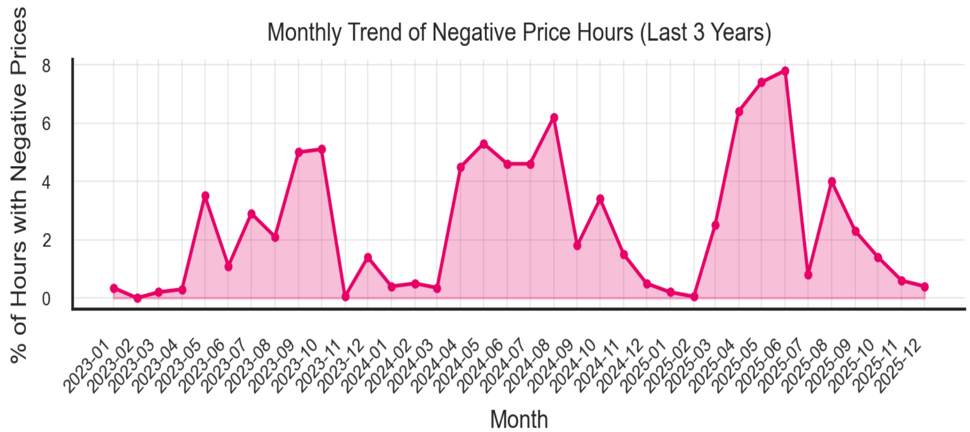


Figure 3: Percentage of hours with negative day-ahead prices by month in the top 20 markets by negative price incidence in the last 3 years. Negative price hours cluster predominantly in spring and summer, coinciding with the longest days and subsequent solar output. Own elaboration from ENTSO-E data.

Other measures of variability in hour-to-hour price in the day-ahead markets offer a similar picture. For instance, mean hour-to-hour price changes rose markedly from an average of around €4/MWh in the period between 2019 and 2020 to over €8/MWh in 2021, peaking at nearly €20/MWh in 2022 amid the energy crisis. Although volatility moderated thereafter, it remained structurally elevated, stabilising in the range of €10–12/MWh between 2023 and 2025. The post-crisis baseline remains remains substantially above pre-crisis levels, suggesting that the structural increase in VRE penetration introduced a persistent source of intra-day price dispersion that was largely absent before 2021. Short-term price formation has become more dynamic and less anchored, even outside crisis conditions.

These developments mark the transition from a transient gas shock to *structural volatility*. This is now a defining feature of Europe's emerging power system, setting the stage for the EU's current market reform and the renewed focus on PPAs and CfDs. In the long run, structural volatility will be mitigated chiefly by deeper market integration and large-scale flexibility – interconnection and congestion relief, alongside storage and demand response – yet these are multi-year investments requiring cross-border coordination.

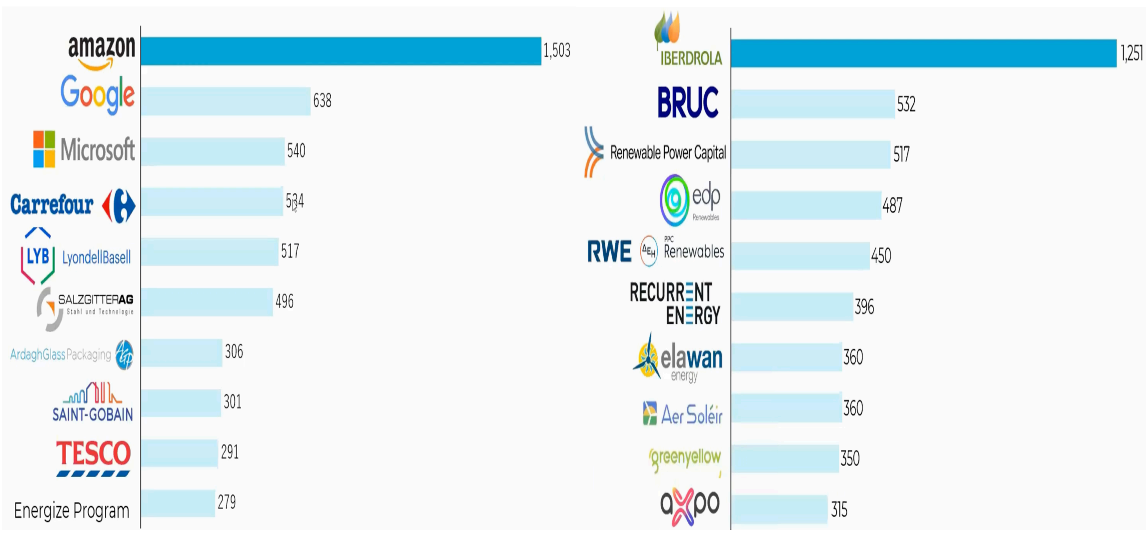
Evidence shows that integration reduces curtailment and costs while improving investability, and today's high redispatch outlays underline the value of targeted grid expansion; until these assets arrive at scale, risk-sharing instruments (PPAs and well-designed financial/profile-indexed CfDs) remain essential to mobilize capital without distorting dispatch.

2.2 The EU PPA market: size, shape, and last year dynamics

Europe's corporate PPA market expanded rapidly between 2020 and 2024. Volumes surged, new buyer segments entered, and more Member States developed active markets – though the bulk of activity remained concentrated in Spain, Germany, and the Nordics. For instance, in 2024, Spain saw the largest increase in PPAs with 47 deals worth 4.66 GW of power, followed by Germany with 48 deals and 2.04 GW; for Italy, France and the UK the newly contracted power amounted to roughly 1.05 GW each, but spread over 39 deals in Italy, far more than in France and UK, with 24 and 26 deals respectively.

Solar dominated new capacity in 2023, while hybrids combining solar, wind, or storage grew steadily in 2024. Buyer portfolios diversified beyond ICT, reflecting the spread of corporate decarbonization commitments (see Figure 4), while, among sellers, Iberdrola maintained the lead. Demand is also uneven across sectors: electricity-intensive digital services and parts of heavy industry tend to be more PPA-prone, while many service-oriented SMEs remain reluctant to commit to long tenors, reinforcing the role of aggregation and standardised platforms.

Figure 4: Main Corporate Offtakers of PPAs and Sellers



Source: Pexapark

By 2025, however, activity slowed. Many contracts closing in 2025 were negotiated during the high-price window of 2023–2024, leaving strike expectations misaligned with the calmer forward curve. Indeed, time-to-closure typically ranges from nine to eighteen months – with an average of twelve – driven by negotiations on strike price, production profile, risk allocation, guarantees of origin, tenor, and counterparty credibility. At the same time, concerns over solar "cannibalization" and risk allocation led counterparties to favor more complex, balanced structures.

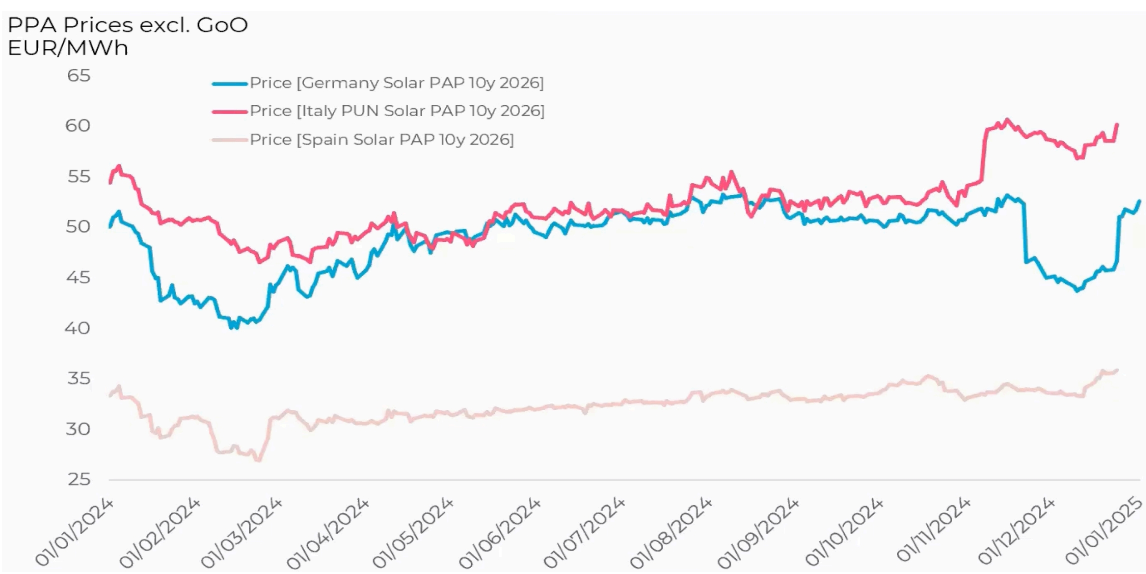
Quantitatively, the market's expansion has been striking up until 2023. According to a recent European Commission assessment, total contracted capacity rose from about 3 GW in 2018 to around 17 GW in 2023, while the number of deals increased from roughly 30 to 300. The pool of first-time corporate buyers grew from about 60 in 2021 to over 160 in 2024. DG ENER reports parallel trends, noting more Member States with functioning PPA markets and increased deal diversity.

A complementary EU-wide snapshot is provided by a recent study requested by the ITRE Committee of the EU Parliament (Demurtas et al., 2026): as of 2024, PPAs had facilitated a cumulative 70 GW of new capacity. Annual contracted volumes slowed in 2024, with contracted capacity slightly declining from 16 GW in 2023 to 15 GW in 2024 despite a higher number of deals. Beyond the descriptive snapshot, the same study highlights through scenario exercises to 2050 that current contracting and auctioning volumes may be insufficient to meet the scale of renewable build-out required under EU climate targets. In this reading, significantly higher annual volumes of risk-mitigated contracts (CfDs and, to a lesser extent, PPAs) would be needed to avoid an excessive reliance on 'merchant' investment exposed to wholesale-price volatility.

Volumes remain concentrated in Spain, Germany, and the Nordic countries, which together accounted for around 60 percent of 2023 activity. Yet Central and Eastern Europe showed visible growth, with several markets recording their first transactions. DG ENER categorizes Member States by maturity – high-volume and diversified, moderate, or early-stage – underscoring heterogeneity across the Union.

Solar represents the majority of PPA volumes (around 60% of deals in 2023), reflecting short project lead times and declining costs. Hybrid PPAs are increasingly common, particularly in systems with mature offshore wind pipelines. Delivery formats are evolving as well: pay-as-produced (PaP) contracts dominate recent transactions, while demand for baseload profiles – though more expensive – has stabilized among experienced buyers. Many stakeholders report that exposure to shaping and firming risk, coupled with policy uncertainty, has made buyers more cautious and inclined toward PaP or hybrid solutions.

Figure 5: PPA Price Index



Source: Pexapark

Although complete price information is unavailable, indexes commonly used in the industry like that of Pexapark describe a situation of higher price volatility in 2025 relative to a stable 2024 and persistent and growing heterogeneity between countries (see Figure 5).

The structure of delivery is also shifting. Physical and sleeved PPAs are gaining ground relative to purely financial PPAs (or virtual, VPPAs), signaling a broader preference for contracts linked to real supply and traceable attributes. Tenors remain predominantly long term (ten years or more), though a gradual shortening trend reflects the growing value of flexibility under volatile market conditions.

Finally, beyond these structural factors, macroeconomic conditions add a new layer of uncertainty. Tariff volatility and shifting LNG agreements influence relative energy competitiveness between regions, while supply-chain frictions – especially EU tariffs on Chinese solar and storage components – raise project costs and delay contracting. At the same time, exuberant expectations of future electricity demand from data centers have inflated long-term price assumptions, though the timing and magnitude of this load remain highly uncertain.[2] Together, these factors contribute to a cautious tone among both developers and corporate buyers entering the 2025 contracting cycle.

Cross-section analysis of the current European PPA Market[3] - We now conclude this snapshot of the current situation in the PPA market leveraging data from Pexapark. We use Pexapark benchmark quotes for standardised PPA specifications (see note to Figures 8–10 for interpretation and limitations). The dataset covers 36 European power markets. While this cross-sectional structure is useful because it isolates cross-market differences in PPA pricing and risk premia from time variation, we stress that it also means that observed dispersion reflects a mix of structural unobserved factors (resource quality, technology mix, grid constraints, regulatory context, market design) and contemporaneous conditions specific to that valuation date.

Across the full sample, PPA prices are right skewed and highly dispersed (median 60.5, mean 71.0, with a s.d. of 63.0). Liquidity premia also display substantial right skewness (median 2.9 and mean 5.0), indicating that "illiquidity" is not uniform across Europe.[4] Deep-diving on the right-skeweness of the distribution of PPA prices: while the median is about 60.5, the 95th percentile is 94.1 and the maximum reaches 434.7. This pattern follows from a Europe-wide "core" of markets where corporate PPA prices cluster in a relatively tight band, and a set of outliers where prices are structurally elevated. Most Western and Northern European markets fall into the core: Great Britain (mean 55.4), the Netherlands (64.1), Germany (65.0), Denmark (around 58 in both bidding zones), and Belgium (61.3) show moderate dispersion

[2] For an insight about the rapid expansion of data centers in the Italian Market, we refer to a report of iCom (*Istituto per la competitività*) of November 2025. https://www.i-com.it/wp-content/uploads/2025/11/Rapporto_Energ-IA.pdf
[3] We exploit a dataset of PPA contracts from Pexapark, as of 4th February 2026.
[4] All values of prices and liquidity premia are expressed in EUR/MWh. About the computation of these metrics, we refer to Pexapark: https://help.platform.pexapark.com/en/articles/9577400-what-are-ppa-prices-shown-on-pexaquote-and-the-market-price-of-risk

and comparatively contained upper tails. Southern Europe appears cheaper on the PPA-price dimension in this snapshot: Spain (44.3) is among the lowest large markets, consistent with a combination of strong solar resource, mature project pipelines, and often lower long-run marginal costs for incremental renewables. Prices in France and Portugal are also quite low (mean of 46.1 and 46.5, respectively). On the other side of the continent, the Nordics stand out for low price levels: Norway's most northern zone and Sweden's most two northern zones are in the mid-20s to high-20s in mean prices, and the broader Nordic system is below 40. This is in line with hydro-heavy systems and high renewable penetration, where forward power prices can be structurally lower. The most-evident exception is Poland, with an extremely high mean (369.4) and a wide left-skewed distribution (min 218.3, median 389.8 and max 434.7), which dominates the overall sample skewness. Interpreting this economically, Poland likely reflects a fundamentally different risk and cost environment, with higher wholesale price expectations, policy and financing risk, and potentially a different reference product. Figure 6 provides a visualization of the evidence described in this paragraph.

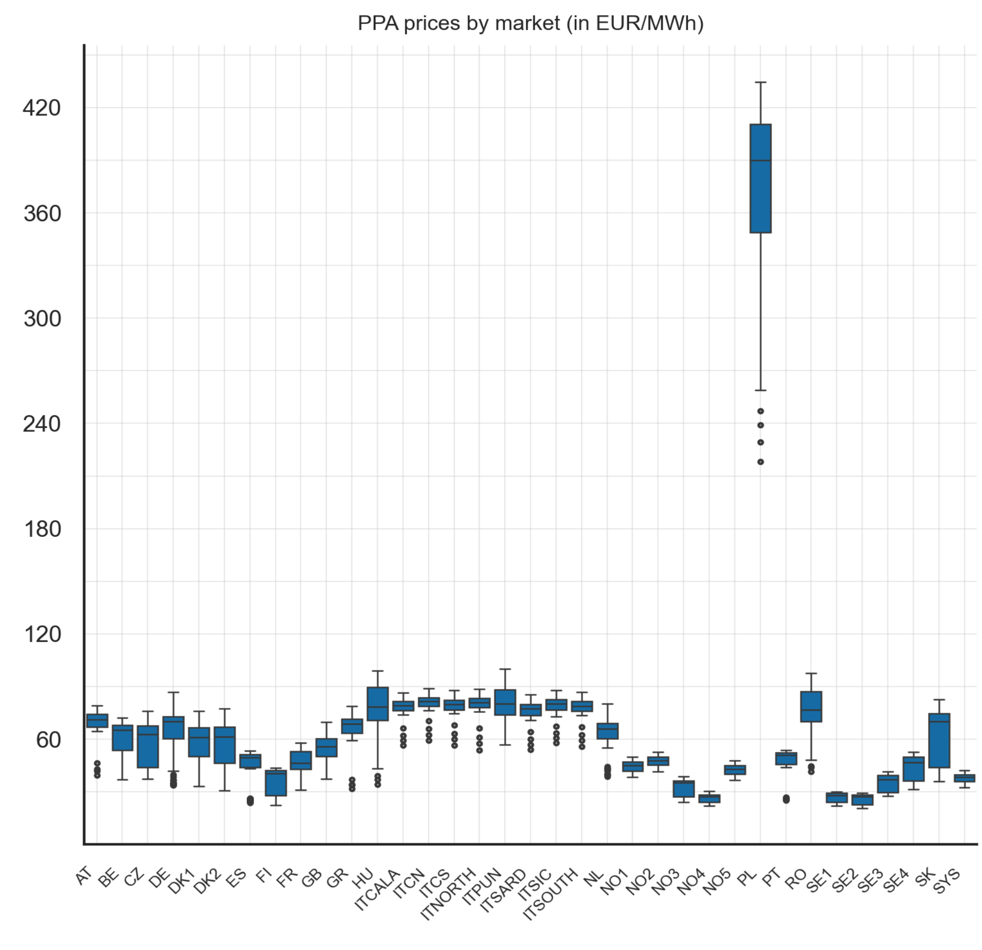


Figure 6: Distribution of PPA prices by market (boxplots by market zone), illustrating cross-market heterogeneity in typical price levels and dispersion. Own elaboration based on Pexapark data from "PPA Prices" section as of 4th February 2026.

Moving to liquidity premia, they exhibit an even stronger cross-country segmentation than prices. In "core" continental markets such as Germany and France, the liquidity premium is very low (means around 0.94 and 1.05, respectively), suggesting deeper deal flow, more standardized contract structures, and more confident valuation benchmarks. In contrast, Great Britain and Denmark show much higher premia (around 8.9–9.1 on average, with 95th percentiles near or above ~18–19). Southern Europe sits between these poles: Spain (1.92) and Portugal (1.49) look relatively "liquid" by this measure, while Italy is clearly higher (Italy PUN averages 2.89 and Italian zonal markets cluster around 3.3–3.5). The tail behavior is again informative: Poland's liquidity premium is extremely high (mean 22.8, 95th percentile ~47.5, max 48.4), and Greece is also elevated (mean 11.9). Attempting an interpretation, compared with Western Europe, some countries of the periphery appear to embed a sizable "friction wedge" in valuations, potentially capturing thinner transaction markets, higher perceived counterparty/credit concerns, or wider bid–ask and structuring costs for long-dated renewable contracts. Figure 7 illustrates the point.

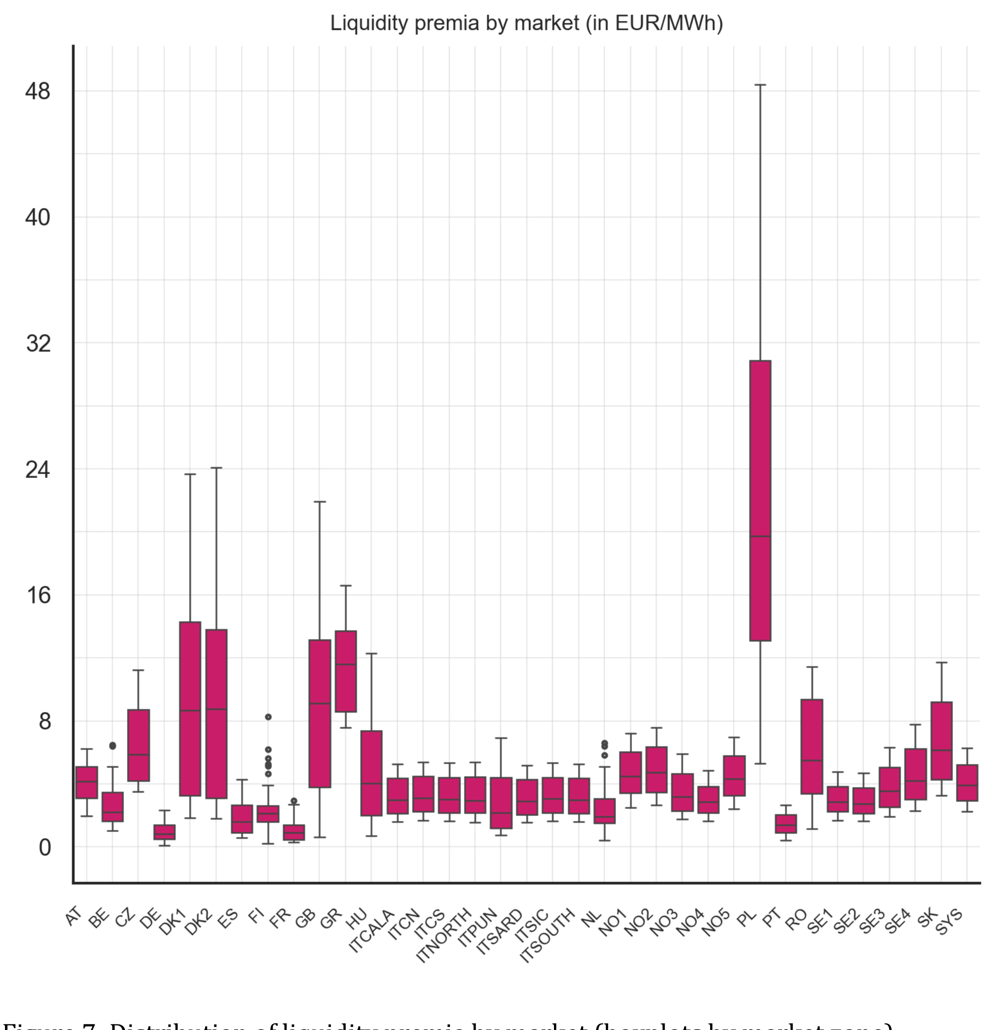


Figure 7: Distribution of liquidity premia by market (boxplots by market zone), capturing cross-market differences in implied illiquidity/valuation adjustments. Own elaboration based on Pexapark data from "PPA Prices" section as of 4th February 2026.

We argue that these comparisons of prices and liquidity premia underscore the need for intervention in less mature markets. Later in this work, we will point in the direction of targeted guarantees, aggregation platforms, and deeper grid; with the aim of improving PPA affordability and bankability. Now, we conclude this subsection by looking at three qualitative dimensions of the contracts in the sample: contract tenor, structure and technology employed.

Tenors are strongly concentrated: 10-year tenors account for 38.4% of all observations, 5-year for 30.5%, and 15-year for 13.4%, with very limited mass beyond 15 years, with few rare 20-year contracts. The market breakdown reinforces the idea that long-dated contracting is more prevalent where the ecosystem is mature. Belgium shows particularly high shares of tenors of 10 years of more (about 78%), while Germany, Great Britain, and the Danish zones are around 60-62%. By contrast, Spain (~38%) and Italy (above 50%) have notably lower shares, and Finland/Poland are similarly low (~37.5%). One interpretation is that in markets where prices are lower (e.g., Spain) or where uncertainty about future policy/market conditions is salient (e.g. Italy), parties may prefer shorter commitments to preserve optionality. Figure 8 provides visual representation of these statistics.[5]

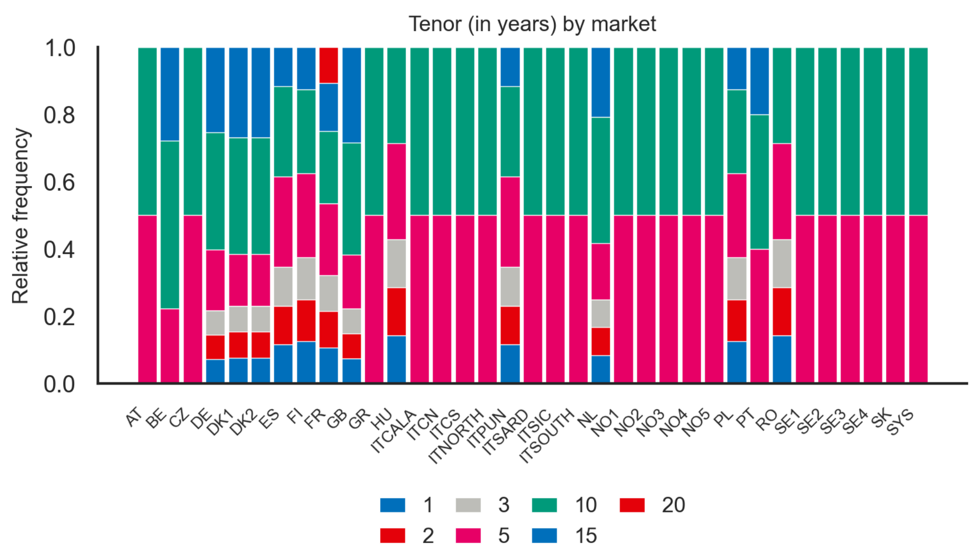


Figure 8: Relative frequency of contract tenors (years) across market zones. Own elaboration based on Pexapark data from "PPA Prices" section as of 4th February 2026.

Moving to contract structure, heterogeneity is virtually absent. In fact, the product dimension is strikingly standardized, with three structures each accounting for roughly a third of the observations: Pay-as-Produced, Baseload Monthly and Baseload Annual, while Fixed Hourly

[5] Pexapark's PPA quotes used for Figures 8–10 are benchmarks for standardised contract specifications derived from pricing models calibrated with market evidence (transactions and market polling), and should not be read as deal-level transaction microdata; moreover, the published 'grid' of quotes may include interpolations across contract dimensions (e.g., profile/tenor/technology) and is not necessarily representative of the distribution of observed contracts.

Profile is essentially residual (below 1% and only in Germany, Italy and Spain). This pattern is shown in Figure 9.

Finally, looking at the technology mix, the overall composition is dominated by onshore wind (43.8%) and solar (39.1%), with offshore wind making up the remaining 17.1% (see Figure 10). Yet there is large heterogeneity between countries.

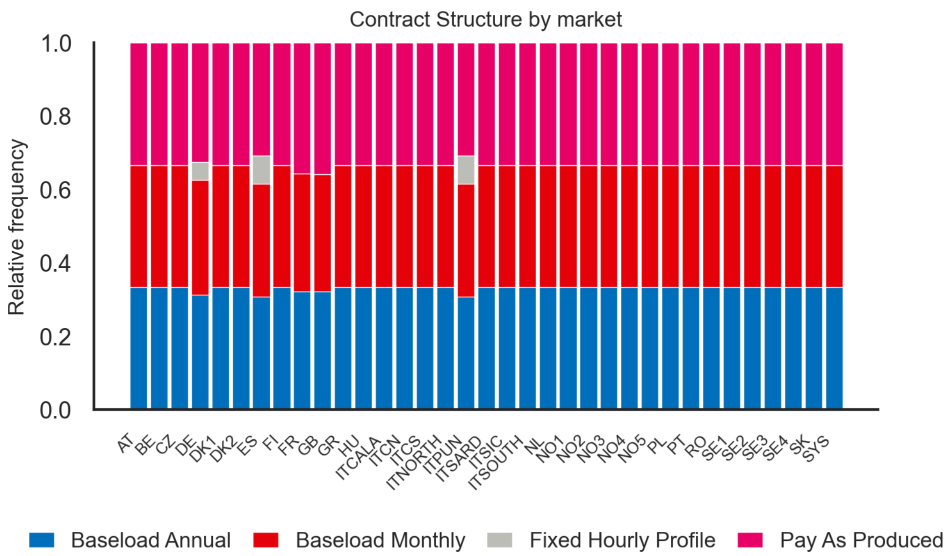


Figure 9: Relative frequency of contract structures across market zones. Own elaboration based on Pexapark data from "PPA Prices" section as of 4th February 2026

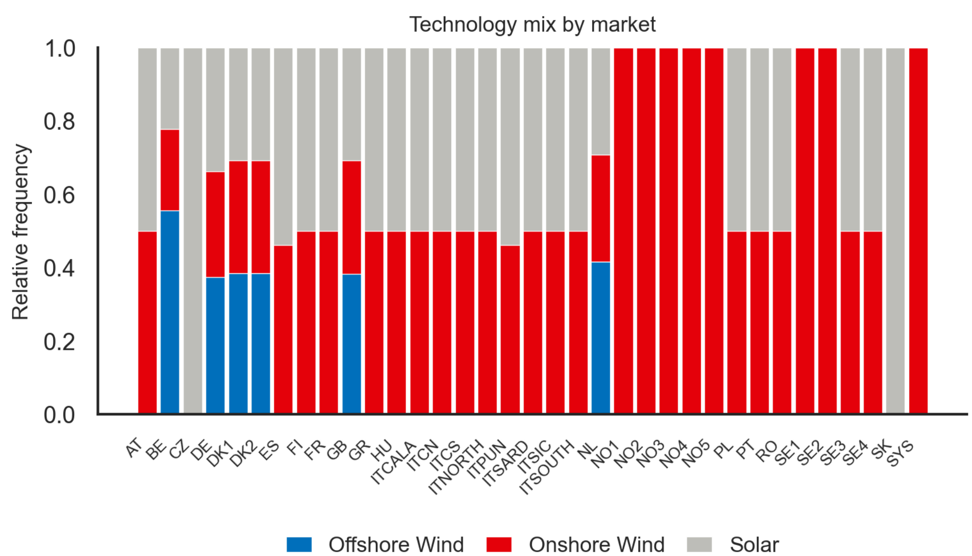


Figure 10: Relative frequency of contracts by technology (Solar, Onshore Wind, Offshore Wind) across market zones. Own elaboration based on Pexapark data from "PPA Prices" section as of 4th February 2026.

In particular, the Nordic markets are essentially all onshore wind in this sample. As expected, offshore wind is concentrated in coastal markets: Belgium has a majority offshore share (about 56%), while Germany and Great Britain are both near 37–38% offshore, and the Netherlands is above 40%. In Southern Europe, solar is comparatively prominent: Spain and Italy PUN tilt slightly toward solar, consistent with a solar-driven pipeline and the economics of PV in high-irradiance regions.

2.3 The EU policy arc: what's been and what's coming next

Over the past five years, EU policy has moved from simply recognizing PPAs in legislation to actively structuring their uptake through legal clarity, systematic monitoring, and targeted risk-sharing instruments. In parallel, the Electricity Market Design (EMD) reform has reframed Contracts for Difference as the central public-support tool, establishing their coexistence with PPAs within an integrated market architecture.[6]

The Renewable Energy Directive (RED II, 2018) first introduced PPAs into EU law, requiring Member States to assess and remove barriers to their use. RED III (2023) expanded this scope to cover all energy purchase agreements, identified credit and counterparty risks as the main barrier, and explicitly recognized public guarantees as legitimate enablers of PPA growth.

The decisive step came with the 2024 Electricity Market Design reform (Regulation (EU) 2024/1747), which – effective from July 2027 – makes two-way CfDs, or equivalent schemes with the same effect, mandatory whenever Member States use public funds to support new renewable, nuclear, or repowered capacity. These CfDs must:

- Provide symmetric price protection, paying the generator when market prices fall below the strike and returning revenues when prices exceed it;
- Be voluntary for producers;
- Redistribute public receipts to final consumers or to investments that reduce system costs, such as grid or flexibility infrastructure.

The reform clarifies that CfDs and PPAs are not competing instruments. CfDs provide a public price floor and ceiling, while PPAs remain private risk-sharing contracts that can coexist at project level. The Commission explicitly promotes this coexistence, encouraging Member States to design CfD schemes that leave a carve-out for market-based contracting.

This is a key element since CfD-type schemes have already supported a substantial share of Europe's renewable rollout: EU-wide reviews summarised by Demurtas et al. (2026) report cumulative allocations on the order of hundreds of gigawatts since the early 2010s, concentrated in a few leading jurisdictions, with auction outcomes becoming more sensitive after 2022 to higher CAPEX and interest rates.

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[6] See the discussion in Eurelectric (2024).

To make that coexistence work, the EU policy agenda now focuses on de-risking private PPAs and preventing CfDs from crowding them out. Key initiatives include:

- The **EIB counter-guarantee pilot**: a €500 million facility offering partial credit-risk coverage (up to 50 % of contract value) to banks issuing guarantees for corporate PPAs – particularly SMEs, mid-caps, and energy-intensive users. The pilot's main limitation is its modest scale and its narrow focus on counterparty default rather than production-profile risk.
- The **Tripartite Contract model**, under the Affordable Energy Action Plan, bringing together producers, industrial buyers, and a public counterparty (Member State or EIB) that provides guarantees or concessional financing. First pilots, expected by end-2025, will target offshore wind, grids, and storage. The design aims to combine the bankability of CfDs with the flexibility of PPAs, but the precise public role is still being defined.[7]
- The **ACER PPA Market Outlook**, foreseen by EMD, will survey national frameworks, identify barriers such as zero-price episodes and transparency gaps, and assess guarantee schemes, aggregation models, and interplay with CfDs across Member States.
- The **Commission's Guidance on CfD Design**, which was released in December 2025. This Guidance on two-way CfD design discusses how CfDs can coexist with PPAs, notably by allowing (or incentivising) partial coverage of a project's output under the CfD (with the remaining share sold via PPAs or other market-based arrangements), and by envisaging the State (as CfD counterparty) reselling part of the electricity through shorter-term PPAs awarded via competitive processes; it also notes that non-price criteria may be used, in limited cases, to facilitate access for customers facing entry barriers (e.g., SMEs or energy communities).
- A **Commission report on PPA barriers**, feeding into 2026 Guidelines. Priorities include (a) joint CfD + PPA design, (b) public credit-risk guarantees, (c) voluntary market platforms with demand aggregation, and (d) harmonized treatment of Guarantees of Origin and carbon accounting.
- A **feasibility assessment of EU-level PPA platforms**, examining voluntary digital marketplaces capable of pooling SME demand and improving price transparency.

Together, these initiatives establish a clear timeline: 2025 for detailed design guidance, 2026 for platform and barrier reviews, and 2027 for mandatory two-way CfDs.

The EIB acts as the main risk-sharing enabler, while ACER ensures oversight and transparency through periodic market assessments. CfDs remain financial instruments – settled ex post and designed not to distort dispatch – whereas PPAs continue to channel

[7] The study of Demurtas et al. (2026) described earlier also discusses demand-side applications of CfD-type instruments to support industrial electrification, including 'four-way' structures where a public intermediary bridges producers and industrial consumers and reallocates price risk on both sides. These approaches are presented as potential complements to PPAs when individual SMEs face high transaction costs or cannot meet credit requirements, and they point to a broader toolbox for hedging demand-side exposure.

private demand for green power. In practice, the EMD now allows CfD-backed projects to reserve part of their capacity for PPAs, with forthcoming guidance ensuring consistency, avoiding double support, and preserving price signals.

Overall, the EU's direction is one of coexistence and gradual convergence: public CfDs secure investment, while PPAs mobilize private demand. The effectiveness of this dual track will depend on how well Member States implement guarantees, aggregation mechanisms, and transmission planning to keep both instruments complementary rather than substitutive.

3. Theoretical Framework & Academic Insights

Following Lo Prete, Palmer and Robertson (2025), this section examines electricity-market design under the dual challenge of reliability and decarbonization. We focus on different analytical lenses – system stability (reliability), short-run efficiency, affordability and long-run efficiency. About clean-energy alignment, we refer to the discussion of Keppler, Quemin and Saguan (2022).

Sections 3.1–3.3 trace how increasing shares of variable renewable energy reshape the economic foundations of electricity markets: how physical constraints affect reliability, how volatility alters price signals, and why incomplete risk markets undermine efficient long-term investment. Section 3.4 then applies financial-economics reasoning to PPAs and CfDs, treating them as instruments that re-allocate risk without compromising dispatch efficiency.

The analytical objective is twofold: (i) to clarify under what conditions the energy-only spot market can remain welfare-optimal in a high-VRE context; and (ii) to identify how long-term contracting – through PPAs and CfDs – can restore investment signals while preserving marginal-cost dispatch.

3.1 Market Design under VRE: system stability

Electricity transmission networks are physically constrained systems whose violations can trigger instability, cascading outages, or even systemic collapse – events with large negative externalities and high social cost. Whether considered a common-pool good or a proper public one, reliability depends on the collective behavior of multiple actors and cannot be efficiently provided through purely individual incentives.

In the current European market design, several entities operate in parallel to align "unconstrained" market schedules with the secure operation of the grid. Yet, empirical evidence shows that market participants can strategically exploit these inefficiencies, extracting rents from redispatch or congestion-management processes (Graf, 2025).

The clean-energy transition complicates this balance. The replacement of dispatchable, carbon-intensive generation with variable renewable energy introduces strong locational and temporal mismatches between supply and demand. Renewable plants tend to cluster where resource potential is high, but production peaks may not coincide with consumption. Limited transmission and storage capacity constrain the system's ability to reallocate energy across time and space, increasing redispatch volumes and costs (Thomassen et al., 2024). Because grid expansion and large-scale storage require long lead times and cross-border coordination, the resulting stress on network stability is a structural rather than transient challenge.

Traditional short-term wholesale markets were built on dispatchable generation – fossil, hydro and, to some extent, nuclear – whose output can be modulated at low cost. In such markets, the economic dispatch curve, formed through day-ahead and real-time auctions, is relatively stable over time, mainly shaped by fossil fuel prices and maintenance schedules (Joskow, 2019, 2022). With high shares of VRE, this stability erodes: wind and solar, with near-zero marginal costs, shift the supply curve dynamically according to weather conditions. Output fluctuations – sometimes within minutes – translate into volatile market prices: zero or negative when renewable output is abundant, rising as storage absorbs excess energy, and spiking when scarcity drives dispatch to its physical limits.

In principle, when supply is scarce, the market price should be able to rise above the variable cost of the last (costliest) available generation unit. This scarcity pricing mechanism ensures long-run equilibrium by allowing all generators to recover capital costs, yielding a welfare-optimal generation mix given technological and demand fundamentals, also including the opportunity cost of capacity (i.e. a scarcity premium which is factored in the energy market price). Prices should thus signal both short-term dispatch efficiency and long-term capacity adequacy.

Nonetheless, certain reliability services, such as frequency response, inertia, and voltage control, remain unpriced. Since these are essential for system stability but not directly remunerated by energy-only markets, most systems implement administrative mechanisms to ensure their provision: operating reserves, technical standards, and grid codes. On the investment side, markets either rely on sharp scarcity events to signal capacity needs (energy-only designs) or adopt explicit resource adequacy mechanisms such as capacity markets, strategic reserves, or capacity payments (Borenstein, Bushnell and Mansur, 2023).

For systems dominated by renewables, the challenge is to preserve the efficiency of marginal-cost dispatch while complementing it with institutional tools that correct the externalities spot prices cannot internalize. In the absence of sufficient transmission and storage, volatility and redispatch will remain structural, implying that stability must come from both physical flexibility and long-term contractual coordination – a link explored further in the following subsections.

3.2 Market Design under VRE: price signals

"Fossil fuel and renewables are not substitutes in all states of nature. They are indeed substitutes every time the wind is blowing." From Ambec and Crampes (2019).

The expansion of VRE generation has made wholesale electricity prices increasingly volatile (Woo et al., 2011), with prices frequently falling to very low or even negative levels when VRE dominates the market. Because these technologies are capital-intensive and have near-zero marginal costs, marginal prices fall below average costs, and energy-only markets may no longer sustain an efficient technology mix at socially acceptable financing costs (Blazquez et al., 2018). Consequently, spot prices lose reliability as long-term investment signals.

Short-run price formation, however, remains indispensable for efficient dispatch and consumption. European economists broadly agree that preserving short-run markets is essential: they reveal the marginal cost of generation, guide storage and demand response, and allocate scarcity efficiently, but by themselves they are too volatile and incomplete to coordinate long-term investment (Ambec et al., 2023). This latter study reports the consensus among most EU energy economists affiliated with the CEPR, which is therefore to complement, not replace, short-run markets with long-term contracting mechanisms – PPAs and CfDs – that transform volatile price signals into stable, investable revenue streams.

The literature highlights that volatility stems from imperfect covariance between generation and scarcity. Electricity's temporal value – the correlation between production and high-price hours – determines its contribution to welfare (Gowrisankaran, Reynolds and Samano, 2016; Abrell, Rausch and Streitberger, 2019; Ambec and Crampes, 2019; Reguant, 2019). To capture this, Ambec, Crampes and Lamp (2025) propose the Economic Cost of Energy (ECOE), which adjusts the traditional Levelized Cost of Energy (LCOE) by a technology-specific bonus–malus term proportional to the covariance between a technology's output and market prices, scaled by its average capacity factor.

In this framework, the optimal fixed remuneration equals the expected wholesale price plus this covariance correction. Technologies whose generation aligns with scarcity exhibit positive covariance (dispatchable extent of nuclear and hydro, fossil, or storage-backed renewables) and thus receive a bonus (ECOE < LCOE); those producing mainly in surplus hours (solar midday, uncorrelated wind) face a malus (ECOE > LCOE). Empirical estimates confirm that these adjustments are economically meaningful and heterogeneous across geographies and seasons. Results for California, France, Germany, and Spain reveal systematic malus effects for many solar and wind technologies (reflecting cannibalization in high-VRE periods) but also bonuses from cross-technology complementarity – for instance, wind–solar covariance can be improved by adjusting PV orientation (Ambec, Crampes and Lamp, 2025). Moreover, hydro can transform "low-value" electricity during VRE peaks into "high-value" output through pumping and storage, acting as an embedded battery and raising its system value (Newbery et al., 2018; Ambec and Crampes, 2019; Joskow, 2019).

The ECOE approach operationalizes a key message from the CEPR economists' statement: short-run prices must remain for dispatch efficiency, but long-term remuneration should reflect system value rather than production cost alone. In energy-only markets, risk and volatility push up financing costs and deter capital-intensive clean investments. Integrating ECOE-based metrics into long-term instruments – CfDs or PPAs – enables technology-neutral auctions with technology-specific payments (Fabra and Montero, 2023), rewarding projects that align with system needs while preserving marginal-cost pricing in spot markets.

In sum, efficient market design under high renewables requires preserving informative short-run prices but coupling them with value-based long-term signals. ECOE provides a transparent and theoretically consistent rule for setting those signals, allowing public and private actors to coordinate investments that both stabilize revenues and enhance system efficiency.

3.3 Market Design under VRE: affordability, risk allocation & long-term contracts

The reliability considerations discussed above have direct implications for retail electricity pricing. Evidence from California shows that volumetric retail rates are often two to three times higher than social marginal cost because utilities recover large fixed and policy costs through per-kWh charges (Borenstein, Fowlie and Sallee, 2021). This wedge discourages electrification and shifts fixed costs regressively onto non-solar and lower-income customers. The authors argue that a pragmatic remedy is to realign volumetric prices with marginal cost and recover residual costs through fixed (ideally income-based) charges or via the tax base.

Interval metering is the enabling technology: by making hourly consumption observable and billable at short-term prices, it allows customers (or their retailers) to manage exposure through hedging, storage, or load shifting. Without it, monthly billing blunts scarcity signals and undermines efficient risk sharing (Wolak and Hardman, 2020). Accordingly, a coherent retail design sets the default retail price equal to the hourly wholesale price; while allowing opt-in hedged contracts whose premiums reflect the cost of managing price and quantity risk. Competition then shifts toward risk-management products rather than cross-subsidized flat tariffs.[8]

Imelda, Fripp and Roberts (2018) show that dynamic pricing yields limited welfare gains in fossil-fuel-dominated power systems (2.6–4.6 percent of baseline expenditure), but much larger gains (8.5–23.4 percent) in fully renewable systems. Moreover, slightly higher demand elasticity magnifies these gains. Yet – looking at the market through a demographic lens – elasticity remains low among large groups of residential consumers, especially older, rural, or peri-urban households living in inefficient buildings and with limited digital access, who spend a large share of income on heating, cooling, and transport.[9] Moreover, empirical evidence suggests that many consumers respond to average rather than marginal or expected marginal prices (Ito, 2014). This behavioral bias leads to suboptimal reactions and alters the welfare implications of dynamic pricing, complicating the policy trade-off between efficiency and equity.

Within this institutional context, long-term contracts reallocate the risk that incomplete spot and forward markets leave on developers, consumers, and public budgets. Power Purchase

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[8] Wolak and Hardman (2020) also mention that sunk network costs should be recovered via fixed – ideally income-graduated – connection charges, while keeping volumetric prices close to marginal cost. This approach reduces inefficient bypass toward distributed generation and improves fairness across consumers with and without distributed energy resources, ultimately aligning efficiency with equity.

[9] Demography and Global Energy: Fast and Slow", by F. Billari https://www.enelfoundation.org/all-news/news/2025/10/population-dynamics-global-energy-context

Agreements (PPAs) act as market-based hedges by converting uncertain spot revenues into stable contracted cashflows, while two-way Contracts for Difference (CfDs) provide quasi-public insurance against price risk. When designed as purely financial instruments – settled against the spot price without affecting dispatch – they stabilize investment while preserving marginal-cost dispatch. It follows that calibrating CfD strike prices and auction volumes is essential to share risk efficiently without crowding out private PPAs or distorting incentives (Kröger, Neuhoff and Richstein, 2022; Schlecht, Maurer and Hirth, 2024).

Micro-evidence from Iberian sequential electricity markets clarifies why long-term hedging and the microstructure of forward/spot trading are inseparable. Ito and Reguant (2016) develop and test a model in which firms transact the same MWh across a sequence of markets (day-ahead, intraday, real-time), but imperfect competition and limited arbitrage prevent full price convergence. A seller committed early faces a different marginal-revenue trade-off later: dominant firms can withhold in day-ahead and expand in real-time, generating a systematic day-ahead premium (day-ahead price > real-time price). Using firm-level data from OMIE, they show: (i) a positive day-ahead premium correlated with market-power conditions; (ii) large incumbents undersell day-ahead while smaller "fringe" suppliers oversell and buy back later (strategic withholding versus arbitrage); and (iii) price gaps that provide a lower bound on day-ahead mark-ups.

In a classical structural Cournot model with forward and real-time stages, adding sequential markets reduces deadweight loss by over 60% and can lower consumer costs by up to 10% (the Allaz-Vila effect, from their seminal work Allaz and Vila, 1993). Yet making arbitrage too effective can raise production costs even as it lowers retail expenditures: in their calibration, full arbitrage reduces consumer costs by roughly 2–9% but increases deadweight loss by more than 20% relative to no-arbitrage. Policymakers must therefore consider that expanding arbitrage (e.g., via virtual bidding) compresses the forward–spot premium and benefits buyers but can reallocate production toward higher-cost fringe resources in some states. The optimal degree of arbitrage depends on the joint policy objective between consumer surplus and productive efficiency.

3.3.1 Evidence about transmission integration from Chile

From a broader perspective, evidence on market integration demonstrates the positive effects of reducing spatial price risk. Gonzales, Ito, and Reguant (2023) study Chile's phased transmission integration linking, through enhanced investments in transmission, a solar-rich northern region with a demand-dense central region. Moreover, at night, Chile's northern mines maintain high electricity demand due to continuous operations, while southern hydroelectric plants have traditionally produced surplus power overnight. Indeed, the authors exploit two large changes in the Chilean electricity market: the 2017 interconnection between the two major electricity markets in Chile, the *Sistema Interconectado Norte Grande* (SING) and the *Sistema Interconectado Central* (SIC); and the reinforcement of the transmission line between the Atacama region and Santiago in 2019. Integration reduced curtailment at generation-intensive nodes, raised local prices where solar output had depressed them, lowered prices in demand centers, tightening spatial arbitrage and shrinking price dispersion. Their analysis – combining event-study estimates and a structural entry model – shows that ignoring investment responses materially understates benefits: holding capacity fixed, integration raises solar generation by about 10% and cuts average generation cost by roughly 3% (≈7% in solar-intensive hours); when accounting for endogenous entry, solar generation rises by about 178%, average costs fall by roughly 8%, and CO_2 emissions drop about 5%. Cost-benefit analysis implies recoverable transmission costs in roughly 7 years at a 5.8% discount rate and an internal rate of return near 20%.

The key design lesson is that a workable architecture combines liquid spot markets – which dispatch least-cost resources and transmit scarcity signals – with institutions that make those signals investable: integration that reduces basis risk, clear and bankable settlement against spot (so contracts hedge price risk without distorting dispatch), and sufficient forward liquidity for buyers and sellers to shape their risk profiles. As spatial basis risk becomes hedgeable and expected capture prices improve, private capital can scale renewables without extensive technology-specific subsidies, because integration transforms volatile local prices into tradable, contractible system-level exposure (Gonzales, Ito and Reguant, 2023).

On the other hand, despite the new north–south grid interconnection, transmission bottlenecks persist, preventing efficient power flow between regions. Sharp regional price disparities emerged because of several constrains: (i) a severe drought from 2021–2023 curtailed hydro supply, (ii) uneven geographical spread of generation technologies and (iii) the fossil fuel price surge following Russia's invasion of Ukraine. In particular, large generators with assets across Chile can offset local imbalances through portfolio diversification, but smaller, potentially single-site operators cannot. Those located in low-price zones have suffered heavy losses, and two Spanish-owned firms have defaulted. (Ferreiro and San-Martin, 2025).

Different policy solutions have been proposed by the authors, requiring either capital investment or changes in the operation rules of the market or the grid:

- **Promotion of Capital Investment** – If price decoupling is caused by a mismatch between supply and demand that the transmission capacity cannot solve, then the most obvious solution would be to invest in infrastructure to fix this mismatch.
    - **Generation Expansion**. The generation expansion is not under the control of the authorities. On an open-access network, the generators can freely choose where to build (and, consequently, to which network node their plant will be interconnected). Moreover, DisCo PPAs have been granted in location-agnostic auctions. Authorities have tools to encourage generation expansion in certain areas. The most common approach is the differentiation of interconnection costs, that is, setting lower interconnection costs in those areas where generation expansion is needed (used in Uruguay, Mexico and Brazil). A different approach (arguably more effective) is the direct establishment of quotas in energy auctions (used in Australia, Texas, and the Philippines). The quota approach seemed to be the preferred one for Chilean

authorities. However, there is a risk of limiting competition and causing an increase in energy prices, as well as higher expectations of price decoupling could lead generators to increase their bids in DisCo PPA auctions.
    - **Network Expansion at bottlenecks**. This is under the authorities' control.
    - **Deployment of Energy Storage**. Time-shifting using batteries, either at the residential or utility scale, the latter either as a complement to generation assets or stand-alone; to enable the time-shifting of supply to meet demand, especially in areas with excess generation (the North and Center-North).

- **Modification of the Operation Rules** – Changing the system's rules. This approach, while fast and inexpensive, is not free of controversy. The first three alter the economic market's operation rules, while the fourth is a modification in the operation of the physical grid.
    - **Transition to an offered-price system**. Moving from an audited-cost system toward an offered-price system. While the audited-cost approach prevents the exercise of market power, it may make capital investments difficult because investors cannot invest when they cannot adjust their return (by bidding higher prices) depending on the circumstances.
    - **Inclusion of the minimum load in the spot price**. This would entail enacting a price floor on the spot market at the cost of generating the minimum load.
    - **Redistribution of tariff revenues**. Attenuating the decoupling by "artificially" increasing the spot price for those generators enduring financial distress, that is, the redistribution of tariff revenues. Under this scheme, end-users would pay the extra cost, and the currently clear price signals to encourage or discourage generation would be somewhat attenuated.
    - **Omission of redundancy in network operations near the bottlenecks**. Full usage of network capacity near the bottlenecks, the only policy involving the physical grid's operation. The network capacity is not used to its fullest for safety reasons.

In summary, the root cause of the problem is the price decoupling between local nodes. Measures to promote capital investment address this problem properly, while changing the rules of the electricity market could only address this problem through redistribution of tariff revenues and operating the network without redundancy near the bottlenecks. An offered price system would not address the root cause.

3.4 Financial-like contracts in the electricity market

The energy production market remains incomplete because several key risk factors are insufficiently covered by existing financial instruments:

- **Price risk** – Spot price volatility and long investment horizons of 20–30 years cannot be fully hedged, since futures and forwards are typically available – and liquid – only for much shorter durations.

- **Volume** (or **intermittency**) **risk** – Standardized derivatives do not exist for variable solar or wind generation profiles.
- **Shape risk** – As discussed above, mismatches between generation timing and demand patterns (e.g. producing during the day while demand peaks in the evening) are not rewarded by spot markets under current market design.
- **Credit** (or **counterparty**) **risk** – Financial markets lack instruments to insure against default, particularly for small and medium-sized enterprises or sub-investment-grade customers.
- **Regulatory risk** – Retroactive policy changes introduce additional risks that cannot be fully hedged (e.g. retroactive cuts to feed-in tariffs in Italy and Spain; see Castro-Rodríguez and Miles-Touya, 2023, or temporary windfall taxes and price caps introduced in 2022).
- **Basis risk** (**spatial basis risk**) – Price differences between local nodes and national hubs persist because futures markets mainly trade at hub prices, leaving local risk largely unhedged. If a plant is curtailed due to local grid congestion, it faces null nodal price even though national market price remains positive.

In the next subsections we analyze the anatomy (structural components) and physiology (functioning) of long-term contracts. As Gohdes (2025) notes, "understanding what a PPA [and a CfD] can and cannot achieve is essential to facilitating a healthy investment environment".

3.4.1 Anatomy: how are CfDs and PPAs structured?

Although CfDs are not uncommon in conventional finance, those used in the energy industry properly belong to the family of swap derivatives, with wholesale electricity (and its hourly day-ahead price) as the underlying asset. These contracts specify a fixed "strike" price per megawatt-hour and regular exchanges between two parties: the electricity producer and a counterparty. From the producer's perspective (the swap buyer), the contract is float-to-fixed: if the wholesale price falls below the strike, the producer receives the difference; if it rises above, the producer pays back the surplus. The counterparty is usually a public entity. For detailed analysis, see Schlecht, Maurer and Hirth (2024).

A PPA, by contrast, is a bilateral private contract between a producer and a corporate or utility buyer that fixes the price and volume of electricity for a long period, typically alongside clauses covering delivery, balancing, and guarantees of origin. Understanding the complementarity and trade-offs between these two frameworks is essential for designing an EU electricity market that preserves short-term price efficiency while restoring long-term investment signals in a decarbonized system.

3.4.2 Physiology: how do CfDs and PPAs work? Risks, distortions & market design

As they provide stable revenues, CfDs are effective in neutralizing price risk – hence supporting capital-intensive renewables – but may create distortions if poorly designed or over-applied.

1. Isolation from price signals – "Plain" (or "poor") CfD designs – those guaranteeing a fixed strike price per MWh irrespective of the timing of generation – can make producers indifferent to the temporal or spatial value of electricity. For example, solar plants under such poorly designed contracts ignore the price incentive of either investing in storage or orienting panels towards late afternoon production – when electricity is scarcer and thus more valuable. Moreover, such plants would also continue generating during zero-price hours, triggering grid congestion and negative prices (Kroger, Neuhoff and Richstein, 2022), although this depends on the exact curtailment rules. Technology and location choices thus cease to reflect scarcity.

Fabra and Imelda (2023) find that the degree of market price exposure of VREs influences their price-depressing effect: when dominant firms hold only minor shares of renewables, exposure increases price discipline, but the reverse occurs when exposure is reduced. Beyond grid and storage investments that directly target scarcity, one solution is to introduce tailor-made hourly or locationally differentiated strike prices that preserve incentives to generate when and where electricity is most valuable (Fabra, 2023).

Schlecht, Maurer and Hirth (2024) further propose a "financial CfD" capable of hedging both price and volume risk through a contract-specific hour-by-hour generation profile, a "production independent" model. This float-to-fixed swap pays the producer a fixed price and links the floating leg to a benchmark generation profile that is exogenous to the producer's operational behavior – such as a normalized, weather-based profile for VRE generation or a constant reference for nuclear. In this production independent framework, distortions are avoided when the benchmark is appropriately selected – mirroring the behavior of standard financial forwards, hence the name.

2. Centralized allocation – CfDs are typically awarded through government-led auctions determining strike prices, volumes, and eligible technologies. While such auctions enhance cost discovery and allocative efficiency, they shift investment decisions (e.g. contractual length) from decentralized markets to administrative processes, making outcomes dependent on regulatory judgment. Inefficiencies may arise from excessive protection: overly long or rigid contracts can lead to systematic over- or under-compensation as costs evolve, undermining dynamic efficiency and innovation.

Corneli (2020) argues for an approach that relies on transparent long-term optimal planning and dispatch models which integrate expected costs and operating characteristics of all zero-carbon and storage technologies with several criteria (decarbonization commitments, supply security and forecasts of electricity demand).

Because CfDs involve public counterparties, consumers ultimately bear part of the market risk: when prices fall, they finance top-ups; when prices rise, they receive claw-backs. While this mechanism provides insurance, it can politicize energy costs during sustained price swings. These issues can be mitigated by developing deeper, union-level private markets for long-term hedging – financial or PPA-based – where price and contract length are competitively formed. The public actor can then supply liquidity, either through the financial market microstructure or via standardized public-PPA auctions.

Unlike auctioned CfDs, PPAs are over the counter (OTC) agreements. Their decentralized nature limits direct public exposure but influences market functioning more subtly. While PPAs effectively hedge both parties against price risk (though not always other risks), their expansion raises several systemic concerns:

1. Bilateral isolation from the market – The following implications are inherent to every OTC agreement. Since PPAs fix prices bilaterally for years: (i) they remove part of demand and supply from the wholesale market, reducing its liquidity (for the durations covered by PPAs) and potentially weakening the informational role of market prices; (ii) they may lock expectations that later diverge from reality; (iii) they also dampen forward-market activity.

2. Reduced transparency – Since OTC PPAs are not disclosed, terms and prices remain opaque to other market participants and regulators. Aggregated or anonymized disclosure of volumes and prices could improve transparency without harming confidentiality. Indeed, recent evolutions in the market point towards OTC platforms where OTC contracts are both traded and recorded. Among others, this point will be developed later in the work.

3. Market segmentation – PPA prices vary widely across sectors, technologies, and regions, reflecting credit quality, consumption profiles, and bargaining power. Such heterogeneity is natural in efficient markets but complicates reference-price formation for financing and policy evaluation.

4. Credit and counterparty risk – Default risk is concentrated in each bilateral contract, whose value depends on the solvency of the parties. Fabra and Llobet (2024) models the market for long-terms power contracts, showing how the buyers' counterparty risk enlarges the probability of default on the contracts, reducing liquidity, increasing the cost of capital and giving rise to under-investment in renewable energy. Without a central counterparty, defaults cannot be absorbed collectively. Multi-buyer PPAs can offer limited diversification, but correlated risks – location-specific or macroeconomic – remain. While credit default swaps or private guarantees can be used deftly when larger counterparties are involved, SMEs often require public risk-sharing. Ryan (2021) shows that intermediation by a risk-free public entity can eliminate this risk premium.

5. Limited alignment with system needs – Producers optimize for contract signature, not for system adequacy, and buyers focus on cost stability rather than flexibility or locational value. Contract portfolios thus may not reflect grid constraints or demand patterns. While on-site PPAs pose fewer issues, off-site models in congested systems may worsen imbalances. Greater coordination between system operators and PPA developers could ensure that contracts support, rather than hinder, optimal infrastructure investment. One of our policy proposals later in the work tackles this issue.

Overall, financial CfDs and PPAs are two sides of the same coin: both exchange price risk, though through different institutional channels. When properly designed, both can hedge not only price but also volume and shape risks. Regulatory and credit risks require complementary public interventions, whereas technical solutions – on-site PPAs, storage, and grid expansion – remain essential to mitigate basis risk inherent in constrained electricity networks.

4. Policy Options to Strengthen Long Term Markets

The analysis above showed that in high-renewable systems, short-run prices remain essential for dispatch efficiency but cannot, on their own, sustain the investment and risk-sharing required for decarbonization. Long-term contracting – through corporate PPAs and public CfDs – therefore becomes the main channel through which market signals are transformed into bankable commitments. The policy challenge is to expand these long-term markets while preserving their complementarity: PPAs should mobilize private demand and reveal heterogeneous value, whereas CfDs should provide system-wide risk sharing without crowding out private contracting.

Against this backdrop, this section sets out four actionable policy options for scaling long-term electricity markets in Europe and Italy. The first three address PPAs by targeting information, credit, and demand barriers; the fourth concerns CfD auction design. Together, these levers aim to create a transparent, liquid, and investable framework that aligns with the EU Electricity Market Design reform and the theoretical principles discussed earlier.

4.1 Information-related factors

A major barrier to efficient long-term contracting is the information gap that affects both sides of PPA negotiations. Buyers and sellers often lack reliable models for forecasting electricity prices, quantifying shape and volume risk, or valuing optionality. This uncertainty inflates negotiation costs, prolongs due diligence, and leads to conservative collateral requirements – particularly penalizing smaller and less experienced counterparties. Addressing these information-related factors can lower transaction costs and accelerate PPA uptake without direct subsidies.

Academic research offers several insights for improving valuation and information frameworks. Ghiassi-Farrokhfal, Ketter and Collins (2021) show that production uncertainty in renewable PPAs can be managed through structured decision tools that jointly optimize pricing and storage limits. Their model produces "win–win" strategies for both producers and buyers by identifying the combinations of storage and pricing that align incentives and stabilize expected profits. Although based on simplifying assumptions (e.g., risk neutrality of producers), their framework can be extended to realistic contracting contexts and supports the design of standardized PPA assessment templates.

Concerning information asymmetry about electricity pricing – and thus PPA pricing – Qorbanian, Löhndorf and Wozabal (2025) review existing methodologies and propose a hybrid modeling approach that combines fundamental electricity-market models with statistical learning techniques. By using regularized inverse optimization on a quadratic programming formulation of a fundamental bottom-up model, they demonstrate strong predictive performance and robustness to distribution shifts like those experienced during 2020–2023. Their framework provides a transparent and flexible "workhorse" model for potential PPA buyers and aggregators, capable of generating scenarios and sensitivity analyses that shorten the negotiation cycle.

Information asymmetry also extends to credit risk assessment. Pombo-Romero, Rúas-Barrosa and Vázquez (2024) argue that current PPA guarantees are often overestimated because creditworthiness is inferred almost entirely from the buyer's corporate rating. They introduce a valuation model that treats a PPA as a financial option, where the underlying asset is the electricity price. From the buyer's perspective, the contract's value – and hence its default probability – depends on the reduction in cost and volatility relative to spot-market exposure. By quantifying this embedded optionality, they derive more accurate estimates of expected loss and therefore of collateral needs. This approach can integrate different electricity-pricing models and account for market volatility.

Viewing PPAs through this option-lens provides an important policy insight. In a structurally volatile market, the hedge value of a PPA increases, meaning collateral requirements can safely be lower than in a stable-price environment: the cost of defaulting (returning to spot exposure) becomes higher, even when the PPA is slightly out-of-the-money. Conversely, for deep out-of-the-money contracts, guarantees remain independent of the specifics of the project until competitiveness (via lower LCOE or strike prices) restores value, triggering a positive feedback loop. Pombo-Romero et al. (2024) suggest that targeted policy actions could push LCOE down to these inflection points, thereby reducing guarantee needs even before deploying formal credit-support schemes. Such interventions should be guided by the Economic Cost of Energy framework of Ambec, Crampes and Lamp (2025), ensuring that adjustments reward technologies and profiles with higher system value rather than uniform subsidies.

Policy implications - Reducing information and valuation asymmetries is a low-cost, high-impact policy lever. Authorities should:

- Establish open, standardized datasets and analytical tools for PPA price, volume, and shape modeling;

- Develop transparent, modular PPA valuation models (like those above) for use by SMEs and aggregators;
- Promote disclosure standards and anonymized registries to generate price and credit benchmarks;
- Apply ECOE-based metrics to align strike or reference prices with system value.

By making risk and value more observable, policymakers can shorten approval times, compress spreads between fixed and expected market prices, and facilitate a more competitive and liquid PPA market – laying the groundwork for guarantees and public-demand instruments to operate effectively.

4.2 Public guarantees for corporate PPAs

A key obstacle to scaling corporate PPAs – especially for SMEs and mid-caps – is limited access to affordable credit and risk-mitigation tools. Counterparty risk remains a binding constraint: most long-term PPA deals require investment-grade ratings or parent guarantees, which smaller buyers cannot provide. This results in a structurally narrow PPA market concentrated among a few large corporations.

At EU level, several complementary mechanisms have been launched under the Clean Industrial Deal State Aid Framework (CISAF) and related EIB initiatives. CISAF clarifies when EIB resources fall outside State-aid rules, simplifies co-investment with Member States, and accelerates InvestEU deployment. The package includes targeted cleantech de-risking tools, notably including:

- €500 million EIB pilot to counter-guarantee corporate PPAs for SMEs through partner banks, covering part of default risk and reducing collateral requirements;
- €1.5 billion in counter-guarantees for grid-component manufacturers, via partner banks, to de-risk working capital and accelerate grid build-out and VRE integration;
- €250 million CleantechEU guarantee scheme for innovative green-tech SMEs (liquidity and working-capital support);
- €1.5 billion top-up supporting the European wind-turbine and component manufacturing base; and TechEU, the Union's largest innovation-financing programme, designed to attract capital and reinforce Europe's technology leadership.

These instruments respond directly to the risk-allocation challenges identified in the previous section, where incomplete forward and retail markets were shown to leave producers and consumers exposed to volatility and credit risk. By offering partial and conditional guarantees, the CISAF framework and the forthcoming EIB pilot operationalize that theoretical insight: they transfer part of the counterparty and liquidity risk away from individual firms while preserving market incentives for efficient contracting. In doing so, they create the institutional bridge between the economic rationale for risk sharing and its practical implementation through scalable, rules-based financial mechanisms.

At national level, Italy has been developing a set of complementary instruments to facilitate PPAs. The original design of the *Mercato PPA* (MPPA) was conceived as an organised market infrastructure with GME acting as central counterparty for standardised contracts, combined with a public guarantee pillar managed by GSE.

The draft "DL Energia", a new legislation advanced in February 2026, introduces a distinct instrument, the Bacheca PPA, explicitly positioned as complementary to (and simpler than) the MPPA. The Bacheca strengthens the role of the GME platform as a place of first contact between demand and supply, while contracts are concluded directly between buyer and seller (i.e., without GME as central counterparty).

In this set-up, GME can organise non-binding auction sessions to facilitate matching of compatible bids (in terms of price/duration/profile), while the GSE group can support aggregation of demand and/or supply and provide standardised contractual templates. Eligible contracts may also access a voluntary public guarantee managed by GSE, subject to a qualification procedure; contracts must have a minimum duration of three years, and plants receiving incentive schemes are excluded.

Policy gaps and recommendations - While this framework is a major step toward standardization and credit enhancement, several refinements could strengthen participation, liquidity, and fairness:

- **Broaden contract types** – Ensure that standard templates and matching/auction sessions (especially under the Bacheca) can accommodate multiple products, not only baseload/peakload products.
- **Expand the platform to financial PPA** – In accordance with our previous section, an expansion of private financial market is timely. Contract characteristics can be analogous to those with physical delivery.
- **Leverage market data** – Use MPPA and Bacheca activity to publish anonymised price bands, tenor distributions, and standard risk premia to reduce information asymmetries without disclosing commercially sensitive details.
- **Expand access** – Open the platform to non-investment-grade participants by introducing proportionate guarantees (8–10 % base collateral without mark-to-market), consistent with the operator proposals and European market practice.
- **Simplify collateralization** – Eliminate daily mark-to-market margining; replace it with periodic revaluation and higher base collateral to reduce operational burden on banks and SMEs.
- **Rebalance guarantee coverage** – Migrate toward a mutualized guarantee fund co-financed by operators and supported by EIB counter-guarantees, limiting direct public spending to exceptional defaults. About amounts involved, we refer to our paragraphs about credit risk assessment.
- **Ensure consistent risk-sharing** – Codify the hierarchy between private collateral, mutual fund resources, and public backstops to enhance predictability and avoid moral hazard.

These refinements would align the MPPA with the EU-level credit-support ecosystem under CISAF and the forthcoming EIB pilot, ensuring that guarantees remain targeted, proportional, and additional. Properly calibrated, they would broaden SMEs participation, expand the buyer base, and increase market liquidity without distorting price signals.

As a complementary mechanism, Italy's FER-X scheme – a two-way CfD auction for mature renewables – provides reference prices and a credit benchmark. FER-X supports PV, onshore wind, hydro, and biogas-from-wastewater through competitive tenders for plants above 1 MW and administered prices for smaller units. Early rounds have shown strong participation and competitive outcomes (≈ €60–65 /MWh, with many bids below €55 /MWh).

Finally, a different, additional channel worth considering is the development of an intermediated "secondary" layer: a credit-strong aggregator could contract long-term volumes with generators and resell (or sleeve) smaller tranches to multiple buyers, thereby pooling credit risk and reducing transaction costs for SMEs.

4.3 Mobilizing Public Demand to Boost the PPA Market

The public sector is among Italy's largest electricity consumers, spending over €12.6 billion annually on energy – of which around €6 billion goes to electricity across central and local administrations. In 2023, Consip-managed procurement alone covered €4.8 billion, equivalent to 38 percent of total public energy expenditure. This scale makes public demand a potentially powerful driver for liquidity and maturity in the national PPA market.

Two complementary pathways can translate this potential into policy action:

1) Direct PPA procurement by public administrations;
2) Indirect uptake, rewarding private suppliers to the public sector that secure their electricity through PPAs.

Both channels would strengthen long-term contracting, enhance visibility for renewable developers, and align procurement with EU and Italy's decarbonization commitments under the PNIEC and EU Green Deal. Indeed, embedding PPAs into public procurement contracts would allow public entities to aggregate energy-efficiency and renewable supply in one performance-based package, combining energy savings and decarbonization outcomes.

1) Direct procurement of PPAs by public administrations - Public administrations are stable, solvent, and long-lived counterparties – ideal PPA buyers. Yet today, almost all their energy purchases are short-term (12–24 months), executed through Consip or regional aggregators.[10] Extending even a modest share (e.g. 15–20%) of annual electricity demand to

[10] Indeed, the existing public procurement rules tend to channel electricity and gas purchases through central purchasing bodies (Consip and regional procurement centers), with autonomous procurement allowed only under strict conditions. In the case of Italian municipalities, Bafundi and Sparacino (2023) document both the institutional pull toward centralized procurement and evidence that centralization is associated with materially lower electricity expenditure relative to autonomous purchases.

long-term PPAs would create immediate demand-side depth, stabilise price expectations, and accelerate renewable build-out.

A recent example in this direction is FS Energy, created by the Italian railways operator (Gruppo FS) in July 2025 to accelerate renewable sourcing and investment: the initiative targets around 1.1 GW of renewable capacity by 2029 (and 2 GW by 2034) and has launched tendering procedures for renewable electricity procurement. Since Gruppo FS is a State-owned enterprise fully owned by the Italian Ministry of the Economy, this case is informative for policy design: it suggests that significant public-sector demand for PPAs may be present, yet practical and legal frictions in public procurement can limit direct adoption by public administrations. In this context, State-owned and publicly controlled companies can provide a workable route to aggregate demand and conclude long-term contracts consistent with procurement requirements.

Design features for public PPAs could include the following actions:

- Launch pilot tenders – aggregated at Consip level – for multi-year (7–10y) pay-as-produced (PaP) or profile-indexed PPAs with renewable developers.
- Enable Consip or GSE to act as central counterparty for settlement, with contractual backstops aligned to FER-X reference prices.
- Integrate Energy Performance Contracts (EPC) as delivery vehicles under the 2024 MEF–RGS standard contract, and integrate the discipline of EPC (or, more generally, project finance) to cover standard PPAs. In Italy, this can be achieved by exploiting the request in October 2025 by the European Commission to revise the discipline on project finance.
- Use the forthcoming EU procurement directive revision (2026) to explicitly recognize PPAs as eligible long-term energy supply contracts for public buyers, removing current ambiguities in project-finance classifications.
- Streamline permitting for projects supplying public PPAs, given that contracting authorities are often also permitting entities, thus reducing regulatory bottlenecks.

The next legislative phase – aligned with the 2026 EU Directive recast – should therefore explicitly authorize long-term PPA contracts within the project-finance and concession framework, clarifying their off-balance-sheet treatment where risk allocation satisfies Eurostat's PPP criteria.

Public PPAs introduce two governance risks – political (price volatility and perception of overpayment) and Court of Auditors oversight. To mitigate these, contracts should use ECOE-based evaluation to demonstrate system-value consistency (see earlier section). Moreover, they should ensure transparency and benchmarking via FER-X reference prices and report results to MEF and ARERA under a dedicated "public renewable exposure" registry.

2) Indirect uptake: linking PPAs to public procurement criteria – Beyond direct electricity purchases, public procurement in Italy represents around 15% of GDP, mirroring

EU averages. Embedding PPA-related criteria across this vast purchasing ecosystem can amplify renewable demand indirectly.

Implementation options:

- In all tenders applying the Most Economically Advantageous Tender (MEAT) criterion, grant bonus scoring to suppliers demonstrating that a significant share of their electricity is sourced through verified renewable PPAs or GOs-backed contracts.
- Integrate this provision into the upcoming EU Directive revision on public procurement (2026), under the sustainability and energy-resilience chapters. This would align national practice with EU strategic procurement principles and the Commission's "Clean Industrial Deal" framework
- Within Italy, adjust Consip standard technical specifications to require disclosure of suppliers' energy procurement mix, verified through GSE data, in energy-intensive tenders (e.g. facility management, transport, logistics).

Such "green PPA clauses" would replicate the mechanism already used for environmental performance (CAM) criteria but tie it specifically to electricity sourcing and long-term risk-sharing. This indirect mechanism could mobilize corporate PPA demand far beyond the power sector, embedding renewables into the entire public supply chain. Embedding such clauses would progressively standardize renewable PPAs as a qualification and scoring factor across all public tenders, creating a self-reinforcing link between procurement policy and decarbonization targets.

4.4 CfD and PPA Auctions: Principles for Coexistence

The coexistence of public CfDs and private PPAs requires careful auction design. CfDs should secure system-wide investment stability, while PPAs should reveal differentiated value and enable private risk-sharing. The challenge is to balance both – ensuring CfDs do not crowd out PPA markets but rather complement them through design choices that preserve dispatch and locational signals.

The Commission's CfD Guidance (published in December 2025) provides a useful benchmark: two-way CfDs should preserve efficient short-term market signals across day-ahead, intraday and balancing markets; avoid incentives to generate at negative prices (given near-zero marginal costs for RES); and, where appropriate, use production-independent or mixed remuneration approaches that reduce gaming risks while maintaining availability incentives. The Guidance also clarifies pathways for combining CfDs and PPAs (e.g., partial-capacity CfDs or freedom to contract PPAs for volumes not covered by a CfD).

Recent reviews of Member State practice by Demurtas et al. (2026) suggest that CfD–PPA coexistence is often implemented through partial coverage (sometimes loosely labelled a 'carve-out'): the CfD applies only to a defined share of the project, either a share of capacity or a reference volume, while the residual volumes are contracted privately (e.g., via PPAs). Concrete variants of this approach described in the study include the UK offshore wind framework, where developers can determine the share of generation covered by a CfD versus a PPA, and Belgium's 'intermittent switching' model in the Princess Elisabeth offshore wind auctions, which allows developers to partially exit the CfD to pursue PPAs within defined limits.

In Italy, the FER-X scheme currently serves as the main auction framework for awarding two-way CfDs to renewable projects. It covers mature technologies such as solar, wind, hydro, and biogas, with competitive tenders allocating contracts based on price. FER-X thus represents the reference point for how CfD auctions function in practice, providing both price discovery and bankability for investors. The lessons from international experiences – particularly Chile's hybrid CfD-PPA model – are therefore relevant to the forthcoming evolution of FER-X, which could become the testing ground for more integrated long-term market designs.

An additional, emerging Italian debate concerns proposals sometimes labelled "FER-z", which would shift bidding from single-plant pay-as-produced support toward the delivery of shaped consumption profiles (e.g., a baseload product) backed by a portfolio of assets and guarantees of origin. While such designs could address profile risk for buyers, they may raise compatibility questions with EU rules, therefore requiring careful legal and economic assessment.

Looking outside Europe, a useful reference is the Chilean market design, which has evolved around a dual structure combining audited-cost spot prices, locational marginal prices (LMPs), and a two-tier contracting framework. One tier consists of DisCo PPAs, which are long-term, fixed-price agreements between generation companies and distribution companies (DisCo); these agreements function as complex Contracts for Difference where generators sell into the spot market but settle financially with distributors to meet their fixed-price obligations. The other tier comprises traditional bilateral PPAs for large, deregulated consumers. This architecture has supported significant investment—especially in renewable capacity—by providing revenue certainty to generators and stable tariffs to end-users, and has been central to Chile's energy transition. At the same time, the way risk is allocated under DisCo PPAs has exposed generators to locational basis risk and episodes of price decoupling when nodal prices diverge, leading in some cases to financial distress and even bankruptcies among contracted generators and prompting public authorities to consider mitigation measures. Thus, while the Chilean experience illustrates innovative contracting mechanisms with real benefits, it also reveals important limitations and stresses whose causes and consequences are worth understanding in comparative market analysis.

The 2015 Chilean reform that introduced centralized PPA auctions with demand-based settlement helped reduce over-contracting and price distortions, although subsequent policy interventions (e.g. the 2019 price freeze) exposed residual risks of regulatory instability.

This hybrid architecture – linking long-term contracting to market demand while preserving locational price signals – could inspire a European and Italian reflection on how CfD auctions and PPAs can coexist within the same portfolio of renewable investments.

At this stage, however, the detailed design of such hybrid auctions remains under discussion. Further work is needed to assess:

- whether demand-indexed or proxy-generation CfDs could better align incentives with system value;
- how to define PPA reservation quotas within CfD-supported projects;
- the possible use of nodal or zonal reference prices to internalize basis risk;
- how to ensure cross-border coordination between national auction volumes and private contracting activity.

Given ongoing EU workstreams – notably the Commission's December 2025 CfD Guidance and the announced work on deeper electricity market integration – it is prudent to avoid locking in a single 'definitive' blueprint at this stage. In practice, the relevant mechanisms (e.g., CfD auctions, PPA facilitation platforms and public guarantees) must balance price discovery with non-trivial constraints, such as eligibility rules (e.g., additionality), profile/firming requirements, network and congestion considerations, and the use of non-price criteria for specific policy objectives. Designing auctions that deliver robust price signals while respecting such constraints is a technically demanding task (Milgrom, 2021).

The recommendation is therefore to launch a structured analytical process, involving GSE, ARERA, and DG ENER, to evaluate how lessons from Chile and other jurisdictions could inform the next generation of FER-X auctions and the interplay between CfD volumes and PPA markets. Indeed, the next iteration of FER-X auctions offers a timely opportunity to test hybrid approaches where CfDs and PPAs coexist under transparent, demand-linked allocation. Such a design would help balance system-wide stability with private-sector flexibility, ensuring that Italy's renewable expansion remains both competitive and investable.

5. Conclusion

The analysis presented in this report highlights that Europe's transition to a high-renewable power system requires long-term contracting mechanisms capable of reconciling market efficiency with investment certainty. Price volatility, basis risk, and incomplete risk markets have eroded the signaling role of spot prices, making instruments such as PPAs and CfDs central to delivering both decarbonization and affordability.

The evidence from European and Italian markets shows that while private contracting showed widespread expansion in recent years up until 2024, this trend has inverted in 2025. Structural barriers – information asymmetry, credit constraints, and transaction complexity – still severely limit liquidity and further expansions. Policy action should therefore focus on completing these markets rather than substituting them. Three complementary levers emerge: improving information and valuation frameworks to reduce asymmetry and standardize pricing; providing targeted public guarantees to unlock SME and mid-cap participation without distorting competition; and mobilizing public demand, using the purchasing power of public administrations to anchor long-term renewable contracts and stimulate private replication.

The next step concerns the careful design of hybrid CfD–PPA systems. For Italy and the EU, this means structuring financial CfDs and standardized PPAs as mutually reinforcing instruments – public schemes stabilizing revenues, private contracts revealing system value.

Ultimately, long-term market reforms should not aim to replace market dynamics with regulation, but to make markets complete enough to deliver Europe's clean energy objectives. Stability, transparency, and credible institutions remain the foundation on which both investment and competition can thrive.

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