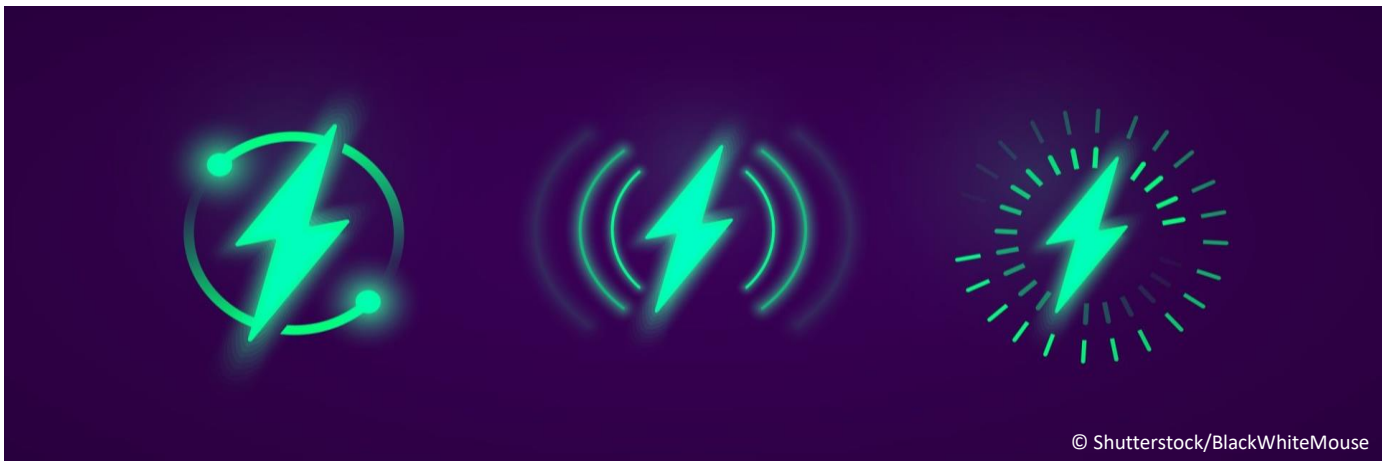


Priorities for an EU Electrification Action Plan

Strengthen Market Mechanisms for European Energy Sovereignty

André Wolf



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The recent turmoil in the global oil market, triggered by the conflict between the US and Iran, has highlighted the significant external risks to which the European economy is exposed due to its continued dependence on fossil fuels. This underscores the importance of decarbonization not only for achieving climate goals but also for European energy sovereignty. Electrification is a key technological solution in many applications. It enables the direct and efficient integration of domestic renewable energy sources into end-use sectors. However, progress on electrification has stalled. Against this backdrop, the Commission has announced to present an action plan on electrification. This ceplnput examines the current barriers to electrification and potential policy solutions, with a particular focus on the manufacturing sector. It proposes a policy strategy in which investment risks are managed through risk-sharing between the public and private sectors and the promotion of efficient hedging markets, rather than discretionary market interventions.

- ▶ Attempts to cut electricity bills must not result in the elimination of market price signals that are essential for an efficient transformation of Europe's energy system. Instead, the EU should boost investment incentives by agreeing on a CO₂-based approach to energy taxation and establishing a long-term framework for state aid support favoring energy efficiency.
- ▶ For efficient hedging of electricity prices, EU-wide access to competitive forward markets should be improved. With many national forward markets still being underdeveloped, this primarily requires eliminating barriers to cross-border hedging. The focus should be on a more frequent and flexible allocation of long-term transmission rights in the short-term and the development of virtual trading hubs in the longer term.
- ▶ Power Purchase Agreements (PPAs) with renewable electricity producers offer industries a flexible approach to decarbonization while avoiding short-term wholesale market risks. To support the formation of competitive PPA markets, existing market access barriers for small- and medium-scale enterprises must be reduced. In particular, this requires lowering financial constraints through public counter-guarantees for collaterals and mechanisms for pooling small electricity buyers to large-scale PPA contracts.
- ▶ To manage grid connection queues, the EU should agree on a merit-based prioritization scheme for handling grid connection requests. Such a scheme should recognize the systemic value of industrial consumers.

Table of Contents

1	Background	3
2	Electrification as Key to Decarbonizing European Industries	4
2.1	Technologies.....	4
2.2	EU Goals	5
2.3	Trends.....	6
3	Barriers to the Electrification of Industrial Processes	7
3.1	Technical Barriers	7
3.2	Economic Barriers.....	7
4	Analysis of Risk Management Options	9
4.1	Market Uncertainty and the Social Value of Electrification	9
4.2	Forward Markets	12
4.2.1	Current Market Situation	12
4.2.2	Barriers and Limitations	13
4.2.3	Support Options	15
4.3	Power Purchase Agreements (PPAs)	16
4.3.1	Current Market Situation	16
4.3.2	Barriers and Limitations	18
4.3.3	Support Options	19
4.4	Recent EU Policy Impulses.....	21
5	Recommendations for a Risk-focused EU Electrification Strategy	23
5.1	Risk Management Framework	23
5.2	Policy Tools for EU-Internal Risk Management.....	24
6	Conclusion	27

Table of Figures

Figure 1:	Share of electricity in final energy use	6
Figure 2:	Ratio of electricity to natural gas prices for non-household consumers in 2024	8
Figure 3:	Feedback effects between RE investments, electrification and system costs and benefits..	11
Figure 4:	Comparison of churn factors on national electricity forward markets in 2023.....	13
Figure 5:	Annual PPA announcements in Europe by generation mix	18
Figure 6:	Interplay of risks in the European energy system during the green transition	23

1 Background

The process of sector coupling, i.e. the interconnection of power generation with energy consumption in industry, transport and buildings, is a key element of the EU's decarbonization strategy. By switching to electricity-based technologies, these sectors help integrating electricity gained from renewables into the energy system and increase its flexibility to adapt to short-term fluctuations in electricity supply. By avoiding further steps of energy conversion, the electrification of end use sectors is also a prerequisite for energy efficiency gains, strengthening Europe's energy autonomy. By providing a strong and stable demand base, it improves the business case of investments in PV and wind power and thus helps to realize future cost reductions through scaling effects. This is also acknowledged by the EU, which sees rapid electrification as key for reaching its long-term goal of energy independence sketched in its RePowerEU plan.¹

In light of these ambitions, the recent progress in Europe's electrification has been disappointing. After decades of positive trends, electrification rates have stagnated in recent years. In response, the Commission has announced a comprehensive EU Electrification Action Plan for 2026. The challenges are manifold, especially due to the complexity of coordinating the energy system and the variety of sectors involved. In addition to technological limitations in areas such as industrial high-temperature processes, economic considerations are also hindering electrification. Balancing short-term volatility in the availability of renewable energy sources with the need for a stable energy supply for end users creates increasing system costs for grid management, as well as the need for investment in flexible generation and storage capacities. Currently, these balancing costs are passed on to end users in the form of higher electricity wholesale prices and network tariffs, which undermines the positive merit order effect of expanding renewable energy sources with near-zero marginal costs.

The structural cost disadvantages are exacerbated by the increased volatility of electricity prices, which is due to rising shares of volatile supply and fluctuations in the price of imported natural gas. In the future, the volatility of end-user prices could further increase. From an investor's perspective, cost uncertainty poses an additional barrier to long-term electrification investments. It translates into uncertainty on the investment returns of the technology switch, raises financing costs and endangers the bankability of decarbonization projects. This latter mechanism is often overlooked in the public debate, which primarily focuses on the disadvantages of high energy prices. Although contractual instruments have emerged to eliminate or hedge electricity price uncertainty, related markets still face significant growth barriers and substantial internal fragmentation within the EU.

This cepInput calls for an EU electrification strategy that includes market-based risk management instruments as a central element, with a focus on further developing electricity forward markets and Power Purchase Agreements (PPAs). Unlike regulatory interventions in the fabric of electricity trading, these tools offer a system-friendly and flexible form of risk insurance that limits the long-term fiscal burden and avoids the distortion of scarcity signals. The analysis takes the perspective of the industrial sector, which has large electricity consumers and is therefore a good candidate for market-based hedging. Specific support instruments are discussed in the context of the EU's macroeconomic resilience goals.

¹ European Commission (2022a). REPowerEU Plan. Communication from the Commission to the European Parliament, the European Council, the Council, the European Economic and Social Committee and the Committee of the Regions COM(2022) 230 final.

2 Electrification as Key to Decarbonizing European Industries

2.1 Technologies

A broad portfolio of technologies has emerged for the direct electrification of energy used in industrial processes. Industrial heat pumps will play a central role. Unlike other electricity-based technologies, they do not convert electricity into other forms of energy, but rather use it to transfer ambient heat from one location to another. Ambient energy is absorbed by a liquid refrigerant, which then vaporizes. The energy is then amplified by compressing the refrigerant, after which it is transferred by the pump to a heat sink. The energy output can exceed the power needed to run the heat pump by a large margin, thus clearly outperforming alternative heating technologies such as gas boilers and electric heaters.² In particular, industrial heat pumps running on waste heat provide industrial companies with an opportunity to optimize the efficiency of their internal energy flows by minimizing energy losses.³ Moreover, the cycle can be reversed to provide cooling instead of heating. Technical limitations are imposed by the maximum temperature lift, i.e. the temperature difference between the heat source and the heat sink. High temperature lifts reduce performance efficiency and require specialized compressor equipment and refrigerants, raising material costs. This limits the practical use of the current generation of heat pumps in industrial high-temperature processes. Commercialized heat pumps reach temperature outputs of around 165 degrees Celsius.⁴ Certain chemical processes, as well as steps in the manufacture of paper and food products, require the continuous provision of steam at temperatures in excess of 200 degrees Celsius. The technology for high-temperature heat pumps has already been developed but is still awaiting commercialization in some areas.⁵

Electric boilers represent an alternative for high-temperature applications. They are already in widespread industrial use. Electric boilers convert electricity into heat in order to produce steam or hot water. There are two types: electrode and resistance. Electrode boilers pass an electric current directly through water in a tank. In resistance boilers, an electric current is passed through a resisting element (e.g. metal), thereby conducting heat to the water.⁶ Compared to heat pumps, the capital costs of electric boilers are typically lower, and they are easier to install and adapt to different circumstances. However, while they can reach efficiency levels close to 100%, as an energy-conversion technology they will never be able to match the maximum performance levels of a heat pump system.⁷ In times of high electricity prices and unreliable availability of PV and wind power, this results in significant cost disadvantages and limits the deployment of electric boilers.

In addition, alternative electricity-based technologies have been designed for more specific production processes in certain sectors. Electric arc furnaces are a well-established technology for melting metals, particularly for producing steel from scrap. In an electric arc furnace, a set of electrodes is introduced into a refractory-lined vessel containing the metal. Connecting a very high-current power supply

² IEA (2022). The future of heat pumps. World Energy Outlook Special Report. International Energy Agency.

³ EHPA (2024). Waste into wealth: how heat pumps can recycle heat to save energy - and the EU policy that matters. European Heat Pump Association.

⁴ Fraunhofer ISI (2024). Direct electrification of industrial process heat. An assessment of technologies, potentials and future prospects for the EU. Study. Fraunhofer-Institut für System- und Innovationsforschung.

⁵ Dena (2022). Industrial high temperature heat pumps in Germany and Europe – potentials, application cases and support policy. Study. Deutsche Energienetz-Agentur.

⁶ See Fraunhofer ISI (2024).

⁷ Nielsen, M. G., Morales, J. M., Zugno, M., Pedersen, T. E., & Madsen, H. (2016). Economic valuation of heat pumps and electric boilers in the Danish energy system. Applied Energy, 167, 189-200.

induces an electric arc in the metal, heating it up. Compared to primary steel production, producing steel from scrap using electric arc furnaces offers substantial energy efficiency gains.⁸ Other technologies with high future development potential include plasma torches and shock-wave heating. Plasma torches create plasma by heating a carrier gas, such as oxygen, nitrogen, or CO₂, to temperatures of up to 20,000 degrees Celsius via electric arcs. However, while they can reach very high process temperatures, their energy efficiency is limited due to the high cooling needs and the extreme temperature conditions that cause high replacement costs for system components.⁹ Shock-wave heating converts kinetic energy into thermal energy. A shock wave is propagated through a medium (e.g. gas), causing massive, instantaneous compression and an increase in temperature. Due to the early stage of development, the future scaling potential is still uncertain.¹⁰

2.2 EU Goals

Besides the prospect of efficiency gains, the EU's goal of increasing the share of energy consumption that makes use of renewable sources is a key motivation for pushing for investments in electrification. The current version of the Renewable Energy Directive (REDIII) sets out a legally binding overarching goal of 42.5% renewables in final energy consumption by 2030, with the aspiration of reaching 45%. The manufacturing sector is subject to a specific sub-target consisting of an average annual increase of 1.6 percentage points in the share of renewables in industrial energy use, calculated for the periods 2021 to 2025 and 2026 to 2030. To comply with this target, REDIII refers to the need of promoting the electrification of process heat, provided that the solutions are cost-effective and align with the 'energy efficiency first' principle.¹¹

Following the energy crisis in 2022, the Commission started to emphasize a second key function of renewable-based electrification in its RePowerEU plan: its contribution to strengthening the overall resilience of the European economy by reducing its dependence on external fossil fuels. This involves a specific installation target for heat pumps: doubling the previous deployment rate to 10 million additional units over five years. The plan also announced dedicated EU measures to support industrial electrification.¹²

The 2025 Clean Industrial Deal Communication adopted this narrative and set out electrification targets. By 2030, electricity's share of final energy consumption is expected to rise to 32%. To achieve this goal, the Clean Industrial Deal aims to mobilize over EUR 100 million to support investments in clean manufacturing.¹³ After 2030, electrification rates will need to continue rising to meet the EU's ambitious long-term climate goals. To achieve the agreed goal of reducing greenhouse gas emissions by 90% by 2040, Commission projections foresee an electrification rate of around 50% by 2040.¹⁴

⁸ Steel Technology (2026). [The impact of arc furnaces on modern steel production.](#)

⁹ ABB (2025). [Creating a sustainable high-temperature plasma torch for industrial processes with ABB drives technology.](#)

¹⁰ See Fraunhofer ISI (2024).

¹¹ European Union (2023). Directive (EU) 2023/2413 of the European Parliament and of the Council of 18 October 2023 amending Directive (EU) 2018/2001, Regulation (EU) 2018/1999 and Directive 98/70/EC as regards the promotion of energy from renewable sources, and repealing Council Directive (EU) 2015/652.

¹² See European Commission (2022a).

¹³ European Commission (2025a). The Clean Industrial Deal: A joint roadmap for competitiveness and decarbonization. Communication from the Commission to the European Parliament, the European Council, the Council, the European Economic and Social Committee and the Committee of the Regions. COM/2025/85 final.

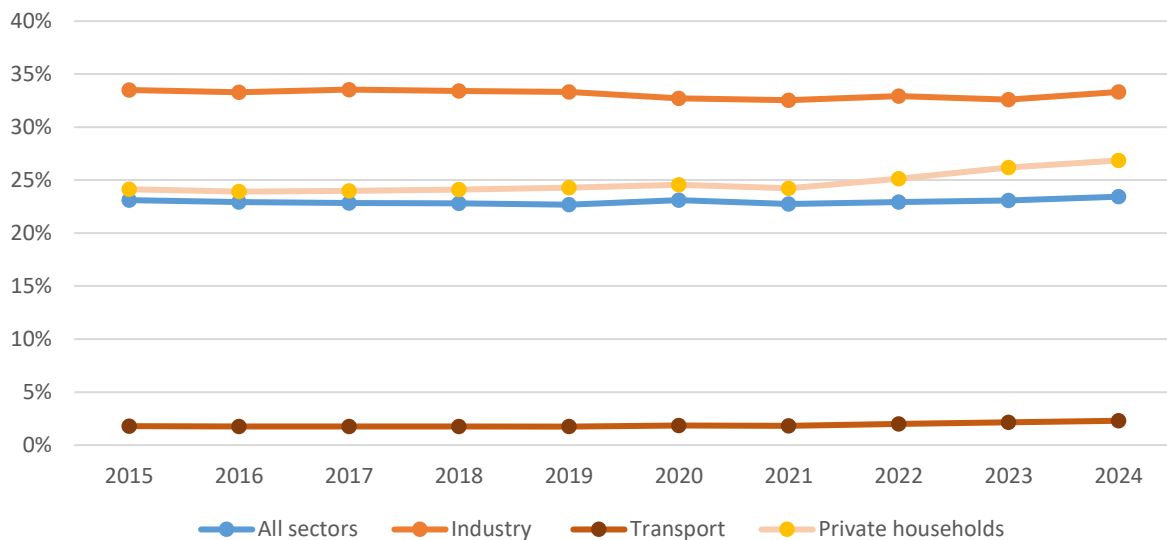
¹⁴ European Commission (2024). Securing our future Europe's 2040 climate target and path to climate neutrality by 2050 building a sustainable, just and prosperous society. Communication from the Commission to the European Parliament, the

2.3 Trends

At the global level, projections by the International Energy Agency (IEA) for a net zero emissions future identify the widespread adoption of electricity-based technologies in industry as crucial to achieving the goal of limiting average temperature increase to 1.5 degrees Celsius. Between 2020 and 2050, the share of electricity in light industry energy consumption is required to double (from 35% to 69%), and in heavy industry it is required to more than double (from 16% to 37%).¹⁵

This high ambition is not reflected in the latest figures at the European level. Overall electrification rates in the EU have stagnated over the past ten years (see Figure 1). The economy-wide electrification rate remains at around 23%, making the 32% target for 2030 (see above) seem unattainable. Only the transport and household sectors have shown a positive trend in recent years, due to the increased adoption of heat pumps and electric cars. The situation is essentially the same in all large Member States. Of the manufacturing sectors, only the chemical industry increased its electrification rate significantly over the ten-year period (from 27% to 29%).¹⁶

Figure 1: Share of electricity in final energy use



Source: Eurostat (2026)

European Council, the Council, the European Economic and Social Committee and the Committee of the Regions. COM/2024/63 final.

¹⁵ IEA (2021). Net zero by 2050 – a roadmap for the global energy sector. Study. International Energy Agency.

¹⁶ Eurostat (2026). [Simplified energy balances](#). Database.

3 Barriers to the Electrification of Industrial Processes

3.1 Technical Barriers

In some industry segments, a switch to electricity-based production faces significant technical barriers. Technological complexity, interoperability and energy system integration pose specific challenges. Concerning technological readiness, industrial processes involving very high temperatures still lack commercial solutions that can compete with fossil technologies in terms of energy efficiency or quality parameters.¹⁷ Integrating new electricity-access equipment (e.g. transformers) into existing production plants can also be difficult due to space restrictions. Electrification also has implications for the energy management of production plants. It requires investment in internal electricity infrastructure (e.g. battery storage) and the digitization of production processes (e.g. smart meters and software).¹⁸ At the same time, digital process equipment must be protected against cyber security threats. In terms of human resources, the technological shift creates a significant demand for specialized skills in the design, installation and operation of electricity-based industrial equipment. This requires industries to invest significantly in training and upskilling their technical workforce. Emerging general bottlenecks in the supply of high-skilled STEM professionals and technicians in Europe exacerbate this problem.¹⁹

A firm-external barrier are delays in the access to the high-voltage electricity grid infrastructure. Although Europe-wide data on average waiting times for grid connection is still lacking, many firms report significant delays in implementation due to growing connection queues.²⁰ The reasons for these queues are numerous and region-specific. Investment delays in local grid capacity (e.g. grid expansion or upgrading) can contribute to the problem and are often caused by insufficient investment incentives for grid operators or lengthy grid planning and permit procedures. Insufficient grid digitization can also be a constraint, limiting grid operators' ability to monitor new electricity demand patterns resulting from the connection of large-scale industrial consumers in real time.²¹ Furthermore, when applying for grid access, industrial enterprises may face strong competition from other large-scale consumers, such as battery storage plants and data centers. In some areas, the situation is further complicated by missing or improperly designed rules for prioritizing connection requests.²²

3.2 Economic Barriers

The expected returns on investments in electrification are affected by high capital and operational expenditure. Investments in new production equipment and internal electricity infrastructure are characterized by high initial costs and long payback periods.²³ Uncertainty regarding long-term revenue potential and operational expenses significantly undermines the business case. Delays in implementation due to lengthy permit granting procedures are another significant source of cash flow risk.

¹⁷ Future Clean Tech Architects (2024). Decarbonizing high-temperature heat in industry. Technical Report.

¹⁸ IEA (2017). Digitalization and Energy. IEA Publication. International Energy Agency.

¹⁹ Business Europe (2023). [Analysis of labor and skill shortages: Overcoming bottlenecks to productivity and growth](#).

²⁰ Eurelectric (2026). [What are grid connections and how can Europe fix the queue?](#)

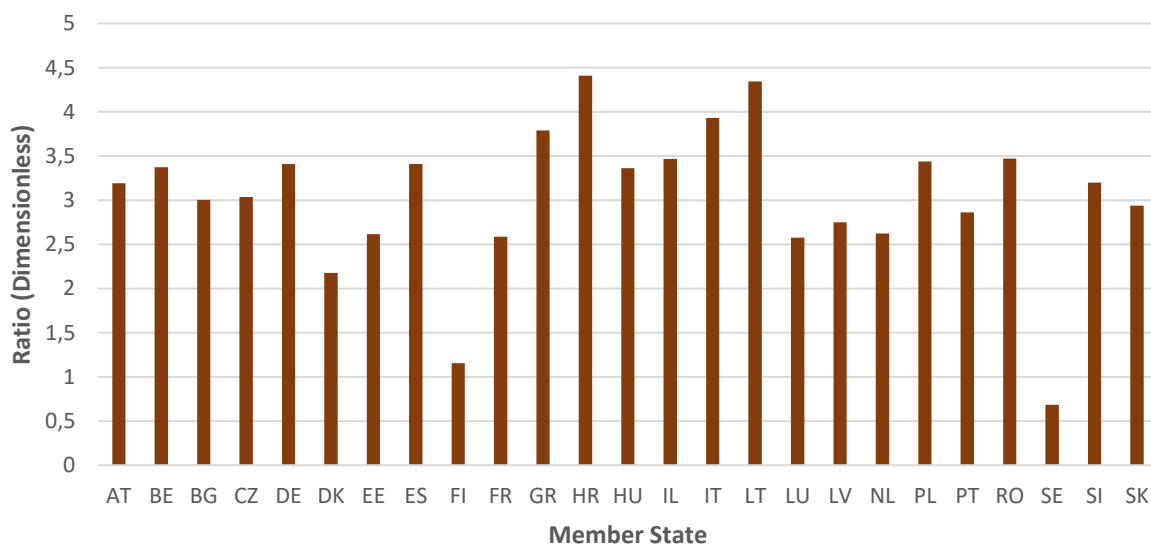
²¹ Monaco, R., Bergaentzlé, C., Vilaplana, J. A. L., Ackom, E., & Nielsen, P. S. (2024). Digitalization of power distribution grids: Barrier analysis, ranking and policy recommendations. *Energy Policy*, 188, 114083.

²² European Commission (2025b). Commission Notice – Guidance on efficient and timely grid connections. *C/2025/8473*.

²³ Wei, M., McMillan, C. A., & de la Rue Du Can, S. (2019). Electrification of industry: potential, challenges and outlook. *Current Sustainable/Renewable Energy Reports*, 6(4), 140-148.

A crucial market parameter is the price of electricity. Investment incentives depend on price comparisons in two dimensions. The first dimension is a comparison of electricity prices with those of currently used fossil energy carriers for industrial process heat. Natural gas is the dominant source. In 2024, the average electricity-to-gas price ratio for non-household consumers in the EU27 was 3.14. In all Member States except Finland and Sweden, this ratio exceeded 2 (see Figure 2).²⁴ These significant gaps in end-user prices are driven by all main price components: wholesale prices, network fees, and taxes/levies. High average electricity wholesale prices reflect the interrelated structural problems of Europe's energy mix: coordination problems between volatile supply and partly inflexible demand, dependence on expensive peak-load production, and windfall profits of inframarginal producers due to marginal pricing. High network fees for electricity reflect the pressure to expand and modernize European grids in order to cope with the challenge of a volatile renewable energy supply. The European Commission has deemed additional investments totaling EUR 584 billion in the electricity grid to be necessary for the implementation of RePowerEU this decade. This sum is similar to the investment required for PV and wind power.²⁵ A disproportionately high level of taxation and levies on electricity is partly the result of some Member States' traditional policy approach of favoring fossil energy sources in energy taxes. The Commission's legislative proposal to align minimum national energy tax rates with a CO₂-based approach is still under negotiation.²⁶ Furthermore, support for renewable energy installations in some Member States is financed through levies on electricity prices, forcing consumers to cover the high investment costs of renewable capacity.

Figure 2: Ratio of electricity to natural gas prices for non-household consumers in 2024



Source: Eurostat (2026). No data for Cyprus and Malta.

The second relevant dimension is the global disparity in electricity prices, which affects the competitiveness of electricity-based European industries in the global market. High energy system costs in

²⁴ Eurostat (2026). [Energy prices](#). Eurostat Database.

²⁵ European Commission (2022b). Commission Staff Working Document Implementing the RePowerEU Action Plan: Investment Needs, Hydrogen Accelerator and Achieving the Bio-Methane Targets Accompanying the document Communication from the Commission to the European Parliament, the European Council, the Council, the European Economic and Social Committee and the Committee of the Regions REPowerEU Plan.

²⁶ European Commission (2021). Proposal for a Council Directive restructuring the Union framework for the taxation of energy products and electricity.

Europe also result in a structural price disadvantage internationally. In the EU27, the average wholesale electricity price in Q4 2025 was 114 USD/MWh, around twice the price in the US (52 USD/MWh) and 60% higher than in Japan (79 USD/MWh).²⁷ A key reason for the significant price discrepancy compared to the US is Europe's reliance on costly natural gas imports for peak-load power generation, whereas US electricity producers can procure natural gas cheaply from growing domestic supply.

Besides high electricity price levels, price volatility is an additional obstacle. Short-term fluctuations in wholesale prices are partly driven by the growing importance of volatile renewable energy sources. Recent research suggests that solar power in particular plays a particularly prominent role.²⁸ However, volatility is also partly a reflection of the changed import situation. The cancellation of long-term import contracts for Russian pipeline gas has been followed by a sharp rise of intercontinental imports of natural gas in the form of liquefied natural gas (LNG). The growing importance of LNG has led to a decline in the prevalence of long-term supply contracts, which previously provided Europe with a certain degree of price stability.²⁹ Consequently, Europe is becoming increasingly vulnerable to volatile global market conditions, further fueled by competition with demand from East Asia. This can be seen in the recent fossil fuel crisis sparked by the war in Iran, where a surge in spot prices for natural gas has led to drastic increase in intra-day volatility in European electricity wholesale markets.³⁰ If this volatility is passed on to end users, it could lead to significant adjustment costs for electricity-dependent industries, potentially requiring additional investments to make processes more time-flexible. Alternatively, firms can try to protect themselves against price volatility by buying hedging products or entering into long-term electricity supply contracts. However, corresponding markets in Europe are still partly underdeveloped (see Section 5).

Finally, regulatory uncertainty is an important source of long-term investment risk. This particularly concerns the future of the EU Emissions Trading Scheme. Rising CO₂ prices are essential for improving the economic balance of electricity-based manufacturing technologies compared to technologies based on fossil fuel sources. This is especially clear for those industries which are considered both electricity- and trade-intensive under EU law. According to current EU state aid rules, they can benefit from compensation payments for the CO₂ price component in electricity costs, which implies that a higher CO₂ price unambiguously lowers incentives for direct fossil gas use.³¹ In this respect, uncertainty over long-term CO₂ price levels, caused by the current controversy surrounding the future level of ambition in the EU ETS-I, is highly detrimental to the investment climate.

4 Analysis of Risk Management Options

4.1 Market Uncertainty and the Social Value of Electrification

In the current transition phase, European electricity wholesale markets are characterized by an increasingly large number of participants and transparent competition. Nevertheless, market outcomes can be considered imperfect, as they disregard several forms of short- and long-term externalities

²⁷ IEA (2026). [Prices Electricity 2026](#). International Energy Agency.

²⁸ Schischke, A., & Rathgeber, A. W. (2026). Unraveling European electricity price volatility: The impact of renewables. *Energy Strategy Reviews*, 64, 102144.

²⁹ Srikantham, R., Lübbers, S., Kreidelmeyer, S., Bornemann, M., Hobohm, J. (2023). LNG-Bedarf für die deutsche Energieversorgung im Prozess des Übergangs zur Klimaneutralität. Studie im Auftrag der Wissenschaftsplattform Klimaschutz. Berlin.

³⁰ Financial Times (2026). [Power prices in Europe swing wildly as Iran war stokes](#).

³¹ European Commission (2025c). Communication from the Commission – Framework for State Aid measures to support the Clean Industrial Deal (Clean Industrial Deal State Aid Framework). C/2025/7600.

associated with the transition. One short-term externality are the costs of grid congestion caused by unexpected short-term peaks of electricity supply and demand. These consist of the congestion management costs of the grid operators, including the purchase of balancing services and compensation payments for the curtailment of renewable energy plants. These costs are not exclusively borne by the responsible market participants, but by passing them on to the network tariffs, by the entirety of electricity consumers. A direct assignment to specific producers or consumers is very difficult, as the relationship between the degree of supply-demand imbalance and the level of congestion costs is highly non-linear.³² With increasing shares of volatile renewables in the grids, these costs increase, burdening the energy costs of electricity-based industrial technologies with higher network tariffs. Conversely, the impact of the electrification trend on the level of grid management and expansion costs is ambiguous and highly technology specific. Demand-side technologies with high time flexibility in electricity use can contribute to a reduction of grid costs. By adjusting their load pattern to short-term fluctuations in electricity supply, they contribute to the avoidance of imbalances and can provide balancing energy to grid operators. Less flexible demand-side technologies can cause additional costs for grids by lowering the overall price elasticity of electricity demand and increasing the magnitude of supply-demand imbalances.

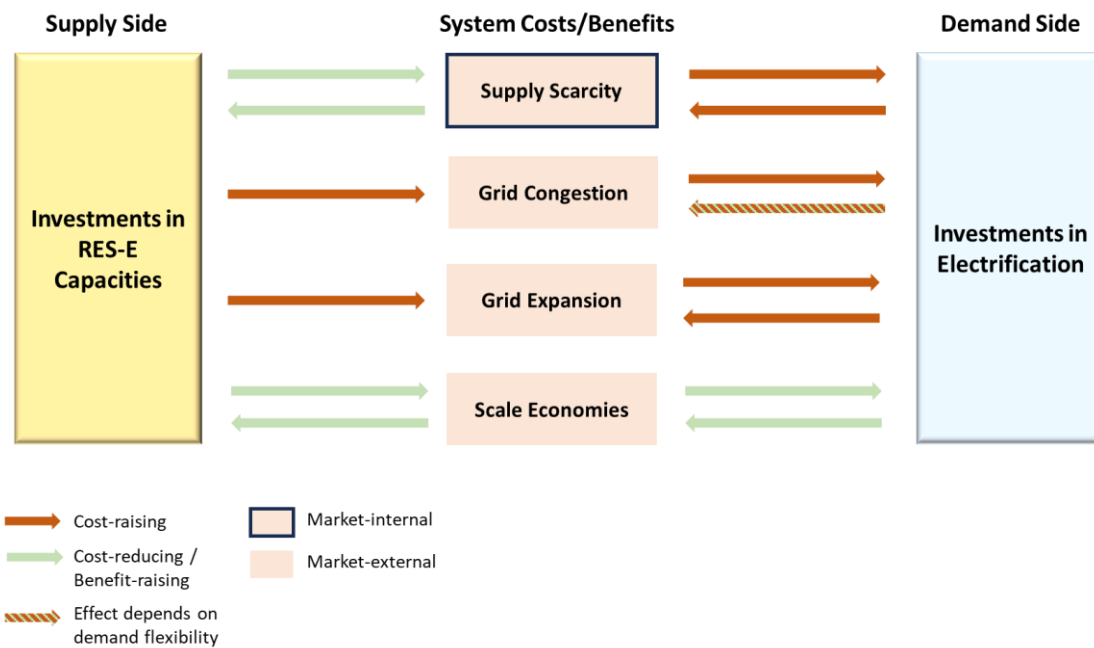
A related long-term externality associated with the green transition is the pressure to expand grid capacities due the occurrence of bigger and more frequent supply or demand peaks. These costs are likewise borne by the entirety of electricity consumers through higher network tariffs. At the same time, the expansion of renewables is characterized by a positive form of long-term externality, the efficiency gains from scaling. Over recent decades, both wind power and photovoltaics have witnessed strong cost declines resulting from technology improvements as well as cost reductions in component manufacturing. For the medium-term future, researchers still expect considerable potential for further scale economies. These affect the capital costs of renewables and may thus not be confused with the merit order effect of renewables expansion on electricity markets, i.e. the price reductions caused by the increased market presence of near-zero marginal cost producers. The capital cost reductions are external in the sense that they enhance the returns to future RE producers. The electrification of energy consumption supports this process by creating a stable demand base for supply scaling.

Finally, system costs involve the market-internal scarcity costs reflected in the wholesale market prices. All else being equal, electrification contributes to supply scarcity through an increase in electricity demand. Unlike the aforementioned factors, however, this kind of contribution to system costs is directly reflected in the market prices paid by the electricity consumers and thus does not constitute a market imperfection.

Figure 3 summarizes the feedback effects between the expansion of renewables, the electrification process and the costs and benefits of the electricity system. It becomes clear that a largely electrified European industry can make both positive and negative contributions to the cost-benefit balance of the electricity system during the transition. The same holds vice versa for the incentive effects of the transition on the demand side.

³² Hirth, L., Eicke, A. (2024). Weiterentwicklung der individuellen Netzentgelte. Kurzgutachten im Auftrag der TenneT TSO GmbH.

Figure 3: Feedback effects between RE investments, electrification and system costs and benefits



Source: own illustration

Theoretically, a first-best response of regulators would be to separate the different impact channels, encouraging the positive externalities and discouraging the negative ones, while keeping the market-internal forces intact. However, in practice, this is complicated by the fact that the channels are closely interwoven. For instance, encouraging scale economies through more comprehensive support of RE investments can cause stronger congestion externalities in the short run. Facilitating grid management by strengthening price-based demand incentives (e.g. dynamic network tariffs, regional disaggregation of wholesale markets) can lead to stronger price spikes in affected regions.

The role of price volatility, in particular, is of an ambiguous nature. On the one hand, a growing price volatility reflects stronger fluctuations of supply costs and more difficulty in matching supply and demand. As such, it is a signal for flexible electricity producers and consumer to adjust their production/usage patterns to the short-term situation, reducing grid congestion risks. On the other hand, higher price volatility implies higher uncertainty regarding the future costs of electricity-based technologies. In this respect, by impairing the opportunities and costs of financing long-term investments, it is an impediment to electrification and can give rise to a “wait-and-see attitude” on the side of investors. In turn, delays in the emergence of new flexible demand sources negatively affect the balancing capabilities of the electricity system in the long-term.

This asks for policy instruments that mitigate cost uncertainty at the end user level, while maintaining the steering effect of wholesale market prices. In particular, risk mitigation may not undermine incentives of suppliers and buyers for system-friendly behavior. In the following, policy options to support two market-based risk mitigation instruments, price hedging on forward markets and the conclusion of Power Purchase Agreements (PPAs), are discussed.

4.2 Forward Markets

4.2.1 Current Market Situation

Forward markets in electricity trading offer three basic types of products: forwards, futures and options. Forwards are customized, bilaterally negotiated contracts, which are settled at the end of the contracting period. Futures are standardized contracts traded on the electricity exchange, where prices are settled daily until the end of the contracting period. Options are asymmetric forms of standardized contracts, where either the buyer gains the right (but not the obligation) to buy electricity (“call option”) or to sell electricity (“put option”) at a predetermined price.³³ The main trade-off between these variants is between flexibility and liquidity. Forward contracts are highly flexible due to their individually negotiated conditions, allowing them to be adapted to specific delivery needs. However, their specificity makes it more difficult to resell them. They also involve high transaction costs (search costs, negotiation costs) and non-compliance risks. Due to their standardization, futures contracts are less flexible, but easy to trade and less risky, as counterparty risks are backed by the exchange platform.³⁴ Hence, the portfolio of available electricity derivatives includes solutions for a wide spectrum of market participants differing in customization needs and market experience.

Contracts on forward markets are often purely financial products, i.e. they do not involve physical delivery of electricity. Instead, contract settlement consists of compensating the difference between the contract price and the price on spot markets for the amount of electricity specified. Currently, the timeframe of contracts on European forward markets ranges from about four years to one month before delivery.³⁵ Hence, forward markets offer a direct hedging of electricity spot price fluctuations for a significant period ahead. Unlike spot price subsidies, they do not distort bidding behavior on spot markets. As contract settlement involves financial compensation for a pre-defined quantity of electricity, incentives to adjust electricity supply or demand to short-term spot price changes are maintained. Moreover, well-functioning forward markets offer additional benefits for the energy system. Forward prices reflect expectations on future spot prices and are thus an indicator of expected scarcity. They are thus an important signal for investors in electricity generation, grid and storage capacity.³⁶ In the same way, price discrepancies between forward and spot markets are an important yardstick for policymakers, signaling market expectations on the success of policies for curbing energy costs.

In the EU, forward market development differs considerably between Member States. One frequent indicator for market liquidity is the churn factor, i.e. the average number of times electricity is traded before it is consumed. Figure 4 depicts estimates of the churn factor by ACER for a selection of European electricity forward markets in 2023.³⁷ Typically, a churn factor of at least 4 or 5 is considered a minimum level for adequate liquidity.³⁸ This level is only surpassed by the German market. Other large markets like France and Italy lie clearly below. These fundamental discrepancies affect the ability to engage in price hedging and thus the electrification incentives across Member States.

³³ Investopedia (2026a). [Energy Derivatives Explained: Futures, Options & Real-World Uses](#).

³⁴ Investopedia (2026b). [Key Differences Between Forward Contracts and Futures Contracts Explained](#)

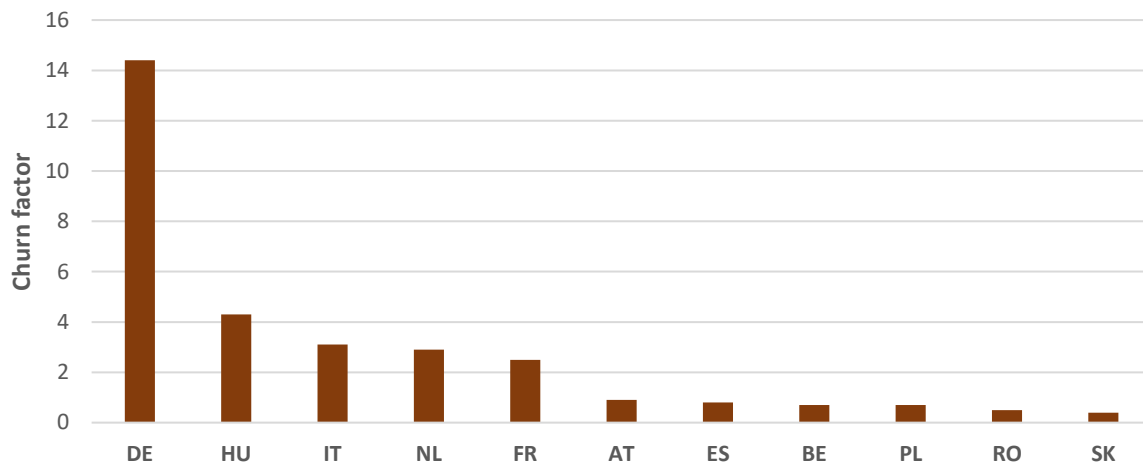
³⁵ TenneT (2026). [Market types](#).

³⁶ Danish Energy Agency (2023). Lessons learned on forward markets.

³⁷ ACER (2024). 2024 Market Monitoring Report. European Union Agency for the Cooperation of Energy Regulators.

³⁸ EFET (2019). Bidding zones delineation in Europe: Lessons from the past & recommendations for the future. Position Paper.

Figure 4: Comparison of churn factors on national electricity forward markets in 2023



Source: ACER (2024)

4.2.2 Barriers and Limitations

A general requirement for well-functioning electricity forward markets is sufficient market liquidity. A lack of market transactions can result in increased search and transaction costs for participants. It also restricts the variety of forward products traded, limiting the ability to customize contracts based on individual time or risk preferences. Moreover, it can give rise to monopoly power of specific traders, biasing forward prices and thus the signaling function of forward markets.

Currently, liquidity levels of the forward markets of some Member States are still very low. To find an appropriate hedge, traders with less liquid domestic markets may be forced to switch to markets of neighboring countries. Hence, they can only directly hedge against price fluctuations on foreign spot markets, not their own markets. This imperfect “proxy hedge” could exacerbate the destabilizing effects of insufficient cross-border trading and market integration of electricity spot markets, especially among neighboring countries with strong discrepancies in the national mix of electricity sources (and thus price patterns). To limit the exposure to cross-zone price discrepancies, the EU electricity market design foresees the allocation of Financial Transmission Rights (FTRs), a form of Long-Term Transmission Right (LTTR). These are auctioned hedging contracts between Transmission System Operators (TSOs) and electricity traders for the right to transmit electricity across bidding zones. FTRs compensate traders for the price discrepancies between bidding zones financially.³⁹

One shortcoming of this forward market design lies in the limitations of current FTR products. FTRs are auctioned only at certain points in time and only with limited maturity (maximum of one year), causing a mismatch with the underlying forward and futures products. In particular, this limits the opportunities for long-term price hedging for electricity consumers in small bidding zones with low market liquidity.⁴⁰ This inequality is worsened by regulatory fragmentation. National regulatory authorities possess a high degree of flexibility in their decisions on when TSOs should allocate FTRs and when not, in

³⁹ SEM Committee (2015). Integrated Single Electricity Market (I-SEM) – Financial Transmission Rights. Consultation Paper. SEM-15-061.

⁴⁰ ACER/CEER (2022). ACER and CEER draft policy paper on the further development of the EU electricity forward market. European Union Agency for the Cooperation of Energy Regulators.

particular concerning the criteria to evaluate the sufficiency of hedging options. Different regulatory requirements at the national level affect supply of different FTR products.⁴¹ A general limitation is the predominance of the option form for FTRs. With these contracts, traders gain the right but not the obligation to exert the FTR. Hence, they will only make use of it in cases where the sign of the cross-border price spread would create losses. First, this asymmetric distribution of risk implies that traders might have to pay a risk premium to the TSO acting as a counterparty in the FTR contract, thus raising the costs of the hedging process. Second, it creates a risk mismatch with the underlying bi-directional forward contracts, limiting price comparability.⁴²

A further constraint concerns the financial requirements set by the need for collaterals. Collaterals are essential to limit the bankruptcy risk and are thus a prerequisite for liquid markets efficient forward pricing. While for standardized futures this risk is taken by the market platforms, this is not the case for the decentral forward contracts.⁴³ As the increased relevance of volatile renewables reduces medium-term price predictability, it also raises collateral requirements, thus aggravating liquidity constraints on price hedging. The changed risk profile also reduces the willingness of private financial institutions to provide guarantees or liquidity for such a collateral.

Another factor affecting price settlement on forward markets potential existence of ex-ante risk premiums in the forward contracts. In the presence of such a premium, the forward contract price differs from the expected spot price for the delivery date, with the discrepancy reflecting a form of risk compensation. As both partners in a forward contract face (opposing) price risk, this discrepancy could be both positive or negative. A positive (negative) risk premium can be seen as an indication that the electricity buyer is more (less) risk-averse than the seller. Empirical studies show that the relative risk position is subject to changes over time. For instance, Bunn and Chen (2013) found for the British electricity market significant differences in the sign of risk premiums between peak and off-peak times. In peak load times, risk premiums tended to be positive, reflecting the fear of electricity retail traders of rising spot prices. In off-peak times (e.g. during night hours), risk premiums tended to be negative, reflecting the fear of wind energy producers of negative spot prices.⁴⁴ An alternative explanation for varying risk premiums is the role of storage costs. Electricity cannot be directly stored, but indirect storage is possible in the form of storing fossil fuels for later electricity production or converting electric into electro-chemical (batteries) or potential (e.g. hydro pump storage) energy. If storage is relatively cheap, sellers in the forward contract can fulfill their contract obligations through energy purchased and stored ex ante, eliminating their exposure to spot price changes (and thus their needs for a risk premium).⁴⁵ Hence, the ability of forward prices to predict spot prices varies with the available mix of electricity generation and storage technologies.

The presence of risk premiums and their variation over time is itself not a sign of market imperfection, as long as they are the outcome of a fair evaluation process. However, they add to the long-term price uncertainty of investors planning electrification investments with depreciation periods exceeding the

⁴¹ See ACER/CEER (2022).

⁴² Holtz, C., Hollmén, S., Spodniak, P., & Perekhodtsev, D. (2022). Measures to improve risk hedging opportunities on the electricity market in Sweden. Ei, Stockholm.

⁴³ See Investopedia (2026a).

⁴⁴ Bunn, D. W., & Chen, D. (2013). The forward premium in electricity futures. *Journal of Empirical Finance*, 23, 173-186.

⁴⁵ Carnero, M. A., Fleten, S. E., Størdal, S., & Westgaard, S. (2025). Ex ante and ex post risk premiums in electricity futures. *Quantitative Finance*, 25(11), 1717-1729.

lengths of available forward contracts. Moreover, they exacerbate existing transaction cost and liquidity issues on forward markets, as the determination of a fair contract price becomes more complicated.

4.2.3 Support Options

The debate on how to overcome illiquidity in national forward markets focuses on measures to strengthen market integration, in particular the reform of the current scheme of compensating cross-border spot price discrepancies. To raise the effectiveness of auctioned FTRs in balancing zonal price discrepancies, TSOs could organize auctions at a higher frequency, with more differentiated FTR products involving time interval for price hedging and customized products for specific grid situations (e.g. peak-load times). To further raise flexibility, the emergence of a secondary market for FTRs could be promoted e.g. through publicly backed market platforms. It would allow FTR owners to adjust their positions on a short-term basis to changes in the perceived risk profile, e.g. resulting from a more frequent occurrence of congestion situations in a certain bidding zone.

A more significant intervention would be to define two-side FTR obligations as the new standard instrument in auctioning cross-zonal price hedging instead of FTR options. This would not only imply a better matching with the risk profile of the underlying forward contracts. It would also help to overcome physical volume constraints in cross-border electricity transport by incentivizing TSOs to balance out their risk-taking associated with auctioning FTRs. The pay-out risk associated with issuing FTRs in one price direction could be fully compensated by auctioning an equivalent amount of FTRs in the opposite price direction. Under these circumstances, injections and withdrawals on both sides of the border are netting out each other, theoretically allowing for an unrestricted auctioning of FTRs. A prerequisite is that expectations on the sign of future price discrepancies between the bidding zones are sufficiently heterogeneous, thus creating sufficient demands for contracts in both directions.⁴⁶ Moreover, due to the two-side nature of the FTR obligations, risk-taking on the side of FTR buyers is increasing, raising potentially collateral requirements.⁴⁷

Alternatively, the system of providing cross-zonal hedging products by TSOs could be completely abandoned in favor of purely decentral cross-zonal forward markets. In this scheme, national price spreads would have to be purely hedged by privately offered and traded products. In this way, TSOs (and thus electricity consumers through network tariffs) would no longer be subject to price discrepancy risks in periods of strong congestion. As such products would evolve as an outcome of competition, they could also adapt more flexibly to the specific hedging needs of different groups of market participants. Moreover, cross-zonal products could be directly linked with zone-specific price futures to form new synthetic products, reducing transaction costs and limiting collateral needs to just one product. However, a requirement for efficient trade in such a system is the willingness of commercial traders to offer such a risk hedging of cross-zonal price discrepancies. If initial liquidity in one of the zonal forward markets is very low, there is likely not sufficient demand for such a synthetic product in the beginning, limiting the ability of decentral markets to achieve a fair risk distribution through efficient pricing. Hence, an untimely abandonment of centrally auctioned FTRs could strip market participants from the ability to hedge at all. The conversion to a purely decentral market allocation of forward products should thus rather be seen as a long-term solution, when existing liquidity gaps between zonal forward markets have already been reduced to some extent by other measures.

⁴⁶ SEM Committee (2015). Integrated Single Electricity Market – Financial Transmission Rights. Consultation Paper.

⁴⁷ ENTSO-E (2022). EU's Electricity Forward Markets. ENTSO-E Policy Paper.

Finally, an option currently considered by the EU (see Subsection 4.4) is the introduction of virtual trading hubs for forward contracts. These hubs are supposed to create artificial, cross-zonal market signals for electricity forwards. They provide stable forward reference prices for different maturities, which are calculated based on an aggregation of forward prices observed in different bidding zones. Most intuitively, this can take the form of a weighted average, with weights based on indicators like transaction or electricity consumption volumes in the different zonal markets.⁴⁸ In this way, virtual hubs can act as a substitute for small illiquid national forward markets, reducing transaction costs for stakeholders and avoiding the distortion by potential market concentration on illiquid markets. In comparison to cross-zonal hedging, virtual hub prices are expected to be more closely aligned with national price movements than prices in single neighboring countries, due to the fact that they are determined as an average of several markets. However, the construction of artificial hub prices is complex and requires choosing among many alternatives. Design elements like the weighting scheme can have strong distributional effects across market zones. Moreover, it is not a priori clear that a virtual hub will raise overall European forward market integration. Initially, increased trading based on virtual hub prices might come largely at the costs of trading on the most liquid zonal forward markets, thus potentially raising instead of reducing European market fragmentation.⁴⁹

4.3 Power Purchase Agreements (PPAs)

4.3.1 Current Market Situation

Power Purchase Agreements (PPAs) are long-term electricity purchase contracts concluded between an electricity producer and a buyer, which can either be an intermediary or an electricity end consumer. Unlike in the case of forward contracts, the traded good is typically not just a risk hedge, but involves the physical delivery of electricity. The contract determines the volumes and the price of the electricity sold over the agreed time horizon (usually between 7 and 15 years, sometimes even longer). The price is either ex-ante fixed or regularly updated based on an agreed price formula.⁵⁰

Specific attention in the energy debate have gained PPAs with RES-E producers and industrial electricity consumers as contract parties. In principle, engaging in such PPAs offers several advantages to both parties. By agreeing on an ex-ante price level or price calculation formula, both RES-E producers and consumers can reduce their exposure to spot price uncertainty. Typical contracts lengths clearly exceed those of forward contracts, offering thus a more long-term hedge. Reduced revenue uncertainty improves the financing conditions for new RES-E projects and thus contributes to a more cost-efficient capacity expansion of renewables.⁵¹ For existing RES-E installations which are about to be phased out of public support schemes, PPAs constitute an alternative business model to continue operation.

For industrial electricity consumers, PPAs with RES-E project developers not only reduce uncertainty on electricity cost, but potentially also on RES-E volumes, provided that contracts include volume guarantees (see below). Direct contracting with RES-E projects is also the easiest way for industries to document the green origin of their electricity consumed. To this end, PPAs typically involve the transfer of the Guarantees of Origin certificates from the RES-E suppliers to the consumers. This not only helps

⁴⁸ Zachmann, G., Hirth, L., Heussaff, C., Schlecht, I., Mühlentfordt, J., & Eicke, A. (2023). The design of the European electricity market. Current proposals and ways ahead. Study. European Parliament: Luxembourg City, Luxembourg.

⁴⁹ Compass Lexecon (2024). Assessment of potential impacts of regional virtual hubs on the forward markets. Final Report.

⁵⁰ MIBEL (2024). Power Purchase Agreements (PPAs). Board of Regulators of MIBEL.

⁵¹ Pombo-Romero, J., Rúas-Barrosa, O., & Vázquez, C. (2024). Assessing the value and risk of renewable PPAs. Energy Economics, 139, 107861.

industries to access green financing instruments, but also to comply with regulatory standards, for instance to meet the definition of Renewable Fuels of Non-Biological Origin (RFNBOs) when using electricity to produce renewable hydrogen.⁵²

As bilaterally negotiated contracts, PPAs provide room for a wide spectrum of financial and technical delivery conditions, can thus be customized based on the specific technological needs and risk preferences of the contracting parties. This also involves flexible use of risk sharing mechanisms for the volume risk associated with naturally volatile energy sources. For instance, in “pay-as-produced”-contracts, the volume risk remains with the buyer, which in turn could ask for a low contract price as a form of risk compensation. In “baseload”-contracts, the RES-E producer guarantees a permanent minimum supply level, potentially requiring the producer to balance out missing volumes through external sourcing in periods of unfavorable weather conditions.⁵³ This form of contract might better match the needs of industries with production technologies highly dependent on continuous electricity consumption.

PPAs can also be distinguished whether they involve physical delivery or not. The latter form of contract is termed virtual or financial PPA. It merely consists of a repeated financial settlement of the differences between the contract price and the fluctuating spot price levels over the contract period. Virtual PPAs differ from forward contracts in their typically longer contract periods and the fact that they involve a transfer of Guarantees of Origin to the buyer. Physical PPAs are distinguished into on-site and off-site PPAs. In on-site PPAs, producer and consumer share a direct connection line to deliver the electricity, thus avoiding infrastructure risks related to public grid bottlenecks. In off-site PPAs, delivery occurs through the public grid, requiring the involvement of a utility company as an intermediate to manage the electricity flow through the grid.⁵⁴

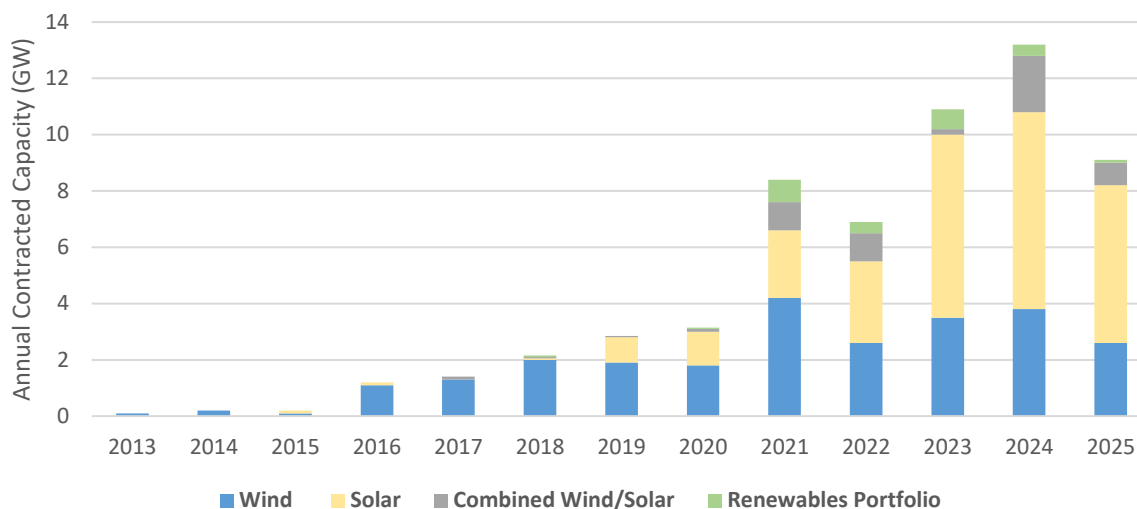
In recent years, PPAs have experienced significant market dissemination in Europe. Annual PPA announcements over the past ten years show an exponential trend (see Figure 5).⁵⁵ While in the early stages PPAs were largely limited to large-scale wind power projects, the application area has been increasingly broadened, including both solar power and projects exhibiting a pooled technology portfolio. However, after the very promising growth in 2023 and 2024, the most recent figures for 2025 show a slump in contract volumes. This is primarily seen as a response to the growing relevance of infrastructure and demand constraints to PPA market growth (see Section 3). Moreover, PPA markets in Europe are still heavily geographically concentrated. The two by far leading national PPA markets Spain and Germany together make up more than one third of EU-wide contracted capacity. Besides different roles of electrification, this is also reflecting a different policy focus on PPA support.

⁵² European Commission (2023). Commission Delegated Regulation (EU) 2023/1185 of 10 February 2023 supplementing Directive (EU) 2018/2001 of the European Parliament and of the Council by establishing a minimum threshold for greenhouse gas emissions savings of recycled carbon fuels and by specifying a methodology for assessing greenhouse gas emissions savings from renewable liquid and gaseous transport fuels of non-biological origin and from recycled carbon fuels.

⁵³ EFET (2024). EFET Insight into Renewable Power Purchase Agreements. Energy Traders Europe.

⁵⁴ See EFET (2024).

⁵⁵ RE-Source (2026a). [PPA deal tracker](#). European Platform for Corporate Renewable Energy Sourcing.

Figure 5: Annual PPA announcements in Europe by generation mix

Source: RE-Source (2026a).

4.3.2 Barriers and Limitations

While the long contract lengths of PPAs are an opportunity to shield against long-term market price risks, they bring about their own specific forms of risks. The first group of risks are of a technological nature. Multi-annual forecasts of the supply potential of RES-E plants are complex and highly uncertain, as weather conditions are highly dynamic. On the side of buyers, technological change can influence future electricity needs, by making less electricity-intensive technologies available or affecting revenue potential on sales markets. Regulatory risks are another serious concern. For instance, fundamental regulatory changes to the design of electricity markets could alter market price patterns, creating misalignment with the market expectations underlying PPAs with fixed contract prices. Future changes to the treatment of PPAs in tax policies could affect net prices for buyers. Adjustments of the emissions trading scheme could change expected CO₂ price paths and thus the economic rationale of RES-E based industrial technologies.

On top of these systemic risks come the specific counterparty risks of contractual non-compliance. From the perspective of the buyer, this involves the risks of a delayed development of the RES-E project or of operational failure on the side of the plant owners. From the perspective of producers, it involves the risk of payment default by the buyer. For newly developed RES-E plants, this default risk is a particularly relevant barrier, as it directly affects future project cash flows. An insufficiently backed default risk can raise financing costs and impair bankability of projects. Therefore, PPAs often contain specific default protection mechanisms like advance payments, the provision of collaterals or the right to terminate or re-negotiate the contract under pre-defined conditions (material adverse effect clauses).⁵⁶

For buyers with a sub-optimal credit rating, high collateral requirements can represent a particular obstacle. They require a long-term commitment of additional capital, potentially creating liquidity issues and withdrawing financial resources from productive forms of investments. If the required collateral cannot be fully provided by firm-internal means, buyers must seek external backing by banks (loans, letters of credit), trade credit insurance or through the use of dedicated capital market

⁵⁶ IRENA (2018). [Power Purchase Agreements for variable renewable energy](#). International Renewable Energy Agency.

instruments like credit default swaps. These forms of risk transfer usually entail additional costs for risk compensation, which further reduce the overall economic attractiveness of PPAs from the perspective of industrial electricity consumers. In particular, this restricts the roll-out of PPAs in the segment of small-to-medium sized industrial companies, which often lack the necessary liquidity buffers to cost-effectively manage contract default risks.⁵⁷

Moreover, the downside of the high flexibility of PPAs is the comparatively high level of search and negotiation costs on PPA markets. If contracts are backed by external guarantees, negotiation costs can be particularly high, as warrantors will aim to exert influence on contract conditions. To reduce this cost barrier in particular for small market players, several public and private institutions have recently started to publish standardized contract templates with benchmark solutions for the main contract clauses.⁵⁸ However, a careless application of such standardized contracts could blur the view on the heterogeneous needs of different businesses and might make market participants less sensible for the specific risks associated with unusual supply or demand profiles.

In a systemic perspective, PPA market growth could collide with the goal of cost-efficient public renewable energy support, if support regimes are not appropriately adapted. This is because the most cost-efficient RE projects are likely to switch to PPA marketization first, as they are least dependent on public subsidies. If no binding upper limit on support volumes is imposed, this selection effect can result in an increase of average support costs per kWh, a phenomenon known as “cream-skimming”. In particular, this risk applies to tender-based support schemes like Contracts-for-Difference (CfDs), where support levels result from auction bids and are thus sensitive to the efficiency of plants and their local generation conditions. Kröger (2024) estimates for Germany that the option to conclude PPAs can raise the strike price in CfD support auctions by 2% to 6%, depending on the level of the cost mark-up associated with concluding PPAs.⁵⁹

4.3.3 Support Options

Supporting the development of European PPA markets requires policy action on many levels. Potential incentive-based measures can be broadly categorized based on their immediate targets: reducing transaction costs, compensating contractual risks, and ensuring compatibility of PPAs with existing RE support frameworks. Measures targeting transaction costs aim to reduce the market frictions stemming from incomplete information, lack of experience and the heterogeneity of market actors. This starts with the provision of basic information on the functions of PPAs and the challenges to address by public institutions. As discussed above, it can also involve the provision of practical toolkits like contract templates suitable for standard PPA applications. Moreover, market efficiency can be raised by financially supporting market platforms for matching RE producers with corporate electricity buyers. Platforms can reduce search costs and improve market transparency by publishing trading indicators. On the demand side, PPA market integration of small electricity buyers could be fostered by providing financial and administrative support to arrangements of pooling small businesses in single

⁵⁷ EIB (2022). Commercial Power Purchase Agreements. A Market Study including an assessment of potential financial instruments to support renewable energy Commercial Power Purchase Agreements. European Investment Bank.

⁵⁸ RE-Source (2026b). [Template PPA contract](#). European Platform for Corporate Renewable Energy Sourcing.

⁵⁹ Kröger, M. (2024). Cream-skimming through PPAs—Interactions between Private and Public Long-term Contracts for Renewable Energy (No. 2092). DIW Berlin, German Institute for Economic Research.

PPAs (“multi-buyer PPAs”), thus helping producers and consumers to jointly benefit from scale economies of large-scale RE projects.

Public risk compensation can have multiple forms as well. Governments could directly take on the risks by pooling electricity demand of public institutions and engage as a contracting party in PPAs with large-scale RE producers. In addition, they can facilitate risk management for PPAs between private parties, by providing public counter-guarantees to underwrite the risk of payment defaults. This reduces revenue risks on the side of producers and enables buyers to negotiate contracts with lower prices. A strategy of publicly pooling risks from a multitude of private contracts could also prove cost-efficient from a macroeconomic perspective. Due to their joint dependence on the market development in electricity-intensive industries, individual default risks should be significantly correlated. Hence, market-based risk diversification will be difficult and costly to achieve, justifying the backing by widely dispersed public budgets. Recent research suggests that public counter-guarantees are not only effective in eliminating risk barriers, but, by reducing discount rates of future RES-E net revenues, also constitute a more cost-efficient support instrument for RES-E deployment than CfDs.⁶⁰

Ensuring compatibility with other public RE support frameworks mainly requires eliminating any barriers for RES-E producers to engage in PPAs that might result from such a co-existence. Most importantly, this concerns the relationship with CfDs as the new EU-wide standard instrument for providing long-term support to RES-E deployment (see Subsection 4.4). From the perspective of RES-E producers, PPAs and CfDs are substitutes in the task to secure long-term revenues. In other aspects, however, they can fulfill complementary functions. For instance, due to the greater contractual flexibility, the option to sell parts of their output through newly negotiated PPAs can be valuable for RES-E producers. In this way, they can adapt their terms of trade to changing market conditions (e.g. rising spot prices, new customer groups with specific supply needs), which is usually not possible under a long-term CfD model with the state as counterparty. Hence, a mixed marketization of electricity combining CfDs with decentrally negotiated PPAs could represent a superior strategy for an RES-E project, as it combines long-term security with flexibility.

A prerequisite is sufficient regulatory freedom for such individual marketization strategies. This starts with the basic permission for such a mixed strategy, allowing RES-E producers to limit their participation in CfD auctions to segments of their overall electricity output. It also involves regulatory decisions on more complex forms of interaction between the two instruments, like opt-in/opt-out options. These would allow RES-E producers to flexibly adjust the output share secured by CfDs upwards/downwards during the contract period of the CfD. However, such options must be handled very cautiously, as they threaten to undermine the very logic of two-way CfDs: enforcing a repayment of subsidies in times of high electricity prices. Alternatively, PPAs can be layered on top of existing CfDs, by allowing electricity covered by an CfD to be marketized via PPAs instead of only via wholesale markets. However, such mixed models can create other forms of inconsistencies in risk management, e.g. a mismatch between the negotiated PPA price and the CfD strike price as well as the risk of cross-subsidization of PPA contract parties.⁶¹

⁶⁰ Schütt, J., & Kächele, F. (2026). Government backed credit guarantee schemes for offtaker counterparty risk under corporate power purchase agreements. *Energy Economics*, 109166.

⁶¹ European Parliament (2026). Overview of the diffusion of Power Purchase Agreements and Contracts for Difference across Member States. Study – Requested by the ITRE Committee.

On a wider scale, regulatory compatibility also concerns the more general long-term parameters affecting decisions to engage in PPAs. A very fundamental one is the evolution of the CO₂ price and the future of the associated price compensation mechanism. Empirical research reveals a significant positive correlation between the CO₂ price level in the EU ETS-I and electricity wholesale prices in Europe. This is due to the relevance of peak-load fossil power (mostly natural gas) as price setter on electricity wholesale markets. In principle, the prospect of rising CO₂ prices for fossil power should thus raise incentives for electricity buyers to switch to direct PPAs with RES-E producers as an alternative procurement strategy. However, this incentive is still contained by the opportunity of Member States to grant an electricity price compensation to industries subject to carbon leakage risk.⁶² Moreover, rising CO₂ prices raise the prospects for RES-E producers to realize windfall profits on wholesale markets, reducing incentives to engage in PPAs on the supply side. This is another motivation for a complementary mix of CfDs and counter-guarantees for PPAs as support instruments.

The application of PPA support policies in Member States is still very underdeveloped. Based on the assessment in the most recent ACER monitoring report, only four Member States (France, Poland, Portugal, Spain) have implemented state-backed counter-guarantees for PPAs so far. Specific market platforms for PPAs only exist in six Member States (Germany, Greece, Italy, Portugal, Spain, Sweden). Regulatory support to demand pooling is only provided in France and Italy.⁶³

4.4 Recent EU Policy Impulses

Through its recent electricity market reform and a series of subsequent action plans and recommendations, the EU aims to improve the framework conditions for market-based risk management. At the heart of the reform is a risk-oriented concept of RES-E support. From Mid 2027 onwards, two-way CfDs (or an equivalent instrument) are prescribed as the standard tool for direct support to new power-generating facilities provided by Member States. Other forms of direct support may only be granted to small-scale renewables installations and demonstration projects. The payment flows from CfDs shall be linked to the consumer side through a direct feedback mechanism. Public revenues generated in times where market prices exceed the CfD strike price shall at least partly be redistributed to electricity consumers. Hence, the switch to CfDs can also contribute to reducing price risks for final consumers in the long-term. A precondition for redistribution schemes is that they do not reduce incentives to shift electricity consumption to low-price periods.⁶⁴

Another focus of the reform is on measures to improve the liquidity of electricity forward markets. To overcome low liquidity on regional forward markets through hedging across electricity zones (see Subsection 4.2.2), the revised electricity market regulation requires TSOs to issue LTTRs to hedge cross-border price discrepancies. An exception to this obligation is only granted if regulatory authorities assess that there are already sufficient alternative hedging opportunities available. Potential more far-reaching requirements concerning future LTTRs (maturity, frequency of allocations) shall be proposed based on a future impact assessment. As an alternative long-term solution to the liquidity problem, the reform considers the introduction of virtual trading hubs. Its potential design and geographical

⁶² See European Commission (2025c).

⁶³ ACER (2025). Power Purchase Agreements country sheets – Monitoring Report 2025. European Union Agency for the Cooperation of Energy Regulators.

⁶⁴ European Union (2024). Regulation (EU) 2024/1747 of the European Parliament and of the Council of 13 June 2024 amending Regulations (EU) 2019/942 and (EU) 2019/943 as regards improving the Union's electricity market design.

scope shall also be assessed by a later impact assessment, reflecting the high sensitivity to design questions (see Subsection 4.2.3).⁶⁵

The revised regulation also requires Member States to take initiative in promoting PPA markets. They are asked to eliminate any discriminate procedures that impose restrictions on the growth of PPA markets on their territories. In particular, this concerns compatibility with national renewable energy support schemes (see Subsection 4.3.2). They shall also offer financial instruments to reduce the financial risks from payment default in renewable PPAs, mentioning state guarantees as one example. At EU level, the reform foresees a regular monitoring of progress through annual assessments by ACER on the evolution of the EU PPA market.⁶⁶ ACER has also started to provide a collection of available PPA contract templates on its webpage, providing guidance to unexperienced traders. As part of the future review process, the EU announces to investigate a potential introduction of a voluntary EU-wide market platform for PPAs. Most recently, the EU has teamed up with the European Investment Bank (EIB) to launch a pilot program for providing counter-guarantees to corporate PPAs with a total volume of EUR 500 million.⁶⁷ This budget will cover parts of the payment default risk, allowing for flexible forms of risk allocation between commercial banks, the EIB and the renewable energy supplier.

With the Clean Industrial Deal State Aid Framework (CISAF), the Commission has widened the scope for Member States to provide price-based subsidies to industrial electricity buyers from trade- and electricity-intensive industries. Price support may be granted for up to 50% of a company's electricity consumption and price reductions may not exceed 50% of the wholesale price. Aid is only provided conditional on investments in energy transformation and is generally limited to a time period of up to three years.⁶⁸

Moreover, besides targeting market prices, the EU has also aimed to harmonize the non-market related components of electricity prices. This is an area where EU competencies are traditionally very limited. The electricity market regulation defines general requirements for tariff methodologies. Amongst other criteria, network tariffs shall be cost-reflective, transparent and consider the need for network security and flexibility. Recently, the Commission made proposals for a concretization of these criteria in the form of a non-binding recommendation to Member States.⁶⁹ It recommends to explore the potential for a more incentive-based regulation of network tariffs. In particular, tariffs should create incentives to reduce specific consumption in peak-load times. In general, tariff methodologies should be dynamic, i.e. differentiate tariffs by time-of-use, and include locational elements. A special treatment of specific user groups, e.g. energy-intensive industries, is still acknowledged, but only in cases where these groups make a lower contribution to overall system costs. In sum, these recommendations raise the pressure to shift a larger part of grid costs to inflexible band-load electricity consumers.

Finally, to overcome technical infrastructure bottlenecks, the Commission has proposed a comprehensive list of legislative and non-legislative measures in the European Grids Package.⁷⁰ Most importantly, it includes a proposal to accelerate permit granting procedure for renewables, grids and energy

⁶⁵ See European Union (2024).

⁶⁶ See European Union (2024).

⁶⁷ ACER (2026). [Power Purchase Agreements \(PPAs\)](#). European Union Agency for the Cooperation of Energy Regulators.

⁶⁸ See European Commission (2025c).

⁶⁹ European Commission (2025d). Commission Notice on Guidelines on future proof network charges for reduced energy system costs. C/2025/8574.

⁷⁰ European Commission (2025e). [European Grids Package](#).

storage. This includes stricter and shorter deadlines for the different infrastructure categories and the application of the principle of tacit approval, specifically for grid connection permits. To achieve efficient and timely grid connections, the package also includes a specific Commission guidance on the legal framework for connection procedures, drawing on best practices in Europe. Moreover, the EU aims to boost cross-border expansion through the concept of energy highways. These are currently eight electricity transport corridors which are considered high-priority bottlenecks. Energy highways will receive prioritized EU support in the form of financing and measures to streamline permit granting.

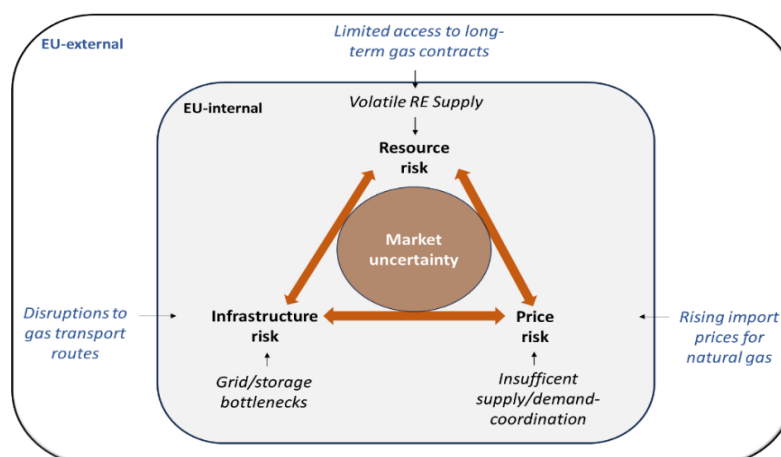
5 Recommendations for a Risk-focused EU Electrification Strategy

5.1 Risk Management Framework

The preceding analysis has demonstrated that uncertainty in the European electricity market is the result of various risks interacting with each other. These risks occur at different points in the energy system. At the same time, due to the constant need to match electricity supply, demand and transport capacity, they directly interact with each other. These risks can be categorized by their cause. Risks relate to the availability of resources for electricity production, the availability of infrastructure (grid and storage) and price formation on electricity markets. Furthermore, these causes can be categorized as either internal or external to the EU.

Figure 6 sketches an example of such a risk classification system. A fundamental risk to internal resources is the natural volatility of the bulk of RES-E supply. Internal infrastructure risks consist of capacity bottlenecks in grid and storage infrastructure availability. Price risks arise from the insufficient coordination of electricity supply and demand, resulting in price fluctuations. This encompasses potential inefficiencies in the electricity exchange's allocation function, as well as a lack of price incentives for consumption flexibility in electricity retail markets. These risks are interconnected. Increasing supply volatility also complicates supply-demand coordination and increases the risk of infrastructure bottlenecks, thereby exacerbating the resource risk. One external source of risk is access to fossil fuel imports for electricity production. This mainly affects natural gas as a technology for peak-load power generation. Here, too, a distinction can be made based on the same three risk categories. Since gas-fired power stations act as controllable complementary technologies for renewable energy sources (RES-E), internal and external sources of risk interact and reinforce each other.

Figure 6: Interplay of risks in the European energy system during the green transition



Source: own illustration

This variety of interdependent risks requires a wide range of policy tools to manage effectively. The cep has already analyzed measures for the long-term reduction of external risk sources in a separate study.⁷¹ Any measures designed to eliminate internal risk sources for market players must consider the interdependencies within the European energy system. They must strike a balance between government risk adoption and maintaining incentives for system-friendly behavior of market participants. A useful criterion for this is the exogeneity or endogeneity of risks. Systemic risks, i.e. those that cannot be influenced by the behavior of individual market players, should be hedged by society. A prime example is the chicken-and-egg problem in the simultaneous expansion of electricity infrastructure and electrification technologies. It requires government support for grid expansion and decarbonization investments. Risks that can be influenced by market players, however, should be managed in a decentral manner via the steering effect of market signals. This also requires political action to eliminate market inefficiencies and support the development of new risk hedging markets. Examples of this include strengthening the regulation of forward markets and providing government support for the development of PPA markets. The following section summarizes six practical recommendations for action based on this concept.

5.2 Policy Tools for EU-Internal Risk Management

1. Support the development of cross-zonal forward markets through symmetric long-term FTRs

Competitive forward markets are the most efficient means of hedging against fluctuations in the market component of electricity prices. As national forward markets in many Member States are likely to remain underdeveloped in the foreseeable future, cross-zonal hedging with minimal barriers is required. To avoid distorting industrial competition, industries in Member States with illiquid markets must not be disadvantaged in their price hedging options. Industrial companies in the EU should have access to reliable hedging strategies everywhere. To this end, barriers to access to forward markets in neighboring bidding zones must be removed. Above all, this requires greater flexibility in the auctioning of cross-border long-term transmission rights (LTTRs). TSOs should auction LTTRs for different multi-year periods. To mirror the situation with intrazonal hedging, LTTRs should be allocated symmetrically, i.e. as obligations rather than options. In the long term, virtual trading hubs could further improve market liquidity across the EU. However, these require careful testing and should only be implemented once the liquidity differences between forward markets have decreased, to avoid market fragmentation and weakening the currently dominant markets.

2. Promote PPAs through pooling platforms and counter-guarantees

PPAs are a key market-based option for long-term electricity supply. In addition to securing supply conditions for electricity producers and buyers, the fact they establish long-term direct business relationships between renewable sources and large demand sinks is a merit in itself. In this way, they contribute to the integration of RES-E projects into industrial value chains, bypassing volatile electricity exchanges. Their adaptability to individual needs enables the full range of electricity-based business models to be exploited. However, realizing these benefits requires increasing liquidity and competition in PPA markets. This, in turn, requires an increasing diversity of players. Alongside large, experienced corporate buyers, this means integrating industrial SMEs as competitive market participants. Therefore, policymakers should focus on removing PPA market barriers for SMEs. To reduce transaction

⁷¹ Wolf, A., Reichert, G. (2025). Die Energiesicherheit Deutschlands. cepStudy No.3/2025.

costs and realize economies of scale, market platforms should be equipped with government-supported pooling mechanisms. These mechanisms should bundle industrial SMEs and other small consumers into multi-user PPAs offering a selection of standardized contracts. Contract pricing should be centralized and algorithm-based, using bid matching. Large public companies could also support the scaling up of such contracts by acting as anchor buyers. To reduce the barriers posed by high collateral requirements, particularly for SMEs, state investment banks should increase their efforts to establish counter-guarantee programs. As growing PPA markets reduce the need for public price support schemes for renewable energy sources, such measures are likely to contribute to a long-term reduction in the fiscal costs of the green transition.

3. Harmonize energy taxation based on overarching climate policy goals

In addition to general carbon pricing, the optimal choice of abatement technologies in the manufacturing sector also requires a harmonized and undistorted design of taxes and other levies on energy sources. To this end, the currently stalled negotiations on the reform of the EU Energy Taxation Directive must finally be brought to a successful conclusion. As originally proposed by the Commission, the adopted version should include a significant spread between the minimum levels of taxation set for fossil fuels and those set for renewable heating fuels and electricity. In turn, Member States should implement the reform consistently, meaning that the actual tax rates on energy sources used in climate-friendly energy technologies are set close enough to the minimum tax rate to support their implementation. In particular, the ratio between the retail prices of gas and electricity should be a benchmark to ensure that the efficiency advantage of electricity-based solutions is sufficiently reflected. In addition, Member States should consider ways to reduce electricity network charges and other specific non-market price components of electricity. Such an approach would complement the incentive effects of the ETS-I and thus serve to reduce the political pressure to dilute its core function.

4. Perpetuate market conditional CISAF rules for price support

As many projections suggest, the structural problems in the European energy system will continue to result in high electricity prices compared to the rest of the world during the transition period.⁷² Under these conditions, incentivizing investments in electrification will require targeted fiscal support. In principle, such support can be justified on the basis that electrified industries facilitate the integration of renewables into the system. However, the effectiveness of this incentive must be weighed against the necessity of maintaining market price signals to efficiently manage electricity flows in a system characterized by infrastructure bottlenecks and national supply disparities. Failing to recognize this necessity would result in a lack of transparency regarding the role of capacity constraints, thereby preventing the development of any long-term solution to the price problem. Against this background, the Commission's approach of enabling Member States to provide limited, market-conditional price support (see Subsection 4.4) is fundamentally sound. However, to strengthen its focus on incentivizing economy-wide electrification investments, adjustments to the current framework are needed.

Firstly, the option to provide price support should not be limited to companies from sectors on the CEAAG list⁷³, i.e. sectors with high trade and electricity intensity. International competition is not the only economic barrier to investments in electrification, and the carbon leakage argument does not

⁷² Prognos/vbw (2024). [Electricity price forecasts](#).

⁷³ European Commission (2022c). Communication from the Commission – Guidelines on State aid for climate, environmental protection and energy 2022. C/2022/481.

justify discriminatory treatment with regard to energy bills. Secondly, to minimize the risk of disincentives, maximum support payments should ideally involve ex-ante elements, rather than being determined on a pure ex-post basis based on actual electricity consumption levels. For example, a calculation model could combine sector-specific reference values for electricity intensity with actual production volumes to create an artificial benchmark for electricity consumption. This would maintain incentives for improving efficiency and motivate investments that contribute the most to system management. Thirdly, the validity of the set rules should be extended to at least 2040, thus aligning with the EU's medium-term climate goals and reflecting the long-term capital commitment required for electrification investments.

5. Incentivize grid investments through revenue regulation and cost sharing instruments

Investments in grid expansion and modernization increase integration capacity for volatile renewable electricity, which has positive external effects for society. It strengthens the superregional and international integration of European electricity markets, enabling the efficient management of macroeconomic investments in electrification via electricity price signals. At the same time, it mitigates the risk of bottlenecks arising from naturally volatile electricity generation. Grid operators should be rewarded for this social contribution through incentives in the regulatory design of tariffs. National tariff systems across the EU should allow for the timely compensation of investment costs to mitigate liquidity risks of grid operators. Revenue incentives should be neutral with regard to financing structures and CAPEX/OPEX intensity of projects, to avoid distorting investment decision (e.g. too strong focus on CAPEX-intensive grid expansion). In addition, best practices should be examined to determine how the significant social benefits of investments that contribute to the elimination of grid bottlenecks could receive more weight in calculating revenue caps. One way to achieve this would be to incorporate output-based multipliers into the revenue cap calculation. As the costs of these subsidies are financed directly by consumers via network charges, it is important to use cost-sharing instruments in addition to this. These instruments should not be limited to strategic projects, such as PCIs or energy highways, but should, in principle, be available for all network-related investments. Government loan guarantees, in particular, are one way of partially absorbing the risks associated with long-term network investments. This type of private-public risk sharing has no immediate impact on public expenditures but is immediately effective in reducing project financing costs.

6. Establish joint merit-based prioritization schemes for grid connection requests

EU regulations stipulate that grid access must be granted in a non-discriminatory manner. However, within the EU-wide framework, grid access continues to be regulated very differently by the member states. According to the Commission's estimates, the 'first come, first served' principle still applies in the majority of Member States where there are connection queues. This is socially suboptimal, as the speed of grid connection is thus independent of the systemic or economy-wide benefits of the installations. The EU should go beyond the published guidance and set specific prioritization guidelines based on transparent criteria. To this end, a methodology should be developed that considers not only project maturity, but also the impact on grid bottlenecks and the contribution to policy objectives. Projects for the electrification of major industrial energy consumers should be granted specific priority. At the same time, the approach must be flexible enough to accommodate differences in local grid conditions. Additionally, member states should implement the flexible connection agreements introduced by the EU electricity market reform into national law to reduce connection waiting times.

6 Conclusion

The electrification of Europe's industries is important not only for reducing greenhouse gas emissions in manufacturing. It is also crucial for establishing new business models for renewable energy producers, freeing them from their dependence on long-term subsidies and volatile wholesale markets. This, in turn, is a prerequisite for ending dependence on fossil fuel imports, and thus Europe's exposure to global energy market turbulences. Hence, demand-side electrification, decarbonization and European energy sovereignty go hand in hand. However, this interdependence also means that all of these policy goals face the same barriers and risks.

In response to the Commission's announcement of an Electrification Action Plan, this cepInput analyses the economics and policy instruments of electrification from a risk management perspective. It conceptualizes prevailing market uncertainty as arising from three types of interdependent risk: resource, infrastructure and price risks. As they are largely rooted in the volatile nature of renewable energy supply, these risks are difficult to eliminate and therefore represent a significant investment barrier. When helping stakeholders deal with these risks, policymakers must strike a careful balance between public risk adoption and strengthening market signals for decentralized risk management activity. This requires a new approach of public-private risk balancing, as well as the promotion of markets for efficient risk sharing among private stakeholders.

Electricity forward markets and PPAs play a key role in managing price risks. However, liquidity and transparency in these markets are still impaired by market access barriers, and market volumes are distributed unevenly across Europe. In order to exploit the potential for cross-border hedging, the EU must adopt a more ambitious approach to align national market regulation frameworks. This should involve both a joint approach to eliminating technical barriers to cross-border trading of long-term contracts and a harmonized strategy to support market formation. Specifically, expenditure-neutral risk-sharing and scaling instruments such as counter-guarantees can be effective in creating liquid and competitive hedging markets.

Additional measures are required to cope with the difficult-to-hedge long-term costs resulting from the need to invest simultaneously in renewable energy supply, demand-side technologies and grids. Most importantly, the technical and financial barriers to expanding and modernizing grid infrastructure — the key bottleneck in matching renewable energy suppliers with industries — must be overcome. In this respect, achieving greater regulatory harmonization between Member States is crucial. Firstly, this concerns the revenue regulation of grid operators, particularly the need for a timely compensation of grid investment costs, which does not discriminate between financing or cost structure. Secondly, to manage grid connection queues, a harmonized, merit-based approach to allocating grid connection permits is needed. Finally, to maintain electrification incentives despite persistently high electricity prices, EU state aid rules should continue to grant Member States some degree of flexibility in providing public price compensation. To minimize disincentives, compensation limits should not discriminate between sectors, have an ex-ante component and provide planning security for the period at least up to 2040.

**Author:**

Dr. André Wolf

Head of Division “Technology, Infrastructure and Industrial Development”

wolf@cep.eu

Centre for European Politics FREIBURG | BERLIN

Kaiser-Joseph-Straße 266 | D-79098 Freiburg

Schiffbauerdamm 40 Room 4205 | D-10117 Berlin

Phone + 49 761 38693-0

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