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Achieving the EU's Energy Ambitions:

What Energy Market Can Weather the Transitions?

POLICY PAPER PART 3 - JULY 2026

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POLICY PAPER - July 2026

Achieving the EU's Energy Ambitions:

What Energy Market Can Weather the Transitions?

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Foreword

Deepening the common energy market is a core objective of the Von der Leyen II Commission. This technical note concludes a series of three studies by Institut Montaigne on the issue. The first looked at the European governance framework, and the second focused on infrastructure. This third installment addresses the structure of the electricity market—specifically, the rules that finance producers and allocate electricity among European consumers.

The current market architecture is under severe strain. It fails to coordinate efforts between Member States, places a growing burden on their public finances, and lacks transparency in its decarbonization pathways. The critical nature of these new economic and security challenges has prompted us to propose several remedies:

- Europeanizing security of supply to lower the costs of blackout prevention policies, which are currently managed strictly at the national level.
- Strengthening private investment in low-carbon energy (both nuclear and renewables).
- Introducing a new consumer offering that enables tracking the origin of energy and better adapts to evolving usage patterns.

These solutions extend far beyond market mechanics alone. At a time when access to fossil fuels is once again becoming uncertain and conditional, Europe's ability to produce abundant and competitive electricity underpins its strategic autonomy and prosperity. It is absolutely essential to Europe's capacity for low-carbon reindustrialization.

As currently structured, the European electricity market lacks coherence. The following note provides policymakers and regulators with an operational roadmap to move forward in a concrete and responsible manner.

Marie-Pierre de Bailliencourt,
Institut Montaigne's Managing Director

Executive Summary

Against the backdrop of an international context in which control over energy costs and reliability has once again become a dimension of power, Europe faces a crisis of competitiveness closely linked to its energy supply. Disruptions such as aggressive industrial policies on the part of the United States, Chinese overcapacity in clean technologies, fragile supply chains, the end of deliveries of Russian gas by pipeline, and hydrocarbon supply tensions following the blockades in the Strait of Hormuz… These disruptions require the Union to achieve a dual objective: On the one hand, decarbonizing its economy—meaning the de-fossilization of its energy systems in tandem with the transition of energy uses—and, on the other hand, preserving its industrial base. This is the third and final policy brief in a series of three dedicated to the energy agenda of Ursula von der Leyen's second term as president of the European Commission, following a first issue on energy–climate governance and a second on infrastructure. It focuses on the internal energy market, which is one of the pillars of the energy union. That is, it examines the rules by which producers and consumers exchange energy—and particularly electricity—sign contracts, and finance their investments.

A MARKET FRAMEWORK WITH SOUND FOUNDATIONS—BUT WITH RULES THAT ARE NO LONGER FIT FOR PURPOSE

The architecture of Europe's energy markets, which was inherited from the liberalization of the 1990s and 2000s, rests on three well-established principles: The establishment of wholesale markets where spot prices are determined by marginal costs (i.e., the price is set at the production cost of the last unit called upon to meet demand); the separation of network activities (which are operated by regulated monopolies) from generation and supply activities (which are competitive); and independent regulation of network operators. These principles represent the direct application of neoclassical economic theory to a commodity whose supply–demand balance must be maintained in real time to ensure the physical integrity of the system.

However, a profound transformation of the electricity mix is putting these foundations under strain. The lawmakers behind the successive energy packages from 1996 to 2018 did not fully anticipate the extent of the impact of variable renewable energy sources (such as wind and solar power), which are giving rise to repeated occurrences of negative prices, cannibalization of market value during periods of high output, increased intraday volatility, and erosion of the long-term signals needed for capital-intensive investments. In particular, the occurrence of negative prices reflects an oversupply of generation bidding at negative prices. This calls for a two-pronged approach: Better supply scheduling (see action policy paper No. 1) and the efficient operation of zero-marginal-cost assets, ensuring that public support mechanisms no longer incentivize 'produce-at-all-costs' behavior (see action policy paper No. 2). The Electricity Market Design (EMD), adopted in June 2024, laid useful initial groundwork in terms of providing for the widespread adoption of two-way contracts for difference (CfDs) for new public support schemes, encouragement of long-term power purchase agreements (PPAs), and initial provisions on flexibility—but largely remains to be put into action. This policy brief charts the path still to be traveled. It is structured around three key axes and eleven concrete proposals.

AXIS ONE: FINANCING DECARBONIZATION AT MINIMUM COST TO THE PUBLIC

Decarbonized energy technologies (i.e., renewables and nuclear power) all have one thing in common: Although they are capital intensive, they operate at a very low marginal cost. Therefore, to deploy efficiently, project developers need to be able to forecast revenue over the long term in order to access the cheapest possible capital. This can be made possible through revenue top-ups (contracts for difference, or **CfDs**—that is, contracts by which the state guarantees a price for the output of generation assets) and bilateral contracts (power purchase agreements, or **PPAs**—that is, long-term purchase contracts between a producer and a private consumer without public intervention). Although public support schemes (feed-in tariffs and CfDs) have enabled the massive deployment of renewable capacity over the past decade, their widespread adoption raises concerns regarding fiscal sustainability (between €113 billion and €167 billion in commitments taken on by France through end-2024 depending on the price scenario assumed) and the need to start transitioning toward a framework in which private counterparties will progressively take over.

Several levers are available to address these concerns. European standardization of PPAs (Proposal 1) would establish a liquid market for long-term hedging instruments. Mixed CfD–PPA auctions using a "proportional allocation" method (Proposal 2) would reduce the cost to public finances while automatically phasing out support once it is no longer needed by allowing project developers to bid only a part of their output for a CfD and to place the rest through a PPA. A European counterparty risk guarantee for PPAs (Proposal 3) would homogenize the cost of capital across public and private contracts. Auctioning synthetic hedging instruments to consumers (Proposal 4) would allow Member States to remove their historical public support commitments from the budget. Finally, clarifying the treatment of existing assets whose operating life has been extended—such as Belgian nuclear plants, hydropower facilities, and repowered wind farms—at a portfolio level rather than an installation-by-installation basis (Proposal 5) would avoid destroying economic value by forcing unnecessarily separate contracts.

AXIS TWO: ALIGNING PRICE SIGNALS WITH THE PHYSICAL CONSTRAINTS OF THE SYSTEM

Decarbonization is not just a question of deploying low-carbon generating capacity; it is also vital to foster the flexibility needed to economically absorb an increasingly variable electricity supply. However, current economic signals, along with the design flaws of legacy public support mechanisms (see action policy paper No. 2) largely fail to reflect these dynamics. Therefore, there are three reform areas that must be addressed.

Once the incentives to bid at all costs have been eliminated, the first challenge concerns **guarantees of origin** (GOs)—that is, certificates that supposedly make it possible to trace the renewable origin of electricity consumed. The system for GOs suffers from two major flaws. First, due to an oversupplied market (notably from Nordic hydroelectric production sold to consumers in continental Europe regardless of whether it is physically possible for capacity to be interconnected), the clearing price is below €2/MWh—providing renewable producers with next to no additional revenue beyond the price of the electricity itself. Second, GOs are currently subject to a twelve-month rolling validity period that creates virtual storage without a physical counterpart, making them an instrument of greenwashing at the expense of the electricity system. Proposals 6, 7, and 8 form an inseparable package aimed at transforming GOs into a robust traceability tool by restricting cross-border trading to booked interconnection capacity, introducing a European obligation to generate certificates for all electricity production (renewable, nuclear, or fossil), and moving to an hourly level of granularity, paired with a ban on cherry-picking only the cheapest hours for renewable claims.

The second area of reform concerns **network tariffs** (Proposal 10), which account for approximately one-third of household electricity bills. Too often flat, weakly differentiated (as in Germany), or frozen in time (as in France), they no longer send the price signals needed to incentivize demand flexibility. To properly value demand shifting and electricity storage, a systematic and regularly revised time-of-use tariff structure is indispensable.

The third reform area concerns **forward products** of electricity (Proposal 11), which are currently structured around two overly broad time bands ("base load," covering the full 24 hours, and "peak load," from 8 a.m. to 8 p.m.), preventing suppliers from designing offers that truly incentivize flexibility. Dividing the day into four homogeneous periods (morning, afternoon, early evening, and night) would better reflect expected price variations to consumers.

AXIS THREE: EUROPEANIZING SECURITY OF SUPPLY

As fossil fuel plants—which obviously have higher operating costs and thus set high prices for the entire market via marginal cost pricing—are wound down and spot prices for electricity go into a structural decline in a mix dominated by low-marginal-cost producers, the energy market alone is even less capable than before of financing the capacity needed to ensure security of supply by itself. Therefore, capacity mechanisms, which pay for availability rather than energy produced alone, are becoming structurally essential. The recent convergence of major Member States (France, Poland, Belgium, and now Germany) around centralized market-wide mechanisms opens an unprecedented window to take further steps toward harmonization (Proposal 9). Achieving this will require four things: Writing capacity mechanisms permanently into the core rules of the European electricity market rather than approving them case by case as state subsidies; ruling out "strategic reserve" schemes for good, as they are distortionary and keep fossil fuel plants running that would otherwise close; agreeing on one common standard for certifying capacity across countries; and fully linking national capacity markets so that capacity in one country can help meet demand in another, since this principle is legally mandated.

A POLITICAL OPPORTUNITY—GROUNDED IN TECHNOLOGICAL NEUTRALITY

The eleven proposals in this policy paper constitute a coherent package, not a catalog of isolated measures. Financing the transition, aligning price signals with the physical realities of the system, Europeanizing security of supply—removing any one of these building blocks weakens the others.

The twenty-seven Member States seem to be converging toward shared conclusions: The need to mobilize private capital alongside public support; the urgency of securing supply in the face of hydrocarbon disruptions and geopolitical tensions; and the growing recognition that current price signals no longer reflect the physical reality of electricity systems.

The European Commission must seize this opportunity and champion these reforms. Aligning our energy systems with the Union's climate and industrial ambitions is the political responsibility of Ursula von der Leyen's second term as president of the European Commission.

Summary of Proposals

Recommendation 1
Establish a Common Contractual Framework at the European Level for Long-Term Energy Procurement.

Require the European Union Agency for the Cooperation of Energy Regulators (ACER) to set general contractual clauses for standardized financial PPA models in each price zone of the Union, with the support of national regulators where required by the specificities of national contract law, while ensuring EU-wide consistency in their overall structure—on the understanding that energy system participants would remain free to use these standard products or not, depending on the risk profiles they deem suited to their own situations.

Require Nominated Electricity Market Operators platforms (NEMOs) to create dedicated market segments for trading these standard contracts under three product types:

- Settlement of the difference between the contract *strike price* and the spot market reference price for the average photovoltaic profile in the delivery zone over the year preceding delivery commencement.
- Settlement of the difference between the contract *strike price* and the spot market reference price for the average onshore wind profile of the delivery zone over the year preceding delivery commencement.
- Settlement of the difference between the contract *strike price* and the spot market reference price for a flat profile over the year preceding delivery commencement.

Recommendation 2

Reduce the Cost to Public Finances of Supporting Decarbonized Energy Deployment Through Proportional Method Auctions.

Make mixed two-way auctions using the "proportional method" the default support mechanism for decarbonized technologies (wind, solar, run-of-river hydro, geothermal, and nuclear power), and make the "tranche method" option available for certain technologies (notably offshore wind) or make it mandatory under a revision of Article 19d of the Electricity Market Design (EMD).

Allow participation in CfD auctions to include stationary batteries behind the meter, as well as any grouping of production installations and batteries, whether behind the meter or at another location. For this to work, revenue top-up mechanisms must be reformed to anchor them not to physical output but to a normative potential output volume.

Recommendation 3

Position the European Union as the Guarantor of Counterparties to Long-Term Contracts.

Establish a European counterparty risk guarantee scheme for PPAs associated with new decarbonized energy projects in Europe, replacing national schemes. At a minimum, all industrial consumers should be eligible.

Recommendation 4
Authorize Member States to Mobilize Publicly Supported Installations to Issue Long-Term Consumer-Oriented Contracts.

Authorize Member States to issue synthetic hedges symmetric to their outstanding public support commitments, within the volume limits of the supported production installations, either through ascending auctions (on the upfront payment) or descending auctions (on the hedge strike price), and to move their outstanding public support commitments off budget.

Recommendation 5
Apply Support Measures to Existing Installations at the Fleet—Not the Individual Installation—Level.

Clarify in sector-specific law that when two-way CfDs are applied to an existing asset, they may cover the full output of a fleet of operationally co-optimized interdependent installations at a strike price corresponding to full production costs, including depreciation and remuneration of the net book value (NBV) at a weighted average cost of capital (WACC) determined by the independent regulator.

Recommendation 6

Reform the Supply of Guarantees of Origin to Better Reflect the Associated Physical Production.

Such a reform would require cross-border trading in electricity GOs to be limited to booked interconnection capacity.

Recommendation 7

Improve Transparency in the Supply of Guarantees of Origin.

To this end, make the issuance of electricity GOs—whether of renewable, nuclear, or fossil origin—as well as their transfer to the final consumer mandatory at the European level. To avoid double-compensating power plants that already receive public support, electricity GOs must be taken into account in electricity revenue top-up mechanisms.

The **life-cycle carbon intensity** of electricity produced must also be included in the information contained in GOs.

Recommendation 8

Align Guarantee of Origin Requirements with Real-time Physical Production to Ensure the Credibility of Demand.

Change, without delay, the validity period of GOs, which is currently twelve months, to the calendar year in which the electricity was generated, thereby ending the accumulation of GOs on the market.

At the same time, announce a timeline for progressively reducing the period over which GOs can certify production, down to an hourly or sub-hourly granularity.

To prevent contracts that only certify the origin of electricity during periods of high generation (i.e., when GO prices are low), ban supply contracts that provide only partial guarantee-of-origin coverage. In other words, the energy sources claimed by a supplier (if it chooses to incorporate GO criteria in its offer) must cover 100 percent of the customer's consumption at all times.

Deterrent penalties (i.e., exceeding the cost of purchasing GOs when renewable generation—and thus GO supply—is scarcest) must be established at the national level against suppliers unable to present their customers with a contractually guaranteed GO.

Recommendation 9

Harmonize the European Capacity Market.

Introduce the principle of capacity mechanisms as an integral part of the European market framework, at a minimum across Europe excluding Scandinavia, by establishing an *ad hoc* framework in a future revision of Regulation 2019/943 and by regulating capacity mechanisms' operating principles in a dedicated network code entrusted to ACER on a joint proposal from the national Transmission System Operators (TSOs).

At the same time, definitively rule out the possibility of using strategic reserves for generation capacity, as they are liable, under the current legislation, to artificially keep fossil fuel capacity in operation and create implicit distortions in energy price formation.

To establish such a market, it is necessary to do the following:

- Require Member States, for each bidding zone in the European system (at a minimum, continental Europe), to define their security-of-supply objective (loss-of-load expectation) and their system's peak hours, according to a public, transparent, and non-discriminatory methodology.
- Establish a harmonized capacity certification methodology and a European capacity registry, operating at a minimum at the daily time step (and eventually quarter-hourly), which is technologically neutral and open to all generation or explicit demand-response capacities.
- Provide for explicit, systematized cross-border participation in the European capacity mechanism through full coupling of local capacity markets.

Recommendation 10

Adapt Network Tariffs to New Uses.

Require Member States to establish a time-of-day and seasonal structure for electricity-network tariffs. This pricing should be differentiated between injection and withdrawal, since the incentives are a priori opposite: During periods of local overproduction, withdrawal should be encouraged and injection discouraged, and vice versa. The pricing should also be adapted to the relevant territory.

Tariffs must also be regularly revised to best reflect the needs of the electrical system, independently of any political considerations or conservatism regarding previously applicable tariffs.

Recommendation 11

Rethink Market Products to Adapt to New Generation Modes and Encourage New Consumption Patterns.

Revise the hourly breakdown of electricity forward products, ensuring that the new products taken together cover the entire day and correspond to broadly homogeneous states of the electrical system (i.e., morning, afternoon, early evening, and night).

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Introduction

This policy paper is the third and final installment of a series of three devoted to the energy challenges facing Ursula von der Leyen's second term as president of the European Commission. The first part, published in November 2024, started from the observation that the pathway to carbon neutrality by 2050—and even more so the intermediate milestones in 2030 and 2040—required a thorough overhaul of the Union's energy–climate governance framework to overcome institutional and political blockages, making the case for reorienting objectives around the carbon intensity of final energy rather than the renewable share alone. The second installment, extending this analysis, examined the concrete conditions for transforming the European energy system into a real asset, proposing the contours of a European Energy Security Act capable of securing, in a technologically neutral manner, the deployment and financing of low-carbon energy production capacity and the networks that must accompany them. This third brief closes the trilogy by focusing on one of the energy union's pillars: Markets.

Europe today faces a crisis of competitiveness linked in no small part to its energy supply. In light of the resurgence of aggressive industrial policies on the part of the United States, massive Chinese overcapacity in clean technologies, persistent fragility of critical raw material supply chains, and geopolitical tensions that threaten the supply of fossil fuels, reforming our markets is structurally essential in an international system in which energy competitiveness has become a dimension of power.

As the physical foundations of our energy supply (and, in particular, our electricity supply) evolve, the current market architecture is struggling to keep pace. The growing share of variable renewable energy in the European electricity mix has given rise to—or amplified—phenomena that the lawmakers behind the liberalization of the 1990s and 2000s did not anticipate would reach these levels:

- repeated occurrences of negative prices;
- progressive cannibalization of the market value of solar and wind output during periods of high production;
- increased intraday price volatility and erosion of the long-term signals needed for capital-intensive investments.

The Electricity Market Design (EMD) adopted in June 2024 laid useful initial groundwork, but there is still a long way to go. This brief proposes to chart the path still to be traveled. It is organized into five parts:

1. The first part provides **the necessary educational grounding in how electricity and gas markets work**, their structure as inherited from successive energy packages, and the special treatment accorded to large industrial consumers.
2. The second part examines **contracts for low-carbon electricity procurement**, notably the interplay between revenue top-up contracts (CfDs) and long-term purchase contracts (PPAs), and proposes an operational framework for the mixed auctions promoted by the EMD Regulation as well as Union-level standardization.
3. The third part explores **hedging for consumers**, who are equally in need of long-term price stability to justify their investments in electrified solutions.
4. The fourth part concerns the **reform of electricity GOs** as an instrument of traceability, supplementary financing, and flexibility management.
5. The fifth and final part addresses **security of supply**, capacity mechanisms, and their regionalization at the European scale, as well as time-based price signals, which are needed to allow the electricity system to absorb the growing variability of its production economically.

Governance, infrastructure, markets: This triptych will define the European energy agenda for the years ahead. The quality of work carried out simultaneously on all three fronts will determine the Union's ability to meet its climate commitments without sacrificing its economic competitiveness or political cohesion.

1 Educational Background: How Energy Markets Work

1.1. THE ELECTRICITY MARKET AND MARGINAL COST PRICING

Electricity is legally classified as tangible personal property. It is treated in the same manner as any other commodity—it is covered, in particular, by the principle of free movement within the European internal market.

However, electricity has particular characteristics. For physical reasons, it is necessary to ensure that at any given moment, as much electricity is produced and injected into the grid as is withdrawn from the grid and consumed. Indeed, a frequency of 50 hertz—that is, 50 cycles per second—must be maintained on the grid: If less power is injected than is drawn, the frequency will drop, and if more power is injected than is drawn, the frequency will rise.

From an economic standpoint, this also leads electricity price formation to exhibit properties that are not always intuitive, even though they reflect exactly the same operating rules as any other market. For electricity, as for any other product, the price is formed by the intersection of the following:

- **A demand curve**, which gives, for each price level, the volume of electricity that consumers (or their suppliers) are willing to buy at that price or lower. In practice, the volume demanded is almost constant as a function of price because in the short term, consumers have already largely decided on the quantity of electricity they will need and have little room to adjust their demand based on price. More broadly, **they have neither the full economic incentives**

nor the habit of varying their consumption in the short term based on market price, even though price signals already exist in some Member States, and new, power-intensive end-uses (such as electric vehicle charging) could drive a shift in this regard to take advantage of off-peak hours. In a more structural sense (outside the short term), however, consumption can be linked to the price of electricity in situations of energy poverty (e.g., households that turn on the heating rarely or not at all to reduce their bills).

- **A supply curve** (supply curve of merit order), which gives, for each price level, the volume of electricity ready to be offered at that price or lower on the market. In practice, for each power plant capable of producing, we look at its marginal cost—that is, the cost, given that this plant is running and available, of producing one additional unit of electrical energy (1 MWh). This marginal cost includes the fuel costs necessary for the production of this electricity, maintenance charges proportional to output, and, for fossil generation, the cost of CO2 emission allowances on the European carbon market. Marginal cost is used, rather than a full-cost approach—which would include the depreciation of capital and the remuneration of that capital at a normal return, as well as fixed costs such as staffing—**because, as soon as the price exceeds the marginal cost, it becomes more advantageous to produce than not to produce**; any positive margin, even a small one, can be captured and then contributes to covering total costs.

The intersection of these two curves occurs at a price and volume such that all producers agree to produce at that price and volume, and all consumers agree to purchase it. As some producers would have been willing to produce more cheaply, they thus capture a margin that allows them to cover their fixed costs, notably to depreciate their capital and compensate their financiers. **The main advantage of this optimization is that it determines, at each moment, which power plants should generate to meet demand at the lowest cost**

to consumers. Moreover, it has been employed in the electricity sector for precisely this reason, including by the historical national monopolies prior to the 1996 liberalization.

Box 1: A Brief History of Marginal Cost Pricing

Economic theory established this principle of price formation according to the marginal cost at the end of the nineteenth century, a moment that constituted the second Copernican Revolution in the history of economic thought after Adam Smith—namely, the *marginalist revolution* (the work of L. Walras in France, around the theory of general equilibrium, and the work of C. Menger and E. von Böhm Bawerk within the First Vienna School). Its application to electricity dates from 1956 and the early articles of Marcel Boiteux.[1] It has been demonstrated in particular that under assumptions of market efficiency, specifically under perfect competition, perfect information, and in the absence of external price distortions, this approach leads to the exact recovery of fixed costs over the long term and to the maintenance of a generation portfolio adapted to the structure of demand. **This principle of marginal cost pricing is therefore in no way an "absurdity" or something "imposed by Brussels" but rather a practical necessity that originates from the most fundamental premises of economic theory**.

[1] *Marcel Boiteux, "La vente au coût marginal" [Selling at marginal cost], Bulletin de l'Association Suisse des Electriciens 47, no. 24 (1956).*

Moreover, this approach is no different from that applied to any other product. For example, for oil, aluminum, or wheat, the price for a delivery at any given moment is determined by the intersection of a demand curve, representing the volume of demand existing for each price level, and a supply curve, representing total output offered at a price at least equal to a certain level. As with electricity, the supply curve is established with reference to the marginal cost of production: Crude oil, aluminum, or wheat are not offered by their production units at a price equal to their average cost but at a price equal to their marginal cost. Thus, the price of oil for all barrels traded on the Brent market is set by the marginal cost of the most expensive production unit still needed to meet demand at a given moment. All cheaper units—for example, Middle Eastern fields exporting to Europe—thereby earn a margin per barrel that covers their fixed costs, remunerates their shareholders, and contributes to depreciating their assets.

If Electricity Were a Hotel Night...

To illustrate this with an analogy, consider a city with three hotels—A, B, and C—each with 50 rooms. The hotels' marginal costs of preparing a room and accommodating a guest are €60, €80, and €100 per night, respectively. We also assume that these hotel stays are perfectly substitutable—that is, that all three hotels are of the same quality.

- On some days—for example, during the week—demand amounts to only 30 room-nights: Only Hotel A operates, filling 60 percent of its rooms, while Hotels B and C remain empty. The price of a room is therefore €60.

- On other nights—for example, an ordinary Saturday—demand is higher, at 80 room-nights. Hotel A is fully booked, while Hotel B fills 60 percent of its rooms. The price of every room is then €80. Hotel A therefore earns a profit of €1,000, corresponding to €20 per room.

- Finally, on some evenings—during a trade show or a major event—demand at a price of €100/night exceeds 150 room-nights. The hotels will then charge the highest room price at which demand is still 150 room-nights. This results in a significantly higher price—for example, €200 per night—allowing all three hotels to earn a margin and cover their fixed costs.

For electricity, since supply and demand must be balanced at every instant, the supply and demand curves must be defined for each moment—in practice, for each quarter-hour time step. **This equilibrium must account for the following average orders of magnitude for the marginal cost of different types of power plants**:

- **Solar, wind: €0/MWh** (producing one additional MWh incurs no extra cost on an already-existing wind or solar farm);
- **Hydroelectric, nuclear: €5–20/MWh** (producing one additional MWh costs almost nothing, but it is necessary to consider the "opportunity cost" of having less nuclear fuel or reservoir water available to generate at a later time in place of another, often thermal, power plant. This results in a low but strictly positive marginal cost, which depends on the cost of that thermal plant);
- **Gas: €80/MWh**;[2]
- **Coal: €120/MWh**;[3]
- **Oil-fired power plants, peaking plants, biomass: €150/MWh and above**.

This causes the short-term electricity price to fluctuate between these different values, depending on whether the most expensive plant required to meet demand is a solar or a wind facility, a hydropower or a nuclear plant, or a thermal power plant. **This effect causes the electricity price in France, during certain hours, to depend on the price of natural gas. This may seem counterintuitive, since natural gas accounts for only a small share of total electricity generation** (3.2 percent in 2024), **but it is logical** as gas-fired plants are more often the last plants needed to meet demand (9 percent of the time in 2024) or, through their "use value," help determine the selling price of hydropower (45 percent of hours but only 13 percent of production). Overall, gas generation directly or indirectly determined prices during 54 percent of hours in 2024. **More fundamentally, during these hours,**

[2] At 2025 market prices of €28/MWh for natural gas plus €80/t for greenhouse-gas emissions.
[3] At 2025 market prices of €140/t for coal plus €80/t for greenhouse-gas emissions.

plants with lower marginal costs—most notably the nuclear fleet—benefit from inframarginal rents that enable them to recoup their investments and provide a return to their shareholders.

Finally, the electricity market does not operate solely within national borders. Two connected electrical systems can exchange electricity. This is notably the case between France and its various neighbors: For instance in 2023, France could export 9.2 GW—equivalent to 9,200 MWh per hour—and import 10.7 GW from Germany and Belgium. In practice, the method used to determine the price remains the same, except that prices are first calculated on either side of the border **in order to then calculate the volume transferred from the cheaper country to the more expensive one**, thus ensuring price equalization between the two countries or saturating the transmission capacity of the interconnection.

In France in 2024, cross-border interconnectors provided the most expensive supply that contributes to meeting demand for approximately 9.2 percent of hours. Overall, a French or foreign fossil fuel plant thus "sets the price" on the French market, directly or indirectly, 63 percent of the time.

This reflects the economic reality of the system, namely that the nuclear and renewable fleet cannot fully cover all demand at all hours—it exports during certain hours, but during others, it must be supplemented. This method of price formation is therefore necessary from the physical standpoint of security of supply. It is also an economic necessity since it makes it possible to cover the fixed costs of the French generation fleet and thus to contribute to its long-term economic balance.

The limit of this system is thus apparent: The more electricity is produced almost exclusively by sources with low marginal costs, such as nuclear power or renewables, the more uncertain their profitability becomes, and the more it depends on the hours during which fossil fuel plants are marginal. Indeed, these technologies are very expensive to build but inexpensive to operate. Yet, without more expensive plants (such as gas-fired power plants) to regularly push market prices upward, the revenue generated by electricity sales may become insufficient to cover the substantial initial investment costs.

As will be seen below, the marginal cost pricing mechanism is very effective at determining which plants should be dispatched at any given moment. However, in an electricity system increasingly dominated by generation technologies with low operating costs, such as nuclear power and renewables, the existence of information asymmetries or uncertain horizons means that this mechanism is no longer sufficient to ensure adequate returns on investment. It must therefore be supplemented by other mechanisms to guarantee the profitability and financing of generation capacity as fossil fuel plants with high variable costs gradually disappear from the system.

In practice, consumers do not purchase electricity on an hour-by-hour basis. They need advance visibility over their supply costs in order to plan their budgets and investments. Similarly, producers may wish to limit their exposure to short-term electricity prices. To provide producers and consumers with this security, the market also offers forward products. These products allow a producer and a consumer to agree on a price for electricity over a specified future period. For example, a product providing for the delivery of 1 MWh in every hour of 2026 is known as the 2026 base load calendar product—which was trading at approximately €50.50/MWh on November 24, 2025. A consumer purchasing this product will receive 1 MWh every hour in exchange for a payment of €50.50/MWh. This future market therefore arises spontaneously from the need for buyers and sellers to secure their revenues in advance, and it is no coincidence that futures markets for agricultural commodities emerged as early as the 17th century.

The price of these forward products is determined by comparison with the alternative of purchasing 1 MWh on the short-term market during every hour of 2026. It therefore reflects market participants' best estimate of the marginal cost of each electricity generation technology in 2026, weighted by the number of hours during which each technology is expected to be marginal.

If Electricity Were a Hotel Night...

Returning to the analogy of a city and its hotels, a calendar year forward contract would be equivalent to a customer purchasing a subscription entitling them to one hotel night on every day of the coming year. The price of this subscription would therefore correspond to the average price of a hotel night over the coming year—or, equivalently, to the marginal price of a night in each hotel, weighted by the number of hours during which each hotel is expected to set the price.

In France, for example, fossil fuel plants are expected to set the price for approximately 60 percent of 2026, at around €80/MWh, while nuclear plants are expected to set it for approximately 40 percent, at around €8–10/MWh. This results in a price of approximately €50.50/MWh.

In Germany, fossil fuel plants play a far more dominant role in setting the price of the same electricity product, resulting in a price of approximately €88/MWh on the same date for the same delivery period.

Far from being a disadvantage to the French system in the current climate, this approach currently produces a difference of almost 80 percent between electricity prices in France and Germany. It also

allows French nuclear producers to export their output on favorable terms once the needs of French consumers have been met.

Conversely, in an exceptional year such as 2022, part of the nuclear fleet was unavailable for maintenance following the detection of indications of stress corrosion cracking, and gas prices were exceptionally high. The combination of these two developments worked against French consumers: France became structurally dependent on imports and was therefore supplied at prices set by the most expensive generation in neighboring countries. This situation was primarily caused by the shortfall in domestic generation. In a scenario in which nuclear generation had remained at its usual level—around 360–370 TWh—France would have remained a structural net exporter; EDF would have earned a profit of several tens of billions of euros, paid by neighboring countries in exchange for the energy they required; and French consumers would have been the only consumers in Europe to benefit from electricity prices decoupled from fossil fuel prices.

1.2. SECURITY OF SUPPLY AND CAPACITY MECHANISMS

The price of electricity is set, at any given time, by the marginal cost of the last power plant needed to meet demand, known as the marginal plant or by the consumer's marginal willingness to pay (when all plants are operating at full capacity). In theory, in a perfectly competitive market in which all market participants have the same information and correctly anticipate long-term prices, this mechanism makes it possible, over the long term, to cover the costs of the different power plants and to ensure a generation fleet suited to consumption needs.

During peaks in consumption, it may happen that the available generation is no longer sufficient to cover all demand. The network operator must then maintain the grid frequency at 50 Hz at all costs. If it falls too sharply, certain power plants will automatically disconnect from the grid in order to protect themselves, further worsening the imbalance and potentially causing a loss of grid control.

To guard against this risk, the network operator has "exceptional measures" at its disposal. These consist first of calling on willing—and remunerated—industrial consumers to be disconnected in an emergency, then of slightly reducing the voltage of the network, and, as a last resort, carrying out rotating load shedding—that is, switching off the system's delivery points in turn.

In theory, when there is not enough electricity to meet all demand, market prices can reach extremely high levels. The idea is that each additional MWh generated makes it possible to avoid power cuts and the economic damage that accompanies them. The cost to society of electricity not supplied—known as the Value of Lost Load, or VOLL—is often estimated at around €20,000/MWh.

In a perfectly functioning market, these very high prices are supposed to encourage investors to build new generation capacity. If a few hours of extreme prices are sufficient to cover the construction costs of a power plant, new projects should theoretically emerge.

In practice, this mechanism functions imperfectly. Building a power plant takes several years and represents a risky investment, especially for installations that will operate for only a few hours per year, and, in practice, the extreme volatility of revenues makes such a project unbankable. Investors do not have perfect information about future revenues. Moreover, in Europe, electricity prices are capped at €4,000/MWh on wholesale markets, which significantly limits the potential profitability of this type of asset.

In the absence of any public regulation, fixed costs are covered for all power plants only if the fleet of generation installations is configured appropriately—that is, if there is the right amount of each technology. This condition is equivalent to saying that for each power plant, fixed costs are equal to the margin captured between the marginal cost of generation and the price obtained on the market during the hours in which that plant contributed to supplying the system, known as the inframarginal rent. In theory, in the absence of constraints on the creation of new generation capacity, if this rent exceeds fixed costs on a lasting basis, these gains will make it possible to develop new power plants until the point at which, for that electricity generation technology, fixed costs are exactly covered by the inframarginal rent. Conversely, if fixed costs exceed this margin on a lasting basis, the plant will not be profitable and will eventually close. The structure of the generation fleet therefore evolves: Plants that are unable to cover their fixed costs will reduce their generation capacity, while those that earn more than is required to cover their fixed costs will expand their capacity. **Over the long term, a stable equilibrium is achieved with a fleet in which fixed costs are exactly covered by market revenues**.

In theory, an unregulated electricity market can ensure the long-term equilibrium of the system. When certain power plants earn substantial profits because of the difference between their generation costs and the market price—known as "inframarginal rents"—this creates an incentive to build new, similar capacity. Conversely, plants that are no longer able to cover their fixed costs eventually close.

This mechanism is supposed to gradually move the electricity fleet toward an equilibrium in which the most profitable technologies expand while the less competitive ones disappear. In theory, the system therefore ultimately reaches a situation in which market revenues exactly cover the fixed costs of the different installations.

This reasoning is, of course, theoretical. In practice, closing or building a power plant is not an insignificant decision from an industrial, regulatory, or social perspective; it takes a great deal of time and requires substantial visibility into medium-term electricity prices. **Therefore, the generation fleet is never perfectly calibrated to demand**.

If Electricity Were a Hotel Night...

As an explanatory analogy, consider a city with three hotels, A, B, and C, each with 50 rooms, for which the marginal cost of preparing a room and accommodating a guest is €60 per night, €80 per night, and €100 per night, respectively. We further assume that these overnight stays are perfectly substitutable, meaning that the three hotels are of the same quality.

When demand for overnight stays is very high—for example, 200 overnight stays during a trade fair—the price may rise to a high level. First, some customers will decide not to travel to the city, and the price will therefore be set at the level at which enough customers withdraw for demand for accommodation to equal exactly 150 rooms. If demand is even higher, however, the price will theoretically be set at the "societal cost of having been unable to accommodate one person," reflecting the losses resulting from the trade fair's failure to reach its expected level of attendance—say, €1,000 per person not accommodated.

If the hotel owners see this type of event recur—for example, one night per year over five years—they will compare the cost of expanding their hotels with the gains associated with the customers they could thereby accommodate, which amount to €940, €920, and €900, respectively, per additional room per year.

If creating a new room costs Hotel A €1,500 per room per year, Hotel B €1,200 per room per year, and Hotel C €800 per room per year, Hotel C will therefore determine that it is worthwhile to build a new room.

Conversely, if there are never any days on which demand exceeds 150 overnight stays, Hotel C will never earn a margin. It covers its marginal costs when it accommodates guests, but only just, and does not cover its fixed costs, particularly the depreciation of the hotel and the remuneration of its shareholders or lenders. It will therefore have to reconsider its offering, for example, by permanently closing one floor, in order to reduce its supply together with its fixed costs.

It is through this process that the market will determine a new form of the "appropriate fleet" of hotels that is better able to meet demand.

The operation of the market alone therefore cannot guarantee compliance with an administratively determined level of security of supply—that is, it cannot guarantee in advance that all existing power plants will be able to meet demand except during a predefined number of hours of system stress. In order to guarantee consumers a certain level of service quality, France has set a security-of-supply objective whereby "the average annual duration of supply failure is less than three hours."[4] This figure of three hours follows a theoretical logic: It ensures equality between €60,000/MW (the estimated annual cost of

[4] *Code de l'énergie [Energy Code], art. D. 141-12-6, https://www.legifrance.gouv.fr/codes/article_lc/LEGIARTI000044622322; Arrêté du 5 août 2022 relatif au critère de sécurité d'approvisionnement électrique mentionné à l'article L. 141-7 du code de l'énergie [Order of August 5, 2022 on the electricity security-of-supply criterion referred to in Article L. 141-7 of the Energy Code], https://www.legifrance.gouv.fr/jorf/id/JORFARTI000046180402.*

building and maintaining a new gas-fired peaking plant) and remuneration of €20,000/MWh over three hours.

Public regulation is necessary to ensure compliance with this criterion. It is based on the establishment of a capacity mechanism, which will operate under a centralized model from 2026. Under this mechanism, RTE—the electricity transmission system operator—defines the total volume of generation capacity needed to cover requirements during peaks in consumption. An auction is then held in which plants capable of being available during peak hours offer availability guarantees at a price expressed in €/MW. The least expensive plants needed to cover the total requirement are selected and remunerated at the highest price offered by the last plant selected. The cost of the capacity mechanism is then recovered from consumers through a dedicated levy, adjusted according to their own consumption during peak periods. Similar mechanisms are in place in many Member States of the European Union, particularly Poland, whose system is the closest to the French model.

If Electricity Were a Hotel Night…

Using the same explanatory analogy, the capacity mechanism would consist of the municipality of the city in which Hotels A, B, and C are located issuing a call for tenders to the city's hotels, asking what payment they would require to contribute to the objective of ensuring that hotel capacity is always available to accommodate 150 people, thereby improving the quality of service provided to tourists and events.

Let us imagine that Hotel A sets the price on 200 days per year at €60 per night; Hotel B on 100 days at €80 per night; Hotel C on 55 days at €100 per night; and that prices are €200 per night on 10 days per year, when demand exceeds 150 rooms.

This gives Hotel A an inframarginal rent of €5,600/room per year. For Hotel B, it is €2,300/room per year, and for Hotel C, €1,000/room per year.

Suppose that Hotel A's fixed costs are €5,000/room per year, Hotel B's are €2,300/room per year, and Hotel C's are €1,200/room per year. In the tender, Hotel A will bid –€600/room per year, Hotel B will bid €0/room per year, and Hotel C will request a capacity payment of €200/room per year in order to remain open. The tender will select all three hotels in order to cover a total capacity of 150 rooms, with a payment of €200/room per year for all three hotels. The municipality will then cover this cost through a tourist tax covering the €200/room per year across all overnight stays, amounting to less than approximately €1 per overnight stay across all nights. The mechanism therefore ensures that the three hotels covering the requirement of 150 rooms remain in operation over the long term.

In this case, Hotels A and B will be slightly over-remunerated—by €800/room per year and €200/room per year, respectively. This is insufficient to allow them to invest in creating new rooms but corresponds to an insurance-like remuneration for the security-of-supply service they provide.

Another approach to ensuring compliance with this criterion is to establish what is known as a strategic reserve. In practice, this consists of maintaining a group of power plants that are set aside and do not participate in the market but are remunerated to cover their fixed costs and called upon only as the system's ultimate backup if necessary. **The cost of keeping these power plants in operational condition is then passed on to consumers**. Certain Member States, including Germany, historically used and promoted this approach at the European level, arguing that it created fewer distortions in the adjustment of the generation fleet. In reality, under a market-wide capacity obligation scheme, there is an assurance that the system's requirements will be met the following year. Conversely, with a strategic reserve, once the reserve volume is determined, significant uncertainty remains regarding the capacity that market participants will actually develop, and therefore the total combined volume of market-driven capacity and the reserve. This renders the mechanism far less secure and less capable of delivering the security of supply that governments wish to guarantee for their citizens. Germany has since shifted its position toward a capacity mechanism comparable to the French model, given the scale of the security-of-supply challenges it faced and the need to maintain its generation fleet seen during the 2022–24 period.

If Electricity Were a Hotel Night…

Still using the same explanatory analogy, a strategic reserve would consist of the municipality "pre-reserving" 30 rooms at Hotel C and paying the hotel to keep them ready throughout the year. These rooms would be "set aside" and offered only if the first 120 rooms had already been taken. The cost of this advance reservation would then be passed on through the tourist tax.

1.3. SUPPORT FOR NEW GENERATION FACILITIES

Electricity market signals do not make it possible to achieve political objectives regarding the composition of the electricity mix—that is, the distribution among generation technologies.

Since 2009,[5] and in accordance with the provisions of the Treaty on the Functioning of the European Union, which gives the Union the competence to legislate by qualified majority in order to "promote energy efficiency and energy saving and the development of new and renewable forms of energy,"[6] European law has assigned Member States targets for the share of renewable energy in their national energy mix. Although the relevant European legislation was revised twice, in 2018 and 2023, on each occasion with the French authorities voting in favor in the Council, its principle remains the same: Each Member State must achieve a minimum share of renewable energy in its "final energy consumption" —that is, in all energy supplied to a customer for consumption, across all energy carriers used: Electricity, gas, liquid fuels, and solid fuels.

To achieve this objective, Member States have implemented different public policy instruments depending on the energy carrier. As a general rule, these consist of the following:

- **Blending mandates *(mandats d'incorporation)*** for fuels—and, in France, for natural gas—under which fuel suppliers must demonstrate that, for every liter placed on the market, they have incorporated a certain proportion of renewable energy, mainly in the form of liquid biofuels such as biodiesel and bioethanol, or that they

[5] *Directive 2009/28/EC of the European Parliament and of the Council of 23 April 2009 on the promotion of the use of energy from renewable sources and amending and subsequently repealing Directives 2001/77/EC and 2003/30/EC, 2009 OJ L 140/16, https://eur-lex.europa.eu/eli/dir/2009/28/oj.*
[6] *Consolidated Version of the Treaty on the Functioning of the European Union, art. 194(1)(c), 2012 OJ C 326/47, https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX:12016E194.*

have purchased a "certificate" attesting to such blending from an actor that carried it out.

- **Support for the development of new generation capacity for electricity—and for natural gas**—through which the public authorities assist renewable electricity or biomethane production projects.

The choice was made to base this support on a different logic, providing certainty regarding the selling price of the renewable electricity—or gas—produced by new projects. Indeed, decarbonized electricity generation technologies, including nuclear power and certain types of renewable energy such as offshore wind, are generally capital intensive, meaning that a large amount of capital must be tied up in order to build a given amount of generation capacity. By contrast, they generate electricity at a low marginal cost, meaning that once they are operating, producing one additional MWh has no—or very little—effect on the plant's cost structure.

a. Public Support

Given the weight of the cost of capital—depreciation and return on net book value (NBV)[7]—in the full cost of a unit of energy produced by these generation facilities, reducing it is crucial to deploy these technologies efficiently. Providing certainty regarding the conditions under which their electricity will be sold over a period of ten to twenty years, consistent with the duration of a loan financing the project, makes it possible to demonstrate to the bank financing the project that the loan repayments can be met. This helps the project obtain a better interest rate, require less equity, and thereby reduce its overall costs.

[7] *The cost of the asset minus depreciation.*

To achieve this objective, support has historically taken the following two forms:

- ***Feed-in tariffs***, under which a centralized entity—in France, an EDF entity known as EDF OA, entrusted with this public service function—purchases, at a tariff determined by the public authorities, the electricity generated by plants meeting certain criteria according to the renewable generation technology and size. It then sought to sell the electricity purchased in this way on the market and subsequently received compensation from the state for the associated cost, corresponding to the cost of purchasing the electricity at the tariff, net of market revenues. However, this system had several limitations. It could lead to the over-remuneration of certain projects when their actual costs fell below the guaranteed tariff, and it largely disconnected producers from electricity market price signals and the incentives they provide. It did, however, have the advantage of being simple to implement, particularly for small projects such as residential solar installations, and it played an important role in the initial development of renewable energy sectors.

- ***Revenue top-up contracts***, or ***contracts for difference (CfDs)***. Under this system, producers sell their output directly on electricity markets, after which the public authorities observe the difference between electricity market prices[8] and the fixed price. If the market price is below this guaranteed price, the public authorities pay the producer the difference in order to secure its revenues. Conversely, when market prices exceed the guaranteed level, the producer pays the surplus back to the public authorities. Thus, the mechanism stabilizes project revenues while limiting excess profits during periods of high prices. To obtain a CfD, a new power plant project participating in a public tender requests the fixed price that would

[8] *On average, according to a reference representing a reasonable sales strategy for a plant of that technology.*

be guaranteed to it. The public authority—in practice, in France, the Energy Regulatory Commission—selects the best-priced tender candidates that together satisfy the total volume sought and comply with the tender specifications. This approach makes it possible to partly expose the supported plants to market signals and requires them to seek the best possible valuation of their output on wholesale electricity markets while preserving the favorable characteristics of generation support in terms of access to capital. Through the tender procedure, it also makes it possible to remunerate projects as closely as possible to their actual requirements, provided that the tender is competitive. Finally, it enables zero-price bidding and non-scheduling when operating the facility is uneconomical, thereby reducing 'produce-at-all-costs' generation and providing better incentives to schedule outages in line with market signals.

b. Long-Term Contracts

Alongside public support, renewable generation projects have also been developed on the basis of selling their electricity output to third parties under long-term contracts known as ***power purchase agreements***, or PPAs.

- These contracts consist of agreeing in advance with a counterparty—most often a large electricity consumer—to sell the power plant's output over a long period, usually ten years or more, at a predetermined price. This is known as a ***physical PPA***.

- An alternative option is for the project to sell its electricity on the market, for the consumer to purchase its electricity at the market price, and for the two parties to **pay one another financial compensation equal to the difference between the market price and a fixed price**, thereby ensuring that the price "received" by both parties is, in practice, fixed. This is known as a ***financial PPA***.

Although PPAs have the advantage of not requiring a public counterparty to cover market risk, they nevertheless present a number of difficulties and disadvantages that limit their deployment. In terms of complexity, while remuneration top-up contracts are relatively standardized—and the associated legal risk is therefore limited and controlled—each PPA is different and requires a specific assessment of the associated risk. The bargaining power within a PPA also depends on the relative size of the seller and buyer. A large producer signing a PPA with a small buyer may impose its conditions on the latter. The reverse is also true for a large buyer dealing with a small producer. Finally, PPAs contribute to the financialization of electricity supply: An actor with a strong market credit rating—for example, a GAFAM (Google, Apple, Facebook/Meta, Amazon, or Microsoft) company—may sign more advantageous PPAs, and therefore obtain electricity at a better price, than a less highly rated actor, such as an indebted state. This break in equal treatment is, in itself, a matter requiring a political decision.

If Electricity Were a Hotel Night…

As an explanatory analogy, consider a city with three hotels, A, B, and C, each with 50 rooms, for which the marginal cost of preparing a room and accommodating a guest is €60 per night, €80 per night, and €100 per night, respectively. We further assume that these overnight stays are perfectly substitutable, meaning that the three hotels are of the same quality.

We assume that hotel demand amounts to 40 rooms on 200 nights per year, 60 rooms on 100 nights per year, 120 rooms on 50 nights per year, and exceeds the available hotel supply on 15 nights per year, when the price is €200 per night. This results in an average overnight price of €76.

Let us assume that the local authority wishes to increase the hotel supply in this city by developing a new campsite with ten bungalows that meets certain public policy objectives. It has the particular characteristic of having very low costs per overnight stay, at €10 per night, but high construction costs of €45,000 per new bungalow—because the land must be prepared and leveled—and of being available for only four months per year, namely June to September. We assume, mutatis mutandis, that the average price of an overnight stay is the same over these four months.

Under the *feed-in-tariff approach*, the local authority calculates a tariff and applies it to all the bungalows. It can be shown that a tariff of €84.90 per night, paid on every night of the four-month period and for every unit, ensures a return of around 7 percent over five years for the operator that builds the campsite. The local authority is then responsible for placing the overnight stays on the market. It earns revenues, which are compared with the cost of the guaranteed tariff, and the difference is then covered by the municipal budget. It can be seen that if the operator manages to extend the campsite's lifespan beyond five years or obtains better financing, it will make a substantial gain.

Under the *remuneration top-up approach*, the local authority holds a tender asking who is prepared to build a campsite meeting the specifications and operate it for five years in exchange for a contract providing compensation calculated as the difference between the price requested in the tender and the average price of an overnight stay during the summer months. Several candidates will participate in the tender. The most competitive bidder will have examined in its financial model how it could earn revenues beyond the five-year period and how it could optimize its debt financing and will submit a bid of €75 per night, taking these revenues into account.

The presence of the campsite within the hotel supply will shift the price equilibrium slightly since some demand will no longer go to the hotels during the summer. Assuming that, on days when capacity is saturated, the price is no longer €200 but €150 per night and the new average price of an overnight stay is €63 rather than €76. This would result in the successful bidder receiving €12 per unit per night from the municipality over the four summer months. In practice, in some years it will receive compensation from the municipality, when occupancy is too low for the variable costs of Hotels B and C, together with the days of saturation, to allow it to sell its overnight stays at an average price equal to or above the €75 guaranteed by the remuneration top-up. Conversely, in years of high hotel occupancy, it may be required to pay money back to the municipality.

Finally, the case of a *Power Purchase Agreement (PPA)* would consist of the bungalows being reserved in advance for several years, at an agreed price, by a tour operator, replacing the overnight stays it previously purchased individually as needed. This may also make it possible to trigger the investment by providing sufficient certainty regarding future revenues to complete its financing.

1.4. OPENING UP TO COMPETITION: NETWORK ACCESS AND UNBUNDLING

In France as well as in most developed countries, the electricity and gas system was historically built according to a vertically integrated model, in which the activities of electricity generation, transmission (on the high-voltage network for electricity or the high-pressure network for gas), distribution (on the low-voltage network for electricity or the low-pressure network for gas), and supply (that is, the commercial relationship with the final customer) **were consolidated within a single operator, often publicly owned or subject to price regulation by the public authorities**.

These vertically integrated monopolies were formed over the course of the twentieth century through the aggregation of local generation-distribution-supply systems, either through mergers and acquisitions, allowing economies of scale to be achieved through the consolidation of transmission network deployment and large-scale electricity generation or through nationalization.

Before 1946, France had several separate electricity suppliers concentrated in the main urban centers, local electricity utilities, independent operators in the generation sector, and even certain electricity-intensive industrial companies with their own generation assets—namely hydroelectric dams. There was significant technical heterogeneity (several distribution frequencies still coexisted in 1950) and tariff heterogeneity (different regions and local utilities charged different prices for electricity), since national tariff equalization—the policy of charging a single uniform price across the whole country—was not completed until the 1980s.[9]

[9] *It should be noted that the nationalization law of 1946 partly preserved certain prior organizational arrangements, maintaining (i) local distribution companies or utilities (providing distribution and supply in certain territories where this function had been carried out by local authorities), (ii) ownership by local authorities of the distribution network, conceded to EDF-Distribution, (iii) certain hydroelectric concessions (CNR, etc.), and (iv) hydroelectric drawing rights for industrialists who owned their dams and had been expropriated (continuing into the 2010s).*

Within the different Member States of the European Union, there were therefore one or more vertically integrated monopolies carrying out all of these functions: EDF in France, Enel in Italy, Electrabel in Belgium, RWE, EnBW, and others depending on the Länder (federal states) in Germany, and Fenosa, Iberdrola, or Endesa in Spain, among others.

Within their respective service areas, these operators already used a scheduling framework based on the principle of marginal *cost pricing*, first to determine the short-term dispatch order of available power plants, since low-marginal-cost plants (hydropower, nuclear, and lignite) and high-marginal cost plants (gas and oil) already coexisted; second, to set the purchase price of electricity generated by other producers, such as Charbonnages de France through the CNET and the dams operated by CNR and SHEM; and third, they also relied on marginal costs for management decisions and to design the time-of-use (hourly and seasonal) structure of consumer tariffs.

In the French case, the absolute level of these tariffs was calculated on the basis of the full operating costs of the vertically integrated operator—that is, all costs, including depreciation and remuneration of its capital, divided by its generation in MWh. By contrast, the structure of the tariffs—the differentiation between low and high voltage at the customer's premises, between peak and off-peak hours, and between peak and ordinary days —was calculated on the basis of differences in marginal costs between these periods in order to encourage flexibility in consumption.[10]

Between their service areas, these operators also traded electricity with one another in the short term using this principle of marginal cost pricing in order to determine the conditions governing the purchase and sale of electricity through interconnectors.[11]

[10] *Granted, this is based on a generation fleet optimized for a 15-year horizon (Y+15), rather than a short-term spot indicator.*

[11] *Except in the rare cases where a vertically integrated actor held stakes in a plant located across the border and sometimes held permanent rights of access to the interconnectors to repatriate the energy into its service area.*

a. A Separation of Activities

In the 1990s, and from 1996 onwards in Europe, the decision was made to gradually open the electricity sector to competition. **This choice was supported and approved in the Council by all successive French governments, leading to the directives of 1996, 2003, 2009, 2019, and 2024, and was transposed into national law by the national legislature**. This liberalization was based on the principle of *unbundling*. This principle, also used to open the telephony and telecommunications services sector, the transport sector—rail and air—and other parts of the energy sector, including natural gas, to competition, consists of dividing the sector into the following parts:

- **Activities constituting "natural monopolies,"** [12] or at least assets to which equal and competitively neutral access must be guaranteed for all actors in the electricity system, and which it is not desirable for private operators to duplicate. **This is particularly the case for network activities** (rail, cable telecommunications, energy, etc.), for which guaranteeing equal access is an important element in enabling competition, and whose operation and deployment according to an integrated model appear more efficient than under a distributed model involving several competing operators within the same service area. *Prima facie*, it is not clear that there would be efficiency gains from having several Enedis or several RTE operators.
- **Activities that can be opened to competition** once equal access to network activities has been ensured, **particularly generation**—the production of electricity and its sale on the wholesale market—**and supply**, consisting of selling final customers electricity purchased on the wholesale market or generated on a supplier's behalf.

[12] *This is the standard expression used in France, which we will avoid using subsequently, as a monopoly is always "unnatural": unnatural in its effects, given that the natural state is competition and any monopoly is the product of a political choice; and unnatural in its origin, which always stems from a political will—expressed either by establishing a legal monopoly or by declining to prevent one from forming.*

In France, this framework reached its current form in both electricity and gas through the Law on the New Organization of the Electricity Market (NOME) in 2010, following fifteen years of gradual implementation, notably through the 2003 law. Its implementation requires strong guarantees regarding the independence and competitive neutrality of network operators in the following forms:

- **The accounting, legal, and functional separation of distribution and transmission system operators** from the remainder of the historically vertically integrated operators: RTE and Enedis in electricity; GRTgaz (now Natran), TIGF (now Téréga), and GRDF in natural gas;
- **The establishment of network codes**, harmonized at the European level, ensuring common rules for operation, network access—connection and pricing—and network management;
- **The establishment of network tariffs ensuring the remuneration of network operators on the basis of their costs**, including operating costs and investment programs, set transparently and without discrimination and paid equally by all network users in the same circumstances;
- **The establishment of an independent public authority** responsible for regulating the sector. This entails overseeing the costs of network operators and approving their investment programs, setting tariffs, and monitoring compliance with their independence and competitive neutrality. In France, this role is performed by CRE. In other Member States, it is combined with the regulation of other regulated networks, such as telecommunications and transport, as in Germany with BNetzA, or combined with the competition authority, as in Spain with the CNMC until 2025.

Once these conditions of network neutrality have been ensured, the "upstream" segments—that is, the development and operation of generation facilities—and the "downstream" segments—that is, the activity of supplying final customers—can be opened to

competition. Opening these activities to competition is then expected to produce efficiency gains[13] compared with the activities of a vertically integrated operator. The economic literature tends retrospectively to identify such gains in Europe[14] on the basis of robust econometric analysis while also noting that the process entails certain lost synergies.

In theory, with the following elements:

- **a generation fleet sized to meet demand**;
- **an "upstream" market operating under conditions of perfect competition and perfect information**;
- **and the same assumptions applying to the "downstream" market**.

It can be shown that this liberalized approach results in an all-in price for customers that is lower than or equal to the price that would have prevailed under a vertically integrated monopoly with the same appropriately configured generation fleet (this equality occurring when monopoly regulation is efficient, on the one hand, and when competition is perfect, on the other).

Within this framework, the setting of network tariffs is based on a periodic exercise through which the following are determined:

1. **Operating expenses:** The operation of the electricity system (losses, congestion, and ancillary services), purchases, personnel expenses, taxes, and levies. These expenses are set on the basis of a forecast

[13] *Net of the additional costs implied by unbundling, notably the structural costs of the independent regulator and those linked to the independence of network operators. See Klaus Gugler, Mario Liebensteiner, and Stephan Schmitt, "Vertical Disintegration in the European Electricity Sector: Empirical Evidence on Lost Synergies," International Journal of Industrial Organization 52 (2017): 450–78, https://doi.org/10.1016/j.ijindorg.2017.04.002.*

[14] *Michael Pollitt, "The Arguments for and against Ownership Unbundling of Energy Transmission Networks," Energy Policy 36, no. 2 (2008): 704–13, https://doi.org/10.1016/j.enpol.2007.10.011; Paolo Nardi, "Transmission Network Unbundling and Grid Investments: Evidence from the UCTE Countries," Utilities Policy 23 (2012): 50–58, https://doi.org/10.1016/j.jup.2012.05.002; Carlo Amenta, Martina Aronica, and Carlo Stagnaro, "Is More Competition Better? Retail Electricity Prices and Switching Rates in the European Union," Utilities Policy 78 (2022): 101405, https://doi.org/10.1016/j.jup.2022.101405.*

trajectory, with performance incentives intended to maintain the network operator's efforts to improve productivity.

2. **Capital charges:** Depreciation allowances and remuneration of capital, again with the regulator overseeing the forecast investment trajectory and providing performance incentives. The remuneration of capital is calculated as the product of a base—the *Regulated Asset Base*, or *RAB*—representing the accounting value of the assets held by the network operator, net of investment subsidies, including European subsidies for certain projects and payments made by users for their connections, and a rate—the *Weighted Average Cost of Capital*, or *WACC*—set by the regulator to reflect a fair level of return in view of the risks associated with the activity.

Forecast discrepancies in the expenses and revenues borne by the network operator, where they concern elements that are difficult to predict and are unrelated to its performance, are finally entered into a *Regulatory Account for Charges and Revenues (CRCP)*, which makes it possible to settle any funding deficits by incorporating them into the future tariff level or, symmetrically, to return to consumers any amounts over-recovered by the operator in the past.

These costs borne by the network operator are then allocated among the network users. This allocation is carried out according to four principles, the first three of which are universal in Europe:

- **pricing independent of the distance traveled by the electricity or gas**, known as the "postage-stamp principle";
- **identical pricing throughout the network operator's service area**—in the case of electricity in France, the continental metropolitan territory (i.e., mainland France excluding Corsica and overseas territories);
- **nondiscriminatory pricing reflecting the costs generated by each category of user according to its consumption characteristics**, independently of the use made of the electricity;

- **time-of-day and seasonal pricing**, meaning a tariff schedule differentiated according to the time of day—peak or off-peak—and the season in order to reflect variations in the network operator's costs between different hours and over the course of the year.

If Electricity Were a Hotel Night…

To continue our hotel analogy, consider the hotel market on an island where several hotels are located. This market is geared toward receiving international tourists.

Historically, Hotel A was the island's only hotel. It was built by an international tour operator that marketed all-inclusive packages, including transport to the island, from several departure points in Europe. To do so, the tour operator had a commercial network of physical travel agencies in different markets as well as its own online booking platform, which had the exclusive right to offer holidays on the island. It also owned the island's airfield, which it had built to receive its holidaymakers. The system was therefore a vertically integrated monopoly.

Liberalization consists of dividing the island's tourism market into the following three parts:

- a market for hotels on the island, corresponding to the upstream market;
- a market for air services to the island, corresponding to the "network";
- a market for the retail sale of holidays on the island, corresponding to the downstream market.

In order to fully develop the island's tourism potential, the local authorities will therefore require the accounting and operational separation of the airfield from the historical tour operator. Its costs will be identified by an independent local authority, which will charge the same airport fee to anyone wishing to land tourists on the island and allocate landing slots on the island through a transparent and nondiscriminatory process. The same authority will be responsible for defining the appropriate investment plan for the airfield in order to improve its accessibility and reception capacity.

At the same time, the local authorities will open the construction of new hotels on the island to competition, allowing any competing operator other than the historical operator to build them. They will also allow any online sales platform or network of agencies to market holidays in the island's hotels.

Naturally, nothing will prevent the historical operator from prioritizing the occupancy of its own Hotel A. However, if Hotels B and C, corresponding to the characteristics described in the preceding sections, also exist as a result of this competitive process, this will allow it to improve its offering.

Ultimately, all tour operators selling holidays will reserve them on the wholesale market for overnight stays, according to the marginalist logic described previously, and some holidaymakers will even be able to purchase their overnight stays directly from the hotels if they prefer this method. On the other side of the market, "pure player" online platforms, not linked to any hotel, will also emerge and simply offer all the island's hotels to prospective holidaymakers.

1.5. LARGE CONSUMERS AND THEIR PARTICULAR TREATMENT

Electricity consumers in Europe are thus exposed to pre-tax electricity delivery prices resulting from the stacking of different blocks, corresponding to each of the "layers" of the electricity system as follows:

- **an energy-supply block**, representing the cost of purchasing the MWh delivered to them, according to the procurement strategy they have chosen—short term or forward—and their hourly and seasonal consumption profile;
- **a capacity-supply block**, representing the cost of that consumer's security of supply within the capacity mechanism, as described above;
- **a network-delivery block**, representing the tariff associated with the operation of the network;
- **a commercial-costs-and-margin block**, representing the costs incurred by the supplier in its commercial activity, as well as its margin, reflecting the risks it bears.

In theory, under perfect competition in both supply and generation, with perfect information and an appropriately configured upstream generation fleet, this approach will result in supply that is at least as efficient as that which could be provided by a vertically integrated monopoly.

In practice, the historical vertically integrated operators had been able, in pursuit of other public policy objectives—including industrial-policy or economic competitiveness considerations—**to grant, or to be required to apply**, allocations of costs among the different blocks which, in the setting of tariffs prior to liberalization, **resulted in advantageous pricing for certain categories of users at the expense of others**. Outside Europe, hyper-electricity-intensive industrial consumers—that is, those whose value added has the highest energy intensity, measured in MWh per euro of value added—sometimes benefit from highly advantageous trade conditions that discount their contribution to the costs of the system.

Several Member States have sought to establish mechanisms that, first, **recognize the contribution made by hyper-electricity-intensive industrial consumers** to the ultimate stability of the electricity system, owing to the specific characteristics of their consumption, and, second, **take account of their particular circumstances in the allocation of network costs**.

First, interruptibility mechanisms exist in several Member States. These ancillary services consist of the network operator **maintaining a reserve of consumers that can be "pre-selected for load shedding" as a priority** before load shedding among ordinary consumers has to be considered in the event of a breakdown in the balance between supply and demand. The consumers concerned are **selected through a tender on the basis of remuneration expressed in €/MW, which is paid to them whether or not they are called upon**. This mechanism has been activated several times over the past decade, with positive feedback from RTE regarding its contribution to maintaining the supply-demand balance in Europe. Given the consumption characteristics required—withdrawal from the network during more than 80 percent of the hours in the year, the ability to interrupt consumption with only a few seconds' notice, and so forth—only hyper-electricity-intensive industrial consumers are capable of providing this service.

Member States have also optimized the allocation key—the formula used to divide network costs among users—to better reflect each consumer's actual use of the network. The objective is for each category of consumers to contribute to the costs of the system according to the actual use it makes of the network. Indeed, for the largest consumers, the direct application of a rule allocating costs in proportion to the MWh delivered would result in exorbitant network costs, potentially exceeding the cost to that consumer of constructing a private line connecting it to the nearest power plant.

If Electricity Were a Hotel Night…

To use the analogy from the preceding sections of an island equipped with an airfield and hotels accommodating tourists, the situation corresponds to that of very frequent travelers who are of particular importance to the island's economy—for example, customers traveling to the island for business.

If these travelers have greater flexibility than ordinary tourists, the local authority may remunerate their interruptibility—that is, issue an annual call for volunteers willing to give up one week's stay on the island at very short notice—within the two hours preceding boarding of their flight to the island—and select those willing to do so in exchange for the lowest remuneration.

Assuming that there is only one day each year on which demand remains at 160 overnight stays even at the maximum "value of the lost overnight stay" of €1,000 per night, and on which the island therefore faces a breakdown in the balance between supply and demand, it may be appropriate to offer up to €1,000 per year to ten travelers in exchange for their agreeing to give up their stays on those nights in order to maintain the balance between supply and demand.

If the tender identifies ten travelers willing to give up their stays for only €900 per year, this is beneficial for the local authority. Over the course of the year, if these travelers are on the island very frequently—for example, 300 nights per year—it still amounts, from their perspective, to a discount of €3 per night.

Similarly, the treatment of their access to the island may be specific. Indeed, if these users pay a substantial airport tax each time they stay on the island, the total annual amount may become so high that it would be worthwhile for them to develop their own means of reaching the island rather than using the shared service. The solution adopted is therefore to offer them a rebate on their airport taxes, bringing them to a level lower than or equal to what it would cost them to create such dedicated infrastructure.

Note: This situation may appear artificial in the case of accommodation, since in real life, a customer is not paid to cancel a booking. This arises from a major difference with the electricity system: The latter must remain balanced at all times, failing which service to all users may be affected through rotating power cuts or even a blackout. In this case, paying a customer to reduce consumption is appropriate in order to preserve service for the community as a whole.

a. The Indirect Effect of Carbon Pricing

Added to this competitiveness challenge is the indirect effect of carbon pricing in Europe. European power plants are required to purchase carbon allowances in proportion to their greenhouse gas emissions. This additional cost increases the generation costs of coal- or gas-fired power plants and is subsequently reflected in electricity prices when those plants are needed to meet demand.

This additional cost increases the price of electricity on the short-term market during the hours in which these plants are used and on forward markets in proportion to the frequency with which

they are expected to be used during the delivery period. Electricity prices in Europe are thus increased by the effect of the carbon-allowance system relative to other regions that choose not to put a price on their fossil fuel emissions. In the absence of a functioning carbon border adjustment mechanism that also covers the indirect emissions of imported products, this competitive distortion results in "indirect carbon leakage"—that is, the displacement of activity from European electricity-intensive plants to their non-European competitors, together with the associated emissions.

The solution adopted under Union law since 2012[15] has been the introduction of ***compensation for indirect costs***. This consists of a category of state aid schemes that Member States may implement, under which they compensate for this effect for companies active in a number of listed sectors that the Commission has determined to face a high risk of indirect carbon leakage in view of their energy intensity—consumption relative to value added—and their exposure to international competition. This compensation is provided according to rules established by the European Commission, which mechanically calculate the aid paid on the basis of the price of emission allowances observed on the market and a parameter measuring the carbon intensity of electricity in the Member State concerned—that is, emissions relative to electricity generation in that Member State, expressed in g_{CO_2eq}/kWh.

This method of calculation works relatively well in many European countries but creates problems in highly decarbonized electricity systems such as France's. Indeed, the price of electricity depends primarily on the power plants setting the market price at a given moment—often fossil fuel plants—and not on the average emissions of the electricity fleet as a whole. Thus, a country relying heavily on nuclear power or hydropower may face high prices linked to gas while

[15] *Communication from the Commission — Guidelines on certain State aid measures in the context of the greenhouse gas emission allowance trading scheme post-2012, 2012 OJ C 158/4, https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX:52012XC0605(01).*

displaying a low average carbon intensity. **This leads to an underestimation of the additional costs actually borne by electricity-intensive industrial consumers in some of the most decarbonized Member States, while countries whose electricity mix relies more heavily on coal or lignite may benefit from comparatively more favorable compensation**. France had obtained a corrective mechanism in the 2021 European guidelines, but this was not renewed in the new rules published in 2025.

If Electricity Were a Hotel Night…

Continuing with our explanatory analogy, consider our city containing Hotels A, B, and C, each with 50 rooms, for which the marginal cost of preparing a room and accommodating a guest is €60 per night, €80 per night, and €100 per night, respectively. We further assume that these overnight stays are perfectly substitutable, meaning that the three hotels are of the same quality.

Let us imagine that Hotel A sets the price on 200 days per year at €60 per night, with total demand of 40 rooms; Hotel B sets the price on 100 days at €80 per night, with demand of 80 rooms; Hotel C sets the price on 55 days at €100 per night, with demand of 140 rooms; and that, on 10 days per year, prices stand at €200 per night because total demand exceeds 150 rooms.

We further assume that the hotels are subject to a tax on the use of water resources. Hotel B has its own desalination facility and is therefore exempt from the tax, but for Hotel A it increases the cost of an overnight stay by €10 per night and for Hotel C by €20 per night.

As a result, the average price of the marginal overnight stay rises from €75.30 to €83.80. The average price of a night spent on the island from the user's perspective rises from €87 to €96. The European approach would therefore consist of compensating €9—whereas a more precisely calibrated approach would compensate €8.50 per night—for the travelers most exposed to the "risk of leakage," that is, those most likely to choose another travel destination.

1.6. THE CHALLENGES FACING THE CURRENT MARKET FRAMEWORK AMID THE TRANSFORMATION OF EUROPE'S ENERGY MIXES

The market framework described above now faces three major challenges.

The first is to continue decarbonizing European energy systems while ensuring sustainable financing conditions for new projects. This requires finding a balance between public support mechanisms, particularly contracts for difference (CfDs), and the development of private long-term contracts such as PPAs. Public support makes it possible to reduce the cost of capital through the guarantee provided by the state and, therefore, to reduce the overall cost of the electricity system. However, it can also limit the development of private price-hedging solutions. In a more constrained budgetary context, Member States must therefore target their interventions more effectively and, where possible, favor guarantee mechanisms over direct subsidies while finding instruments that ensure a smooth transition between the two forms of contracting—CfDs and PPAs.

The second challenge concerns the definition and valuation of low-carbon electricity. Not all decarbonized MWh provide the same value to the electricity system; this depends on when the electricity is generated and on the ability of the different technologies to meet consumers' actual needs. Therefore, the development of markets and certification mechanisms will have to more accurately reflect the physical constraints of the electricity system and the actual value of the different forms of decarbonized generation.

The third challenge concerns security of supply and the associated economic signals. The decarbonization of the electricity system does not depend solely on the development of renewable capacity; it also requires the deployment of flexibility resources capable of balancing the system. Without them, the rapid increase in wind and solar capacity could lead to increasingly frequent situations of overproduction, requiring a growing share of generation to be curtailed. At the same time, dispatchable capacity—currently mainly fossil fuel-based—will remain necessary to guarantee supply during periods without wind or sunlight, despite a gradual reduction in its operating hours. This development raises major challenges for both energy security and European industrial competitiveness.

2 Recommendations: Ensure the Emergence of Long-Term Signals

2.1. STANDARDIZE PPAS AT THE EUROPEAN LEVEL

Investing in new generation facilities requires visibility over the cash flows that will be generated in order to finance them under the best possible conditions. This is particularly true for decarbonized generation technologies, both nuclear power and renewable energy, which are both capital intensive. As we have seen, Member States, under the close coordination of the European Commission in the exercise of its state aid control powers, have established support schemes intended to provide this visibility. They first did so through feed-in tariffs, which are now concentrated on the smallest installations but enabled renewable energy sectors to emerge on a large scale, and subsequently through remuneration top-up contracts, or CfDs, which today constitute the main means of deploying renewable energy, as well as new nuclear power in the states that choose it, including the Czech Republic, France through the EPR2 program, and the United Kingdom. This approach has been an indisputable success in scaling up the deployment of decarbonized energy and attracting capital under extremely competitive conditions in the Union's principal markets over the past ten years.

This support framework—under which public authorities alone act as the centralized guarantor of stable prices for new installations—has succeeded in bringing about the emergence of decarbonized sectors. Yet the prospect of a 2050 market framework built primarily on decarbonized capacity, in which almost all installations are covered by a remuneration top-up contract with public authorities, raises questions as a target model for organizing the electricity system and its markets.

Taken to its limits, this framework will result in a mix composed almost entirely of installations under CfDs with the public authorities that cover their full costs (subject to remuneration during negative price periods—even if the CfD operator may then be prompted to shut down or curtail its output—or alternatively, where the tender specifications have excluded remuneration during negative price periods from the outset, meaning auction participants have internalized this into their strike price), and installations whose contracts have expired and which are fully depreciated and which are therefore fully exposed to the short-term market.

In this scenario, the short-term market would fluctuate between extremely frequent periods of negative or zero prices when installations with zero variable costs are marginal (and acting as 'produce-at-all-costs' bidders in the case of negative prices) and periods of very high prices—even though these are capped in Europe—when the last dispatchable capacities are marginal or when batteries or the consumers' marginal willingness to pay ensure the balance of the system. The difference in prices between these periods and their frequency will ultimately determine the financial flows generated by an efficiently operated battery. This will create an implicit ceiling for the wholesale market price, which will therefore fluctuate between zero and this implicit ceiling, provided that the latter is lower than the ceiling established by regulation; otherwise, a market for such capacity cannot exist. In such a market, making investment decisions becomes extremely difficult for consumers or for facilities that do not correspond perfectly to public tenders. By increasing the risk premium attached to the post-CfD revenues of supported installations, this approach also reduces their post-contract value and therefore, in theory, slightly increases the cost of capital of these installations relative to current practice.

The deployment of these long-term contracts guaranteed by the public authorities also creates substantial commitments for the public sector. In France, these are documented each year[16] by the Committee for the Management of Public Electricity Service Charges (CGCSPE), a mixed body composed of experts from, among other institutions, the Energy Regulatory Commission and the Court of Auditors, in conjunction with the ministries responsible for the budget and energy. According to its latest report: "The total cost of the commitments made by the state between the beginning of the 2000s and the end of 2024 in relation to support schemes for renewable energy and natural gas cogeneration in continental metropolitan France, financed through the CSPE, is between €113 billion and €167 billion in 2024 euros, depending on the market price scenario, including past payments and the remaining amounts payable. These amounts correspond to past and forecast generation of approximately 2,808 TWh over the full duration of the support contracts entered into by the end of 2024."

If support schemes remain unchanged, these commitments will increase in the coming years if France is to meet its climate commitments and continue deploying decarbonized electricity generation capacity capable of meeting the needs of a decarbonized—and therefore highly electrified, directly or indirectly—economy in the 2040s and beyond. For example, the deployment of the first stage of the EPR2 program, consisting of three pairs of reactors, or 9,900 MW, will result in annual generation of 73 TWh at a capacity factor of 85 percent. Under the CGCSPE's median-price scenario, and assuming that the politically assigned objective of an EPR2 CfD strike price not exceeding €100/MWh in 2024 euros is met, the charges associated with the CfD would amount to approximately €2.2 billion in 2024 euros per year, or €132 billion in 2024 euros over the lifetime of the contracts.

[16] *Pursuant to the provisions of Code de l'énergie [Energy Code], art. L. 121-28-1, https://www.legifrance.gouv.fr/codes/id/LEGISCTA000023985566.*

The ability of the Union's Member States to continue deploying generation capacity according to this model over the long term risks coming up against the limits of their own budgetary capacity.

From the consumers' perspective, the decarbonization of energy use is also capital intensive, at every level, for both households and businesses. From the purchase of an electric vehicle or a heat pump to the deployment of electrolyzers or decarbonized heat-generation equipment, decarbonization technologies are now widely available and proven but require substantial initial investment by consumers. Making these investments under the best possible financial conditions requires long-term visibility over the conditions of access to energy, particularly its price, and therefore over the financial flows that these investments will generate. This is what will allow consumers to finance them, particularly through debt, within the limits of their cash flow constraints—as in the case of households and some businesses—or their financing capacity, which must be allocated among several other possible uses, including the development of their core business. **Consumers are therefore also seeking long-term protection against fluctuations in wholesale electricity prices in order to undertake their investments**.

For consumers, this protection must take a form symmetrical to that granted to producers. Whereas producers want a price floor during periods when prices are below their full costs and are prepared, in exchange, to give up part of the value created above their full costs when market prices are higher, consumers want a price ceiling during periods of high prices and are prepared to give up part of the gains they would make if prices fell below a certain level. This symmetry, therefore, quite naturally leads to a desire to connect these two needs for security, which can offset one another.

This threefold ambition—namely, (i) **building a market framework** capable of meeting the challenges of an almost entirely decarbonized energy mix, (ii) **continuing the transition** by making greater use of private counterparties to provide decarbonized installations with the security they require and limiting reliance on national public finances, and (iii) **ensuring the natural connection between consumers' needs and producers' capacity** in terms of financial security—was the key element of the reform of the European market framework completed in 2023 through Regulation (EU) 2024/1747.

To achieve this objective, the co-legislators designed a framework in which decarbonized generation facilities can benefit from two categories of long-term hedging against the risk posed by the market price of electricity: **PPAs, that is, hedges freely agreed between two private counterparties**, generally a producer and a consumer, and **two-way CfDs, that is, CfDs concluded between the state and a producer, the costs or gains from which are subsequently passed downstream to consumers** so as to neutralize their effect on public finances, excluding cash flow carrying effects. As recital 45 of the Regulation states: "Through [PPAs], private investors contribute to the deployment of additional renewable and low-carbon energy while securing low and stable electricity prices over the long term. Similarly, through two-way CfDs or equivalent schemes with the same effects, public entities can achieve the same objective on behalf of consumers. Both instruments are necessary to achieve the Union's decarbonization objectives through the deployment of renewable and low-carbon energy while passing on the benefits of low-cost electricity generation to consumers."

Article 19d of the Regulation **requires** Member States to use this format for direct price-support schemes concluded after July 17, 2027, where they concern a new decarbonized installation—wind, solar, geothermal, run-of-river hydropower, or nuclear power. It provides that the positive financial flows associated with these two-way CfDs must, by default, be distributed to final customers, in principle in proportion to their consumption, although the Regulation also provides that they may be used to "finance the costs of direct price-support schemes or investments intended to reduce electricity costs for final customers."[17] Recital 35 of the Regulation also provides that this type of mechanism may be introduced "in the case of new investments intended substantially to repower existing electricity generation facilities, significantly increase their capacity, or extend their operating life." The sentence is a bit too "heavy": This is a new possibility from which Belgium, in particular, has benefited by using a CfD to cover the of generation the Tihange 3 and Doel 4 reactors, whose operating lives it decided to extend. The obligation thus introduced represents a profound change in paradigm, even though the balance reached in the negotiations led to its scope being weakened in relation to the arrangements for redistributing funds to consumers and financing the costs of the CfDs through them. It introduces a generic framework and homogeneous characteristics for all aid schemes involving direct price support for new decarbonized generation. Because this framework is incorporated into sector-specific law, it will apply automatically to any future Commission decision concerning such mechanisms under its state aid powers pursuant to Articles 107 and 108 TFEU, in accordance with the principle that aid cannot be compatible with the Treaty if it is not compatible with sector-specific law.

With regard to PPAs, Article 19a of the text establishes an aspirational objective calling on Member States to support their deployment. Paragraph 3 provides Member States with the option of introducing "instruments such as guarantee schemes at market prices, intended to reduce the financial risks associated with default by the buyer under [PPAs], which are in place and accessible to customers who face barriers to entering the [PPA] market and are not in financial difficulty." Put more simply, **this means establishing guarantee schemes for consumers wishing to conclude a PPA with a decarbonized electricity producer in order to cover the counterparty risk—the risk of default—of these purchasers**. Without such protection, for a renewable generation

[17] *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, 2024 OJ L, 2024/1747, art. 19a(5), https://eur-lex.europa.eu/eli/reg/2024/1747/oj.*

project developer, at the same purchase contract price, a public counterparty under a CfD always presents a lower counterparty risk than a private purchaser and will therefore always be preferable. This situation prevents the PPA market from emerging, except where renewable projects are abundant relative to the scale of public tenders and there is strong demand for renewable electricity from private consumers that attach significant value to long-term security. These two cumulative circumstances may have arisen in Europe during the 2022–24 period but should not, in principle, constitute the permanent market framework. The establishment of these guarantee schemes ensures a degree of equivalence—where the contractual clauses are identical—between PPAs and CfDs in the market segment covered by the guarantee. The Regulation also provides for the voluntary standardization of PPA contractual formats, at the initiative of ACER—the European regulator—jointly with market platforms.

Continuing this effort to build a liquid market for long-term hedging, so that producers and consumers can access a variety of long-term hedges—over five, ten, and fifteen years—with different delivery start dates and covering different generation or withdrawal profiles, such as the average solar profile, the average wind profile in a given delivery zone, or an annual base load strip, requires further changes. As designed by the co-legislators in Regulation (EU) 2024/1747,[18] the market framework for long-term hedging would operate through two arrangements that are sealed off from one another: Two-way CfDs arising from public tenders, whose financial flows are ultimately guaranteed by the public authorities and which constitute the standard format for support schemes for new installations, and PPAs, which may optionally be standardized but ultimately remain governed by freedom of contract and which are intended for all other decarbonized installations, including those whose CfDs have expired and projects outside public support schemes. For these, public

[18] *Regulation (EU) 2024/1747 (the "Electricity Market Design" regulation); see the previous note.*

intervention is limited, at the discretion of Member States, to eliminating the competitive distortion between such contracts and contracts involving a public counterparty.

The first proposal in this area is undoubtedly to take the step of standardizing contractual formats. Having a standard financial PPA contract at the Union level is a prerequisite for establishing price benchmarks and a liquid market for long-term hedging within the Union, allowing renewable projects to be developed efficiently.

Proposal 1

Establish a Common Contractual Framework at the European Level for Long-Term Energy Procurement.

Require ACER to establish general contractual clauses for standardized financial PPA templates in each of the Union's bidding zones, with support from national regulators where required by the specific features of national contract law, while ensuring that their overall structure remains consistent across the Union.

Require Nominated Electricity Market Operators (NEMOs) to create dedicated market segments for trading these standardized contracts based on three types of products:

- settlement of the difference between the contract strike price and the spot market reference selling price for the average solar photovoltaic generation profile in the delivery zone during the year preceding the start of delivery;

- settlement of the difference between the contract strike price and the spot market reference selling price for the average onshore wind generation profile in the delivery zone during the year preceding the start of delivery;
- settlement of the difference between the contract strike price and the spot market reference selling price for a constant generation profile during the year preceding the start of delivery.

2.2. IMPROVE COMPATIBILITY BETWEEN PPAS AND CFDS

A crucial issue is then to provide fluidity and flexibility between the two forms of long-term hedging: CfDs and PPAs. Allowing project developers to freely choose the share of their procurement—or sales—covered through private third parties or through a public support contract, while also allowing the public authorities to participate fully in and support the development of the PPA market, contributes to ensuring the liquidity and depth of the long-term hedging market, preserves opportunities for arbitrage, and ensures the fair pricing of the different products offered on it.

The principle of such flexibility is enshrined in Article 19a of Regulation (EU) 2024/1747, which expresses the following aspiration: "Support schemes for electricity from renewable sources shall allow the participation of projects which reserve part of the electricity for sale through a renewable PPA or other market-based arrangements." Although this flexibility has also been permitted under French law since the Law of March 10, 2023 on accelerating renewable energy production,[19] it has

[19] *Loi no. 2023-175 du 10 mars 2023 relative à l'accélération de la production d'énergies renouvelables [Law no. 2023-175 of March 10, 2023 on accelerating the production of renewable energy], https://www.legifrance.gouv.fr/loda/id/JORFTEXT000047294244.*

not yet been made operational, either in French renewable energy tenders or within a European framework.

One approach to stimulating the PPA and long-term hedging markets would consist of the widespread implementation of **mixed tenders**. Such tenders would be structured as follows:

- the authorities open a tender for two-way CfDs covering a volume V, in MW, of new decarbonized capacity;
- a project developer developing a generation project with a capacity C, in MW, is free to bid in the tender for a portion *(1 – x)*C of its capacity at a price p_{CfD}. It is also free to contract the remaining *xC* with private counterparties under PPAs at a price pPPA. In absolute terms, it is not necessary to incentivize the developer to conclude PPAs rather than sell these volumes on the spot market because its need to finance the project under the best possible conditions will strongly encourage it to seek long-term hedges with consumers, provided that consumer demand exists. It would nevertheless be possible to specify in the tender requirements that generation volumes not covered by the CfD must be covered by a purchase contract with a minimum duration equal to that of the PPA and with a counterparty meeting certain creditworthiness criteria;
- the successful projects are then selected in ascending order of the p_{CfD} requested, until the volume V has been fully allocated.

Although this approach is now expressly promoted by the European Commission, the manner in which such tenders should be made operational remains to be specified. Therefore, let us attempt to describe more precisely how such mixed tenders would operate. In practice, the project developer will proceed as follows:

- observe its ability on the market to place a share *xC* of its output at a price pPPA;

- determine the optimal level of output to be placed under the CfD, covering at least *(1 – x)C*, so as to maximize the project's long-term leveraged equity IRR. This represents the financial performance that the developer seeks to achieve and wishes to maximize relative to its cost of equity.

There are then **three possible cases:**

- demand for PPAs is weak or even nonexistent. **The situation is then that of a conventional tender**, and the entire volume is placed under a CfD;
- demand for PPAs exists, and the market is competitive. It can then be demonstrated that there is a certain volume offered under PPAs, x, that minimizes the price offered in the CfD tender;
- the PPA market is not competitive. The producer then places all of its volumes under PPAs, or includes as much as possible in its CfD bid where there is a volume constraint.

Annex I to this paper develops the formal demonstration of these statements and provides a numerical example.

As soon as conditions are favorable—that is, where there is a competitive PPA market with demand—this approach therefore allows consumers to benefit from a supply of PPAs calibrated at the lowest price level that enables projects to proceed. At the same time, it reduces both the price of the CfDs and the volume concerned, thereby very significantly **reducing the cost to public finances of supporting the deployment of decarbonized energy**.

Moreover, the more mature the PPA market becomes, the more liquid it becomes, and the lower the counterparty risk becomes. Debt financing conditions become increasingly similar between PPAs and CfDs, and the equilibrium shifts toward smaller shares covered by CfDs, thereby reducing the price differential between PPAs and CfDs. If the debt conditions available to PPA-backed projects can be brought sufficiently close to those granted to CfD-backed projects, a point is eventually reached at which it is always advantageous to use PPAs—that is, **the point at which public support tenders can ultimately be discontinued**.

The advantage of this dual approach is that it makes it possible to maintain public support for **exactly** as long as it is necessary, in the necessary quantity and at the necessary price—provided that the tenders are genuinely competitive—and **automatically discontinue** it when it is no longer required to achieve deployment objectives and market signals alone are sufficient.

The preceding discussion addresses only the contractual dimension from a theoretical perspective. In the specific case of wind and solar PPAs, the effects on PPAs of the market impact of simultaneous wind or solar generation must also be taken into account. These effects run counter to those described above. Let us assume that solar generation is competitive, meaning that it has a moderate production cost. The first solar panels installed in an area do not significantly affect the market and allow the consumer acting as the PPA counterparty to benefit from a price close to their production cost during the hours in which they generate electricity—that is, during the afternoon. The consumer, therefore, has an interest in signing such a PPA. However, the more solar generation develops, the less negligible its impact on the market becomes, until very low—or even zero—prices are almost guaranteed during periods of solar generation. This phenomenon can already be observed. At that point, the consumer's interest in signing such PPAs, rather than purchasing electricity on the spot market, declines until it disappears. Indeed, the consumer has no interest in securing an electricity purchase price close to the cost of solar generation if it can benefit from near-zero prices on the spot market during the afternoon. During the other hours of the day, the solar PPA provides no assistance in reducing its costs.

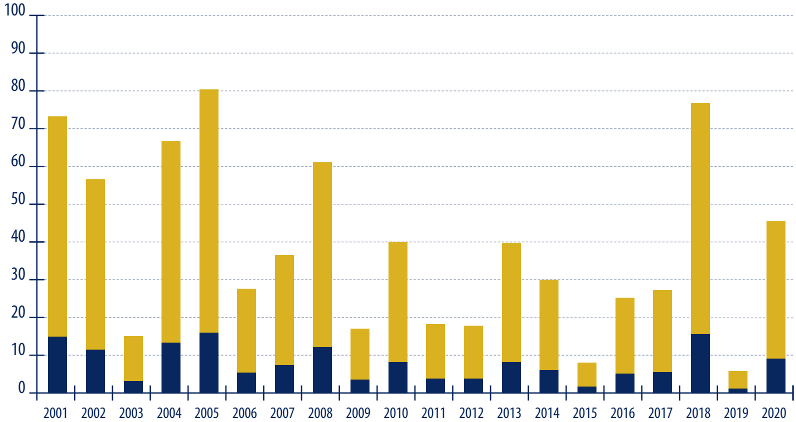
This fundamental limitation of wind and solar PPAs can be resolved only through the optimization of the electricity system **by developing new forms of flexibility and, above all, price signals capable of bringing them about. This will be the subject of the following sections of this paper. It does not resolve the structural adequacy issues in aligning the demand trajectory with state-directed capacity expansion, which we propose to address through better coordination within the NECP exercises (see Policy Paper No. 1)**.

The mixed CfD–PPA approach developed above can be refined. Candidates under these mechanisms could be permitted not to bid for a CfD covering a percentage *(1 – x)* of their output applied in each hour to actual generation—that is, with the same delivery profile as the facility's generation profile—and, therefore, to also offer PPAs with the same profile as the facility. For example, it could be provided that the first X percent of MW are offered under PPAs and that the CfD covers only the share of generation exceeding this X percent—the "tranche method." Indeed, although the capacity factor of a wind farm is only 25–30 percent, and up to 40–45 percent offshore, periods of zero generation are much rarer over the course of the year. The first 10 percent of a wind farm's generation can therefore approximate a capacity factor exceeding 70 percent, which is sufficiently stable to be attractive to industrial consumers. This naturally does not work for photovoltaic generation, since even the first 1 percent of the facility's output produces nothing at night.

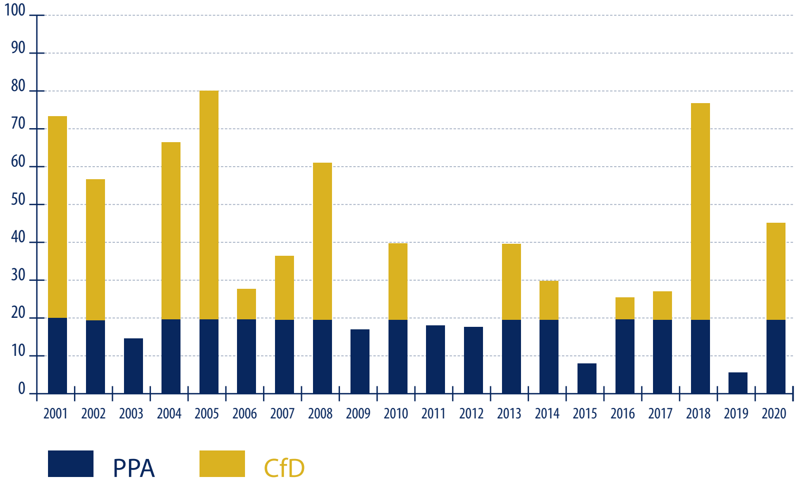
Proceeding in this way makes it possible to take advantage of the fact that consumers have a greater appetite for profiles that are more stable and closer to continuous base load delivery than for exposure to the variability of renewable generation profiles—or, for that matter, to the generation uncertainties of dispatchable assets. This would therefore make it possible to reduce the CfD strike price still further, while concentrating the volume risk in that contract. In theory, this methodological refinement therefore helps stimulate the market for base load hedges at the cost of greater complexity in the arbitrage decisions made by tender candidates and greater volatility in the amount of public expenditure associated with CfDs, since the expenditure is concentrated over fewer hours of the year, during which spot prices are lower. This methodological refinement therefore appears more appropriate for offshore wind, given the size of the projects and the greater sophistication of the candidates.

Figure 1 • PPA/CfD coexistence

"Proportional" approach



"Tranche" approach



Source: explanatory graph realized by the authors.

Additional flexibility could be considered by allowing a facility with a capacity of X MW and generation of Y TWh to place under a CfD not only the profile injected by the facility—including batteries located "behind the meter" of the project—but also to participate in a tender through any group of generation facilities and batteries, whether connected to the generation sites or located at third-party sites, that complies with the tender specifications, on the basis of a profile corresponding to the net flows injected into the network.

Proposal 2

Reduce the Cost to Public Finances of Supporting the Deployment of Decarbonized Energy Through Auctions Using the Proportional Method.

Make mixed two-way auctions using the "proportional method" the default support scheme for decarbonized technologies—wind, photovoltaic generation, hydropower without reservoirs, geothermal energy, and nuclear power—and permit the use of the "tranche method" for certain technologies, particularly offshore wind, or even make it mandatory through a revision of Article 19d of the EMD framework.

Allow participation in CfD auctions to include behind-the-meter stationary batteries, as well as any group of generation facilities and batteries, whether located behind the same meter or at another site. For this development to function, remuneration top-up mechanisms would need to be revised so that they are based not on actual physical generation but on a standardized reference volume of potential generation.

2.3. HEDGING FOR CONSUMERS, NOT JUST PRODUCERS

Finally, the question arises as to what can be done to reduce the financing cost of decarbonized generation projects under such a market framework. Beyond the costs of the project itself and its operational performance—capital expenditure and capacity factor—two other factors fundamentally influence the strike price of a PPA or CfD. The first is the level of risk affecting the project and its future financial flows, which determine the cost of capital. The second is the time required to complete the project—the longer the construction period without revenue, the more the project's financial performance deteriorates.

Under the current market structure, the CfD covers all volumes in full and, therefore, covers most of the risk affecting future financial flows, leaving the project developer primarily exposed to construction risk. Projects submit bids in public auctions at CfD prices expressed in €/MWh that reflect very similar costs of capital, indicating that financiers have adapted to this type of product and operate under conditions of near-perfect competition. The duration of construction therefore becomes one of the parameters determining the competitiveness of projects: Those that can be built most quickly are favored and can offer a lower CfD strike price.

The market framework proposed here **increases fluidity between CfDs and PPAs, supporting the transition to fully decarbonized energy mixes and improving the ability to finance installations**. It also makes this transition fully compatible with maintaining the most competitive possible access to capital for new installations and may even let consumers benefit sooner from their competitiveness.

A first approach consists of guaranteeing the counterparty risk of consumers entering into PPAs with decarbonized installations. We have seen that the European framework resulting from Regulation (EU) 2024/1747—the Electricity Market Design Regulation—allows Member States to establish this type of mechanism, subject to notification to and approval by the European Commission under state aid rules, since such schemes benefit both consumers and renewable energy projects and mobilize state resources. There is, however, no reason why these schemes, which contribute to a common European objective set out in Article 194 of the Treaty and can very easily be designed in a technologically neutral manner, could not be established at the European level.

In the first action paper in this series,[20] we put forward the proposal that the Union should act as the ultimate guarantor of payments by Member States under outstanding low-carbon public support contracts, honoring those contracts if a Member State defaults on its contractual obligations and subsequently incorporating the shortfall, where appropriate, into that Member State's national contribution to the Union budget. This approach would ensure the highest possible degree of certainty regarding the cash flows of low-carbon projects and the lowest possible cost of capital. That proposal is synergistic and consistent with the present one, since both contribute to harmonizing the cost of capital of projects marketed through PPAs or CfDs at a level consistent with a guarantee from the Union budget.

[20] *Pierre Jérémie, Maxence Cordiez, and Lola Carbonell, Achieving the EU's Energy Ambitions: The Need for a Pragmatic Governance Framework (Paris: Institut Montaigne, November 2024), https://www.institutmontaigne.org/en/publications/achieving-eus-energy-ambitions.*

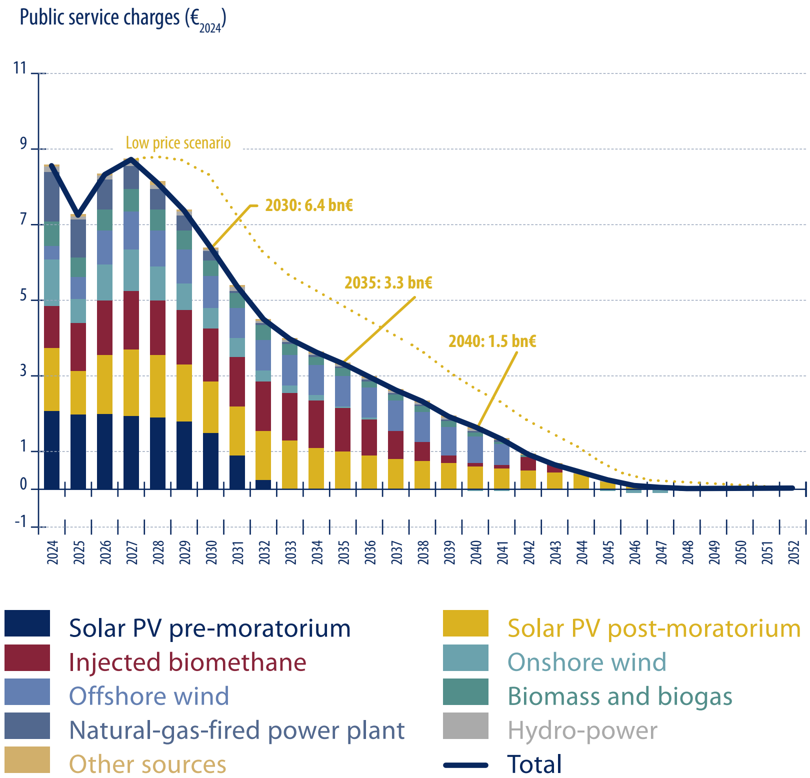
Proposal 3
Establish a European-Level Counterparty Risk Guarantee for Long-Term Contracts.

Establish a European scheme guaranteeing the counterparty risk associated with PPAs concluded with new decarbonized generation projects in Europe, replacing national schemes and open, at a minimum, to all industrial consumers.

Once these various arrangements have been put in place, the question remains of how to treat the outstanding public support contracts carried on Member States' national budgets. These involve public energy service charges corresponding to historical contracts, which may amount to several tens of billions of euros. In France, according to the latest CGCSPE report, these charges amount to between €113 billion and €167 billion in 2024 euros.[21]

[21] *Comité de gestion des charges de service public de l'électricité (CGCSPE), Rapport annuel n° 6 [Sixth annual report] (Paris: Ministère de la Transition écologique, 2025), https://www.ecologie.gouv.fr/politiques-publiques/comite-gestion-charges-service-public-lelectricite-cgcspe.*

Figure 2 • Timeline of French energy public service charges corresponding to commitments through (end-2024 in €$_{2024}$)—median market price scenario (€70/MWh)[22]



[22] *CGCSPE, Rapport annuel n° 6.*

These amounts vary according to realized market prices because of the way support for decarbonized energy operates. When market prices fall, the state compensates for the widening gap between the fixed price and the market price, and the amount of the charges therefore increases. When market prices rise, the top-up required in addition to the market price in order to cover the price contracted with the project decreases and may become negative, resulting in negative public service charge flows to the benefit of the state budget. Between 2022 and 2023, net public energy service charges associated with renewable electricity thus became negative, amounting to -€4.6 billion in total over the two years. Between the low-price scenario of €50/MWh and the median-price scenario of €70/MWh, the charges to be disbursed in 2030 with respect to commitments made by the end of 2024 therefore differ by €1.9 billion. Put differently, for every €1/MWh reduction in wholesale market prices, the payments to be made by the public authorities increase by €95 million.

It would be entirely possible to allow Member States to sell synthetic financial hedges on the market to consumers—or suppliers—wishing to purchase them. Specifically, Member States holding a support contract with a generation installation—covering a capacity of (X) GW, for a duration (D), and at a strike price of €$\hat{p}$/MWh—could offer hedges to consumers or their suppliers under which, when the market price realized by the generation installation is p, the consumer would receive $p - \hat{p}$ from the counterparty to the contract with the generation installation—EDF OA in France. The payment would therefore flow from the counterparty to the consumer when market prices were higher than $\hat{p}$, and from the consumer to the counterparty when market prices were lower than $\hat{p}$. Thus, if the full (X) GW were subscribed, from the perspective of the counterparty to the support contracts, the support contract would become neutral in terms of financial flows, regardless of the realized market price.

The question then arises as to how these contracts would be allocated. There are two possible cases:

- The case in which $\hat{p}$ is below current wholesale and forward-market prices. This is almost never currently the case in France, but it is the case in other Member States—particularly Germany—for substantial portfolios of renewable energy contracts, including onshore wind and ground-mounted photovoltaic installations. In such a case, it could be proposed that the synthetic financial hedges be auctioned: The counterparty to the support contracts would periodically auction (X) GW of hedges at a price of $\hat{p}$, which could be acquired in exchange for an upfront payment determined through the auction.
- The case in which $\hat{p}$ is above current wholesale market prices. In such cases, the public authorities could conduct descending auctions for hedges at a price $\tilde{p}$ determined through the auction, with $\tilde{p}$ serving as the selection criterion. Once consumers representing (X) GW had agreed to subscribe at a price greater than or equal to $\hat{p}$ for a duration (D), the auction would be deemed successful. Because $\tilde{p}$ would be established in equilibrium with forward prices, the measure would contain no aid element: The public counterparty to the support contracts would be merely hedging its exposure to market prices under market conditions, and the consumers acting as counterparties to this hedge would enter into it on neutral terms relative to other market-hedging opportunities. Under such an arrangement, over the duration (D), whether market prices fell below $\tilde{p}$ or rose above $\hat{p}$, the exposure of the public counterparty would likewise be neutralized and would no longer depend on market prices. It would depend only on the difference between $\hat{p}$ and $\tilde{p}$.

Once the entire portfolio of outstanding support contracts had been placed through one or the other of these arrangements, the historical amounts of public service charges would cease, to a first approximation, to depend on market prices. **It would then become possible to move**

this expenditure off budget, for example, by allowing Member States to transfer these commitments to an independent entity assigned a revenue stream, such as a share of ETS2 revenues—that is, revenues from carbon pricing in the building and tertiary sectors. The auction proceeds would provide this entity with an initial cash contribution, allowing it to manage payment-default risks and, more generally, its cash-financing costs, or even to raise debt at the level of this structure in order to smooth the amounts over time.

Proposal 4

Allow Member States to Issue Long-Term Contracts Aimed at Consumers Based on the Generation from Installations Receiving Public Support.

Allow Member States to issue synthetic hedges symmetric to their outstanding public support commitments, within the volume limits of the supported generation installations, either through ascending auctions based on the upfront payment or through descending auctions based on the hedge strike price, and to move their outstanding public support commitments off budget.

Finally, during a future revision of the EMD Regulation, it will be necessary **to clarify how the possibility of implementing two-way remuneration top-up contracts—CfDs—for existing installations applies**. This possibility is already recognized by the Regulation currently in force in the following terms: "Member States should be able to decide to grant support schemes in the form of two-way contracts for difference or equivalent schemes with the same effects also in the case of new investments intended substantially to repower existing electricity generation installations, significantly increase their capacity or extend the operating life of those installations."[23] The precedent set by the extension of the Belgian nuclear fleet, the negotiation of which predated the EMD Regulation, provides some initial guidance. However, incorporating this possibility into sector-specific law would provide greater certainty for investors, operators, and consumers called upon to act as counterparties to these two-way contracts, thereby ensuring that their respective transitions can be financed under the most competitive conditions: Investment in generation on the upstream side and investment in the direct or indirect electrification of energy uses.

Two points of ambiguity remain particularly significant today: (i) **The scope of the eligible facilities** when a decision is taken to extend their operating life or increase their capacity, and (ii) **the price level at which such a two-way CfD would be concluded**. Although previous decisions provide an initial indication, in line with which the proposals in this action paper have been developed, these principles are not yet anchored either in sector-specific legislation or in the state aid guidelines.

Regarding **scope**, first, decisions to extend operating lives or increase capacity apply, from an administrative perspective, to each of the facilities concerned—renewable energy facilities, dams, or nuclear installations—under their environmental authorization regime or their authorization regime under national energy law, these two regimes most often being combined in practice. However, the economic assessment of an extension does not apply at the level of these administrative decisions; it forms part of an economic whole that, for most operators, must be understood at the level of a group of facilities operated on a co-optimized basis. Taking an extension decision in isolation for a dam located upstream or downstream of another dam makes no economic sense—although it may make sense from an environmental or

[23] *Regulation (EU) 2024/1747, art. 19d and recital 35, https://eur-lex.europa.eu/eli/reg/2024/1747/oj.*

administrative perspective—since its operation and the management of the resource are carried out across all the generating units within the same river basin, whose output and water reserves are closely correlated. The same applies to several separate wind farms connected to the same point of injection into the network, whose curtailment and operating arrangements may be managed in a correlated manner. Finally, the same applies within a fleet of nuclear reactors that are separate for the purposes of their authorization regimes but operated as a whole, with extensive pooling of operational, maintenance, and engineering resources, and whose short-term generation schedules, medium-term outage and maintenance programs, and long-term management timetables are fully co-optimized. Requiring separate contracts in each of these cases would undermine the overall economic coherence of the system, since it would result in a price being set for each CfD that took into account the cost of coordinating the different facilities. That price would have to be based on the counterfactual scenario of each asset being managed individually, without the benefits of the pooling arrangements in place, while also incorporating a risk premium relating to interference from decisions concerning the other assets.

Similarly, with regard to the **CfD strike price**, the strict parallel with their application to existing facilities, combined with the need to respect existing property rights and the principle of legitimate expectations, provides a good indication of the appropriate price at which they should be set. The primary purpose of the CfD is to support the continued operation of a facility, but it must also be compatible with the proper functioning of the internal market and with free competition. Its price must, therefore, recreate the position in which the fleet would find itself if its operating life were extended under conditions of perfect competition. Accordingly, the scenario on which the price is modeled is not the lowest price at which the incumbent operator would agree to continue operating the facilities—which would in fact correspond to cash costs plus remuneration of the new investments required for the extension. Rather, it is the contract strike price that would be awarded competitively to a new entrant that purchased the asset base at its NBV, earned a return based on a WACC no more favorable than that of the incumbent operator, and extended the facilities' operating lives by ten years. The asset base could not be purchased more cheaply than its NBV, since this would entail an impairment and the state's forgoing of a state resource, and therefore implicit aid. If remuneration were based solely on cash costs, with no return on the NBV, this would constitute state aid to consumers and would be highly distortive, since the state would be forgoing a resource—the fair remuneration of the NBV held within an operator, for example, one that is wholly publicly owned. The same would apply for as long as the IRR remained below the operator's WACC, taking this regulation into account. If the remuneration exceeded the operator's WACC, taking this regulation into account, this would constitute state aid to the producer in addition to the strictly necessary aid for the life extension.

Proposal 5

Apply CfDs to Existing Facilities at the Level of a Fleet Rather Than an Individual Facility.

Clarify in sector-specific legislation that, where two-way CfDs are applied to an existing asset, they may cover the entire output of a fleet of facilities that are interdependent because of operational co-optimization at a strike price corresponding to the full costs of generation, including depreciation and remuneration of the NBV, based on a WACC determined by the independent regulator.

2.4. CERTIFYING THE RENEWABLE ORIGIN OF SUPPLIED ELECTRICITY—REFORMING THE GUARANTEES-OF-ORIGIN MARKET

In Europe, a mechanism for certifying the renewable origin of consumed electricity was introduced in 2009.[24] This GO mechanism remains in place and is defined in Article 19 of the revised Renewable Energy Directive (EU) 2018/2001.

It provides that renewable electricity producers may request the issuance of certificates guaranteeing the renewable origin of the electricity generated. By default, each guarantee represents 1 MWh, although guarantees covering smaller volumes may be issued.[25] Although the mechanism was initially designed solely to promote renewable energy, it now allows Member States to issue certificates of origin for energy from any source, rather than only renewable energy.

By default, these certificates are valid for twelve months in Europe, although some states have reduced their period of validity domestically. This is the case in France, where GOs are valid for only one month. They may also be traded between countries belonging to the Association of Issuing Bodies (AIB), without geographical or volume constraints. Finally, once issued, electricity GOs may be traded independently of the electricity whose origin they certify.

A consumer in northeastern Europe may therefore have electricity purchased on a winter night guaranteed as renewable through a certificate backed by solar photovoltaic generation produced on an afternoon during the preceding summer in southwestern Europe. There is no physical link between GOs and the electricity consumed.

[24] *Directive 2009/28/EC, art. 15, https://eur-lex.europa.eu/eli/dir/2009/28/oj.*
[25] *This possibility was introduced during the 2023 revision.*

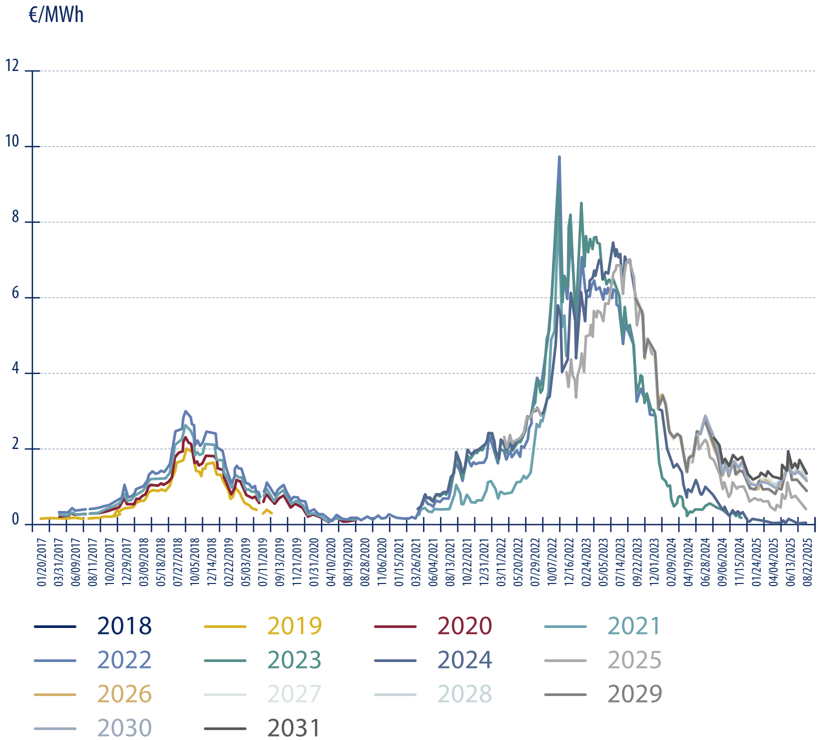
This entire section concerns only GOs for electricity. GOs for gas, being backed by a storable asset, face different issues.

a. Problems Arising from the Current Operation of Guarantees of Origin

The electricity guarantee-of-origin (GO) mechanism, which was designed to provide supplementary financing for such capacity through voluntary contributions from consumers, suffers from multiple shortcomings. First and foremost, it is worth noting that for a Guarantee of Origin to have any value, both supply and demand must exist. To date, the signals boosting the supply of Guarantees of Origin (public support) are much stronger than those driving demand (the ability to qualify as a green offering).

The first shortcoming lies in an oversupplied market, resulting in a very low price for GOs—see Figure 3—averaging less than €2/MWh. At this price level, the mechanism is particularly ineffective in contributing to the financing of renewable sources of electricity. Two main reasons explain the excess of supply over demand on the GO market.

Figure 3 • Price evolution of electricity GOs[26]



- The first is that **there is currently no geographical limit on the trading of electricity GOs**. A consumer in continental Europe may therefore have its electricity consumption certified as renewable through GOs issued in Iceland, a member of the AIB, even though

[26] *QuiEstVert, Position de QuiEstVert sur l'évolution souhaitable des mécanismes des Certificats d'Attributs Énergétiques (EAC) [QuiEstVert's position on the desirable evolution of Energy Attribute Certificate (EAC) mechanisms] (January 2026), https://www.quiestvert.fr/wp-content/uploads/2026/01/Rapport-QEV-GO-Horaire-Position-sur-levolution-souhaitable-des-mecanismes-des-Certificats-dAttributs-Energetiques_compressed.pdf.*

there is no interconnection between Iceland and continental Europe, and it is therefore strictly impossible for renewable electricity generated in Iceland to be physically consumed on the Continent. In practice, certain countries such as Norway, which have very high renewable generation—consisting mainly, in Norway's case, of hydropower produced by old and fully depreciated dams—flood the European market with their GOs, thereby driving prices down. This problem raises another consideration: The risk of *de facto* double counting of renewable generation. Norwegian consumers know that the electricity in their country is physically almost entirely renewable. Therefore, they have no reason, in principle, to purchase—even at a low price—GOs for the electricity they consume. However, if those guarantees are sold elsewhere in Europe, another European consumer will be entitled to claim that the electricity it consumes is renewable. The situation is therefore as follows: The Norwegian consumer receives electricity that is physically renewable but is treated for regulatory purposes as corresponding to the European residual mix—that is, primarily fossil fuel-based—while the consumer that purchased the GO consumes electricity that may physically be largely fossil fuel-based, depending on the country in which it is located, but is treated for regulatory purposes as renewable. Considering both the physical and regulatory character of the electricity's origin, both consumers then believe that they are consuming renewable electricity.

- **The second reason for the overabundance of electricity GOs on the European market lies in their twelve-month validity period** rather than validity within a single calendar year, which in practice results in GOs accumulating from one year to the next. Despite increasing demand for GOs, this continually growing stock prevents their price from rising, severely limiting the mechanism's contribution to the financing of capacity.

Beyond their limited contribution to financing renewable energy, another—and probably more serious—criticism can be leveled at the electricity GO system: It serves as an instrument of greenwashing and misinforms consumers about the actual conditions required for a 100 percent renewable electricity supply. The complete absence of a physical link between GOs and electricity conceals a fundamental characteristic of electricity: The difficulty of storing it. Electricity must be consumed instantaneously when it is produced in order to maintain the balance of the electricity system. Yet because GOs are valid for a rolling twelve-month period in Europe, they operate as a system for virtually storing the renewable character of electricity, without any physical counterpart.

In other words, a consumer choosing a 100 percent renewable supply contract will have to pay only a very small—if not negligible—additional cost, resulting from the low value of GOs for the reasons explained above. It will be able to consume as much electricity as it wishes without additional cost, even during hours when renewable electricity generation is very low. The electricity consumed at such times—for example, on a winter night—will most likely not be physically renewable, but it will be guaranteed as such, and the consumer may therefore believe that it is. Supply contracts described as 100 percent renewable and based on the GO mechanism impose no economic constraint on consumers to adapt their consumption to renewable generation by consuming at certain times rather than others, or to pay more for their electricity when renewable generation is low in order to reflect the cost of the storage needed to bridge the gap between renewable generation at a particular time and the relevant consumer's demand several hours or days later.

Because consumers are not generally specialists in the operation of the electricity system and are unlikely to suspect that an electricity GO in no way guarantees the origin of the electricity they consume, they may reasonably believe that it is easy to move to an electricity system based entirely on renewable energy sources. Indeed, if they can consume 100 percent renewable electricity without constraints or additional costs, it would appear sufficient for the entire population to choose such contracts in order to move to a 100 percent renewable system.

In practice, the GO system takes no account whatsoever of the flexibility resources that will have to be deployed within the electricity system in order to integrate renewable energy effectively: Storage and demand-side flexibility. This shortcoming creates a twofold threat in the following respects:

- **A threat to the climate:** By failing to account for the challenges of making the electricity system more flexible, which are inseparable from the deployment of renewable energy, this service will continue to be provided by the most dispatchable capacity, namely fossil-gas-fired power plants. It therefore does not make it possible to achieve a 100 percent renewable system;
- **A threat to security of supply:** Fossil fuel power plants, primarily coal-fired plants, are closing in Europe in response to climate concerns. However, the flexibility service they provided is not being replaced, weakening the electricity system. The fact that, over an entire period such as a month or year, Europe has more than enough capacity to generate sufficient electricity to meet demand does not mean that this will necessarily be the case at every moment. The lack of progress in making the electricity system more flexible, in the context of a shrinking fossil fuel fleet, therefore threatens supply during periods without sunlight or wind.

Finally, although the latest versions of the Renewable Energy Directive allow Member States to issue GOs for nonrenewable sources of electricity, the system remains centered on renewable electricity. This arbitrarily narrows the range of low-carbon energy sources that Europe will need to achieve carbon neutrality and limits the potential of GOs to establish a traceability system capable of supporting all low-carbon energy sources and the flexibility resources that must accompany them while informing consumers about the physical constraints associated with their choices regarding the origin of electricity.

b. Correcting Guarantees of Origin to Turn Them Into a Genuine Traceability Instrument Supporting the Phasing-Out of Fossil Fuels

The fundamental reform of the electricity GO system proposed in this paper has two objectives:

- **to enable the system to genuinely contribute to financing an internally coherent low-carbon electricity system**, including both low-carbon electricity sources and the associated flexibility resources;
- **to turn it into a functional instrument for tracing electricity, providing consumers with realistic information about the constraints associated with their choices regarding the origin** of electricity, thereby informing public debate on the decarbonization of the electricity sector.

Regarding the second objective, it should be noted that GOs are already used in practice by all actors as a traceability instrument—even though their current operation does not allow them to perform this function properly—and that consumers subscribing to a 100 percent renewable contract sincerely believe that they are consuming 100 percent renewable electricity.

To increase the value of GOs so that they can genuinely contribute to financing decarbonization assets, the market must be tightened by combining a reduction in supply with an increase in demand. Proposal 6 seeks to reduce the supply of GOs and their accumulation on the market.

Proposal 6

Reform the Guarantees-of-Origin System So That It Better Reflects the Geographical Realities of the Associated Physical Generation.

Such a reform would require cross-border trading in electricity GOs to be limited to booked interconnection capacity.

In order to increase GO prices and thereby fulfill their original objective of contributing to the deployment of new low-carbon capacity, demand must also be increased alongside the reduction in supply. This requires, in particular, informing consumers that if they do not request a GO, they will consume electricity corresponding to the European residual mix, which is primarily fossil fuel-based. To provide consumers with reliable and accurate information, it appears necessary to make the issuance of guarantees mandatory for every unit of electricity generated, regardless of its origin—renewable, nuclear, or fossil—and to ensure that they are transferred to the final consumer. GOs should also include the carbon intensity of the generation technologies, and this information must cover the entire life cycle so as not to underestimate the emissions of certain energy sources, particularly fossil fuels.

However, some states oppose the issuance of GOs for capacity receiving public support in order to prevent such capacity from being remunerated twice. In other words, a renewable energy facility benefiting from a remuneration top-up mechanism—and therefore already protected against market risk—should not receive additional remuneration from the sale of GOs. Including GOs in the calculation of support for new installations would reduce the burden on the state while preventing double remuneration.

Proposal 7
Improving Transparency in the Supply of Guarantees of Origin.

To achieve this, make the issuance of electricity GOs mandatory at the European level for all generation, whether renewable, nuclear, or fossil fuel-based, as well as their transfer to the final consumer. To prevent the covered capacity from being remunerated twice, electricity GOs must be taken into account in electricity remuneration top-up mechanisms.

The life-cycle carbon intensity of the electricity generated must also be included in the information contained in GOs.

Beyond the preceding proposals, which will increase the value of GOs so that they can finance elements involved in decarbonizing the electricity system, this financing must be designed to extend to all measures required to build an internally coherent low-carbon electricity system—that is, not only generation but also the flexibility resources that must accompany it. These measures will also make GOs an effective instrument for tracing the origin of electricity and providing consumers with accurate information. Not immediately imposing hourly granularity is necessary in order to give all actors using GOs sufficient time to introduce the tools required to manage GOs at a much finer temporal resolution. However, the timetable must not postpone the completion of this reform until an excessively distant date.

This proposal is central to turning GOs into an effective system for tracing electricity. It will cause the price of guarantees to fluctuate over time, encouraging consumers to shift their production or stimulate investment in storage. The proposal nevertheless entails a risk: Consumers may choose to guarantee the low-carbon origin of their electricity only during hours when the price of guarantees is virtually zero—for example, on summer afternoons—while relying on residual GOs during the rest of the time through contracts described as "low-carbon X percent of the time" or "renewable X percent of the time." This would undermine the usefulness of GOs in developing the flexibility resources needed to accompany the selected energy sources. The reform of the system must therefore make homogeneous supply contracts mandatory whenever they incorporate GO criteria. In other words, the electricity claimed as guaranteed must be guaranteed 100 percent of the time.

Proposal 8

Align Guarantee of Origin Requirements with Real-time Physical Production to Ensure the Credibility of Demand.

Without delay, change the validity period of GOs, which is currently twelve months, so that they are valid only within the current calendar year, thereby ending the accumulation of GOs on the market.

At the same time, announce a timetable for progressively reducing the period during which GOs may be used to certify generation, ultimately moving toward hourly or sub-hourly granularity.

To prevent contracts from guaranteeing the origin of electricity only during periods of high generation—that is, when GO prices are low—prohibit supply contracts that do not provide homogeneous GO coverage. In other words, the selection of energy sources claimed by the supplier, where it chooses to incorporate GO criteria into its offer, must cover 100 percent of the customer's consumption at all times.

Deterrent penalties—meaning penalties exceeding the cost of purchasing GOs during the tightest periods—must be introduced at the national level for suppliers that are unable to present their customers with a contracted GO.

By turning electricity GOs into a robust instrument for tracing the origin of electricity, they could be used to guarantee the carbon footprint of certain industrial products, which is not currently possible. Consider the example of a battery factory located in Poland, a country in which the carbon intensity of electricity is high. European regulation does not currently allow the electricity GO system to be used to calculate the carbon footprint of the batteries produced because the European Commission is aware of the mechanism's inherent limitations. The batteries produced must therefore incorporate the average carbon intensity of the country's electricity generation unless the factory is physically connected to a renewable power plant. Once the electricity GO mechanism has been corrected, the relevant regulations could subsequently be amended to refer to it and allow industrial companies to use the system to calculate the carbon footprint of their products. This would increase the value attributed to the electricity GO system and its impact on the electricity system.

The reform of electricity GOs proposed here is systemic and derives its strength from the full set of proposed measures. These measures must therefore be implemented simultaneously in order to make an effective contribution to financing the decarbonization of the electricity system while ensuring accurate traceability capable of informing consumers.

2.5. COMPLETING THE DEVELOPMENT OF ECONOMIC SIGNALS FOR SECURITY OF SUPPLY AND FLEXIBILITY

a. Converging Capacity Mechanisms Across Europe

In Part I, we presented the rationale underlying capacity mechanisms. An energy-only market—that is, the remuneration of each MWh at its marginal cost for all facilities called upon to generate during a given hour—can admittedly, in theory, ensure that the fixed costs of an appropriately configured generation fleet are exactly covered, under assumptions of perfect competition and perfect information among market participants, while also assuming that generation capacity can be built or dismantled almost instantaneously. These are, of course, highly restrictive assumptions that are not borne out in practice.

This equilibrium is achieved when the realized price multiplied by the number of hours during which supply and demand are out of balance—requiring reductions in customers' consumption, for example, through rotating load shedding—exactly covers the cost of constructing new power plants. The number of hours of supply failure is therefore not explicitly selected by the public authorities but results from the intrinsic characteristics of economic agents' choices: The limits of their willingness to pay during hours of extremely high peak demand and the exogenous cost of constructing new capacity.

By contrast, political authorities have considered it legitimate to explicitly determine a security-of-supply objective for the electricity system. Regulation (EU) 2019/943 introduced this concept at the European level, while the French legislature set the average annual duration of loss of load at three hours.[27] Loss of load is defined as: "The need to resort to exceptional measures, whether contracted or non-contracted, in order to ensure the balance between electricity supply and demand. Exceptional measures include recourse to the interruptible capacity referred to in Article L. 321-19 of the Energy Code, calls for voluntary action by citizens, requests to cross-border transmission system operators outside market mechanisms, the deterioration of operating margins, voltage reductions on the networks and, as a last resort, the load shedding of consumers."[28]

In addition to this fundamental problem arising from the disconnect between security of supply as a market outcome—an emergent property of the preferences of economic agents—and security of supply as a public service objective determined by political authorities, several practical considerations may prevent the spot price of electricity alone from providing adequate coverage of the fixed costs of generation facilities.[29]

[27] *Code de l'énergie, art. L. 141-7.*

[28] *Décret no. 2021-1781 du 23 décembre 2021 relatif au critère de sécurité d'approvisionnement électrique mentionné à l'article L. 141-7 du Code de l'énergie, art. 2 [Decree no. 2021-1781 of December 23, 2021 on the electricity security-of-supply criterion referred to in Article L. 141-7 of the Energy Code], https://www.legifrance.gouv.fr/loda/id/JORFTEXT000044559349.*

[29] *Peter Cramton and Axel Ockenfels, "Economics and Design of Capacity Markets for the Power Sector," Zeitschrift für Energiewirtschaft 36, no. 2 (2012): 113–34, https://doi.org/10.1007/s12398-012-0084-2.*

First, the market design may include technical price caps—€4,000/MWh on the European day-ahead spot market since 2022—which prevent spot prices from reaching the Value of Lost Load (VOLL).[30] This results in the structural under-remuneration of peaking capacity during the admittedly very rare events in which this cap is reached.[31]

Second, prices are highly volatile during these peak hours, and their frequency is extremely difficult for market participants to anticipate. Given their risk aversion, participants discount these revenues relative to the very real costs of maintaining or constructing capacity, resulting in structural underinvestment.

Third, the market is imperfectly coordinated. Several market participants may undertake competing investments in peaking facilities, or conversely, each may expect another participant to launch a project that will "use up" the available market space. Finally, where the generation market is not perfectly competitive, various phenomena—such as capacity withholding—may occur and prevent generation assets from being remunerated efficiently.

Associated with the preceding point, new capacity is far from being commissioned instantaneously. Taking into account permitting, the search for financing, construction, and connection to the network, at least several years are required for a fossil fuel power plant, and more than a decade may be required for a nuclear plant. The considerable inertia involved in changing capacity levels may therefore result in relatively persistent deficits—or surpluses, although primarily deficits—relative

[30] *Value of Lost Load: the value a consumer is willing to pay to avoid an interruption in their electricity supply.*

[31] *It should be noted that the fact that this cap is never reached in Europe is due to the security-of-supply criteria discussed above, which result in excess capacity compared with the counterfactual scenario in which security of supply is managed through a purely market-based approach. Thus, if the security-of-supply criteria and the price cap on the spot market were removed, many fossil-fuel power plants would probably close—thereby reducing excess capacity and weakening security of supply—until peak-hour prices rose sufficiently to halt further closures of peaking plants and justify keeping the remaining plants in operation.*

to the level required for security of supply, which would already be substantially lower than the standard currently experienced in Europe. This inertia in the emergence of new capacity may also create multiyear cyclical effects: Capacity shortages trigger large-scale investment in peaking plants, which come online several years later and create excess capacity; this then causes investment to cease and plants to close, ultimately resulting once again in insufficient capacity.

Finally, relying exclusively on a market-based approach to ensure security of supply will necessarily lead market participants to favor plants with low capital expenditure and short construction periods, thereby reducing investment risk—in other words, fossil fuel peaking plants. This approach is therefore inherently unfavorable to the capital-intensive and slow-to-build low-carbon capacity that Europe specifically needs, such as nuclear power plants and wind farms.

For all these reasons, it has been considered preferable at the European level to guarantee the balance between electricity supply and demand according to an administratively determined security-of-supply target—the three-hour criterion described above in the French case. Defining and implementing such a target requires public intervention.

The way in which this intervention now operates in France—as well as in Poland, Italy, and Belgium, among others—is based on a **centralized capacity mechanism**. This approach operates as follows:

- For each delivery year, the central regulator—in the French context, RTE—identifies the hours during which the electricity system is under the greatest stress and certifies the level of generation capacity available during those hours for each generating unit in the electricity system. Each unit certified as having X MW available during those hours is awarded X capacity-guarantee certificates.
- For each delivery year, the central regulator determines the total level of capacity, N, that must be present in the system during its

tightest hours in order to comply with the security-of-supply criterion, taking into account the probability of unforeseen events, particularly weather-related events, given the temperature sensitivity of electricity demand. On this basis, it defines a capacity obligation level for the various system users (consumers or suppliers), coupled with deterrent penalties in the event of non-compliance.

- It then conducts one or more ascending auctions in which it purchases N capacity-guarantee certificates. All certificate suppliers are remunerated at the price of the final certificate selected, expressed in €/MW: The auction therefore operates on a pay-as-cleared basis.
- In practice, the various national frameworks involve several auctions before the delivery year: One conducted sufficiently far in advance—sometimes including a multiyear category intended to facilitate the financing of new facilities if the system becomes structurally short of capacity—generally four or five years before the delivery year; another held in the preceding year to correct any discrepancies; and potentially a further auction at the end of the delivery year to allow corrective ex-post trading.
- Finally, the cost of this auction—which reveals the cost of achieving a given level of security of supply—is allocated among all users of the electricity system in proportion to their consumption during the system's tightest hours. This is intended to encourage them to reduce their consumption specifically during those hours and thereby promote flexibility. The cost may be passed on either through a fiscal instrument, as in France, or as a component added to the tariff.

Historically, the mechanisms contributing to the management of the supply–demand balance have taken a wide variety of forms, giving rise to intense theoretical and legal debates concerning their most appropriate design, both within the European internal market and in other regions, particularly the United States. Several alternative formats have been tested in Europe. France historically had a **decentralized capacity mechanism**, with no central auction but with an organized market for capacity guarantees and an obligation imposed on all suppliers to purchase them. Other Member States, including Germany, historically defended the logic of **strategic reserves**. Under such mechanisms, the central regulator contracts with certain flexible generating units—most often fossil fuel-based—not to participate in the ordinary spot market but instead to be held in reserve and called upon only as the electricity system's final safeguard before rotating load shedding. Because strategic reserves cover significantly smaller volumes—only a few GW—held outside the market, they are less costly on paper. They have also sometimes played a role in the "social and territorial management" of mothballing fossil fuel assets but do not address the fundamental challenges associated with transforming energy mixes. Finally, certain states, including Ireland, have experimented with a variant of capacity mechanisms in which the capacity product is not a simple certificate but a reliability option, giving the holder the right to purchase volumes of energy if the market price reaches a certain level or if a specified degree of supply stress occurs. In theory, this is an elegant solution that is closer to a model relying exclusively on the energy market and may therefore appear less distortive. In practice, however, it presents disadvantages both in terms of its efficient calibration—particularly the level of the option's activation threshold—and the ability of economic agents within the electricity system to efficiently price the option value of reliability.

These debates have left a significant mark on both European sector-specific legislation and the European Commission's decision-making practice. They led the Commission to treat these mechanisms not as integral components of the European electricity market framework—given the lack of consensus regarding either their fundamental appropriateness or universal design principles—but as national state aid measures requiring prior Commission approval under Articles 107 and 108 of the Treaty. This approach was intended, first, to establish a degree of harmonization in their design principles and, second, to address criticisms of these instruments. Their critics argue that they are distortive measures benefiting incumbent operators and that they perpetuate fossil fuel assets that should ultimately leave the system. Decision SA.39621 concerning the French mechanism illustrates the particular effort made by the Commission to establish its jurisdiction over these instruments.[32] Although the measure imposed only obligations on producers—to obtain certification—and on obligated parties, primarily suppliers—to cover their capacity requirements—and relied solely on the trading of certificates in a decentralized market, the Commission argued that the mere fact that the state relinquished resources by awarding capacity certificates free of charge amounted to a renunciation of resources and therefore involved state resources, a necessary condition for classification as state aid.

Between 2015 and 2020, the Commission's decision-making practice consequently established a number of principal criteria for designing these mechanisms. These criteria sought, first, to ensure that the mechanisms were calibrated as precisely as possible on the basis of a resource-adequacy assessment establishing the required level of capacity in national systems according to common European rules while allowing certain national methodological derogations. They also sought to ensure that any other market distortions resulting from national regulatory choices were properly examined through implementation plans. This framework also allowed the Commission to progressively exclude the highest-emitting installations from these mechanisms, thereby addressing the criticism that the instruments would keep fossil fuel assets in operation even though they were intended to leave the market as part of the transition of Europe's electricity systems. These principles were subsequently incorporated in full into Regulation (EU) 2019/943.[33] This required the schemes to share certain harmonized characteristics without imposing a single design framework, and allowed capacity mechanisms and strategic reserves to continue to coexist.

[32] *Commission Decision of 8 November 2016 on State aid SA.39621 (2015/C) implemented by France, Capacity mechanism, §54 ff., https://competition-cases.ec.europa.eu/cases/SA.39621.*

[33] *Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity (recast), 2019 OJ L 158/54, arts. 20–27, https://eur-lex.europa.eu/eli/reg/2019/943/oj.*

The gradual cessation of European gas supplies from Russia beginning in February 2022 revived the debate regarding the design principles of such mechanisms, given the urgency of transforming national electricity systems while maintaining security of supply in order successfully to electrify the European economy. These considerations led Germany, in particular, to commit to launching a national capacity mechanism—something that had appeared inconceivable three years earlier—and to begin working with the European Commission toward implementation for the 2028 delivery year.[34] At the same time, the convergence of the French mechanism—historically decentralized under the provisions of the NOME Law of December 7, 2010 and Commission Decision SA.39621 of 2016—with its Polish and Belgian counterparts around a centralized model[35] provides an additional contribution to the conceptual convergence of these mechanisms as a whole.

The alignment of most major Member States around centralized, market-wide capacity mechanisms creates a unique opportunity to take a further step toward harmonizing these mechanisms and establishing a consistent European framework for security of supply. This would create new benefits for the system but would require several significant changes to the current approach. These could be introduced without radically redesigning national mechanisms by continuing their gradual convergence, in line with the proposals contained in a recent Compass Lexecon report for Eurelectric.[36]

[34] *Stellungnahme der Bundesregierung zu der Entschließung des Bundesrates "Eine starke und sinnvoll flankierte Kraftwerksstrategie für eine versorgungssichere Energiewende" [Position of the Federal Government on the Bundesrat resolution "A strong and sensibly supported power-plant strategy for a supply-secure energy transition"] (Bundesrat, March 12, 2025).*

[35] *Commission Decision of 22 December 2025 on State aid SA.117564, https://competition-cases.ec.europa.eu/cases/SA.117564 (press release: https://ec.europa.eu/commission/presscorner/detail/en/ip_25_3132).*

[36] *Fabien Roques, Charles Verhaeghe, and Clément Cartry, Towards a Regional Approach for Capacity Remuneration Mechanisms in Europe (Brussels: Eurelectric and Compass Lexecon, December 2025), https://www.eurelectric.org/publications/towards-a-regional-approach-for-capacity-remuneration-mechanisms-in-europe/.*

The shift by Member States toward centralized, market-wide capacity mechanisms creates an opportunity to cease treating these mechanisms as state aid and instead to make them an integral part of the European market framework. This would be legitimate, given their profound overall consistency with the most fundamental principles governing electricity markets. At the same time, strategic reserves, which have distortive characteristics, should be gradually excluded from the scope of permissible aid schemes. This development is all the more necessary because the structural decline in spot prices resulting from the growing share of low-carbon energy in the mix is increasingly reducing the market's ability to finance new capacity. The role of the spot market will increasingly be concentrated on its primary function: The short-term optimization of the use of existing capacity. The capacity market is therefore set to play a growing role in the European electricity system and must be sufficiently harmonized across the continent.

Under this approach, each European bidding zone—that is, each zone in which an electricity price is formed—would have both: A price per MWh established through the matching of supply and demand in 15-minute intervals according to marginal pricing and a price per MW of available capacity. The latter would likewise be determined through the matching of supply and demand. Demand would be established annually by the transmission system operator on the basis of a politically defined level of security of supply—for example, through national energy and climate plans—and according to a harmonized methodology that took account of national specificities, such as the temperature sensitivity of electric heating demand in France. This matching of supply and demand would be conducted in each year A for the years A+5 to A+10—analogous to the day-ahead electricity market—as well as for year A+1 in order to correct forecasting discrepancies—analogous to the intraday electricity market—and finally during year A in order to settle the balancing positions of obligated parties, analogous to the balancing mechanism. European network operators would conduct all their auctions across the continental interconnected system according to a single calendar, with full transparency regarding price formation and the submission of bids. They would be authorized to add the costs of these auctions—and, therefore, the cost of security of supply—to network charges and pass them through transmission tariffs.

Under this approach, Member States would be responsible for determining politically the desired level of security of supply and therefore both their assessment of the hours during which their national electricity systems would be under stress and the level of capacity required during those hours to ensure the appropriate balance between supply and demand. The methodology would be harmonized at the European level while allowing scope for national scenarios or sets of assumptions to be developed in greater detail so as to fully reflect the diversity of stress situations, factors, and exogenous supply-and-demand sensitivities within Europe's different electricity systems.

Member States prepared to accept supply–demand imbalances in their systems would be entirely free to do so by setting a security-of-supply objective sufficiently undemanding that it could always be met at zero marginal cost by the capacity already present within their system. They would, however, have publicly—and politically—to assume responsibility for that choice and also accept that, in the event of a supply–demand imbalance in their market, interconnector flows would not provide support beyond that point.

The process of defining security-of-supply objectives nevertheless requires two challenges to be addressed.

The first is to ensure a harmonized definition of periods of stress within the energy system. For capacity mechanisms serving nationally determined security-of-supply objectives to interact, their capacity products must be defined consistently. As currently defined, 1 MW of capacity certified under the French mechanism is certified on the basis of its availability during certain hours, but there is no guarantee that these will also be stress hours under the future German mechanism or the Spanish mechanism. This also prevents a single power plant from fully monetizing its availability in two interconnected systems where the relevant hours overlap because part of the capacity service supplied in one market is no longer available to contribute to security of supply in neighboring markets if their peak hours partly coincide. Moreover, because Article 194 of the Treaty leaves Member States with primary competence for energy security of supply, they must legally remain free to determine the desired security-of-supply level—and, therefore, the expected number of tolerated loss-of-load hours—within their territory. This necessarily results in heterogeneous availability periods under national capacity mechanisms.

The solution to this problem is to certify the availability of facilities for every day of the year—or even every 15-minute interval—with a different capacity product for each time interval and each bidding zone. The capacity product would therefore become the availability, at a given time, of 1 MW of generation capacity—or explicit demand response—in a specified bidding zone. The network operator would then conduct not a single tender for delivery during the N peak hours of the year but N parallel tenders for each of those N hours, in which capacity resources would participate. Although this may appear more complex in practice, it would achieve the following:

- fully reveal information concerning forecast availability;
- allow renewable capacity to participate more precisely—for example, photovoltaic generation contributes to security of supply during daylight hours but not at night—than under the current standardized approach;
- allow demand response or batteries available for only a few hours to be valued precisely;
- allow capacity mechanisms with different hourly windows to be linked together.

The second challenge that must be addressed in constructing this European approach to capacity markets is to allow generating facilities to participate across borders in balancing capacity between interconnected Member States, given that this principle is legally mandated by EU law. Where interconnected Member States have abundant flexible capacity, they can monetize the service they provide to their partners. Conversely, states facing temporary adequacy challenges can allow the market to efficiently determine the optimum balance between developing or upgrading domestic capacity and relying on external support through interconnectors. By revealing the capacity contribution of interconnectors, this approach also allows them to be remunerated more efficiently and thereby supports the development of a more interconnected European internal market.

Numerical Example

Consider two capacity mechanisms—for example, **a mechanism in Country A and a mechanism in Country B—connected through an interconnector with a maximum capacity of 5 GW**. Assume that in Country A, peak days are December 1 to 20, with a target capacity level of 50 GW on those days. In Country B, peak days are December 15 to 31 and August 1 to 7 —because air conditioning is particularly widespread—with a target capacity level of 40 GW.

Assume that Country A contains three types of power plant: Technology 1, with *missing money* of €0/MW per year and 20 GW of certified capacity; Technology 2, with *missing money* of €10,000/MW per year and 20 GW of certified capacity; Technology 3, with *missing money* of €20,000/MW per year and 7 GW of certified capacity. The total capacity present in Country A is therefore 47 GW.

Country B also contains three types of power plant: Technology 1, with *missing money* of €0/MW per year and 10 GW of certified capacity; Technology 2, with *missing money* of €15,000/MW per year and 10 GW of certified capacity; Technology 3, with *missing money* of €25,000/MW per year and 30 GW of certified capacity. The total capacity present in Country B is, therefore, 50 GW.

In the absence of cross-border participation in the capacity mechanisms, Country A will be short of capacity and will therefore set its capacity price at the cost of constructing a new power plant, assumed to be €60,000/MW. The total cost of security of supply will be €3 billion, and 3 GW of new capacity will be commissioned. Country B will select Technologies 1, 2, and 3, at marginal missing money of €25,000/MW per year, producing an annual security-of-supply cost of €1 billion.

Under a scenario involving cross-border participation between the capacity mechanisms:

- from August 1 to 7, 5 GW of capacity from Country A contributes to balancing supply and demand in Country B and is remunerated at the marginal missing money level of €25,000/MW per year;
- from December 1 to 15, 3 GW of capacity from Country B participates on the Country A side and is remunerated at €20,000/MW per year;
- from December 15 to 20, 3 GW of Country B's capacity participates on the Country A side, and the equilibrium price is €25,000/MW per year in both countries;
- from December 21 to 31, equilibrium is established within Country B alone, at €25,000/MW per year.

Under such an arrangement, capacity is therefore remunerated at €23,333/MW per year in Country A and €25,000/MW per year in Country B, for respective social costs of €1.16 billion per year and €1 billion per year. In this simplified scenario, the interconnector and cross-border participation in the capacity mechanisms avoid the need to construct new peaking capacity and save Country A almost €1.84 billion per year, while generating €40 million in additional remuneration for the 3 GW of Country B capacity supporting security of supply in Country A.

This simplified example illustrates benefits that have also been demonstrated in more complex cases,[37] such as the Franco-British interconnectors, which show gains in total social surplus. The remuneration of interconnectors through capacity revenues could also, in theory, support the construction of additional exempted or regulated interconnectors, thereby improving the efficiency of the European internal market.

Within a pan-European capacity mechanism, it would therefore be necessary to fully couple all balances between participating capacity resources at each certification interval, taking account of interconnector constraints, exactly as is done in the energy market through *Single Day-Ahead Coupling*. This would involve establishing a *Five-Year-Ahead Capacity Coupling* mechanism, followed by a *Single-Year-Ahead Capacity Coupling* mechanism serving as an adjustment. The relevant methods and algorithms are already available and understood, and they could readily be replicated.

[37] *M. Cepeda and D. Finon, "Generation Capacity Adequacy in Interdependent Electricity Markets," Energy Policy 39, no. 6 (2011): 3128–43, https://doi.org/10.1016/j.enpol.2011.02.063; M. Cepeda, "Assessing Cross-Border Integration of Capacity Mechanisms in Coupled Electricity Markets," Energy Policy 119 (2018): 28–40, https://doi.org/10.1016/j.enpol.2018.04.016.*

Proposal 9

Harmonize the European Capacity Market.

Introduce capacity mechanisms as an integral part of the European market framework, at a minimum across Europe (excluding Scandinavia) by establishing a dedicated framework through a future revision of Regulation (EU) 2019/943 and governing their operating principles through a dedicated network code entrusted to ACER on the basis of a joint proposal from national transmission system operators.

At the same time, definitively rule out the possibility of using strategic reserves for generation capacity, as they are liable, under the current legislation, to artificially keep fossil fuel capacity in operation and create implicit distortions in energy price formation.

To establish such a market, it will be necessary to do the following:

- require Member States, for each bidding zone in the European electricity system—or at least in continental Europe—to define their security-of-supply objective, expressed as loss-of-load expectation, and their system's peak hours using a public, transparent, and nondiscriminatory methodology;
- establish a harmonized capacity certification methodology and a European capacity register, operating at least on a daily basis and eventually at 15-minute intervals, technologically neutral and open to all generation capacity and explicit demand-response resources;

- **provide for systematic and explicit cross-border participation in the European capacity mechanism through the full coupling of local capacity markets.**

b. Electricity-Network Tariffs Suited to the Needs of the Electricity System

The development of electricity transmission and distribution networks represents both a potential constraint on electrification and a significant source of costs. Increasing quantities of electricity already must be transmitted and distributed, and even greater quantities will have to be in the future, particularly if efforts to improve the temporal flexibility of the electricity system remain limited.

Optimizing the integration of renewable energy into the electricity system while limiting overall costs requires action on both storage and demand flexibility. This flexibility consists of shifting demand toward hours of high electricity generation, particularly sunny afternoons, in order to make use of low-carbon electricity generation. Without these shifts in the timing of certain uses and the deployment of storage capacity, the network will face the following issues:

- surplus generation at certain times, particularly during the afternoon peak in solar photovoltaic generation, requiring electricity to be transported from generating sites to potentially distant consumers because the local demand is insufficient, while also requiring part of the generation to be curtailed;
- insufficient generation at other times, particularly during periods without wind or sunlight and during episodes of extreme cold, requiring electricity generated by potentially distant power plants to be transported to customers because of a shortage of dispatchable capacity capable of meeting demand on its own.

Making the electricity system more flexible will reduce costs for consumers and taxpayers by reducing the need to invest in network reinforcement and by improving the use of generation assets, thereby reducing the amount of renewable or nuclear electricity that must be curtailed. This increased flexibility must be anticipated because it will require substantial investment in certain types of infrastructure—such as converting conventional reservoirs into pumped-storage hydropower facilities and modifying industrial processes—as well as household equipment, including systems for managing heat pumps and electric vehicle charging, and changes in behavior. Moreover, the emergence of new flexibility resources within the electricity system depends on their economic attractiveness to the different actors involved: Producers, suppliers, and consumers.

Only real and visible economic gains for users will allow these flexibility resources to emerge. At present, however, the economic signals faced by the different actors in the electricity system largely conceal the need for flexibility by sending temporally averaged, relatively high price signals. These do not allow market participants to either adopt beneficial behavior or invest in equipment that would enable them to make savings.

Network tariffs, which account for approximately one-third of household electricity bills depending on the level of electricity taxation, provide an effective lever for encouraging such flexibility. Some European states, including Germany, still have flat tariffs that do not reflect predictable fluctuations in network utilization, including the time-of-day or seasonal patterns of generation and demand peaks. Even in countries with a more sophisticated approach to time-of-use and seasonal differentiation, the tariff structure is too often fixed over time and no longer reflects the needs of the current electricity system. This is the case in France, where the Energy Regulatory Commission makes only marginal adjustments to the Tariff for the Use of Public Electricity Networks (TURPE) with each new version, even though the speed and scale of changes in the electricity system require a complete redesign to adapt it to current challenges.

Tariffs that are not adapted to network requirements cannot provide users with an appropriate financial incentive for shifting consumption or providing storage services because these services are not properly recognized as such. The importance of sending an economic signal supporting the flexibility of the electricity system through network tariffs—in order to distribute network use more evenly over time—has been clearly identified by the European Commission.[38] It must nevertheless be implemented in practice within each Member State.

Proposal 10

Adapt Network Tariffs to the Current Needs of the Electricity System.

Require Member States to introduce time-of-day and seasonal differentiation in electricity-network tariffs. Tariffs should distinguish between electricity injection and withdrawal, since the underlying incentives are generally opposed: During periods of local overproduction, withdrawal should be encouraged and injection discouraged, and vice versa. The tariff structure should also be adapted to the territory in which it applies.

[38] *European Commission, Guidance on Innovative Technologies and Forms of Renewable Energy Deployment (Commission Notice), July 2, 2025, paras. 33–42, 2026 OJ C/2026/127, https://eur-lex.europa.eu/eli/C/2026/127/oj.*

Tariffs should be reviewed regularly so that they reflect the needs of the electricity system as closely as possible, independently of political considerations or institutional inertia regarding previously applicable tariffs.

On this final point, energy regulators enjoy the status of independent authorities specifically to protect them from political considerations and inertia, enabling them to adapt and optimize a technical system so that it serves consumers as effectively as possible. A widening gap between the rapid development of the network and only marginal changes to tariffs—as is currently the case in France—is therefore inconsistent with the regulator's responsibilities.

It should be noted that certain states will require preliminary measures before they can genuinely establish network tariffs encouraging flexible energy use and the integration of rapidly expanding renewable energy. These measures include deploying smart meters in Member States that remain behind in this area and, potentially, rationalizing distribution system operators. In certain Member States, the large number of these operators—and the limited resources available to each—hampers both the deployment of smart meters and the management of tariffs that vary over time and are therefore more complex to administer.

c. Restructuring Electricity Forward Products

In addition to taxes and network costs, approximately one-third of the electricity bill results from the purchase of the electricity itself. A large share of this electricity is purchased on forward markets, allowing suppliers to hedge their exposure when offering customers fixed-price contracts lasting one, two, or three years.

The forward products currently offered by EEX, the European Energy Exchange, are structured around two products:

- base load: A constant block of consumption throughout the entire day;
- peak load: A constant block of consumption between 8 a.m. and 8 p.m.

These products do not allow suppliers to benefit from contrasting prices according to the time of day or season, which they could then pass on to consumers through peak- and off-peak pricing arrangements, allowing users to optimize their consumption and thereby save money. Even when a supplier knows that electricity will be very inexpensive during the afternoon in France three years from now, expensive during the early evening and then inexpensive again during the night, the current structure of forward products does not allow it to take account of this pattern. Moreover, even if the supplier knows the shape of spot prices two or three years into the future, it must still minimize its exposure to spot prices as far as possible because knowing their general profile provides no information about their average level at those future dates. In other words, even if it is certain that electricity will be less expensive on a winter afternoon three years from now than during the early evening of the same day, the average value around which the spot price will fluctuate remains unknown.

Hedging on forward markets is therefore essential for suppliers and their customers in order to avoid the risk of default during a crisis, as occurred in certain isolated cases involving insufficiently hedged suppliers during the 2021–22 energy crisis. To allow suppliers to design offers that genuinely contribute to electricity system flexibility, forward products must therefore reflect in their structure the different price conditions prevailing during the day: Morning, afternoon, early evening, and night.

EEX's consideration of a new product corresponding to the afternoon solar peak is a step in the right direction but is insufficient. Unless the day itself is divided into non-overlapping products, suppliers will be forced to purchase averaged products covering different periods—base load or peak load—in order to hedge certain hours, such as the morning, even though these products also cover the afternoon. This will limit suppliers' ability to benefit fully from the new "solar peak" product and reduce its attractiveness.

Proposal 11

Adapt Market Products to the Needs of the Electricity System.

Revise the hourly segmentation of electricity forward products, ensuring that the new products collectively cover the entire day and correspond to broadly homogeneous conditions within the electricity system: Morning, afternoon, early evening, and night.

Conclusion

This paper concludes a three-part series devoted to the European energy agenda of Ursula von der Leyen's second term as President of the European Commission. The first paper argued for an overhaul of the Union's energy and climate governance, centered on targets based on the carbon intensity of final energy rather than solely on the share of renewables. The second drew out the implications for infrastructure by outlining a technologically neutral European Energy Security Act. This third paper operationalizes the downstream component: Adapting electricity markets to a physical system undergoing rapid transformation, without abandoning the fundamental achievements represented by marginal cost pricing, liberalization, and the competitive neutrality of networks.

The foundations established since the 1990s remain relevant. **Marginal pricing is the direct application of neoclassical economic theory to a good for which the balance between supply and demand must be maintained in real time to ensure the physical integrity of the system**. However, certain aspects of the framework must be thoroughly revised in order to align the cost of the electricity system more closely with the price paid by consumers and to accommodate the transition toward a mix dominated by capital-intensive assets with low marginal costs. The Electricity Market Design Regulation of June 2024 established some useful initial foundations; this paper proposes their operational extension.

Three lines of action emerge for improving the systemic coherence of the framework. The first seeks to finance decarbonization at the lowest possible cost to national public finances by coordinating PPAs and two-way CfDs, deploying mixed tenders, and establishing a European counterparty risk guarantee. The second seeks to reconnect price signals with the physical constraints of the system by reforming GOs to move toward hourly granularity, revising network tariffs, and restructuring forward products. The third Europeanizes security of supply through the coupling of national capacity mechanisms, the gradual exclusion of distortive strategic reserves, and the recognition of a dedicated common framework in sector-specific legislation.

These proposals, like all those put forward in the Achieving the EU's Energy Ambitions series, confirm a necessary direction: Technological neutrality in the decarbonization of the European energy system. Whether in relation to support mechanisms for new facilities, the European capacity register, GOs extended to all low-carbon energy sources, or the treatment of life extensions for existing assets, the approach advocated here rejects sector-specific *ad hoc* arrangements in favor of general frameworks allowing each Member State to determine its energy mix in accordance with the competence reserved to it under Article 194 of TFEU. By concentrating public intervention on what the market cannot produce by itself—an administratively determined level of security of supply, the stabilization of cash flows for capital-intensive assets, and the traceability of decarbonization—while leaving market signals to allocate resources among technologies and market participants, technological neutrality is the key to effective state action.

A political window for implementing such a reform appears to be opening at the continental level. More than a series of isolated reforms, the roadmap is clear: It is the coherent sequencing of governance, infrastructure, and markets that will determine the Union's ability to meet its climate commitments without sacrificing its economic competitiveness. In a tense international environment in which energy competitiveness is both a dimension of power and a geopolitical lever, and as the Clean Industrial Deal seeks to reconcile decarbonization with reindustrialization, the reform of electricity markets is less a technical matter than a decisive test of Europe's collective capacity to act.

Annex I • Demonstration of the Mixed Auction Approach

THEORETICAL FOUNDATIONS

Let us revisit the approach presented in the brief, where:

- V (MW) is the new decarbonized capacity opened by the authorities for a bidirectional CfD auction
- C (MW) is the production capacity of the project developer
- x is the share proposed by the project developer as PPA
- $p_{\_CfD}$ is the price proposed by the project developer in the CfD auction
- $p_{\_PPA}$ is the price proposed by the project developer for PPA contracts

In practice, the project developer will proceed as follows:

- Observe on the market its ability to place at a price $p_{\_PPA}$ a share *xC* of its production.
- It then determines the optimal level of its production placed in the CfD, which is the level covering at least *(1 - x)C* so as to maximize the project's long-term leveraged equity IRR, representing the financial return it seeks to achieve and wants to be as high as possible;
  - either PPA demand is weak (either because consumers have a very strong preference for the present and low aversion to future price risk, or because few consumers have the contractual capacity to commit to a long-term contract) or nonexistent (the market not yet being sufficiently liquid—or even established—to constitute a genuine competitive market, in the sense of allowing the project developer to really choose between a PPA and a CfD at equivalent

prices for the same exposure level $\hat{p}$, the *strike price* of the CfD). The optimal level is then obviously 1; all volumes are placed in the CfD, and the project developer will try to place its production at a $p_{\_CfD}$ as high as possible in the auction. **This is therefore exactly the situation of a conventional tender**. If the latter is competitive, it will offer $p_{\_CfD}$ such that the project IRR exactly covers its cost of capital, which we denote $p_{\_0}$;

- or there is PPA demand, and the producer manages to place its production at a price equal to $p_{\_1}$, which designates the sale price of volumes as PPA such that the project IRR then exactly covers its cost of capital, for a given quota $x_{\_max}C$. If the PPA market is competitive and efficient, the project developer is prepared to conclude a PPA as soon as it achieves its target return on equity —that is, any price of at least $p_{\_1}$. As the risk is higher for PPAs than for CfDs, which translates into less favorable debt conditions, we have $p_{\_1} > p_{\_0}$.

One can show that in such a case, if $p_{\_blend}'(0) < p_{\_1} - p_{\_0}$, there exists an optimum for a non-zero value of x. Indeed, noting: $p_{\_blend}(x) = x\,p_{\_1} + (1-x)p(x)$, with $p(x)$ the bid price in the CfD auction to achieve an equity IRR of 10 percent, we find:

$$p_{\_blend}'(x) = p_{\_1} - p(x) + (1-x)p'(x)$$

If the condition is met, we then have $p'(0)<0$, i.e., that incorporating a little PPA into the project's hedge allows the CfD price to be slightly reduced. As on the other side, $p'(1)$ is indeed positive; this implies by the intermediate value theorem that there indeed exists a value of x for which $p'(x)$ is zero, and therefore which minimizes p, the price offered in the CfD auction;

- if finally the PPA market is not competitive, and the producer manages to sell at a better price than $p_{\_1}$, it is interesting to place everything as PPAs (in any case to include as much as possible in the CfD bid if there is a volume constraint).

WORKED NUMERICAL EXAMPLE

Consider, for example, a 100 MW onshore wind farm with capital expenditure of €1,300/kW, a capacity factor of 30 percent, an operating life of 25 years, and maintenance costs of €25/kW per year. Assume that the project developer's cost of equity is 10 percent. We further assume that it has access to the following:

- under a scenario in which the entire output is contracted under a CfD, debt financing with 70 percent gearing at an interest rate of 4 percent over 18 years;
- under a scenario involving partial PPA contracting, potentially extending to 100 percent of output, sculpted debt with differentiated debt-service coverage ratios—a lower DSCR for CfD revenues and a higher DSCR for PPA revenues—and a discount applied to PPA volumes when sizing the debt, resulting in 50 percent gearing at an interest rate of 5.5 percent over 18 years.

If the project developer bids to sell 100 percent of its output under a CfD, it participates in the tender at €55.15/MWh, denoted $p_{\_0}$, which provides precisely the 10 percent return required on its equity. On the PPA market, its equity return exceeds 10 percent as soon as it places its output at a price above €61.15/MWh, denoted $p_{\_1}$.

Where debt terms deteriorate continuously as the PPA share increases, it is preferable to seek CfD coverage alone if PPAs are placed at a price below €61.15/MWh. If PPAs can be placed at a higher price, it is always advantageous to maximize the PPA share, potentially up to 100 percent, because this produces an equity return that is consistently higher than the return available through the CfD auction. In the latter, the developer will bid at the lowest possible price while continuing to meet its target return. Finally, where the PPA price is exactly €61.15/MWh, the condition set out above is not met in this case study because the debt terms remain sufficiently favorable under the PPA structure. Therefore, it remains advantageous to maximize the PPA share.

Where debt terms do not deteriorate continuously—for example, because threshold effects arise once a certain PPA share is included—circumstances may exist in which there is a nontrivial local optimum for the CfD share, meaning an optimum other than 0 or 1. One of the most frequent cases, and one of those closest to actual market practice, arises where the debt-repayment period shortens significantly once the PPA share exceeds a particular threshold, such as 50 percent. In most cases, this causes that threshold to become the optimal PPA share, provided that the PPAs are placed at a price above $p_{\_1}$.

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Energy is at the heart of the European Commission's priorities. While the von der Leyen mandates have been marked by a succession of crises, they have also helped define a common ambition: Achieving carbon neutrality by 2050. This comes with medium-term intermediate milestones: A 55% reduction in greenhouse gas emissions compared to 1990 levels by 2030—implemented through sectoral policies grouped under the "Fit for 55" legislative package—and, more recently, a target to reduce emissions by 90% by 2040.

Beyond the challenges of reforming European energy-climate governance (the focus of the first policy paper in this series) and the mechanisms to facilitate a massive, rapid, and coordinated deployment of low-carbon infrastructure—including production, transmission, distribution, and storage (the focus of the second paper)—the energy transition must also be driven by private investment. This requires an appropriate market framework that values both low-carbon production and security of supply.

This policy brief concludes Institut Montaigne's trilogy on European energy policy. While the current architecture of European markets has long proven its worth, its parameters are no longer adapted to the transformation of the power mix. The massive penetration of variable renewable energy is disrupting the model, resulting in repeated occurrences of negative prices, increased intraday volatility, and the erosion of the long-term signals needed for massive investment.

This paper provides a practical and clear explanation of how the electricity market works, and suggests actionable solutions for its adaptation. Europe's dual challenge is immense: Successfully achieving the complete defossilization of its energy systems while preserving its industrial base.

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