Electricity Markets in Transition

A proposal for reforming European electricity markets

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Abstract

In the context of the debate about the reform of electricity markets in Europe, this document proposes a new electricity market architecture. It is based on two pillars: (i) a well-functioning short-run energy market; and (ii) a set of efficient and equitable long-run contracts, signed between firms and the regulator on behalf of all consumers. The design of long-term contracts takes into account the characteristics of the various technologies in order to strike the right balance between exposing them to the short-run price signals while de-risking the investments. The proposal would facilitate the achievement of carbon-free and diversified power markets, allowing for substantial reductions in the cost of electricity for consumers. The proposed design is mostly in line with the recent European Commission (2022b)'s proposal, and it further provides details on key elements that the European Commission has not yet specified.

Keywords: electricity, energy crisis, energy transition, market design.

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1 Introduction

On September 12, 2022, in her State of the European Union speech, the President of the European Commission, Ursula von der Leyen, acknowledged the need to reform electricity markets in Europe: *"The current electricity market design – based on merit order – is not doing justice to consumers anymore. They should reap the benefits of low-cost renewables. So, we have to decouple the dominant influence of gas on the price of electricity. This is why we will do a deep and comprehensive reform of the electricity market."* (von der Leyen, 2022a).

She had good reasons to worry. Europe was going through the worst energy crisis in decades, and its systemic effects were starting to propagate across the economy. The conflict in Ukraine had triggered significant reductions in the supply of Russian gas,[1] which had pushed gas prices to record highs (Figure 1).[2] The multiple-fold increase in gas prices relative to their historical average reflected a growing fear that gas supply during winter would not be enough to avoid curtailments.

In turn, the gas price increase had been passed on to wholesale electricity markets – where gas-fired generation often sets market prices – leading to electricity prices well above their historical average (Figure 2). The heat wave across Europe, the low hydro and wind generation, and the extended outages in the french nuclear fleet (that was operating at only 40% of its capacity) had also contributed to the electricity price increase.

The sharp increase in energy prices was the major contributor to rising inflation in the Euro area. October inflation hit a feared two-digit rate – 10.6%, – the highest since the euro was created in 1999, with energy prices increasing by 41.9%, i.e., adding 4.44 % directly to total inflation (Figure 3). Their indirect effects were felt across the whole economy as firms passed on the increase in their energy costs to the prices of many other goods and services. Indeed, inflation excluding energy also climbed to a record high,

[1] This was first made manifest by mid-2021 when gas storage by Gazprom in Europe was well below its historical average. By June 2022, gas flows from Russia to Europe were less than one-third of the previous five-year average (Zachmann, Sgaravatti, and McWilliams, 2022).

[2] In particular, gas prices at the dutch exchange (TTF) surged above €310/MWh in late August 2022, which was paralleled by similar price increases in the Italian exchange. Prices in the Iberian gas market (MIBGAS) remained below the European average due to Iberia's large regasification capacity and limited interconnection capacity. Still, MIBGAS prices also exceeded 200€/MWh. The historical average of wholesale gas prices is around 20€/MWh.

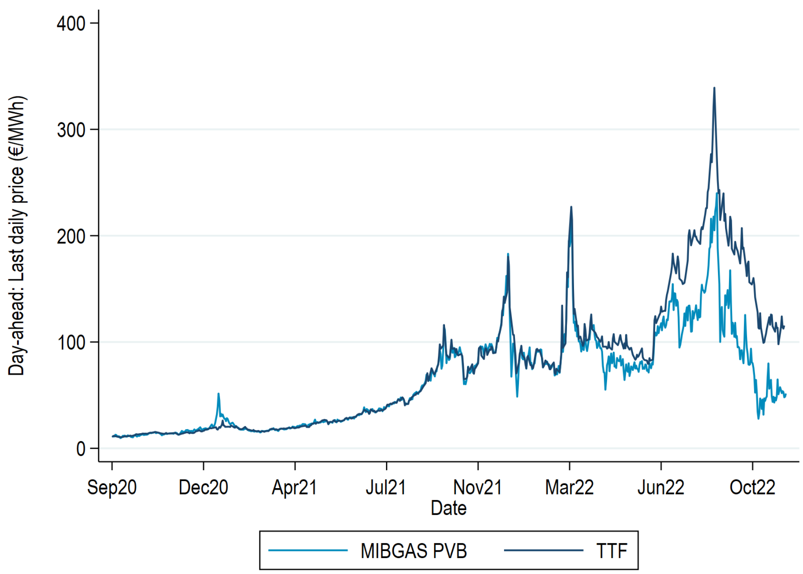


Figure 1: Gas prices at the Dutch (TTF) and Iberian (MIBGAS) gas hubs

Source: MIBGAS, investing.com

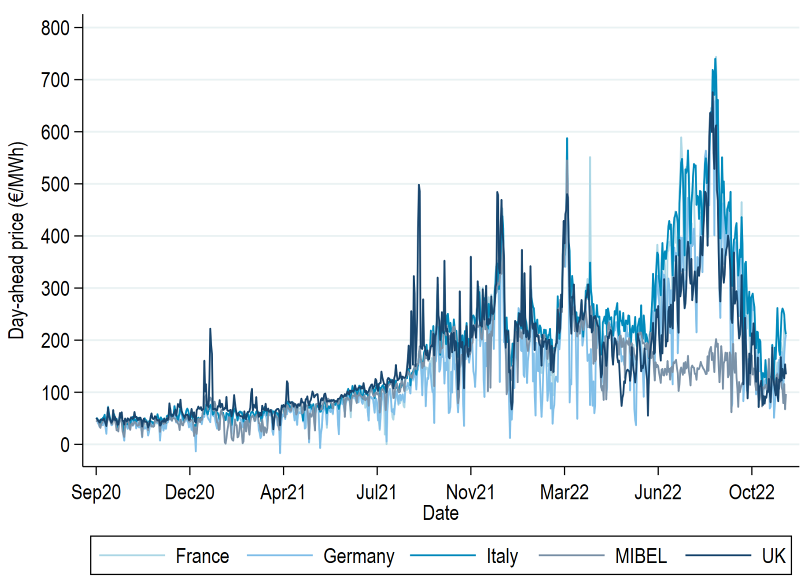


Figure 2: Electricity prices in European wholesale electricity markets

Source: esios, Red Eléctrica de España

6.9% (Eurostat, 2022).

The response of the European Central Bank was to increase interest rates to bring prices down. By October 2022, it had decided on two consecutive 75 basis points increase in interest rates, despite early signs of economic weaknesses. Growth figures showed a weak 0.2% rise in GDP in the euro area in the third quarter, below a 0.8% rate in the second quarter. Three European member states (Belgium, Latvia, and Austria) had already registered negative GDP rates.

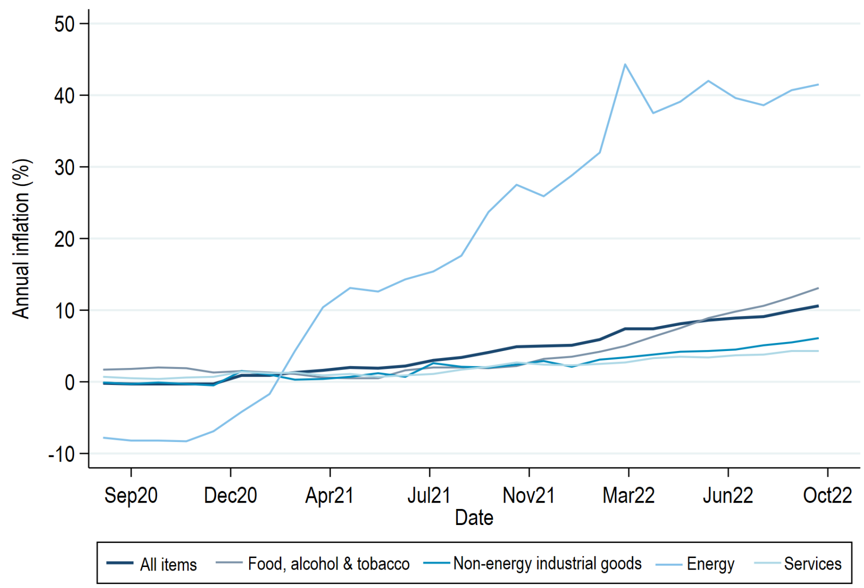


Figure 3: Euro area annual inflation and its main components

Source: Eurostat (2022)

It is in this context that the European Commission embarks on a discussion about the need to reform electricity markets. Some previous attempts to reform electricity markets had turned unsuccessful, as exemplified by the discussions during the European Council meeting in March 2022. Member States asked the Commission to submit proposals to tackle excessive electricity prices (European Council, 2022), a request that ended with the European energy regulator's conclusion that *"the current market design is worth keeping"* (ACER, 2022). However, the overwhelming evidence about the economic consequences of the electricity price increases made it compelling to address the problem. This was compounded by the doubts raised as to whether the current electricity market design is fit for achieving the Energy Transition in Europe at least cost for society.

1.1 Is the current electricity market design to blame for the current crisis?

It is beyond dispute that electricity prices have increased due to the gas price shock. However, the electricity market design has aggravated the problem. Electricity market design is at the core of the problem because it establishes that all generation technologies should be paid at the price offered by the most expensive plant needed to cover demand in short-run markets.[3] Therefore, while only the costs of fossil-fueled generation have increased, all technologies have received inflated prices reflecting the cost of gas-fired generation, not their own. This has caused electricity prices to jump well beyond the increase in costs.

The current electricity market design is inspired by the textbook competitive electricity market model, which concludes that technology-neutral electricity markets maximize efficiency and consumer surplus while generators break even (Hogan, 1993). However, this conclusion rests on an assumption that does not apply in practice: the free entry (and exit) condition. Under this assumption, firms make zero profits as, otherwise, entry or exit would take place until the zero profits condition holds.[4] However, in real-world markets, various entry and exit barriers (including legal obstacles or constraints on the availability of resources or locations, among others) prevent profit adjustments, or at least not at the necessary speed. Even in those technology segments with free entry (e.g., renewables), investments take time and face constraints (e.g., availability of materials and adequate sites, administrative approvals, access to the grid, etc.), which prevent rapid adjustments in electricity prices and firms' profits. In sum, even if entry is possible, delays in market adjustments can be very costly economically, socially, and politically.

To illustrate this, using Eurostat (2020)'s data on the energy mix in Europe and

[3] This is true even when a fraction of total electricity is traded through bilateral contracts, outside the pool. The reason is that all contracts tend to converge to the underlying market's price, which is the pool.

[4] More specifically, the competitive electricity market model assumes that *"generation capacity will enter (exit) the wholesale market as long as profits are positive (negative). Thus, competitive investment drives long-run profits to zero. This implies that there is short-run allocative efficiency and long-run efficiency of capacity investments"* (Borenstein and Holland, 2005). These results would not hold in the absence of free entry.

the International Energy Agency (2020) 's cost estimates,[5] it is possible to compute the price-cost markups of non-fuel generators when paid at 300€/MWh – a proxy of current electricity wholesale prices:[6] 1,000% for nuclear, 750% for hydro and onshore wind, and 700% for utility-scale solar. Multiplying these profit margins times their generation in 2020,[7] delivers an astonishing figure of approximately 400 Billion € of excess profits for electricity generation in Europe over a year.[8] The aim of reporting this rough estimate is only to illustrate the orders of magnitude of the problem.

In sum, the wedge between the marginal costs of gas-fired generation and the average costs of the remaining plants has led to excessive profits at the expense of consumers. To mitigate this, member states have put in place several short-lived market interventions – ranging from windfall taxes on generators' profits to introducing a reference price for gas to lower the electricity market price – and the European Commission has allowed member states to introduce a price cap of up to 180€/MWh to inframarginal generation (excluding hydro). These measures have temporarily alleviated the pressure on electricity prices but have broadly left the market arrangements unchanged.

[5] In industry parlance, the average costs of electricity generation are referred to as the Levelized Costs of Energy (LCOE). Note that these costs include both investment and production costs. Hence, paying generators at their LCOE allows them to break even.

[6] While there are cost differences across plants depending on their vintage, location, or technology, the median estimates for the average costs of nuclear and hydropower generation are 30 and 40 USD/MWh, respectively. In the case of renewables, the median average costs of utility-scale solar and onshore wind are 43 and 40 USD/MWh, respectively. These cost estimates are computed assuming a 3% discount factor. These costs have remained broadly unaffected during the current crisis since these plants do not consume fossil fuels and do not need CO2 permits. Older plants face higher average costs as they did not benefit as much from the learning and scale economies. However, the costs of the newer renewable plants have gone below those figures, as demonstrated by recent auctions in Europe. For instance, Spain ran two auctions in 2021, and the resulting prices ranged between 25€/MWh and 31€/MWh for onshore wind and utility-scale solar.

[7] In 2020, Europe produced 647 TWh in nuclear power plants, 368 TWh in hydro plants, 392 TWh in onshore wind plants, and 141 TWh in solar plants (Eurostat, 2020).

[8] This figure does not include the gains made by fired-gas generation, a vast majority of which buys gas at lower prices under long-term contracts and yet price their electricity as if they purchased all gas at the spot price.

1.2 Is the current electricity market design fit for the energy transition?

Beyond the current economic crisis, there is a powerful reason to reform electricity markets in Europe: their current design is not well suited to unchain the energy transition in the power sector, which is the cornerstone for economy-wide carbon abatement.

These concerns are becoming mainstream. As MIT Professor Paul Joskow (2019) has put it: *"These developments* [the wider penetration of renewable energy] *raise profound questions about whether the current market designs can be adapted to provide good long-term price signals to support investment in an efficient portfolio of generating capacity and storage consistent with public policy goals."* The UK Government (2022) has also voiced similar concerns: *"Current arrangements will not deliver a fully decarbonised power system by 2035, as renewables alone will not be enough to meet 2035 targets, and the Capacity Market is unlikely to bring forward low carbon flexibility at the pace required."*

First and foremost, decarbonizing the power sector requires significant investments in new low-carbon generation capacity. Indeed, Europe has been updating its renewable energy targets up to 45% in order to meet the goal of reducing net greenhouse gas emissions by at least 57% by 2030. Second, to counteract renewable resource volatility and seasonality, renewable investments must be coupled with flexible resources, including energy storage, demand response, and interconnection capacity. Last but not least, decarbonizing hard-to-abate emissions (in transport, heating, and manufacturing) requires that the lower costs of renewable generation translate into lower electricity prices as a necessary condition to promote carbon abatement through electrification. However, the current electricity market arrangements are not well suited to meet these requirements, as argued below:

1. **Investments in renewable energy are not adequately rewarded**
   The increasing penetration of renewables will put downward pressure on electricity prices. In the absence of market power, market prices reflect the marginal cost of the price-setting technology, which is very close to zero in the case of renewable energies. Thus, as more renewables get deployed, the likelihood that renewables will set low market prices will go up, pushing average market prices down. This price-depressing effect will be particularly acute for renewables because prices go

down when they produce – a phenomenon known as the *cannibalization effect*. This price-depressing effect is already taking place in some European countries with high shares of renewable energy, particularly during weekends when demand is lower or during winter when wind production is higher.

Hence, at least until energy storage gets massively deployed, the changing availability of renewable resources will make electricity markets fluctuate between high-priced periods (when renewable energy is scarce) and low-priced periods (when it is abundant). However, renewables will only capture the lower tail of the price distribution, i.e., their captured prices are below the market average price.[9]

Access to capital at low financing costs is critical in the case of renewables (or in low-carbon assets, more generally), given that they are highly capital-intensive. However, uncertainty about future prices and whether these will be enough to cover their costs makes it difficult for investors to finance their projects. This challenge is particularly relevant for medium-sized stand-alone companies that, unlike the large vertically integrated energy companies, do not have a natural hedge and cannot support their projects with their balance sheets. Indeed, some banks have shown reluctance to fund renewable projects exposed to future price risks.

In sum, the expected evolution of future prices weakens generators' incentives to invest in renewable energy and could even jeopardize the objective of achieving carbon-free electricity markets.[10]

[9] The competitive electricity market model does not see this as a problem. Again, the free entry and exit assumption and the perfect foresight assumption imply that investments in renewables adjust until their captured price covers their investment costs. Hence, by assumption, renewables always break even.

[10] In contrast to this view, some stakeholders advocate in favor of the current market design as they argue that today's high electricity prices make renewable energy investments more profitable. However, this view disregards the fact that investors do not care about today's prices but rather about the net present discounted value of future prices during the lifetime of their assets. For instance, an investor who considered investing today in a plant that would become operational by 2024 would be concerned about the expected electricity price from 2024 to 2049 (assuming a 25-years lifetime), weighing more on those hours in which the plant would produce more. It is not easy to estimate such an expected price, not least because futures markets are not very liquid and do not trade long enough contracts. In any event, not disregarding the high degree of uncertainty, the future prices captured by renewable investments will necessarily be low in markets with high renewables penetration.

2. **Investments in flexibility and firm capacity are not adequately rewarded**
   Investments in assets that provide flexibility to ramp up or down in response to changes in renewables' availability become key to guaranteeing security of supply at all times and nodes of the network. However, flexibility is not adequately rewarded in energy-only markets, where payments to generators are solely a function of their production. Furthermore, some flexible technologies are still not mature enough (e.g., some forms of energy storage are still benefiting from learning externalities) and need additional support to become profitable.

   The same applies to plants providing firm capacity: they are a valuable hedge even when they do not produce but are only rewarded for their production. This issue will become particularly worrisome as more renewables get deployed. Indeed, the load factors of backup plants will go down and become increasingly uncertain as they will produce only when renewable energies will not be enough to meet total demand.

   The inability of energy-only markets to provide the right incentives to invest in generation capacity is well understood (Joskow, 2008; Fabra, 2018; Llobet and Padilla, 2018). Indeed, several European regulators have introduced capacity mechanisms to address the so-called missing money problem – the fact that generators' revenues do not capture the total value of investments that improve security of supply. However, there are reasons to believe that these mechanisms should be reviewed. First, since these mechanisms tend to be technology neutral, they fail to discriminate across the different services provided by the various types of assets (e.g., short-run versus long-run storage, demand response, resources with faster ramping rates, etc.), leading to the under-provision of some of the resources required. And second, some degree of homogenization across the diverse capacity mechanisms in Europe would facilitate market integration.

3. **Beyond electricity markets, high and volatile electricity prices are a threat to carbon abatement**
   High and volatile prices hinder electrification as they discourage households and firms from investing in electric equipment (e.g., heat pumps to decarbonise heating, electric vehicles to decarbonise transport, and green hydrogen to decarbonise

some of the hard-to-abate industrial energy needs). Furthermore, high energy prices undermine the case for carbon prices as they make it politically unfeasible to put additional pressure on energy bills.

1.3 How will Europe address the electricity market reform?

Europe has by now understood that the knockdown impacts of the energy crisis on the economy and the need to speed up the energy transition require a reform of electricity markets. On November 2022, the European Commission (2022b) circulated a non-paper entitled *"Policy Options to Mitigate the Impact of Natural Gas Prices on Electricity Bills"*, which describes some of the key ingredients of the structural reform that the European Commission is working on. The objective is two fold: to *"mitigate the effect of high gas prices on power prices"* and bring *"the benefits of lower cost renewables...to consumers on a lasting way"*. The proposal rests on the combination between long-run contracts and a liquid short-term energy market:

1. *Remunerating Renewables and other Technologies Based on Their True Production Costs*

   For the new generation plants, the proposal is to rely on long-term contracts, which would be implemented through Contracts-for-Differences. Since these contracts would be allocated through auctions before investments are made, the expectation is that their prices would reveal the actual average costs of the investments.[11] For the existing plants, the proposal is to initially rely on the current inframarginal cap, while incentivizing a transition towards a Contracts-for-Differences pricing structure.

2. *Effective Competition for Gas in Well-Functioning Short-Term Markets*

   In addition, the proposal relies on a well-functioning short-term energy market to achieve productive efficiency at every moment. This market will be key to counteract the volatility of renewable resources through the dispatch of gas-fired generation, storage, and demand response, as well as to ensure that trade takes place efficiently across member states.

[11] See Section 3.1 for a definition of these contracts.

The remainder of the paper is devoted to describing a new electricity market architecture that is broadly in line with the European Commission's proposal (with one key difference).[12] In doing so, it fills up some details not yet provided by the European Commission while discussing the objectives and economic principles that justify a reform in this direction. Section 2 gives an overview of the proposed electricity market architecture and discusses how it contributes to achieving efficient and equitable outcomes. Section 3 describes the proposed long-run contracts. Section 4 provides details on the regulatory treatment of the various technologies. Section 5 sets out the paper's main conclusions.

Many crucial regulatory debate elements are out of this document's scope. These include the regulation of network investments and the expansion of network interconnection, the performance of the EU ETS cap & trade market for emission permits, and the measures to reduce gas prices, to name a few. By no means does this imply that they do not deserve equally detailed treatment.

2 A New Electricity Market Architecture

We propose a market architecture that allows reconciling the efficiency and equity objectives by combining short-run energy markets – that provide short-run signals for efficient operation and consumption – with long-term contracts – that facilitate efficient investments in generation while adjusting their profitability through competitive forces whenever possible (see Figure 4 for an illustration of the building blocks of the proposal).

Before moving to the proposal, we enumerate some economic principles that inspire the regulatory proposals described below.

1. Remunerating generators according to non-linear prices (a fixed fee, that can be positive or negative, plus a term that depends on short-run prices times output) allows to preserving the short-run price signal while providing a fair rate of return to all generation technologies.

2. Since risks are costly, allocating them efficiently allows to reduce costs and prices. The resulting efficiency gains can be subsequently shared with consumers.

[12] As it will be later described, the main discrepancy regards the treatment of the existing generation plants. See Section 3.3.

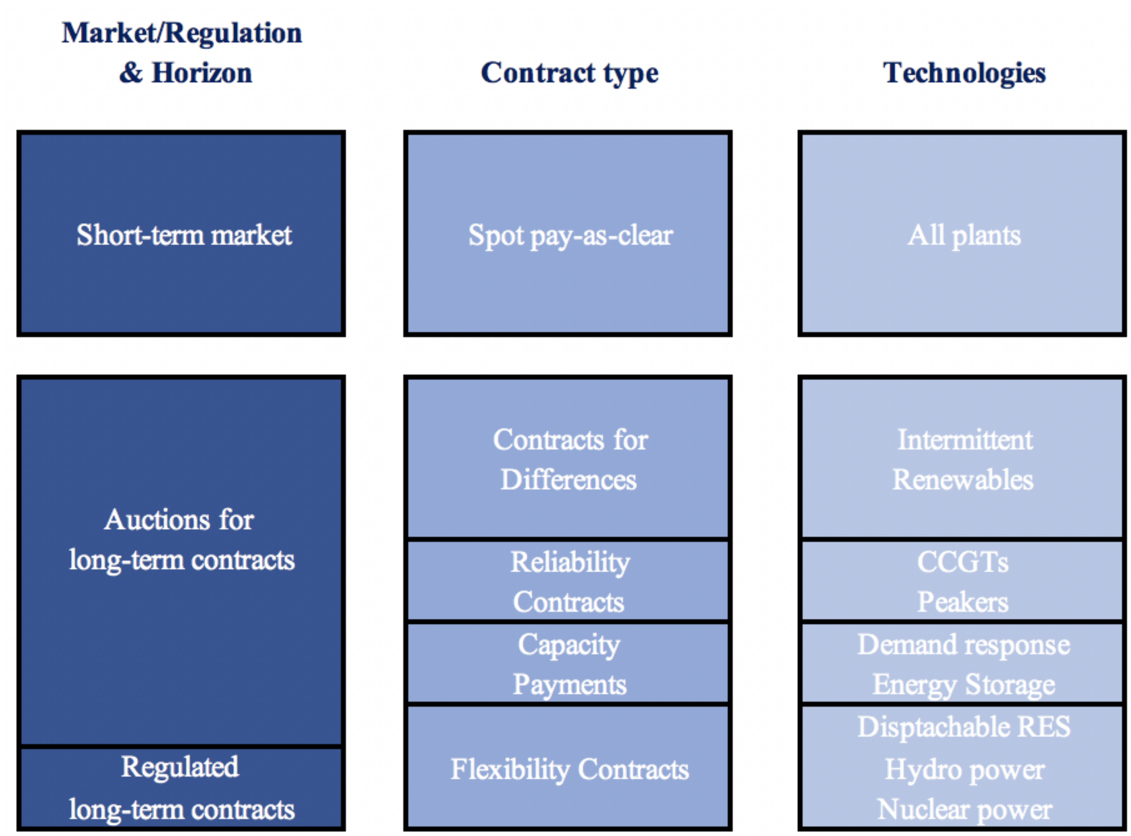


Figure 4: Proposed market and regulatory architecture

3. There is a trade-off between de-risking the investments and exposing technologies to short-run prices. This trade-off depends on the characteristics of each technology, depending on their ability to respond flexibly to short-run price signals.

4. The suitability of technology-neutrality should be assessed on a case by cases basis. If the costs of the competing technologies are too asymmetric, technology-neutrality tends to overcompensate the low cost technologies. It might also penalize technologies that are needed.

5. Competition is a powerful tool to set prices and quantities whenever the market is competitive. Otherwise, regulation might be a preferable option.

2.1 A well-functioning short-term market

At every moment, productive efficiency requires that electricity demand must be covered by the plants with the lowest marginal costs. As the costs of meeting demand change at high-frequency (due to changes in the availability of renewable energies and changes in the prices of fossil fuels and carbon permits), the final dispatch must incorporate these changing costs in the short run. At the same time, flexible assets should be incentivized to shift demand/supply across time, from when it is less valuable to when it is most valuable for the system. Two additional conditions are necessary for short-run efficiency: (i) generators must not exercise market power, as it would distort the merit order across plants and inflate the price signal, and (ii) there must be the possibility to trade electricity across members states to ensure the minimization of the overall costs of meeting electricity demand in Europe.

To achieve these goals, the proposal is to rely on a liquid day-ahead market (or pool), that operates as a **pay-as-clear auction**. Reliance on a liquid and transparent day-ahead market contributes to short-run efficiency by allowing the final dispatch to incorporate the changing costs and availability of electricity generation in the short run.

Electricity trade across member states would be carried out at the resulting short-run prices, allowing to maximize productive efficiency across borders, subject to the existing interconnection constraints. The fact that some of the energy traded through the short-run market would be subject to long-term contracts minimizes the likelihood of distortions due to market power (as will be explained later).

To maximise market liquidity and achieve full transparency regarding plants' availability, our proposal is to make **participation in this market compulsory** for all the demand and supply units. Market agents are free to enter into financial contracts with third parties. Sufficient market liquidity is needed to ensure that no low-cost plants remain idle while high-cost plants operate, which could be the case if some plants commit their output outside the pool (Mansur and White, 2012).[13] Additionally, a liquid pool also facilitates entry by independent non-vertically integrated companies, which should contribute to reducing market concentration and market power.[14]

[13]Mansur and White (2012) examine market outcomes before and after a large region in the Eastern US switched from a system of bilateral contracting to an auction-based market design. They found that the organised market design substantially improved overall market efficiency, beyond the implementation costs, mainly due to better information aggregation about trading opportunities. In particular, they find that switching to the centralised design reallocated production from higher-cost plants to lower-cost plants.

[14]Furthermore, as will be explained further below, the fact that all demand participates in the pool

Last, we propose that generators submit **bids for each of their plants** (and not for their portfolios). Portfolio bidding and self-dispatch, a common practice in Europe, make it difficult for regulators and competition authorities to monitor generators' bidding behaviour. Also, it does not allow System Operators to know which plants are available and which are not, which is instrumental for security of supply. For these reasons, our proposal contemplates that firms submit bids per production plant, not for their whole portfolio. Intraday markets provide the flexibility they might need to change their production plans as real-time approaches.

2.2 Efficient and equitable long-run contracts for all consumers

Given the scale of the new investments required, the most critical challenge of the electricity market design is to minimise the long-run costs of meeting demand with low-carbon resources while guaranteeing security of supply. Since low-carbon assets are long-lived and capital intensive, it is vital to put in place mechanisms that allow for efficient investment decisions. This involves a two-fold objective:

(i) The risk of cost recovery must be minimised and efficiently allocated between firms and consumers; and

(ii) Generators must face adequate incentives for the location and technology decisions regarding the new assets.

Efficiency cannot be disentangled from equity considerations, not least because the electricity price – which determines how total surplus is split between firms and consumers – is an input cost for other sectors of the economy. Cost-reflective prices for electricity are also crucial for the efficiency of long-run investment decisions such as industry location or electrification. Hence, an indispensable objective is that:

(iii) The lower costs of low-carbon generation must be passed on to the final consumers.

To achieve long-run investment efficiency and equitable outcomes, the proposal is to rely on a system of long-term contracts signed between the regulator (who acts on behalf

greatly simplifies the liquidation of the CfDs so that all consumers benefit from the lower costs of the inframarginal technologies and contribute to the costs of securing supplies.

of all consumers) and the generators.[15] These contracts are settled against the short-run market prices, and incorporate different degrees of price exposure depending on the characteristics of the various technologies (as described in Section 4).

The fact that these contracts are a cornerstone of our proposed market design explains why we propose relying on a pay-as-clear format for the short-run market (see above) rather than on a pay-as-bid format. First, settling long-term contracts against a single market clearing price is more straightforward and transparent than settling it against each plant's winning bid. And second, pay-as-clear and pay-as-bid give rise to similar market outcomes in competitive markets. However, if generators can act strategically, pay-as-bid tends to be more effective at curbing market power (Fabra, Fehr, and Harbord, 2006; Fabra and Llobet, 2022; Fabra, 2003). Yet, we expect that reliance on long-term contracts will be enough to make the short-run market sufficiently competitive, with no need to change the auction format to pay-as-bid.

Long-term contracts allow for an efficient transfer of risk – from the more risk-averse side (i.e., the private investors) to the less risk-averse side (i.e., the system as a whole). Contracts between power producers and the regulator reduce counter-party risk compared to PPAs between private companies, and contribute to increased liquidity in forward markets, particularly for contracts of long duration. In this way, our proposal contributes to de-risking the investments, which facilitates the investors' access to funding opportunities at a lower capital cost. In turn, using auctions to allocate these contracts allows passing on these efficiency gains to final consumers.

Our proposal can thus be viewed as a centralised system of Power Purchase Agreements (PPAs). However, it has several advantages relative to a system of private PPAs between generators and large energy consumers or retailers:

1. First, by relying on contracts between power producers and the regulator, our proposal significantly reduces counterparty risk, which has shown to be instrumental in reducing the costs of procuring renewable energy (Ryan, 2021). No other market player can credibly parallel the regulator's ability to commit over long periods.

2. Furthermore, private counterparties have shown to be unwilling to bear the risk

[15] The counterparty of these contracts could be the regulator or any entity representing the system as a whole. In the UK, they have opted to create the so-called Low Carbon Contracts Company & Electricity Settlements Company, a private limited company owned by the State.

of future price fluctuations for more than a few years. This has resulted in a lack of liquidity in forward markets, particularly for contracts of enough duration relative to the plants' payback periods.[16] Our proposal addresses this market failure by empowering regulators to provide liquidity currently missing in private PPA markets.

3. Last but not least, a system of centralised PPAs guarantees that all consumers – regardless of their bargaining powers – benefit equally from the reduced counterparty risk and the enhanced bargaining power of the single buyer.

Our proposal also contributes to achieving equitable outcomes. If the auctions for long-run contracts are sufficiently competitive, the resulting price will reflect the average cost of the investments, thus giving a fair rate of return to the investors and allowing consumers to benefit from the lower costs of the low-carbon investments. The existing assets would also obtain a fair rate of return through the use of contracts at regulated prices (see Section 3.3).

However, there is a risk that the auctions for long-run contracts are not sufficiently competitive if there is not enough participation. One reason might be that the outside option of selling directly to the short-term market, without entering into long-term contracts, might be relatively more attractive. Once renewables are massively deployed, the short-term market prices captured by renewables will converge towards their (almost zero) marginal costs, i.e., below their average costs. Hence, entry outside the auction will not be attractive. Until then, participation in the auction could be promoted by limiting the maximum price that renewables can obtain in short-run markets.

Th next two sections describe in more detail the design of long-run contracts and the treatment of the various technologies.

[16] The prediction of the competitive electricity market model is that these contracts would arise spontaneously. For instance, Hogan (1993) predicted that *"In the presence of the short-run market, many variations on the theme of contracts for price differences will arise naturally. Suppliers with generation can sign contracts with customers and provide any desired mix of fixed and variable prices over some extended period."* This prediction has not been satisfied in practice, as reported by ACER (2022).

3 Which Types of Long-run Contracts?

Given the critical role of the various long-term contracts proposed, we now focus on their specific design. We suggest using two types of long-run contracts, depending on the characteristics of the technologies: contracts-for-differences (CfDs), which in turn allow for various design choices, and capacity payments.

3.1 Contracts-for-Differences

Under a contract-for-differences (CfD), generators sell their electricity in the market and then pay/receive the difference between a 'strike price' and the 'reference price' times a 'reference quantity'.[17] The strike price can be set by the regulator or through an auction. If the auction is sufficiently competitive and is run before the investment has been made, the resulting strike price reflects the plant's average cost.

There are different types of CfDs, with different properties, depending on how the reference price and quantity are defined.

Two-way Contracts-for-Differences. The simplest type of CfD (which we refer to as a two-way CfD) is one in which the 'reference price' is the market price actually earned by the plant, and the 'reference quantity' is the actual output it produces (Figure 5). This contract implies no price exposure and no price risk.

Formally, we can express generators' payments under Contract-for-Differences as follows,

$$\pi = pq + (f - p')q$$

where π denotes the plant's payments, p is the price at which the plant sells its output q in the market, f is the contract's strike price, and p' is the reference price. The above expression can also be written as

$$\pi = fq + (p - p')q$$

[17] If the reference price falls to zero or even becomes negative, the plants are not paid at the strike price. This discourages these plants from bidding negative prices down to minus the strike price, which would not reflect their actual variable costs.

showing that the plant sells its output at the strike price f and obtains a bonus (penalty) if it sells its output at a price above the reference market price. If the latter equals the price actually received by the firm, then its payments are simply fq.

A slight modification of the two-way CfD described above would be to set the reference quantity ex-ante (using, for instance, a measure of the plant's capacity). Doing so has the additional advantage of mitigating generators' incentives to withhold output. If they do, they lose the difference between committed and actual output times the market price. To see this, let k denote the pre-determined output. Payments become

$$\pi = pq + (f - p')k,$$

which can be re-written as

$$\pi = fq - (k - q)p$$

where we have assumed that the reference price equals the price actually received by the plant, $p' = p$. Interestingly, the last term in this expression becomes a penalty for withholding output, i.e., if $q < k$.

Two-way Contracts-for-Differences provide the following benefits:

- Capacity owners reduce the uncertainty over cost recovery – which, in the case of the new investments, contributes to reducing their capital costs – while consumers get protection against excessive prices.
- Competition for these contracts through auctions allows consumers to benefit from the lower financing costs.
- CfDs mitigate market power, as generators would not benefit from increasing the market price above the strike price (Fabra and Imelda, 2022), and they can be penalized for withholding.
- The CfD can be designed so as to reduce the incentives for capacity withholding.

Flexibility contracts. Contracts-for-Differences can also contain a sliding premium so as to face generators to the desired degree of price exposure. We have labeled these contracts as *flexibility contracts*. For instance, the regulator could set the 'reference price'

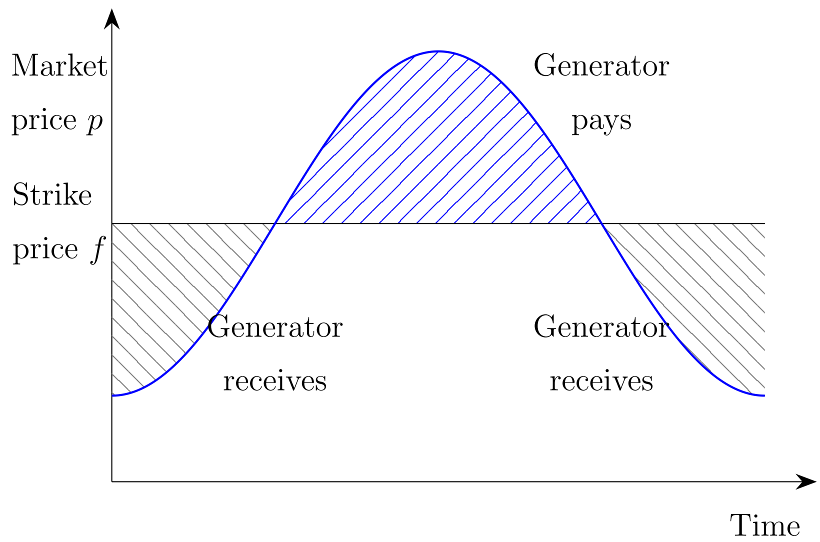


Figure 5: Contracts-for-Differences

Notes: Under a two-way Contract-for-Differences (CfD), generators sell their electricity in the market and then pay/receive the difference between a 'strike price' (f) and the 'reference price' (p). The shaded area represents total payments from the generator to the regulator or vice-versa.

p' equal to the average market price over an extended period, e.g., a year, $\tilde{p}$ (Figure 6).[18] In this case, payments become

$$\pi = fq + (p - \tilde{p})q$$

Now, the second term can be interpreted as a bonus for flexibility, i.e., a reward for plants that produce at times when prices are above the average, $p > \tilde{p}$. Symmetrically, the plant has to pay a penalty whenever the plant operates below the market average. Since the bonus or penalty size equals the difference between the actual market price and the average market price, the generator faces total price exposure.

This type of contract is thus suitable for hydropower plants that can decide when to produce with their stored amounts and for nuclear plants that have to choose when to schedule their maintenance periods. Note that if generators could influence the average price, they would like to reduce it to maximize the flexibility bonus. In this sense, flexibility contracts mitigate the incentives to exercise market power. However, they

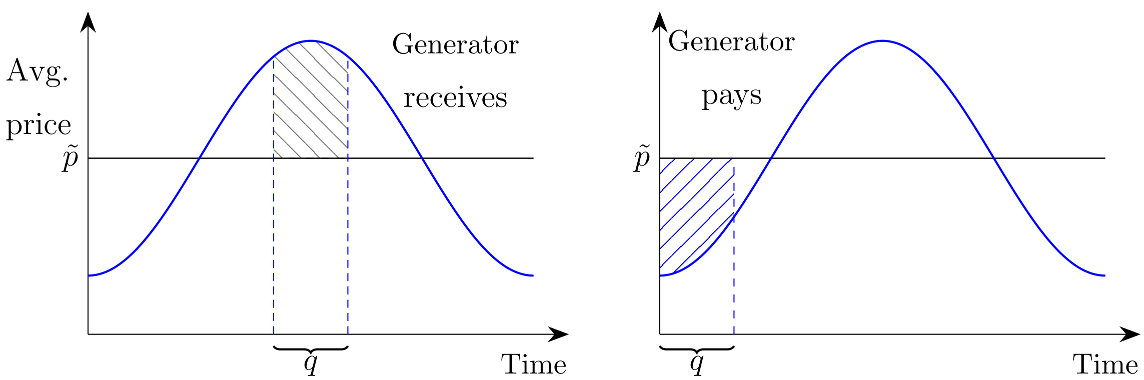
[18] In financial terms, this contract is equivalent to a combination of a spot contract and an Asian forward with strike f. This contract is known as a CfD with a sliding premium in the electricity jargon. Aures (2022) provides a concise definition of the difference across contract types.

might also be encouraged to increase the wedge between their captured price and the average market price to increase the bonus payment.

Furthermore, as discussed above, if the contract is defined over a pre-determined output, it is possible to mitigate the incentives for withholding. The contract would thus include a flexibility bonus/payment and a penalty for withholding,

$$\pi = fk + (p - \tilde{p})k - (k - q)p$$

For renewables, $\tilde{p}$ could be made technology-specific, i.e., be defined as the average price captured by plants belonging to a specific technology over a given period (e.g., a month), similarly to the German *Reference yield model*.



(a) Flexibility bonus

(b) Flexibility penalty

Figure 6: Flexibility contract or CfD with a sliding premium

Notes: The flexibility contract pays the generator's production at a strike price, set by regulation or through an auction, plus a flexibility bonus or penalty depending on whether production is at prices (p) above or below the average market price ($\tilde{p}$). On Panel (a), the generator produces at a peak time and receives a bonus equal to the difference between the actual hourly market price and the average price. On Panel (b), the generator produces at an off-peak time and pays a penalty equal to the difference between the average price and the actual hourly market price.

Flexibility contracts provide the following benefits:

- Capacity owners face full price exposure and hence the correct incentives to dispatch it when it is most valuable for the system.

- Auctioning the flexibility contracts allows setting strike prices that better reflect the profitability of the investments while reducing the volatility of their revenues.

- For existing assets, flexibility contracts allow adjusting their profitability without distorting the incentives for an efficient dispatch. This would require regulating the strike price to provide a fair rate of return.

- If capacity owners can affect market prices, flexibility contracts encourage them to reduce (rather than increase) the average price. However, they might also be encouraged to increase the wedge between their captured price and the average market price to increase the bonus payment.

Reliability options. A reliability option is a one-way Contract-for-Differences that commits the generator to pay back any positive difference between the reference price and the strike price times the committed quantity (which need not be the quantity actually produced) (Figure 7). The strike price can be indexed to the price of fossil fuels to ensure that the price generators receive for the output is enough to cover their marginal costs. In exchange for this commitment, the generator receives a capacity payment (the option price, s).

Reliability options thus provide investors with a certain flow of revenues, while consumers benefit from the commitment that prices will not be increased above the strike price (f). Hence, reliability contracts provide a secure source of revenues for the capacity owners in exchange for making them subject to price caps (i.e., the strike price).[19]

These options are allocated through auction mechanisms with a pre-determined strike price and the option price set competitively.

Formally, payments under a reliability option can be expressed as

$$\pi = pq + max(0, p - f)k + sk$$

where k is the quantity committed in the contract.

Alternatively, if $p < f$, payments can also be written as

$$\pi = pq + sk$$

while for higher prices $p > f$, payments become

$$\pi = fk + sk - (k - q)p$$

[19] Various versions of these options have been used in Colombia, Ireland, and Italy.

This latter expression shows that: (i) generators do not have incentives to bid above f as any price above it has to be paid back to the regulator; and (ii) the firm is highly encouraged to produce up to capacity when prices are high, as failure to do so would imply an endogenous penalty equal to $(k - q)p$. As this penalty is harsher, the higher the market price, the incentives for being available are greater during scarcity times.

Reliability options provide the following benefits:

- A producer subject to a reliability option has strong incentives to be available when it is most needed (which typically coincides with periods of high prices) as if the producer were unavailable, it would have to buy the energy that it does not produce at a high price to sell it back to the regulator at a lower strike price. Explicit penalties could be added in case of poor availability.

- Reliability options have the additional advantage of mitigating market power, as generators would not benefit from increasing the market price above the strike price. This problem could be particularly acute at times of scarcity when these plants are likely to be pivotal.

- For the existing plants, the auctions for reliability contracts allow for an efficient and orderly phase-out of fossil fuel plants.

3.2 Capacity payments

Plants sell their output at the short-run market price and then receive a fixed payment, which is solely a function of their capacity. They receive this payment regardless of whether they produce or not, just as long as they are available. Hence, full price exposure is preserved while plants receive an amount contributing to cost recovery.

Capacity payments could be seen as an alternative to flexibility contracts. However, these alternatives are not entirely equivalent, even if both preserve full price exposure:

1. In some cases, it might be adequate to set the strike price of a flexibility contract below the expected market price. This would be suitable for assets whose expected market revenues exceed their average costs, as is currently the case for existing nuclear and hydropower plants (see Section 4). Capacity payments can replicate the same outcomes only if they can take negative values. However, when dealing

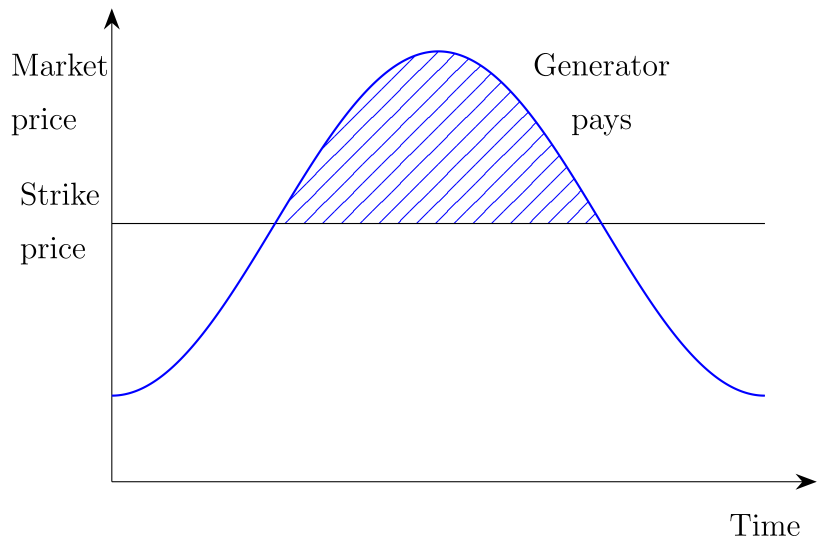


Figure 7: Reliability option or one-way CfD

Notes: A reliability option is a one-way contract for differences, such that generators sell their electricity in the market but have to give back the difference between a 'strike price' (f) and the market price (p) whenever $p > f$. The shaded area represents total payments from the generator to the regulator. In exchange, generators receive a fixed payment ('option price') set at an auction.

with new plants or concessions, if entry outside the auctions is allowed, it would be impossible to enforce a negative capacity payment as investors would instead enter the market without those payments. Instead, a strike price below the expected market price could well be the outcome of an auction, reflecting the benefits of reduced risk when entering the market through a long-term contract.

2. Another difference is that the bonus/penalty under the flexibility contract negatively correlates with market revenues, as market revenues tend to increase when the average market price increases. Hence, payments under a flexibility contract tend to be relatively stable. This contrasts with capacity payments, which remain fixed regardless of market prices, thus resulting in more volatile firms' earnings.

3. Last, in contrast with capacity payments, the bonus/penalty under the flexibility contract is a function of output, not capacity. If it is possible to forecast the expected production over the lifetime of the assets well, this should not be a problem when deciding about the profitability of the investments. Otherwise, being paid as a function of output instead of capacity becomes riskier for the firm.

These differences should be taken into account when deciding on the suitability of capacity payments versus flexibility contracts for the various technologies.

3.3 Contracts for the new and the existing plants

For the new investments, contract terms would be set through competitive tenders. Participating in these tenders would be voluntary, i.e., generators could access the market freely without entering into long-term contracts, which would be paid at the short-run market price. Adding an inframarginal cap in the short-run market - as the European Commission has proposed - would reduce the attractiveness of this outside option, thus contributing to increasing participation and competitive pressure in the auctions.

In implementing the auctions for long-term contracts, regulators have a pivotal role as they must determine the amount and possibly the mix of the investments. Their choices should consider several externalities that markets find hard to internalise, e.g., security of supply, flexibility, learning by doing, and the existence of potential complementarities across technologies, among others. For this reason, our proposal allows regulators to resort to a technology-specific approach whenever necessary to correct market failures and reduce inframarginal rents. This possibility is in line with the recently approved Guidelines on State aid for climate, environmental protection, and energy (European Commission, 2022a) (see Section 4 for more on this).

The short-run market would be suitable to set payments for the existing CCGTs and the peakers. the short-run market price accurately reflects their production costs given that they are the price-setting technology whenever they produce.

This conclusion does not apply to the existing inframarginal plants, given that short-run market prices might give rise to high inframarginal rents – as is currently the case. Furthermore, it is not feasible to make them compete to access the market, given that they are already in the market. Hence, auctions cannot be relied upon in order to set cost-reflective prices for the existing inframarginal plants.

The European Commission, in its non-paper, is proposing to use inframarginal caps similar to the ones in place through the emergency package (Commission, 2022). We consider this suitable for nuclear and intermittent renewable plants as long as the price cap level is cost-reflective, which would be in line with the Guidelines on State Aid for Climate, Environmental Protection and Energy (CEEAG) (to have some orders of magnitude, see the International Energy Agency (2020) cost estimates). Setting the price cap at 180€/KWh (as specified in Article 6.1 of the Council regulation) would not be adequate, as the average costs of those technologies are well below that level. Allowing them to earn up to 180€/MWh would not prevent them from making high windfall profits for quite some time.

For hydropower plants, using an inframarginal cap would distort their incentives for an optimal dispatch. Not making them subject to any contract would not be suitable either – certainly not so from consumers' point of view – given the magnitude of their windfalls. We propose to make existing hydropower plants subject to *flexibility contracts*, which were described above, with a strike price chosen by the regulator to assure a fair rate of return to the plant owners (see Section 4.3 for more on this).

3.4 Passing contract prices to final consumers

Last but not least, a key question is how to pass on the long-term contract prices to the final consumers, an issue that has both efficiency and distributional implications. We propose that the settlements of these contracts are passed on to consumers as a rebate (if the strike price is lower than the market price) or as an extra charge (if it is higher), proportionally to their consumption over an extended period of time. The amount of the rebate/charge could be computed monthly, quarterly, or yearly (if the seasonality of the price signal is to be preserved) so as not to distort the incentives to shift demand form relatively low-price to high-price hours. Figure 8 provides an illustration. Additionally, some of the proceeds can be used to finance the system's costs (e.g., the cost of distribution and transmission, capacity payments for storage and demand response) that are typically added to prices as fixed or volumetric fees, or be distributed as targeted support (e.g., for low-income households).

4 What is Proposed for the Various Technologies?

The above discussion translates into various regulatory treatments for the numerous technologies, depending on their characteristics (whether they are intermittent or flexible, whether they provide firm capacity o not, and whether they are new or existing). Putting the properties of the long-run contracts described above together with the characteristics

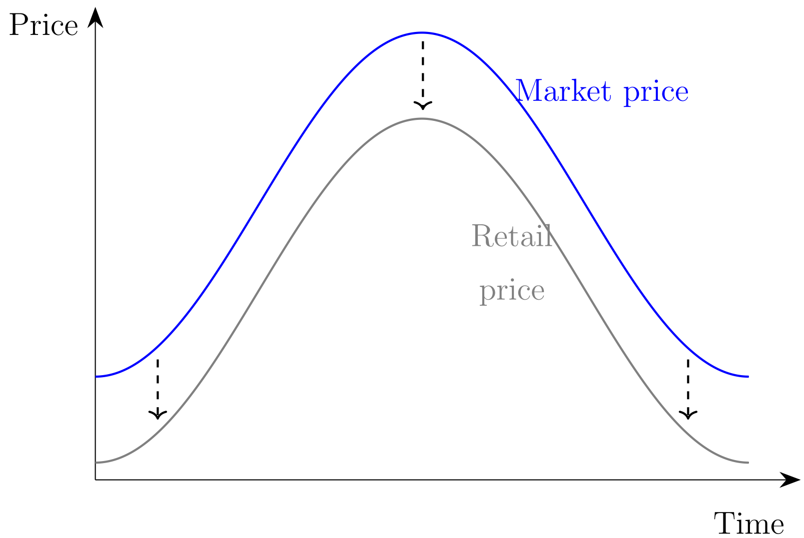


Figure 8: Passing on contract prices to final consumers

Notes: Once the CfD are settled, they provide a surplus/deficit distributed among consumers as a uniform rebate/charge over an extended horizon. This enables passing on the lower/higher prices at which renewable energy is bought without distorting the short-run price differences over time.

of the technologies, we can conclude that:

- **Two-way Contracts-for Differences** are suitable for **intermittent renewables** (e.g., solar PV or wind), whose production is primarily exogenous. Since price exposure provides little benefits to improve the operation of these plants, priority should be given to the de-risking objective.

- **Flexibility contracts** are suitable for assets that have the flexibility to choose when to dispatch (**hydropower plants and dispatchable renewables** such as biomass or solar thermal) or when to go under maintenance (**nuclear plants**).[20] For these technologies, short-run prices provide a valuable signal to induce optimal operation decisions. Hence, the de-risking objective is partially sacrificed to leave some scope for price exposure.

- **Reliability options** are suitable for plants that provide firm capacity (**CCGTs, coal plants, and peakers**). Capacity payments contribute to de-risking, while optimal dispatch is promoted through full price exposure when prices are below

[20] More specifically, for nuclear plants, the flexibility contract should set the reference quantity at the plant's capacity to avoid strategic withholding.

the cap. In turn, the cap contributes to mitigating their market power at times of scarcity.

- **Capacity payments** are suitable for **energy storage and demand response**. Full price exposure encourages these assets to shift demand from high-priced and high-cost periods to low-priced and low-cost periods while the capacity payment allows to address their missing money problem.

We next develop these ideas in greater detail.

4.1 Renewable energies

Massive investments in renewable energies are required to meet the decarbonization objectives. For this purpose, we propose relying on pay-as-bid auctions in which investors would compete for long-term contracts: two-way Contracts-for-Differences (CfDs) for the intermittent technologies (mainly solar photovoltaic, wind and run-of-river hydro) and flexibility contracts for the dispatchable renewables (primarily solar thermal and biomass). These contracts contribute to de-risking the investments while providing a hedge for consumers, who are protected from paying renewable output at high prices. For the dispatchable renewables, these contracts preserve the price signal for an efficient dispatch.

While auctions for long-term CfDs have already been used in several European countries (e.g., Spain, Germany, and the UK, to name just three), their use should increase significantly relative to the total amount of renewable investments foreseen in the National Energy and Climate Plans. Regulators should commit to a schedule of auctions within a five-year horizon, allowing investors to plan and face less uncertainty about the expected evolution of electricity market prices and the likelihood of curtailment.

Since there are many different ways to design these auctions, below we provide some guidelines on the preferred approaches, which should, in any event, be assessed on a case-by-case basis.

Auctions for new *versus* existing plants. We propose auctioning long-term contracts for the new plants as well as for existing plants that are not under a contract.

These two auctions would be run separately, given the differences in the costs incurred by the new and existing plants and how valuable they are for the system.

Under the auctions for the new build, investors would be willing to bid prices down to their average costs since investments have yet to occur. Alternatively, one could expect that auction prices converged to expected spot prices during the timespan of the contract minus a risk premium to avoid future price risks. However, for many investors, selling the output of new plants at the spot price is not an option simply because only with a long-term contract do they find it possible to obtain funding. Furthermore, future price uncertainty is so significant that risk premia tend to be high, leading to auction prices that reflect or come close to the average cost of the new plants. Competition through the auctions allows the lower costs of renewables to be passed on to final consumers.

These auctions provide several benefits. First, long-term contracts for the new plants protect generators from volatile wholesale prices, contributing to de-risking the investments. This gives them easier access to financing at lower capital costs. Furthermore, paying renewable plants for their production encourages investors to locate at resourceful places.

Related to this, the possibility of running these auctions for specific technologies or locations allows regulators to pursue other objectives. For instance, expanding the renewable capacity, reducing procurement costs, promoting investments in technologies that are not yet mature or whose production profiles are particularly valuable for the system, or those that bring in further socio-economic objectives, among others.

Auctioning long-term contracts to the existing renewable plants does not trigger some benefits of promoting the new plants. The reason is simple: since location and technology decisions have already been made, these auctions cannot contribute to de-risking the investments or encourage efficient location decisions.

However, using long-term contracts to protect renewable producers from the volatility of future electricity prices allows transferring risk from the more risk-averse side (i.e., the plant owners) to the less risk-averse side (i.e., the system). This risk reallocation would ultimately benefit consumers as competition in the auction would drive down the strike price to the expected market prices minus firms' risk premia. Furthermore, paying existing renewable plants through long-term contracts would avoid the prospect of rescuing some of them in the future if, as already alluded to in Section 1, their captured prices fall below a level that would lead to plant closures.

Technology-neutral *versus* technology-specific auctions. One important dimension is whether auctions should be technology neutral (i.e., multiple technologies compete within the same auction) or whether they should be technology-specific (i.e., there is some degree of discrimination across technologies, either by type, location, and scale). There are also hybrid formats that combine features of both approaches.[21]

A critical difference between these approaches is that under a technology-neutral approach, the final technology mix is decided through auctions based on the technologies' current costs. Under a technology-specific approach, the regulator must decide how much to procure from each technology. Thus, the former might be subject to market failures, while the latter might be subject to regulatory failures. Furthermore, while technology neutrality effectively minimizes current costs, it may result in over-compensation for low-cost technologies, unnecessarily increasing procurement costs. It follows that the preferred approach may vary on a case-by-case basis. The UK Government (2022) shares a similar view when it argues that *"wider competition is not always better, or even possible…cross-technology competition needs careful design in order for it to be effective."*

There is a clear case for technology-specific schemes when it comes to supporting immature technologies. The reason is that technology-neutrality favors technologies whose costs are currently low at the expense of less-mature technologies whose costs could become lower over time.

Even among mature technologies, a technology-specific approach might be preferable if the costs of the various technologies are very asymmetric (Fabra and Montero, 2020). The reason is that low-cost investors would get too high rents in technology-neutral auctions if the high-cost investors set the auction price. This could be avoided under technology-specific auctions that pay each technology at its market-clearing price or under hybrid mechanisms (such as banding or minimum technology quotas) that mitigate

[21] One example is provided by the auction design implemented in Spain, by which certain technologies are guaranteed a minimum quota. If the quotas are not binding, the outcome is technology neutral. Another example of a hybrid mechanism is provided by the *Reference yield model* used in Germany, which introduces a bonus for bids from low wind speed regions and penalties for high wind speed regions. According to Kroger, Neuhoff, and Richstein (2022), this discrimination will allow for a reduction of consumer costs of around 24.8 billion Euro or 13% between 2023 and 2030.

the existing asymmetries among the projects and, thus, the resulting rents. This conclusion is fully acknowledged in the recent Guidelines on State aid for climate, environmental protection, and energy (European Commission, 2022a), which state the following: *"The bidding process should, in principle, be open to all eligible beneficiaries to enable a cost-effective allocation of aid and reduce competition distortions. However, the bidding process can be limited to one or more specific categories of beneficiary when there is a significant deviation between the bid levels that different categories of beneficiaries are expected to offer (when the expected competitive bid levels differ by more than 10%); in that case, separate competitive bidding processes may be used so that categories of beneficiary with similar costs compete against each other."* Furthermore, the guidelines acknowledge that technology-neutrality may give rise to overcompensation: *"Where deviation between the bid levels that different categories of beneficiaries are expected to offer, Member States should consider the risk of overcompensation of cheaper technologies... Where appropriate, bid caps may be required to limit the maximum bid from individual bidders in particular categories."*

Furthermore, if the regulator has relatively precise information about the profitability of the various technologies, she can run technology-specific auctions to reduce the rents of low-cost technologies without distorting the allocation across technologies. In other words, the relative advantage of technology-neutral auctions, which is to select low-cost investments, is relatively less valuable when the regulator has enough information to replicate the same outcome.

Also, a technology-neutral approach risks not promoting valuable technologies if competing technologies not providing similar services have lower costs. Examples could be intermittent technologies versus those that provide some storage (like solar thermal plants and biomass plants that further contribute to cleaning forests and avoiding fires); or technologies with production profiles that complement the system needs (for instance, solar investments in markets with a lot of wind capacity, or vice-versa). This calls for using technology-specific policies as technology-neutral auctions fail at internalizing those complementarities.

In contrast, there is a clear case for technology-neutral schemes when technologies are very similar across them (both in the value they provide as well as in their costs) and when the regulator lacks precise information about the technologies. In the latter case, deciding how much to procure from each technology might prove challenging and ultimately costly.

Pay-as-clear *versus* Pay-as-bid. The auction format can have an impact on the outcomes. Two formats are typically considered: (i) a pay-as-clear format, under which all the winning projects receive the highest accepted price offer; and (ii) a pay-as-bid format, under which all the winning projects receive their own bid. Under both formats, the projects that offer the lowest prices are selected first until all the demand in the auction has been covered.

These formats have been widely studied in the academic literature, and while some of the results are mixed, two robust conclusions emerge. First, if the auctions are sufficiently competitive, the outcome of the two formats is the same. The conventional wisdom believes that the pay-as-bid format saves the difference between the highest accepted offer and each winning bid. However, this reasoning is incorrect: it takes the bids as given and overlooks that generators change their bidding behavior when the rules change. Indeed, under the pay-as-bid format, bidders tend to bid as close as possible to the expected market clearing price in the auction, giving rise to the same payments as under the pay-as-clear format. However, the economic literature has also concluded that bidders can more easily manipulate pay-as-clear auctions than pay-as-bid auctions. The reason is that a pay-as-bid design forces all bidders to compete at the margin, i.e., offering prices close to the market clearing price, which gives rise to head-to-head competition. This is true when bidders know the size and cost of others' projects (Fabra, Fehr, and Harbord, 2006; Fabra, von der Fehr, and Harbord, 2002), or when they do not (Fabra and Llobet, 2022). For this reason, we recommend using the pay-as-bid format for renewable auctions.

Another critical ingredient of the auction format refers to the quantity demanded. Very often, regulators commit to auctioning off a fixed capacity. However, it might make sense to condition the final capacity allocated on the bids received in the auction. If bids are low (high), it might be optimal to procure more (less) than initially expected (Fabra and Montero, 2020).[22] Furthermore, demand uncertainty may mitigate anti-competitive behavior in the auction.

[22] A similar approach is used by Central Banks in liquidity auctions. See Klemperer (2010).

Full price insurance *versus* price exposure. Another critical dimension is whether renewable energies should be exposed to short-run market price changes. This question poses a fundamental trade-off. On the one hand, since the costs of renewable energies are mainly fixed, price exposure would increase generators' uncertainty over cost recovery, leading to higher financing costs. On the other, exposing generators to price variation might encourage them to innovate to increase their production in high-priced hours, which is most valuable for the system. Also, price exposure might induce them to locate at sites where their expected availability would be positively correlated with market prices, contributing to reducing overall system costs. The trade-off between the costs (increased uncertainty) and benefits (increased flexibility) of exposing renewables to price changes should be carefully assessed.

One of the key determinants of the optimal degree of price exposure is the flexibility of renewable energies to change their production in response to price changes. Intermittent renewables (e.g., solar PV, wind, or run-of-river hydro) cannot respond to price signals because their output is exogenously given by weather conditions at the chosen location. Hence, as a general principle, full-price insurance is optimal. In contrast, other renewable technologies, such as solar thermal and biomass, have a greater ability to change their production patterns in response to short-run price changes. Hence, a higher degree of price exposure is optimal. For these reasons, we propose using *two-way Contracts-for-Differences* for intermittent renewables and *flexibility contracts* for dispatchable renewables. It would also be suitable to use *flexibility contracts* for intermittent renewables, using the average captured price by the technology as the baseline against which the contracts are settled - very much in line with the German model. These contracts provide some price exposure that might affect investors' location or equipment choices while they have a solid de-risking potential.

Paying for output *versus* paying for capacity. A related issue is whether the contract should specify payments as a function of output or capacity (or equivalently, only until a specific production is reached). Paying contracts according to output presents several advantages. First, as already mentioned, it encourages investors to locate at more resourceful sites. Second, in contrast to paying for capacity, paying for production reduces investors' degree of price exposure which, as already argued, contributes to de-risking the investments.

There might be a reason for favouring capacity payments over energy prices. Suppose there are large differences in the availability of natural resources across locations. In that case, there is a risk that the plants in the most resourceful places (whose average costs are low because their expected production is high) get excessive rents if the auction price is set by plants in less resourceful sites with higher average costs. Paying for capacity mitigates this as the advantages in terms of expected production of the resourceful sites would diminish. However, there are other options for avoiding this. Suppose the regulator wants to promote distributed investments in all areas. In that case, it might be advisable to run separate auctions across locations or a single one with a handicap for plants in less resourceful sites.[23]

Curtailments of renewable energy. Even if renewable energies enter the market through CfDs with full price insurance or little price exposure, they face a quantity risk: the probability that renewable production might exceed total demand, giving rise to curtailment. To reduce such risks, we propose that those plants that have entered the market through renewable auctions be given priority in case of curtailments. This lower risk will benefit consumers as generators will be willing to offer their output through the auction at lower prices.[24] Together with the inframarginal cap, this measure contributes to reducing the value of the auction's outside option, which is to enter the market without long-term contracts.

4.2 CCGTs, coal plants and peakers

In the coming years, significant amounts of firm capacity will be needed to counteract the seasonality and intermittency of renewable resources – at least until energy storage is deployed at a sufficient scale. Therefore, it is necessary to count on enough firm capacity to guarantee security of supply at all times and nodes of the network.

It is widely recognized that energy-only markets are inadequate to promote invest-

[23]The German reference-yield model provides an example (Kroger, Neuhoff, and Richstein, 2022).

[24]Note that local network congestion might give rise to curtailment even when market prices are above zero. When prices are zero or negative, our proposed CfD does not apply in order to prevent plants from bidding negative prices down to the strike price.

ments in firm capacity.[25] The main reason is that energy-only markets reward generators for their production, but the value they provide in strengthening security of supply remains unpaid. This problem will be aggravated in the future, as the increased penetration of renewable energies will reduce the market revenues of backup plants while making them more uncertain.

Experience with capacity mechanisms is broad and widely studied, as different countries have implemented several designs. These include centralized capacity mechanisms (such as the capacity market in the UK), decentralized systems of supplier obligations (as in France), or strategic reserves (as in Germany, Sweden, Poland, or Belgium, among other countries). As pointed out by the European Council (2016) in its capacity mechanism sector inquiry, there is a need to homogenize capacity mechanisms across Europe.

Among the potential mechanisms, we propose to rely on a **system of auctions for reliability options** among plants that can provide firm energy (see Figure 7 for an illustration). The System Operator determines the need for firm capacity for the coming year and up to the following five years. The regulator runs a capacity auction annually to ensure those needs are satisfied. Separate auctions are run for the existing capacity and the new build to avoid excessive rents for the former. Furthermore, while the contracts for the existing capacity could be one year long, the contracts for the new capacity should last longer to allow for cost recovery at lower risk premia.

In some cases, building a strategic reserve is also an appropriate option as a complement to the capacity market. Under a system of strategic capacity reserves, some plants are paid to stay on standby, and they are only used in case of output shortfalls according to criteria that are determined ex-ante by the System Operator. An auction scheme is used to determine the compensations.

[25] For instance, the European Council (2016) agrees that *"uncertainty may persist about whether an increasingly volatile market price and rare scarcity situations can drive long-term investment decisions."* Similarly, the UK Government (2022) does *"not consider that an 'Energy Only' market (where there is no capacity mechanism) would address security of supply needs or bring forward the new investment needed."*

4.3 Hydro and nuclear power plants

Hydro and nuclear power plants currently serve Europe's lion's share of total electricity demand.[26] Furthermore, their contribution to security of supply is critical. This conclusion is particularly true in the case of hydropower, given that it can be stored and used whenever it is most valuable, which is essential to facilitate the increasing integration of renewable energy.

Nuclear and hydropower plants differ in several dimensions, but they have several characteristics in common. First, their variable costs are low relative to the variable costs of gas-fired generation, leading to large inframarginal rents whenever market prices are set by fossil-fuel generation. Furthermore, current market prices are – by several orders of magnitude – above any legitimate price expectation that the owners of nuclear and hydropower plants might have had at the time of the investments. These conclusions are justified on several grounds:

1. Current electricity prices are well above their historical average (approximately 40€/MWh). Hence, if nuclear and hydropower plants did not go bankrupt in the past, current spot prices must give them large rents.[27]

2. Current electricity prices are well above their estimated average costs. As reported by International Energy Agency (2020), the median estimate of the Levelised Cost of Energy (LCOE) for the nuclear and hydropower plants is 30€/MWh and 40€/MWh, respectively. At the same time, power prices exceed those figures by several multiples (Figure 2).

3. Furthermore, the construction of most of the existing nuclear and hydropower plants dates back to the past, before the introduction of the current market arrangements. In most cases, the revenues they have obtained since then (either market-based or regulated) have allowed their owners to cover a significant fraction of the investment costs. Hence, the relevant costs of nuclear and hydropower plants might be between their variable costs and the LCOE figures reported by the

[26] For instance, according to Eurostat (2022) data, in 2020, nuclear and hydropower plants in Europe served 24.3% and 13.8% of total demand, respectively, summing to 38.1%.

[27] Needless to say, matters are different for those nuclear plants that have to go through significant repair works because of faulty construction.

International Energy Agency (2020).

In the words of Ursula von der Leyen, president of the European Commission: *"The low-carbon energy sources are making in these times – because they have low costs, but they have high prices on the market – enormous revenues...revenues they never dreamt of; and revenues they cannot reinvest to that extent. These revenues do not reflect their production costs"* (von der Leyen, 2022b). This fact makes it accurate to refer to these *"enormous revenues"* as windfall profits.

However, going forward, these windfalls might become losses as soon as renewables start setting electricity market prices more often. In those cases, market prices would reflect the production cost of renewable technologies, which is below the average costs of nuclear and hydropower plants. This should not come as a surprise. Windfall gains and windfall losses are two manifestations of the same phenomenon: the production cost of the marginal technology is unrelated to the average cost of the various generation technologies. In the absence of free entry and exit, there is no mechanism allowing for profit or loss adjustments (see the discussion in Section 1).

Buying the output of nuclear and hydropower plants through long-term contracts would provide a hedge for both consumers and plant owners. Making contract prices cost-reflective would reduce the currently massive wealth transfers from consumers to electric utilities. As already argued in Section 1, such transfers have adverse distributional consequences, and also give rise to efficiency losses as the artificially high electricity prices get passed through to the rest of the economy, becoming a threat to electrification.

When designing these long-term contracts, the challenge is three-fold:

(i) How to preserve the plants' correct incentives to dispatch when their output is most valuable (in the case of nuclear, to schedule maintenance when the forgone value is lower)?

(ii) How to give plant owners a fair rate of return, i.e., how to make their remuneration cost-reflective?

(iii) How to ensure that the operators do not have incentives to behave strategically to obtain additional market power rents, e.g., withholding output or shifting it across time to benefit other plants in the market under the same ownership?

On the one hand, price exposure achieves the first objective, as competitive hydro operators maximize profits by dispatching their limited production when prices are higher. This is also when their output is most valuable as it replaces costlier plants. However, dispatching at peak times can give rise to exceptionally high profits, jeopardizing the second objective.

Price exposure. To reconcile both objectives, we propose using *flexibility contracts*, as already discussed in Section 3.1 (see Figure 6 for an illustration) for hydropower and nuclear plants.[28] Recall that generators subject to a flexibility contract sell their output at the market price and then receive the difference between a strike price and the average market price over an extended period (e.g., the annual average). Therefore, they are akin to a standard Contract-for-Differences with a key difference: the settlement is not computed by differences between the strike price and the actual price but between the strike price and the average market price, which acts like a yardstick. This implies that full-price exposure is preserved as if plant owners only sold their output at market prices.[29]

From a practical point of view, flexibility contracts could be settled at the end of each month, considering the last 12-month moving average. Doing so would smooth out the reference price, avoiding end-of-year effects, e.g., if the following year's market average is expected to be higher than the current year's average, generators might have incentives to withhold production until after the turn of the year. Using the moving average avoids this.

[28]Strictly speaking, nuclear plants are not flexible to ramp up or down as hydropower plants are. However, they have the flexibility to decide when to schedule their maintenance, subject to the approval of the System Operator. Hence, for nuclear plants, we use the term "flexibility" in this sense.

[29]The German CfDs system follows the same logic. The contract is settled by differences according to a technology-specific average market price (e.g., using the production profile of all plants of the same technology). If a given plant manages to produce at higher-priced hours times than the technology average, it makes higher profits. Thus, even though plants are fully hedged if they behave like the yardstick, they retain full-price exposure to market prices. Newbery (2021) also proposes a contract for renewables with a similar logic. In particular, this yardstick involves settling the contract as a function of the forecast output (not metered output), which could be technology-specific or location-specific. Note that hydropower and nuclear plants are in the hands of a few generators. It is thus inappropriate to set a technology-specific yardstick for these plants as the owners could potentially manipulate it.

Fair rate of return. The second challenge remains: how to set the strike price of the flexibility contracts for nuclear and hydropower plants. Ideally, the strike price should be set so that, in expectation, if the plants are operated efficiently, generators make revenues that are exactly sufficient to cover their costs (considering that their revenues also include the flexibility bonus/penalty). Eventually, as the concession rights of the hydropower plants expire, it will be possible to use auctions to set the strike prices. However, until this is the case, it is impossible to resort to competitive mechanisms to infer the actual cost of the existing plants. The reason is that competition among existing assets drives the electricity price to their opportunity cost, i.e., the expected revenue from selling that electricity in the short-run market. Hence, the resulting auction prices would reflect future electricity prices (minus, possibly, a risk premium) and not necessarily their actual costs.

All this makes it unavoidable to regulate those prices for the existing assets. Regulators have precise information about the costs of nuclear and hydropower plants and valuable expertise developed under regulatory systems. Furthermore, it is feasible to compute the revenues they have received since then and hence the fraction of their fixed costs not yet been recovered. This information, together with the additional information requested from companies and independent experts, should allow regulators to determine a fair price for the nuclear and hydro output. An example of a cost-reflective policy for nuclear power plants is the ARENH scheme agreed upon between the European Commission and the French government. The price to be paid for 25% of EDF's nuclear production (100 TWh) was initially set at 42€/MWh (European Commission, 2012).

It is worth stressing that plants should not be compensated for their actual costs, which would create a moral hazard problem, but for a cost benchmark that would serve as a yardstick for the efficient operation of these plants.

The European Commission (2022b)'s proposal fails in this front: *"For existing generators, the current inframarginal cap could be directly integrated into the functioning of the wholesale market to facilitate its practical implementation and incentivize the transition of existing generators to a long-term pricing structure based on contracts for difference."* However, the "current inframarginal cap" is set at 180€/MWh: if it remains binding, it will give an excessive rate of return to nuclear plants; and if it does not bind, the reform proposal will imply no difference for nuclear power plants. Furthermore, while the European Commission (2022b)'s proposal does not mention hydropower plants explicitly, the "current inframarginal cap" does not apply to them. Would this mean that hydropower plants would also escape any measure despite the large windfalls they currently obtain at market prices? Our proposal – namely, using flexibility contracts for nuclear and hydropower plants – would address both concerns.

What if market power distorts the dispatch? The availability of hydroelectric production is one of the most critical determinants of the severity of market power in wholesale electricity markets. The reason is that the storability of hydro allows producers to decide when to use it to increase their profits, which need not coincide with when it has the greatest value. For instance, strategic hydro producers might have incentives to shift their production from peak to off-peak periods to avoid depressing market prices when their infra-marginal output is larger (Bushnell, 2003; Garcia, Reitzes, and Stacchetti, 2001). Similarly, nuclear plant owners might have incentives to withhold output, raising market prices and, thus, the revenues made through the generators' remaining output. Not only does this strategic behavior increases average prices, but it is also a threat to security of supply. The same applies to the maintenance schedule for nuclear plants, which involves a similar dynamic problem.

Under our proposed market architecture, hydropower and nuclear operators have weaker incentives to exercise market power than in the absence of long-term contracts. The reason was already alluded to before: raising the market price would not allow the plant owners to benefit through their remaining inframarginal output, given that its prices are essentially fixed (Fabra and Imelda, 2022). However, if hydropower and nuclear operators have sufficient market power, flexibility contracts only partially prevent them from distorting the dispatch to their own benefit. In particular, hydro operators might have incentives to shift hydro or nuclear power away from those hours when market prices fall more in response to the increase in supply. In other words, they might be incentivized to move hydro or nuclear output from hours when prices are more elastic to when they are less elastic. Doing so would allow the plant owners to increase the difference between their captured price and the average market price, thus enlarging the flexibility bonus.[30]

[30]This effect is akin to the one arising under *Average revenue regulation* or *Revenue yield control*. See p.69 of Armstrong, Cowan, and Vickers (1994).

Since the hours with less elastic prices need not coincide with those when hydro or nuclear production are more valuable, this behavior can result in productive inefficiencies. This problem is not present when the plant owners are price takers, i.e., when they are not able to affect market prices through their actions.[31]

Therefore, the conflict of interest between the private and the social objectives might become particularly acute when a single firm concentrates most of the hydro production or owns a significant fraction of the inframarginal capacity. In such cases, there is a trade-off between letting generators make dispatch decisions versus allowing an independent body to decide on the dispatch of hydropower plants and the maintenance schedule of nuclear plants. The former might be distorted due to market power, while the latter might be distorted due to a lack of information or proper incentives.

One option for limiting withholding incentives by nuclear operators is to make the flexibility contract a function of a pre-determined fixed quantity (e.g., the plants' output under an efficient base load operation, accounting for a maintenance phase of standard duration). In this case, as explained in Section 3.1, the firm would be penalized if it produced a lower quantity, very much as under a reliability option. It would not be easy to apply the same approach to hydropower plants, given that their available output varies yearly depending on weather conditions.

For these reasons, the possibility of creating an Independent Low Carbon Operator (ILCO) should be considered. With the right incentives, it would be responsible for scheduling hydro production and nuclear maintenance to minimize the system's costs and maximize security of supply. There would be no conflict of interest between this independent body and the generators, given that the former would not own the plants or receive any direct benefit from dispatching them at one time or another. The tasks of the ILCO could also be performed by the System Operator, which has the technical skills in the matter and also faces no conflict of interest to carry them out.

4.4 Energy storage and demand response

The power sector will increasingly need flexible resources, i.e., those capable of shifting demand or supply across time or locations, thus counteracting the intermittency of most

[31] This is likely to be the case for the remaining sources of flexibility, i.e., energy storage, demand response, and dispatchable renewables, which are often in the hands of smaller players.

renewable resources. The primary sources of flexibility are hydropower plants (as already discussed), interconnection capacity across countries, energy storage, and demand response. Since the issue of how to promote sufficient interconnection capacity is out of the scope of this document, here we focus on the other two.

Energy storage and demand response provide several benefits:

1. By smoothing production over time, energy storage and demand response reduce generation costs and flatten the price curve, which translates into improved production efficiency and lower prices for consumers.

2. By storing electricity when renewables' availability is high and releasing it when it is low storage facilitates the integration of renewables in electricity markets. The same applies when demand shifts from when renewables are abundant to when they are scarce.

3. Since energy storage and demand response contribute to security of supply, they reduce the need to invest in firm capacity.

4. Last but not least, energy storage and demand response make demand more elastic, contributing to mitigating market power.

The business models of energy storage and demand response rely on arbitrage opportunities: batteries or pumped storage charge when prices are low and discharge when prices are high; similarly, demand response moves demand from high-priced to low-priced hours. If the market is perfectly competitive, prices equal marginal costs, allowing them to internalize the productive cost savings they bring about.

However, the other benefits create externalities that the private investors do not internalize (enhanced security of supply, easier integration of renewables, and market power mitigation). This implies that, relative to the social optimum, the market provides weak incentives to investments in energy storage and demand response (Andrés-Cerezo and Fabra, 2022). Addressing this market failure calls for regulatory support for these investments. Furthermore, these technologies, particularly in the case of energy storage, are still experiencing learning by doing externalities. These constitute an additional market failure that further justifies support.

Future market developments will likely push the incentives to invest in flexible resources in opposite directions. On the one hand, flexible resources and renewable energies are complements. In particular, renewable energies provide the sort of price variation that make energy storage and demand response more profitable. Thus, as the penetration of renewables increases, the private benefits of investing in renewable resources go up. On the other hand, as is the case for renewables, there is a *cannibalization effect*: additional storage and demand response reduce the value and the profitability of the existing units because they narrow down the price differences across time.[32]

Therefore, we propose complementing firms' market revenues with additional payments to promote efficient investments in flexibility. On the one hand, facing them with full-price exposure is necessary to ensure they are operated efficiently. Conversely, complementing the market revenues is needed to allow investors to break even. We thus propose that these assets receive capacity payments, which are determined competitively through auctions. The flexibility providers would then participate in the energy markets and therefore receive energy market revenues in addition to the capacity payment. The regulator should assess which technologies should compete within the same auction, considering that not all forms of flexibility provide a similar value or have identical costs. For instance, short and long-duration storage provide different types of hedge, both of which are needed. And storage and demand response are not perfect substitutes as they provide different degrees of reliability. The guidelines for these choices are similar to the ones discussed in Section 4.1 for renewables.

5 Conclusions

Europe must take advantage of the opportunity to redesign an outdated electricity market design, which has now become a threat to the achievement of Europe's economic, social and environmental objectives. The unjustified magnitude of the electricity price increase has contributed to rising inflation in Europe. The reduction in households' disposable

[32]Using data from California, Butters, Dorsey, and Gowrisankaran (2021) find that energy storage is not profitable until 2027, when renewable energy is expected to cover half of the market. They conclude that battery adoption is virtually non-existent until 2040 without a storage mandate or subsidy. Their model indicates this is due to the decreasing marginal value of storage investments and the expected cost reductions, which incentivize delayed investments.

income due to soaring energy bills, the worsening of energy poverty, and the increase in firm shutdowns and layoffs exemplify how the energy turmoil has turned into a social and economic crisis with uncertain consequences. Electricity market design is at the core of the problem as it makes electricity consumers pay for all generation at the cost of the most expensive plant. This design is inadequate whether gas prices are high or low. The reason is that a single price cannot suit the myriad of coexisting generation technologies: it either leads to losses to some technologies or gains to others. One size does not fit all.

Beyond the current crisis, the achievement of the environmental objectives is also at risk under the current electricity market arrangements. The energy transition requires a radical change in the technology mix, with fossil-fuelled plants being replaced by a combination of renewable energies and flexible technologies able to counteract the intermittency of solar and wind. These technologies have very different characteristics that often make them complementary. They also have different cost profiles with a high weight for capital costs. Various externalities – including environmental and security of supply externalities and learning economies – call for greater involvement of regulators in procuring an adequate mix of low-carbon technologies. To play this role, the human and material resources at their disposal should be drastically improved.

Our proposed electricity market architecture seeks to achieve two complementary objectives: to allow electricity prices to reflect the actual cost of electricity generation and to facilitate the energy transition in the power sector. To achieve these goals, our proposed architecture rests on two pillars:

1. A liquid and transparent short-term energy market, which contributes to short-run efficiency in production and consumption; and

2. A set of auctions for long-term contracts, which promote efficient investment decisions while providing a competitive mechanism to determine reasonable profitability to the investors.

Technology diversity is reflected in the diversity of contracts suitable for each type of asset, given their distinctive characteristics. We propose four types of contracts:

1. For intermittent renewables, Contracts-for-Differences contribute to de-risking the investments;

2. For flexible resources, flexibility contracts incentivize their production at times when they are most valuable;
3. For assets able to arbitrage price differences across time, capacity payments give them full price exposure while reducing the risk of cost recovery; and
4. For plants providing firm capacity, reliability options provide a secure stream of profits in exchange for an explicit price cap and an implicit penalty for not being available during system stress.

The double hedge provided by these long-term contracts will benefit consumers and producers. Competition for these contracts will, in turn, contribute to passing the resulting efficiency gains to lower prices for consumers. In cases where competition to enter the market is impossible because the investments have already been made and there is no free entry, the regulator will set the contract prices through cost audits to guarantee a fair rate of return.

The proposed new electricity market architecture would facilitate the achievement of carbon-free and diversified power markets at least cost for consumers and society. It would reduce capital costs of low-carbon assets (mainly renewable energies and flexibility resources, including storage) by de-risking the investments. It would also promote innovation by supporting not-yet-mature low-carbon technologies that are expected to achieve substantial cost reductions in the future. The new market design would allow passing the lower costs of renewable electricity generation to consumers while preserving the short-run price signals. This is key not only for reducing electricity bills – which in turn encourages further carbon abatement through electrification – but also for encouraging people to support the energy transition as they are better able to perceive its benefits.

The proposed new electricity market would also contribute to the robustness and well-functioning of electricity markets. It would mitigate market power in the wholesale market and reduce barriers to entry for new players. It would also prevent gas prices from propagating through the entire electricity market, allowing for lower and less volatile consumer bills. This would prevent firms from making windfall profits and losses, contributing to keeping electricity prices down for consumers over the coming years while providing a certain stream of profits for firms.

The proposal made by European Commission (2022b) in its non-paper *"Policy Options to Mitigate the Impact of Natural Gas Prices on Electricity Bills"* is aligned with the proposal made in this paper. However, the European Commission still has to specify several details that may be crucial - including the treatment of the existing plants, which should avoid consolidating their current excessive profits. There is a non-negligible risk that market arrangements are seemingly modified, with no substantial effects on actual market outcomes.

By providing details on several of those pending issues, this proposal has sought to contribute to the ongoing regulatory debate in Europe.

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