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The design of electricity markets: an economic analysis

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Abstract

Fighting against global warming requires electrifying energy uses and giving up on carbon-based power. Consequently, the organization of electricity production and transmission must not only promote short-term efficiency in dispatch, but also send out reliable signals to guide investment by producers and consumers; and this under normal macroeconomic conditions as well as in the face of unforeseen events, such as Covid 19 and Russia's invasion of Ukraine. To meet these challenges, the European authorities and the EU member states are negotiating the introduction of long-term physical and financial contracts that will complement wholesale electricity markets. This note compares the costs and benefits of these contracts and emphasizes the assignment of risks among stakeholders.

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The organization of the electricity market faces several challenges.

1. Decarbonization. The issue of decarbonization is paramount and must be addressed with the appropriate instruments, in particular a proper carbon price and disruptive green innovation. A carbon price compatible with our climate ambitions and governing the EU emissions trading system must guide investment by businesses, households, electricity producers and green innovators. Mixing decarbonization goals with market design might be counterproductive, resulting in higher electricity prices and even working against the goal of zero net emissions by 2050. The electricity market must provide the appropriate signals for the massive investments needed to decarbonize the energy sector.

2. Short-term efficiency. In the short term, the cheapest sources of electricity production should be called upon first, and its most productive uses should prevail on the demand side. Because the spot wholesale market and dispatching according to the merit order create a relevant price signal of current resource scarcity, they respond effectively to this objective. Their principle has appropriately been reaffirmed in the agreement signed by European energy ministers on October 17.

Why are electricity prices in France very high when natural gas is in short supply, while gas represents only a small proportion of the primary energy used in France's electricity generation, and French electricity production is on average inexpensive? To understand this phenomenon, it should be noted that gas is often the "marginal" source of energy, which means that if 1 extra MWh is needed for European consumption, this additional MWh will most likely be produced by a gas turbine, as decarbonized plants (renewables and nuclear) are already operating at capacity. But why should France "import" European prices of €150/MWh (which is the variable cost of producing electricity from gas[2]) when the accounting cost[3] of its existing nuclear fleet, which provides most of its generation, is around €60/MWh? To answer this question, let us assume that the price in France is administratively maintained at €60/MWh. A manufacturer willing to pay €70/MWh to consume 1 MWh would buy this MWh. However, the cost of this MWh for society is the European price of €150, because its consumption could have been resold at this higher price. The outcome is a shortfall of €90 for France, which could have more than compensated the industrial customer for his loss when it refrains from consuming (€70 - €60 = €10), leaving €80 for the community. So, there's nothing irrational in considering that the price determined by the intersection of the marginal cost curve and the demand curve reveals the true value of electricity, €150/MWh in our example. Aligning French prices on French production costs is misguided.

While the wholesale market fulfils its function of efficiently allocating resources, it is also important to ensure that incumbents who are dominant in their market do not have market power at national or zonal level, which could lead them to hold onto unused capacity during periods of tension between supply and demand, when electricity prices are already high. There are various ways of limiting the market power of incumbent operators. In addition to ongoing monitoring by national regulatory agencies under the European REMIT rules, the three least intrusive approaches to limiting incumbents' incentives to manipulate market prices are:

- opening up to international competition (which could be reinforced by increasing cross-border electricity transit capacity),
- electricity sales on forward markets. While cross-border competition has a clear competitive effect, it is perhaps less obvious that forward sales also contribute to a healthier market. The

[2] Gas prices on the European wholesale market exceeded €150/MWh in the summer of 2022. They were around €50/MWh in October 2023.

[3] The accounting cost includes the operating cost (marginal cost per MWh) and the cost of extending the life of existing power plants, given that the construction cost has already been amortized.

idea (which has been put into practice several times in Europe and the UK) is that raising prices by withdrawing capacity from the spot market is less profitable for a dominant operator when most of its generation capacity is subject to a previously fixed price. Indeed, price rises will only benefit the company on the remainder of its production sold on the spot market. Forward sales weaken the market power of the dominant operator and will therefore not occur spontaneously. This is why regulators sometimes force companies to sell part of their production forward, for example through long-term sales contracts, as we will see later.
- increasing the elasticity of demand, with the use of home automation, smart meters, batteries and other energy storage systems, and the installation of decentralized production units, limits the benefit of any price manipulation.

On the other hand, it is just as important to avoid creating rent-seeking behaviour among other operators in the electricity sector. Generation capacity sold forward by an incumbent operator must be sold at a market price, not a price of convenience. From this point of view, the policy pursued by ARENH (Accès Régulé à l'Electricité Nucléaire Historique) in France, which consists in forcing EDF to sell part of its capacity to retailers at the regulated price of €42/MWh when the market value of this resource is much higher, cannot be economically justified. Fortunately, this clumsy policy will come to an end in 2025. The nuclear rent could have gone either to EDF (and therefore in part to the French State, which is now EDF's sole shareholder), or, if EDF itself were considered to be in a position to benefit from the rent, directly to the French State. Under no circumstances should public money have been transferred to private retailers. The official motivation was that this would create competition for the incumbent operator, which was clearly not the case, since a fixed quantity of nuclear electricity put on the grid has the same impact on the spot price of the electricity market whether the electrons are labeled EDF or under another retailer's name. It was a mistake to create a sham of competition via ARENH. It would be better to stimulate the development of competitive long-term contracts, which more effectively limit the risks of abuse of a dominant position and incentivizes new capacity instead of redistributing rents on existing one.

<u>3. Investments, rents and electricity prices</u>

Three interdependent questions require more thought:

- *Imperfect adaptation to short-term price volatility*. Electricity is not (yet) a storable commodity. Consequently, spot prices are sometimes very low and sometimes very high, depending on temporary fluctuations in supply and demand. When electricity prices are high, users should reduce their consumption. For technical and/or behavioral reasons, consumers react very little to daily variations in electricity prices. This lack of flexibility reduces their well-being relative to the case in which they would be able to adapt their consumption. Similarly, production lines may not be flexible enough to take advantage of price variations. With the deployment of ever-more-sophisticated smart meters (for households) and more flexible production technologies (for business users), retail and business users will be able to take advantage of price fluctuations by benefiting from low prices and avoiding some of the impacts of high ones. The development of electricity storage will also contribute to the smoothing of prices.
- *Absence of signals for investment*. So far, we have focused on the spot market and its price as a signal of current scarcity. In the longer term, maintenance and investment decisions need to be guided by a price signal reflecting expectations of electricity scarcity in the future. This is particularly important as nuclear power plants reach the end of their lives (despite major refurbishment operations), and as the uses of electricity increase rapidly with green mobility and green heating. The investments required in the near future, both upstream (green electricity production and transmission) and downstream (decarbonized electricity

consumption), will be considerable, and all players need reliable price signals; this is particularly the case for investors in green electricity generation, who require reliable information about the return on these investments if they are to take up the challenge. This is where the regulatory framework and its credibility are crucial.

- *Keeping prices affordable and covering costs*. Besides the investment imperative, another key challenge for authorities is to avoid a large impact of uncertainty on the financial strength of specific agents (the aggregate risk cannot be avoided, but it must be shared through some insurance mechanism). Fluctuations may not be temporary (low prices compensating high ones), but last for a while (as illustrated by the war in Ukraine, the carbon abatement efforts, or the decommissioning of nuclear power in Germany). Long-term uncertainty about the average price of electricity makes managing companies' and households' budgets complex. Poor households may no longer be able to afford electricity, and business users may face financial hardship or even go bankrupt. If prices are very high (as was recently the case with the gas shortage, or as will be the case if we increase electricity use without investing adequately in generation and transmission network reinforcement), households and industry face a cost shock that can compromise their financial viability, and, for manufacturers, their international competitiveness. Conversely, low prices jeopardize the financial health of power-generating companies, and the anticipation of low prices slows down investment, creating consequent shortages downstream.

Uncertainty over medium and long-term price levels and the need to protect against them logically call for the signing of long-term insurance contracts. To stabilize their balance sheets, buyers and sellers of electricity can agree on the price of electricity delivery in advance; this is referred to as a physical contract (requiring guaranteed access to the corresponding network between the points of withdrawal by the buyer and injection by the seller). These contracts are named Power Purchase Agreements (PPA). Under a PPA, the volume specified in the bilateral contract is effectively supplied and withdrawn on the power grid.

A Contract for Differences (CfD) does not specify any real electricity delivery, and just sets a nominal quantity that will form the basis for pure monetary transfers. Any electricity placed on the market by the producer is remunerated at the market price; similarly, the buyer on the other side of the contract pays the market price if they decide to consume. But there is no obligation to inject or withdraw the quantity specified in the CfD contract. The nominal volume is only the basis to compute financial transfers: the contract is a mutual insurance or financial contract. The seller receives from the buyer a payment equal to the difference (on this volume) between the contract price and the market price if the latter is smaller. Symmetrically, the buyer receives from the seller a payment equal to the difference between the market price and the contract price on this volume if the latter is smaller. So, if for example the volumes actually injected and withdrawn correspond to the volume specified in the contract, both sides are fully protected from price risk. Furthermore, as actual wholesale market transactions are totally disconnected from the CfD contract, they are efficient: the seller puts on the market electricity that is profitable to produce at the market price, and symmetrically the buyer consumes if and only if their willingness to pay exceeds the market price.

Ideally the volume specified in a CfD contract should correspond roughly to the production volume that is contemplated for the plant. This has two benefits. First, the producer is insured on average; it is not fully insured as adaptation to market conditions is desirable. Second, such forward sales curb market power, if any. Withdrawing electricity capacity from the market raises price in the wholesale market, especially in periods of scarcity, where the supply response is weak. But if most of the electricity is the object of CfDs, raising the price is not very profitable even for a dominant electricity producer: the price increase will be compensated by a payment from the producer to its counterparty in equal magnitude for the CfD volume.

In fact, the October 17 agreement encourages the signing of the two types of long-term contracts that are PPAs and CfDs. However, the CfD contract differs from the standard one of the economics literature. It resembles a CfD except that the insurance component is triggered by physical delivery. For this reason, we will call “c-CfD” the EU version of the CfD, where the “c” refers to the *conditionality* of the agreement, that is applied only if physical delivery occurs. As we will note, this mix of financial and physical features is an inferior design as it fails to disconnect the insurance and the dispatching part of the agreement. The producer's remuneration is fixed in advance by a reference price known as the "strike price". The contemplated version of c-CfD involves the government as the buyer of electricity. In such a c-CfD the government compensates the producer for lost revenue when the market price is lower than the strike price; conversely, the producer pays the difference when the market price is higher than the strike price. However, and in contrast with an ordinary CfD, these monetary transfers occur only if the producer actually puts the corresponding volume on the market. Let us see what this implies.

c-CfDs reduce the risk faced by investors in new electricity plants without jeopardizing the existence of the wholesale market. Nevertheless, as the producer’s remuneration is contingent on delivery, there is no guarantee that the market’s allocative efficiency will be preserved. Some power plants could be called upon to produce even though they are not the cheapest, and conversely, electricity whose production cost lies below the market price may not be dispatched. To illustrate this, suppose an electricity producer signs a c-CfD with a strike price of 60 euros per MWh. If the market price is 40 euros per MWh, the State will pay the difference of 20 euros per MWh. If it rises to 80 euros, the producer will have to pay back 20 euros per MWh. As a result, the producer earns 60 euros per MWh regardless of realized wholesale market prices. It is therefore in its interest to produce if the strike price exceeds its production cost (if so, it will bid the lowest possible price to be sure of being called into the dispatching, which is built by stacking production bids in ascending order of bidding).

If the market price is €40 per MWh, a plant with a production cost of €50 per MWh should not operate if efficiency is to be achieved. Yet, when the c-CfD strike price is €60 per MWh, it bids below €40 and is called in on merit and pocket a margin of €60-50 = €10 per MWh. Symmetrically, if its production cost is higher than the strike price, it would lose out on every MWh produced. It therefore bids an amount high enough not to be called. If its cost is €70 per MWh, it does not produce to avoid making a loss, even if the market price rises to €80 per MWh. The conditionality of the insurance contract on actual delivery thus creates an artificial wedge between market price and plant revenue from generation, and leads to inefficient dispatching. In this respect, by fully insuring the producer against price variations, a c-CfD works like the guaranteed feed-in tariffs for renewable energies, which have contributed to the occurrence of episodes of zero or even negative prices (see the Ambec-Crampes post on the subject).

The challenges of developing long-term contracts. In practice, there are very few insurance contracts in the absence of regulation. There are three reasons for this.

- *Anticipation of state bailouts, implying limited insurance demand*. The first reason for the lack of insurance contracts is the expectation by the buyers and sellers involved of a government intervention in the event of solvency problems. Electricity consumers (households, industry, utilities) expect a "soft budget constraint", i.e. a government bailout: when the price is high and politically powerful lobbies have not covered themselves through forward sales/purchases, the government is under pressure to bail them out. This bailout makes sense ex post, but generates the wrong incentives ex ante.

Government bailouts (benefitting banks, industry, farmers, …) usually are not announced ex ante. In fact regulators often state that they will not bail out uninsured players, although they renege on their commitment when facing the *fait accompli*. In the electricity market, the recent tariff shields were decided ex post, after the shock occurred. But some ex-ante promises of bailouts also exist in the electricity sector. A case in point is the option for electricity consumers who hold a contract in which the price they pay is indexed on the spot price to switch back to EDF's regulated tariff if wholesale prices rise. Similarly, retailers benefit from a free option under ARENH, a resource they turn to only when wholesale prices increase.

The electricity market is not unique in this respect; farmers who refuse to insure themselves against price or production contingencies rely on a gesture from the State in the event of a problem. Their strength lies in their numbers. A single uninsured farmer would not be listened to by the State, whereas a large number of farmers in this situation are sure to be heard. Similarly, the individual who builds his house next to an airport will not prevent the expansion of that airport. Ten thousand individuals who do so may block it. Economists call this phenomenon a problem of "collective moral hazard".

The appropriate remedy is therefore to mandate insurance. In the electricity context, this consists in forcing a large proportion of electricity generation capacity to be bought/sold on the forward market or to hedge it with a long-term financial contract.

- *Lack of liquidity on the futures market*. A vertically integrated company (e.g. an electricity producer who is also an electricity retailer) is "naturally hedged", and therefore has little interest in participating in the futures market, which in turn reduces its liquidity. Once again, compulsory participation would help avoid excessively low liquidity.
- *Limited offer of insurance*. The solvency of insurers can also be an obstacle to the conclusion of forward contracts. Uncertainty about their ability to meet their commitments can be a brake, in the same way a bank can be excluded from the interbank market when information about its balance- and off-balance sheet activities leaks out and raises concerns about its ability to repay loans or honor obligations in the derivative markets. The monitoring of solvency of both sides of long-term markets or the use of margin calls may help foster such markets. Solvency regulations may also prevent specialized companies from developing their portfolio of insured contracts.

Regulatory changes (in particular an updating of prudential regulations) and changes in practice are possible and desirable to remove these three types of limitations.

The centralized approach: the State as intermediary.

The agreement reached on October 17 by the European energy ministers seeks to encourage, but not force, the signing of the two types of long-term contracts mentioned above (PPA and c-CfD). It also sets conditions for the development of c-CfDs, which are likely to be more distortive of intra-European competition than PPAs, as they are more administered. Member States will be authorized to conclude c-CfDs for new decarbonized installations (renewables and nuclear), and for existing assets under more restrictive conditions controlled by the European Commission, in particular for historical nuclear power. The latter is a concession made to France by Germany, which fears that the French industry will benefit from low electricity prices, and that Rhineland companies might be attracted to France if c-CfDs are reserved to companies established on French territory.

State underpricing c-CfDs (which would happen, for example, if a price of €60, corresponding to the historical accounting cost of the existing nuclear fleet, were below the expected future price of electricity) would de facto constitute state aid. If inframarginal (the price would not apply to the entire demand by business users, who would remain, at the margin, subject to market prices for their electricity purchases), this would not be a subsidy that artificially reduces the marginal cost of production for electricity-consuming companies. Rather this state aid would swell the coffers of these companies. This would create a free cash flow that could be used to finance investment, conferring a competitive advantage over their competitors (or conversely, this additional "equity" could save the manufacturer from bankruptcy). In this case, the distortion of competition is indirect.

There is no reason why the historical cost should correspond to the "true price", or even the "true cost" of electricity in France. News accrues: the unexpected profitability of historical nuclear power, climate ambitions that become more demanding as we procrastinate, or supply and demand conditions that react to geopolitical events. We should keep aware that renewing the generation fleet with decarbonized means of production (nuclear and renewables) and adjusting the production capacity to accommodate new usages will require massive investments. The spot electricity market will not disappear under the recent European agreement, which is a good thing. But the agreement is silent on the signals to be sent to investors to make the expected investments.[4] What strike price will be specified in the c-CfDs for new installations? The same as for historical installations? The previous point shows that there is no particular rationale for this standardization of c-CfD prices. Let's suppose that Europe (finally) decides to eliminate its subsidies to fossil fuels, i.e. to stop using coal and be more sober in its consumption of gas, and more generally to comply with its ecological ambitions. Is it clear that a c-CfD at €60/MWh will attract the amount of investment needed in decarbonized electricity production? Without stimulus on the supply side, it will be very difficult for the government to ensure that the energy transition goes as planned.

Let's conclude with the "elephant in the room". In recent years, households have been protected by a tariff shield that has been extremely costly for public finances. These protective measures could have been less costly if they had targeted only the poorest households, but the absence of institutions to limit state intervention undoubtedly made this policy indispensable. However, there is no reason why we should submit ourselves to such a Cornelian choice if identical conditions arise again. We can and must prepare for the future. The European agreement is silent on the subject. It merely recommends that, in the event of a new and sustained surge in prices, countries could easily adopt tariff-shield-type measures as part of a crisis mechanism. The economic rationality of the tariff shield remains to be proven. The absence of consumer reactivity to price variations, at least in the short term, can be invoked[5], but this does not suppress the need for ex-ante insurance instruments (such as long-term contracts). We must prevent collective moral hazard in the form of a wide-scale lack of insurance and the concomitant fait accompli motivating tariff shields (on the consumer side) and bailouts (on the corporate side).

This brings us to our final point. The fight against global warming, geopolitical tensions, the unsettled social acceptability of most means of production, and technological uncertainty create a significant macroeconomic risk. *In fine* someone has to bear this risk, which many people pretend to ignore. What's more, in a world where investment must guarantee a minimum level of profitability to attract financing, not all the risk can be placed on electricity producers. This means that consumers, both retail

[4] It seems, however, that the economy will be highly administered, more so than in the former EDF public monopoly where Marcel Boiteux and his colleagues created internal price signals.

[5] See Gerlagh, R., M. Liski and I. Vehviläinen (2022) Rational Rationing: A Price-Control Mechanism for a Persistent Supply Shock, MIT CEEPR Working Paper 2022-014.

and industrial, must also be exposed to risk. Or they must sign up to insurance contracts (through their suppliers in the case of households) at prices in line with the scarcity of the resource.

Long-term contracts are the ideal instrument for sharing these macroeconomic risks. The State can govern and regulate this insurance market, but it must not rigidify all its terms and conditions, for example by placing all electricity production under the regime of single-price c-CfD, which could kill off the market and prevent optimal risk sharing.