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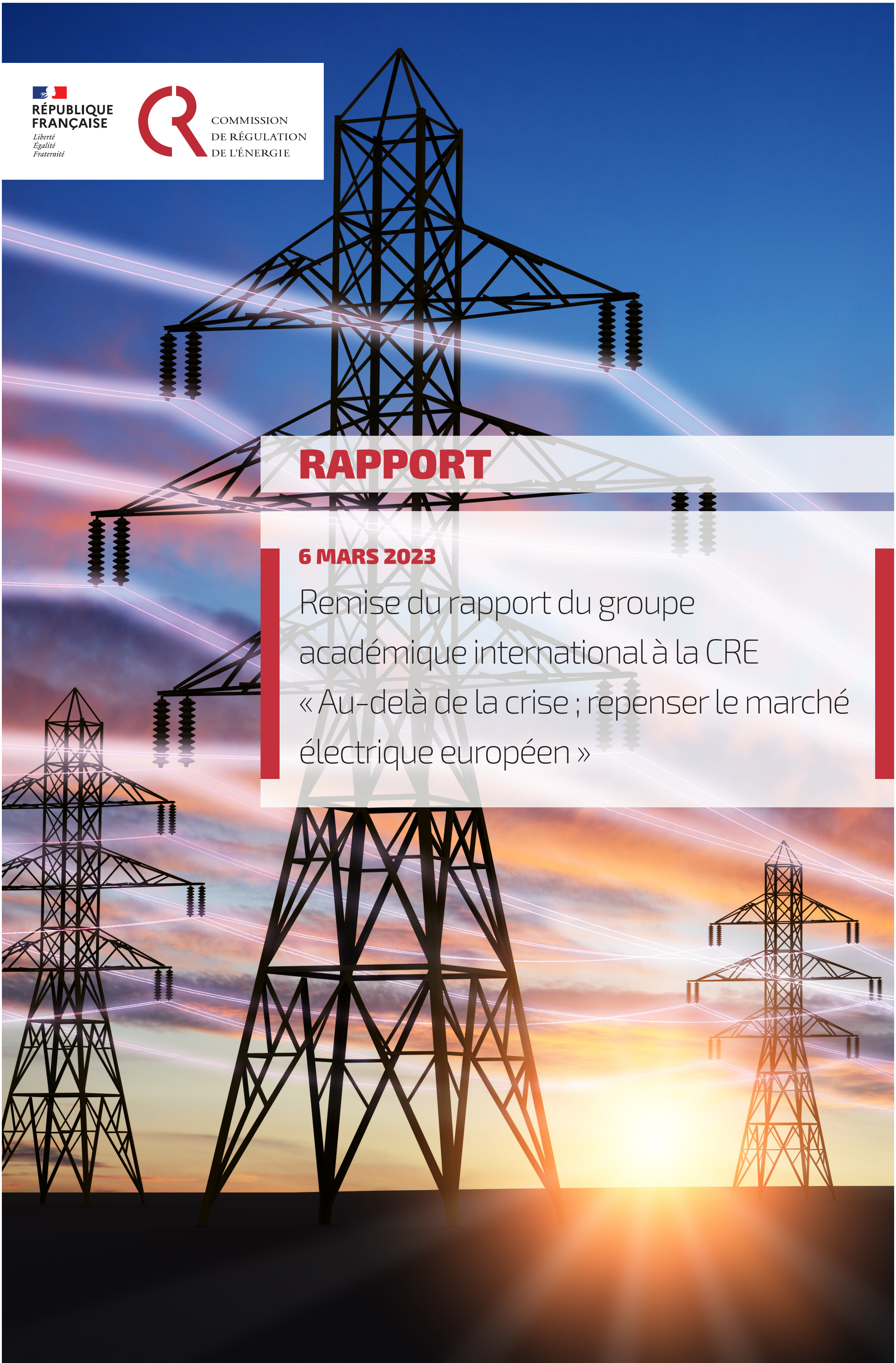

RAPPORT

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Beyond the crisis:
re-thinking the design of power markets

Report

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For the

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(*French Authority of Regulation of the Energy Sector*)

Contents

Note : this report has been collectively reviewed, accepted and endorsed by all coauthors.

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Introduction and methodology

The notion of a "reform of the European electricity markets" is very topical while writing this Working paper in early 2023. The issue has been making the headlines of public debate from mid-2022 onwards in Europe. The European Commission has announced a reform plan for March 2023. The current debates often mix short-term adjustment measures - which do not replace the market but correct it at the margin - with new, more structural measures that would partly replace the market. The former reflects the desire to mitigate as quickly as possible the macroeconomic implications of the surge in electricity prices that began in September 2021 after gas prices soared. The latter is often linked to the effect of the development of intermittent renewable energies on the functioning of the electricity market as it has been designed since the liberalization of power markets. These issues have an important common thread: the question about short run markets which might not reflect the cost of the whole mix, but only the marginal cost of the marginal technology – whether it is gas or renewables, coupled with the lack of long-term contracting.

Electricity has unique economic characteristics, which account for the specific functioning of its market. Firstly, electricity demand is extremely volatile - it can usually vary by 70% between the middle of the night and the end of the afternoon of a same day, especially in winter when the consumption of households increases rapidly in the late afternoon. It is also very price insensitive in the short run. Moreover, electricity cannot nowadays be stored in large quantities at reasonable prices in most countries. Storage technologies are developing but are far from having reached economic maturity and a significant role in the networks. As a result, the balance between supply and demand is always achieved in real time on the grid, minute after minute.

One of the implications of this singular situation is that producers with very different cost structures between fixed and variable costs coexist in the electricity market. Nuclear, photovoltaic and wind power have relatively high fixed costs (around 80% or more of the average full cost) and relatively low variable costs. On the other hand, gas, coal and even oil-fired power producers have a very different cost structure, with relatively high variable costs but relatively low fixed costs. High variable cost plants, such as gas turbines, are called on when lower cost plant is running at its full capability, and are very likely to determine the system marginal cost.

In contrast, normal markets can buffer demand variations through stocking and can therefore commit to stable prices, at least until cost increases or supply chain problems create shortages.

In this context, engineers had to devise a particular way of operating the electricity market that could minimize the total system cost of production (to preserve the competitiveness of industries and the purchasing power of households) while protecting against supply disruptions and, in liberalized markets, to ensure that prices were sufficient for electricity producers to invest).

The mid-twentieth century economic literature on optimal dispatch and investment in electricity generation[1] taught that these objectives could be achieved by operating electricity generators in the short run in increasing order of variable (or marginal) costs of production. Some members of the group note that this result depends on *an implicit "copper plate" assumption*, *i.e.*, that the economic conditions of the power system and network are not altered by localization of production and consumption. Other members also recall that this holds only under the assumption of free and instantaneous entry and exit (that does not really apply in practice).

This market setting has worked relatively well for three decades. However, if the price of natural gas soars, as it did recently during almost two years in Europe, it implies that wholesale power prices in turn skyrocket (and when renewables become the price setting technology, they tend to set prices at their marginal cost which is well below their average cost).

[1] Cf. Boiteux (1951), Boiteux (1956), Boiteux (1960), Drèze (1964), Turvey (1968).

Some energy economists do not see this gas-led rise in power prices as necessarily problematic, as one of the functions of the market is to achieve a price that reflects, among other things, scarcity. The problem is that such a functioning of the electricity market can have very damaging consequences for the economy in general (and the manufacturing sector in particular). When the price of electricity increases tenfold in a few months, the macroeconomic effects on activity and welfare are clearly detrimental. An important economic problem emerges for the economy as a whole, which must be adequately addressed. Additionally, as other members of the group also recall, short-run efficiency may not be the only objective of policies in the power sector. Efficiency in the long-run (*i.e.*, does the short-run price signal provide an accurate signal for long-run decisions?) and equity can be seen as other, somewhat different but equally legitimate objectives.

With the said copper plate assumption, producers with very low variable costs (*e.g.*, wind, photovoltaics, hydro and nuclear power, which do not consume gas or CO2 permits and are thus subject to different cost shocks) make particularly large gains when the production costs of gas-fired power plants soar if their revenues are linked to market prices. Indeed, the market price can be very high while the marginal costs of these producers of renewables are almost zero. As a matter of urgency, the European public authorities decided in autumn 2022 that any income from renewable electricity producers generated at prices above €180/MWh would be paid back to the central government, so as to finance measures protecting households and businesses against soaring energy prices. In technical terms, it is a question of "redistributing the inframarginal rents" of producers with very low variable costs. This solution may seem effective, at least in the short term, in limiting the unfavorable macroeconomic effects of the recent surge in electricity prices. However, it is not intended to be sustainable (see Note n°1).

An important economic policy question emerges here, *i.e.*, whether the considerable and prolonged shock to European electricity markets experienced over the past two years, in the wake of the surge in gas prices, is likely to repeat in the future. The functioning of electricity markets has not raised major problems in most European countries for thirty years, even as prices in some scarcity hours have reached as high as €3,000/MWh. It has raised a major one in the recent, very particular, context where the price of gas increased by four to eight times in 2021-2022.

Beyond short-term issues and mechanisms, the minds that discuss electricity market design often consider issues that are quite different from a redistribution of the inframarginal rents of low variable cost producers. They consider that the operating model of the electricity market inherited from the liberalisation period will be shaken in the years to come by the large-scale emergence of renewable energies (photovoltaic and wind power, in particular). In the medium and long term, a growing and ultimately majority share of electricity production will come from intermittent, near or at zero-marginal-cost renewable producers. These intermittent producers, whose production is constrained by the immediate resource (wind or sun), have normally priority on the electricity market: disconnecting a wind turbine or a photovoltaic installation to displace thermal generators violates least cost operation, unless that fossil generation is needed for stability or because it is even more costly to shut down only to need to restart it shortly.

Increasing penetration of renewable plants not only decreases the price level, but also increases volatility. Accordingly, it reinforces a critical problem of profitability when their surplus drives prices to zero, threatening the survival of thermal plants needed to ensure security of supply when renewable energy are not operating. Various solutions exist to preserve the existence of these back-up producers needed to avoid a blackout in the electricity system.

* * *

In this context, the French Energy Regulation Authority – the *Commission de Régulation de l'Energie* – and her President Mrs Emmanuelle Wargon have gathered since the end of 2022 an international group of high-level academics from different countries.

A *group*, first of all, because experience shows that we often think better with several people than alone. This is one of the basic methods of scientific research, that of discussions between colleagues, which allows to better see the different aspects of a subject to be studied. We are 11 university professors brought together to discuss the short and long term functioning of power markets in Europe.

Our economic and geographical backgrounds are different, and this is done on purpose. The group gathers American colleagues, and European colleagues belonging to countries where the functioning of the electricity market is very different from one country to another. We see this very positively. For none of us is it a question of applying the rules that work more or less in his or her country to the French or to the European case. Rather, it is a matter of comparing the different responses that have been made in different countries on issues that are sometimes very similar.

A *group of academics*, and in this case university professors. That is to say that the people we are gathering have both a long experience of scientific research, but also a long experience of teaching students. Practicing scientific research is good but we put also emphasis on being able to explain it to non-specialists.

The objective of this Working paper is to enlighten French and European public decision-makers in March 2023 about the functioning of the electricity markets. Enlightening does not mean imposing nor proclaiming. It is regularly difficult to know what a "complete truth" is in economics – but we do think we can often discern what is wrong in economics. And informing policymakers about the potentially detrimental costs of their decisions (as concerns economic efficiency, for instance) is already an important part of our profession.

To enlighten public decision-makers also necessarily implies to formulate clear and, if and when possible, operationally feasible proposals. The academics that we have brought together in this group have enough experience to understand that economic analysis recommendations are bound to follow an evolutionary path once they reach the real world of administrations and political decision-making. The recommendations must be clear, for example: "we advise you to go down this path". But they can also be of the type: "however, if you really want to implement such and such a device, then you must pay particular attention to such and such a side effect".

A group of academics is necessarily a diversity of opinions. Economists are well aware that in their field there may be many differences in analysis, while there are also many points of consensus. The report will reflect this diversity of opinion. Therefore, when disagreements arise, which we don't see as tragic at all but rather as enriching, the main text of this document will reflect the majority position, and a footnote will add the minority position. This will reflect what academics know how to do: namely, to clearly analyze reality in all its complexity.

In this document, we do not address some of the issues related to the electricity market debate, as we do not seek to be exhaustive. In particular, we will not address issues related to demand-side management (*i.e.*, load shedding, raising price caps to influence demand...) which is a means to avoid low and volatile prices and to maintain non-renewable energy producers able to take over when wind and sunlight are missing. Similarly, the issues related to the emergence of hydrogen in the energy mix will not be analysed.

Executive summary and main recommendations of the group

Discussions of electricity market reform, in the present European context but also in general, often make implicit assumptions that are highly consequential. By contrast, here we highlight important examples of our working assumptions and address their implications. Among the most important assumptions are:

- Profit-seeking market participants have material discretion to participate through bidding or self-scheduling, as well as through investment decisions.
- Real-time markets require coordination through a system operator, and the system operator can accommodate a workable approximation of the complex multi-part supply and demand bids.
- The grid is not likely to be a copper plate, implying sometimes large differences in economic conditions across the grid.
- The product demanded by consumers is for power delivered at their respective locations.

These assumptions in turn entail significant constraints when thinking about workable wholesale electricity market design. Profit-seeking market participants will anticipate the real-time settlements system when making forward commitments. As a result, market design must begin with the real-time market. Forward market structure and prices should be made consistent with the real-time structure, and the reverse approach may bring about difficult issues.

In real-time, productive economic efficiency requires economic dispatch. Given sincere bidding, this can be provided by the system operator. Absent non-convexities, prices exist to support this economic dispatch.

The usual arguments about matching instruments with design objectives then combine with these conclusions to suggest, or sometime dictate, key elements of workable wholesale electricity market design. These elements concern for instance economic efficiency (real-time bid-based, security-constrained, economic dispatch ideally with locational marginal prices), scarcity pricing, resource adequacy and the missing money problem, longer-term forward hedging. The problem of resource adequacy and capacity deliverability under stressed conditions is more complex (see Note n°3).

All this should hold whatever the degree of penetration of renewables, or any of the particular cost structures of load and generation, which all affect the outcome of prices and quantities but do not impact the basic market design.

While in this document we do not address all of the issues related to the electricity market debate (as we do not seek to be exhaustive), this framework dictated the issues we expand on in the forthcoming pages: short term issues (keeping the short-term market working, how to assess the taxing of inframarginal rents, locational marginal pricing), long-term choices about production assets and technology choices (technological challenges with a carbon price and a taxonomy, the case for (or against) capacity markets, long term contracts and their design). We also address some more aggregate issues that are especially also relevant for public decision makers in a period of crisis (protecting against extreme wholesale prices of electricity, cushioning the aggregate shock for private agents).

Each item is addressed in a specific note that articulates two sections, one centered on economic analysis, the other on empirical implications and, most importantly, broad recommendations for policy makers. In writing the latter, we have kept clearly in mind that the situations can be very different from one country to another in Europe, and that, accordingly, our recommendations should be robust to this heterogeneity of situations.

Summary of the main recommendations of the group

Inframarginal rents:

- If governments want to redistribute revenues made by electricity professionals, better to use mechanisms outside the short-term wholesale markets, like long-term contracts and taxation, and to let short term market mechanisms rank the different technologies and various assets according to their economic efficiency and reactiveness to the electricity system needs.

Keeping the short-term markets working:

- Market design options that do not take into account the increased need of liquidity in short-term trade and market integration should not be chosen.
- Changing the auction rule on wholesale power markets should not be a priority. Instead, fostering demand response, prosumers and electricity storage should be promoted as more efficient remedies against the exercise of market power. Close market monitoring and interventions or requirements for maintaining bids for longer periods than a day or an hour are used in some markets to reduce the exercise of transient or local market power. Also, supply expansion and supervision of anti-competitive behavior should be pursued by regulators and may prove to be more important than changes in market design.

Capacity markets:

- If the objective consists in providing adequate capacity to meet load under stressed conditions, some members of the group consider that this problem has no solution through regulations but provides the impetus for delivered energy hedging contracts. These members consider that capacity markets have not been very successful at tackling reliability of the power system (while costly) and that such systems seem to work best in island systems like the island of Ireland and Great Britain.
- That said, if capacity markets are implemented at the EU level, they should be open to all resources contributing to system security and stop favoring certain ones, as with discriminatory long-term contracts. Criterion used to conceive and dimension the capacity requirements should be clarified and harmonized with explicit reliability standard as loss of load expectation, target reserve criteria. Definition of certification and verification procedures of activated resources should be regionalized.
- Nevertheless, capacity adequacy assessments seem difficult to implement at the European level. Not only the security of supply is part of Member States sovereignty (even if solidarity to avoid shortages has a role to play), but also remuneration rules which are not national cannot be easily defined (how an asset in a Member country X contributing to security of Member country Y and Z simultaneously should be remunerated by taking into account multiple cross-border effects?).

Long term contracts (PPAs, futures, CfDs):

- **Principal recommendation**: Long-term contracts are vital to the efficiency of electricity market designs. Choosing to limit them on one type only (either PPAs, or future contract, of CfDs) would narrow hedging opportunities and perhaps increase situations prone to the exercise of market power, which is not desirable. This is all the most important as each Member State has a different mix and different size/number of stakeholders willing to enter contracts.
- **As concerns future contracts in the wholesale power market:** future markets in the wholesale power sector allow for avoiding the need for complex legal and commercial arrangements. This option is flexible and less complex to set up than long-term contracts, and accessible to all companies (directly or through intermediaries). However, it would require a rise in the liquidity and size of the market of future contracts. Thus a compulsory mechanism would enhance liquidity on the longer segment of the future markets. Also, better coordination on the standardised (futures) contracts should not be neglected, together with further design possibilities to reduce the collateral

in order to improve liquidity. More monitoring and transparency on premia on power markets should be encouraged.

- **As concerns power purchasing agreements (PPAs):** Signing PPAs is complex so they are mainly an option for professional buyers willing an active role in the energy transition. PPAs alone are not very fit to deliver low-carbon investments at the scale and speed needed. They are only fit for the professionals having particular characteristics to value in a bilateral agreement, on the production or on the consuming side.
- **As concerns Contracts-for-Differences:** Regulatory-backed auctions for CfDs, run and underwritten by regulators on behalf of consumers, can be designed to hedge price or volume risks. In practice, they have already been used in order to secure revenues for renewables and neutralize spot price variability. Auctions are effective mechanisms for extracting investors' information about their actual costs if appropriately designed. The CfD auctions can also be designed to avoid large inframarginal rents. Government (agencies) can pool these underwritten CfDs and pass them to final consumers (or retail companies on their behalf) in ways that do not distort the short-run price signals or retail competition.
- **As concerns all long-term contracts:** if the market design drops the copper plate assumption (*i.e.*, if it takes account of economic conditions (prices, quantities) of the power system and network being altered by localization of production and consumption because of congestions, which may rise in the future due to the development of intermittent renewables), then the long term futures contracts will have to be implemented in a rather specific way: localization of the contract (point of generation *vs* point of consumption), object of the contract (energy *vs* installed capacity)…

Locational marginal pricing:

- Strong theoretical considerations suggest that locational marginal prices, on average, would efficiently address important issues of the current and future wholesale power markets. However, their implementation in Europe would raise significant organizational and regulatory problems that should be ironed out beforehand. The gains from LMPs would be different from one European country to another. In any case, guiding investment location will be needed. Other solutions would involve longer term pricing of location, or locational components included in the network tariffs paid by producers – with these latter requiring further harmonization rules across Member States.

Cushioning the aggregate shock for private agents:

- Fiscal policy aiming at cushioning the recent energy price shock on private agents should reach a balance between the support to different kind of agents (households vs businesses, notably). Such a shock triggers different macroeconomic effects through different channels (mainly demand-side effects through households, mainly supply-side effects through firms) and firms may be more detrimentally influenced by such an event than most households.
- The coordination at the EU level of local support measures is fundamental to avoid market distortions that can spill over into industrial sectors creating local advantages.
- In this context, there is also a rationale for increasing the obligations of suppliers to better protect consumers (industries and households) from short-term price hikes.
- Higher energy efficiency would attenuate greatly the aggregate impacts of a spike in power prices.

Market design, carbon price and the Taxonomy:

- The implied reliance of the Taxonomy on well-functioning financial markets and investors' confidence may well be just a third best. It is more efficient to use the markets directly and provide a substantial price signal on carbon. Even more important is that the future carbon price should be predictable and bankable - which is an argument either for a floor or - better - a legislated carbon tax increasing at an agreed rate.

Note n°1: Taxing inframarginal rents

1. Economic analysis

Daily energy wholesale markets are known, since more than 15 years, as creating a problem of "missing money" for several classes of assets. In many countries, it is very new and perhaps very transitory to question them for an "excess of money".

The EU daily forward wholesale energy market gives to all the winning sellers the price corresponding to the highest accepted bid. This is called '*marginal pricing*.' What is the rationale for this pricing rule?[2]

- The first rationale is '*short term efficiency*', *i.e.*, economising the variable generation costs. Assuming no market power, each generator will bid the variable cost incurred when generating (not the fixed cost incurred even when not generating) and not much more in order to be sure to be selected by the market to serve demand.
- The second rationale is '*long term survival*', *i.e.*, reimbursing the fixed generation costs. These fixed generation costs are paid to many generators when another type of generator with higher variable costs is called on by the market to generate, and in this way allows for reimbursing the fixed costs not covered at lower levels of market demand. This extra money to reimburse the fixed costs is usually called an 'infra-marginal rent.' When the size of the entire generating fleet has been well conceived and the proportions of the different generation technologies correctly anticipated, these infra-marginal rents are able to just cover the fixed costs of the generators including a standard rate of profit, sufficient to justify the initial investment.[3]

However, when an unanticipated 'supply shock' pushes up the variable cost of a technology absolutely needed by the market to cover demand, the formerly normal 'infra-marginal rent' received by the non-marginal generators turns into a 'windfall profit'.[4] This is what the EU wholesale electricity market has been facing since the second semester of 2021. Non-gas generators, be they nuclear, hydro, wind, solar or even coal (despite the carbon price applied to coal generation in the EU) can benefit from 'windfall profits'. This worsens the consequences of the wholesale gas price shock by creating another supplementary price shock in the wholesale electricity market.[5]

2. Empirical implications and recommendation

To control such provisional increase in 'infra-marginal rents' and take back the 'windfall profits,' several emergency tools can be used:

- A few wholesale markets outside the EU use regulatory tools to limit the 'infra-marginal rents' when the marginal bidders deviated from the ordinary cost trend.[6] They are 'clawback mechanisms' letting the price mechanism to work, but confiscating the excessive 'infra-marginal rents' inside the wholesale market.

[2] The following paragraphs implicitly rely on the copper plate assumption, *i.e.*, that the economic conditions of the power system and network are not altered by localization of production and consumption.

[3] Cf. Green (2021). Some members of the group suggest that this conclusion holds only when the market can adjust freely and instantaneously all the time in response to shocks of any nature.

[4] Cf. Fabra (2022), Grubb (2022), Maurer *et al.* (2022).

[5] Some members of the group recall that this is a strong simplification, insofar as it abstracts from possible effects related with localization of production and demand. For example, prices that are above the highest marginal cost in the system can occur at the same time albeit at different locations, due to transmission constraints.

[6] Cf. ACER (2022), Hogan *et al.* (2022).

- A different way is to classically tax 'ex post' the excess profits made by electricity-related companies (producers, pure traders or suppliers) by defining a reference 'normal profit' which will stay safe. The new Rishi Sunak UK government has employed this extra-taxation scheme.

- Other ways are simply practices which do not claim to be models[7]. In France for more than a decade, public authorities have organised a regulated access to nuclear electricity. In 2022, 120 TWh, 40% of the country's nuclear output, were sold at 42-46 euros per MWh.

  Furthermore, most renewable entities in France have 2-way long-term contracts (*Contracts for Difference*) with public authorities. The French regulator estimates that 30bn€ of their infra-marginal rents will be returned to the public treasury in 2022-23.

- The so-called 'Iberian Model' combines changes in the wholesale and retail markets. In the wholesale market, the price of gas used to generate electricity is subsidized - by the difference between the spot price of gas and a reference price (40€/MWh initially, ranging to 70€/MWh). Therefore, the market price is as if generators had bought gas at the reference price, and the 'infra-marginal' rents diminish. In the retail market, a charge is added to the wholesale supply price to compensate CCGT generators for the second half of the gas cost that was not taken into account at the wholesale level. This two-level manoeuvre is said to have decreased the Spanish wholesale supply cost to retailers by 15% to 20%.[8]

One consideration has to be kept in mind: by lowering the price of energy sold by non-marginal generators, one also lowers the incentives for demand to react to the gas price shock, unless that infra-marginal rent is returned as a fixed amount independent of actual demand.[9]

The worst part of the EU gas price shock seems to have stopped at the end of year 2022. In January & February 2023 gas trends make unnecessary the use of emergency tools to tax inframarginal rents. Consequently, Spain & Portugal have already been officially notified by European Commission that the exemption to use the "Iberian Mechanism" in their market will not be renewed when it will expire in this year 2023.

Recommendation: if governments want to redistribute revenues made by electricity professionals, better to use mechanisms outside the short-term wholesale markets, like long-term contracts (as, among others, Contracts for Differences) and taxation, and to let short term market mechanisms rank the different technologies and various assets according to their economic efficiency and reactiveness to the electricity system needs.

[7] Some members of the group, however, think that they can be defended as anti-monopoly interventions, or as capturing some of the rent from state-owned assets that we initially sold at a discount in a market with uncertain future prospects.

[8] Cf. Collado *et al.* (2022).

[9] The empirical effect might be subdued, though, insofar as the demand for electricity remains fairly inelastic.

Note n°2: Keeping the short-term markets working

1. Economic analysis: spot markets - how to efficiently trade electricity

The institutional framework set by the European Directives lays out the need for competitive electricity markets. However, identifying a benchmark design for competitive power markets is a never-ending concern in the debate on electricity sector restructuring.[10] Uncertainty about how best to support competition, political barriers and, last but not least, physical and economic attributes of electricity, have all contributed to this trend.

Academics have come to an agreement on the reference frame:[11]

- The creation of wholesale energy market institutions is among the prerequisites for the overall architecture for the development of competitive markets for power. The pillar of such an architecture is day-ahead (largely financial) and real-time physical dispatch of power, cost-reflective allocation of scarce network transmission capacity, timely and consistent response to accidental outages of both generation and transmission facilities and, more extensively, any facet linked to efficient trading of power.
- The implementation choices may differ: the market can be centralized or decentralized; it can include ancillary services or not; it can be based on physical or financial obligations; these contractual obligations can be customized or standard; participation in wholesale markets can be mandatory or voluntary; secondary markets can be favored or discouraged; and so on.

The solution to what could have been a theoretic stalemate has come from national experiences. Since the mid-2000s, empirical evidence from early market restructuring has shaped the characteristics of centralized dispatch. This latter provides standardized, physical – both day-ahead (spot) and real-time– obligations for handling power shortages (and excesses), thus complementing the advantages of decentralized bilateral markets with the effective and efficient, centralized, physical delivery of the underlying commodity. Real-time positions must be physical and binding at the time of dispatch. Moreover, as imbalances must be corrected faster than in a conventional market, bid-based auction markets are used and real-time balancing dispatch is handled by the system operator.

Centralized dispatches are timely, transparent and integrate every aspect of power system operations, thus minimizing transaction costs, capturing productive efficiency goals and handling real-time balancing. According to the theory of Schweppe *et al.* (2013), the system marginal price: i) coincides with the marginal cost of the producer that has the highest marginal costs, if there is some spare capacity and that producer is not fully dispatched; ii) is higher than the marginal cost of the last unit fully dispatched, and lower than the marginal cost of the first unit not dispatched; iii) is higher than the marginal costs of all producers and coincides with the expected Value of Lost Load if there is no spare capacity.[12] Moreover, in liberalized electricity markets with adequate competition, market-like processes ensure the efficient allocation of resources and efficient coordination of certain decisions, through market signals.

The day-ahead market yields financial contracts that can be settled by real-time physical of imbalance payments at real-time prices. As for the clearing rules in the day-ahead market, uniform pricing outperforms pay-as-bid rules in that it leaves inframarginal generators what is usually referred to as a 'scarcity rent' which helps to recover not only generators' operating costs, but also fixed capital expenditures (*see Note n°1*). Nevertheless, if both pay-as-bid and uniform pricing may be prone to market power, a vast strand of the literature has underlined withholding as an important weakness of uniform

[10] Cf. Joskow and Schmalensee (1988), Schweppe *et al.* (1988), Fehr and Harbord (1993), Stoft (2002).

[11] Cf. Hunt and Evans (2011), Joskow (2008), Shioshansi (2013).

[12] Some members of the group recall that this is a strong simplification, insofar as it relies on the copper plate assumption – *i.e.*, it abstracts from possible effects related with localization of production and demand.

pricing[13], noteworthy in presence of private information on the availability of (renewable) capacity (cf. Fabra and Llobet, 2023).[14]

Operating reserve services may add further rewards to generators and can work as out-of-market means either to accelerate restructuring or to correct spot market signals.

The potential flaw of uniform pricing (and operating reserves) is that it provides short-term signals which – as for the properties of energy carriers – are highly volatile, while long-term, sunk investment decisions dictate for stable pricing frameworks. Short-term prices potentially expose market participants, both on the demand and the supply side, to substantial risks, which however can be addressed by standardized hedging instruments.

All in all, a competitive power market consisting of a centralized (fully integrated) energy market for real-time, standardized, physical needs and a decentralized system of bilateral trading for long-term needs[15], tailored, financial agreements have been receiving some relatively broad consensus in the literature.[16] This is the so called "wholesale market design".[17] However:

- Some members of the group consider that such an architecture may not likely allow for an adequate volume of long-term contracts emerging spontaneously. Another problem is that such long-term contracts drain liquidity for the spot market, which is likely the case unless participation in this market is compulsory.
- Other members of the group also consider that markets for long term contracts may not need to be decentralized: auctions for contract for differences or CfDs are indeed centralized markets. (On as to whether long term contracts should be negotiated bilaterally or through auctions, see Note n°4).

2. Empirical aspects and recommendations

The following points assume that the power system works as a copper plate (*i.e.*, that the economic conditions (prices, quantities) of the power system and network are not altered by localization of production and consumption because there are, for instance, no congestions, which may seem restrictive for some European countries):

- European electricity markets have evolved towards an articulation between a centralized energy market for short-run needs and a decentralized system of bilateral trading for long-term ones -

[13] Cf. Fabra (2003), Fabra *et al.* (2006), Cramton (2017).

[14] More precisely, the exercise of market power with pay-as-bid pricing by favoring larger bidders will tend to encourage consolidation and discourage entry (Wolfram (1999)), whereas the exercise of market power with uniform pricing encourages entry and reduces concentration. Moreover, market may evolve to more competitive structures under uniform pricing (Cramton (2017)). Nevertheless, there is still a debate on long-term efficiency and investment levels. When demand elasticity is considered, uniform auctions outperforms pay-as-bid. Market monitoring and the design of market power mitigation is seen as central to good market outcomes.

[15] Cf. Allaz and Vila (1993).

[16] Some authors propose the implementation of a dual electricity market. The market would consist of two compartments, one with tenders for power plants with a high proportion of fixed costs and a low proportion of variable costs (nuclear and renewables), the other with tenders for power plants with a high proportion of variable costs (coal, oil and gas). In the first case, the price would be aligned with the average cost (under long-term contracts) and in the second case the spot price would remain fixed in the short term on the basis of the marginal cost (fuel). Then the two market solution may be a two contract market solution, where the contracts might be an average of the flexible and as available contract prices. As the fossil fuel plants disappear from the market, the boundary between the two compartments would shift and, in the future, the price of electricity would be aligned with the average cost of the electricity fleet composed of nuclear and renewable energies alone.

However, some members of the group do not necessarily share this view, arguing that sector coupling would make this "two-markets" proposal less sensible. Indeed the general EU and the Taxonomy regulation envisage a "Sector coupling" by 2050, involving electricity, transport and heating. Electricity will become the central pillar of the whole integrated system. In this connection, policies aimed at pricing them differently will be ineffective. When reasoning about a possible market reform it may be important to take into account the spillover effects to and from coupled sectors.

[17] Cf. Creti and Fontini (2019).

even if through a learning process of two decades. The integration of different trading zones, together with appropriate congestion management rules for cross-border network capacity, has resulted in day-ahead prices that are also "cointegrated" in statistical terms.[18] Additionally, the progressive penetration of variable resources such wind and solar, benefitting from low short-term costs, has put downward pressure to day-ahead prices in all the European exchanges. Evidence on the merit-order effect is clearly documented.[19]

Recommendation: Market design options that do not take into account the increased need of liquidity in short-term trade and market integration should not be chosen.

- The legal, administrative and institutional context ensuring that markets integration speeds up is still a concern. As the European Court of Auditors has stressed in his latest report (2023) "Delays in coupling national power markets have piled up because of weaknesses in EU governance and a complex system of regulatory tools for enabling cross-border trade, which has held back the implementation of market rules. Nor has market monitoring by the European Commission and ACER, the EU's energy agency, brought sufficient improvement. Surveillance measures to restrict abuse and manipulation have not gone far enough, meaning that the main burden of risk on the EU electricity market has been passed on to final consumers. »

  Recommendation: Efforts in accelerating market integration would improve the functioning of the short-term markets.

- A contentious issue is whether the auction format that is most commonly used in wholesale electricity markets – the uniform-price format that pays all winning bids at the market clearing price - is responsible for the recent high electricity prices.

  It has been argued that paying each winning producer at their own bid – the so-called pay-as-bid format – would allow saving the difference between the highest winning bid and each winning bid. This reasoning is flawed given that firms would change their bidding behavior if the auction format switched from uniform pricing to pay as bid. Some analyses have shown that the pay as bid format may mitigate market power and through that reduce prices and firms' rents.[20] However, this is not enough to justify the change in the auction format. Solutions like the UK market design with a real-time (balancing) market and pay as bid clearing have not been considered successful and have been replaced by the pay-as-clear.[21]

  Another question relates to portfolio bidding *vs* unit commitment. There is extensive literature on this. Generators prefer portfolio bidding since it allows more internal flexibility, while unit bidding and commitment makes operations easier for the TSO that have to program injections and withdrawals consistent with the network capabilities. A debate in Italy in this suggested overall that unit commitment might be a preferable solution. In a highly and increasingly interconnected EU network, portfolio bidding would place additional operational burden on TSOs.

  Recommendation: changing the auctions' rule on wholesale power markets should not be a priority (pay-as-bid vs pay-as-clear, unit commitment vs portfolio bidding, though unit commitment might be preferable in the latter case).

  Fostering demand response, prosumers and electricity storage should be promoted as more efficient remedies against the exercise of market power, by increasing elasticity of (respectively) demand and supply, still contributing to security in electricity systems with a high share of renewables.[22]

  Close market monitoring and interventions (to replace unreasonable bids with cost-related bids) or requirements for maintaining bids for longer periods than a day or an hour are used in some markets to reduce the exercise of transient or local market power.

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18 Cf. Zachmann (2008), Gugler *et al.* (2018).

19 Cf. Antweiler et Muesgens (2021).

20 Cf. Fabra (2022).

21 Cf. Liu (2022).

22 Cf. Carson and Novan (2013), Zhao *et al.* (2015), Steffen and Weber (2013), Müller and Möst (2018).

> *Also, supply expansion and supervision of anti-competitive behavior should be pursued by regulators and may prove to be more important than changes in market design. For example, given low demand elasticity in the short-run, any supply expansion will have a strong impact on prices.*

In case the copper-plate assumption is dropped (which may be more accurate in the future given the implied effect of the development of intermittent renewables on network congestions), all the above-mentioned contracts must eventually be implemented in a rather more specific way: localization of the contract (point of generation *vs* point of consumption), settlement rules or penalties for failure to deliver, object of the contract (energy *vs* installed capacity)…

Note n°3: Capacity markets

1. Economic analysis

Traditional analysis of wholesale electricity markets[23] suggested that the "energy only" markets were able to incentivize investors to build all types of plants needed to serve the load, from base-load to peaks (hence the so-called "peakers").

However, the pressures exerted during and after the Californian crisis in 2000-01 to deter very high prices[24] resulted in legitimating many regulatory actions of market price capping. As soon as capping wholesale market prices is not exerted in a very precise and highly accurate way, a "missing money" issue occurs, and some types of assets are not any more built by market-based investors. Others have argued that the problem in a dynamic world was in addition one of "missing markets", notably adequately long-term futures and contract markets.[25]

As long as these types of assets are needed by the electrical systems to serve the load for all peaks, a pragmatic approach emerged, being to complement the revenues missing from energy sales by either a targeted payment for *capacity* for certain classes of "selected assets" or a capacity auction with longer-term contracts for all controllable new entry.

These capacity markets are second or third best options to deliver the needed "capacity adequacy". Targeted assets are chosen by a public authority, or a proxy of public authority (as a licensed system operator or a market operator). Therefore, the choice of the technology and operational characteristics (including size & location) of these assets is of a regulatory nature. Frequently, the choice is made through engineering models in which engineering dominates. Paul Joskow tried to get more economic analysis in the process, but did not succeed. As William Hogan showed repeatedly, it is very difficult (not to say impossible) for engineers working for system operators or market operators to accurately and continuously update their information about available technologies & operational characteristics, and to simulate the real decisions taken with the high incentives of free pricing for peak and scarcity.

The alternative approach is for the Government, advised by the System Operator, to determine the volume of Equivalent Firm Capacity to meet agreed reliability standards and then, after announcing de-rating factors for each technology, to run a technology-blind auction for current generators (offered one-year contracts) and new entrants (offered 12-15 years contracts), *e.g.* as in the island of Ireland.

Many governments were keen to transform their building into "political economy bargaining", given the very special practicalities involved, the key role of so many details and parameters, and the very high skills required to assess proposals pushed by interested parties.

When gas-fed CCGTs started to revolutionize the wholesale market, nuclear plants were not always able to cover their total costs and eyed some "capacity payments" or low-carbon compensation. When renewables started their own revolution in the wholesale energy market, being stimulated by Governments by non-market revenues, the CCGTS eyed similar capacity payments to make their money and not to close, and in some cases, to enter to meet foreseen shortfalls. Now that the EU is considering 70% of renewables in the power mix in 2030, many assets being dispatchable are calling for this dual revenues: (energy sold + capacity financed). In the USA, this problem is addressed by operating reserve demand curves (ORDC) and the implied scarcity pricing.[26]

The consequences of this lack of market incentives to invest into the technologies and amount of assets needed to guarantee the system security have amplified with the rise of renewables increasing the volatility

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[23] Cf. Glachant *et al.* (2021).

[24] Some members of the group recall that there are no documented examples of generators exercising market power during the California crisis. The failures were failures of market design and regulation.

[25] Cf. Newbery (2016).

[26] Cf. Hogan (2013).

of market prices and the uncertainty of revenue streams for investor. These concerns have not been adequately attenuated by the right activation of the growing potential flexibility of demand permitted by digitalization and advanced suppliers' innovation (up to sub-metering of different consumption usages).

As long as "capacity revenues" are gained in an open tendering, the "competition for the market" has become a supplement to "competition in the market".

In the case of highly capital-intensive large and long-lived assets such as nuclear power stations or hydro reservoirs, D.Newbery argues that new investment will not be forthcoming without credible counterparties signing long-term contracts. In return for such future guaranteed revenues, existing nuclear and hydro stations could reasonable be required to accept long-term contracts closer to their expected prices when privatized. N. Fabra, from Spain, calls this formula of re-regulation as "mandatory Contracts for Differences".

2. Empirical implications and recommendations

- *If the objective consists in providing adequate capacity to meet load under stressed conditions, some members of the group consider that this problem has no solution through regulations but provides the impetus for delivered energy hedging contracts (see Note n°4).*[27]

  These members consider that capacity markets have brought about more and diverse problems than they have delivered solutions. This stems mainly from the fact of retributing capacity instead of energy produced. According to their analysis, capacity markets have not been very successful at tackling reliability of the power system, even though they may sometimes have been costly.

  Such systems seem to work best in island systems like the island of Ireland and Great Britain.

- Now, in case capacity markets are implemented at the EU level, many (but not all) existing European "Capacity Markets" are still conceived according to engineering rules of highly centralized generating units, and not conceived to benefit from the many GWs of flexibility that demand could deliver in the commercial, administrative and domestic sectors (up to 10 or 15 GW in France). A similar reasoning could target the storage assets, as a specific new ingredient of modern electricity systems (including the batteries on wheels that are electric vehicles…).

  Recommendation: if implemented, capacity markets should be open to all resources contributing to system security and stop favoring certain ones, as with discriminatory long-term contracts.[28]

- Second, EU capacity markets are heterogeneous and variously rely on strategic reserves, capacity payments, supplier capacity obligations, forward capacity auctions, or reliability option auctions. It has become hard to impossible to unify this heterogeneous framework into a single European one. At least some more coherence could come, upstream and downstream when it comes to cross-border trading in these capacity obligations.

  Recommendation: if capacity markets are implemented at the EU level, the criterion used to conceive and dimension the capacity requirements should be clarified and harmonized with explicit reliability standard as loss of load expectation, target reserve criteria. At the implementation stage, definition of certification and verification procedures of activated resources should be regionalized. Operational rules to access cross-border capacity, and to operate cross-border delivery at times of system stress, have to be set.

  Nevertheless, capacity adequacy assessments at the European level seem difficult to implement. Not only the security of supply is part of Member States sovereignty (even if solidarity to avoid shortages has a role to play), but also remuneration rules which are not national cannot be easily defined (how an asset in a Member country X contributing

[27] If the objective consists in providing revenue to ensure no missing money, the problem may be handled through the operating reserve demand curves (ORDC) and the implied scarcity pricing.

[28] A new metric could be "equivalent firm power" for all resources. However, some members of the group consider that there are serious problems if extending this concept to highly correlated devices like wind and solar.

to security of Member country Y and Z simultaneously should be remunerated by taking into account multiple cross-border effects?).

- Third, the information and scenarios used in the EU to calculate the needs and useful resources can evolve, thanks to the active regionalization of transmission services created by the EU "*Clean Energy Package*" voted in 2019. Since July 2022, there are *Regional Coordination Centres* created all over EU to deliver additional tools and analysis to the national TSOs to understand the system constraints and available options at the regional level. Therefore, the European TSO industry will not stay restricted to "national only" sets of information, options and identifiable interactions. The new EU regional level of electricity system coordination might permit soon to perform new assessments of regional system security and regional resource adequacy.

  Could we expect to get, say in 2025, the very first European fully regional set of studies of "Capacity & Capabilities" requirements for electricity regional security, and the corresponding "Adequacy" forecasts at the same regional level. If working well, 2030 could then be the first year of renewed "EU level" security and adequacy studies built on these new regional skills and experiments.

Note n°4: Long-term contracts (futures, PPAs, CfDs)

Long term contracting has become increasingly debated in power markets over the recent years – in line with high future price risks, and the trend towards lower prices as more renewables get deployed. Additionally, technological change has implied that the new technologies of production have low variable costs but heavy upfront capital needs which they can hardly finance unless they reduce their price risks.

"Long term contracts" refer here to three types of contracts: the 'power purchasing agreements' (PPAs), the standardized contracts on the wholesale future markets, the Contracts-for-Differences (CfDs) which articulate some market features (auctions) with some contractual elements.[29]

In all cases, one aim is to protect agents against extreme wholesale prices of electricity:

- The **'power purchasing agreements' (PPAs)** are long-term private commercial contracts directly tying a generator with a given professional consumer[30] or a small group of professional consumers. For instance, in PPAs, consumers directly sign a long-term contract with large wind and solar farms for buying renewable electric energy. These long-term energy contracts can last for 15–20 years. PPAs secure the revenue stream of the renewable energy developer despite the generation intermittency; while consumers are able to achieve the environmental commitment as well as ward off the volatility of the wholesale price, plus – if willing to- valuating better the particular characteristics of their load as, in the future, supply might consider better the many potential flexibilities of demand. Long-term contracts between large consumers and producers already exist in many European countries. The literature on PPAs is scarce.[31]
- **Future contracts in the wholesale power sector** are contracts with future delivery of products for a price fixed today, where all parameters are standardized (quantity, date...) except the price, which is negotiated on the market with a clearing house.[32] The futures market is used to hedge against commodity price variations: an actor who wishes to hedge against the risk of rising prices (e.g. a trader selling at a fixed price to his customer) buys a future contract in parallel. If prices rise, he will gain as much on the future market as he will lose on the spot market, and vice versa. Futures contracts are not traded for physical delivery (this is the aim of *forward* contracts) but for protection. In the power sector in Europe, the futures markets are usually not very liquid nor important[33].
- A **Contract-for-Differences (CfDs)** is a long-term contract, *e.g.* between generators and a public agent (regulator, public fund...), whereby generators sell their electricity on the market and then pay/receive the difference between a "strike price" and the "reference price". The strike price can

[29] Equity partnerships between large consumers and producers are a theoretically possible direct way for the former to access a cost-plus price of power facilities with low marginal prices - though this may not be necessarily the case. It can be achieved through a joint venture between the producer(s) and the (industrial) consumers, where consumers have a stake in the capital, participate in the financing of the company and benefit from a drawing right in proportion to their participation in the joint venture. This type of scheme can be found in Finnish or English projects. The allocation of risks between the stakeholders can be very variable. Overall, equity partnerships between large consumers and producers mirror the traditional concept of industrial partnership. These solutions require careful examination as to their compliance with competition and antitrust law.

[30] The increase in wholesale power prices and their volatility has become a threat to European (energy-intensive) industries. They weigh on their competitiveness, may temporarily block their production and threats their viability in Europe. The economic and social consequences are potentially serious since the basic products of these industries feed all the value chains.

[31] For a useful, empirical publication, see Pedretti and Kanellakopoulou (2023).

[32] When two operators have negotiated the purchase/sale of a contract, the transaction is recorded by the clearing house which becomes the counterparty of the buyer/seller. Any contract bought/sold is unwound at the latest at maturity, most of the time by clearing: the operator who has a short (long) position buys (sells) the same number of contracts of the same maturity. The presence of a clearing allows the trader to collect or disburse the difference between the prices of the two transactions without intervening in the spot market.

[33] This is especially the case in France where the ARENH mechanism removes much liquidity from wholesale future markets.

be set by the regulator or through an auction. There are different types of CfDs, with different properties, depending on how the price and the reference quantity are defined.

1. Economic analysis

Here we focus on contractual relationships between generators and retailers/big consumers on standardized contracts traded in centralized platforms along the following topics: contracts and hedging ; contracts and competition ; standardized contracts traded on platforms.

Contracts and Hedging price risk

The whole discussion of hedging starts by observing there are offsetting risks that can be traded. In the literature on wholesale electricity markets, participants are sometimes assumed to be risk neutral. In practice, however, electricity market participants are risk averse and seek to insulate themselves from wholesale electricity market risk, by trade in hedge contracts.

Here we focus on price/volume risk in time (and not depending on geographical localization). For simplicity, we thus make no distinction about the location of the defined prices and quantities (*e.g.*, we rely on the copper plate assumption).

Hedge contracts can take a wide range of forms. As noted earlier, hedge contracts may be specially tailored arrangements. However, *we focus here on the standardized hedge contracts known as swaps and caps* (and we will briefly mention their relatives – collars and floors). Contracts of this form make up the bulk of the contracts traded in the over-the-counter hedging market.

In order for a hedging contract to reduce the risk faced by a firm, it must require the firm to make a financial payment (or to accept a financial payment) that is based on some observable outcome correlated with the firm's profit. The most common form of hedging contracts base the financial payment on the observed spot market price – which is usually highly correlated with the profit of the market participants.[34]

The main contracts are:

- ***Swaps*** are a financial agreement under which one party (known as the seller) agrees to pay another party (known as the buyer) an amount equal to the difference between the spot price at a predetermined half-hour period and a predetermined fixed price multiplied by a predetermined quantity. Contracts of this form are called swaps because the effect of the contract is to swap a floating revenue stream for a fixed revenue stream.

  In the electricity industry, *contracts-for-differences* display the features of simple fixed-volume forward contracts. Contracts-for-difference involve a fixed strike price - the quantity typically depending on the production of the plant subject to the CfD.

  Swaps may involve two-way flows of payments. If the spot price is higher than the fixed price, the swap seller pays the buyer the difference. On the other hand, if the spot price is lower than the fixed price, the swap buyer pays the seller the difference. Although it is technically feasible to trade swap contracts applying only to a given date and time in the future, in practice it is common to group swaps with the same volume and similar time periods together.[35]

- ***Caps*** (also known as 'call options' or 'one-sided obligations') are a financial agreement under which one party agrees to pay the difference between the spot price at a predetermined half-hour period and a given strike price multiplied by a predetermined quantity, but only in the event that the spot price exceeds the strike price. As compensation for this future payment stream the buyer pays the seller a fixed up-front sum.

[34] Cf. Biggar and Hesamzadeh (2014).

[35] For example, in the Australian National Electricity Market (NEM), so-called peak swaps cover the hours from 7:30 a.m. to 10:00 p.m. on weekdays, over a month, a quarter, a calendar year or longer. Flat swaps cover all 48 half-hour periods in a day for (again) a month, a quarter, a calendar year or longer. Off-peak swaps can be obtained by purchasing a flat swap and selling a peak swap for the same time volume and period.

Some theoretical analysis suggests that an electricity producer that purchases natural gas on the spot market and that sells electricity on the spot market could obtain a perfect hedge using a financial instrument, which is like a cap but which depends on the difference between the electricity and the natural gas price.

Standardized futures contracts

Electricity futures are derivatives that fix the price ahead of the delivery period. During the trading periods, market participants exchange standardized contracts composed of a unit of energy. The latter is going to be delivered to the buyer by the seller at the exchange price for the whole delivery period, for the contracts with physical settlement. On the contrary, a cash settlement is foreseen based on the difference between the spot and the forward price for financial contracts, which are indeed the majority of future contracts exchanged in the above-cited markets.

High volatility, mean-reversion, sudden and huge price spikes are well-known characteristics of wholesale electricity spot prices.[36] These features are due to power limited storability and load fluctuation. These factors imply that the classic approach used for financial forward evaluation, *i.e.* non-arbitrage condition, cannot be applied. Electricity cannot be sold short; it cannot be purchased at the spot price today, stored it for a certain period of time and resold it at the forward price. Moreover, the classical concepts of convenience yield and cost of carry, that explain the relationship between forward and future prices, loose their meaning here, since they imply that traders can acquire and store the underlying asset (Hoff and Mortensen, 2014[37]).[38]

Contracts and competition

- In the context of contracts complementary to the day-ahead electricity trading, **forward markets** play a crucial role.

  Forward contracts are financial contracts enabling the parties to lock in acceptable prices, without necessarily requiring physical delivery. Both parties can make adjustments in response to changed circumstances. For example, a retailer may decide to satisfy its demand through spot purchases, whenever the spot price is below the supplier's costs. Ideally, the spot price only is used to price deviations from positions taken in forward markets. Contracts participants need to engage in bids and offers in advance of real time simply to enable the system operator to look ahead and ensure physical feasibility of the proposed schedule.

  For these reasons, (financial) forward contracts also play an important role in mitigating the incentive to exercise market power[39], an issue that might always arise with uniform auctions in the day ahead market. A supplier that has sold its generation forward has no interest in manipulating the spot price. And indeed both suppliers and demanders have an interest in forward contracts, since the contracts reduce the risks of both parties.[40]

- There are also additional issues related to long-term contracts and competition, which mainly concern **PPAs**. PPAs are subject to competitive concerns, because in the past, some incumbents

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[36] Cf. Knaut and Paschmann (2019), Li *et al.* (2016).

[37] Cf. Haugom *et al.* (2018).

[38] According to the hedging pressure approach (Bessembinder and Seguin, 1992), the forward price of a certain asset can be read as the sum of the expected spot price on that asset and the risk premium. This latter is paid by the risk-averse operator in order to transfer the price risk to the counterparty. Both electricity producers and buyers may be interested in incurring an additional cost to cover themselves from price risk. This would result in both positive and negative risk premium (Pietz, 2009). In particular, a positive premium, namely, a positive difference between forward and expected spot price, would signal that buyers are relatively more risk averse than sellers, and therefore are willing to buy electricity forward at a premium compared to the spot. Doing so, they can guarantee themselves a fix price, transferring the risk due to spot price volatility to sellers. On the contrary, a negative premium, *i.e.*, a forward price lower than the expected spot, implies that sellers are willing to pay a premium to buyers in order to transfer them the risk of spot price volatility.

[39] Cf. Cramton (2017), Borenstein (2002), Anderson and Hu (2008).

[40] Cf. Ausubel and Cramton (2010).

were trying to give to some large consumers preferential treatment being obviously discriminatory. Furthermore PPA benefits are kept by the contractors, and not passed to the non-contracting-users.

PPAs are private because the parties kept them mainly confidential. This privacy might weaken competition and create barriers for other players being less involved or less skilled. The development of PPAs remains limited to a class of motivated players because bilateral contracts all face a counterparty risk. These risks can, however, be reduced by new rules arranging the PPA market. Also, PPAs can be quite sensitive to the level of interest rates (which are rapidly increasing in the current context), though new PPA market rules may also reduce some of these concerns.

Overall, signing a PPA is mainly an option for very active professionals (buyers and consumers), not a tool to secure large and fast energy transition for the vast majority but not very active bulk of the market.

Implementation of long-term contracts.

As a matter of fact, contracts are hedging instruments. They are not new to the electricity industry but have evolved recently due to implementation choices taken by different Member States. Thus CfDs have been used in France and UK to incentivize renewable capacity. At the same time, PPAs have allowed some professional users to secure purchases of green electricity. For instance, carbon contract for differences are another form used in practice, even if not yet generalized, when governments commit to pay a fixed carbon price level to the investors.[41]

The CfD mechanism might have the disadvantage of having to heavily subsidize the producer in case the wholesale price is durably low and this will then go against the European texts that prohibit public subsidies.

These implementation differences are justified as long as Member States can have specific objectives for the evolution of the sector, that is decarbonization or consumers' protection, and investors have heterogenous risk attitudes.

2. Empirical aspects and recommendations

Principal recommendation: Long-term contracts are vital to the efficiency of electricity market designs. Choosing to limit them on one type only (either PPAs, or future contract, of CfDs) would narrow hedging opportunities and perhaps increase situations prone to the exercise of market power, which is not desirable. This is all the most important as each Member State has a different mix and different size/number of stakeholders willing to enter contracts.

As concerns future contracts in the wholesale power market:

- *Recommendation: Future markets in the wholesale power sector allow for avoiding the need for complex legal and commercial arrangements. This option is flexible and less complex to set up than long-term contracts, and accessible to all companies (directly or through intermediaries). However, it would require a rise in the liquidity and size of the market of future contracts. Thus a compulsory mechanism would enhance liquidity on the longer segment of the future markets.*

  For instance, the New Jersey BGS auction provides a rolling hedge for the delivered energy and price (without being strictly "mandatory").[42]

  Policies aiming at increasing the size of these future markets (and, consequently, of optional markets), especially at 5 to 10 years, would allow for significantly improving the long-term visibility

[41] Cf. Richstein and Neuhoff (2022).

[42] Another solution would be to create long-term liquidity on the market with government regulating producers so as they offer volumes for buying and selling market products with specific maturities. Market orders (volume, price, delivery date) would be managed centrally by an independent structure (public or not) within a regulatory framework. From the point of view of European regulation, no legal barriers have been identified at this stage. In particular, the possibility of committing to a long period is not a priori hindered by Directive 2019/944, subject to ensuring the impartiality of the operator.

on electricity prices for consumers, through strategies of hedging comparable to those already existing for many commodities.

- There is a proliferation of standardized contracts. At the EEX, for instance, electricity futures are traded for delivery periods equal to one week, one month, one quarter and the entire year. In addition, the delivery can refer to the whole period, or just a subset of hours throughout the period.

  Recommendation: Better coordination on the standardised (futures) contracts should not be neglected, together with further design possibilities to reduce the collateral in order to improve liquidity.

- Empirical research of futures shows both positive and negative premia. The recent electricity crisis has also created extreme tensions in the forward market (see report of the French TSO – RTE – in 2022 for the French markets where an « excessive » risk premium seems at stake during 2022 summer).

  Recommendation: More monitoring and transparency on premia on power markets should be encouraged.

- *In case the copper plate assumption is dropped (i.e., if congestions are taken into account in the market design, which may be more accurate in the future), all the above-mentioned long term futures contracts must eventually be implemented in a rather specific way: localization of the contract (point of generation vs point of consumption), object of the contract (energy vs installed capacity)… For example, the New Jersey BGS contracts are for tranches (shares of total covered consumption) for delivered anergy at the load location and at the delivered price plus an allocation of capacity charges for the load at that location. This is a contact-for-differences of a special type, where the supplier takes the delivered LMP price risk at the load location (on LMPs, see Note n°5).*

As concerns power purchasing agreements (PPAs):

- *Recommendation: Signing PPAs is complex so they are mainly an option for the highly motivated professional buyers. PPAs alone are not very fit to deliver low-carbon investments at the scale and speed needed. They may involve significant counterparty risks, if no remedy is provided, and seem to be only suitable for very active market players.*

As concerns Contracts-for-Differences:

- *Recommendation: Regulatory-backed auctions for CfDs, run and underwritten by regulators on behalf of consumers, can be designed to hedge price or volume risks. In practice, they have already been used in order to secure revenues for renewables and neutralize spot price variability. Auctions are effective mechanisms for extracting investors' information about their actual costs if appropriately designed. The CfD auctions can also be designed to avoid large inframarginal rents. Government (agencies) can pool these underwritten CfDs and pass them to final consumers (or retail companies on their behalf) in ways that do not distort the short-run price signals or retail competition.*

Note n°5: Locational marginal pricing

1. Economic analysis

The low carbon energy transition in the power sector involves rising investments in the transmission and distribution networks. In this context, it is important to ensure that the locations of the new generators and the investments in the networks (to evacuate the generation) minimise total systems costs. For example, decarbonising electricity needs massive investment in wind and solar where the best resource is not always where the grid is strong enough - hence the importance of guidance for their location to minimise the total cost (*i.e.*, grid + generation). This has been well-recognised in a few countries that have locational Transmission Use of System charges for connection to and use of the network. Thus in Great Britain, annual charges vary across the country by about €40,000/MW per year, giving quite strong signals about where new injections are costly and where needed.

Transmission constraints are developing rapidly along with the low carbon transition in the power sector. The true locational marginal cost of meeting load can be both higher and lower than the marginal costs of any of the operating generators.

In this context, the Locational Marginal Prices (LMPs, or nodal prices) are used to settle, in the short-run (spot) market[43], all resource injections and withdrawals at each interconnection point (node) on the transmission system. These prices reflect the cost of meeting load at each location at each point in time, i.e., they account for the physical constraints of the transmission system. Accordingly, LMPs become more important as network constraints become more severe, which is likely with the future foreseeable development of renewables. More precisely, in a LMP market… :

- Power produced at locations where incremental supply cannot be dispatched to meet load due to transmission constraints will be paid a low price, while in non-LMP markets it is often paid the same price as generation that can be dispatched. Thus LMPs indicate clearly (for generators exposed to real-time prices) where generation should be increased or decreased to resolve constraints.
- Power produced where net demand is low will not be paid the same price as generation that is produced when net demand is high.
- Resources that cannot vary their output to produce more power when net load and prices are high or to produce less when net load and prices are low will receive lower average prices than resources that are dispatchable. Hence, fast ramping resources will earn larger margins than slow ramping units at the same location because they will produce more power when prices are high and less when prices are low.
- In a LMP market, consumers that can reduce their consumption when prices are high and increase consumption when prices are low will pay lower average prices than consumers that continue to consume at high levels when prices are very high. Moreover, power intensive consumers that have choice in where they locate their operations can locate where prices are typically low due to transmission congestion.

Ensuring that these arrangements send appropriate temporal and locational signals, both in terms of where to invest[44] and which assets to dispatch, and that prices are sufficiently granular to drive efficient and flexible behaviour, should result in higher global welfare and lower consumer bills. The evidence on the benefits of LMP suggest that the cost of moving to a LMP market might be paid back by system

[43] Implementing nodal prices at a distribution level (and not for a wholesale market) would be very complex, the prices would be highly non-linear and difficult for connectees (and DNOs) to predict. Small reconfigurations to the local network would make big differences to nodal prices. Local market power and its monitoring would be an acute problem.

[44] However, some members of the group that achieving this objective would rather need long-term contracted price signals, not volatile and unpredictable short-run prices like LMPs.

benefits in two years or less in a GB-size system. Neuhoff *et al.* (2013) estimate cost reductions between 1.1% and 3.6% for the EU, and Aravena and Papavasiliou (2016) find savings of 2.8% for Central Western Europe. Eicke & Schittekatte (2022) analyze the criticisms of LMP and provide more references covering case studies of the gains from LMP in other countries and states.

2. Empirical aspects and recommendations

Heterogeneous effects of LMPs among countries. The effects of switching to a LMP market may vary significantly among different countries:

- The US inherited thin networks relatively poorly connected to neighboring dispatch zones with significant constraint problems, but had the advantage of central dispatch so introducing LMPs was simple and in some cases led to cost reductions (power savings) of around 2%.
- France has a history of integrated siting decisions of generation and transmission over a country wide zone so constraints are likely to be lower, at least when all nuclear plants are in service. France is probably more like a copper plate than countries like Italy and Great Britain, so the gains from LMP would be probably less than in the United States, at least at present. Also, the gains from LMP in France would be probably less than in the other European countries, as Germany for instance (where a large part of the electricity generation is located in the north while the consumption is rather concentrated in the south) or as Italy.
- LMP would entail significant heterogeneity among wholesale prices in countries where producing areas are located relatively far from consuming areas - which may be the case of Germany.

While future constraints on power networks may indeed become more severe with renewables connecting in very different places to past large conventional generation, **efficient long-run connection contracts may alternatively reduce significantly the stress of the power system**. LMPs reflect short-run marginal costs whereas investment decisions are driven by long-run marginal costs (LRMC or full cost). To minimize risk, investors should be as confident as possible about the future costs of locating at different nodes. In this context, annually changing charges may be replaced by some long-term contracts that at each date signal the best places to locate, based on a realistic estimate of the LRMC. The published set of contract prices would be updated each year as networks and generation change, but past contracts would continue to be honored. Charges for existing generation would be replaced by grandfathered equivalent contracts for remaining life.

Switching to LMPs may raise some **organizational challenges**. Apparently ESO needs years to set up the security constrained dispatch system and the critical settlement systems, so this is a reform that it is well-worth setting in motion.

LMPs would give **a relatively weak investment signal to the Transmission Owner**. They signal short-term transmission constraints that will change as the network is reinforced, but the nodal price differences across different nodes will fall far short of paying for the cost of the reinforcing that link.[45]

The case for **zonal prices** (*i.e.*, an intermediary between a central dispatch at a country size and a strict nodal pricing framework) may provide with some second-best solution, but the case is not clear-cut either. Italy's experience with 21 pricing zones across the territory did not eliminate congestions across the country and therefore unequal pricing effects across zones and thus consumers, especially in regions where renewable penetration is the highest.[46] Another argument that does not support zonal pricing is that it may appear as an intermediate step with the associated risk of incurring all the transaction costs twice *en route* to full LMPs.

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[45] And, according to some members of the group, in any case give misleading systems as network reinforcement is a system-wide problem.

[46] Cf. Ardian *et al.* (2018), Concettini *et al.* (2022).

Recommendation: strong theoretical considerations suggest that locational marginal prices, on average, would efficiently address important issues of the current and future wholesale power markets. However, their implementation in Europe would raise significant organizational and regulatory problems that should be ironed out beforehand. The gains from LMPs would be different from one European country to another. In any case, guiding investment location will be needed. Other solutions would involve longer term pricing of location, or locational components included in the network tariffs paid by producers – however, these latter require further harmonization rules across Member States.

Note n°6: Cushioning the aggregate shock for private agents

1. Economic analysis

Given the size and the very recent timing of the shock on electricity prices in Europe, the academic research about the aggregate impacts of a price spike in electricity prices still remains in its early stages.

However, a significant number of studies tend to suggest that firms and households may not be homogeneously affected by energy and/or power prices:

- Henriet, Maggiar and Schubert (2014) develop a dynamic growth model to study the effect of energy shocks on the French economy. Energy is included in the model through the production of energy services by the household, and the production of goods and services by the firm. In this model, the effect of the carbon tax is more important on the energy consumption of firms than on the energy consumption of households. However, this study only considers fossil fuels.
- Likewise, the econometric analysis of Corbier and Gonand (2023) suggest that firms may be less able to adjust some of their consumption behavior in the event of an energy price increase. The inter-energy substitution elasticity of firms appears to be relatively lower than that of households. This is because households may renew their technologies more often because the durability of durable goods is relatively lower than the durability of physical capital. Durable goods have an average life of about ten years, whereas physical capital has a life of about twenty years. Furthermore, sunk costs and the amount initially invested in energy-interacting capital (*i.e.*, physical capital for firms and durable goods for households) seems to play a more important role for firms than for households. Thus, firms are less likely to switch energy types in their production process because the technology used is relatively more expensive (which can be seen as mirroring a form of lock-in).[47]
- From a macroeconomic point of view, De Miguel and Manzano (2006) suggest, using a DSGE model, that taxing firms on their energy consumption is detrimental to long-term growth, because of the potential depressive effect on their output.

By construction, a price shock on households triggers mainly demand-side effects while the same shock on firms brings about also supply-side effects that dissipate less rapidly and weigh on long-term growth.

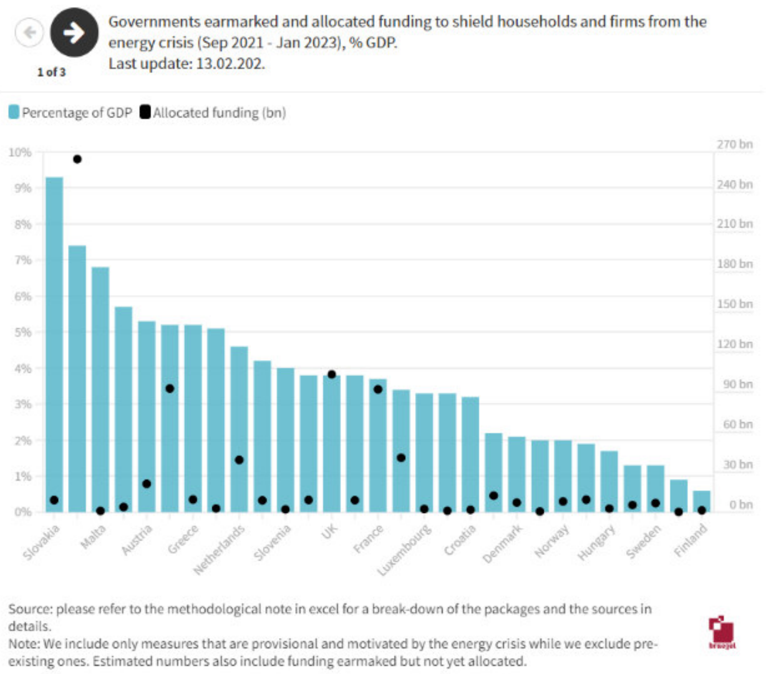
In its recommendation of April 2022, ACER pointed out that there can be solutions to be implemented to contrast future periods of high and volatile electricity prices, in order to protect particular groups of consumers. Measures like affordability options or "temporary relief valve" require the identification of groups of consumers deserving protection, a choice resorting mainly to Member States.

2. Empirical aspects and recommendations

Governments may cushion in different ways the price shock experienced by private agents (*i.e.*, households or firms), as empirical data show:

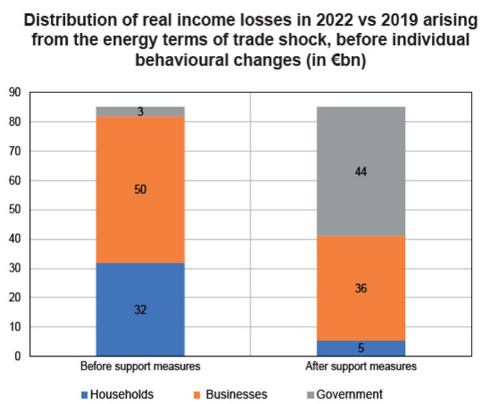
- The magnitude of the support can vary greatly among European countries. By far the biggest support has been provided to date by German public finances for the German economy.

[47] cf. Unruh (2000).



Source: Bruegel Institute (https://www.bruegel.org/dataset/national-policies-shield-consumers-rising-energy-prices).Germany is represented by the second bar on the left.

- The breakdown of the support between the manufacturing sector and households may also vary greatly across countries:
  - In Germany, industry—around 25,000 companies with a gas consumption above 1.5 million kWh/y— benefits from a price cap of 7 c€/kWh on 70 percent of their 2021-level gas consumption. By contrast, households benefit from a cap on the gas price of 12 c€/kWh that remains well above the price in 2021 (*i.e.*, 7.06 c€/kWh). Accordingly, German households will still experience a significant increase in their gas bills.[48]
  - In Italy, to mitigate the impact of the increase in energy prices, the burden of system charges has been shifted to the tax revenue, away from energy bills. Energy-intensive businesses received a tax credit.
  - In France, the Ministry of Finance estimates that public finances made up for almost all of the price shock for households, but only around 1/3 for businesses.



Source: DG Trésor calculations.

How to read this chart: Ex-ante losses over the full year before behavioural changes and macroeconomic feedback, calculated relative to values in 2019.

[48] See https://www.energypolicy.columbia.edu/publications/understanding-germanys-gas-price-brake-balancing-fast-relief-and-complex-politics/#_edn28 . The policy starts in January 2023 and ends on April 30, 2024.

Recommendation: Fiscal policy aiming at cushioning the recent energy price shock on private agents may try to reach a balance between the support to different kind of agents (households vs businesses, notably). In so doing, it may keep in mind that such a shock triggers different macroeconomic effects through different channels (mainly demand-side effects through households, mainly supply-side effects through firms) and also that firms might be more detrimentally influenced by such an event than most households.

Recommendation: The coordination at the EU level of local support measures is fundamental to avoid market distortions that can spill over into industrial sectors creating local advantages.

Recommendation: In this context, there is also a rationale for increasing the obligations of suppliers to better protect consumers (industries and households) from short-term price hikes.

Recommendation: Higher energy efficiency would attenuate greatly the aggregate impacts of a spike in power prices.

Note n°7: Technological challenges, Taxonomy and Carbon tax

1. Economic analysis: technological challenges and framework for decarbonization

Decarbonization is a long-term issue that requires substantial **technological change**. There have been significant technological advances in solar PV, wind and batteries.[49] Some technologies required for decarbonization are just about to enter markets and have to be upscaled quickly to integrate variable renewable electricity.

Carbon prices have also been a key driver of decarbonization in recent years. They create uniform incentives for climate-friendly behavior for all actors in Europe, foster the penetration of new technologies, and provide important incentives for technological change. Investments in clean energy technologies are affected by the relative prices of inputs, with higher investment being directed towards technologies that imperfectly substitute[50] more expensive (fossil) inputs. Carbon prices as well as high gas prices increase the rent of producers with low marginal costs and increase investments in alternative capacities. Substantially higher CO2 prices can put a strain on the competitiveness of European industry. However, carbon prices in Europe have been too low for many years, and are still too unpredictable, to send the right signal about what should be done today to reduce emissions and are also not sufficient for carbon neutrality as current technologies are not capable to fully decarbonize the economies.

Broader technology efforts are needed especially for technologies like CO2 capture, electricity storage, and biofuels in laboratory, prototype, or pilot phases[51]. **Policies that support R&D** of new technologies as well as the associated network infrastructure for clean energy innovation has to be adapted and developed. This relates to the electricity, but also to the transport, distribution and storage of hydrogen and synthetic energy carriers.

Wise investments determine the **speed and efficiency of the green energy transition** and given the long duration of energy investments depend crucially on proper discounting.[52] Discouraging or delaying technological change might be costly, as it could result in an extended transition period with slow growth in the future.[53] This is of importance as there is the fear that low carbon energy transition will have negative impacts on GDP per capita. A well implemented energy transition on the other hand might result in lower price of energy in the future.

Reforms of the electricity market design have to consider that important frameworks have been established, particularly with regard to EU legal requirements:

- **The EU Taxonomy Regulation** is a classification system providing very detailed criteria under which an activity can be considered environmentally sustainable. The EU taxonomy targets the financial sector with the aim of funneling investments towards the sustainable activities, that will receive more funds from investors, who will be protected from greenwashing. As a consequence, the EU Taxonomy cannot be considered a command-and-control instrument, since free markets are preserved, nevertheless, leveraging on the financial channels, it may have a substantial effect on industrial sectors. In particular, the Complementary Delegated act on gas and nuclear activities sets a path where coal and old gas-fired plants will be substituted with more efficient gas installations, which can be fueled with fossil gas in the short term and switch to renewable gases including hydrogen in the long term. The structure of future electricity market supply will be influenced by the boosting effect of the Taxonomy regulation towards investment in new technologies.

[49] Cf. Clarke *et al.* (2022).

[50] Except with a copper plate.

[51] Cf. IEA (2020).

[52] Cf. Cherbonnier and Gollier (2022).

[53] Cf. Acemoglu *et al.* (2012).

- **Clear certification standards with CO2 emissions** caused by the production, use and disposal of goods as the decisive assessment criterion are needed in order to enable effective European and international climate protection. The increased transparency reduces information asymmetries in order to ensure a more efficient allocation of capital. In order for CO2 emissions to serve as the relevant assessment measure, emissions must be registered credibly and reliably across sectors.[54] This is also needed for sector coupling and an essential prerequisite for many industrial policy measures and climate-neutral international value chains.

  However, the determination and crediting of emissions in the value-added process is not straightforward and requires the development of international valuation standards. This holds all the more for such a mechanism as the Carbon Border Adjustment mechanism, the efficiency of which is not guaranteed according to different studies[55] since its effect on global emissions of CO2 (and not only the Europeans ones) may be dubious.[56]

2. Empirical implications and recommendations

- *The implied reliance of the Taxonomy on well-functioning financial markets and investors' confidence risks to be a third best.* It may in the short run compromise what might be more competitive in the long run. Moreover, the complexity of the technical screening criteria and the stringent requirements about emissions, based on a life-cycle assessment approach, might hold back new projects and investments. Even though the taxonomy might raise the cost of capital of fossil fuels and in this sense can be seen as be complementary to carbon prices, *it is more efficient to use the markets directly and provide a substantial price signal on carbon* in order to activate the required capital from private sector investors.

  Recommendation: The implied reliance of the Taxonomy on well-functioning financial markets and investors' confidence risks to be a third best. It is more efficient to use the markets directly and provide a substantial price signal on carbon. Even more important is that the future carbon price should be predictable and bankable - which is an argument either for a floor or - better - a legislated carbon tax increasing at an agreed rate.

- If implemented, *long-term contracts* (cf. Note n°4) *should not be "too long-run" insofar as they should not introduce some kind of lock-in in current technologies that may be surpassed in the future.*[57]

[54] Cf. Mehling *et al.* (2019).

[55] Cf. Liu (2015), McKibbin *et al.* (2008), Winchester *et al.* (2011), Branger and Quirion (2014), Jakob *et al.* (2013).

[56] Cf. Fischer and Fox (2012).

[57] However, some members of the group suggest that they have to be long enough to reduce investment risk - most RES contracts are 12-20 years long and do not lock into a technology as successive auctions introduce better ways of delivering power from the same sources.

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