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# Why the Sustainable Provision of Low-Carbon Electricity Needs Hybrid Markets: The Conceptual Basics

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# Why the Sustainable Provision of Low-Carbon Electricity Needs Hybrid Markets: The Conceptual Basics

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**Abstract**

Deep decarbonization of energy systems poses considerable challenges to electricity markets and there is a growing consensus that an energy-only market design based on short-term marginal cost pricing cannot deliver the adequate levels of investment and long-term coordination across actors and sectors. Based on the vivid example provided by the evolution and adaptations of the European electricity market design, this paper first discusses several shortcomings of energy-only markets and explains how ad-hoc policies that intend to address these limits also have limits of their own, notably due to a lack of systemwide coordination. Second, it characterizes how deep decarbonization exacerbates these issues, raises short- and long-term uncertainty in energy-only markets, and how private investment in capital-intensive low-carbon technologies tends to fall short of the social optimum. Ambitious emission reduction targets (e.g. net zero by 2050) thus require an evolution of market design, which we argue should shift towards hybrid market design regimes. The key feature of a hybrid design is the separation of long-term investment decisions from short-term operations through a careful and balanced use of competitive and centralized design elements to coordinate and de-risk investment. Finally, a conceptual analysis of the evolution of different market designs in a historical perspective shows how hybrid markets constitute the contemporary form of long-run marginal cost pricing that is appropriate for meeting deep decarbonization objectives with radically reduced uncertainty and at least private and social costs.

**Keywords:** Electricity market, Deep decarbonization, Hybrid market design, Long-term contracts, Low-carbon investments.

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## I. INTRODUCTION

In liberalized energy-only markets (EOM), competitive short-term prices should in principle drive both the cost-effective use and dispatch of existing generation assets in the short run and the coordination of capacity investments and shutdowns towards the socially optimal generation mix in the long run. In this long-run equilibrium, all assets would break even and recoup their fixed investment costs, even with a dominant share of intermittent near-zero marginal-cost generation technologies. Yet, there is a growing consensus among scholars and practitioners alike that both the ideal and current market design models – respectively, a pure EOM and an EOM flanked by various ad-hoc policies – fall short of short of ensuring security of supply and the deep decarbonization of power systems as economically as possible and on schedule (e.g. Roques & Finon, 2017; Newbery, 2018; Joskow, 2021; Wolak, 2021).

Against this background, the objectives of this paper and its contributions to the literature are threefold. As a first contribution, we establish a diagnosis of the shortcomings of the ideal and current market designs that we categorize into four main issues, namely (1) security of supply externalities, (2) innovation externalities and industrial or social preferences, (3) climate change externalities, and (4) missing long-term markets. We do so in the EU context, based on past and current experience. While these issues are interrelated and often mutually reinforcing, it is key to analyze them separately to ensure a sound diagnosis and assess how alternative market designs may overcome them. On its own, each issue is amenable to specific ad-hoc remedies and corrective interventions – for instance, capacity remuneration mechanisms, technology-specific support schemes, carbon pricing policies, or regulators stepping in as long-term market makers. However, these ad-hoc remedies also have limits, notably because they are added on top of one another without sufficient systemwide coherency and coordination. The resultant multilayered policy environment conveys conflicting signals, suffers from adverse interactions, and is difficult to navigate for market participants and investors. Taken together, therefore, these issues challenge the idea that free market provision delivers first-best solutions.

As a second contribution, we substantiate how the energy transition and deep decarbonization objectives exacerbate the above issues. The quantitative changes the new policy environment implies are such that they call for a qualitative change in market design. That is, while the issues are fundamentally inherent to the EOM, we describe how they are magnified by the permeation of intermittent renewable energy at scale and the need for highly capitalistic investments to decarbonize the power system. We illustrate two important aspects. First, needed investment is hindered and/or made more expensive due to high capital costs resulting from unprecedented uncertainty levels in the short to medium term as market prices and rents become more volatile (these risks become more difficult to hedge) and in the long term as future market conditions and price distributions are deeply uncertain (these risks cannot structurally be hedged). Second, deep decarbonization entails the risk of proliferation of uncoordinated ad-hoc remedies (on top of short-term markets) to meet political targets. Absent a design overhaul that clarifies the roles of markets and society/regulators, this would further lower the performance and consistency of the policy patchwork and in turn negatively affect the electricity generation mix and costs.

In line with other scholars (e.g. Roques & Finon, 2017; Roques, 2020; Joskow, 2021), we next propose a bifurcated evolution of the current market design model into hybrid markets which have the potential to overcome the identified shortcomings and deliver on deep decarbonization targets. A hybrid market design consists of two modules, a long-term module which de-risks and separates investment decisions from short-term operations through long-term contractual arrangements, and a short-term module which harnesses the forces of competitive wholesale markets to exploit existing assets cost-effectively as at present. In this paper, we briefly review associated market design challenges and tradeoffs but the contours and functioning of hybrid markets are fully sketched out in a companion paper (Roques et al., 2021).

Finally, as a third contribution, we discuss the conceptual basis for hybrid markets in a historical context as a solution that combines centralized and decentralized elements in order to achieve the normative and socially optimal objective of long-run marginal pricing. Hybrid markets constitute in fact the contemporary form of long-run marginal pricing that is fit for today's policy context and political targets. These differ substantially from those that prevailed in the 1990's and led to the liberalization of electricity markets. In a nutshell, if the priority in the 1990's was operational efficiency, today it is rapid and massive investment in low-carbon generation assets. Crucially, hybrid markets do not constitute a radical departure from current practice but rather a more coherent and integrated use of existing economic tools alongside wholesale markets working as at present. Because they entail a balanced dosage of centralized long-term decision-making, the transition to hybrid markets would also call for an abandonment of the double-speak of energy policy-making – specifically, what *should* in principle drive low-carbon investment (i.e. short-term price signals) is very different from what *actually* drives low-carbon investment (i.e. policy-targeted long-term pricing) even today.

## II. THE CONCEPTUAL BASICS IN A HISTORICAL CONTEX

Electricity provision poses a distinct challenge to the Walrasian ideal of ensuring socially optimal economic equilibria via decentralized production and consumption decisions that are coordinated through the *tâtonnement* process of converging short-run prices. Several different conceptual perspectives can delineate this challenge and will be discussed below, one by one. At the heart of the matter is, in the terminology of the seminal contribution by Boiteux (1949, 1960), the difficulty to have short-run and long-run optimal prices coincide.

Specifically, prices that in a perfectly competitive market à la Walras would be equal to short-run marginal costs do not cover the long-run costs of building (and if necessary, expanding) the required fixed capacity. More than 100 years of economic literature going back to discussions about the setting of optimal rates for various non-storable services at the beginning of the 20$^{th}$ century have provided ample commentary on this issue. Specifically, in the electricity sector, two general solutions for resolving this conundrum can be distinguished. The first implies delegating generation and investment decisions to a regulated entity and setting regulated electricity tariffs (and when demand is variable, tariffs for electricity consumed during periods of peak demand) at the level of the long-run marginal cost, i.e. the cost of an additional unit of capacity plus variable costs. The second implies letting generators guided by the principle of individual profit maximization in liberalized markets choose a level of generation capacity that is low enough to induce enough scarcity hours with very high prices to allow recuperating the differential between short-run and long-run marginal costs.

The first approach has the advantage of providing a high level of certainty about the availability of sufficient funds to finance an adequate level of capacity to cover demand at all times.[6] It has the disadvantage of providing limited incentives for generators to improve efficiency and to innovate. The advantages and disadvantages of the second approach are symmetrical as it harnesses the power of market competition but generates uncertainty with respect to capacity investment on top of a certain number of incompressible scarcity hours. These disadvantages are magnified in low carbon electricity markets that inevitably rely on highly capital-intensive technologies. The shortcomings of the second approach, which has dominated the literature and market designs in OECD countries in recent decades, are discussed in more detail in Section 3.

Nevertheless, the alternative cannot be the return to regulated systems of old. Technological innovation, as well as changed behaviors and expectations, today both demand and enable a third way. Going forward, future market designs will need to combine the advantages of both approaches and mitigate their drawbacks. This fundamental conviction underlies the search for hybrid electricity market designs that combine efficient dispatch in competitive markets with complementary long-term mechanisms to ensure adequate investment. The key features of such hybrid market designs are briefly outlined in Section 5.[7]

### 2.1. Long-run marginal cost pricing for full cost recovery

The above remarks have highlighted the inevitable challenge in absolutely all electricity market designs, which is to combine the economic efficiency of short-run marginal cost pricing with the coverage of full costs, including fixed capacity investment, in an industry producing a non-storable good. The universal answer to this challenge is the fundamental principle of electricity market design that prices, i.e. the revenues of generators, must be sufficient to cover long-run marginal costs. When comparing regulated systems, competitive markets, or hybrid markets, it is important to understand that their underlying theoretical justifications all postulate full cost recovery without excess profits, i.e. social welfare optimization.

Fundamentally, these three approaches cannot therefore be distinguished by the mechanics of equating revenues with costs, but with respect to the dynamic incentives for generators, the conditions under which cost recovery is ensured, and the validity of the underlying assumptions. It is thus important whether the gap between short- and long-run marginal costs is recuperated over the entirety of operating hours, a subset of suitably defined peak demand hours, or an even smaller subset of scarcity hours.

The underlying principle of long-run marginal cost pricing stays the same, however, as set out in its canonical form by Boiteux (1949, 1960). Its reference case assumes that total capacity can be adjusted and that prices (or rather tariffs) are set by a regulator (or a welfare-maximizing monopolist). In this case, short-run prices (i.e. the optimally set tariffs faced by customers) are simply fixed so that they correspond with the long-run marginal cost of expanding capacity by one additional unit:

[6] Of course, security of electricity supply is ultimately a statistical concept and absolute certainty of supply would require infinite redundancy. A major meteorological event could always neutralize significant shares of capacity. However, in a regulated system with appropriately set tariffs, such an event could be confined to instances that would be considered not only legally, but also socially and politically, as cases of *force majeure* and would thus fall outside the remit of electricity regulation.

[7] A more detailed description of hybrid market designs can be found in a companion paper Roques et al. (2021).

> "Provided there is an optimal investment policy, short-term pricing is also long-term pricing [i.e. long-run marginal cost], and there is no longer any contradiction between the two." (Boiteux, 1960, p. 165)

This optimal tariff is under such circumstances equal to the marginal cost of increasing capacity, i.e. the long-run marginal cost:

> "Under the theory of selling at marginal costs, prices must be equal to the differential costs for existing plant. Plant is of optimum capacity when the differential cost and the development cost are equal, that is to say when differential cost pricing covers not only working expenses but also plant assessed at its development cost." (ibid., p. 167)

With demand that varies through the day, week or year, and with capacity that can be flexibly adapted in the long run, Boiteux develops a detailed analysis of demand-side management via efficient pricing and arrives at the principle of differentiated pricing during off-peak and peak hours, specifically:

> "After efficient pricing, the load curve becomes horizontal with 'hollows'. During the off-level hours, the rate charged will cover energy costs only. The level [peak] hours bear rates which will also cover daily power charges assessed at development cost when the level [of capacity] is adjusted to demand." (ibid., p. 176)

Reading Boiteux's original article, it is striking to see the extent to which, already back in 1949, the ideas of demand management and peak flattening were central to his analysis. This is should be kept in mind when considering structurally analogous forms of peak-load pricing to finance generation capacity such as VoLL-pricing or some capacity remuneration mechanisms. The original concept of peak-load pricing was indeed predicated on the basis of having fixed costs supported by as broad a base of customers and as large a number of operating hours as possible.

Boiteux's seminal results were repeatedly taken up by various theorists (see for instance Steiner, 1957, Crew et al., 1995 for a review, or Green, 2006 for a primer). At a purely conceptual level, abstracting in particular from uncertainty about the number of 'peak-load' hours, investors' risk aversion and its impact on capital costs, peak-load pricing yields optimal results irrespectively of the technical characteristics of available technologies – and even when they are intermittent with near-zero marginal costs (e.g. Crampes, 2018). However, as discussed further below, these issues matter decisively in practice.

Later, in the late 1980s and 1990s, technological and institutional changes suggested that other solutions than optimized tariffs set by welfare-maximizing monopolists or regulators could achieve optimal levels of capacity. On the technological front, new possibilities were offered by the advent of (i) combined cycle gas turbines (CCGT) with comparatively low fixed costs and (ii) low-cost computing power allowing for a rapid resolution of bid-clearing algorithms in competitive electricity markets. On the institutional front, political preferences for deregulated markets coalesced into a separation of electricity generation – which was deemed fit for market allocation – from transmission, distribution, and the supply of system services.

Under these conditions, electricity market economics rapidly converged around a new paradigm that was defined by scholars – inter alia, Joskow & Schmalensee (1983), Newbery (1995) and Stoft (2002). Joskow (2008b) summarizes the main features of this new paradigm (or 'textbook architecture' as he calls it) as (i) privatization of state-owned electricity monopolies, (ii) vertical separation of potentially competitive segments, (iii) horizontal restructuring to make generation more competitive, (iv) integration of transmission grids and network operations, (v) competitive spot markets for energy and operating reserves, (vi) institutions to integrate demand responses, (vii) competitive allocation of transmission capacity, (viii) unbundling of tariffs to allow for competitive retail services, or (ix) distribution monopolies obliged to source energy through competitive markets or benchmarked alternatives, (x) competent regulatory agencies, and (xi) appropriate transition mechanisms.

This design paradigm for electricity markets quickly caught the imagination of regulators and policymakers. From the United States to continental Europe and the UK, from Latin America to Australia, New Zealand, and parts of Asia, they unbundled vertically integrated monopolies, created competitive wholesale markets and instituted retail competition. Their intent was to achieve lower prices through more efficient operations, end corporate slack and engender a new technological dynamism.

Certain drawbacks became visible almost immediately, e.g. complex new regulatory framework or disorientated retail customers. Yet, competitive markets delivered on the central element of the promise of reform, which was operational efficiency. Competitive markets are indeed very good at "sweating assets" (Newbery). Existing generation assets were utilized to their fullest extent in a highly efficient manner through competitive dispatch. On some aspects, electricity is an ideal good for competitive markets, e.g. it is undifferentiable beyond a small number of easily observable features such as frequency, voltage, or stability. Outside the world of finance, it is a rare example of a market with negligible transaction costs or product differentiation. Strict short-term marginal cost pricing is thus the norm in competitive electricity markets other than during hours of extreme peak demand.

Precisely these hours of extreme peak demand, in addition to the inframarginal rents accruing to generators other than the marginal one, are supposed to provide the remainder of revenues required by generators to finance capacity and recoup full costs. Due to enforced scarcity during those hours, prices would equal the value of lost load (VoLL), i.e. the value of the marginal unit of electric energy or equivalently, the cost of a unit of involuntary and unplanned demand reduction. In theory, the exit and entry of operators ensures that, in the long run, the number of VoLL-hours multiplied by the VoLL covers the gap between the revenues from the wholesale markets during off-peak hours and the costs of an additional unit of investment, hence supplying the otherwise 'missing money' (e.g. Stoft, 2002; Joskow, 2008a).

On paper, it all adds up. VoLL-pricing exhibits a powerful structural identity with the theory of peak-load pricing enunciated by Boiteux, i.e. it is during the hours of extreme peak demand that the revenues for adequate capacity are generated. While VoLL-pricing results from the profit-maximizing behavior of competitive generators in deregulated markets and Boiteux had in mind a benevolent monopolist aiming at maximizing social welfare, both approaches imply that (i) prices equal short-run marginal costs outside of extreme peak hours, (ii) prices equal long-run marginal costs during extreme peak hours, and (iii) full costs are recuperated and budget constraints are satisfied at the level of both the individual firms and the overall system. That is, there is no structural 'missing money'. Ultimately, even the Walrasian postulate is vindicated since, as Boiteux points out, during those extreme peak hours short-run pricing is long-run pricing given that marginal cost, i.e. the cost of an additional unit of output, necessarily includes the costs of an additional unit of capacity.[8]

[8] From a theoretical perspective, it is worth comparing long-run marginal and average cost pricing in industries producing storable goods, where firms choose capacity based on total demand and not peak demand. In industries for non-storable goods, peak-load pricing at long-run marginal cost ensures social optimality while in industries

### 2.2. Endogenous & exogenous factors limiting the viability of deregulated power markets

However, there also exists a fundamental difference between VoLL-pricing and the adequate financing of low carbon generation capacity that is at the basis of the original article of Boiteux. This difference is at the core of the argument developed throughout this article and of the need to turn towards hybrid markets, which have the potential to allow for the implementation of new forms of long-run marginal cost pricing that are appropriate for low-carbon electricity markets with large shares of variable renewable energies (VRE).

The difference relates to the level, number of hours, volatility, predictability and ultimately the social and political acceptability of prices during VoLL-hours. VoLL-pricing resulting from the limited capacity of generators with respect to extreme peak demand was always supposed to be limited to a small number of hours per year, a few dozen at worst. This was made possible in the mind of its original proponents by the advent of the combined cycle gas turbine (CCGT) that was expected to set prices as the marginal technology. With its comparatively high variable costs and low fixed costs, the shortfall to be financed during hours of extreme peak demand appeared manageable, even considering the inevitable annual variations of the latter.

In practice, things turned out rather differently. The failure of deregulated electricity markets to provide adequate revenues for investment in generation capacity is, at least for European markets, well documented (see e.g. Finon & Pignon 2008; Keppler 2017; Fabra 2018; Weale et al., 2021). This failure can be attributed to two sets of reasons, one related to factors endogenous to the underlying theory, the other to exogenous factors. The former relate to (i) a naïve vision of the nature of the involuntary demand reductions that are intrinsic to VoLL-pricing and (ii) the fact that the capacity frontier and hence the number of VoLL-hours to guarantee fixed cost recovery is far more porous and unpredictable than originally assumed.[9] The latter result from policy initiatives that (i) pursue ambitious carbon reduction objectives and (ii) introduce large amounts of VRE capacity, mainly wind and solar PV, via out-of-market financing mechanisms. The two policy objectives are, of course, related but nevertheless not identical. Decarbonization, with its shift towards high-fixed costs technologies, poses challenges for deregulated electricity markets also when it is achieved by means of dispatchable low-carbon technologies such as nuclear or hydroelectricity.

The endogenous factors point to fundamental conceptual flaws intrinsic to the assumptions made to justify deregulated electricity markets. Inter alia, these assumptions neglect the true social costs of VoLL-pricing. However, supporters may argue that in practice such weaknesses

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for storable goods, only pricing at short-run variable cost is socially optimal. With storable products and increasing returns to scale, first-best optimality thus requires capital cost subsidies to ensure economic viability. In practice, a regulator who sets prices at average cost can ensure near-optimal outcomes. The two cases coincide if marginal costs are rising and the demand curve is horizontal, as is the case with the U-shaped average cost curve. The horizontal demand curve ensures that the distinction between storable and non-storable goods becomes irrelevant, since demand is perfectly flexible. The rising marginal cost curve ensures that the price at the optimum is equal to both marginal and average costs. Of course, this also means that production takes place at a point of constant returns to scale, which makes this latter constellation of primary conceptual interest.

[9] The term 'capacity frontier' is used to signify that the level of physically and economically relevant generation capacity is considerably more imprecise than presented in the literature. The capacity limit corresponds to a zone rather than a line – i.e. even if one leaves aside voluntary load shedding and demand response, which is primarily a question of definition, there exist auto-generation capacities 'behind the meter' that can be switched to supplying the market, the possibility for the operator to vary the frequency, the impact of the temperature on network losses, mothballed capacities that can be rapidly mobilized and so forth. This malleability of the capacity frontier adds to pre-existing uncertainty as it makes it difficult to assess the number of scarcity hours the system is likely to produce and on which operators rely to align total revenues with total costs.

may be manageable by implementing appropriate patches, typically a combination of capacity support mechanisms and regulatory interventions to stabilize the capacity frontier.

The exogenous factors, i.e. decarbonization and VRE deployment, instead do not so much pose fundamental conceptual challenges but magnify the conceptual shortcomings of the theory of deregulated electricity markets to an extent that the latter is no longer viable in practice. On the one hand, decarbonization requires technologies with high capital intensity and low marginal costs. VRE units, on the other hand, are not only variable but also auto-correlate, i.e. all units of a certain kind produce precisely during the same hours at zero marginal costs. This leads to highly volatile prices including the striking phenomenon of negative prices when VRE supply exceeds demand during certain hours but is unavailable during others. Market prices are thus lower, more volatile, and more unpredictable (without mean reversion) precisely at a moment where the need for stability and predictability is higher than ever.[10]

Summing up, deregulated electricity markets might have worked with appropriate patches in a reasonably satisfactory way under certain assumptions, most notably if a fossil fuel technology with high marginal and low fixed costs sets prices during most hours. However, in the context of radical decarbonization, and a fortiori in a perspective of net zero carbon emissions and heavy VRE deployment, whatever their other merits they become positively unworkable.[11]

The remainder of this paper will discuss the challenges of electricity provision via deregulated markets in greater depth and substantiate the need to turn towards hybrid market designs as a contemporary form of long-run marginal cost pricing that is fit for large-scale investments in low-carbon technologies. Presenting the main features of the hybrid markets, it will also spell out the elements of deregulated markets, such as competitive dispatch, that will be preserved and combined with specifically designed elements to ensure full cost recovery.

## III. ISSUES WITH CURRENT AND TARGET MARKET DESIGN MODELS IN THE EU

In an energy-only market (EOM), the market clearing price equals the variable cost of the marginal producer outside of scarcity hours. When capacity is scarce (i.e. supply is tight relative to demand), the market price should be able to rise above the variable cost the last (i.e. costliest) available generation unit. Such scarcity prices are needed to ensure that a long-term equilibrium exists in which all generators earn back their capital costs. In this equilibrium, given relative technology costs and demand fundamentals, the technology mix and overall capacity installed are endogenously determined (i.e. free optimization variables) and welfare optimal. As spelled out in Section 2, equilibrium prices reflect not only variable costs, but also the opportunity cost of capacity (i.e. a scarcity premium is de facto factored in the energy market price).

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[10] These are not just qualitative considerations, e.g. Peluchon (2019) shows quantitatively how more volatile prices in low-carbon electricity markets lead risk-averse investors to demand higher rates of return, which in turn raises the cost of capital and the social cost of electricity provision. See Sections 3 and 4 for more detail.

[11] EOM defenders will reply that such a statement is predicated on assumptions concerning the availability and cost effectiveness of large-scale storage, demand flexibility and other flexibility options. This is true in principle. Yet, whatever the so far unrealized hopes in this respect, the workability of deregulated electricity markets can no longer be taken for granted. The latter are rapidly becoming more fragile as decarbonization progresses.

In a liberalized EOM, competitive short-term price signals should thus guide both the dispatch of generation units on an economic merit-order basis in the short run and the coordination of capacity investments and closures leading to the socially optimal generation mix in the long run. The purported ability to steer the long-term generation mix adequately however rests on a set of demanding assumptions that do not hold in practice.[12] In addition, various externalities and market failures warrant internalization and corrective interventions.

In this section, we identify four main issues with both the EOM and the current market design (i.e. an EOM flanked by a series of ad-hoc policies) in ensuring long-term investments to meet deep decarbonization and security of supply targets in a cost-effective and timely manner:[13]

1. Security of supply externalities
2. Innovation externalities and industrial & social preferences
3. Climate change externality
4. Missing long-term markets

These issues are interrelated and often reinforcing one another but it is key to understand them separately to establish a sound diagnosis of current market design shortcomings and assess how hybrid market designs have the potential to remedy those (Section 5).[14] Moreover, these issues are not fundamentally new but they are exacerbated in capital-intensive decarbonized power systems with a high share of intermittent resources (Section 4). Importantly, as we will see, each issue may, on its own, be amenable to specific ad-hoc remedies. Together, however, they challenge the idea that free market provision delivers first-best solutions, especially under deep decarbonization and energy transition trajectory.

### 3.1. Issue 1 – Security of supply externalities

**The issue**. Even when assuming a privately optimal number of scarcity hours, an EOM provides less than socially optimal capacity levels due to security of supply externalities (e.g. Keppler, 2017). In turn, these externalities are one of the most important reasons behind 'missing money' issues. Because market remuneration only allows to fully cover the private cost of the market equilibrium level of capacity, and because this level is lower than the socially optimal capacity level, energy-only market remuneration is by construction insufficient to fully finance the latter (e.g. Joskow, 2008a, 2019; Wolak, 2020).

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[12] For instance, Lebeau et al. (2021) illustrate how an EOM generates energy mix trajectories that can considerably deviate from optimality when one relaxes idealistic investor behavior assumptions (e.g. perfect rationality, perfect information, or perfect coordination between decommissioning and investment decisions).

[13] A related fundamental issue that we have not formally treated but that permeates our analysis is the limited cost-competitiveness of large-scale storage opportunities combined with the high inelasticity electricity demand. This challenges standard market mechanics as power generation remains akin to infrastructure-based service provision

[14] Let us consider one example of issue interrelation. High costs of capital (e.g. due to missing long-term markets, Issue 4) may deter investment in renewable energy, nuclear power or CCS and instead encourage the use of fossil fuels since low-carbon technologies are more capital-intensive than conventional technologies. This in turn can undermine the effectiveness of carbon pricing (Issue 3), i.e. for a given carbon price the cost-optimal technology mix comprises less low-carbon sources the higher the cost of capital (e.g. Hirth & Steckel, 2016). This implies that complementary instruments are needed to lower capital costs by reducing and/or spreading out risks (e.g. Steckel & Jakob, 2018) to allow for an adequate deployment of these technologies (Issue 2).

Security of supply externalities are due to transaction costs and imperfect information, which prevent the formation of a well-functioning market for the good in question (e.g. Coase, 1960, 1988; Keppler, 1998). Due to the complexity of the good 'security of electricity supply', which depends on social preferences, political circumstances, the state of technology, behavioral structures and various other factors, transaction costs tend to frustrate its appropriate pricing in an EOM. This is equivalent to stating that a market for security of supply is missing. As Arrow famously formulated, "the problem of externalities is [...] a special case of a more general phenomenon: the failure of markets to exist" (Arrow, 1970, p. 76).

This notwithstanding, security of electricity supply also has public good features.[15] Just as in the general case that Coase and Arrow had in mind, transaction costs prevent individuals from negotiating among themselves the correct level of security of supply. This does not concern the negotiation between buyers and sellers in the electricity market, a confusion that pervades some of the literature on this topic. The level of security of supply between a buyer and a seller of electricity can very well be negotiated by means of appropriate prices or penalties, which ultimately feed through to the level of system capacity. Even where secure products such as bilateral long-term supply contracts exist, market participants will have no incentive to invest in them up to the optimal level since their private benefit of secure supplies will always be lower than the corresponding social benefit.

Security of supply is essentially a public good because one person's electricity consumption affects another person's utility without adequate inter-person communication about individual utility impacts. This effect is all the more important that electricity touches upon virtually every single economic transaction. With its corollary of lockdowns, teleworking and online shopping, the Coronavirus epidemic has recently brought out in sharp relief that electricity consumption by one individual actor affects a large swath of other individuals. However, the latter have no possibility to influence the former person's decisions regarding the price, volume, and security of supply of his or her electricity. This inability to provide relevant economic feedback through appropriate side-payments is the reason for security of electricity supply externalities in EOMs and their inability to deliver socially optimal levels of security of supply.

It is important to understand that security of supply externalities arise only if non-consumption is involuntary. With voluntary and remunerated demand response, these externalities are likely to be internalized: if sufficient shares of demand were sufficiently elastic, the public good issue would fade away.[16] Yet, in the absence of sufficient demand elasticity, reciprocal externalities in electricity consumption make private contracting for the appropriate level of security of supply suboptimal. The aversion of customers and politicians towards scarcity pricing thus has a serious underlying rationale – that is, due to economic network effects, the social costs of an interruption of electricity supplies are larger than the private costs.

A simple example taken from Keppler (2017) illustrates the point. Imagine a visitor riding down the elevator in a multi-story office building after an afternoon meeting that stretched into the winter evening. Suddenly, the elevator stops, and the lights go out due to a scarcity

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[15] More generally, security of supply and electricity quality in terms of low interruption risk and stable voltage and frequency has a public good character (e.g. Abbott, 2001). As a result, each new capacity investment has a positive external effect that increases the utility of all agents in the electricity system (e.g. Fabra, 2018).

[16] The inelasticity of the short-term electricity demand function is not only a result of technical and informational constraints but also of behavioral inertia at the level of individuals and households. All three aspects are part of the 'transaction costs' which impede the emergence of the first best optimum.

event during evening peak hours. Even when electricity eventually comes back, the stress is considerable, and the evening is done for. In the present context, there are two important points:

1. This situation can arise even when the building manager has correctly anticipated both his consumption and his capacity. This is not an issue of free-riding or misrepresentation of true willingness-to-pay as implied by some researchers (e.g. de Vries & Hakvoort, 2004; Salies et al., 2007). This is a classic externality where due to transaction costs, the visitors stuck in the elevator were unable to transmit their preferences for continuity of service in a meaningful economic manner to the building manager and the market at large. Security of supply is thus undersupplied.
2. By contrast, if the distributor had participated in a demand-side management program contracting for voluntary and hence anticipated load shedding during certain peak hours, things would have been different. A message sent several hours before the scarcity event would have asked the building manager to minimize electricity consumption by shutting down elevators. The manager would then have posted a warning sign on the closed elevator door 'Do not use elevators', which would have internalized the externality. Of course, the disutility of using the stairs remains. Yet, a possibly traumatic or dangerous event with high utility costs has been transformed into an appropriately priced disutility.

The example illustrates that security of supply externalities occur due to the involuntary and/or unexpected character of enforced load shedding during scarcity hours. The difference between an involuntary disconnection with inelastic demand and a voluntary reduction or deferral of demand consists precisely in the externalities associated with electricity consumption.[17]

**Ad-hoc remedies and their limits**. Auto-generation or costly back-up systems are, of course, not a solution, as they would raise the overall cost of the electricity system above the cost of a centralized system with an appropriate level of capacity. Back-up is thus warranted only for those installations where the risk of massive externalities – e.g. hospitals or data centers – is so high that it outweighs any concerns about the economic efficiency of electricity supply.

In the absence of elastic demand on the part of a wide swath of market participants, it will hold that the social willingness-to-pay for additional capacity is greater than the private willingness-to-pay for additional capacity even in markets with full information where both producers and consumers express their true costs and preferences. The social costs of supply disruptions thus exceed the value that can be captured in an EOM by the provider of the marginal capacity unit. Hence, the number of VoLL hours in an EOM is always higher than the social optimum.

The ad-hoc remedy for security of supply externalities are capacity remuneration mechanisms (CRM) or strategic reserves that ensure exogenously set levels of systemwide capacity that are deemed socially optimal (e.g. Joskow, 2008a; Cramton et al., 2013). This is by and large a logically consistent response (e.g. Keppler, 2017; Holmberg & Tangerås, 2021). In practice, CRMs cover a broad range of instruments that provide different forms of remuneration with different levels of certainty over different timeframes for different

[17] Most theorists treat electricity exclusively as a private good, thereby failing to distinguish an expected voluntary from an unexpected involuntary reduction in demand whose social costs are not included in electricity pricing.

technologies. Due to the sensitivity of electricity systems and their capacity frontiers even to small changes in the electricity mix, demand, or contextual factors such as the availability of demand response or storage, CRMs have also on occasion generated highly volatile price signals, which inevitably increase capital costs (see also Issue 4).

### 3.2. Issue 2 – Innovation externalities and industrial & social preferences

**The issue.** In principle, full cost recovery is ensured through the market for all generation assets in the technology mix that endogenously emerges in the long-term equilibrium. In practice, however, a variety of economic and political considerations outside the realm of the market prevail, which reflect innovation externalities, industrial policies, and social preferences for specific technologies. These should partly dictate the mix composition and evolution as there is no reason that the desired mix should coincide with that resulting from market forces alone. In other words, specific policies and regulatory interventions are justified to factor in those considerations and internalize associated market failures. Because the mix is not only market-driven but also steered towards exogenously set targets, sole market-based remuneration is by construction insufficient for all units to break even and recoup their capital costs – the logic is similar to that of the missing money problem (see Issue 1). This is especially true for those supported technologies that are brought to the market in excess capacity relative to the levels that would materialize based on market revenues only.

**Ad-hoc remedies and their limits.** Support schemes for VRE technologies are an archetypical example of such ad-hoc policies, e.g. targeted feed-in tariffs (often with priority dispatch), feed-in premia or contracts for difference. Their *raison d'être* is to: (i) support the deployment of immature technologies in a bid to bring down technology costs through economies of scale and capture learning spillovers (e.g. Newbery, 2021); (ii) steer the power mix towards political targets; and (iii) ultimately de-risk investment in relatively more mature but highly-capitalistic low-carbon technologies to lower finance and deployment costs (see Issue 4). VRE deployment however suffers from decreasing market returns due to autocorrelation. That is, the larger near zero marginal cost renewable infeed, the more depressed market prices by merit-order effect and the lower energy market revenues (e.g. Joskow, 2011; Hirth, 2013; Eising et al., 2020). This so-called cannibalization effect is further exacerbated by VRE non-dispatchable nature.[18] As it turns out, VRE market value tends to decrease faster than its generation costs as installed VRE capacity increases (e.g. Green & Léautier, 2017). As a result, market-based equilibrium VRE capacity levels are often lower than policy targets.

Achieving renewable and decarbonization targets may in turn necessitate continued support, for otherwise market forces alone are bound to undershoot on those targets and fall short of inducing the desired mix. In particular, sole market remuneration would constrain VRE entry at lower, economical levels – even in the presence of technology cost reduction and adequate carbon pricing (e.g. Hirth, 2015; Joskow, 2019; Kraan et al., 2019).[19] In fact, keeping

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[18] This effect tends to be more prevalent for solar than wind generation given its stronger correlation with demand and thus larger downward price impacts. Additionally, as an aggravating factor, some support schemes do not disincentivize VRE infeed when prices are near zero or in negative territory. Note that storage deployment at scale has potential to mitigate cannibalization by spreading out VRE generation over time through arbitrage based on intertemporal usage value, e.g. in the spirit of Hotelling's rule (Ekholm & Virasjoki, 2020).

[19] Specifically, assuming high technology cost reduction, Hirth (2015; e.g. Fig. 14) finds that the optimal VRE share that would emerge in a pure market setup remains below 25% and is non-monotonic with the carbon price, because a higher carbon price incentivizes investment in baseload low-carbon technologies (e.g. nuclear, CCS) that reduce VRE profitability. If, however, investment in such technologies is hampered by high capital costs or risks (see Issue 4), the optimal VRE share would be larger but with a maximum of 45%.

the current market design unchanged, the system-wide gap between market revenues from energy sales and generation costs is projected to widen over time. For instance, for given investment paths, the International Energy Agency estimates that energy sales may only cover 50% of long-run generation costs in 2030, or up to 60% with 'high' carbon prices (IEA, WEO 2018; Fig. 10.21).

The main issue with support schemes is that they only target specific technologies and escape systemwide reasoning and coherence, with insufficient coordination between schemes and technologies. For instance, VRE support schemes are not innocuous for those unsupported market segments, against which at least two biases are introduced. First, they increase both revenue inadequacy and uncertainty for those capacities remunerated based on market prices alone: increasing VRE permeation lowers prices on average and raises price dispersion, making it more difficult to hedge for both producers and investors (Section 4). Second, they may give rise to stranded assets for those long-lived units whose investment decisions were made prior to support introduction. Additionally, some support schemes have proven to be inadequately designed in that they distort short-term market operations, e.g. by maintaining generation and in-feed incentives even when it is economically ineffective (i.e. price < variable cost).

### 3.3. Issue 3 – Climate change externality

**The issue.** To combat climate change, the EU instituted its emissions trading system (ETS) in 2005 as the cornerstone of its climate policy package.[20] In principle, the resulting price signal for carbon emissions should be the main policy driver towards decarbonization. In the power sector, for instance, credible climate regulation and robust carbon price signals are deemed of importance to meet environmental targets (e.g. Petitet et al., 2016; Bergen & Munoz, 2018). In practice, however, companion energy and technology policies, such as those discussed in Issue 2, incidentally undermine the carbon price signal – in terms of level, volatility, and credibility – and associated low-carbon investment incentives. Specifically, they tend to eat away at the demand for emission permits independently of the market permit price, thereby eroding the stringency of cap on emissions and depressing prices (e.g. Burtraw & Keyes, 2018; Borenstein et al., 2019; Chèze et al., 2020; Aune & Golombek, 2021).[21] On the face of it, low carbon prices may appear virtuous as they suggest that emission targets are attained at a 'low cost', but they often reflect two interrelated market design issues.

The first one is insufficient policy coordination and poor anticipation of policy interactions. As a result, cost effectiveness of the whole policy package is reduced due to unexploited synergies and/or conflicting objectives. In the EU, energy and technology policies have driven most of the emission reductions and low-carbon innovation, and the carbon price has hitherto not been at the center of the decarbonization process (e.g. Tvinnereim & Mehling, 2018; Edenhofer et al., 2021). This has two adverse consequences. First, carbon prices are artificially kept at low levels and that the true policy costs are not transparent (and likely larger than what market prices suggest due to inefficiencies).[22] Second, low and uncertain carbon prices dent

[20] Other environmental externalities, such as air pollution (e.g. SOx, NOx, particulate matter) generated by power generation and associated fossil-fuel combustion processes are outside the scope of this article. These are usually addressed through command-and-control regulatory measures, e.g. the Large Combustion Plants Directive.
[21] Given the emission reductions driven by renewable and energy efficiency policies, Aune & Golombek (2021) even find that carbon prices are redundant to achieve the EU's target of -40% by 2030 (now ramped up to -55%).
[22] To see this, note that implicit carbon price equivalents of renewable subsidies are an order of magnitude larger than explicit price levels that prevailed in the EU ETS (e.g. Marcantonini & Ellerman, 2015; Abrell et al., 2019).

confidence in the ETS as being the central tool to drive low-carbon investment.[23] In fact, contrary to the official phraseology, energy and technology policies are not complementary to the ETS. Rather, they are the core policies and the ETS complements them, acting as a backstop ensuring the overall target is met in case they are not sufficient or underperform.[24] The second design issue is a lack of supply responsiveness that would adjust the emissions cap in the face of naturally occurring permit demand shocks.[25]

**Ad-hoc remedies and their limits.** To address the structural issue of low carbon prices and embed some price resilience into its ETS, the EU recently equipped it with a supply-side control mechanism, the market stability reserve (MSR). Since its launch in 2019, the MSR has started to absorb the historical permit oversupply and contributed to increasing carbon prices up from previously moribund levels (e.g. Perino et al., 2021; Quemin & Trotignon, 2021). In parallel, one has also witnessed the emergence of other policies to supplement the ETS in attaining deep decarbonization objectives, suggesting that the ETS falls short of conveying robust signals for necessary investment and retirement decisions. These include carbon contracts for difference (CCfD) to foster heavy industry decarbonization (e.g. Richstein et al., 2021) and technology phaseout policies to prevent carbon lock-in through long-lived capital assets (e.g. Geels et al., 2017) notably in a bid to shut down coal-fired power plants (e.g. Osorio et al., 2020).[26]

Although the MSR helps sustain a higher price regime by constricting supply, this does not ensure a robust, stabilized price signal per se. As it turns out, the long-term volume and price impacts of the MSR are uncertain, convoluted and hinge on market behavior – see Perino et al. (2021) for a comprehensive literature overview. Specifically, its core design does not enhance synergies with other energy and technology policies (in fact, it may even be counterproductive and engender a form of 'green paradox', see Gerlagh et al., 2021) nor price stability (in fact, it may even induce volatility of its own).[27] Because its implications lack both transparency and simplicity, at least compared to those of a price-based control (e.g. Newbery et al., 2019; Flachsland et al., 2020), the MSR thus appears as another ad-hoc fix on top of other policies without sufficient coordination.

As already discussed in Issue 2, regulatory interventions (e.g. phaseout policies) or support schemes (e.g. CCfDs, RE CfDs) are commendable to internalize market failures and social preferences. Yet, they often target specific technologies/units and tend to be designed in silos, entailing a risk of policy overlap (raising overall policy costs) and insufficient coordination (blurring the path to a decarbonized mix). First, renewable energy support policies should be

[23] On top of this, demand-side fundamentals (e.g. coal and gas prices) explain carbon price variations only weakly, see Friedrich et al. (2020) for an empirical literature review. By contrast, expectations and market sentiment play a key role in price formation, which tends to be catalyzed by regulatory events and politics (e.g. Koch et al., 2016).

[24] As Tvinnereim & Mehling (2018) argue, explicit carbon pricing has so far proven useful where it can incent marginal optimization (e.g. fuel switching for electricity generation) but prices have remained far below levels that could trigger investments and radical changes in line with decarbonization objectives. High explicit carbon prices make policy costs 'too visible' and have so far been politically unpalatable.

[25] In principle, on the demand side, market actors can also smooth out demand shocks over time through banking and borrowing, but the efficiency of such intertemporal trading depends on their degree of cost optimization and risk management procedures (e.g. Fuss et al., 2018; Quemin & Trotignon, 2021).

[26] For instance, CCfDs are contemplated at the EU and Member State levels to remove the carbon price uncertainty by guaranteeing a sufficiently high fixed price over the contract duration. This could stabilize remuneration of and de-risk investment in targeted technologies (e.g. low-carbon hydrogen production).

[27] The main design issue with the MSR is that it is based on an ill-suited indicator of permit scarcity, the market-wide permit bank. By contrast, supply-side policies are usually price-based and typically introduce price steps in otherwise inelastic supply curves in order to constrain price variability and policy costs in the face of uncertainty about permit demand and abatement costs (e.g. Fell et al., 2012; Borenstein et al., 2019; Burtraw et al., 2020).

adjusted to reflect both the carbon value embedded in the electricity price and the extent of fuel switch away from coal to gas (e.g. Abrell & Kosch, 2021). Second, there are cost-efficiency and risk-sharing gains in jointly designing support policies (e.g. Richstein et al., 2021).[28] Also, in this case, if the reference price is based on the carbon market price, CCfDs may affect carbon price formation and create another source of uncertainty for other market actors.[29]

### 3.4. Issue 4 – Missing long-term markets

**The issue.** In an EOM, spot electricity prices are supposed to guide long-term investments and efficiently shape the future power mix. These prices are however extremely volatile and imply significant risks for investors, meaning that the EOM investment performance crucially hinges on the extent to which investors can hedge long-term risks. Risk and risk aversion are not an issue per se provided that markets are complete – that is, provided that Arrow-Debreu securities exist for every possible state of nature and that agents can trade and transfer risk via adequate hedging instruments (e.g. Willems & Morbee, 2010; Léautier, 2016). In simple terms, market completeness corresponds to an ideal situation where all risks can be traded for all relevant time horizons. This would be the case if it were feasible to hedge all price and volume risks, and thus revenue risks, for each asset over its entire lifetime, including construction time (e.g. de Maere d'Aertrycke et al., 2017; Abada et al., 2019).

In reality, however, power-related hedging markets are severely incomplete (e.g. Rodilla et al., 2015; de Maere d'Aertrycke et al., 2017; Roques & Finon, 2017), an issue which is commonly referred to as 'missing long-term markets' (e.g. Newbery, 2016; Wolak, 2021).[30] That is, long-term hedging instruments do not emerge spontaneously in financial markets, which exhibit limited efficiency at pricing some types of risks and where counterparties are not keen to develop some relevant instruments. Even though both producers and consumers are risk averse and prefer a certain price over an uncertain price, they only sign hedging contracts over a few years at most.[31] There is thus a large discrepancy between available contract maturities and investment timeframes, which is especially salient for long-lived capital-intensive assets.

The fact that the power sector is particularly subject to market incompleteness has much to do with the three preceding Issues, for instance (i) the semi-public good character of electricity as a product, its specificities (i.e. multiple electricity services and technical constraints with strong intertemporal dependencies) or its high price volatility (because of limited storage and demand flexibility), (ii) consumers' perception of regulatory intervention/paternalism in case of price spikes (Genoese et al., 2016),[32] and (iii) uncertainty about long-term fundamentals and relative technology competitiveness (Newbery et al., 2018) or regulatory risk due to

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[28] Richstein et al. (2021) show that coupling CCfDs and VRE CfDs has the joint potential to hedge the risk of two key decarbonization components and yield a reduction in both CfD strike prices. This improves cost effectiveness of the policies and preempts over-subsidization.

[29] CCfDs tend to reduce carbon hedging needs, which in turn (i) reduces forward market volume and liquidity and (ii) affects MSR impacts on supply. Both aspects have a bearing on price formation.

[30] To be precise, Newbery (2016) uses the more generic term of missing markets to refer to situations where "risks cannot be efficiently allocated with minimal transaction costs through futures and contract markets, or if important externalities such as $CO_2$ and other pollutants are not properly priced" while Wolak (2021) speaks of "a missing market for long-term contracts for energy with long enough delivery horizons into the future".

[31] The number of available (standardized) financial products is relatively limited and the forwards market liquidity quickly drops along the contract maturity curve, and traded volumes for contracts with maturity beyond four/five years are virtually zero (e.g. Genoese et al., 2016; Newbery, 2016).

[32] One recent illustration of the reasons that may sustain this perception is the current discussions in Spain about regulatory interventions to contain the impacts of soaring electricity prices on final consumer invoice – see e.g. https://www.theguardian.com/world/2021/sep/14/spain-cuts-soaring-energy-prices-with-emergency-measures.

unpredictable legal changes which is unhedgeable in nature (Abada et al., 2019).[33] This latter point is particularly telling of a structural aspect of long-term market incompleteness. As Newbery (2016) notes, private actors (generators, consumers) are poorly equipped to deal with uncertainty about future energy policy and regulatory choices when "politicians and/or regulators are not willing to offer hedges against future market interventions that could adversely affect generator profits". As a result, a central economic agent (or market counterparty) is simply missing.

Because of missing long-term markets, risk-averse agents cannot fully hedge their risk and price exposure, especially for long-term investments. In this context, even an idealized competitive short-term EOM can lead to starkly inefficient outcomes (e.g. Newbery & Stiglitz, 1984; Abada et al., 2019).[34] If perceived risks cannot be arbitraged out or partially spread and shared with other agents, risk-averse producers will utilize risk-adjusted probabilities to gauge investment value and/or truncate risk profiles to reflect untradeable risk (e.g. Willems & Morbee, 2010; de Maere d'Aertrycke et al., 2017). Impaired risk-taking capabilities result in a crowding-out of long-term private investment and downside price risk weighs heavily on investment decisions, which in turn distorts the generation mix towards less capital-intensive, less risky technologies and increases the capital cost and average cost of production (e.g. Ehrenmann & Smeers, 2011; Peluchon, 2019, 2021). Additionally, under uncertainty and investment irreversibility, there is an option value in deferring decisions to invest in new plants (e.g. Rios-Festner et al., 2020). To summarize, market incompleteness drives a wedge between private investors' and socially optimal discount rates, implying that in a pure EOM the private cost of capital remains too high to drive long-term investments in line with reliability, sustainability, and affordability goals.

**Ad-hoc remedies and their limits.** A classic, private lever to address risks is self-insurance, different forms of which (e.g. diversification, increase in size, vertical integration between generation and retailing) have been used by utilities through internal growing or reconfiguration (mergers & acquisitions). In particular, in terms of risk sharing, vertical integration tends to outperform liberalized futures markets in restructured power systems (e.g. Chao et al., 2008; Meade & O'Connor, 2009; Aïd et al., 2011). However, self-insurance levers are limited in scope by competition rules and more fundamentally cannot insulate capital-intensive investments from strong price volatility, especially downside price risks due to unpredictable changes in the economic conjuncture and/or technology costs.

Regulators have also taken steps to tackle risk-sharing issues by setting up contract mechanisms to provide additional remuneration (typically for capacity) on top of energy sales or guarantee a fixed energy price over a certain time horizon for specific technologies (typically renewables that benefit from support schemes based on long term contracts, e.g. May &

[33] Other related reasons have been put forth to explain why adequate hedging tools fail to emerge and transaction costs are prohibitively high, including: asymmetric willingness to contract between suppliers and generators as the former face strong customer switching risks with retail competition (e.g. Green, 2004; Neuhoff & De Vries, 2004; Roques, 2008); an hold-up problem between generators and consumers, e.g. once an irreversible investment takes place generators' bargaining power drops (e.g. WindEurope, 2017); asymmetric information about what future competitive prices would be (e.g. May & Neuhoff, 2021); an exponential increase in counterparty default risk (that is difficult to hedge) and cost of guarantee with contract duration (e.g. Genoese et al., 2016).

[34] Even if spot market revenue is potentially adequate (i.e. no missing money), it may not be perceived to be so by generators or their financiers (e.g. Newbery, 2016). Moreover, even if short-term prices were fully efficient, there would still be the issue of price backpropagation to longer investment timeframes, i.e. efficient short-term prices are essentially irrelevant if they cannot be properly conveyed to and appraised by investors. Such backpropagation will fail if significant risks cloud the investment path and cannot be adequately hedged (e.g. Abada et al., 2019).

Neuhoff, 2021).[35] While capacity remuneration mechanisms have potential to stabilize generators' total revenues and thus reduce investment risk relative to a pure EOM (e.g. Petitet et al., 2017; Abani et al., 2018; Duggan, 2020),[36] they provide insufficient incentives to invest in capital-intensive, low-carbon technologies for at least three reasons:

- Prices for capacity contracts, especially for annual ones, have proven to be quite volatile (e.g. Spees et al., 2013; Jenkin et al., 2016; Bhagwat et al., 2017; Bublitz et al., 2019).[37] Investment de-risking is thus limited due to combined energy + capacity price volatility.
- Multi-year fixed-price capacity contracts for new assets or refurbishment investments only cover a fraction of the asset lifetime (e.g. 7 years in France and up to 15 years in the UK) and remuneration only starts at commissioning (i.e. no coverage of construction risk nor support during the construction phase which can be substantial for some assets).
- They are a construct poorly suited to remunerate intermittent technologies as VRE units are only entitled to a small fraction of capacity prices. In other words, these schemes are currently primarily designed for thermal generation dominated mixes but not for future capital-intensive low-carbon technology mixes (e.g. Joskow, 2019; Wolak, 2021).

Finally, the pros and cons of existing VRE-specific long-term support schemes have already been discussed in Issues 2 and 3. In short, while they guarantee a fixed energy price over the contract duration and have thus substantially de-risked investments in supported technologies, they have a number of limitations. For instance, they only target renewable units and leave aside other low-carbon or flexible technologies, i.e. there is a lack of overall energy mix coordination and this increases the risk exposure for unsupported market segments. Additionally, existing support schemes based on long-term contracts are ill-suited to de-risk investment in assets with long lead and construction times as remuneration only starts at commissioning.

## IV. ENERGY-ONLY MARKETS UNDER DEEP DECARBONIZATION: FROM IMPERFECTION IN INVESTMENT SIGNALS TO BREAKDOWN

In this section, we summarize the diagnosis of existing market design issues and expound on how these are bound to worsen over the next decades in a context of deep decarbonization of power systems and energy transition more broadly. We then illustrate how this diagnosis calls for an adequate regulatory treatment and design overhaul in the form of hybrid markets.

[35] May & Neuhoff (2021) quantify the extent to which these tools reduce WACC (via a reduction in financial and regulatory risks by facilitating implicit hedging between producers and consumers) and in turn deployment costs.
[36] For instance, Petitet et al. (2017) find that investment and decommissioning decisions as well as price levels are less sensitive to agents' risk aversion degree with a capacity remuneration scheme compared to a pure EOM. Abani et al. (2018) find similar results and Hary et al. (2016) also show that capacity remuneration schemes can reduce investment cycles that are otherwise prone to appear in an EOM (e.g. Arango & Larsen, 2011).
[37] Specifically, three factors can explain observed capacity price volatility: (1) uncertainty or variability of capacity market fundamentals (e.g. load growth, incremental supply cost, energy and fuel prices); (2) frequent changes in capacity market rules and parameters (e.g. auction rules, demand curves, cost-of-new-entry estimates, penalties, load forecasts); and (3) changes in interrelated policies and regulations (e.g. transmission tariffs, $CO_2$ price).

**The existing patchwork of ad-hoc remedies lacks coherency in most markets.** A good example for this is the regulatory framework for electricity markets in the EU. While the current regulatory package sets forth useful guiding principles to enhance and better integrate short-term markets in a bid to better manage VRE expansion and intermittency, it lacks a structured and coherent framework to allow for a coordinated planning of investments and implementation of associated support contracting/hedging mechanisms. Specifically, decentralized markets fall short of conveying effective long-term investment signals and producing outcomes in line with political objectives. These shortcomings have been at least partly identified, which led to the gradual introduction of various types of ad-hoc remedies (Section 3).

As a result, there is now in the EU an increasing wedge between the Commission's political vision of what investment drivers *should* in principle be (i.e. undistorted short-term energy price signals) and the *actual* investment drivers in the field. Over the last decade, for instance, only few new capacity additions have been fully merchant (i.e. triggered by the expectation of sole future market revenues) and most investments have materialized through a dedicated regulatory framework (e.g. Roques, 2020). Specifically, low-carbon technologies have benefited from long-term support schemes while some conventional units have been entitled to complementary remuneration based on short- or long-term contract for capacity.

Moreover, the uncoordinated implementation of ad-hoc remedies has created additional issues of its own. Current design fixes target separate perimeters (e.g. capacity remuneration to tackle security of supply issues, support schemes to foster VRE permeation) and are added on top of one another without sufficient coordination both within and across countries. The resulting policy patchwork is thus difficult to navigate because of complex interactions, many moving parts and, at times, conflicting objectives. This casts serious doubts on the ability of the current EU market design regime – that is, decentralized wholesale markets flanked by a collection of uncoordinated ad-hoc remedies – to achieve political targets (including security of supply and deep decarbonization commitment) as economically as possible and on schedule. As we discuss further below, these concerns are exacerbated by the very nature of these targets.

A recent European example further illustrates the shortcomings and uncertainty created by the EOM and the short-term marginal pricing principle. By mid-2021, an extreme tension on the natural gas and fossil fuel markets and a $CO_2$ price increase have led to soaring electricity prices with sizable impacts on affordability (residential consumers) and competitiveness (industrial consumers). As a result, several Member States are contemplating measures to contain such price impacts, which may lead to additional non-coordinated ad-hoc interventions. This shows how an EOM is very sensitive to external shocks and ad-hoc interventions are ineluctable when electricity prices significantly differ (below or above) from the long-term marginal generation cost, creating situations of dire over- or under-coverage of fixed costs. This type of uncertainty, which is intrinsic to market designs purely based on short-term marginal pricing, severely impedes the sustainability of an EOM.

**Deep decarbonization exacerbates market design issues.** Decarbonization is a growing trend worldwide and climate change mitigation has become a pivotal aspect of policymaking. Many jurisdictions have committed to deep decarbonization and established commensurate targets, notably in the electricity sector. For instance, the EU is aiming at net zero carbon electricity by 2050. The provision of carbon-free electricity is all the more important that electrification (i.e. the use of electricity as a clean energy vector) is meant to play a key role in decarbonizing our economies at large. However, deep decarbonization tends to exacerbate the issues presented in Section 3, rendering the current market design even less up to the daunting task that lies ahead of us. Below, we describe five (non-exhaustive) paths through which decarbonization-induced issue-exacerbating factors materialize, and then zoom in on three specific aspects:

- The enormous scale of needed investments implied by deep decarbonization targets in the coming decades and the deep uncertainty that comes with it.
- The high capital intensity of low-carbon technologies increases the importance of de-risking investment and providing visibility to investors over relevant timeframes.
- The increasing challenge of ensuring security of supply in decarbonized power systems.
- An increasing need for systemwide policy coordination through sector coupling – both horizontally (across energy sources or carriers such as power, gas or H2) and vertically (via end-usage electrification) – with large economies of scale for some infrastructures.
- As the number of hours where fossil fuel-fired plants set power prices declines, carbon prices have less of an impact through the merit order. Carbon pricing thus becomes less efficient in conveying adequate decarbonization signals.

**Investment, uncertainty, and cost of capital**. Deep decarbonization necessitates significant investments in low-carbon generation technologies in the coming decades, both upstream (e.g. VRE, hydro, nuclear, storage) and downstream (e.g. electrolyzers, heat pumps).[38] Importantly, because most of these investments are capital-intensive and have a long lifetime, capital costs will be the main component of total generation costs. As an illustration, the International Energy Agency estimates that a tripling of investments worldwide is needed in the coming decade to transition to a decarbonized power system (IEA, 2021).[39]

However, ensuring that these investments are made in a timely manner and at lowest possible cost (project by project but also in a coordinated, system-wide approach) poses considerable challenges to market and policy design. Capital-intensive investment projects are particularly susceptible to unhedgeable risks and the time to recuperate finance costs exceeds financiers' willingness to lend without guarantee.[40] This causes finance costs, and in turn generation costs, to rise dramatically. Capital intensiveness of low-carbon technologies thus strongly reinforces the issue of missing long-term financial markets. Below, we highlight two main sources of uncertainty and risks associated with deep decarbonization scenarios:

- As power systems become increasingly decarbonized, i.e. composed of low or zero marginal cost technologies (e.g. wind, PV, nuclear), price and revenue volatility rises. Specifically, low or zero or even negative price hours will become dominant as those

[38] Whatever the long-term zero-carbon scenario considered, a considerable amount of investments is necessary: to replace the conventional generation fleet with VRE and other low-carbon generation assets, to develop and install carbon capture and storage infrastructures (e.g. BECCS), to ensure security of supply and develop sources of flexibility (e.g. storage, demand-side response assets) to make the power system compatible with more VRE sources and less dispatchable units. Sizable investments are also required downstream notably to improve energy efficiency (e.g. renovating buildings), to electrify heating/cooling sectors (e.g. heat pumps) and to decarbonize the industry and transportation sectors (e.g. electrolyzers to produce $H_2$).

[39] Specifically, over 2021-2030 (resp. 2031-2040) average annual power sector investments worldwide amount to roughly 1.2 and 0.65 (resp. 1.3 and 1.2) trillion 2019 USD in generation and network+storage respectively.

[40] Capital-intensive investments are often also irreversible, meaning that once done they cannot be redeployed elsewhere. This makes such investments very susceptible to risks of sunk costs and regulatory opportunism.

technologies are more frequently at the margin. There will also be many more high price hours determined by storage units and scarcity pricing when dependable assets are stock-constrained, implying a fatter-tail price risk.[41] As a result of this 'binary' price structure, inframarginal rents concentrate in a smaller number of hours with higher and more volatile prices. Increased reliance on high prices with increased volatility implies sizable risks for all generators and investors, which raises capital costs. This holds for all technologies – and particularly for those capital-intensive technologies (e.g. Genoese et al., 2016; Tietjen et al., 2016; Cramton, 2017; Peluchon, 2019, 2021; Joskow, 2021).[42]

- At a more fundamental level, the future energy mix, market conditions and wholesale price distributions remain deeply uncertain today. For a given end-point target, there is a multiplicity of transition pathways with different combinations of energy carriers, generation technologies, levels of demand (energy efficiency gains vs. electrification of power needs), levels of flexibility provided by electrical vehicles or storage, consumers' behavioral changes, etc. Also, the future cost and social acceptability of low-carbon technologies are deeply uncertain. In other words, the technology mix and key policy or economic factors 20-40 years from now remain elusive. It is thus impossible to assign objective probabilities to future energy scenarios or to enumerate all of them (e.g. Abada et al., 2019; Joskow, 2021). This magnifies the missing long-term market issue.

**Security of supply in VRE-dominated systems.** Historically, the ability of decentralized markets with a dominant dispatchable fleet to provide an adequate level of capacity to ensure security of supply has been limited by various externalities and the missing money issue (see Section 3). As power systems transition to a dominant VRE share, VRE non-dispatchable and intermittent nature strengthens the need for flexibility assets (e.g. storage or demand response increases VRE supply security value) and magnifies security-of-supply externalities.[43] This calls for a profound rethink of the traditional approaches to ensuring security of supply (e.g. Joskow, 2019, 2021; Duenas-Martinez et al., 2021; Newbery, 2021; Wolak, 2021). A sound approach to market design should thus jointly address security-of-supply externalities and deep decarbonization commitments.

Specifically, the definition of needed available capacities to address reliability issues (e.g. N-1 contingencies rule) can no longer assume statistical independency in VRE-dominated systems notably because resources display increasing correlation. That is, compared to gross demand, the peak net demand (i.e. net of wind and PV generation) that must be balanced out can occur at virtually any time, is much more variable, and exhibits steeper ramps. Moreover, individual generation supplies become strongly correlated within wind and PV bins, so that the risk of a widespread fall in supply need be accounted for. Finally, a system-wide approach

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[41] In essence, the load-duration curve rotates to the south west around its intersect as VRE increases because of a small reduction in maximum residual load, reduced full-load hours for baseload plants, VRE overproduction and negative prices, and increasing load gradients.

[42] As the VRE share rises, the whole fleet will be impacted by higher revenue volatility, not just peak units as at present. VRE-dominated power systems will also be more susceptible to extreme climate/weather fluctuations, further adding to the increased power price volatility (e.g. Bossmann et al., 2018).

[43] Recall that because of such externalities, purely merchant capacity provision is suboptimal systemwide because interdependencies and knock-on effects of a capacity shortage are not accounted for in private decision-making (Section 3, Issue 1). These interdependencies do not only relate to the physical transmission network but to all economic networks that make up the fabric of modern societies. As the reliance on electricity is bound to increase in zero-carbon scenarios, interdependencies and thus the consequences of externalities will dramatically increase.

(i.e. all along the supply chain) is necessary to tackle extreme weather events triggered by climate change, as attests the massive gas supply failure across Texas during the blackout of February 2021.

## V. THE NEED TO TURN TOWARDS HYBRID MARKETS

To sum up, the previous sections have shown that aligning market and policy design with urgent energy transition objectives requires the explicit acknowledgment that

- Due to a collection of market failures and externalities, the generation-technology mix should be guided to meet broader policy objectives that liberalized markets on their own would otherwise fail to deliver, all the while recognizing other benefits brought about by competitive forces. These issues are to a large extent magnified by the sheer scale of the investments needed to achieve decarbonization targets and the nature of low-carbon technologies (i.e. high upfront capital costs, low or near-zero variable costs).
- Adequacy, technology, innovation, industrial and decarbonization policies de facto modify the role and influence the functioning of electricity markets. For the most part, these policies have so far been designed in silos, i.e. superimposed on one another with a lack of systemwide coordination. The resulting multilayered policy environment is thus inconsistent overall and prone to unforeseen and undesirable interactions. It risks compromising the attainment of political targets (on schedule and as economically as possible) and is hard to navigate for all parties involved.
- There is a tension between the two purported coordination roles of power markets, i.e. short-term operational efficiency and long-term dynamic efficiency. While competitive short-term pricing has proven able to cost-effectively exploit the existing generation fleet, regulatory instruments and complementary policies have historically been the main drivers for capacity investments and retirements. The latter aspect stands in stark contrast to political aspirations and phraseology, i.e. the EU current target model of sole, fully liberalized energy-only markets to ensure both short- and long-term coordination functions. This doublespeak results in, as it were, policy schizophrenia in the field.
- With demanding and urgent deep decarbonization targets, policymakers are more likely to directly intervene to have some control over the transformation of their energy mix. Increased intervention, albeit laudable and necessary, may intensify the above concerns (e.g. opaque price formation, detrimental policy interaction and complexity) without a market and policy design overhaul that enhances systemwide coordination and clarifies the roles of market forces and companion policies in driving the mix transformation.

A hybrid market design approach takes stock of the above diagnosis and consists in a system-wide, coherent treatment that has the potential to overcome the identified issues. Central to the notion of hybrid market models is the role of the visible hand of public intervention as a policy coordination device placed at the heart of a unified investment framework (see Finon & Roques, 2013 and Roques & Finon, 2017). In essence, hybrid markets rest on a bifurcated approach to market design whereby long-term investment and dynamic mix coordination are addressed in a specific module that is separated from – but complements and works alongside with – a short-term module that handles dispatch and balancing operations. Although the long-term module exhibits a regulatory dimension, competitive forces are an integral part of both modules. That is, market design hybridization does not constitute an abandonment of competition, but rather a departure from competition as deployed at present (types of competition abound, and a variety of designs may perform similarly). Specifically, the core characteristics of the two modules can be delineated as follows.

- Long-term investment planning and procurement module (*competition for the market*):
  This module has two fundamental goals: (a) hive off and de-risk investment decisions from volatile and remuneration-wise insufficient short-term price signals; (b) organize and steer the evolution of the mix towards political targets in a structured, coordinated investment framework that helps spur innovation in yet immature technologies. This framework is typically broken down into three stages: (1) the identification of system needs and definition of the associated planning process; (2) the definition of long-term contractual or hedging arrangements (LTCA); and (3) the management of the LTCA competitive procurement process and interface with the short-term module. Overall, decarbonization trajectories and security of supply objectives are met as economically as possible due to competition effects and reduced cost of capital.
- Short-term dispatch module (*competition in the market*):
  This module relies on liberalized short-term markets to carry out dispatch and balancing operations cost-effectively (as at present in the EU). There exist improvement margins, especially to accommodate the expansion of decentralized and/or intermittent resources and reap the benefits of a more flexible management of these (e.g. network coordination, energy-reserve product harmonization, platform integration). Improvement margins are to a large extent addressed by and outlined in the EU Clean Energy Package.

In practice, multiple variations of the above market architecture can be conceived. While similar views on the need to transition to hybrid markets are increasingly being shared by prominent energy economists (e.g. Newbery, 2018; Joskow, 2021; Wolak, 2021), they still widely diverge on implementation and design issues, with key hybrid design pillars spanning the full spectrum between centralized and decentralized approaches.

In a companion paper (Roques et al., 2021), we provide a detailed description of the possible designs of the long-term module and its articulation with the short-term module. Additionally, we highlight key design tradeoffs and sketch out the contours of feasible design options. Below, we briefly flag four key design items on which we expound further in Roques et al. (2021):

- *Planning and coordination*. The primary goal of the long-term module is to introduce a coordinated systemwide investment planning process to achieve decarbonization and security of supply targets cost-effectively in a context of deep uncertainty.
- *Competitive procurement*. Once system needs are defined, LTCA must be defined and procured competitively. This process can be decentralized, centralized or combine both approaches. Procurement format and scope involve key design choices (e.g. technology-neutral or specific auctions, which treatment for new vs. existing assets).
- *LTCA design*. Contract design must ensure (a) adequate long-term risk sharing to reduce investment costs by trading off long-run uncertainty with the visibility that investors need, and (b) a seamless, non-distortive interface with short-term markets by sending economically effective operation incentives (i.e. generate if variable cost < price).

- *Upstream-downstream articulation*. Financial balance of the long-term module between its upstream (investors, generators) and downstream (suppliers, final consumers) ends must be carefully orchestrated to ensure a smooth functioning of an hybrid architecture, recover LTCA costs, and spread out risks in a socially efficient and acceptable way.

## VI. CONCLUSION

As energy-only markets show the limit of their ability to bring about sufficient amounts of low-carbon generation capacity to meet ambitious targets to reduce carbon emissions, it is necessary to turn towards a hybrid market design regime. Combining a module for long-term investment coordination (possibly working with centralized capacity choices) with a module for short-term dispatch based on competitive markets as at present, hybrid markets constitute a contemporary form of long-term marginal cost pricing. In essence, this approach is an evolution rather than a revolution as competitive short-term markets remain the defining feature of one module of a hybrid market design, in which the stable remuneration of fixed costs defines the other module. In particular, existing policies that seek to ensure long-term price visibility for capital-intensive low carbon technologies are no longer considered as ad-hoc patches to energy-only markets but rearranged to be an integral part of a coherent long-term investment planning process. While some key characteristics of hybrid markets are indicated above, further research will study the variety of hybrid design options in more detail, both at a conceptual and empirical level.

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