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Marginal pricing and the energy crisis: Where should we go?*

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Abstract

The fundamental principle of marginal pricing in electricity markets has been strongly challenged following the recent European energy crisis. One of the main criticisms is the inability of current markets to drive investments, as spot prices provide only short term information about supply, demand, and costs. This paper revisits the seminal work of [Boiteux, 1960] in the context of the recent energy crisis to discuss the fundamental assumption of *adapted capacity*, which underpins the equality between long term and short term marginal costs in the theory of marginal pricing. We argue that capacity is no longer adapted to current economic conditions in Europe. We then leverage techniques of mathematical programming to generalize the results of [Boiteux, 1960] and propose a market clearing mechanism that preserves the efficiency of current short term marginal pricing to induce optimal plants operations while also providing a long term investment signal when capacities are not necessarily adapted. Through an analysis of captured margins, our proposal, which differs only marginally from the current market clearing, identifies plants that should remain in the current mix and those that are no longer economical. We also discuss possible extensions of our proposal to accommodate capacity markets and price caps. Finally, we implement our models with the French power mix and demonstrate their advantages over the current market clearing mechanism using a realistic case study.

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*The opinions expressed in this paper are those of the authors alone and might not represent the views of GEM, ENGIE, or CORE-LIDAM.

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1 Introduction

1.1 Context of the recent European energy crisis

Unusual operations in Gazprom European storage in the second half of 2021 announced the energy crisis. These were followed by the war in Ukraine in February 2022, the disruptions on Russian gas supplies, and ultimately by the (so far unattributed) blowing up of the Nord-Stream pipelines between Russia and Germany. This rocked the European gas market, which suddenly had to resort to other, more expensive, gas sources. This turmoil had dramatic consequences on the European power market and led to a flurry of criticisms on its design (see [Batlle et al., 2022b] and [Batlle et al., 2022a]). Some were purely opportunistic, arguing once more that this was all due to the restructuring of the power system towards a more competitive system; others addressed fundamental questions on the rationale of an organization where gas events directly impacted electricity prices through short run marginal cost pricing. The European Commission responded to these concerns by announcing an investigation of a possible reform of the design of the power market. This analysis closed in March 2023 with a Commission's proposal ([European Commision, 2023]) that itself induced various comments ([Fabra, 2023], [Batlle et al., 2023], and [Schittekatte and Batlle, 2023]). From an institutional point of view, the proposal initiated the discussions between the European Parliament and the Council of Member States that in EU governance lead to new legislation. This latter process was concluded in December 2023 ([Council of the European Commission, 2023]). The new Regulation EU 2024/174 ([Council of the European Commission, 2024]) was published in June 2024: its preamble gives a detailed account of the process.

The energy transition and the massive investments that it requires constituted a complicating factor that remained in background in all these discussions. One can easily argue that investments in the power system are not properly incentivised by a market design that concentrates on short term efficiency, leaving to un-identified "market forces" to transfer this short term efficiency to the long term. This problem is explicitly recognized in the "hybrid market" literature that points to a lack of coordination of long term decisions in a restructured electricity system balanced between market incentives and public interventions driven by national and European energy policies. A direct consequence of that concern can be found in the introduction of capacity markets that are meant to complement the energy price signal by introducing some additional payments for capacities. While capacity markets were rather reluctantly and only provisionally allowed with proper justification in the EU before the crisis, they are now fully accepted in the new legislation EU 2024/174 [Council of the European Commission, 2024]).

An extreme version of the criticisms of the lack of long term coordination saw the resurgence of the idea of planning together with a very central role for public authorities in some French proposals ([Finon and Beeker, 2023]).[1] This is because both the crisis and concerns about investments raise questions on the role of short and long run marginal cost in the power industry. This is obviously not a new subject as the sector, operating under monopoly regime, was indeed at the forefront of the rich economic and computational developments involving these concepts. The introduction of competition and the crisis of 2021-2022 recalled the relevance of these notions possibly with a higher degree of urgency, as the spot market, based on the notion of "short run marginal cost", was and remains the core of this competition.[2] Though the criticisms against short run marginal cost during the crisis progressively waned after gas prices returned to more acceptable levels, the fundamental arguments related to the lack of long term signal in the spot market subsisted. This was most clearly and operationally expressed in [Finon and Beeker, 2023]'s terse comment that the current spot market does not contain any long term signal.[3] The argument is elaborated in more formal terms in [Batlle et al., 2023]'s analysis of the Commission's 2023 proposal where, in a section appropriately titled "Dealing with Long Term Market Nothingness", these authors describe the incompleteness of the long term market and make some proposals to remedy it. Interestingly, the new legislation with its acceptance of capacity markets remedies, addresses these shortcomings, and its recognition of the need for more powerful hedging instruments dedicated to investment is a further contribution to solving the problem.

1.2 The research questions

The new legislation does not, however, respond to [Finon and Beeker, 2023]'s criticism which implies that the available spot price, because it *does not contain any long term signal*, is not

[1]One can obviously argue that the power sector is not the only one that requires coordinating long term investment and wonder why it needs a special treatment for doing so. In that vein, the *difficult transportation* and *non-storability* of electricity arguments that were often informally mentioned against restructuring in the early days could be reactivated in this discussion. Both impose some unusual coordination constraints compared to other sectors. They increase the likelihood of equipment being stranded because of plausible ex ante (investment) decisions turning erroneous ex post without recourse possibilities because of the inherent physical characteristics of the sector. Long term physical hedging is not possible and hence no underlying exists on which to base financial hedging. Considering transportation first, one has to acknowledge that the transportation of the good by trucks, rail, or air is just impossible in electricity (less so, but still delicate with compressed or liquefied gas). Capacities of generation and energy intensive industries are thus exposed to a much higher risk of being stranded because of inadequate infrastructures as is well realized now. This reasoning extends but in a subtler way to the lack of short term storage: the grid can collapse in a few minutes and at a subcontinental level as a result of a local short term imbalance. This can only be remedied by careful co-operations or operations that require that capacities be sufficiently adapted (to use a term that we will extensively come back to in the following). This means that generation and industrial intensive consumption of electricity are extremely vulnerable to risk of capacity misalignment, in contrast with what happens for other commodities. Interestingly, the market seems to realize this issue as it did not develop the long term hedging products found with other commodities where transport and storage are more standard. Long term physical contracts linked to physical capacities can mitigate the issue as extensively discussed before restructuring. They encountered, however, the criticism of foreclosing the market to competitors. [Boiteux, 1960]'s fundamental results assume that capacities are adapted ex post and hence that the issues of *non-storability* and *difficult transportation* are naturally solved.

[2]We refer to "notion" because short term marginal costs in the pure textbook economic sense are never really computed as briefly discussed later.

[3]For instance: *The functioning [of markets] significantly reduces the role of market prices as long-term signals to encourage investment in production capacity* in page 31 of [Finon and Beeker, 2023] (authors' translation).

a proper underlying of instruments such as Contract For Differences (CfDs) or Power Purchase Agreements (PPAs). The present paper strives to address that very problem: it stays away from any financial construction related to long term incompleteness, but rather concentrates on the construction of a spot price that should, in order to respond to [Finon and Beeker, 2023]'s criticism, contain a long term signal. A fundamental property we want to keep in this process is short term efficiency: because the new legislation wants to retain the efficiency resulting from the current short term market which drives optimal plant dispatch, this modified spot price should be compatible with the underpinning market clearing mechanism that guarantees this efficiency. To do so, this paper looks at that problem through a simple but fundamental approach (in a sense based on first principles). It concentrates on the cause of the lack of long term signal in the current spot market, finds that it is due not to the design of the market but to the conditions inherited from the stress imposed on the system by both the war and the energy transition, and explores how this can be locally (on the horizon of the spot market) corrected in a way that is compatible with the current market design. In passing, we also demonstrate that this can be made compatible with the introduction of capacity markets. Interestingly, our proposal (of a new spot price construction) can be readily accommodated in any long term contract compatible with the new legislation.

1.3 Contributions of the paper

While our interest is ultimately the long term signal, our departure point is the period 2021-2023 and the many comments on short and long term signals expressed at that time. We concentrate on three claims that capture a good part of these comments: (i) prices and generators profits were excessive, (ii) this was due to short run marginal cost pricing that should be replaced by average cost, and (iii) the price obtained from the spot market based on short run marginal cost does not contain any useful signal for investment. These three predicates form the basis of our discussion. Our first contribution is to analyze them through a model that asserts their *exact opposite* provided some condition is met: (i) prices based on short run marginal costs are not excessive as they would just cover investment cost, (ii) marginal and average cost would not make a difference for consumers' bill, and (iii) short run marginal prices (spot prices) would give very precise long term signals. But there is a condition for this to be valid: capacities should be *adapted*, a notion that pervades the whole analysis. The model that leads to these conditional statements is well known in the power profession. It is due to Marcel Boiteux and has been at the origin, since the sixties, of considerable computational and economic developments that go beyond the sole power sector ([Boiteux, 1960]). It can be interpreted in both planning and market terms and thus fares well whether we refer to a public monopoly or competitive markets. It can even accommodate a stylized version of capacity markets (as it did in the days of monopoly organization), a property that we will extensively leverage. Our approach is to try to cast some of the events of 2021-2023 in that model in the hope that this will reveal insights that more informal discussions overlooked.

The discrepancies between the observations during the crisis and the desirable properties of Boiteux's model have sometimes been attributed to deficiencies of the market design. Our model reveals an alternative and simpler explanation rooted in the assumption of adapted capacities that conditions the conclusions of the model. Production capacities of 2022 were certainly not adapted to the economic (demand and fuel costs) conditions; or in other words they were not optimized with respect to these conditions. Surely, the mix of price driven coordination due to competition on the one hand with renewable policies largely made of quantity targets and subsidies on the other hand, did not help. Last but not least, the rigidities created by non-storability and transport difficulties mentioned above certainly exacerbated the impact of the discrepancies between economic conditions at planning and real time stages. Notwithstanding the foregoing, the model still fared reasonably well in the period that followed the financial crisis until the combination of the loss of cheap Russian gas supply and of a significant fraction of French nuclear capacities destroyed any hope of capacities remaining reasonably "adapted". Therefore, looking at what happens when capacities are no longer adapted is of paramount interest in the context of the transition, but also given the very chaotic evolution of geopolitics and its possible consequences foreseen today by both verbal and quantitative analysis of our societies. This has become a problem of "Economic Security" ([Pisani-Ferry et al., 2024]).[4]

Coming back to the particular context of 2022, Boiteux's theorem and its condition of validity suggest that the non adaptation of the capacities, much more than a fundamental defect of the market design itself, is at the origin of the observed turmoil in the electricity market. The natural question that comes to mind is whether we can say more. This requires to move from Boiteux's original assumptions that capacities are adapted to one that accommodates non adapted capacities. This constitutes the second contribution of our research which provides insight on the possibility of inserting a long term price dimension in a spot price that keeps the current short term efficiency of plant operations (our above point (iii)). To do so, we leverage techniques of linear programming to propose a novel price clearing mechanism that keeps the short term efficiency of the current one, but has the advantage of embedding long term investment signals. We subsequently implement our proposal on a simple representation of the French power mix to assess its impact on prices, profits, and profitability of power plants.

[4]Very briefly (see the contribution in the so called "Paris Report 2" cited in [Pisani-Ferry et al., 2024]), the new field of economic security addresses problems caused by political disruptions (for instance initiated by sanctions) in the economic world inherited from the World Trade Organization system. In our context, we look at that problem by moving from an equilibrium paradigm to one of shocks on equilibria.

1.4 Structure of the paper

Section 2 investigates Boiteux 's seminal model and its interpretation in the context of the crisis. The spot market in the restructured electricity systems serves two purposes: one is physical as the spot market directs an efficient operation of generation; the other one is economic as the spot market also provides electricity prices that support this efficient operation and, in principle, constitute the basis of a forward financial market to ideally provide long term signals for investment. In Central Western Europe for instance, the design is implemented through a particular software, EUPHEMIA, that expands on the so called standard "optimal dispatch" model to accommodate the variety of idiosyncrasies of the European market. Our analysis is stylized and based on the simplest possible representation of EUPHEMIA that is an "optimal dispatch" model to which we associate an equally simple "capacity expansion model". These models are probably the most basic ones found in the power industry. Their main advantage is that they simplify the analysis without invalidating its generality. In this context, our reasoning in the present paper can be summarized very simply as follows: (i) The European spot market uses an optimal dispatch to determine an efficient operations of the system and a price system that supports this operations. (ii) We keep this first objective as such but in contrast with the existing system, we derive the supporting price system from a capacity expansion model that is directly tied to the optimal dispatch. (iii) We show that the obtained price formation mechanism contains a long term signal that supports short term operations at the same time. (iv) We also show that this mechanism responds to several criticisms made against the current market design. (v) Last but not least, the mechanism questions the current separation of energy and capacity markets. Our discussion in Section 2 is conducted with reference to the traditional thermal system, which is itself based on the co called merit order rule. It is recognized that the penetration of intermittent renewable technologies will impose drastic modifications of this system as we go more deeply in the transition. The analysis proposed here does not touch these aspects on which there remains considerable uncertainty. We thus concentrate on the current standard thermal system to explore this question of long term signal and spot market. Optimal dispatch and capacity expansion models are common in this traditional system. They are efficiently formulated and solved as linear programming problems and their optimal solutions described by so called primal dual conditions, or KKT (first order) conditions. Naturally, EUPHEMIA involves more complex equilibrium conditions but accounting for them would unnecessarily complicate the analysis without providing any fundamental change to the basic considerations developed in the present paper.

Section 3 goes into the analysis of the alleged shortcomings of the system. It delves into [Finon and Beeker, 2023]'s crucial remark that the current spot market does not contain any long term signal to delineate its validity and the root of the absence of such a long term signal. In this section, we argue that Boiteux's results hold only when capacities are "adapted", that is optimized with respect to the economic conditions (demand and input costs) of the market. In that respect, the European crisis burst when generation capacities suddenly became strongly non optimal because of the brisk evolution of the gas market. Therefore, we argue that Boiteux's results need to be adapted to reflect this situation.

In Section 4, we show that one can construct a modified capacity expansion model calibrated on the optimal short term generation pattern that produces a meaningful long term price signal and supports that efficient short term operations at the same time. We examine thoroughly the properties of this long long term signal and provide a number of results allowing to identify which plants in the energy mix are no more adapted and those that we would like to keep in the future. We also demonstrate that like Boiteux's results that describe an economy that is efficient both in price and quantity, our proposal also inherits properties pertaining to system efficiency, which, by construction, can only be absent from the current design when the existing portfolio of generation plants becomes non-optimal. In that regard, [Fabra, 2023] is, to the best of our knowledge, the sole author that drew the attention to the importance of this optimality condition in the analysis of the market. The section also explains why other events, such as regulatory policies, can make capacities non optimal, thereby emphasizing the utility of our proposal.

Section 5 explores means to amend our proposal to accommodate capacity markets and price caps which constitute some remedies that have been implemented in Europe to incentivize investment in the absence of long term signals in the formation of prices for the former, and to limit windfall profits in case of crisis for the latter. In particular, we show how our proposal modifies the formation of prices in the energy only and in the capacity markets and how to identify plants that are no longer adapted in the power mix.

Section 6 concludes the paper by providing some concrete policy recommendations. All our models are tested with the French power system for years 2019 (before the crisis), 2021 (the beginning of the crisis), and 2022 (the acme of the crisis), to demonstrate their applicability and assess their impacts on the formation of prices in real power markets.

All our proposals assume the existence of a central entity that gathers bids of producers and computes prices and dispatched volumes to minimize system cost, similar in spirit to what EUPHEMIA does in Europe. We depart slightly from the most general functioning of EUPHEMIA by assuming that bids are independent from one another and are plant specific. This is equivalent to a decentralized system where agents receive only price information if the market is perfectly competitive, market players are rational, and information about investment and operational costs and existing capacities is perfect and transparent. We consider henceforth a centralized functioning of the markets.

2 The short term market and the criticisms of the market design

2.1 Principles

Spot prices in restructured electricity systems are meant to reflect short run marginal costs of operations. These are obtained by software implementing principles inherited from the so-called optimal dispatch. The early model went through considerable developments especially for dealing with the "non-convex" characteristics of the machines (start up cost, minimum up and down times, etc. hereafter simply referred to without elaboration as non-convexities), leading to the so called Unit Commitment. These models initially developed for enhancing the efficiency of physical operations (the operations of the generators), saw their role considerably enhanced in the restructured system when being endowed with the role of producing spot prices. Difficulties with non-convexities in the optimization of physical operations were also reflected in the computation of spot prices. We neglect non-convexities in this paper and refer to the basic economic concept of short run marginal cost that underpins the early optimal dispatch and remains the notion of reference in discussions of pricing and market design. This was indeed the case in the debates during the crisis that we summarized in the introduction by the three propositions: (i) short short run marginal costs were high and claimed inappropriate for pricing; (ii) average cost pricing would have performed better, and (iii) last but not least for this paper and almost by definition, short run marginal cost did not contain any long term signal.

We rely on the simplest possible version of the short term model. It is stated next (with some useful normalized dual variables written in parenthesis next to their constraints):

$$\begin{aligned}
\text{Min} \quad & \sum_{t=1}^{T} \sum_{g \in \mathcal{G}} \tau_t c_{g,t} y_{g,t} & & \\
\text{s.t} \quad & \sum_{g \in \mathcal{G}} y_{g,t} \geq d_t & (\pi_t \tau_t) \quad & \forall t = 1, ..., T \\
& x_g^{installed} - y_{g,t} \geq 0 & (\mu_{g,t} \tau_t) \quad & \forall t = 1, ..., T, \ \forall g \in \mathcal{G} \\
& y_{g,t} \geq 0 & & \forall t = 1, ..., T, \ \forall g \in \mathcal{G}.
\end{aligned} \tag{1}$$

where g and G respectively designate a power plant and the set of power plants. t and T denote a time segment and the number of time segments of the horizon; τ_t is the duration of time segment

t in hours. $c_{g,t}$ and $y_{g,t}$ respectively denote the operations cost of the plant in €/MWh and the operation level in MW while d_t is the (exogenous) demand in time segment t in MW. Finally, $x_g^{installed}$ represents, in MW, the installed capacity of plant g during the horizon covered by the model.

The optimality conditions of the problem are stated through their KKT conditions as:

$$0 \leq y_{g,t} \quad \perp c_{g,t} + \mu_{g,t} - \pi_t \quad \geq 0 \quad \forall (g,t) \in \mathcal{G} \times \{1, ..., T\} \tag{2}$$

$$0 \leq \mu_{g,t} \quad \perp x_g^{installed} - y_{g,t} \quad \geq 0 \quad \forall (g,t) \in \mathcal{G} \times \{1, ..., T\} \tag{3}$$

$$0 \leq \pi_t \quad \perp \sum_{g \in \mathcal{G}} y_{g,t} - d_t \quad \geq 0 \quad \forall t \in \{1, ..., T\}. \tag{4}$$

where $\pi(t)$ is the spot price in t. The first relation states that the hourly spot price in t is a function of the fuel price and of the marginal value $\mu_{g,t}$ of operating capacity g in t. $\pi_t - c_{g,t}$ is thus the hourly gross margin made by the plant in t. Because capacities are exogenous in the optimal dispatch, $\mu_{g,t}$ is determined internally by the model without reference to any external long term information. The spot price therefore contains no long term signal as stated by [Finon and Beeker, 2023] and [Batlle et al., 2023] who claim that the long term market is fundamentally incomplete. This is a direct consequence of the design and hence not a surprise.

Even if it does not give long term information, the spot price provides interesting insight on the situation at hand: specifically it measures the possible lack of adaptation of the generation system to the current economic conditions of the market. The gross margin made by a plant over some period can indeed be compared to its capital cost over that period (typically a year) to give, by difference, a net margin. This latter should be zero if capacities are perfectly adapted in a perfectly competitive market (in reality close to zero since capacities are rigid in the short to medium term and can never be fully adapted because external costs and demand conditions, as well as the regulatory environment are constantly changing, thereby modifying the adapted generation system). In contrast, positive net margins signal an insufficient capacity and negative margin an excess capacity. Note in passing that this basic phenomenon is unrelated to the concept of missing money that agitates the world of restructured power since more than a decade and which justifies specialized capacity markets as discussed later. The negative margin only signals stranded capacity and hence stranded money: accounting methods recognize a residual plant value that is unrecoverable from the market.

2.2 Illustration, the spot price in years 2019, 2021, and 2022

We develop a numerical dispatch simulator of the French market inspired by the simple model shown in relationship (1), to which we add a curtailment possibility at a very high price cap of 10,000 €/MWh. We aggregate the set of power plants of the French system by technology: fuel oil fired plants (denoted by Oil in the rest of the paper), coal fired plants (denoted by Coal), gas fired turbines (denoted by GT), nuclear reactors (denoted by Nuke), onshore/offshore wind mills (denoted by Wind), solar panels (denoted by PV), hydro-power (denoted by Hydro), and combined cycle gas plants (CCGT). We assume equal investment, operational, and maintenance costs as well as equal efficiencies for all plants of the same technology. We model a one hour time granularity and focus on three years representing varying economic conditions; 2019, 2021, and 2022. This implies, in particular, that we express capital costs as annuities (€/MW/year) assuming an interest rate of 5% and a technology dependent lifetime of the investments. The hourly demand is obtained from the publications of the French Transmission System Operator RTE ([RTE, 2022]). Our simulations also account for plants' emissions via a CO_2 price. All sources and additional details about our datasets are given in Appendix B.

Figure 1 compares the observed and simulated spot price duration curves. Spot prices appear to be relatively well aligned which means that the simulation of the dispatch process is realistic; we estimate an average absolute error of less than 10% throughout the three years (the differences are mainly due to the plants aggregation by technology and to a simplified representation of demand response).

Figure 1:
Price duration curves for 2019, 2021, and 2022.

Going further, Figure 2 reports on the corresponding net margins accrued in the spot market. As expected, net margins of the different plants are close to zero in 2019 but quite different from it in 2021 (the beginning of the crisis) and are substantially high in 2022 (its climax).

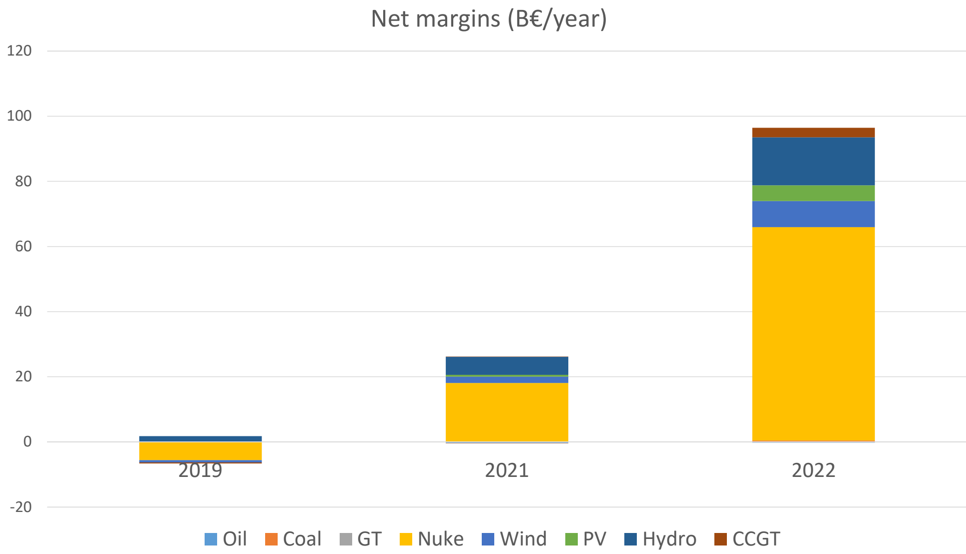

Figure 2:
Net margins for 2019, 2021, and 2022.

2.3 Towards a long term signal: principle

[Boiteux, 1960] states that short and long term marginal costs of generation are equal when capacities are "adapted". The short term marginal cost is then also a long term price signal. Plants which could not cover their capacity cost at current spot prices should not be invested in. [Boiteux, 1960] also implicitly contains another element directly related to the debate on short run marginal cost vs average cost during the crisis. The bill paid by the consumer is identical whether with average or marginal cost, but again under the condition that capacities are adapted. Average cost pricing is thus, at best, an alternative to the current marginal cost system to hide price volatility in time of crisis when capacities are not adapted and to simplify the understanding of price formation. It is no different from marginal cost in terms of bill to the consumer otherwise. We turn to the derivation of these results in preparation for their extension to the case where capacities are not adapted.

We reason on a capacity expansion model that extends the optimal dispatch model described in the preceding section. This is again an extremely simplified model but it captures the important elements of the problem. As for the dispatch problem, capacity expansion models have been extended in various ways leading to the large scale global energy models used today for the construction of the energy transition scenarios. The following developments may help introduce the principle of the model. Let K_g be the capacity cost of a plant g intended to cover a reference period from 1 to T (expressed in €/MW/year if, for instance, $t \in 1, ..., T$ spans a whole year). Parameters K_g can be derived from the overnight cost of plants by standard actuarial methods. Let $\mu_{g,t}$ be the marginal value of the capacity of the plant in time segment t as determined by the optimal dispatch. The optimality of the generation system requires $K_g = \sum_{t=1}^{T} \tau_t \mu_{g,t}$ for positive investment x_g: the gross margin $\mu_{g,t}$ collected by the plant *in the short term spot market* recovers its capital cost. This is what the capacity expansion model achieves as discussed next.

Consider a model that only differs from the optimal dispatch Problem (1) in two points: capacity levels are endogenous and their value is introduced in the objective function in linear form. We simplify the discussion by assuming that the dispatch and the capacity expansion models cover the same horizon with the same time granularity (a day, a year or any other horizon with hourly time granularity). The model is stated as:

$$\begin{aligned}
\text{Min} \quad & \sum_{g \in \mathcal{G}} K_g x_g + \sum_{t=1}^{T} \sum_{g \in \mathcal{G}} \tau_t c_{g,t} y_{g,t} \\
\text{s.t} \quad & \sum_{g \in \mathcal{G}} y_{g,t} \geq d_t && (\pi_t \tau_t) && \forall t = 1, ..., T \\
& x_g - y_{g,t} \geq 0 && (\mu_{g,t} \tau_t) && \forall t = 1, ..., T, \ \forall g \in \mathcal{G} \\
& y_{g,t} \geq 0 && && \forall t = 1, ..., T, \ \forall g \in \mathcal{G},
\end{aligned} \tag{5}$$

where x_g (expressed in MW) is an endogenous capacity variable that one wants to optimize (the definition of the other parameters and variables remain the same as in Section 2.1). The optimality conditions of the problem are stated as:

$$0 \leq x_g \quad \perp K_g - \sum_t \tau_t \mu_{g,t} \geq 0 \quad \forall g \in \mathcal{G} \tag{6}$$

$$0 \leq y_{g,t} \quad \perp c_{g,t} + \mu_{g,t} - \pi_t \geq 0 \quad \forall (g,t) \in \mathcal{G} \times \{1, ..., T\} \tag{7}$$

$$0 \leq \mu_{g,t} \quad \perp x_g - y_{g,t} \geq 0 \quad \forall (g,t) \in \mathcal{G} \times \{1, ..., T\} \tag{8}$$

$$0 \leq \pi_t \quad \perp \sum_{g \in \mathcal{G}} y_{g,t} - d_t \geq 0 \quad \forall t \in \{1, ..., T\}. \tag{9}$$

where π_t is here the dual variable of the demand constraint of the capacity expansion model, which is thus also the short term marginal cost of demand. As stated in relationship (7), this price consists of the sum of $\mu_{g,t}$, which is the instantaneous value of the capacity g in time segment t, and $c_{g,t}$, which is the fuel cost. The relation is formally identical to the one obtained for the optimal dispatch Problem (1), but its interpretation is different: the $\mu_{g,t}$, which are still the instantaneous values of capacity g in t, are now linked to K_g through relationship (6), that states that their sum over the horizon (from period 1 to T) is equal to K_g if plant g's capacity is expanded during that horizon: $x_g > 0$. This sum is smaller than K_g otherwise. The short term price signal π_t is thus now also a *long term* signal for an investment. The KKT condition (7) can also be interpreted as π_t being a short term price signal if capacities in the spot market are exogenously given at x_g (whether these capacities are adapted or not), but here are equal to those found by the capacity expansion model. This gives Boiteux's key proposition: π_t is equal to both the short and long term marginal costs when capacities are optimal, that is when $x_g^{installed} = x_g$ for all plants $g \in \mathcal{G}$. To the best of our knowledge, except for [Fabra, 2023], one finds no trace of this key condition in the comments emitted during the crisis.

A standard result of linear programming is that the primal and dual optimal values are equal. This relation can be stated as:

$$\sum_{t=1}^{T} \tau_t \pi_t d_t = \sum_{g \in \mathcal{G}} K_g x_g + \sum_{t=1}^{T} \sum_{g \in \mathcal{G}} \tau_t c_{g,t} y_{g,t}. \tag{10}$$

This shows that the price π_t collected over all the d_t of the horizon covers exactly the sum of investment and operating costs of all capacities g when they are *optimal* (or adapted in the sense of Boiteux). These π_t can then be used to compute the average cost over the horizon, which is then (by construction) the lowest possible and is thus non excessive. This implies that pricing at marginal or average cost will make no difference for the consumer when capacities are adapted.

2.4 Illustration, capacity adapted spot price (long term marginal costs) in years 2019, 2021, and 2022 in France

Figure 3 compares the spot price computed with existing (observed) capacities and the short term marginal costs (meant to represent spot price as computed in section 2.3); by construction these latter prices also represent long term marginal costs. The loss of optimality as well as the loss of a valid long term signal appears clearly. The spot prices computed with existing capacities diverge from the prices computed by the capacity expansion model in 2021 and 2022 while being reasonably similar in 2019. This confirms that the current spot price indeed lost any long term interpretation in 2021 and 2022 because capacities were no longer adapted.

A capacity expansion model complies equally well with the philosophies of planning through a central agency or full decentralization in the energy only market. The price signals are the same. The energy only philosophy takes it for granted that this suffices to induce investment, while planning requires a public intervention to drive investment. In between, organizations that include a capacity market require capacity payments in addition to energy prices. These take the form of subsidies to providers of capacities that fulfill certain obligations. Their level is deter-

Figure 3:
Price duration curves for 2019, 2021, and 2022. Existing capacity versus adapted capacity.

mined by an auction. We will come back to this organization in Section 5 but we note here that this capacity payment in some sense completes the market by introducing a signal on another element that is not a commodity (the capacity). We also remark here that capacity is just a single undifferentiated item in this systems as is the case in current organizations. Referring to the comment of [Batlle et al., 2023] on market incompleteness, we shall show later that the capacity expansion model provides technology differentiated capacity value signals. These are the marginal values of individual capacities $\mu_{g,t}$. We will also note that these signals satisfy the same fundamental property as long and short term marginal costs, meaning that they are equal when the system is adapted.

It remains to see what all this becomes when capacities are not adapted. This is what we turn to now.

3 Towards non adapted capacities: identifying the problem

Boiteux's results relate short and long term price signals (marginal costs) when generation systems are (reasonably) optimized with respect to economic circumstances. The economics of the European energy system drastically changed between 2019 and 2021-2022. Primary energy supply which was anchored in abundant low cost Russian gas before 2019 had to operate with limited and expensive alternative supplies from 2022 on. Various phenomena were at work to tighten the market: demand that had been stagnant during the worst time of the pandemic was picking up; capacity investments that were low in the preceding decade, were slowly recovering in 2021 thanks to financial support for renewable technologies at the same time that some excess fossil fuel capacity was dismantled; last but not least, common technical problems affecting the French nuclear fleet reduced available capacity. All in all, generation capacity was suddenly unadapted and the consumer exposed to scarcity prices. Boiteux's results provide a rationalization of the situation: capacities had become unadaptated to the new conditions of the market and this had nothing to do with a misconception of marginal cost pricing as some had claimed. It was also thought counterproductive to embark in a overall upheaval of the existing organization without really knowing where one was heading to. That major point was taken on board in the reform proposals of the Commission.

Notwithstanding the early criticisms against spot prices, it was progressively admitted that the organization of the short term market had effectively helped mitigate the impact of the crisis. The argument was a bit spurious in the sense that this outcome was attributed to the price system and not to the optimization of the dispatch that determined prices. But the two are intimately related and the observation that the short term market increased the resiliency of the system progressively became well admitted. The Commission's proposal thus kept this fundamental organization intact and concentrated, among others, on the lack of incentives to invest leading to the introduction of capacity markets and hedging instruments to reduce investment risk. (The text remains quite general though.)

This sets the scene for the rest of the paper. The main point is that the current spot market is essentially unchanged: the centralized organization of the dispatch based on a notion of short term marginal cost remains, and will extend to other participants as they join the EU power market. It is recognized that this extension may require technical adaptations for computing prices (resorting to the so called "convex hull pricing") because of the difficulties caused by non-convexities in the operations of the plants and their impact on the computation of prices.[5] In any case, short run marginal cost pricing will remain the principle of market clearing even if its exact implementation could change. This will not have any impact on the long term market *that remains to be completed.*

4 Spot and Long Term Signals: formulating the problem

The objective is thus to propose spot prices that are incentive compatible with the current dispatch and encompass information about long term marginal costs at the same time. "Incentive compatible" has the usual interpretation: the spot prices should not induce agents to depart from the central dispatch of Section 2. This maintains the efficiency of (short term) day-ahead (DA) operations. The second condition implies that the spot price, considered as an underlying of long term contracts foreseen in the new legislation, should contain a long term signal. The proposed model is of the same type as the one driving the spot market today or in the future and hence is

[5] These are currently well taken care of in the EUPHEMIA software responsible of the clearing of European spot market prices but it is not clear that the current system will be scalable to include new members.

not more complex. As a by-product, this model also produces valuations of capacities compatible with both the current dispatch and the long term price information. In other words, plants that are no longer economically viable but need to be momentarily kept for reasons of dispatch feasibility will break even (recover their capital cost) even if the model will also signal that they have become uneconomical. On the contrary, those plants that are adapted and supported by the long term signal will make so called *"excess profit"* (or positive net margin) as expected from scarce resources.

4.1 Principles of the proposal

Our computational method is again inspired by some of Boiteux's fundamental developments. The shock on the gas market in 2019 to 2022 that suddenly made the capacity structure of the power system non adapted can be compared to what happens when a power system modifies the set of its operating machines in reaction to a change of demand. [Boiteux, 1986] (page 217 and following) discusses that problem using the example of marginal cost pricing for a hydro plant that either produces nothing at zero marginal cost, or operates at full capacity when marginal cost are undefined. Boiteux then argued that marginal cost is then ineffective and should be replaced by average cost or accounting cost in a way that efficiently spreads the full cost over several periods. This was the idea behind so called "Boiteux-Ramsey" pricing, see [Dierker, 1991] for instance. The standard treatment of that question in power systems is to be found in the pricing of non-convexities (e.g. start up costs) in thermal generation system. We rely on recent work on that question in US day-ahead markets ([Garcia and O'Neill, 2024]) that provides an in depth treatment of that problem where average cost pricing comes as a natural replacement (under the name of Average Incremental Cost) of marginal cost pricing in some circumstances. Even though we do not consider indivisibilities, we transpose some of the ideas of that work and adapt the associated computational approach to our problem. Our treatment is self contained

4.2 A spot price with a "long term" price signal

Let $y^*_{g,t}$ be the solution of the optimal dispatch on the horizon from 1 to T, obtained by solving Problem (1). This solution accommodates some demand d_t and fuel costs $c_{g,t}$ for $g \in \mathcal{G}$ and $t = 1, ..., T$, using existing physical capacities $x_g^{installed}$. We remind the reader that these capacities might not be adapted, that is, they might differ from the optimal investments x_g obtained by solving Problem (5). In other words, this solution corresponds to the short term view in Boiteux's model and it applies whether the generation system is adapted or not. Similarly, we denote by π^*_t and $\mu^*_{g,t}$ the market prices and scarcity rents of the original optimal dispatch solving Problem (1).

In contrast with the usual result that considers an adapted generation system, we are interested in a generations system that needs to re-adapt to respond to a shock. This will imply a decrease of some less economical technologies (in our example gas generation in 2022) and an increase in existing or new ones. We want to model a marginal movement of this evolution conditional on the requirement that it still incentivises the current dispatch. The underpinning objective is not to sacrifice current efficiency (which is certain) to expectations that remain uncertain. We thus first assume that this marginal movement takes place without change of technologies. In other words, we do not change set $\mathcal{G}$.

Transposing the analysis led in [Garcia and O'Neill, 2024] of the DA problem to the investment context, we model this marginal movement as follow: let $y_{g,t}^{max}$, which we set equal to $y_{g,t}^{*} + \epsilon$, be a maximal allowable level of operations of plant g's production at time t, $y_{g,t}$, where $\epsilon > 0$ is an arbitrary small parameter. In other words, we assume that plant g's production at time t, $y_{g,t}$, can vary from 0 to $y_{g,t}^{max}$. We also define the new maximal available capacity for plant g by $x_g^* := \text{Max}_{t=1,\dots,T}\ \left(y_{g,t}^{max}\right)$. We then consider the following modified capacity expansion model, which we denote by Problem MCEM(ϵ):

$$
\begin{aligned}
\text{Min} \quad & \sum_{g\in\mathcal{G}} K_g x_g^* u_g + \sum_{t=1}^{T}\sum_{g\in\mathcal{G}} \tau_t c_{g,t} v_{g,t} & & \\
\text{s.t} \quad & \sum_{g\in\mathcal{G}} v_{g,t} \geq d_t & (\pi_t\tau_t) \qquad & \forall t = 1,\dots,T \\
& y_{g,t}^{max} u_g - v_{g,t} \geq 0 & (\mu_{g,t}\tau_t) \qquad & \forall t = 1,\dots,T,\ \forall g\in\mathcal{G} \\
& v_{g,t} \geq 0 & & \forall t = 1,\dots,T,\ \forall g\in\mathcal{G} \\
& u_g \leq 1 & (\gamma_g) \qquad & \forall g\in\mathcal{G}.
\end{aligned} \tag{11}
$$

The new u variables measure an adjustment of the use of the existing capacities (this use being quantified by $v_{g,t}$), when switching from a dispatch based on the sole short term operating cost to one based on long term investment and operating costs. The v variables are simply the new notation of the previous y variables (production variables) in this modified capacity expansion problem. We draw the attention of the reader that this model is parametrized by ϵ and, from now on, we denote the pure original dispatch model (1) by POD.

Problems MCEM(ϵ) will in general lead to a dispatch different from that obtained from POD whenever $\epsilon > 0$. One can also note that letting ϵ tend to zero will, through the constraints, force the dispatch of MCEM(ϵ) to converge to the one of POD. This can easily be seen from the fact that $y_{g,t}$ cannot exceed $y_{g,t}^*$ at the limit and that their sum must be greater or equal to d_t. This argument is stated in the following proposition:

Proposition 1. *At the limit when letting ϵ tend to zero, the dispatch of Problem MCEM(0^+) is identical to that of POD.*

We denote by Problem MCEM(0^+) the limit of Problem MCEM(ϵ) when $\epsilon \longrightarrow 0$. The key step in the reasoning is to note that a similar property does not hold for prices (the dual variables) determined by the MCEMs problems. Indeed the variables π_t and $\mu_{g,t}$ of MCEM(ϵ) will in general (when capacities are not adapted) not converge to the π_t^* and $\mu_{g,t}^*$ of POD as the former are determined, among others, by capacity costs K_g that are absent from the POD problem. The relevant question is whether these MCEM prices still support the POD optimal dispatch and hence can be seen as valid spot prices. This can easily be shown from the KKT conditions of MCEM(ϵ) (where the indexing of the variables by ϵ has been omitted to facilitate reading; the following KKT conditions are thus implicitly parameterized by ϵ):

$$
\begin{aligned}
0 \leq & u_g && \perp K_g x_g^* - \sum_t \tau_t \mu_{g,t} y_{g,t}^{max} + \gamma_g && \geq 0 \quad \forall g \in \mathcal{G} && (12)\\
0 \leq & v_{g,t} && \perp c_{g,t} + \mu_{g,t} - \pi_t && \geq 0 \quad \forall (g,t) \in \mathcal{G} \times \{1,...,T\} && (13)\\
0 \leq & \mu_{g,t} && \perp y_{g,t}^{max} u_g - v_{g,t} && \geq 0 \quad \forall (g,t) \in \mathcal{G} \times \{1,...,T\} && (14)\\
0 \leq & \pi_t && \perp \sum_{g \in \mathcal{G}} v_{g,t} - d_t && \geq 0 \quad \forall t \in \{1,...,T\} && (15)\\
0 \leq & \gamma_g && \perp 1 - u_g && \geq 0 \quad \forall g \in \mathcal{G}. && (16)
\end{aligned}
$$

These conditions hold for any $\epsilon > 0$; they consist of continuous relations (linear inequalities) between bounded variables (prices and quantities) and hence also hold at the limit (when $\epsilon \longrightarrow 0$). Condition (13) taken at the limit is identical to the optimal dispatch condition of the POD (relationship (2)) and is the main result of this discussion. Proposition 1 had stated that the limits of the $v_{g,t}$ variables are equal to $y_{g,t}^*$ (solutions to the POD problem). This shows that the limits of π_t and $\mu_{g,t}$ when $\epsilon \longrightarrow 0$, which we denote by π_t^{lim} and $\mu_{g,t}^{lim}$, effectively support the POD dispatch $y_{g,t}^*$.[6] One can thus write:

$$
0 \leq y_{g,t}^* \quad \perp c_{g,t} + \mu_{g,t}^{lim} - \pi_t^{lim} \quad \geq 0 \quad \forall (g,t) \in \mathcal{G} \times \{1,...,T\},
$$

and hence the second proposition:

Proposition 2. *π_t^{lim} and $\mu_{g,t}^{lim}$ support the short term optimal dispatch $y_{g,t}^*$ of POD. Because of standard upper semi continuity of dual variables of convex optimization problems, π_t^{lim} and $\mu_{g,t}^{lim}$ are also dual variable of MCEM(0^+).*

[6] It can be shown that variables π_t and $\mu_{g,t}$ are always bounded and belong to a compact set independent on ϵ. Therefore, one can always consider converging subsequences when $\epsilon \longrightarrow 0$ that define π_t^{lim} and $\mu_{g,t}^{lim}$.

4.3 On limit points and adapted capacities

Problem MCEM(ϵ) is parameterized by ϵ. The combination of constraints (14) and (15) defines a neighborhood of $y^*_{g,t}$ that shrinks to this single point when ϵ goes to 0. The reproduction of the dispatch of POD thus results by construction of problems MCEM(ϵ). As stated above, in contrast, variables π_t and the $\mu_{g,t}$ in MCEM(ϵ) belong to a set of dual constraints that, at the limit, does not impose them to boil down to the corresponding constraints of POD. This is in particular the case of constraint (12) in MCEM(0^+) that forces a relation between the $\mu_{g,t}$ and the long term capital costs. This implies that by construction, dual variables (energy price and plant values) are, at the limit $\epsilon \longrightarrow 0$, different from those found in POD. One can show that the equality between the π_t and the $\mu_{g,t}$ variable in MCEM(0^+) and POD is restored when capacities are adapted, that is, when x_g coincides with $x_g^{installed}$ for all plants. Therefore, we fall back on Boiteux's result but by involving both a dispatch and a pricing model.

Proposition 3. *Barring degeneracy of the data, variables π_t^{lim} and $\mu_{g,t}^{lim}$ of MCEM(0^+) are identical to those of the dispatch problem POD when capacities are adapted:*

$$\forall t \in \{1, ..., T\},\ \pi_t^{lim} = \pi_t \textit{ and } \forall (g,t) \in \mathcal{G} \times \{1, ..., T\},\ \mu_{g,t}^{lim} = \mu_{g,t}.$$

Proof. Because the optimality conditions of MCEM(0^+) are the limits of continuous functions that state the optimality conditions of the MCEM(ϵ), the limits π_t^{lim} and $\mu_{g,t}^{lim}$ of π_t and $\mu_{g,t}$ when ϵ tends to zero satisfy the optimality conditions of MCEM(0^+). The proposition is proven if one can show that the primal and dual solution of the POD also satisfy these conditions when capacities are adapted. We first note that, because of Boiteux's theorem, we know that the primal and dual solutions of the POD obtained with adapted capacities $x^*$are also the primal and dual solution of the capacity expansion model that determines these capacities. Inserting these capacities in MCEM(0^+), setting all u_g to 1 and noting that $y_{g,t}^{max}$ are equal to the $y_{g,t}$ of the POD when $\epsilon \longrightarrow 0$, one then reproduces the optimal solution of the capacity expansion model. Because this model is less restricted than MCEM(0^+), its solution is thus also optimal for MCEM(0^+). Barring degeneracy, this primal dual solution of the capacity expansion model is unique and is thus also a primal and dual solution of MCEM(0^+). □

It can be verified that complementarity conditions associated with MCEM(0^+) enable plants with positive γ to collect more than their capacity costs. These were referred to as making excess profits during the crisis, which carries a judgment value. We simply refer to them as plants with positive net margin. One can envisage different reactions to positive net margins. For instance, one can consider that they are a further incentive (beyond the normal remuneration of the cost of capital) to investment that will contribute to the re-balancing of the generation system. Another interpretation could be that these excess profits can be used to compensate consumers facing higher prices. We briefly touch upon this point when discussing capacity markets, but we already raise here the question of what would happen if all the γ were set to zero through some legislative or regulatory process. It is easy to see that setting the γ to zero would make the computation of long term signals impossible: accounting for capacity cost (that is for the minimal long term signal that one can think of) is simply incompatible with imposing zero γ when existing capacities are not adapted. In other words one cannot hope to exclude "excess profits" while trying to recover from disequilibrium on the basis of standard long term market signals. This means that measures acting on the γ to reduce them, besides hiding some measures akin to state aids (which are not the subject of this paper) are likely to have unintended consequences. At this stage, we note that plants with zero net margin are adapted in the sense of Boiteux. They break even in the sense that the marginal value created by the operations of their capacity as computed with the long term prices is just equal to their cost of capital.[7] Plants having a negative or positive net value are not adapted. Note that high prices may be necessary to cover the cost of capital of plants (in particular those that are adapted), and this is replicated by our proposal. As in the traditional theory of peak load pricing, one observes that plants can cover their capacity cost during some periods only (this will occur in periods when the plants are infra-marginal).

4.4 Sensitivity analysis

As argued above, constraint $y_{g,t}^{max} u_g - v_{g,t} \geq 0$ together with the equality of u_g to 1 when ϵ converges to to zero for the plants in Problem MCEM(0^+) force the dual solution of the capacity expansion model to incentivize the dispatch of the POD and hence is central to the analysis. Variables u_g are not, however, necessarily equal to 1 when ϵ is not zero, that is, when relaxing the constraint of incentivizing the current dispatch. This implies that u_g can effectively become smaller than 1 when ϵ is positive. Exploring the neighbourhood of $\epsilon = 0$ can thus be seen as a sensitivity analysis on the dispatch that may tell something on the profitability of the plant when the system departs from current conditions (which it surely does in reality). The following structures the information that can be gathered from Problem MCEM(ϵ) when ϵ convergence to zero.

As stated before, we first note that u_g must be equal to 1 at the limit as assuming otherwise would violate the compatibility with the dispatch as ϵ converges to 0. Because of complementarity conditions, we also know that γ is non negative, which leads to three possible cases:

1. Suppose γ is strictly positive at the limit for a plant g. Then the available capacity x_g^* is fully used in some neighborhood of ϵ equal to 0, with a positive net margin. This reflects

[7] As we will discus below, this would be a standard "degeneracy" effect that one should not expect to occur in practice.

a plant that one wants to invest in. Its capacity is not, however, adapted in the sense of Boiteux as a higher capacity would be warranted.

2. Suppose γ is zero at the limit and u_g is less than 1 throughout the sequence for a plant. This plant is no longer economical but remains necessary for the dispatch. This also implies that the plant recovers its capacity cost only because it is needed in the short term dispatch, but it is not adapted in the sense of Boiteux and some stranding of the capacity is to be expected in the future when the short term dispatch changes.

3. Let now γ be zero at the limit for a plant g with u_g equal to 1 throughout the sequence. Then the available capacity x^*_g is fully used in some neighborhood of ϵ around 0 for economic reason. It is thus adapted in the sense of Boiteux and recovers its capacity by the sole virtue of its economics.

Capacity costs can thus be recovered either because the plant is economical or because some of this capacity is necessary for retaining the short term dispatch. Some stranding of that capacity can be expected with the change of the dispatch constraint. This suggests adaptations of the capacity to move away from the current imbalance. The optimal extent of that adjustment is another problem that should be treated separately.

We summarize our findings before moving on: only plants with zero net margin ($\gamma_g = 0$) and u_g equal to 1 in a neighborhood around $\epsilon = 0$ are adapted to the system in the sense of Boiteux. They break even inasmuch as the marginal value of their capacity computed with the long term prices is just equal to their capacity costs. All other plants are *not* adapted: the economic values of their (existing) capacities are not in line with their investment costs, (one would want to invest more of them or strand some of their capacity) which expresses the lack of optimality.[8] This has nothing surprising: adapted capacities are a notion of equilibrium and the crisis created a disequilibrium. This also implies that none of these cases of non adapted capacities can be traced to an issue of missing money (a concept of incomplete static market). The phenomena observed during 2021-2023 (in particular the high prices) reflect a good behaviour of the short run market that needed to adapt to a structure of capital that suddenly became inadequate because of geopolitical events.

As a last remark, one shall note that because the $y^{max}_{g,t}$ are defined as $y^*_{g,t} + \epsilon$, MCEM(ϵ) is by construction limited to use the same (current) technologies as POD. This obviously restricts what

[8] Putting it differently, it should be intuitive that plants with a positive γ_g at the limit $\epsilon \longrightarrow 0$ are those whose capacity should be increased if one can marginally re-optimize the mix starting from the installed capacities. On the other hand, some plants whose γ_g is naught at the limit and u_g lower than 1 in the sequence should ideally see their capacity decreased. Our methodology allows to incentivize this re-configuration in the future because it provides positive margins to those plants belonging to the first category.

we mean by "long term" in the sense that it is limited only to the set of technologies existing in the current generation system. We remove this restriction in Appendix C.

4.5 Illustration, new spot prices and adapted capacities in years 2019, 2021, and 2022 in France

This section reports on the results of our simulations with the French market for the years 2019, 2021, and 2022. We first show in Figure 4 market prices as cleared with existing capacities (POD) and as computed via our proposal MCEM(0^+). Table 1 reports on average values. As a benchmark, we also show in Table 1 the prices that would be obtained for a system adapted to the real fuel cost conditions of the time, as defined in Problem (5), which assumes that one scraps the existing system and rebuilds it to optimality with respect to fuel cost conditions of the time. One observation stands out: prices are similar except for some peak hours where our proposal leads to substantially higher prices during less than 10 hours of the year. The reason for this is simple: because our proposal reconciles short term and long term price signals in an energy-only market, plants that one wants to keep in the system have to recover their investment cost during some hours, which is not possible in the current dispatch when capacities are not necessarily adapted and considering that we overlook, for the time being, revenues accrued from capacity markets. As a consequence, we estimate that our proposal increases prices by 15 €/MWh on average in 2019, 9 €/MWh on average in 2021, and 6 €/MWh on average in 2022. We remind the reader that both models (POD and MCEM(0^+)) elicit the same physical dispatch of plants at each hour.

Table 1: Average prices (€/MWh).

	2019	2021	2022
Current dispatch (POD)	40.9	105.6	289.9
Proposed dispatch (MCEM(0^+))	55.9	115.3	296.6
Optimized system	52.6	61.5	65.8

These figures convey an uncomfortable message: 2021 and 2022 electricity prices that were already outrageous with the current computation method still increase if one modifies the spot price to include the long term signal. This is obviously unavoidable as capacity costs are sunk in the current spot price while they are included in the long term signal. As pointed out at the time by ACER (Agency for the Cooperation of Energy Regulators) and repeated in the new legislation, part of this situation is due to the price of gas. But the other reason is the sudden inadequate capital structure of our power system after the disruption of gas supplies: it not only increased our fuel bill but also stranded part of the value of the generation structure (with a symmetric phenomenon for the gas supplier: a loss of revenue from gas sale and a loss of capacity value of the pipelines). The discrepancy between prices with existing capacity and optimal prices, which is extreme in years 2021 and 2022, is in line with the difference found between the installed capacity of plants and the optimal one. As an illustration, in year 2022, a complete re-optimization of the power system would require 7 GW less of gas fired power plants and 14 GW of additional nuclear capacity. The 2019 column illustrates what is going on in a system where capacities are almost adapted. The proposed spot price is higher than the current one because it contains capacity costs. But the spot price of the optimized system is 6% lower than the new spot price. The implication is also that the "long term" re-optimization of the dispatch is limited for positive ϵ implying that the new spot prices are close to the existing one except in a few hours of scarcity.

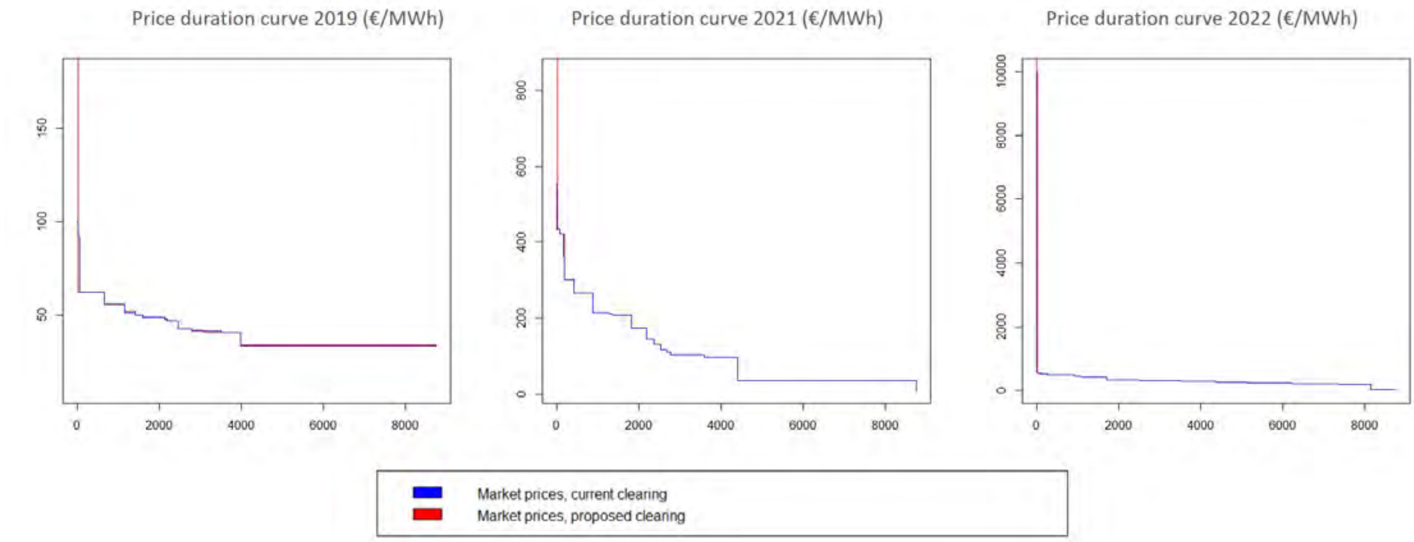

Figure 4:
Price duration curves for 2019, 2021, and 2022. Dispatch with existing capacity (blue) versus with our proposal (red).

Figure 5 reports on the net margins of plants obtained from prices derived from our proposal. We remind the reader that only plants whose net margin is positive are those we want to keep (or increase) in the system, given economic conditions of the French market.

Our results suggest that in 2019, only nuclear reactors, CCGTs, and hydro production are the technologies whose capacities need to be increased. In 2021, wind and solar technologies become adapted as well, reflecting further the need to shift away from fossil fuels because of the gas markets crisis. In 2022, the impacts of the crisis are further emphasized as it appears that wind and solar, along with nuclear production make substantial profits. More generally, because we consider a CO_2 price in our models, these findings are also in line with the constraints of the energy transition going on in Europe. Consistently, we also find that coal and fuel oil fired power

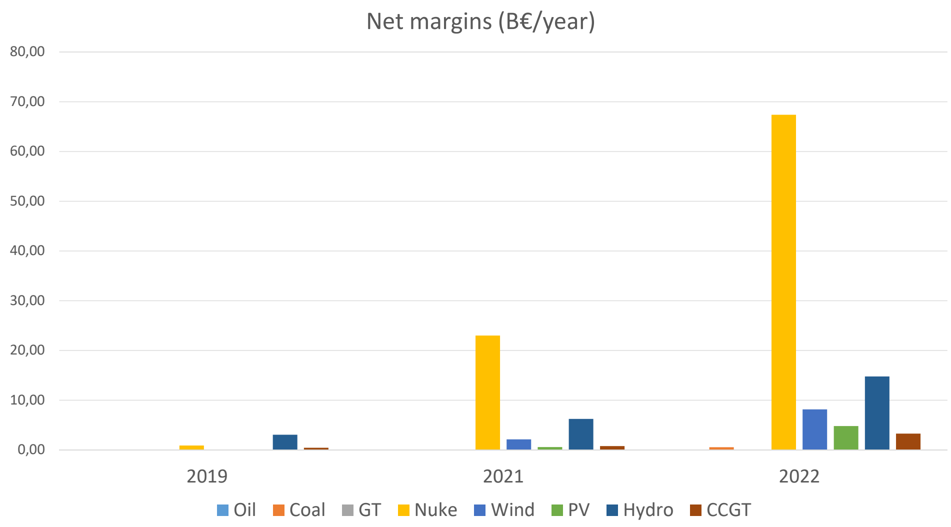

Figure 5:
Net margins as estimated from our proposed price clearing.

plants are not adapted in all years. It is important to note that these results strongly depend on the economic conditions of the French system in recent years and projections of the French System Operator about future investment costs. Therefore, they provide only a picture of what prices could steer producers to invest today in capacities that would make the system closer to an optimal capacity expansion plan, as estimated in France given current market data.[9] Finally, as stated before, by construction, our MCEM model does not allow to consider new technologies in the mix, which explains why only existing technologies can be adapted in our results.

5 Embedding capacity markets

The public and scientific debates on how to insure long term adequacy focused on two models. "Energy only" ascertains that revenues obtained from the sole functioning of the energy market suffice to induce investment. The capacity market model requests additional payments. Discussions on these alternatives were intense, both in the literature and industry practice. Capacity markets were initially seen by European Institutions as potential state aids that should be restricted to particular circumstances and only permitted in so far as these persisted. In contrast, the industry advocated capacity markets as a permanent necessary mechanism. The reaction of Member Sates was a patchwork of both measures with different implementations ([Papavasiliou, 2021], [Kozlova et al., 2023], [Simoglou and Biskas, 2023]). The new EU legisla-

[9] In particular, we are aware that costs of nuclear technology are strongly debated today.

tion ([Council of the European Commission, 2024]) makes capacity markets a matter of market design and no longer of competition law. This is a significant evolution in line with the idea that missing money issues are inherent to restructured markets whatever their particular implementation and hence deserve a dedicated mechanism to be treated ([Joskow, 2022]). It is interesting to note that the difference between energy only and capacity markets was already present in the mathematical formulations of the capacity expansion models of the sixties, that is well before restructuring. Early EDF (Electricité De France) models were based on the minimization of total investment and operating cost, including a cost of un-served energy. This is a true energy only reasoning: electricity valuation possibly moving up to the cost of un-served energy (measured by the VOLL or Value Of Lost Load) was the driving signal of investment in the model. An alternative formulation implicitly introduced a capacity market through special physical constraints on top of the relations implementing the energy only arbitrages between investment and operations costs. This model applies a standard engineering approach found in different areas to capacity expansion. The interesting interpretation of these constraints for today's conversation is that it recognizes that the cost of un-served energy is possibly a too elusive notion to drive investments and that something more physically related to adequacy should be imposed. The special constraint can be seen as expressing the demand for a new good (interpretable as useful or available capacity) to be supplied by a new market (a capacity market).[10] We take stock of these two formulations to structure the rest of the discussion. Specifically we note that the models discussed so far in the paper are of the energy only type: investments are entirely driven by cost minimization in the energy market, eventually given a certain level of VOLL. In contrast, capacity markets require the introduction of a new good (different from energy) as in the physical constraint of the traditional capacity expansion model. We refer to the fixed requirement or more generally the elastic demand ([Cramton and Stoft, 2005] and [Cramton et al., 2013]) for this new good as "adequacy" constraint. Transmission System Operators (TSOs) would typically be in charge of defining this constraint: not all generators provide the same capacity service and TSOs would at least differentiate them by their availability throughout the year. For simplicity our notation resorts to a single linear adequacy constraint, but it should be clear that the discussion can accommodate a set of these constraints (and hence a non linear convex constraint). Coming back to the original motivation of the paper, we note that the notion of missing money that underpins the debates between energy only and capacity market systems can be seen as reflecting an incomplete price signal. The statement that the current spot market lacks a long term signal mentioned before is effectively the recognition of an extreme case of missing money: the

[10] It is useful to note that these two versions of the capacity expansion models are not necessarily equivalent: probabilistic capacity constraints on capacities, for instance based on expected number of hours of interruptions (e.g. 10 hours in average per year), introduce non-convexities that are absent from the cost of un-served energy formulation. This was not important at the time in the closed area system that characterized the pre-restructuring period but could be relevant when transposing these two formulations to cross border trade issues in the multiarea European model.

current spot price says nothing about the future value of an investment. The capacity market or the provision of the adequacy good is intended to remedy that missing money. As before, the question is to embed a long term signal in the spot price without changing the current dispatch. We discuss two models. A first model supposes that some authority (e.g. a regulator) imposes a certain adequacy objective to be satisfied today and in the long run (where long run, as mentioned before, is taken as the horizon considered by the TSOs). We suppose that the current generation system (and hence the current dispatch) satisfies this constraint. One then needs to impose that the expanded capacities must also satisfy the long term view of the adequacy constraint. This will be reverberated in today's spot prices and in today's valuation of existing capacities. As in the preceding section, we also impose that the current optimal dispatch remains optimal for the long term prices and hence that we do not perturb current short term efficiency of generation. The spot price generated by the long term capacity expansion model thus supports the current physical optimal dispatch and does not modify it. The new feature with respect to the previous section is that the spot price also supports the adequacy constraint. A second model notes that price caps constitute a new source of missing money in restructured markets. Price caps were initially introduced to limit the exercise of market power ([Fabra, 2018]). They were also considered in the crisis as a tool to protect the consumer. This interpretation, due to the consequences of the marginal cost principle arose in the 2021-2022 crisis and has found its way but in different forms in Regulations 2022/1854 ([Council of the European Union, 2022]) and 2024/1747 ([Council of the European Commission, 2024]). Whatever the origin or implementation of price caps, they distort the energy only economics supposed to induce adequacy and reduce the incentive to invest. The phenomenon is easy to understand: price (or revenue) caps limit the possibility to capture the full benefits from high electricity prices that induce investment in peak plants and complete the payment of the full cost of other plants. This implies both a problem of adequacy and a distortion of the economics of the rest of the system. As in the previous model, the capacity market is aimed to restore adequacy. The extent to which it modifies the overall efficiency of generation depends on the implementation. Appendix A provides additional details on the issue of missing money and its relation to capacity markets.

5.1 Adequacy constraint

The energy only model supposes a perfect arbitrage between different energy sources and the willingness to pay to avoid interruption. Suppose that some imperfections affect this arbitrage: a market for capacity is then introduced to induce additional investments. We stylize this operation by simply inserting the requirement of a capacity product.[11] The demand for capacity is a weighted combination of physical plant capacities where the weights are defined by the TSO

[11] We assume a fixed demand for capacity.

for different periods t. Therefore, these weights, whose role is to model plants' availability in providing capacity, should depend on both g and t. As discussed later, the KKT conditions of that extended model provide the market interpretation of the model as an interaction between the energy and capacity markets. The standard implementation is to organize the capacity market as an auction. Without loss of generality, we suppose that the current dispatch satisfies whatever adequacy constraint is imposed on today's system. This can be interpreted in a standard way (as in former capacity expansion models) with a reserve margin. But the context of the crisis (or more generally of the transition) suggests to also consider another less usual interpretation. Some technologies, for instance gas fired peakers, may have become undesirable for geopolitical reasons even though they are perfect capacity providers in today's generation system. One may thus desire to also (on top of the provision of capacity) send a signal that disincentivizes these capacities because of that concern: there is a trade-off between the two objectives. We can reflect that feature by a particular adequacy constraint that gives a negative marginal value to undesirable plants. On the other hand, and as discussed in the preceding section, one could also care for other technologies that are not tight today (or even not existent today) but can be expected to play a significant role in the transition. These should be properly included in the adequacy constraint. Therefore, as indicated above, the capacity market may involve several items on which an adequacy capacity constraint is imposed. Taking this remark into account, we model the problem as the capacity expansion model embedding the adequacy constraint as follows:

$$\begin{aligned}
\text{Min} \quad & \sum_{g\in\mathcal{G}} K_g x_g + \sum_{t=1}^{T}\sum_{g\in\mathcal{G}} \tau_t c_{g,t} y_{g,t} & & \\
\text{s.t} \quad & \sum_{g\in\mathcal{G}} y_{g,t} \geq d_t & (\pi_t\tau_t) \qquad & \forall t = 1,...,T \\
\text{s.t} \quad & \sum_{g\in\mathcal{G}} \tau_t \alpha_{g,t} x_g \geq \kappa_t & (\eta_t) \qquad & \forall t = 1,...,T \\
& x_g - y_{g,t} \geq 0 & (\mu_{g,t}\tau_t) \qquad & \forall (g,t) \in \mathcal{G}\times\{1,...,T\} \\
& y_{g,t} \geq 0 & & \forall (g,t) \in \mathcal{G}\times\{1,...,T\},
\end{aligned} \tag{17}$$

where plant capacities in the adequacy constraint are each given an adequacy credit $\tau_t\alpha_{g,t}$ in time segment t, with $\alpha_{g,t}$ typically representing availability of the plant. Parameter κ_t is the total capacity target in time period t. As indicated above there may be as many capacity markets as desired, depending on policy objectives: a single constraints is sufficient if one wants to just ensure a sufficient available capacity.[12] The KKT conditions of this problem are:

[12]We remind the reader that an undesirable plant can be modeled in the usual way with negative $\alpha_{g,t}$.

$$
\begin{aligned}
0 \leq & x_g && \perp K_g - \sum_t \tau_t(\mu_{g,t} + \alpha_{g,t}\eta_t) && \geq 0 \quad \forall g \in \mathcal{G} && (18)\\
0 \leq & y_{g,t} && \perp c_{g,t} + \mu_{g,t} - \pi_t && \geq 0 \quad \forall (g,t) \in \mathcal{G} \times \{1, ..., T\} && (19)\\
0 \leq & \mu_{g,t} && \perp x_g - y_{g,t} && \geq 0 \quad \forall (g,t) \in \mathcal{G} \times \{1, ..., T\} && (20)\\
\leq & \eta_t && \perp \sum_{g \in \mathcal{G}} \tau_t \alpha_{g,t} x_g - \kappa_t && \geq 0 \quad \forall t = 1, ..., T && (21)\\
0 \leq & \pi_t && \perp \sum_{g \in \mathcal{G}} y_{g,t} - d_t && \geq 0 \quad \forall t = 1, ..., T. && (22)
\end{aligned}
$$

The compensation for the alleged missing money of plant g appears in the investment incentive constraints (18) at the value $\sum_t \alpha_{g,t}\eta_t$ where η_t is the value of the capacity in t. This value reflects the outcome of a capacity market. The η_t price was part of the outcome of an integrated energy only+capacity model before restructuring. It is now the marginal value of the "adequacy service" determined by the capacity market in the restructured market. The economic interpretation of the model is that the energy and capacity markets interact; the value of the capacity service in the capacity market is indeed determined in an auction where generators anticipate the revenues accruing from the energy market and bid what they deem necessary to build the plant in the capacity market. This value will be zero if the energy only market suffices to produce a sufficient quantity of the capacity product. The $\alpha_{g,t}$ are characteristics of the plants; they are assessed ex ante and controlled ex post by the regulator or the TSO. These properties are standard in capacity auctions and are just transposed as such here. As alluded to before, a gas plant can have both a negative and positive value: the positive value expresses its contribution to the global adequacy constraint whereas the negative value formulates the desire to eventually strand that capacity for geopolitical reasons.

Before moving to the case where we will impose the dispatch to be consistent with the optimal operations of the system under current capacities, we insist on the fact that the addition of the revenue from the capacity market to the one coming from energy is the only change compared to the models of the preceding sections.

5.2 Capacity constraints, physical distortion, and dispatch support

In this section, we modify the model of Section 5.1 to impose that the spot price supports the current dispatch. The adequacy constraint does not modify the dispatch which is conducted with capacities at hand. We can thus adopt the same notions and notations as before except for the capacity market that may take a new dimension in case of "undesirable" plants as discussed next.

Consider now the case where the dispatch relies on a "undesirable" (for ecological or geopolitical reasons) technology and we want to exclude an expansion of that capacity in the future generation system. In other words the expression $\sum_t \tau_t \alpha_{g,t} \eta_t$ should now include a negative contribution to the value of the capacity. This has a repercussion on the parameterization of the dispatch discussed in Section 4.1. The perturbation of the dispatch that allows for marginal increase of available capacity with respect to $y^*_{g,t}$ should now be replaced by a marginal decrease of operation (by some ϵ that will be submitted to a same convergence to zero as the marginal increases). This implies that we need to define $y^{max}_{g,t}$ as $y^*_{g,t} - \epsilon$ for a certain subclass of equipment $\bar{G}$ (precisely, plants that we do not want to keep in the mix). Furthermore, to avoid unfeasibilities, we assume that the adequacy need is accommodated by the existing capacity: at time t, the demand for capacity is $\sum_g \tau_t y^*_{g,t} \alpha_{g,t}$, a value that we denote by κ^*_t. Except for these changes, the formulation and notation of the problem remains the same.

$$
\begin{aligned}
\text{Min} \quad & \sum_{g \in \mathcal{G}} K_g x^*_g u_g + \sum_{t=1}^{T} \sum_{g \in \mathcal{G}} \tau_t c_{g,t} v_{g,t} && && \\
\text{s.t} \quad & \sum_{g \in \mathcal{G}} v_{g,t} \geq d_t && (\pi_t \tau_t) && \forall t = 1, ..., T \\
& \sum_{g \in \mathcal{G}} \tau_t \alpha_{g,t} x^*_g u_g \geq \kappa^*_t && (\eta_t) && \forall t = 1, ..., T \\
& y^{max}_{g,t} u_g - v_{g,t} \geq 0 && (\mu_{g,t} \tau_t) && \forall (g,t) \in \mathcal{G} \times \{1, ..., T\} \\
& v_{g,t} \geq 0 && && \forall (g,t) \in \mathcal{G} \times \{1, ..., T\} \\
& u_g \leq 1 && (\gamma_g) && \forall g \in \mathcal{G}.
\end{aligned}
\tag{23}
$$

The KKT conditions are then:

$$
0 \leq u_g \quad \perp K_g x^*_g - \sum_t \tau_t \left(\alpha_{g,t} x^*_g \eta_t + \mu_{g,t} y^{max}_{g,t} \right) + \gamma_g \quad \geq 0 \quad \forall g \in \mathcal{G} \tag{24}
$$

$$
0 \leq v_{g,t} \quad \perp c_{g,t} + \mu_{g,t} - \pi_t \quad \geq 0 \quad \forall (g,t) \in \mathcal{G} \times \{1, ..., T\} \tag{25}
$$

$$
0 \leq \mu_{g,t} \quad \perp y^{max}_{g,t} u_g - v_{g,t} \quad \geq 0 \quad \forall (g,t) \in \mathcal{G} \times \{1, ..., T\} \tag{26}
$$

$$
0 \leq \gamma_g \quad \perp 1 - u_g \quad \geq 0 \quad \forall g \in \mathcal{G} \tag{27}
$$

$$
0 \leq \eta_t \quad \perp \sum_{g \in \mathcal{G}} \tau_t \alpha_{g,t} x^*_g u_g - \kappa^*_t \quad \geq 0 \quad \forall t = 1, ..., T \tag{28}
$$

$$
0 \leq \pi_t \quad \perp \sum_{g \in \mathcal{G}} v_{g,t} - d_t \quad \geq 0 \quad \forall t = 1, ..., T. \tag{29}
$$

The interpretation of these conditions is similar to that of the energy only market: in particular the appearance of dual variable γ_g in the investment criterion (24) will provide positive remuneration to the plants that we would like to keep in the system given economic conditions and the installed capacities. This remuneration is collected from both the energy market $\sum_t \tau_t \mu_{g,t} y_{g,t}^{max}$ and the capacity market $\sum_t \tau_t \alpha_{g,t} x_g^* \eta_t$. It is useful to note that there may be a non zero value to the capacity market constraint, even though the coefficients have been selected to make that constraint feasible for the current optimal dispatch. The capacity expansion model modifies the optimization and can give a non zero value to the capacity, even if it had been zero in the optimal dispatch.

5.3 Price cap and market distortion

Consider now the situation where a regulator imposes a price cap $\bar{\pi}$ in each time period t and the corresponding capacity expansion model:

$$
\begin{aligned}
\text{Min} \quad & \sum_{g \in \mathcal{G}} K_g x_g + \sum_{t=1}^{T} \sum_{g \in \mathcal{G}} \tau_t c_{g,t} y_{g,t} + \sum_{t=1}^{T} \tau_t \bar{\pi} z_t \\
\text{s.t} \quad & \sum_{g \in \mathcal{G}} y_{g,t} + z_t \geq d_t && (\pi_t \tau_t) && \forall t = 1, ..., T \\
& \sum_{g \in \mathcal{G}} \tau_t \alpha_{g,t} x_g \geq \kappa_t && (\eta_t) && \forall t = 1, ..., T \\
& x_g - y_{g,t} \geq 0 && (\mu_{g,t} \tau_t) && \forall (g,t) \in \mathcal{G} \times \{1, ..., T\} \\
& y_{g,t} \geq 0 && && \forall (g,t) \in \mathcal{G} \times \{1, ..., T\}.
\end{aligned} \tag{30}
$$

This model differs from the capacity expansion model of the preceding section by two features. One is the introduction of a possibility of curtailment z_t in each time segment in the demand constraint, which becomes $\sum_{g \in \mathcal{G}} y_{g,t} + z_t \geq d_t$. The other one is the introduction of an additional term $\sum_{t=1}^{T} \tau_t \bar{\pi} z_t$ in the objective function. The role of these modifications can be understood by noting that plant g will not operate if its operating cost in t is higher than the capped price $\bar{\pi}$. Note that the price cap is different from the revenue cap introduced by Regulation 2022/1854 ([Council of the European Union, 2022]): it is less distortive in terms of market efficiency and it simplifies the presentation by avoiding a different more complex mathematical model (see also [Fuest and Ockenfels, 2022] for a non technical discussion of these questions).[13] This implies that there will be curtailment at time t if the total capacity in operation (the total capacity of plants with operations cost lower than $\bar{\pi}$), is not sufficient to satisfy demand d_t. Price caps did not appear in this form in the crisis of 2022 when there was no curtailment in the dispatch and the high price to consumers was compensated by fiscal measures. Referring to our overarching objective of looking at long term pricing impact, we now assume that the physical dispatch should not be modified (as before), that the price signal should obey the price cap, and that the whole

[13] Available at: https://www.project-syndicate.org/onpoint/eu-windfall-profit-tax-how-to-do-it-by-clemens-fuest-and-axel-ockenfels-2022-10.

process should not jeopardise the incentive to invest, an objective that we rely on the capacity market to satisfy. The above argument on the operations of the system under price cap will then apply in the sense that plants with operating costs higher than this cap will not be considered for investment on the sole basis of the energy only market. These plants will in turn suffer from a true missing money problem which will have to be compensated by the revenue accruing from the capacity market and directed to investment in other plants. We model this market through the same adequacy constraint $\sum_{g\in\mathcal{G}} \tau_t\alpha_{g,t}x_g \geq \kappa_t$ for all times t, exactly as in the preceding section. Therefore, the model imposes a price cap in the energy market at the same time as it simulates the capacity market that will remedy any missing money induced by the cap.

The KKT conditions of the problem are:

$$
\begin{aligned}
0 \leq & x_g && \perp K_g - \sum_t \tau_t(\mu_{g,t} + \alpha_{g,t}\eta_t) && \geq 0 \quad \forall g \in \mathcal{G} && (31)\\
0 \leq & y_{g,t} && \perp c_{g,t} + \mu_{g,t} - \pi_t && \geq 0 \quad \forall (g,t) \in \mathcal{G}\times\{1,...,T\} && (32)\\
0 \leq & z_t && \perp \bar{\pi} - \pi_t && \geq 0 \quad \forall t = 1,...,T && (33)\\
0 \leq & \mu_{g,t} && \perp x_g - y_{g,t} && \geq 0 \quad \forall (g,t) \in \mathcal{G}\times\{1,...,T\} && (34)\\
\leq & \eta_t && \perp \sum_{g\in\mathcal{G}} \tau_t\alpha_{g,t}x_g - \kappa_t && \geq 0 \quad \forall t = 1,...,T && (35)\\
0 \leq & \pi_t && \perp \sum_{g\in\mathcal{G}} y_{g,t} + z_t - d_t && \geq 0 \quad \forall t = 1,...,T. && (36)
\end{aligned}
$$

As is now usual, we resort to our ϵ perturbation and build on Problem (30) to guarantee that the capacity expansion model has the same dispatch as the short term solution via :

$$
\begin{aligned}
\text{Min} \quad & \sum_{g\in\mathcal{G}} K_g x_g^* u_g + \sum_{t=1}^{T}\sum_{g\in\mathcal{G}} \tau_t c_{g,t} v_{g,t} + \sum_{t=1}^{T} + \tau_t\bar{\pi}z_t \\
\text{s.t} \quad & \sum_{g\in\mathcal{G}} v_{g,t} + z_t \geq d_t && (\pi_t\tau_t) && \forall t = 1,...,T \\
& \sum_{g\in\mathcal{G}} \tau_t\alpha_{g,t}x_g^* u_g \geq \kappa_t^* && (\eta_t) && \forall t = 1,...,T \\
& y_{g,t}^{max} u_g - v_{g,t} \geq 0 && (\mu_{g,t}\tau_t) && \forall (g,t) \in \mathcal{G}\times\{1,...,T\} \\
& v_{g,t} \geq 0 && && \forall (g,t) \in \mathcal{G}\times\{1,...,T\} \\
& u_g \leq 1 && (\gamma_g) && \forall g \in \mathcal{G}. \quad (37)
\end{aligned}
$$

With KKT conditions:

$$
\begin{aligned}
0 \leq & u_g && \perp K_g x_g^* - \sum_t \tau_t(\mu_{g,t} y_{g,t}^{max} + \eta_t \alpha_{g,t} x_g^*) + \gamma_g && \geq 0 && \forall g \in \mathcal{G} && (38) \\
0 \leq & v_{g,t} && \perp c_{g,t} + \mu_{g,t} - \pi_t && \geq 0 && \forall (g,t) \in \mathcal{G} \times \{1, ..., T\} && (39) \\
0 \leq & \pi_t && \perp \sum_{g \in \mathcal{G}} v_{g,t} + z_t - d_t && \geq 0 && \forall t = 1, ..., T && \\
0 \leq & \mu_{g,t} && \perp y_{g,t}^{max} u_g - v_{g,t} && \geq 0 && \forall (g,t) \in \mathcal{G} \times \{1, ..., T\} && (40) \\
0 \leq & \eta_t && \perp \sum \tau_t \alpha_{g,t} u_g x_g^* - \kappa_t^* && \geq 0 && \forall t \in 1, ..., T && (41) \\
0 \leq & z_t && \perp \bar{\pi} - \pi_t && \geq 0 && \forall t \in \{1, ..., T\} && (42) \\
0 \leq & \gamma_g && \perp 1 - u_g && \geq 0 && \forall g \in \mathcal{G}. && (43)
\end{aligned}
$$

The interpretation of these equations is, here again, similar to that of the energy+capacity model of Section 5.2 with the notable difference introduced in equation (42) that enforces the cap on energy prices.

5.4 Numerical results obtained for France with energy and capacity markets with price caps

We implement our methodology with the French case for years 2019, 2021, and 2022. The capacity market is modeled via the adequacy constraint by clearing the demand for capacity κ_t^*. As explained above, we assume that this demand for capacity is optimal for the dispatch, as it is directly estimated from the optimal dispatch model POD. We also note that this does not imply that it remains optimal in the capacity expansion model. All our following results are reported for two benchmarks: the first, which we name "current clearing", simply refers to historical energy and capacity prices in France. Therefore, results of this benchmark are the same for any price cap. The second benchmark, which we name "proposed clearing", computes our proposal presented in Section 5.3.

We first set the price cap at 10,000 €/MWh. Figure 6 reports on our results with this high price cap. We observe that energy prices between the current dispatch and our proposal are overall aligned, except for a very small number of scarcity hours (less than five hours), because CAPEX costs can now be recovered from the capacity market. On average, our proposal increases energy prices by 8 €/MWh in 2019, by 0 €/MWh in 2021, and by 3 €/MWh in 2022. The capacity price is, however, substantially higher in 2021 with our proposal: 80,000 €/MW vs 40,000 €/MW in reality, which reflects even further that capacity was non adapted (with overall a lack of capacity as a comparison between the installed capacity and the optimal one reveals) with energy+capacity prices being unable to reflect the (long term) investment costs necessary to adjust investments. This situation was, on the contrary less visible in 2022 as energy prices were already quite high. Reassuringly, net margins are quite low in 2019 as the system was overall quite balanced. On the contrary, they become positive for some plants (mainly nuclear and wind plants) in 2021 and remain so in 2022. Nuclear production has the maximum revenue, followed by hydro production, wind, PV, and then CCGTs. A comparison between the installed capacity and the optimal one shows that these technologies are overall the ones one would like to keep or whose capacity should be increased in the system. Most importantly, given the increase of gas prices in 2021 and 2022, our results reveal that nuclear capacity is the most desired substitute. Reassuringly, because of their high CO_2 content combined with high fuel costs, coal and fuel oil powered plants do not earn money with our proposal.

Figure 6:
Top: Price duration curves for 2019, 2021, and 2022. Bottom left: capacity prices. Bottom right: net margins of technologies with our proposal. The price cap is 10,000 €/MWh

In a sensitivity analysis, we now carry out the same calculations with a price cap reduced to 200 €/MWh. The objective here is to test the efficiency of imposing a hard price cap in the market to limit extreme excess profits under non adapted capacities that might harm consumers, such as the ones of 2021 and 2022 in Europe. To ease the exposition, we only provide a summary of our results. Table 2 displays the average market price under the current clearing procedure and under the one we propose for both price caps. Some observations stand out: in the presence of a capacity market, the current clearing procedure and the one we propose lead to comparable prices on average when the price cap is very high, as already reported. Unsurprisingly, when the price cap decreases, our proposal leads to lower market prices, with the aftermath that capacity prices have to increase because most of the investments costs need to be recovered there. This is what Table 3 reveals.

Table 2: Average energy prices (€/MWh) for two prices caps.

	2019		2021		2022	
Price cap (€/MWh)	Current clearing	Proposed clearing	Current clearing	Proposed clearing	Current clearing	Proposed clearing
10,000	40.9	49.6	105.6	105.3	289.9	293.1
200	40.9	43.4	105.6	93.5	289.9	187.9

Table 3: Capacity prices (€/MW) for two prices caps.

	2019		2021		2022	
Price cap (€/MWh)	Current clearing	Proposed clearing	Current clearing	Proposed clearing	Current clearing	Proposed clearing
10,000	17365	26173	39095	81298	23899	28775
200	17365	81172	39095	81429	23899	81429

Therefore, the combined effect of lower energy prices and higher capacity prices on profits of power plants, due to a decrease of the price cap, is not trivial. The results of our simulations of profits are reported in Table 4, where, for ease of exposition, we focus on the total profit across all power plants. With a high price cap, profits are similar to what plants have earned with the notable difference that in 2019, our proposal leads to positive profits, but very close to zero because capacities were relatively adapted then as argued before. With a lower price cap, our proposal seems to have the advantage (added to the one of respecting short term efficiency and providing a long term signal for investment at the same time) to limit excess profits when the mix is not adapted anymore. In particular, when profits were excessive in 2022 at the peak of the energy crisis, our proposal would have reduced excess profits by 45% for a price cap of 200 €/MWh combined with a capacity remuneration. Such excess profits cannot, however, be totally eliminated without additional redistribution processes, which we do not discuss in this research, because capacity remains fundamentally non adapted in the short term. Besides, such a low price cap might not be implementable currently given the values that were proposed by the Commission during the crisis, but it provides evidence that policy makers have leverage on the market design to reduce excess profits without taxation or other redistribution schemes, while keeping the fundamental principle of marginal pricing.

Table 4: Total net margins (B€/year) for two prices caps.

	2019		2021		2022	
Price cap (€/MWh)	Current clearing	Proposed clearing	Current clearing	Proposed clearing	Current clearing	Proposed clearing
10,000	-2.2	2.8	28	30.3	96.8	98.3
200	-2.2	2.5	28	24.3	96.8	53.5

6 Conclusion

The crisis of 2021-20222 was a shock to the European power sector. While the sky rocketing power prices reached during the crisis, due to gas supply disruptions, have since subsided, the events that created them, however, are still well alive today even if less virulent. Threats on the US gas exports for environmental reasons and price increases due to the tightening of hydrocarbon supplies through the red sea show that new vulnerabilities can arise on the very short term, even from our most secure sources and for very unexpected reasons. The crisis also highlighted how limited our responses can be. Emergency measures to tweak the correct behaviour of the power market quickly revealed to be just costly expedients that cannot stand out in the long term. By construction, the longer term measures proposed to enhance investments take time: whatever the promises of the medium to long term, we first have to face the immediate turmoils. The short term of the transition can indeed be devastating for some sectors (such as energy intensive industries), the most vulnerable consumers, and eventually, by feedback effects and when combined with other external factors, our whole economies. This paper concentrates on a particular point of this short term transition.

The benefits of the integration of the short term power market have been acknowledged even by those most opposed to the introduction of competition. Furthermore, it has been recognized that, despite the crisis, it is preferable to keep the current short term market alive. The long term integration is another matter but the new legislation with its mix of energy only and capacity markets allows for a combination that is both implementable (and in fact already implemented in many jurisdictions) and compliant to some extent with theoretical models. The crucial question is to drive the market out of its current dependence on unreliable sources in the least costly way, knowing that the process is likely to remain very expensive anyway.

This paper concentrates on the discrepancy that exists in the current market between the spot price and the need for a long term signal. That discrepancy has been pointed out by several authors and remains a concern whether one considers that investment is driven by an energy only market or a mix of energy only and capacity markets. A pure planning model would not be immune to that discrepancy problem as it would need to fully disconnect the short term prices from the implicit prices embedded in capacity expansion. Expressed in general terms, that discrepancy hides an arbitrage between the long and short term, and this arbitrage is always costly.

Our analysis focuses on the very short term: it aims at developing a spot price that is compatible with the efficiency currently attained in the short term market (the current Day-Ahead market) and what we know on the *future economics* of the power system. Compatibility is defined in a very standard but precise way as incentive compatibility: the long term price should not induce market agents to depart from the short term efficient operation of the system. What we mean by future economics are assumptions on costs and availability that one can build from expertise of industrials and system operators, combined with data of production of power plants. Going in that direction, we construct a model that generalizes the fundamental result developed by Boiteux in the sixties. Conceptually, this generalization is quite simple: Boiteux derives its results under the assumptions that capacities are "adapted". We take it for granted, however, that current geopolitical and environmental preoccupations imply that capacities will remain far from adapted for quite some time and that market agents, consumers, and system operators have to deal with that. Therefore, our proposal strives to accommodate unadaptability of capacities in the short term efficient dispatch. The generalization is computationally simple. It is of the same type as what is implemented today for computing spot prices. We do not, however, treat financial instruments, although these play a major role in the new legislation. The main reason is that financial instruments cannot modify what is physically possible in an optimal way, and we believe that this is where our main limitation lies. Another reason is that financial instruments require a well defined underlying and the absence of long term signal in the current spot market implies a lack of proper underlying. This work can thus also be seen as an attempt to construct a better underlying than the current spot market.

We exploit our model to explore some phenomena that made the headlines during the crisis and hence that may come back possibly in an altered form as events develop. By conducting a thorough numerical application inspired by the French power system, we show that our proposal does reconcile short term efficiency with long term investment signals. Unfortunately, this comes at a cost of higher prices that consumers should bear for some time before better, less polluting, and more economical technologies are incentivized enough (via the prices computed by our proposal) to penetrate the system to replace gas, coal, and oil fired plants which were, in part, responsible for the crisis. We highlight how this cost could be limited by properly tuning the price cap of the energy only market, when we combine it with a capacity market. Finally, we also show the limits of what can be achieved in the short term and insist on the fact that such limits are not due to poor policies, although they can be made worse by bad policies, but rather simply because of the factual situation that capacity unadaptability has lead us to in past years.

Future research can address several aspects missing from our analysis. Firstly, the benefits of some risk-sharing and mitigating instruments advocated by European policymakers, such as CfDs and PPAs, could be considered alongside our long-term price signals to encourage the needed investments. This would require additional modeling burden to account for risk and risk aversion. Secondly, demand elasticity and storage assets could easily be incorporated into our framework to analyze the extent to which our long-term price signals effectively trigger flexibility in the system. Finally, the question of how to integrate non-convexities arising from unit-commitment constraints into our models remains to be addressed.

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APPENDIX

A Missing money and capacity markets

The spot market, as implemented through a model derived from the optimal dispatch indeed contains no long term signal. This does not mean that the European market does not contain any long term signals. While the European Commission has insisted on a long term market based on the sole energy prices (which should then ideally contain a long term signal), the industry argued that the current system does not provide the proper incentive to invest and that an additional instrument is necessary to provide an additional remuneration to investment. We do not get into the discussion that supported this debate but simply note that capacity markets, whether transient or permanent, exist today in the European market. [Papavasiliou, 2021] provides a survey of these systems in Europe with a brief discussion of the US situation. The paper notes that ERCOT is today the sole US system that relies on a pure energy only mechanism. Leaving aside these capacity markets for a moment and sticking to the preference of European authorities for the pure "energy only market", the question arises of what would send the long term signal necessary for driving investment. The relation between short and long term marginal cost stated in Boiteux's model sheds some light on the issue. It states what could be expected from the market and in what conditions. In the same way as the old simple optimal dispatch model underpins the derivation of the short term signal sent by the spot market, the equally old capacity expansion model underpins the derivation of a long term signal, but with the important distinction that there is no organized market to send that signal, henceforth the well founded criticism against the incompleteness of the current market alluded to in the paper.

B Data sources

All data are extracted from French public sources. We derive fuel costs from the French energy transparency platform ODRÉ (see https://opendata.reseaux-energies.fr/). The hourly demand for electricity as well as the hourly production profiles of nuclear, hydro, and renewable plants are provided by RTE ([RTE, 2022]). We calculate annuities of investments by considering capital costs provided by the ADEME (Agence de la transition écologique, see https://www.ademe.fr/) and an interest rate of 5% for all technologies.[14] The lifetime of investment projects are provided in Table 5. The table also reports on plant efficiencies. CO_2 content factors are derived from the ADEME publications. Exports and imports, which we set exogenously, are derived from [RTE, 2022].

[14]This implicitly assumes equal risk premia for all technologies, an assumption that is arguably taken in most of RTE's economic assessments of the French power system but has recently been challenged in the case of market incompleteness for

Table 5: Additional data.

	Fuel	Coal	GT	Nuke	Wind	PV	Hydro	CCGT
Lifetime (years)	35	35	35	60	20	30	40	35
Efficiency (%)	38	38	38	33	100	100	0.75	57

C Longer term and the Transition

The analysis conducted in the paper assumes an existing technological context: capacities can be adapted but within an existing set of technologies. In this sense, the obtained long term signal is still relatively short term because new technologies are not allowed to replace existing ones and hence to change the portfolio of plants. This is the result of the constraint that long term prices should be able to support today's dispatch and hence are restricted to deal with today's technologies. One can mitigate this limitation by introducing "promising" technologies that we allow to marginally penetrate the dispatch.

C.1 Principles

Referring to our general approach, the set of promising technologies will only marginally modify the current dispatch and we can arrange for this modification to go to zero as usual. But at the same time, these technologies will affect the price signal in a way that keeps it capable of supporting the dispatch, while sending some long term information. We do so by extending the interpretation of ϵ and enable a non zero operation of new technologies that do not exist in the current system but are promising in the sense that we have plausible scenarios of the future where these technologies would penetrate our generation system. The methodology developed in the paper then applies almost unchanged here. A first step in that direction is to explore utilisation of existing capacities before ϵ reaches zero and to enable promising technologies to enter the market. If we denote by $\mathcal{E}$ the set of new technologies, this can be implemented as follows: we assume that each promising technology $e \in \mathcal{E}$ has a *virtually* installed capacity of $x_e^* \geq 0$, which we will make converge to zero. In line with what we perform for exiting plants that are called in the current dispatch, we define the maximum time-dependent production of each promising

risk.

technology by: $y^{max}_{e,t} = x^*_e + \epsilon$ and solve the following optimization problem:

$$
\begin{aligned}
\text{Min} \quad & \sum_{g\in\mathcal{G}} K_g x^*_g u_g + \sum_{e\in\mathcal{E}} K_e x^*_e u_e + \sum_{t=1}^{T}\sum_{g\in\mathcal{G}} \tau_t c_{g,t} v_{g,t} + \sum_{t=1}^{T}\sum_{e\in\mathcal{E}} \tau_t c_{e,t} v_{e,t} \\
\text{s.t} \quad & \sum_{g\in\mathcal{G}} v_{g,t} + \sum_{e\in\mathcal{E}} v_{e,t} \geq \left(d_t + \sum_{e\in\mathcal{E}} y^{max}_{e,t}\right) && (\pi_t\tau_t) && \forall t = 1,...,T \\
& y^{max}_{g,t} u_g - v_{g,t} \geq 0 && (\mu_{g,t}\tau_t) && \forall t = 1,...,T,\ \forall g \in \mathcal{G} \\
& y^{max}_{e,t} u_e - v_{e,t} \geq 0 && (\mu_{e,t}\tau_t) && \forall t = 1,...,T,\ \forall e \in \mathcal{E} \\
& u_g \leq 1 && (\gamma_g) && \forall g \in \mathcal{G} \\
& u_e \leq 1 && (\gamma_e) && \forall e \in \mathcal{E} \\
& v_{g,t} \geq 0 && && \forall t = 1,...,T,\ \forall g \in \mathcal{G} \\
& v_{e,t} \geq 0 && && \forall t = 1,...,T,\ \forall e \in \mathcal{E}.
\end{aligned} \tag{44}
$$

To ensure that existing plants g will meet exactly the same demand d_t at each period, we now also perturb the demand that has to be cleared in our proposal by adding to it the virtual production of the promising plants $e \in \mathcal{E}$: $\sum_{e\in\mathcal{E}} y^{max}_{e,t}$. The obtained problem has the following first order conditions:

$$
\begin{aligned}
0 \leq & u_g && \perp K_g x^*_g - \sum_t \tau_t \mu_{g,t} y^{max}_{g,t} + \gamma_g && \geq 0 \quad \forall g \in \mathcal{G} \\
0 \leq & u_e && \perp K_e x^*_e - \sum_t \tau_t \mu_{e,t} y^{max}_{e,t} + \gamma_e && \geq 0 \quad \forall e \in \mathcal{E} \\
0 \leq & v_{g,t} && \perp c_{g,t} + \mu_{g,t} - \pi_t && \geq 0 \quad \forall (g,t) \in \mathcal{G} \times \{1,...,T\} \\
0 \leq & v_{e,t} && \perp c_{e,t} + \mu_{e,t} - \pi_t && \geq 0 \quad \forall (e,t) \in \mathcal{E} \times \{1,...,T\} \\
0 \leq & \mu_{g,t} && \perp y^{max}_{g,t} u_g - v_{g,t} && \geq 0 \quad \forall (g,t) \in \mathcal{G} \times \{1,...,T\} \\
0 \leq & \mu_{e,t} && \perp y^{max}_{e,t} u_e - v_{e,t} && \geq 0 \quad \forall (e,t) \in \mathcal{E} \times \{1,...,T\} \\
0 \leq & \pi_t && \perp \sum_{g\in\mathcal{G}} v_{g,t} + \sum_{e\in\mathcal{E}} v_{e,t} - d_t + \sum_{e\in\mathcal{E}} y^{max}_{e,t} && \geq 0 \quad \forall t \in \{1,...,T\} \\
0 \leq & \gamma_g && \perp 1 - u_g && \geq 0 \quad \forall g \in \mathcal{G} \\
0 \leq & \gamma_e && \perp 1 - u_e && \geq 0 \quad \forall e \in \mathcal{E}.
\end{aligned}
$$

It should be clear that, baring degeneracy, the addition of a new technology to an *adapted* system will have no impact on the price solution determined by the POD or MCEM models. The same spot price, equal to the long run marginal cost is obtained. The dispatch is only perturbed by the ϵ in the capacity constraint of the $\mathcal{E}$ plants and hence these perturbations go to zero when ϵ converges to zero. This is no longer true when the system is not adapted. One can then observe that the reasoning conducted in the paper applies as such to this expanded model. Specifically, the sum of the $v_{g,t}$ and $v_{e,t}$ from plants in $\mathcal{G}$ and $\mathcal{E}$ must now be no lower than d_t which will again imply the equality of the $\sum_{g\in\mathcal{G}} v_{g,t} + \sum_{e\in\mathcal{E}} v_{e,t}$ to d_t when ϵ goes to zero.

C.2 A numerical illustration obtained for France with Carbon Capture and Storage

We now illustrate the dynamics of our proposal with gas plants using Carbon Capture and Storage, or CCS (see for instance [Osman et al., 2021] and [Raza et al., 2019] for a review). Many studies have already highlighted the potential of CCS technologies in the decarbonization process of the power system (see [Lau et al., 2021] for instance). In that regard, gas fired plants associated with CCS are of interest but they are not yet viable options from an economical and technological perspectives. Prospects are, however, more optimistic as their investment cost is expected to drop by 38% by 2050 ([Statista, 2023]). We consider then the same framework and data of Section 4.5 to which we add combined cycle gas turbines with CCS as a promising technology. We denote the latter by CCGT_{CCS} and define set $\mathcal{E}$ accordingly. CAPEX and OPEX costs are derived from [Statista, 2023] and we consider those that are forecasted for 2050 to ensure their economic viability in the current power mix.

For ease of exposition, we focus only on year 2022 when the energy crisis was at its climax and report only on aggregated results, the objective being mainly to showcase the proposal. First, we verify that the new technology is indeed promising inasmuch as the optimal capacity planning Problem (44) does invest some capacity in it for a small $\epsilon > 0$. Second, we report on the obtained prices in Table 6 when $\epsilon \longrightarrow 0$. The average price increases slightly with the introduction of the promising technology to ensure that it also recovers its investment cost, which is higher than that of standard CCGT (and other gas fired) plants because of the CO_2 capture and storage components. In other words, this new clearing will naturally make the promising technology attractive for investors. Table 7 shows the net margins accrued by the different power plants. Oil, gas, and coal turbines are still those technologies that one want to get rid of in the power mix and the introduction of CCS in the clearing will increase profits of nuclear plants and renewables, while keeping standard CCGTs (without CCS) equally profitable.

Table 6: Average energy prices in 2022 (€/MWh).

Current clearing	Proposed clearing	Proposed clearing with CCGT_{CCS}
289.9	296.6	306.9

The increase of the total price is the striking feature of these findings. One would expect that

Table 7: Net margins in 2022 (B€/year).

	Proposed clearing	Proposed clearing with $CCGT_{CCS}$
Oil	0	0
Coal	0.5	0.5
GT	0	0
Nuke	67.4	69.7
Wind	8.1	8.4
PV	4.8	5.6
Hydro	14.7	15.3
CCGT	3.3	3.3

the perspective of the introduction of a cheaper technology would lower the long term signal. This is not what happens and the question is to understand why. The response is that one is looking for a long term signal while insisting on keeping the spot market as it is. Because the current system is highly unbalanced, with the unbalanced caused by the technology that sets the price (the gas turbines), the insertion of a new cheaper technology in the long term market at zero capacity only increases the unbalance. Actually, what we measure here is that this technology would potentially make a high excess margin, increasing thereby its economic incentive to penetrate the power mix. Investments in the promising technology are likely to follow and this would, in turn, force fossil fuels out of the merit order in future years, ultimately leading to lower spot prices.