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ELECTRICITY MARKET-CLEARING PRICES AND INVESTMENT INCENTIVES: THE ROLE OF PRICING RULES

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Abstract

Pricing rules in wholesale electricity markets are usually classified around two major groups, namely linear (aka non-discriminatory) and non-linear (aka discriminatory). As well known, the major difference lies on the way non-convex costs are considered in the computation of market prices.

According to the classical marginal pricing theories, the resulting market prices are supposed to serve as the key signals around which capacity expansion revolve. Thus, the implementation of one or the other pricing rule can have a different effect on the investment incentives perceived by generation technologies, affecting the long-term efficiency of the whole market scheme.

The objective of this paper is to assess to what extent long-term investments incentives can be affected by the pricing rule implemented. To do so, we propose a long-term capacity expansion model where investment decisions are taken based on the market remuneration. We use the model to determine the optimal mix in a real-size thermal system with high penetration of renewable energy sources (since its intermittency enhances the relevance of non-convex costs), when alternatively considering the aforementioned pricing schemes.

1 INTRODUCTION

Wholesale electricity markets restructuring has been constant since the original liberalization processes of electric power sectors started back in early eighties in Chile. Yet, the unavoidable complexities of electricity generation have led to many different market designs and many associated regulatory questions (many of which remain open). In general, each design includes various markets to represent different timescales in which energy and ancillary services are traded (Batlle, 2013). This sequence of markets could be classified into long-term markets, day-ahead markets (DAM) and intraday plus balancing markets (in the EU) or real-time markets (in the US).

The core of wholesale markets is commonly the DAM, whose purpose is to match generators' offers and consumers' bids to determine electricity prices for each time interval of the following day. However, this can be achieved in a number of different ways and, as mentioned, DAMs evolved very differently in each system. An essential difference lies in the way generators can submit their offers. As explained in detail in Batlle (2013), in the majority of European Power Exchanges, market clearing is built upon simple bids (i.e. generators submit quantity-price pairs per time interval). Although some additional semi-complex conditions can be added to the bids (as for instance block bids linking bids in consecutive time intervals), this approach does not reflect either the real generation cost structure (e.g. the start-up costs) or many of the plants operation constraints (e.g. the start-up trajectory). These features can be explicitly declared in the markets run by US ISOs, where generation agents submit offers representing the parameters and costs that define their generating units' characteristics.

In principle, auctions based on simple bids have the advantage of applying a more straightforward and transparent clearing process to compute prices, but this is obtained at the expense of the efficiency of the economic dispatch[1]. In contrast, complex auctions resort to a traditional centralised unit commitment

[1] However, while it is true that the schedule resulting from the clearing of the simple bids in the DAM is often not close to the one that in principle would result from solving a unit commitment problem with perfect information, intraday markets provide market agents with an opportunity to partly correct these potential inefficiencies.

(UC) algorithm (security constrained economic dispatch optimization), with the only difference from the traditional UC problem solved in the non-liberalized context being that the data considered are market agents' bids instead of costs. The downside of complex auctions is that finding a way to compute short-term prices has no obvious solution.

In a complex auction, a uniform[2] price computed as the marginal cost of the economic dispatch solution cannot guarantee total production cost recovery for all generation agents. The marginal cost reflects the variable costs components of the offers but not the non-convex costs (start-up, no-load cost). This led to different approaches to calculate market-clearing prices that can sufficiently compensate generators for their non-convex costs; these approaches can be classified into two large groups: non-linear and linear pricing rules.

Non-linear pricing rules (also known as discriminatory) obtain a uniform marginal price (marginal cost) from the unit commitment model and, on top of it, additional side-payments are provided on a differentiated per generation unit basis. Side-payments account for the non-convex costs that the generation units could not recover solely through uniform prices[3].

On the other hand, linear pricing rules (or non-discriminatory) produce a uniform price that includes in it the effect of non-convex costs such. In the short term, the most important reason given in favour of linear pricing rules are based on efficiency implications. In particular, linear prices should bring generators' short-term offers closer to their real costs. See for example Hogan and Ring (2003) for further details.

Both of these two pricing approaches support the optimal short-term operation of DAMs but prices also have to serve as the key signal for new investments. Prices do not only compensate for operations costs, in the long run, prices resulting from a well-designed and well-functioning market should allow generators to recover the investment costs. For all inframarginal units, the difference between market prices and their operation costs should be considered a payment to finance their capital costs. Given that the uniform price perceived by all units differs from one pricing rule to the other, so does the remuneration aimed at compensating investment costs and therefore, different investment decisions should in principle be expected under each pricing rule. This long-term consideration should help to discern which of the pricing approaches is more appropriate (Vázquez, 2003). Nonetheless, it has been profusely pointed out by some of the most reputed academic experts in the field that the full long-run incentive effects of these pricing rules are not well understood (Hogan and Ring, 2003), (Ring, 1995).

This paper further analyses the long-term impact of different pricing rules in an energy mix if investment is driven by short-term market prices. In particular, we follow the evidence presented by Vázquez (2003) who compared various pricing rules and stated the following: "Although, when exclusively studying operation decisions, it seems that only variable costs need to be considered (in the price formation); when the impact of the price on investment decisions is considered it is observed that it also has to partially include non-convex operation costs. When including in the price the corresponding part of start-up and no-load cost of the marginal unit, a larger remuneration is given to inframarginal units. These inframarginal units will find a greater long-term incentive to invest, and as a consequence will partially substitute the marginal technology."

Moreover, intermittent renewable energy sources (RES-E) which are expected to reach larger penetration levels in the next decades, can make this discussion more relevant. We build on the foundations of Veiga et al. (2013), who already exposed how RES-E penetration increases conventional thermal plants cycling -augmenting the share of non-convex costs (mainly start-up costs) in total operation costs- and therefore increases the differences in remuneration perceived under each of the pricing rules, especially for the case of base-load plants. This article, in the light of the increasing share of RES-E in generation

[2] "Uniform" indicates that all generating agents are compensated using the same price regardless of their offer.

[3] Note that side-payments resemble a "pay-as-bid" system for non-convex costs, bringing along all its inefficiency issues (Baldick et al., 2005).

mixes, considers a system with a large deployment of intermittent generation and analyses the impact of pricing rules on investments through the application of a very detailed capacity expansion optimization model.

The paper is organized as follows. The general methodology is described in Section 2. A brief revision of necessary background and a mathematical formulation are included in Section 3 in order to complement the description of the method and to detail some calculations. Section 4 presents the results obtained, which are discussed in Section 5, and Section 6 summarizes the outcomes of this research.

2 MATERIAL AND METHODS

The approach developed in this paper aims at calculating the perfectly adapted generation mix to be installed in a market context under different pricing rules. We base our analysis on a very detailed long-term greenfield capacity expansion optimization of a real-size case example. Three different thermal generation technologies (Nuclear, CCGT and OCGT) and their detailed costs and operation constraints are considered in the simulation (overnight costs, fuel variable costs, start-up costs, minimum stable load, ramps, etc.). These three technologies are chosen to represent base-load, mid-load, and peak-load plants. The mix is optimized to supply the chronological hourly demand of Spain for 2012 (assumed to be perfectly inelastic). This mix includes a fixed level of RES-E penetration assuming its remuneration is not provided by the DAM but through some additional payment mechanism. The effect of renewable energy sources is represented by means of a high penetration of solar photovoltaic (PV). The exogenous PV production profile has been scaled from the 2012 hourly production profile in Spain and in the short-term simulation the PV power output can be curtailed when needed for optimized operation.

Figure 1 aims at illustrating the different stages of the implemented methodology, while the following sections detail the operation of each element of the model.

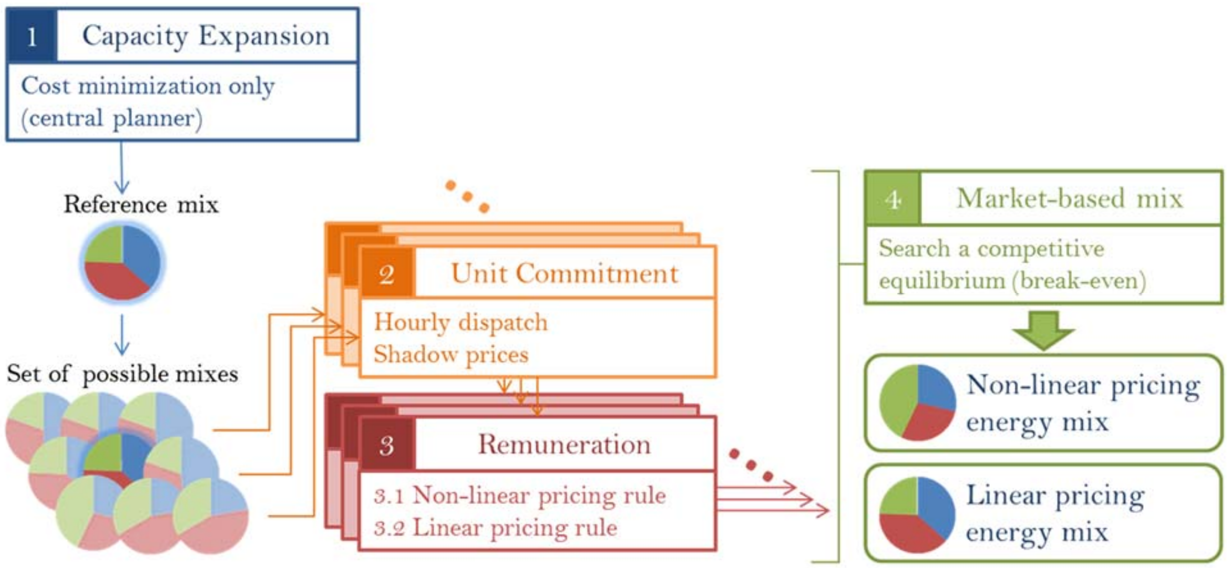

Figure 1. Methodology summary diagram.

2.1 Module 1: Reference generation mix

Module 1 calculates the least-cost energy mix using a traditional capacity expansion model as in a centralized planning case[4]. This energy mix is used only as initial reference for the subsequent search of the perfectly adapted mix corresponding to each of the pricing rules. Since in principle market prices are

[4] The model used in this step includes a detailed representation of both expansion and operation. The formulation is similar to that of presented later in Section 3.1, but the number of units available of each technology is in this case variables to be determined by the problem itself. To do so, obviously associated investment costs are included in the objective function.

believed to drive investment towards the least cost generation mix, we assume that the market-based mixes to be obtained later will not deviate substantially from this reference, although as it is right next described, we explore up to around 4000 different alternatives.

We build a set of possible mixes by considering all combinations of the three thermal generation technologies which amount to n^3 possibilities (where n is the maximum number of units considered for each technology). In a real size example this produces a number of possibilities in the order of 10^6. We reduce the search by excluding those mixes that significantly deviate from the initial reference to handle some thousand combinations only. This way, the computation time[5] in following modules is minimized while maintaining an extensive set of possible solutions, so that an optimum can be found.

Each possible solution is evaluated separately in modules 2 and 3. Module 4 will find an optimum once the whole set of possible solutions is fully characterized.

2.2 Module 2: Short-term Unit Commitment

Module 2 takes as an input a given energy mix and simulates the day-ahead market outcome for a full year. The output of this module includes the detailed economic dispatch and the hourly marginal costs.

We consider a single node system, so no locational marginal prices (LMP) are produced. This way prices will have the same impact on each investment decision regardless of the location of power plants. In turn, price influence on investment behaviour will be easier to analyse. We assume perfect competition, so generators are supposed to declare their true marginal and non-convex costs. The UC formulation is detailed in section 3.1.

2.3 Module 3: Price and remuneration calculation

Module 3, from the dispatch and marginal costs given by module 2, calculates the remuneration of each of the generation units committed, computing first the corresponding hourly prices and as a result the side-payments needed for the units to recover their full short-term operation costs under two different pricing rules.

The computation of prices and side-payments is detailed in Section 3.1 and 3.2. No reserves or other ancillary services are considered in this simulation since our interest is on differences produced exclusively by the aforementioned pricing rules on the day ahead energy-only market[6].

2.4 Module 4: Market-based mix search

Module 4 compares all the previously evaluated generation mixes to obtain, for each of the pricing rules, the best adapted mix. This direct search approach is similar to that of Shortt et al. (2013), who, to calculate a least cost portfolio, evaluated all possibilities separately and then chose the optimal solution by direct search. In our case the desired energy mix for each pricing rule is not the one minimizing total costs, instead, we consider as optimal the mix that a competitive market would choose to invest on. The corresponding market-based optimality conditions are based on the condition that all agents are break-even. In other words, an agent would choose to invest if and only if short-term market remuneration fully ensures the recovery of both investment and operation costs. On the other hand, a perfect competitive market will ensure that the short-term remuneration exactly recovers the previous costs[7]. The details are provided in Section 3.3.

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[5] It took 2h and 37 min to analyze the real-size case example presented in this paper. The model was run using CPLEX on GAMS on an Intel Core i7@ 2.8 GHz, 3.5 GB RAM.

[6] This is also the scope of some well-known references on the topic like Hogan et al (2003) and Baldick et al (2005).

[7] If the market remuneration was above these costs, competitors would enter de market and depress prices down to the break-even point.

3 THEORY/CALCULATION

3.1 Unit Commitment formulation

An accurate short-term simulation is necessary to obtain precise results in the long term. Our first attempt was to use a complete UC as the one presented in Morales-España et al. (2013) to simulate the short-term operation of the day-ahead market for a whole year. This approach made the problem computationally intractable so our next step was to reduce the number of variables by considering only a few representative weeks instead of a year. This approach could have been successful for other purposes but it was not appropriate for ours. This is because important discontinuities that affect the long-term problem are introduced when this simplification is applied.

For example, the amount of time intervals with scarcity of capacity is a key issue to determine the long-term adequacy of an energy mix. When generation capacity is insufficient the market price is set at the so-called non-served energy (NSE) price. If properly determined (i.e. if turns to be a good proxy of demand's utility), this price is the required remuneration to promote the properly adapted investment in capacity, and it is crucial to allow for the investment cost recovery of all units in general and peak-load units in particular. If only a few weeks are considered in the problem a discontinuity is introduced in the number of time intervals in which the price is at the NSE level. For example, if four weeks were considered and the result was then scaled to a year, the number of intervals with NSE price in a week would be multiplied by thirteen. This discontinuity produces big differences in the remuneration of all units when small changes are made in the mix yielding unrealistic results. Therefore, a full year representation is needed.

To accurately represent the short-term dynamics of power plants and still being able to run this simulation for a whole year with a computationally tractable problem we based our model on the clustered UC formulation proposed for example in Gollmer et al. (2000) and later applied by Palmintier and Webster (2011). This means technically identical units are grouped representing commitment decision with integer variables instead of binary variables. Clustering units speeds computation and still allows for a very accurate representation of the UC.

3.1.1 Nomenclature

Indexes and sets

$g \in G$	Generating technologies
$t \in T$	Hourly periods
$g \in G^{MR}$	Must-run generating technologies

Parameters

C_g^{LV}	Linear variable cost of a unit of technology g [$/MWh]
C_g^{NL}	No-load cost of a unit of technology g [$/h]
C^{NSE}	Non-served energy price [$/MWh]
C_g^{SD}	Shut-down cost of technology g [$]
C_g^{SU}	Start-up cost of a unit of technology g [$]
D_t	Load demand in hour t [MWh]
PV_t	Solar photovoltaic available production in hour t [MWh]
$\overline{P}_g$	Maximum power output of a unit of technology g [MW]
$\underline{P}_g$	Minimum power output of a unit of technology g [MW]

RD_g	Ramp-down rate of unit g [MW/h]
RU_g	Ramp-up rate of unit g [MW/h]
N_g	Number of units installed of technology g

Variables

nse_t	Non-served energy in hour t [MWh]
$p_{g,t}$	Power output at hour t of all technology g units above the minimum output $\underline{P}_g$ [MW]
pv_t^{spill}	Solar photovoltaic energy spill in hour t [MWh]
$u_{g,t}$	Number of units of technology g committed at hour t
$v_{g,t}$	Number of units of technology g starting-up at hour t
$w_{g,t}$	Number of units of technology g shuting-down at hour t

3.1.2 Formulation

$$\min \sum_{t\in T}\left[\sum_{g\in G}\left[C_g^{NL}u_{g,t}+C_g^{LV}\left(\underline{P}_g u_{g,t}+p_{g,t}\right)+C_g^{SU}v_{g,t}+C_g^{SD}w_{g,t}\right]+C^{NSE}nse_t\right] \quad (1)$$

$$s.t. \quad \sum_{g\in G}\left[\underline{P}_g u_{g,t}+p_{g,t}\right]+PV_t-pv_t^{spill}=D_t-nse_t \qquad \perp \rho_t \qquad \forall t \quad (2)$$

$$u_{g,t}-u_{g,t-1}=v_{g,t}-w_{g,t} \qquad \forall g\notin G^{MR},t \quad (3)$$

$$p_{g,t}\le\left(\overline{P}_g-\underline{P}_g\right)u_{g,t} \qquad \forall g\notin G^{MR},t \quad (4)$$

$$p_{g,t+1}-p_{g,t}\le RU_g \qquad \forall g\notin G^{MR},t \quad (5)$$

$$p_{g,t-1}-p_{g,t}\ge RD_g \qquad \forall g\notin G^{MR},t \quad (6)$$

$$0\le u_{g,t},v_{g,t},w_{g,t}\le N_g, \quad u_{g,t},v_{g,t},w_{g,t}\in\mathbb{Z} \qquad \forall g\notin G^{MR},t \quad (7)$$

$$u_{g,t}=N_g, \quad v_{g,t},w_{g,t}=0 \qquad \forall g\in G^{MR},t \quad (8)$$

$$p_{g,t}=N_g\left(\overline{P}_g-\underline{P}_g\right) \qquad \forall g\in G^{MR},t \quad (9)$$

$$pv_t^{spill}\le PV_t \qquad \forall t \quad (10)$$

$$p_{g,t},nse_t,pv_t^{spill}\ge 0, \quad p_{g,t},nse_t,pv_t^{spill}\in\mathbb{R} \qquad \forall g,t \quad (11)$$

Equation (1) shows the objective function to be minimized which is a sum of all operation costs (no-load cost, linear-variable cost, start-up cost and shut-down cost) and the value of the non-served energy. Restriction (2) equals production (allowing solar PV production to be reduced by a certain amount if needed) with demand minus non-served energy. As well-known, its dual variable ρ_t represents the marginal cost of the system for each time interval. As shown in equation (7), binary variables are here integer with the upper bound being the number of units installed. In this model we consider a must-run restriction for nuclear power plants so the constraint (9) fixes the power output to its maximum. For an extensive description of a UC model see Morales-España et al. (2013).

3.2 Non-linear (discriminatory) pricing rules

Non-linear pricing rules are the most extended alternative in markets with complex auctions. This is the case of most US markets such as NYISO (2013), MISO (2013a) or ISO-NE (2014).

The general approach consist, as described in the introduction, in obtaining a uniform marginal price from the unit commitment model (marginal cost) and giving additional side-payments on a differentiated per unit basis. Side-payments are sometimes referred to as make-whole payments or uplifts. In practice, a side-payment is calculated as the difference between the incurred costs of a unit (according to its offer) and its uniform-price-based market remuneration[8]. The difference generally considers the complete day costs and incomes (i.e. side-payments are calculated on a daily basis, not hourly) and only exists if the difference is positive (if costs happen to be higher than market remuneration). This paper follows this simple approach to compute non-linear prices[9] and side-payments according to:

$$\text{UniformPrice}_t = \rho_t \tag{12}$$

$$SP_{j,day} = \max\Big(\sum_{t\in day}\big[\underbrace{C_j^{NL}u_{j,t} + C_j^{LV}(\underline{P}_j u_{j,t} + p_{j,t}) + C_j^{SU}v_{j,t} + C_j^{SD}w_{j,t}}_{\text{Operation Costs}} - \underbrace{\rho_t(\underline{P}_j u_{j,t} + p_{j,t})}_{\text{Market Remuneration}}\big], 0\Big) \tag{13}$$

Where j denotes generating units and the production of each unit has been derived from the clustered production obtained in the UC model. Note this side-payment is only paid if positive and represents the payment needed when the uniform price ρ_t does not suffice to compensate for all the costs incurred in a day. Therefore, the income of each generating unit per day is:

$$\sum_{t\in day}\rho_t\left(\underline{P}_j u_{j,t} + p_{j,t}\right) + SP_{j,day} \tag{14}$$

3.3 Linear (non-discriminatory) pricing rules

Linear pricing rules rely on a uniform price to account for variable and fixed (non-convex) costs at the same time. This can be achieved in a number of ways: different authors propose alternative pricing mechanisms to reflect non-convexities in the marginal price perceived by all units (see for example Vázquez (2003), Hogan and Ring (2003), Gribik et al. (2007) which minimize side-payments or Ruiz et al. (2012) which completely eliminates side-payments). These methods seek to minimize side-payments and find a price that truly captures the value of energy (this is the reason why they are called non-discriminatory, although in most cases some sort of side-payments are still needed)[10].

Since side-payments would still be necessary in most cases (although minimal), this approach, strictly speaking, should still be considered discriminatory. On this paper though, we will refer to these pricing rules as linear representing the fact that non-convexities are considered in price formation and distinguishing it from the non-linear rule previously introduced.

All of the mentioned alternatives are similar in nature although very different in its implementation. Probably the most promising alternative is the convex-hull pricing (Gribik et al., 2007) which is the foundation of the recently accepted MISO proposal of extended locational marginal pricing (ELMP).[11]

[8] Again, here we have restricted the scope of the paper to the energy only day ahead market. When adding in the analysis more products or subsequent markets, the side-payments may include other concepts such as the opportunity cost derived from providing reserves.

[9] Some more refined methods to calculate side-payments are worth mentioning -see for example O'Neill et al. (2005)- although not representative of current market practices.

[10] A real case example is the pricing rule implemented in Ireland (SEMO, 2013) where an ex-post optimization model increases marginal prices in the least costly way until all units recover their declared costs. In this case no side-payments are needed and all units perceive the same price.

[11] See MISO (2013b) and FERC (2012).

The method proposed by MISO does not follow completely the convex-hull methodology (or full-ELMP) in favour of a computationally simpler formulation. This simplified method is based on virtually allowing fractional commitment of some units, even though fractional commitment is not physically feasible, and allocating the corresponding share of non-convex costs on the market price.

We chose to use a similar approach, generally referred to as "Dispatchable Model". It consists in a modification of the unit commitment model used for dispatch in which binary restrictions are relaxed. This way some units are partially committed and now, marginal costs depend on non-convex costs since an additional unit of energy would require an increase in the continuous commitment variable. Only equation (7) needs to be changed to:

$$0 \le u_{g,t}, v_{g,t}, w_{g,t} \le N_g, \quad u_{g,t}, v_{g,t}, w_{g,t} \in \mathbb{R} \qquad \forall g \notin G^{MR}, t \tag{15}$$

The relaxed model is used only to compute prices. We will now call ρ_t^{relax} to the new hourly price which is the marginal cost of the relaxed UC solution. The feasible economic dispatch is still obtained from the unmodified unit commitment. We apply the same procedure to calculate side-payments:

$$\text{UniformPrice}_t = \rho_t^{relax} \tag{16}$$

$$SP_{j,day} = \max\Big(\sum_{t \in day} \big[C_j^{NL} u_{j,t} + C_j^{LV} (\underline{P}_j u_{j,t} + p_{j,t}) + C_j^{SU} v_{j,t} + C_j^{SD} w_{j,t} - \rho_t^{relax} (\underline{P}_j u_{j,t} + p_{j,t})\big], 0\Big) \tag{17}$$

Finally, the income of each generating unit per day in the linear pricing context is:

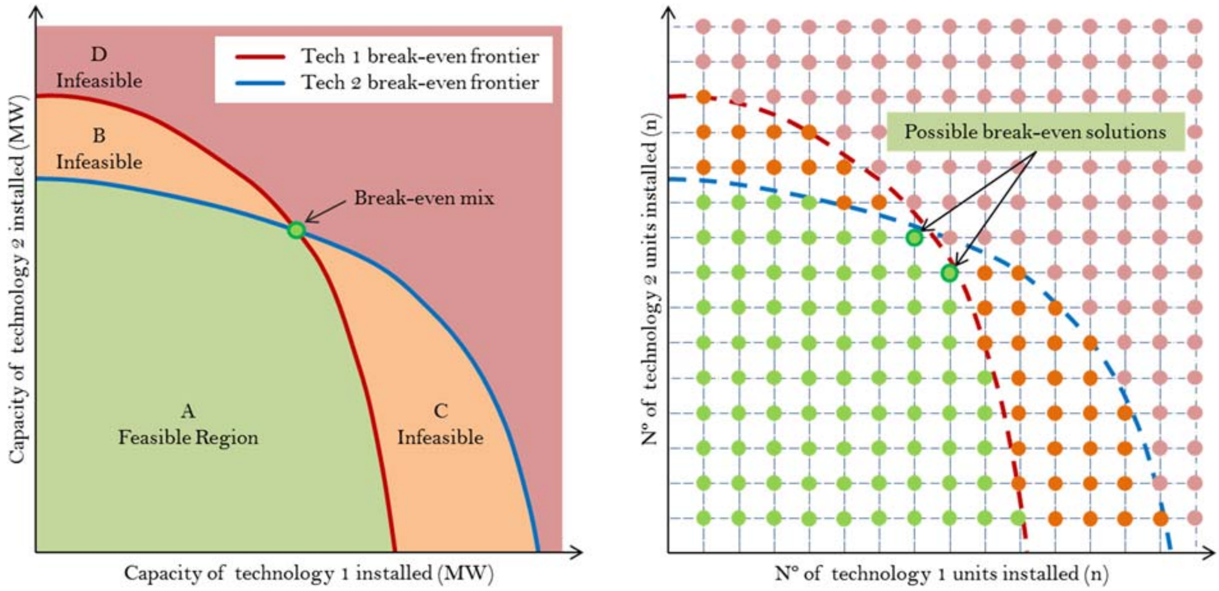
$$\sum_{t \in day} \rho_t^{relax} \left(\underline{P}_j u_{j,t} + p_{j,t} \right) + SP_{j,day} \tag{18}$$

Note that the dispatch remains the same as in the non-linear case; the linear pricing rule only affects the remuneration by producing a higher uniform price through the dual variable of the relaxed problem which reduces the side-payments requirements.

3.4 Market-based mix search

To illustrate our methodology to find the perfectly adapted mix, first consider the following simple case with only two generation technologies. In order to determine how much capacity of each of the technologies will be installed, all possible combinations of technology one (T1) and technology two (T2) are represented in the plane shown in Figure 2 (a).

If we focus on T1 only, the area of all possible combinations can be divided into a region of mixes that would make all units of T1 recover their capital cost (profitable) and a region where not all units of T1 recover their capital costs (not profitable). In the figure, region A + B represents the profitable area for T1. For a fixed level of T2, the boundary of the profitable area (break-even frontier) gives the capacity of T1 that would be installed since new investments would be made as long as these are profitable. No additional capacity would be installed beyond the boundary since these would not recover their investment costs or would make other units of T1 unprofitable bringing the total capacity installed back to the frontier.



(a) Continuous investment break-even mix (b) Discrete investment break-even mix

Figure 2. Break-even solutions.

The same reasoning applies to determine T2 capacity, which adapting to changes on T1 capacity and vice versa can only find equilibrium on the intersection of both break-even frontiers. Thus, the perfectly adapted mix can be obtained from the remuneration information calculated for each possible mix by modules 2 and 3 in our model. Note that these break-even frontiers will change under each of the pricing rules.

Figure 2 (b) represents this methodology applied to a discrete investment problem, which is our case. Break-even frontiers can be interpolated from the point cloud and the continuous break-even mix obtained as the intersection. However, we are considering the more realistic discrete investments which present a lumpiness problem. As illustrated in the figure, no point will probably coincide with the continuous break-even mix and various discrete energy mixes may seem valid under the break-even criteria. To discern which of these nearly optimal points is preferred, the value of the net social benefit (NSB) resulting under each of the mixes is compared and the NSB-maximizing mix is selected.

In our analysis, three technologies are considered (nuclear, combined cycle gas turbines and open cycle gas turbines), extending this illustrative example with a third dimension. Therefore, break-even frontiers become surfaces and these three surfaces (one for each technology) intersect at one point. An extension to *n* dimensions would be mathematically analogous although not easy to represent graphically.

4 RESULTS

Three different energy mixes are calculated and compared. First, the least-cost (reference) energy mix from a centralized perspective is obtained as described by module 1. Around this reference mix a set of possible mixes containing 3706 potential solutions is built. All these possibilities are characterized by modules 2 and 3. Module 4, considering market-based investment decisions, selects the two mixes that best adapt to a non-linear and a linear pricing rule. These results are obtained in a context of a rather significant solar PV penetration (19.2 GW-peak) in a power system supplying the chronological hourly demand for Spain 2012 (40.4 GW-peak). The data used to represent each power plant type is summarised in Table i.

Table i: Generating technologies characteristics[12]

	Max Output MW	Min Output MW	Max Up Ramp MW/min	Max Down Ramp MW/min	Capital Cost K$/MW-year	C^{LV} $/MWh	C^{NL} $/h	C^{SD} $	C^{SU} K$
OCGT	150	60	12	12	78.58	104	1650	-	14.75
CCGT	400	160	10	10	142.8	57	2440	-	28.33
NUCLEAR	1000	500	-	-	590.0	8.5	1500	-	-

$C^{NSE} = 5000$ $/MWh

Figure 3 shows first the minimum cost reference mix followed by the mixes resulting from applying the two different pricing rules considered. Both the mix produced by the linear pricing rule and the mix produced by the non-linear pricing rule deviate from the reference mix. In fact, none of the pricing rules supports the reference energy mix (i.e. they do not provide sufficient remuneration to make all units in the reference mix profitable), which would be a desirable characteristic of a pricing rule. Both pricing rules require a deviation from the reference mix including a slight decrease in total capacity. This deviation though, is significantly smaller when the linear pricing rule is applied.

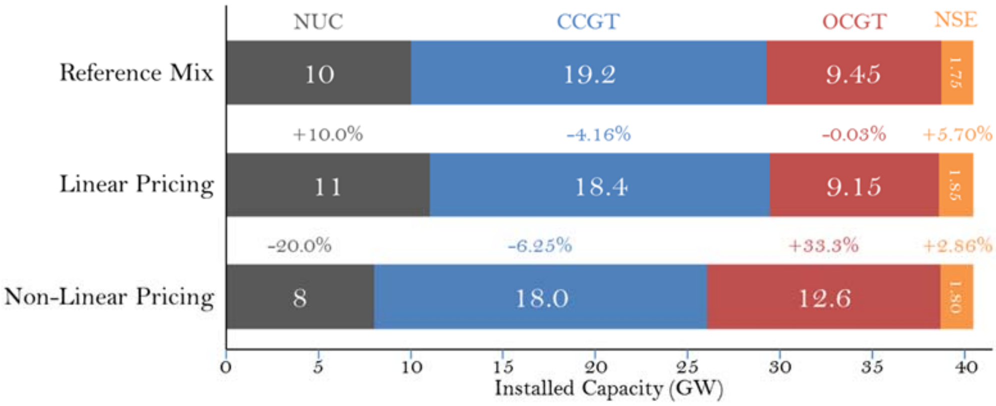
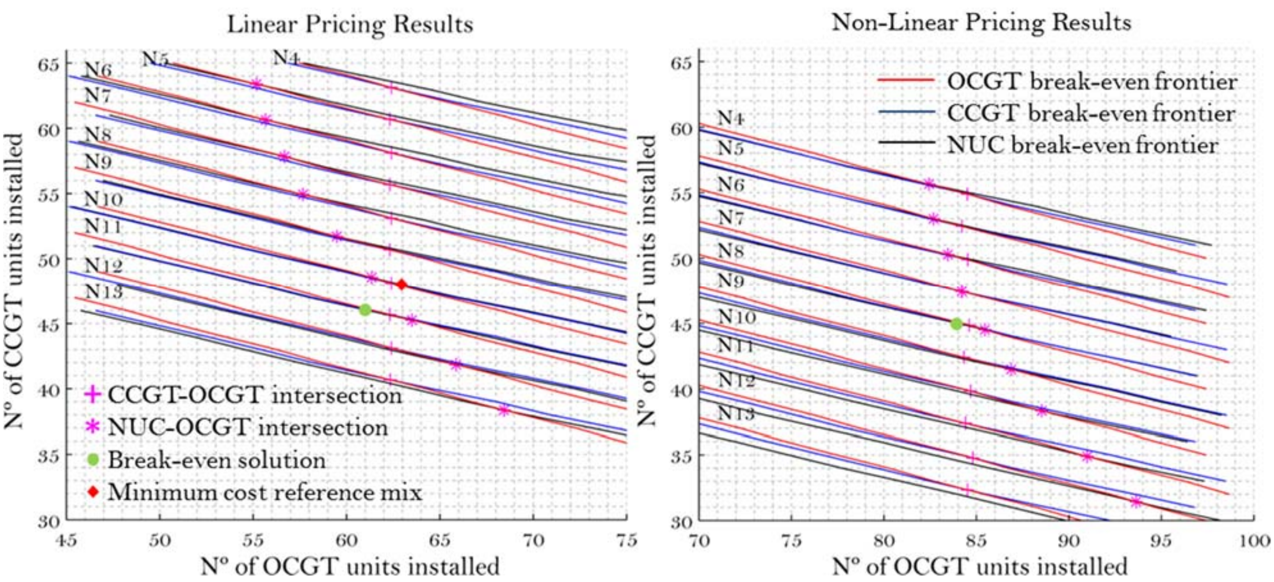


Figure 3. Generation mix results.

The major difference is the shift in capacity of nuclear and OCGT (base-load and peak-load) which in the non-linear pricing context substantially deviates from the reference. Some small differences between these three mixes are a result of lumpiness since only discrete investments are considered. Bigger differences are more representative of the pricing rule influence.

To gain more insight, the representation presented in Figure 2 has been extended to include three technologies and the results of this simulation are shown in Figure 4. Doing this requires an extension to 3 dimensions but for the sake of clarity this figure shows 2-dimensional break-even frontiers obtained for all combinations of CCGT and OCGT units and only discrete combinations of nuclear power plants. These frontiers can be thought of as the contour lines of the three surfaces that should intersect only at the break-even solution point. This way, a point where all three contour lines intersect will indicate the desired solution but this point may not be represented in the figure since the optimal continuous solution could require a non-discrete level of nuclear capacity.

[12] These data is based on Black and Veatch (2012). The start-up costs take as reference Kumar et al. (2012).



(a) (b)

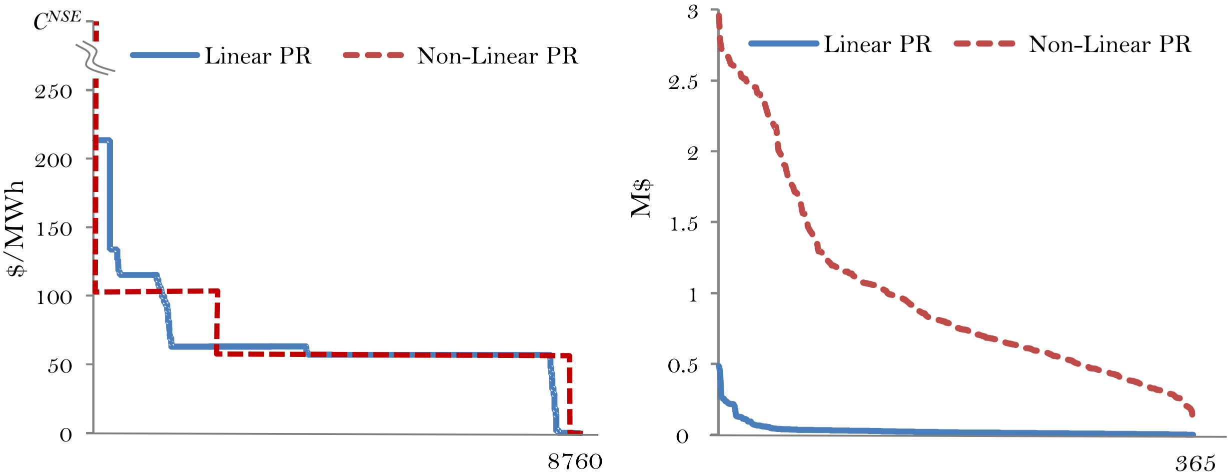
Figure 4. Break-even frontiers under (a) linear and (b) non-linear pricing rules

Figure 4 (a) shows the result for the linear pricing rule. To easily find the point where all three surfaces intersect look at the crosses (+) which represent the intersection of the CCGT (blue) and OCGT (red) lines and the asterisks (*) which represent the intersection of the NUC (black) and OCGT (red) lines. The perfectly adapted generation mix to be installed under a linear pricing rule would have between 10 and 11 nuclear power plants. Since we are assuming that only discrete investments are possible the final solution requires 11 nuclear power plants and is indicated by the green dot. The red diamond points the minimum cost reference mix, it is hard to tell with the figure but it is located outside of the feasible boundary.

The same analysis can be made for Figure 4 (b) which shows the results for the non-linear pricing rule. The ideal solution would lie between 7 and 8 nuclear power plants but the discretization simplifies it to 8. Note the difference in the horizontal axis; in this case the perfectly adapted mix requires a totally different amount of OCGT capacity and the reference mix lies out of the bounds of this plot.

This figure helps to discern what is the trend produced by each of the pricing rules. Linear pricing rules attract capital intensive technologies in alignment with the desired minimum cost energy mix. Non-linear pricing rules produce price signals that do not include non-convex costs and thus, infra-marginal units that could lower total operation costs result unprofitable and are not installed. The gap left by the lack of base-load capacity is filled with peak-load capacity with lower investment costs and higher variable costs.

In Figure 5 (a) we sorted in descending order the hourly uniform prices produced by each of the pricing rules in the corresponding energy mix. The non-linear price consists of four different regimes; the price is set to C^{NSE} when not enough capacity is available, the other two steps correspond to OCGT and CCGT variable costs. Nuclear power plants can never be marginal since they are not able to regulate their output, therefore the price is set to zero when production exceeds demand and solar PV production is spilled. The linear pricing rule is not limited to these four steps and a continuum of prices is possible. Compared to the non-linear case, the price is lower when the additional nuclear power plants substitute CCGT units and when CCGT units replace OCGT units. Figure 5 (b) illustrates how daily side-payments are, as expected, reduced by the linear pricing rule.



(a) Monotone curve of uniform market prices (b) Monotone curve of daily side-payments

Figure 5. Pricing regime comparison between linear and non-linear pricing rules

5 DISCUSSION

This section aims to qualify the results presented previously, mainly to determine the relevance of the pricing rule and to clarify some common misconceptions.

While pricing rules clearly affect the energy mix, these differences should be quantified in terms of total cost (investment + operation + non-served energy) of the thermal mix installed. This is the variable to be minimized in an expansion planning problem and its minimization necessarily implies the maximization of NSB.

$$TotalCost_{year} = \sum_{t \in year} nse_t C^{NSE} + \sum_j \sum_{t \in year} OperationCost_{j,t} + \sum_j AnnualInvestmentCost_j \qquad (19)$$

Figure 6 details the share of each component of total costs. It is clear that the linear pricing energy mix is composed of more capital intensive technologies with lower variable costs. Interestingly, the share of non-convex costs (no-load and start-up costs) is relatively small (around 7%) although these are responsible for the price differences between each of the pricing rules and thus, responsible for the difference in the final energy mix.

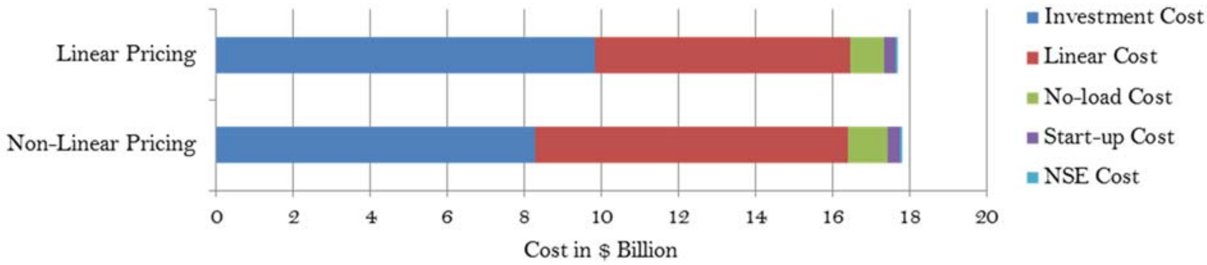


Figure 6. Cost structure of each generation mix

In particular, start-up costs only represent around 1.5% of total costs. This suggests that we could use the so-called screening curves (SSCC) method (Phillips et al., 1969) to gain some more insight on the results we are obtaining. In particular, we use an alternative representation of the SSCC (Figure 7), where the horizontal axis which generally represents hours of operation of each generation technology (up to 8760 hours) here represents installed capacity. This simply requires a change of variable using the relation between time and power given by the net load-duration curve of the system[13]. The area under each curve represents the costs incurred when a certain capacity of each technology is installed.

In this type of representation we get the total cost involved when instaling a MW of each of the technologies at each of the load levels (under the simplified dispatching assumptions of the SSCC methodology).

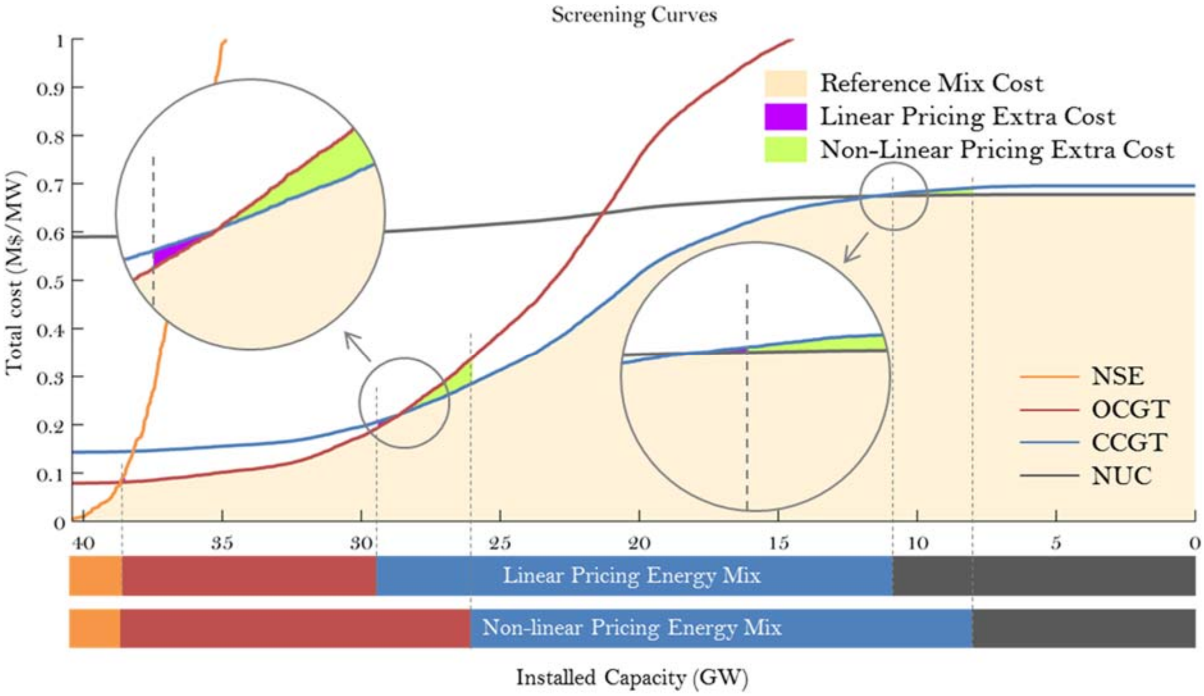


Figure 7. Screening curves representation of total costs

This figure should help to better interpret what at first might seem a counterintuitive result: the structure of the optimal mix changes significantly as a consequence of the pricing rule implemented, but the total costs are affected to a lower extent when compared in relative terms. With this representation we shall see that effectively not-so insignificant changes in the mix may not affect total costs in relative terms.

To begin with, let us graphically identify the total cost of the optimal mix obtained with the SSCC method as the solid area of the figure above. Now we shall compare the costs resulting from the mixes depicted in figure. The extra cost of the non-linear pricing mix is produced by the excess of peak-load capacity and the lack of base-load capacity. These extra costs are represented by green areas in the figure and are relatively small if compared to the total costs of the system.

Table ii compares the total cost for each of the three generation mixes obtained. The difference in total cost between a mix and the reference mix can be interpreted as a measure of the inefficiency of each pricing rule.

Table ii: Total cost comparison of the resulting mixes

	Total Cost $ Million	Absolute Difference $ Million	Relative Difference %
Minimum Cost Reference Mix	17,692		
Linear Pricing Energy Mix	17,693	+0.584	+0.0033
Non-Linear Pricing Energy Mix	17,816	+124.074	+0.7013

As already illustrated by the SSCC, the percentage difference with respect to the minimum cost is very small for both pricing rules so it could seem that the impact of pricing rules in total costs is negligible.

[13] See Batlle & Rodilla (2013) for a more-in-detail explanation of this alternative way to represent the SSCC methodology

Actually, we should first know what can be called a small difference in this context and what the impact of installing a sub-optimal generation mix can be. One clear reason for this difference to be small is that the cost data considered for mid-load units makes it a very competitive technology for peak-load and base-load alike and this diminishes the effect of deviations in the energy mix. Take for instance a mix in which only CCGT units are installed; this mix would produce a 3% increase in total costs with respect to the minimum cost reference mix. Considering this we can say that the non-linear pricing rule produced a relatively big increase in total costs while the linear pricing rule produced a cost increase two orders of magnitude lower.

We now compare the result of applying (changing) the pricing rule to the adapted-to-the-other-pricing-rule energy mix. We can see how the changes are relevant (Table iii). The non-linear rule does not produce sufficient remuneration for the linear mix and the linear rule produces excessive remuneration for the non-linear mix.

Table iii: Investment cost recovery under different generation mix - pricing rule combinations

	Linear mix and non-linear rule	Non-linear mix and linear rule
OCGT	110.86 %	104.79 %
CCGT	78.011 %	153.47 %
NUCLEAR	88.146 %	114.95 %

This allows to extract two additional conclusions. First, in the previous table it is clearly illustrated that the performance of one or the other pricing rule can only be judged in the long run: it would make no sense to evaluate the suitability of the implementation of one rule on the basis of the estimated returns or costs calculated for a mix adapted to any other market design context, or even to the mix resulting from a pure cost minimization. Second, from the regulatory design point of view, it has been evidenced that a change in the pricing rule would produce an economic imbalance requiring new investments but also divestments that could take a long time before a new economic equilibrium is reached. So, although further research would be needed, regulators should be discouraged to change the particular pricing rule in force (linear or non-linear) since the negative impact of "disadapting" the mix could be relevant, and the potential benefits in the long run are yet not clear enough.

6 CONCLUSIONS

This paper has proposed a practical and computationally efficient methodology to compare the long-term effect of pricing rules in the investment signals perceived by market agents. We asses this impact in terms of the expected energy mix to be installed under different pricing rules.

A real size example of a power system was used to compare two pricing rules; a non-linear pricing rule resembling current market practices in the US and a linear pricing rule including the main characteristics proposed in literature. Two important results can be extracted from this simulation. First, the way in which non-convex costs are reflected in the uniform price can have a significant impact in the investment signals perceived by market agents and the linear pricing rule seems to promote a more efficient energy mix. Second, contrary to what a superficial analysis may suggest, a linear pricing rule does not necessarily produce higher energy prices than a non-linear pricing rule; in fact it can lower the price since it attracts generation technologies with lower variable costs.

The results presented in this paper suggest that a properly designed linear pricing rule can be more efficient in the long term. But it has been evidenced that adapting a market from an existing non-linear settlement mechanism (or the other way around) could be a problematic process that requires careful planning.

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