Texto de Discussão do Setor Elétrico n. 28

Market design in electric systems with high renewables penetration

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Rio de janeiro

Setembro de 2010

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Introduction

The objective of the liberalization reforms of the electric sector around the World as of the end of the 1980s was to promote competition in the segments of the value chain that are considered potentially competitive: generation and retail. In the European countries, competition in generation was organized through a day-ahead market, with prices and production levels for each every generator determined via auctions. While this market design showed adequate in systems where prices are mostly set by fossil-fueled generators, it cannot be considered a universal solution.

Depending on the techno-economical characteristics of the generation matrix, price formation in a short-run, competitive market may not turn out to be functional, sending erroneous price signals and jeopardizing generators' financial stability. This is particularly evident in systems where the energetic mix is dominated by generators with high fixed costs and very low or close to zero variable costs. In such systems spot prices tend to be too low in the long-run and investments generation are a money-loosing proposition. Moreover, systems with an energy mix dominated by nuclear, hydroelectric, wind and other renewables, with no

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interconnections to systems dominated by fossil-fuelled generation, cannot establish a functional spot market. A competitive energy market can exist in such systems, but only when non-market mechanisms are introduced so as to guarantee that generators' fixed costs are covered and to signal (correctly) the necessity for system expansion.

The Brazilian electric sector is an example of a liberalized system where a competitive short-term wholesale market for electricity never came to be. This results from the characteristics of the generation matrix, based primarily on hydro resources. In Europe, increasing generation capacity from renewables (a growth stimulated by non-market financial incentives) will have an impact on competitive mechanisms, lowering spot prices and compromising thermal plants' business model.

This article deals with the preponderance of low to zero variable costs generation in liberalized energy markets in general and particularly with the impact of the increasing renewables penetration in European energy markets. After this brief introduction, the text tackles the microeconomics of traditional competitive markets and that of markets dominated by large, sunk fixed costs generation sources, with very low variable costs. A brief case-study of the Brazilian electric sector is outlined – a system dominated by zero variable costs, where no truly competitive energy market has been created. Next, microeconomic fundamentals of thermally-dominated electricity markets are appointed. Finally, the text discusses the impact growing renewables penetration in the Iberian Energy Market.

The liberalization of the electric sector and generation competition

The electricity industry is characterized by capital-intensive investments with long maturing periods and high economies of scale. Nonetheless, these characteristics are more or less intense depending on each segment of the electricity value chain.

Notably, economies of scale are more important in transmission and distribution, where variable costs are practically null. A new client can be served at an extremely reduced extra cost if installed capacity is already in place. Economies of scale in distribution result from a combination of high capital requirements and low variable costs, which result in descreasing average cots as scale grows. Economies of scale are such that in the absence of regulation, an incumbent with partially amortized investments would be capable to deter eventual competitors by lowering prices, derailing any hypothetical returns of the new entrant. Furthermore, minimum efficient scale in distribution and transmission is of such a magnitude that the market optimum is reached with the presence of only one firm in each locality. This is why these segments are examples of natural monopolies.

In counterpart, generation and retail, which are not subject to economies of scale of the same rank, are considered as potentially competitive. The liberalizing reforms in the electric sector have promoted competition in these segments though guaranteeing transmission grid access to every player interested in commercializing energy. Promoting competition where this is possible, the liberalizing reforms aim at promoting economic efficiency via markets and limit price regulation to the segments considered as natural monopolies.

Generation and retail competition in European countries was centered in the creation of a spot energy market with an hourly auction-based price. Such a market emits economic signals for optimal market functioning and for generation expansion.

In the meanwhile, a competitive spot market, that is at the same time able to operate efficiently and at the same time is capable to emit correct signals for supply expansion may not be an adequate option for all systems. Notably, systems dominated by generators with low or zero variable costs (nuclear, hydro, other renewables) are not good candidates for day-ahead markets. This can be better perceived with the help of some precepts from Microeconomic Theory applied to electricity market structures.

Microeconomics: mechanisms for competitive markets

The works of a competitive market can be understood through Microeconomics, especially through theories for determination of the supply of a firm and of short and long-run market prices.

The main concepts for these topics are:

i. ***Fixed costs***: costs that do not depend on production, including capital costs, rents for production spaces, administrative expenses, among others. The average or unit fixed cost is the fixed cost divided by output number – the fraction of fixed costs attributed to every unit produced.

ii. ***Variable costs***: costs that depend on the size of production. Fuel costs are the main variable costs in the case of energy generation. The average variable cost is a fraction of the variable cost incurred for each unit produced.

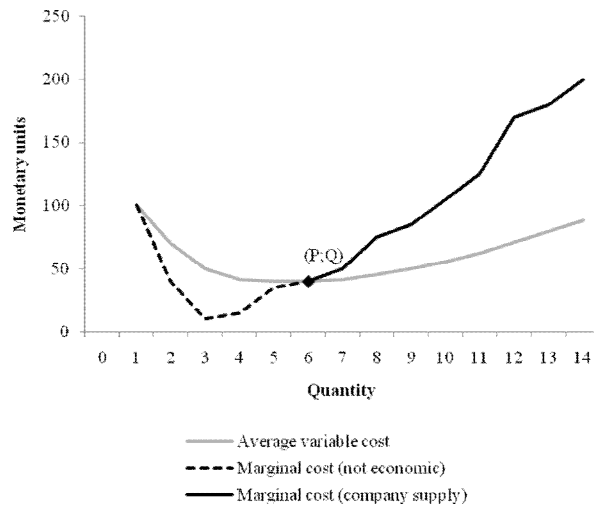
iii. ***Marginal cost***: cost to produce an additional unit. In the case of an electricity generation plant, the marginal cost is the cost to produce one more MW or kW, which in its turn is a function of the fuel costs in the production process.

Perfectly competitive markets are those where a great many producers and buyers compete for a homogenous product and where no entry/exit barriers exist (namely, no sunk costs or other barriers to capital mobility). Producers cannot exert market power. They must sell their merchandise for the price of the moment, which they cannot influence. Producers are *price takers*: they can either sell at market price or not sell at all.

In perfect competition, market price equals the industry's marginal cost. This is because every producer increases its output as long as the revenue per unit sold overcomes the (marginal) costs incurred in its production. As producers only differentiate themselves through their prices, all competitors accept to sell as long as the revenues are in accordance with economic rationality: as long as prices are equal or greater than marginal costs. Accepting a price smaller than marginal cost of a newly produced unit is an economically unjustifiable loss. It is better to stop producing that to sell at such a price.

In a perfectly competitive market, the supply of a firm in the short run is the part of the marginal cost curve above its variable cost curve, as showed in Graph 1[5].

[5] The supply of a firm in perfect competition is generally determined by its marginal production costs with one exception: the firm will not sell its products when marginal cost is smaller than average variable cost. The logic behind this behavior can be understood through an example. Many thermal power plants have significant start-up (or *ramp-up,* in the industry jargon) costs, as they need to burn fuel to heat the boiler up before they can produce any electricity. For such generators the variable average cost to produce the first few MWh is high, despite the fact that the cost to produce any additional MWh (marginal cost) is low. Such thermal plants will not start production unless the market prices cover ramp-up expenses, that is, unless market price is higher than variable unit costs.



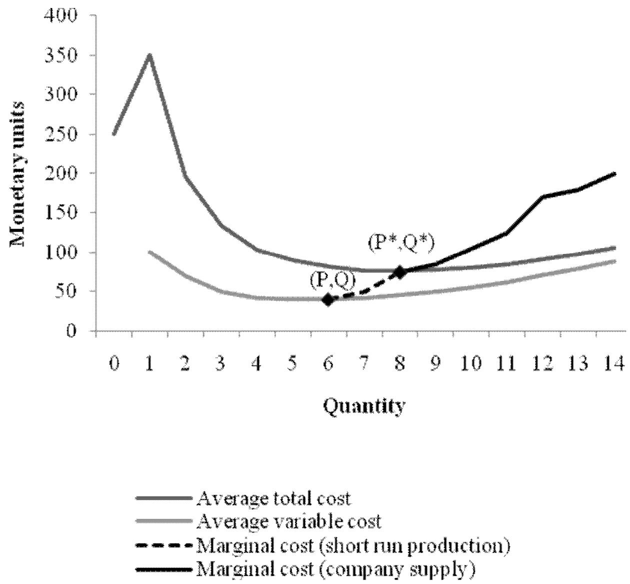
Graph 1 **– The supply of a firm in perfect competition**

Source: based on Varian (1999)

Graph 2 deals with the question of *break-even*, that is, tries to determine the level of production[6] that covers all the firm's costs. This Graph includes the average costs curve (costs per unit, including both fixed *and* variable costs). A firm's supply curve is the part of the marginal cost curve above the average variable cost curve. So, revenues cover *all costs* only at (P*,Q*). Between (P,Q) and (P*,Q*) – the dotted part of the supply curve – the firm covers all variable costs but only a part of fixed costs. Being in this situation is better than stopping production: when production stops, all fixed costs will be lost, while selling above variable costs will at least pay part of fixed costs.

In the short run, firms can act in the "dotted" supply curve interval, were only variable costs are completely covered. But in the long run, this situation is not sustainable. Many firms do not resist a long time if they cannot pay fixed costs.

[6] To simplify, sales and production are considered equal.



Graph 2 – **The supply of a company under perfect competition**

Source: based on Varian (1999)

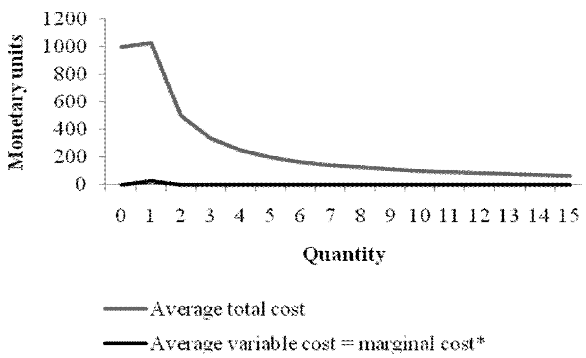
In the long run firms have to leave the market if they don't break even. When firms leave the market supply contracts, and this will eventually raise market price to a level at or above the industry's average cost. In a competitive market, revenues tend to equal total costs in the long-run, prices tend to equal both total unit costs and marginal costs. The classic explanation is that economic agents take decisions so as to anticipate the market's natural tendency: any perspective of economic gain or loss attracts or deters investors until the envisaged gain or loss is neutralized.

Markets with very low variable costs

Day ahead energy markets are designed to work as competitive markets. But depending on the generating system's cost structure, a truly competitive market may *not* actually work.

Industries with high fixed costs – especially with investments that involve specific assets that due to this specificity are sunk costs – are not good candidates for hosting competitive markets, especially if they also have very low variable costs. Hydroelectric power plants, nuclear plants, wind parks and other renewables have this cost structure. They are expensive to build, but their fuels are very cheap (nuclear plants) or actually have zero-cost[7] (most renewables).

Graph 3 shows the supply curve of a low variable costs firm. Total average costs are essentially fixed costs, while average variable very low.



Graph 3 **– The case of firms with low variable costs**

*The only point where the marginal and average variable costs do not equal one another is when Q=2 and the marginal cost is actually -29,98 m.u.

Source: GESEL / IE / UFRJ

In a competitive market, firms with such cost structure will offer their products at any price. In the short run, price equals marginal cost, that is, it is always close to zero. This is because all firms will try to produce at full capacity all the time in order to minimize losses: it is better to sell all production and cover part of fixed costs than stop the factory and have to cover all fixed costs. Should all competitors

[7] The discussion about the *opportunity cots* of such fuels is not the object of this article. See Hartley and Moran (2000).

try to produce as much as possible, accepting any price, an extremely low market price will prevail. As a consequence in such markets ***prices will always lower than average costs***. Firms will never *break-even*: market price is always a point on the marginal cost curve, but this curve never actually crosses the total unit cost curve.

If firms never break-even in the short-run in very low variable cost markets, in the long run no equilibrium can be expected. If some firms leave the market, price levels do not change, remaining equal to the industry's marginal costs – that is close to zero – as the remaining will maximize production. The situation only changes if firms exit the market *en masse*. In this case, installed capacity will be lower than demand, and may prices rise above marginal costs. But this will not attract new investments. Given that these investments would include high sunk costs (due to assets' specificity), who would undertake them in markets where prices tend to be too low whenever sufficient supply is adequate?

A market with a homogenous product in a fixed cost based industry with high sunk costs is only sustainable in three cases:

i. When firms have revenues from alternative sources;
ii. When firms have market power to deter potential entrants and influence prices;
iii. In regulated markets.

i. The best example of the first case, of firms that thrive with alternative sources of revenues in a competitive market is the "market" for Internet pages (Shapiro and Varian, 1999). Putting up a web site essentially implies fixed costs with hardware, salaries, administration, operation and maintenance. The (marginal) cost of reproducing that web page is minimum – a small fraction of a penny. More, as fixed costs are sunk costs (assets cannot be sold for a reasonable price) and unit variable cost is close to zero, there is no reason to stop production.

Producing the *contents* of a page does have a cost, for instance, hiring a *freelance* writer to produce the text and a *freelance* designer to format it into the page. But the essential aspect of this business is that *reproducing* the page – that is when a new (marginal) user opens the page in its browser – costs next to nothing. The consequence is that web sites with no copyrighted content cannot charge for access. Whatever the price, it will be higher than marginal cost and therefore, according to the microeconomic logic presented above, competitors will be willing to sell even for a lower price. Marginal costs in this industry are so reduced that most firms do not even think of charging for access.

Naturally, it is possible to make money in the web page "market". There are other revenue sources besides charging for access. If many users access a page, advertising is an option.

ii. Highly capital-intensive markets with low variable costs are normally oligopolies. When competition sends prices downwards, entrepreneurs with available financial resources buy distressed competitors. With concentration firms gain market power: they manage to influence prices, for instance limiting supplied quantities when prices are too low. When fixed costs are predominantly investments in specific assets or in other sunk costs, incumbent firms occupy a particularly comfortable position in the market. The mere fact that they posses partly amortized assets serves as a deterring factor against new entrants, who fear been expelled from the market with heavy losses in a price war. Capital intensive markets with high sunk costs that also have high economies of scales and are the classic examples of natural monopolies.

iii. Finally, markets in a fixed cost based industry may work well with proper regulation. Regulation does not need to be restricted to natural monopolies, nor does it have to eliminate competition. It is enough to give shape to competition so that it works in a healthy way. This is the case of mobile telecommunication where most costs are fixed and where market equilibrium would not be possible under full competition. This is why only a limited competition is allowed, for example through limiting the number of mobile operator licenses. In this case, regulation seeks equilibrium between profitability, which would be impossible under open competition, and consumer's interests, which are met if services have adequate quality and affordable costs.

Competition in energy markets

Energy market design should be fundamentally linked to each country/region generation sector's cost structure. Only in this way can energy markets work adequately: remunerating generators appropriately and signaling the need for capacity expansion.

Let us take up the example of European Energy markets. All European energy exchanges have day-ahead markets where generators make price offers in order to supply an hourly forecasted demand. For every time interval, the most economic bids that (summed) satisfy demand are dispatched. In most markets, the most expensive supply price that is accepted sets market price to *all generators* that are dispatched during a given auction period (the mechanism is called *uniform price auction* or UPA[8]).

This spot market design emulates the classic competitive market with some fidelity and has been working for several years in several European countries. Another common feature to European electricity markets is particularly salient: all of them

[8] The alternative is called *pay-as-bid auction* (PABA). In such auctions, each and every generator is remunerated exactly at the price it bid in the day-ahead market, according to the quantity effectively dispatched. It is a less used auction system.

have noteworthy fossil fuel generation, so that most the time prices are set by a firm with high marginal costs.

Yet this market design would not work properly in a system where all generators have very low or zero variable costs. In such systems, spot prices would always be low and companies would never break even. This is one of the reasons why hydro-dominated systems, like the Brazilian, have never managed to develop a real spot market.

The Brazilian case: fixed cost based generation

The Brazilian system, with a generation park made up mostly of hydroelectric plants is a good example of a fixed-cost-predominant generation system. National Interconnected System's (NIS) installed capacity is presented in Table 1.

Table 1

The Brazilian electricity generation matrix,
at the end of 2009

Type	MW	%
Hydro*	82.189	83,2
Conventional thermal	13.945	14,1
Biomass	33	0,0
Nuclear	2.007	2,0
Wind	358	0,4
Other	196,5	0,2
Total	**98.727**	**100,0**
** Includes all Itaipú capacity*		

Source: www.ons.org.br (Dados relevantes 2009).

Despite some considerable thermal capacity, electricity production is mostly done by hydroelectric plants, as can be seen in the Table below.

Table 2

Hydro generation in the NIS as % of total generation

Year	%
2000	94,11
2001	89,65
2002	90,97
2003	92,14
2004	88,63
2005	92,45
2006	91,81
2007	92,78
2008	88,61
2009	93,27

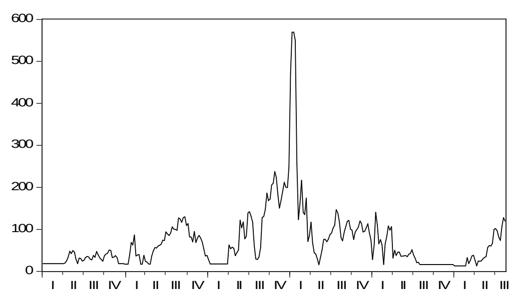
Source: www.ons.org.br (Histório da operação)

Apart from hydro generators, the Brazilian system also has other fixed cost generators. Nuclear plants, responsible for 3,5% of total power production in 2009 have *take or pay,* producing energy on a continual basis, independently of any economic signal. Furthermore, part of the coal-fired plants also have *take or pay* contracts, and therefore are a fixed cost to consumers. The same occurs for several cogeneration units and for all the still nascent wind generation. In years of favorable hydrology as was 2009, the authors estimate that 99% of all the energy within the NIS was fixed cost only production.

In such a system a true spot market, where dispatch is based price offers would not work effectively. The literature regarding the Brazilian model emphasizes that liberalization process preserved the centralized dispatch model in order to guarantee a long-term optimization of hydro resources in several hydrographical basins (Araújo, 2009). This point of view is correct, yet it does not by any means deplete the issue. From the strictly economic point of view, a true spot market would under no hypothesis be functional in a system like Brazil's.

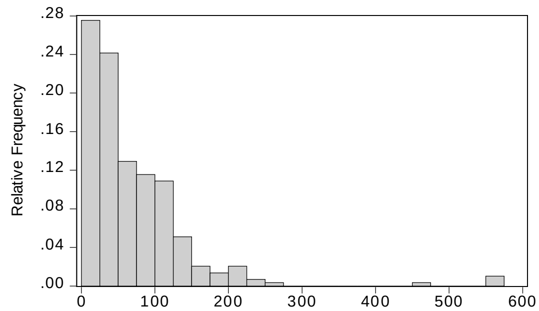
In favorable hydrology Brazilian spot prices would always be derisory as demand would be fully satisfied with zero-variable-cost only generation. On the other hand, during severe draughts, the complimentary, fossil-fueled thermal capacity would need to be dispatched and high prices during extended periods would be unavoidable. The alternation of long low price periods and brief very high price periods would ruin most generator's businesses and would reduce their ability to contract debt in order to build new plants.

The Graphs below give an idea of this erratic price behavior. They show the evolution (Graph 4) and distribution (Graph 5) of the weekly *Differences Clearing Price* (PLD[9]) in the main electric submarket in Brazil, the Southeast-center-west (SE/CW) market from 2005 to 2010. PLD is not determined via market mechanisms, but established according to marginal operation cost, calculated with dispatch optimization models. However, PLD illustrated the point in question.



Graph 4 – **Weekly PLD average in the SE-CW submarket, Jan 2005 – Aug 2010**
Source: GESEL/IE/UFRJ analysis, data from www.ccee.org.br

[9] *Preço de Liquidação das Diferenças,* in Brazilian Portuguese.



Graph 5 – **PLD distribution from Graph 4**

Source: GESEL / IE / UFRJ analysis, data from www.ccee.org.br

The Brazilian commercial scheme that emerged out of the 2004 reforms, was designed to avoid excessive volatility in generators' revenues. The Brazilian model is based on bilateral contracts between consumers and generators or retailers. All consumption should be based on contracts and it is not possible for a consumer to buy energy in a power exchange. Besides bilateral contracts, there is also a balancing market, called *Mercado de Curto Prazo*. Even if this expression literally translates as *short-term market*, it is not more than an automatic adjustment mechanism between contracted energy and energy effectively produced (valued at PLD). It is not a place where generators bid to set prices and quantities to be dispatched.

Contracts with power plants are designed according to each generation type cost structure and to its risk matrix.

i. *Contracts for hydroelectric power plants*. These plants' generation is limited by water availability. Furthermore, as Brazilian dispatch is centralized, the system operator may decide to decrease hydro generation in order to save water for the future even when it is currently available, without generators being able to interfere. Given the high level of uncertainty regarding actual production levels, a stable cash-flow for hydro plats was achieved through a pair of commercial mechanisms. Firstly, generators are allowed to sell *guaranteed energy* and not actual energy. Guaranteed energy (*garantia física*) is defined by an official methodology and it is always a fraction of installed capacity. It is also lower than expected hydro output. Secondly, an Energy Relocation Mechanism was built to distribute actual energy among generators. It is an automatic hedge system that distributes surpluses or deficits of actual production relatively to guaranteed energy of hydroelectric plants. In this way, a plant that generates less energy than the amount of guaranteed energy it sold, either due to lack of water or due to a System Operator decision, receives enough actual energy from other generators to cover its deficit. This way all the hydroelectric plants operate conjointly, as a condominium and share hydrological risk.

Through this contractual arrangement hydroelectric plants' revenues are mostly fixed revenues as they do not depend on actual generation. Risk is limited to all hydroelectric generators producing more or less actual energy than the amount of guaranteed energy established for all of them. The surpluses or deficits are settled in the balancing market, the *Mercado de Curto Prazo*, and the financial unbalance is usually quite small.

ii. *Contracts for thermal power plants*. Thermal generation is highly volatile in a system based on hydropower like Brazil's. In normal or rainy years, many thermal plants will remain idle most of the time. But in dry years even the most costly thermal generators may be dispatched for months non stop. Given the thermal dispatch's high volatility, contracts for new thermal power plants were designed to isolate them from risks associated to the frequency of dispatch, from fuel price risks. Every new plant has fixed revenue and variable are charged to consumers. Thermal generators' risks are limited to penalties should they not prove able to generate when dispatched.

On the other hand, this there is *some* competition between generators, as they dispute contracts with free and captive markets. As these contracts always have long timeframes (between one month and 35 years) and as revenue do not depend strictly on physical output, they tend to reflect generators' long-term fixed costs and not short-run variable costs.

The microeconomics of European Energy Markets

In Europe, regional energy markets have all a similar structure, with commercial transactions at various levels: bilateral contracts outside the power exchange, day-ahead markets (spot), intraday markets, ancillary services markets, balancing markets. Among them, the day-ahead (spot) market is structurally the most relevant – as the prices and conditions of long-term contracts are guided by spot price expectations[10].

The microeconomics behind European spot markets relies on the assumption that the most efficient generators receive extra rents above their marginal costs. Theses extra rents are difference between market price (determined by the least efficient, and therefore more costly generator) and their own marginal costs. With this extra rent, efficient generators manage to cover fixed expenses and to have economic profits. These extra rents also fulfill competitive markets' signaling function for capacity expansion as they are a stimulus for investments is new, efficient plants. It is for this reason that UPA (*uniform price auction*) prices are referred to as efficient, being able to cover marginal costs in the short and log run for those generators that

[10] Nowadays, around 30% of the energy consumed in the EU passes though power exchanges.

are more economical[11]. Nonetheless this market design has presents three distinct problems, usually tackled via regulatory intervention.

The first relates to economic signaling for investments, represented by extra-revenues for efficient generators. This economic signal is biased against highly capital-intensive power plants. Nuclear or hydroelectric projects, for instance, are difficult to build without fixed revenue long-term contracts. Nevertheless, consumers and retailers will not assume voluntarily the price risk involved in such contracts, as in the long-term they may prove costlier than spot market prices. Fossil-fueled plants' variable costs usually set market prices and they depend in turn on fuel market prices. In the long-term, spot market prices tend to rise and fall according fuel prices, unlike capital-intensive plants costs. This explains why even if a capital-intensive plant has extra-profits for an extended period, similar projects may prove difficult to replicate through pure market mechanisms. That is why the liberalizing reforms had, in Latin America, the collateral effect of stimulating investments in fossil-based electricity generation in countries with large hydrological resources.

The lack of clear economic signaling for capital-intensive investments in electricity generation is such that regulators need to create mechanisms to provide fixed revenues to investments considered as priorities. In Finland for instance, the construction of new nuclear reactors is part of the country's energy policy and has been made possible through long-term Power Purchase Agreements (PPAs) with a consortium of distributors. In the Portuguese and Spanish cases, contracting renewables is done in the so-called *special regime*, which guarantees non-market revenues. Yet in this case, the main interest is to foster low CO_2 technologies, acknowledged as expensive and not to create economic signaling that the market alone does not provide.

[11] Marques *et al.* (2008) is an example.

The second distortion that market designs centered on the spot market can present regards prices during demand peaks. During these moments, generators with the highest variable costs set market prices. Given the fact that demand for electricity in the short-run is inelastic, these generators – the last in the economic merit order – are able to set prices way above their marginal costs. As very high prices are not socially acceptable, the regulator frequently sets a price cap on spot prices. This cap in its turn jeopardizes peaking generators' business model: they dispatch just occasionally, and it is only during these rare periods that they can recoup capital investments, charging above marginal costs. A price cap can therefore pose a threat to system reliability during demand peaks. The regulatory path correct this problem is through a fixed payment to peak generators.

The third problem with markets designs based on day-ahead markets is the difficulty to accommodate growing renewables penetration in the generation mix. The growth in generation from renewable sources – mainly the result of CO_2-reduction efforts – lowers fossil-fuel plants' share in the mix. On the other hand generators with cost structures centered on fixed costs are increasingly important.

Higher renewables penetration increases spot price volatility and reduces average market prices. Nonetheless, a spot market with excessively low prices and high volatility can turn out dysfunctional and can loose its capacity to provide economic support to generators and correct signals for investors. We tackle this topic in the following sections, though the study of the Portuguese and Spanish cases.

The growth of the renewables penetration in Spain and Portugal

The growing renewables penetration in the electricity matrix is a phenomenon that is taking place at a European scale. The Spanish and Portuguese cases are of particular interest because the Iberian Peninsula is a relatively isolated system where renewables are expanding at such a rate that that the generation matrix is soon to assume a cost structure centered upon fixed costs.

The Iberian Electricity Market (MIBEL) operates under rules harmonized with those of the rest of the European regional energy markets. The interconnections between Portugal and Spain are large – to the point that a common price occurs during most of the bid periods. The interconnections to the rest of the European continent through France are relatively small, even when considering the present expansion plans[12]. This leads one to believe that the true interconnection of the European and Iberian electric systems is still distant.

The growth in renewables in Portugal and Spain has been intense and the CO_2 reduction objectives until 2020 will probably lead these two countries to continue to support it. There are ambitious projections for wind and solar capacity growth in Spain, for instance. Portugal has plans to increment wind, hydro generation and pumped storage capacity.

The Table below shows the composition of the electricity matrix in Iberia, as a percentage of total installed capacity for both countries, separating low and high-variable cost technologies.

Type of technology	Spain	Portugal
Low variable cost		
Hydro*	20,1	29,5
Nuclear	8,0	-
Wind	20,0	20,8
Solar	3,7	0,5
Other renewables	1,1	0,0
High variable costs		
Gas	25,0	17,9
Coal	12,0	10,5
Fuel/Gas	3,0	11,1
Thermal (RE)	7,2	9,6

** Includes special regime*

Table 3 – **The Iberian generation matrix, as a percentage of total installed capacity, 2009**

[12] Today, these interconnections are equivalent to 3% of the Spanish peak, the current plan being to reach 6% by 2014. The European Union recommends a minimum of 10%. See REE (2008) for details.

Sources: REE (El Sistema Electrico Español 2009) REN (Caracterização da Rede Nacional de Transporte 2009).

In 2009, Spain possessed a 52,3% participation of low variable cost technologies in its generation matrix, while Portugal had 50,8% of its generation in the same category. Still, as Spain has nuclear generation and as these power plants have a high capacity factor, in 2009 low variable cost sources had a larger slice of effective energy production, as can be verified in the table below.

Type of technology	Spain	Portugal
Low variable cost		
Hydro*	11,1	18,9
Nuclear	19,0	-
Wind	13,8	16,3
Solar	2,6	0,3
Other renewables	1,6	-
High variable costs		
Gas	29,0	24,9
Coal	12,0	26,0
Fuel/Gas	1,0	0,7
Thermal (RE)	10,4	13,0

** Includes special regime*

Table 4 – **Effective production of electricity per type of technology as a percentage of total production, 2009**

Sources: REE (El Sistema Electrico Español 2009), REN (Caracterização da Rede Nacional de Transporte 2009).

About 48% of all energy produced in Spain came from low variable cost generators, against “only” 35,5% in Portugal. The prevalence of these generators in Span bring a tendency for lower prices and therefore, this country frequently exports energy to Portugal.

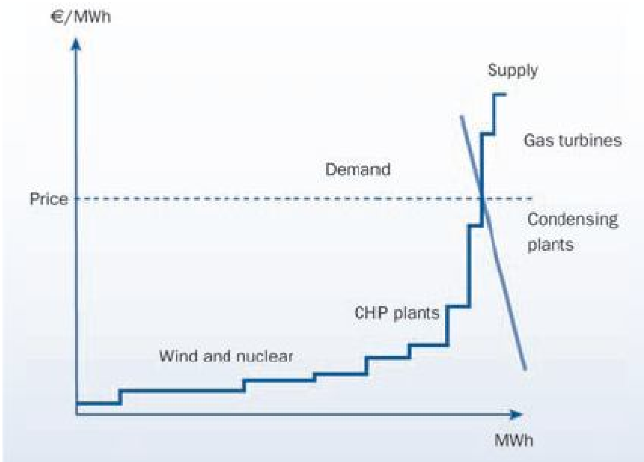
An additional increase in renewables (i.e. in the share of low variable cost generation) will probably have a sensible impact on the Iberian electricity market, above all on its capacity to emit adequate economic signals. The most direct consequences are more price volatility and a reduction in average market prices.

An increase in price volatility is a consequence of the forecasted increase in wind generation in the generation matrix. Most of the times, wind parks work with relatively low capacity factors, but on windy days generation capacity factors may very high. In consequence, prices go down as and other sources must cease production for a while.

The reduction of average market prices for energy within a market with an ever growing share of renewables is a parallel tendency to the reduction in the levels of operation of thermal generators. It is worth explaining how this happens in a little more detail.

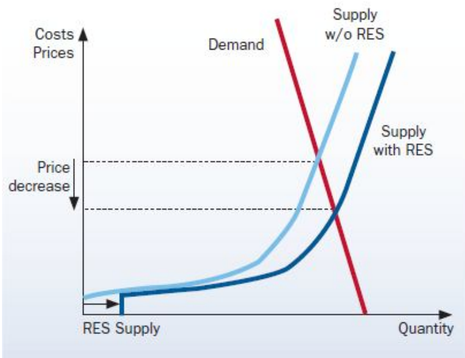
Renewables reduce market prices

In competitive electricity markets, with several types of generators, in balanced proportions, the market supply curve is the so-called merit order curve. The merit order curve comprises the supply curve of all generators: it is a combination of all capacity price offers in a day-ahead auction. In competitive markets generator will bid according to their marginal costs. The bids are ordered from the most economical to the most expensive. In this way, at the left side of the curve low variable-cost generators while at the opposite side are those with high variable costs, as it can be seen in the Graph below. The demand curve is, as it has been stated, fairly inelastic, commonly represented as an steep line. In real-life auctions the demand is the forecasted consumption for each hour in the next day – it is, therefore always a vertical line. The spot price is set at crossing of supply and demand curves.



Graph 4 – **Demand and supply curves in the electricity market**
Source: EWEA (Economics of Wind)

An increase in the generation of renewable energy sources (RES) or of other generators with high fixed and low variable costs brings forward a dislocation of the market supply curve to the right, as illustrated in the Graph below. It forcedly results in reduced market prices.



Graph 5 – **The merit order and the effect of renewables participation in total generation**
Source: WEIGT

This tendency for lower prices may appear to be a bonus for consumers at first sight. However, a deeper analysis reveals a more complex situation.

Undoubtedly, in a competitive market, an increase of the participation of companies with low variable costs translates into lower prices. Yet an issue emerges when this is the result of a *systemic predominance* of power plants with very low variable costs. In this case, price reductions may not be in line with a similar reduction in production costs and the economic signaling power of market prices may be seriously affected.

This unbalance between prices and production costs can be perceived through the new renewable generators' business model. In Portugal and Spain, new renewables do not depend solely on the market as they earn complementary revenues in the form of premiums defined by the regulator. So, renewables can increasingly depress market prices, with no impact on their own competitiveness.

This unbalance can also be perceived in an even clearer form, through the impact of lower prices in traditional generators revenues. Most traditional thermal generators belong to the *ordinary regime* and their business model depends on the market. More renewables means less dispatch for traditional players, and shrinking income.

Deficiencies of the economic signal with the increment of renewable participation

In an energy market capable of providing *correct* economic signaling, power plants that cannot break even will sooner or later close down. But, if the economic signal is a consequence of increasing renewables penetration it will be an incorrect signal. Low spot prices are a property of markets dominated by firms with low variable and high fixed costs. As explained in the Microeconomics section of this paper, in competitive markets, this kind of firm offer its products at any price and firms do not break even. Therefore, it is not correct to tax thermal power generators as inefficient when they fail to break even with lower market revenues due to increased renewables penetration. Actually, non-manageable energy, as wind or solar, claims for generators with fast ramp-up and flexibility to modulate generation to compensate the intermittence of renewable energies. Should there not exist enough reserve-generators, system stability may not be guaranteed.

A larger share of renewables in the Iberian Peninsula puts the business model of thermal generators at risk: they will dispatch less, dispatch will be highly uncertain and prices will be lower. But most of these plants are needed for system stability. Actually, more of them will be necessary as demand growth will urge for new thermal capacity to ensure supply during periods of low renewable energies availability.

Sensible to this issue, the Spanish Government created a capacity charge in 2007 (*pagos por capacidad*) for thermal generators, managed by the System Operator. The mechanism provides a fixed revenue for peaking thermal plants in contracts of up to one year. For new thermal generators, fixed revenue is offered for up to ten years, so as to economically justify investments. Capacity charges are a non-market economic signal that avoids the closing down of existing thermal power plants and make new thermal projects attractive.

Increased renewables penetration in the Iberian system will further increment the weight of generation low variable cost generation. The probable result will be an increased in economic regulation and a progressive decrease in the structural importance of the energy market.

Conclusions

A system where the energy commercialization centers upon a day-ahead market will never give birth to a system based on very low variable costs power generation. As we have seen, such a market cannot emit *correct* market signals for projects that, as all highly capital-intensive projects, have costs that are not correlated to fossil fuels prices. Nevertheless, the impulse to avoid CO_2 emissions resulted in non-market stimuli for renewable generation expansion, modifying the cost structure of the Iberian electric system. This text showed that a transition to a system where sunk fixed costs are preponderant and where prices are frequently determined by a generator with very low or zero variable costs destroys the basis for day-ahead markets.

The wholesale, day ahead markets can only work properly if thermal generators with high usually set the prices. When high fixed-costs and low variable-costs power plants prevail, a market molded according to European-style power exchanges will not promote economic efficiency. Under short-run competition, fixed cost dominated systems are marked by:

i. Very reduced market prices, which are independent of production costs;

ii. Impossibility to guarantee that existent firms will break even;

iii. Lack of *adequate* economic signaling for new investments;

iv. A tendency for concentration, where large market players gain market power; e

v. Frequent regulatory interventions to correct distortions in the economic signals emitted by market prices.

The advance of renewables in Europe and particularly in the Iberian Peninsula raises the share of renewables dominated by fixed costs with serious consequences for day-ahead markets. Among them:

i. Pressure on the Regulator for the creation of mechanisms that provide non-market economic signals, in order to guarantee that generators' cope with fixed costs;

ii. Lack of market signaling for all types of generation investments;

iii. Economic signaling for imports and exports of energy are progressively less aligned to energy costs.

The loss of structural importance of the day-ahead markets does not imply that competition in power generation is not possible or desirable. The commercial model adopted in Brazil, a country with a large hydroelectric capacity, based thus on fixed costs, can provide some hints as to how competition can be established in systems with such characteristics.

The liberalization of the Brazilian electric sector occurred without the creation of an energy spot market. Instead, generators' revenues are mostly independent of energy output; competition between companies (above all, private ones) occurs mostly in auctions for energy contracts.

The Brazilian solution to promoting generation competition in a system where fixed costs are paramount cannot simply be transposes to Europe, where fossil-fueled generation is still to remain important for many years. But, with an ever growing share of generators with very low variable costs, the role of the day-ahead, market price is to becoming less relevant in terms of *adequate* economic signaling.

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