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Security of electricity supply at the generation level: problem analysis

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Since the very beginning of the restructuring process, back in 1982 in Chile, the ability of an electricity market to provide the system with the required level of security of supply has been put into question. The mistrust on the ability of the market, left to its own devices, to provide sufficient generation availability when needed, is more and more leading to the implementation of additional regulatory mechanisms. This matter is undoubtedly gaining importance and it has taken a key role in the energy regulators' agendas.

In this paper, we revisit this discussion under the light of thirty years of electricity market experience. We analyze the different reasons why, although ideally the market is supposed to provide itself an adequate security of supply at the generation level, this result is still far from being achieved in practice.

Keywords: electricity market rules; security of generation supply; regulatory intervention.

1 INTRODUCTION

The energy industry, and particularly the electricity sector, has been subject to major reforms over recent decades. Until these processes started, the activity that we now call "supply" was a part of the complete chain of activities of vertically integrated utilities and was therefore performed as a public service or as a regulated monopoly.

Since there are no fully comparable energy systems, these reforms have taken very different forms, but all of them have shared a common approach, consisting in taking steps towards introducing competition at any feasible level. Ideally competition is useful because it sends sound economic signals –market prices- to market agents, which are supposed to drive their decisions in the direction of efficiency.

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These reforms have been traditionally denoted as "liberalization" or "deregulation" processes, terms which might appear to be slightly misleading, since they could easily be understood as just a relaxation of government limitations, leading to a weaker or "lighter-handed" regulation.

From the regulatory perspective, the fact is that in the case of the energy industry, the reform has entailed exactly the opposite: rather than a "deregulatory" process, it has been (and it is still being and still expected to be) an intensely "re-regulatory" one, see Borenstein and Bushnell (2000) or Ruff (2003). Indeed, the term "restructuring" has sometimes been preferred to denote this process in some systems (particularly in the United States).

The discussion that we develop in this paper, the need for the regulator's intervention to complement the electricity market in order to guarantee supply, is a good illustration of this paradox: the deregulation in electricity systems has accentuated the crucial need for reinforcing regulation.

Broadly speaking, the objective of regulation is to prevent (produce) inefficient (efficient) outcomes in different places and timescales which might (might not) otherwise occur. In this same direction, we show in this paper how, in the (already not-so) new "deregulated" and "liberalized" scheme that governs electricity business, the intervention of the regulator is needed to guarantee a minimum required level of security of supply in different places and timescales, since it has been largely demonstrated that otherwise they will not occur.

2 IS THE MARKET CAPABLE OF ENSURING A RELIABLE SUPPLY?

The changes in the regulation of the electric power industry worldwide have modified the traditional security of supply issues and approaches drastically. In the vertically integrated utility, under cost-of-service regulation, security of supply was seen as a major ingredient in the global exercise of centralized utility planning at all levels: generation, transmission and distribution. Under the market-oriented paradigm, the new regulation must make sure that the appropriate economic incentives exist for each one of the activities so that quality of supply is maintained at socially optimal levels.

This paper only concerns security of supply at the generation level, where the change was more pronounced since, in the new regulation, the generation activity is opened to competition. The theoretical orthodox reason justifying the liberalization process at the generation activity was mainly to promote efficiency at all levels: operation, planning and expansion. However, the market ability to bring efficient results at all these levels in the real world (and especially in the medium to long term) remains as a far-from-being-clear issue.

Since the very beginning of the restructuring process, back in 1982 in Chile, the ability of an electricity market to provide the system with the required level of security-of-supply has been put into question. Some authors, for instance Pérez-Arriaga (2001), Stoft (2002), Hogan (2005), and Joskow (2007) contributed to this debate by claiming that, in a number of different contexts, and for a variety of reasons, there is a market failure. This is arguably one of the issues of greatest importance still awaiting a solution under the current regulatory scheme. Although no international consensus has been reached in this regard, with countries opting for one alternative or the other, the more and more accepted existence of this market failure leads to the conclusion that without regulatory intervention, the market, left to its own devices, is unable to provide sufficient generation availability when needed. Indeed, as shown in Batlle and Rodilla (2010), in almost every electricity market, in one way or another, the regulator has designed some kind of rule to drive or put boundaries to the natural market evolution in an attempt to guarantee supply in the short, medium and long term.

Next we discuss this issue, analyzing the reasons that are leading actual markets to the necessity of this regulatory intervention so as to ensure security of supply. We first review the major results stemming from the marginal theory applied to electricity markets, showing how short-term prices, under ideal hypothesis, are supposed to drive and efficient operation, planning and investments.

3 IDEALLY THE MARKET SOLVES THE PROBLEM

Under a market-based scheme, driven by demand and supply laws, an equilibrium price[1] and an equilibrium quantity are determined as the result of generators and demand interaction in the market.

In perfect competitive short-term markets, on the one hand all generators' supply offers should reflect their actual production costs, and on the other hand, demand bids should reflect their willingness (utility) to purchase electricity. The equilibrium price, also known as the system's *marginal price*, should ideally be equal the demand's marginal utility, which except in the case of an scarcity in the generation resources, should also equal the system's marginal production cost[2].

Under several strong simplifying hypotheses, these short-term marginal prices are known to provide optimal incentives for the efficient operation and investments that will lead to the maximization of the system's overall efficiency.

The most relevant ideal hypotheses are:

- Both generators' costs functions and demand's utility functions are convex and no complex conditions are being considered[3].
- Risk can be allocated efficiently. That is, there is a well-functioning long-term market. Indeed, most of the theoretical analyses are based on the risk neutrality assumption.
- Generators can only get revenue from the sale of their energy in the short term market.

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[1] Assuming that a single price is used to clear the market.

[2] This statement holds as long as cost and utility functions are convex and no complex conditions are being considered.

[3] Although these hypotheses do not hold in electricity systems, we will not analyze here the difficulties that non-convexities and complex conditions may introduce. The definition of market prices when there are non convexities exceeds the scope of this paper. For a comprehensive and detailed description of the problem, see Vázquez (2003), Hogan and Ring (2003) and O'Neill et al. (2005).

- There are neither economies of scale nor lumpy investments.

- There is a perfect competitive market with perfect information.

It can be demonstrated that under such as context, the expected outcome of a perfect competitive market model (in which market agents make decisions in a decentralized way) equals that which is achieved by the traditional utility model with perfect information (in which the utility centralizes decisions to meet demand, maximizing the system's net social benefit).

Next, we develop the analytical demonstration of this issue. The classical approach assumes demand is fully inelastic. Here, in order to widen the scope of the analysis, we express the demand-side problem on the basis of the utility function. This allows us to illustrate the role of demand preferences in the market price determination, and accordingly, to highlight a (sometimes forgotten) key result which has significant regulatory implications: the fact that in case of scarcity the efficient market price should be set by the demand (by the marginal utility, not by any of the marginal costs of the generating plants). Later on in section 4.3 we revisit this discussion when reviewing the impact of regulatory establishing a price cap. Moreover, this problem might arise even in case that no "explicit" price cap is set, since as later analyzed, electricity regulators, under the threat of generation scarcity, often resort to "out-of-the-market" measures complicating the optimal price formation process.

Optimal short-term prices under ideal hypotheses

The application of the microeconomic marginal theory to the electric power systems was first sketched by a MIT research group, see Caramanis et al. (1982), Caramanis (1982), Bohn et al. (1984) and Schweppe et al. (1988) and has been subsequently complemented and refined by some other works, among others Pérez-Arriaga (1994), Pérez-Arriaga and Meseguer (1997) and Baughman et al. (1997).

The classic analysis makes use of a reference model, which consists in an ideal centralized planner having perfect information about costs and agents' preferences, and whose objective is the maximization of the net social benefit. This reference model is compared with that of resulting from a market context where short-term energy prices are the sole signal driving agents' decisions. The main objective is to analyze whether or not both contexts are equivalent, in other words, whether or not short-term market prices are capable of driving an efficient operation, planning and investments. It is relevant to remind that this analysis is based on a series of hypothesis previously enumerated.

Optimal prices for operation

The optimal centralized operation problem consists in a central planner maximizing the net social benefit. Thus, this central planner's problem can be schematically represented as:

$$\begin{aligned} &\underset{q_{ih}}{Max} \quad \sum_h [U_{dh}(\sum_i q_{ih}) - \sum_i C_i(q_{ih})] \\ &s.t. \\ &\qquad q_{ih} \le \overline{q}_{ih} \quad \perp \psi_{ih}, \quad R(q_{ih}) = 0 \quad \perp \zeta_{ih} \end{aligned}$$

Where:

$C_i(q_{ih})$ are the variable costs incurred by the unit i when producing the quantity q_{ih} in the hour h

U_{dh} represents the demand utility function in hour h for the total consumption Q_h, where $Q_h = \sum_i q_{ih}$.

$\overline{q}_{ih}$ is the maximum output limit of unit i in hour h.

$R(q_{ih}) = 0$ represents schematically the operational technical constraints of the different generating units.

ψ_{ih} and ζ_{ih} are the dual variables of the previous constraints.

By forming the Lagrangian function and then calculating the first order derivative with respect to the decision variables (q_{ih}) we obtain the optimality conditions of the central planner's problem:

$$\frac{dU_{dh}(\sum_i q_{ih})}{dq_{ih}} - \frac{dC_i(q_{ih})}{dq_{ih}} + \psi_{ih} + \frac{dR(q_{ih})}{dq_{ih}}\zeta_{ih} = 0 \Rightarrow$$
$$\Rightarrow \frac{dU_{dh}(Q_h)}{dQ_h} = \frac{dC_i(q_{ih})}{dq_{ih}} - \psi_{ih} - \frac{dR(q_{ih})}{dq_{ih}}\zeta_{ih}$$

In order to better understand this expression, let us consider that generation unit $i's$ output limits and technical constraints are not binding (i.e. ψ_{ih} and ζ_{ih} have a zero value). In this case, the generating unit i should produce in each hour up to the level in which its marginal costs equals the marginal demand utility, in other words, the cost of producing an additional unit ($/MWh) should equal the price ($/MWh) that the demand is willing to pay for the last MWh consumed.

On the other hand, the demand's and generators' problems in a market context can be represented as:

Demand's problem

$$\underset{Q_h}{Max} \quad \sum_h [U_{dh}(Q_h) - \pi_h \cdot Q_h]$$

Generator's problem

$$\underset{q_{ih}}{Max} \quad \sum_h [\pi_h \cdot \sum_i q_{ih} - \sum_i C_i(q_{ih})]$$
$$s.t.$$
$$q_{ih} \leq \overline{q}_{ih} \quad \perp \psi_{ih}, \quad R(q_{ih}) = 0 \quad \perp \zeta_{ih}$$

Where:

π_h is the market price in hour h.

Again, we obtain the first order condition for each one of the corresponding Lagrangian functions with respect to the decision variables (Q_h and q_{ih} respectively) so as to analyze the optimality conditions of each problem:

Demand's optimality conditions

$$\frac{dU_{dh}(Q_h)}{dQ_h} = \pi_h$$

Generators' optimality conditions

$$\pi_h = \frac{dC_i(q_{ih})}{dq_{ih}} - \psi_{ih} - \frac{dR(q_{ih})}{dq_{ih}}\zeta_{ih}$$

It is straightforward to check how these optimality conditions are equivalent to the conditions obtained in the central planner problem. Therefore, under the ideal hypotheses enumerated above, both contexts should provide the same outcome.

Note that short-term prices should always be determined by the marginal demand utility. These short-term prices are also equal the marginal costs of the marginal unit when there is enough generating capability to meet demand needs. However, in the particular case where all existing plants are at their full capacity, since ψ_{ih} will no longer be zero, the market price will not correspond to any of the generators' marginal costs. This is a very important result that will be used in the following: when there is not enough generation to meet demand requirements, the price has to be set by the demand (not by any of the marginal costs of the generating plants) so as to ensure an efficient outcome.

Optimal prices for investment

We have seen how short-term prices should drive an efficient operation in a market context. But, in order to conclude that both, the ideal central planner and the market context, lead to the same results, it is essential to prove that short-term market prices send also optimal signals to long-term investments. With this purpose we next extend the previous analysis in order to include the investments in generation.

The new optimal centralized operation and investment problem can be schematically represented as:

$$\begin{aligned}
&\underset{\overline{q}_{ih}}{Max} \quad NSB(q_{ih}, \overline{q}_{ih}) - \sum_i IC_i(\overline{q}_{ih}) \\
&NSB = \begin{cases} \underset{q_{ih}}{Max} \quad \sum_h [U_{dh}(\sum_i q_{ih}) - \sum_i C_i(q_{ih})] \\ s.t. \\ \qquad q_{ih} \le \overline{q}_{ih} \quad \perp \psi_{ih}, \quad R(q_{ih}) = 0 \quad \perp \zeta_{ih} \end{cases}
\end{aligned}$$

Where NSB is the short-term net social benefit, i.e. the objective function of the centralized scheduling problem and IC_i represents the investment costs of the generating plant i.

The optimality condition of the investment problem is:

$$\frac{dNSB}{d\overline{q}_{ih}} = \frac{dIC_i(\overline{q}_{ih})}{d\overline{q}_{ih}}$$

Meaning that investments should be carried out up to the point in which the long-term marginal cost equals the short-term marginal increment of the net social benefit. In the operation problem, if we take into account the relation existing between the objective function and the dual variable ψ_{ih} we have:

$$\frac{dNSB}{d\overline{q}_{ih}} = \psi_{ih} \Rightarrow \psi_{ih} = \frac{dIC_i(\overline{q}_{ih})}{d\overline{q}_{ih}}$$

Thus, if we introduce the previous expression in the first order condition of the operation problem:

$$\frac{dU_{dh}(Q_h)}{dQ_h} - \frac{dC_i(q_{ih})}{dq_{ih}} + \frac{dR(q_{ih})}{dq_{ih}}\zeta_{ih} = -\frac{dIC_i(\overline{q}_{ih})}{d\overline{q}_{ih}}, \forall i, h$$

On the other hand the generators' and demand problem in a market context can be represented as:

Demand's problem

$$\underset{Q_h}{Max} \quad \sum_h [U_{dh}(Q_h) - \pi_h \cdot Q_h]$$

Generator's problem

$$\underset{\overline{q}_{ih}}{Max} \quad B - \sum_i IC_i(\overline{q}_{ih})$$

$$B = \begin{cases} \underset{q_{ih}}{Max} \quad \sum_h [\pi_h \cdot \sum_i q_{ih} - \sum_i C_i(q_{ih})] \\ s.t. \\ \qquad q_{ih} \leq \overline{q}_{ih} \quad \perp \psi_{ih}, \quad R(q_{ih}) = 0 \quad \perp \zeta_{ih} \end{cases}$$

Where B is the generator accumulated benefit (along the period considered) in the short-term market, i.e. the objective function of the generator's operation dispatch problem in a market context.

The optimality conditions of this problem are:

Demand's optimality conditions

$$\frac{dU_{dh}(Q_h)}{dQ_h} = \pi_h, \forall h$$

Generators' optimality conditions

$$\frac{dB}{d\overline{q}_{ih}} = \frac{dIC_i(\overline{q}_{ih})}{d\overline{q}_{ih}} \Rightarrow \psi_{ih} = \frac{dIC_i(\overline{q}_{ih})}{d\overline{q}_{ih}}, \forall i,h$$

$$\pi_h = \frac{dC_i(q_{ih})}{dq_{ih}} - \psi_{ih} - \frac{dR(q_{ih})}{dq_{ih}}\zeta_{ih}, \forall i,h$$

Again, it is straightforward to check how these optimality conditions are equivalent to the conditions obtained in the central planner problem. Therefore, under the ideal hypotheses enumerated above, both contexts should provide the same outcome in terms of operation and investments.

4 MARKET IMPERFECTIONS AND FLAWED REGULATORY RULES

Before revisiting the discussion of the nature of the so-called market failure in the context of real electricity markets, we briefly present two relevant imperfections that will not be discussed here, for they are considered to fall outside of the scope of the present work:

- The first imperfection is the non-existence of the ideal conditions to introduce the "reform" at the generation level. We will not analyze here the direct and indirect effects derived from not having the well-known textbook conditions for the introduction of competition at the generation level: no economies of scale, vertical unbundling, an adequate horizontal structure, etc. For further details on this textbook conditions see Joskow (2006)

- The second imperfection is the lack of effective short-term demand elasticity. Although ideally, the most efficient result would be achieved if prices were perceived by the demand-side in real time, this is still far from being the case in electricity systems. Nowadays there are still some barriers that avoid this situation from being fully achieved (although less and less as time passes, thanks to the so-called smart meters and demand response programs).

  For the efficiency of the whole scheme, and from a theoretical point of view, it is essential that in case of a scarcity, the price could be determined by the demand offer curve. Otherwise markets will not provide effective incentives for efficient resource management, either to new generators to come or to generators that are already present in the market. Today, this demand price has to be administratively determined. The problem, as reviewed next, is that when calculating this price, several other considerations are taken into account..

Thus, considering that we have the textbook conditions for the implementation of the reform, and also taking as a boundary conditions the inexistence of short-term demand elasticity, we next analyze the impact of the non-accomplishment of some relevant previously mentioned ideal hypotheses, namely:

- The consequences of the lumpiness problem in generation (affects investments).
- The consequences of an inefficient risk allocation (affects both resource management and investments).
- The consequences of introducing regulatory flawed rules that distort the market signals (affects both resource management and investments).

4.1 The effect of the existence of the lumpiness problem in generation

Investments in generation are lumpy, that means that certain technologies present a minimum feasible size (installed MWs). This problem has an important implication: short-term prices may not be capable of providing the optimal ideal signal described in section 3. However, this effect is negligible if the size of the system is sufficiently large with respect to this minimum feasible size of the different technologies.

Nevertheless, in small systems the result can be dramatic: high prices in the market cannot provide a correct signal for an investor, since the correct (and optimal) amount of investment, i.e. the one that would recover at least both the investment and operation costs, is not feasible. To illustrate this problem with a real example we present below the situation in Peru by March 2009.

When the market started, a capacity payment (additional fixed annual remuneration to reward installed capacity) was implemented. The value of this payment was determined by taking as a reference the investment cost of a new investment in an efficient peaking plant (an open-cycle gas turbine). This payment constituted an incentive for "undesirable" generators, leading to a dash for extremely expensive junk peak generation, due to their relatively small capital requirements. This has led to a situation in which, from the standpoint of reliability, the reserve margin is much larger than is theoretically suitable but at the same time, prices are significantly high. The left graph of Figure 1 illustrates the current situation.

A quick look at it might lead to the conclusion that installing an efficient generating plant would be extremely good business for a potential investor. But unfortunately this is not the case, due to the existence of an (in this case penalizing) lumpiness problem. The fact that such prices will disappear as soon as a more efficient generating unit comes on stream, is one of the reasons discouraging the investment needed to remedy the scarcity episodes to which the system is presently prone (other reason is risk aversion, reviewed later). Figure 1 illustrates the consequences of installing a brand new combined-cycle gas turbine of, for instance, 400 MW.

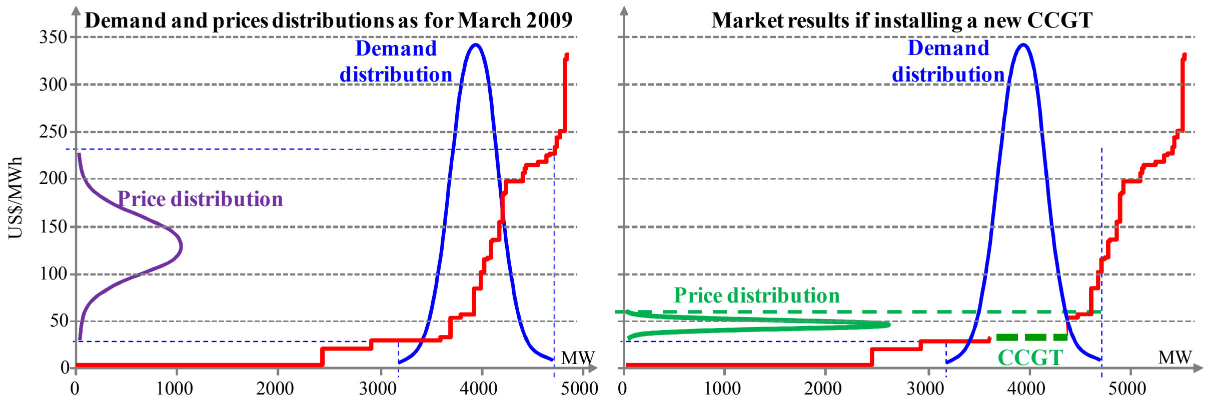

Figure 1. A real case example on the lumpiness problem: the Peruvian power system.

4.2 Agents risk aversion and the consequences of an inefficient allocation of risk

Power generation investment decision-making risk is high and failures[4] are likely. Risk, although to a lesser extent, also plays a key role in the resource management decision-making process.

[4] By 'investment failures' we make reference to those investments that do not maximize the net social benefit as much as other available possibilities would have. The uncertainty involved in the power sector investment decision-making process is the main factor responsible for these suboptimal (when evaluated ex-post) investments.

The traditional regulatory scheme

In the traditional regulatory scheme, a government-controlled centralised co-ordinator is responsible for overall electric power system operation decisions, resource management, control and monitoring. This body is likewise entrusted with the formulation of plans for system expansion as regards the installation of both new generating capacity and transmission grid lines and facilities.

In this context, the regulator has traditionally provided a risk free environment for generators, meaning that, the risks involved were not borne at all by those who actually invest. Thus, in this context, errors in planning are paid for by (not always all) customers via tariff or even the whole society through the general budget.

From the resource management perspective, the regulator again provides an stable remuneration to generators, and decisions are also taken by the regulator. Thus, potential inefficiencies stemming from over-contracting fuel provisions or from planning an excessively conservative water reservoir management are in the end completely borne by the final consumers.

This is an extreme risk management strategy, where generation is fully hedged and bears no risk.

As we discuss next, in the market context, risk can be ideally more efficiently allocated between the different agents through market signals and market mechanisms.

Generation risks in a fully liberalized market

In a business in competition, each generator decides its investments for itself and profitability is not necessarily guaranteed ex-ante (it will depend on the agents preferences in the long-term markets). Analogously, each agent has to decide the medium term resource management of its generating plants, and again the profitability of its decisions is not necessarily guaranteed.

For many different reasons, risk aversion is a particularly relevant characteristic defining generators' behavior in power markets, and as we next comment, it significantly affects a generator's decisions regarding long-term investments and medium-term resource management[5] (e.g. water reservoir management, fuel provision, maintenance scheduling, etc.).

How generators' risk aversion affects long-term investments

New facilities require very large investments, they take time to be installed and operational and there is a lot of uncertainty involved during the typically long economic lifespan (due to, among others, technological, price and regulatory uncertainty). These issues make investment especially risky and also make generators more risk averse than investors in other types of markets. The major consequence is that generators, in the absence of long-term contracts, in their attempt to protect themselves against low price scenarios will tend to install less capacity than if they were risk-neutral.

How generators' risk aversion may affect medium term resource management

In real systems, suppliers have to make important decisions (generally in the medium term) to ensure the capability of existing generation to produce electricity in the future. Thus they have to sign contracts to procure their future fuel requirements[6], they have to decide when it will be more profitable to produce using the limited hydro energy resources available (under the uncertainty of future inflows or the risk of spillage) or they have to decide when to carry out plant maintenance. All these decisions will affect the availability of electricity in the future, and thus, the system's security of supply level. But again, in the absence of long-term contracts, in their attempt to protect themselves against risks (low prices, losses derived from water spillages, fuel overcontracting, etc.) generators will be conservative and for instance, they will prefer to produce with the limited water resources when prices are moderately high rather than wait for the possible uncertain scarcity in generating resources (implying very high peak prices) in the future.

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[5] The importance and the effect of generators' risk aversion depend on the particular structure and characteristics of the system.

[6] Some contracts may imply rigid constraints as is the case with the "take or pay" or "use it or lose it" modalities.

There are good number of real case examples we could mention to illustrate how extreme volatility affects investors in generation (for instance Colombia or New Zealand), but maybe the Brazilian case is the most paradigmatic one. Brazil represents an extreme example of a hydro-dominated system, for very large hydrological cycles tend to make generators' income very volatile during a plant's lifespan, see Barroso et al. (2006). These characteristics lead to the market prices and centrally managed reservoir levels represented in the following figure.

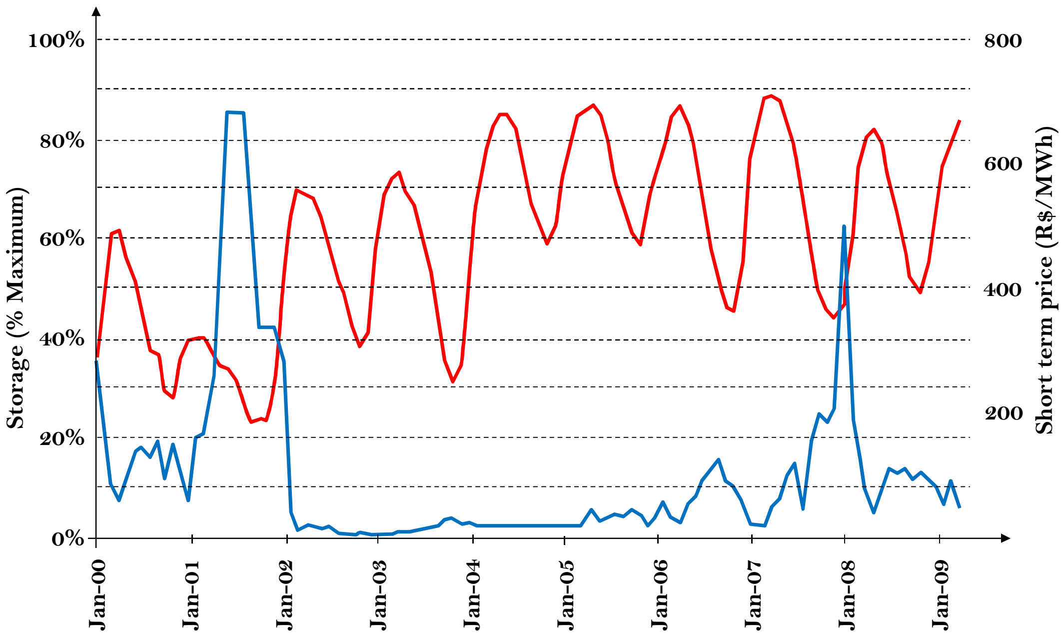

Figure 2. Market prices in Brazil from 2000 to 2009 (Barroso, 2009).

In principle, an energy scarcity such as the one that, due to the exhaustion of hydro reserves, affected the country for nine months during 2001-2002 and resulted in extremely high prices should theoretically be incentive enough for both optimal resource management and investment in suitable generation (not only hydro but also thermal generating units).

Although Brazil is a centralized electricity system, these extreme prices serve to illustrate that when the risk involved in a fully liberalized context is as large as the one observed in this case, a risk averse generator not able to sign long-term contracts would certainly tend to take medium- and long-term conservative decisions. Indeed, with respect to long-term investments, there is no practical way to get any project financing on the basis of an expectation of high profits in perhaps five or seven years' time, if ever.

The other side of the market: demand is also risk averse

Risk-averse consumers want to protect themselves against high prices, and would therefore prefer a system with greater installed capacity and greater resource availability than they would prefer if they were risk-neutral.

The ideal market based solution

From a theoretical perspective, there are consistent reasons that support the idea that in a market scheme, both the generation and the demand have enough incentives to hedge their risk and thus allocate the risk efficiently (by signing long-term contracts). In the case of the generator, we have seen how volatile prices may difficult the project finance, or may lead to a sub-optimal resource management (derived from being conservative in the use of the resources).

In the case of the demand there are also clear incentives to enter into long term contracts:

- First, long-term contracting provides demand with the means to hedge against the aforementioned peak prices.
- Second, there are benefits resulting from an efficient management of the generation-side risk.
  - It is widely accepted that the required expected return on an investment (in any asset but particularly in a generating unit) depends critically on the degree of risk involved (the higher the risk the higher the expected rate of return). Therefore, if demand plays a role in the long-term market and collaborates in the risk management process by signing long-term contracts, it reduces generators' risk exposure, and consequently their required expected rate of return.
  - By entering into long-term contracts a more efficient medium-term resource management can also be achieved, see Rodilla et al. (2010).
  - For all these reasons, even if the demand was risk neutral, by entering into long-term contracts, a more efficient outcome is achieved. It is a well-known result, that when at least one of the market sides is risk averse, the net social benefit can be maximized by means of well-functioning long-term markets.

By liberalizing the generation sector, a means to efficiently allocate the risk between the different agents is ideally found, since both sides have clear incentives to take optimal decisions which should ideally lead to the maximisation of the net social benefit.

Therefore, in this context a long-term market should spontaneously arise that would supplement the spot market and solve the risk aversion problem. In this way, agents' risk management would be left to be entirely determined by market forces[7].

This way, in the new liberalized context, both sides of the market also have to bear part of the risk involved in the investment and resource management processes. A serious problem arises when this is forgotten, and this has been the case with most supplier (retail and particularly regulated retail) companies worldwide, which typically commit to purchasing electricity at the price applicable to their wholesale market operations but have yet to enter into long-term commitments (i. e. longer than a year). This modus operandi has been mainly driven by a complete reliance on the fact that "somebody else will ensure the supply"[8].

The need of learning processes of immature electricity markets

Real electricity markets, even after more than two decades of functioning, cannot yet be considered mature. Even in those rare markets where demand is really exposed to spot prices, long-term contracts (with a duration of more than one year) are not entered into. Most consumers are not mature enough to realize the risks involved in electricity markets and in these cases they tend to make their decisions using only very short-run criteria.

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[7] This does not mean that introducing long-term markets guarantees an efficient outcome. Several experiences (the case of OMIP in the Iberian market is a clear example) have shown that if the regulator decides to put in place (and even provide some funding) a long-tem market (power exchange), this does not bring demand participation. Efficient long-term markets arise because of the willingness of market participants. Regulators can help by creating a suitable transparent framework for trade, but if the market structure conditions are not adequate, artificially implementing a trading floor makes no difference.

[8] It has been also pointed out that allowing consumers to change retailer without penalization does not provide the right incentive for long-term contracting, see Neuhoff and de Vries (2004).

This lack of demand-side response creates a malfunctioning of the long-term market that cannot be solved in the short run, and it causes both a lack of generation investment and also a very conservative (and thus inefficient) medium term resource management, which paves the way for potential future shortages. Note that the need here is not just for consumers to demand less energy from the market when prices are high -this is the typical goal of demand-side management programs- but especially for them to sign efficient hedging contracts to express their need for a higher security of supply level(i. e., to express their risk aversion).

The most orthodox solution to this problem would be to do nothing[9]. Consumers, having not signed contracts, would suffer the high prices and the severe consequences which derive from rotating blackouts and, the following year, some of them would realize the need to protect themselves against this situation and would sign some contracts. This process would continue until consumers understood how to operate efficiently in the long-term market.

This reasoning has been defended by various authors in the literature to support the argument that there is no need for any specific security-of-supply regulation. The most common case taken as paradigmatic of this view is the supply shock that hit the Nordic electricity market in 2002-2003 (Von der Fehr et al., 2005).

Regulators' risk aversion

Given what we have seen internationally thus far, it is likely that a long learning period, which may include several rationing episodes, would ultimately be considered to be more of a problem caused by the market than a problem caused by consumers that are not acting efficiently.

Electricity is an essential good, without an easy replacement in modern society; shortages of electricity have significant social and political implications which make politicians, regulators and system operators particularly aware of the need for a reliable electricity supply. In most systems, and this was the case for instance in California and Ontario, the market rules will be changed

[9] Although some educational programs which provide information about the potential consequences of not contracting may help to reduce the potential impact.

dramatically before consumers have time to complete their learning process. The long-term market will never reach a steady state because it will be completely refurbished before that can happen. In fact, what underlies beneath this problem is the principle that a wise regulator should not assign responsibilities to any individual who is not prepared to carry them out appropriately. In addition, nowadays there is a common (although arguable) belief that most of the demand is not yet prepared to deal efficiently with the long-term security of supply problem.

This discussion can therefore be summarized as follows: politicians' risk aversion is by far larger than that of almost any power consumer. Regulated rates preclude the need for protection against high prices and even consumers initially exposed to spot market prices ignore reliability when making their decisions. There is a certain implicit assurance that leads consumers to believe that the regulator will never allow supply shortfalls or inordinately high prices that would jeopardise their interests.

The consequence of the above is dramatic from the market functioning standpoing, demand does not respond suitably in the long-term market. Consumers take no interest in a suitable level of security of supply -mainly because there is no real need - and therefore do not include the item in the pricing process. This affects both to the installation of new generation and to the medium term resource management, which will in the end affect the security of supply of the system.

After reviewing the role of risk aversion in the absence of well functioning market for risk, we next analyze another relevant source of inefficiencies: the existence of regulatory flawed rules. This last factor is the responsible of the so-called "missing money" problem.

4.3 The consequences of introducing regulatory flawed rules that distort market signals

It has been long debated in the literature the importance of having an appropriate pricing mechanism to be applied in the event that the market fails to provide enough supply to meet the demand. Indeed, this is considered as one of the cornerstones of the market model.

However, more often than not, we still find many regulators intervening in the short-term marginal signal with the aim of limiting the revenue that generators can extract from the market. These measures are in most cases justified by the absence of adequate demand elasticity, and represent an attempt to administratively determine the value of non-served energy. The problem is that at the same time, the regulator also introduces some other considerations when determining this relevant value:

- to limit market power, since in the event of the reserve margin tightening drastically, generators could eventually bid (and be committed) at extremely high prices,
- to directly and artificially decrease the inframarginal income of generating units. This approach is currently in force in some Latin American markets, in which, for various reasons, the only generating units which have entered the market in recent years are extremely inefficient and therefore expensive fuel plants.

In particular, these regulators' interventions in the determining of marginal market pricing formation have taken many different forms:

Price or offer caps

- Explicit price caps for market prices, for example, 180 €/MWh in the Spanish market or 1000 $/MWh in Alberta, see AESO (2009). See Batlle et al. (2009) for a simple illustrative analysis of the long-term effect of introducing a price cap.
  - "Failure price" ("Precio de falla"), in force in certain Latin America power markets. This consists of an administratively defined maximum market price to be paid to the generators committed in hours in which a certain failure has been declared, with the exception of those plants that can certify that their production costs are higher. These plants are paid-as-bid.
- "Offer caps", i. e. codes defining constraints to generators bids. For example:
  - in the Spanish electricity market, the law stipulates that generation units are 'obliged to make economic bids', see Comisión Nacional de Energía (2005);
  - in the Irish market, the "Bidding Code of Practice" stipulates that generating units have to based on the "Opportunity Cost", defined as 'the value of the benefit foregone by a generator in employing that cost-item for the purposes of electricity generation, by reference to the most

valuable realizable alternative use of that cost-item for purposes other than electricity generation', see All Island Project (2007);

- in California, the Automatic Mitigation Procedure (AMP) implemented in 2002, intended to limit the ability of suppliers of energy in the real-time market to exercise market power. This basically consists in an automatic comparison with previous bids. If an offer price is too high, the AMP reduces it to a price reference that is in accordance with the cost of production in that power plant.

• "Operating reserve shortage" actions. In other cases, when operating reserves fall below a certain level, the SO take "out-of-the-market" actions, such as voltage reductions and non-price rationing of demand (rolling blackouts), to reduce demand administratively see Joskow (2005). These types of measures complicate the price formation process in conditions of scarcity, and again affect the proper and expected recovery of generation investments[10].

All these measures lead to a situation in which in one way or another, the system's marginal prices are only based on generation bids, precluding the participation of the demand in the determination of these prices. The existence of these rules, with their influence on short term market price formation, may affect both the suppliers' medium term resource management and long-term investments. With respect to the latter, these regulatory interventions can hinder the recuperation of the investment costs of those generation units which have already been installed, which, in the longer term, may lead the generation system to expand in ways which are a long way from what is theoretically supposed to be the perfectly adapted situation as described previously.

Long-term markets could alleviate the effect of these flawed short-term regulatory rules

Intervening in short-term prices has severe consequences, but this does not necessarily mean that under this scenario it is impossible for the liberalized market approach to guarantee the recovery of investments. As stated, the fundamental problem is again the lack of demand-side participation. By contracting in the long term, demand could alleviate the effect of these flawed regulatory rules.

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[10] Another similar example is the Maximum Generation Service contracted by the SO in UK (NGET,).

5 THE NEED FOR REGULATORY INTERVENTION

Under the market-oriented paradigm, the new regulation must make sure that the appropriate incentives exist so as to ensure an efficient long-term security of supply level. We have shown that although ideally the market itself should be enough to provide adequate production resource management and investment incentives, there are several factors that prevent this result from being achieved, and some actually existing markets have already experienced problems related with a lack of generation availability (due to lack of production resources that may have been caused by a deficient middle-term resource management and/or by a lack of new investments).

This market failure, sometimes "helped" by some of the aforementioned regulatory interventions regarding short-term price formation, results in the so-called "missing money problem"[11], the "missing signals problem", "missing markets problem", etc. In the end, this has led to the conclusion that in most cases some kind of regulatory intervention is required.

In this context the regulator has two alternatives to deal with long-term security of supply: to do nothing (in the belief that the market will provide an efficient result, hopefully sooner rather than later, given the possibility of periods of scarcity in the meantime) or to take an active role trying to represent its own view about demand's best interests by introducing a long-term mechanism.

Once the regulator has decided to undertake the task of "helping" the market to reach what he/she considers to be an efficient outcome, the next key question is how to introduce the necessary adjustments in the market design in place so as to achieve the objective pursued in the long term. This is particularly complicated and controversial, because in the end, all long-term planning may, directly or indirectly, fall again into the hands of a central planner, and we should not forget that avoiding the potential inefficiencies stemming from the central planner scheme was one of the principal motors behind the liberalization wave that started a few decades ago.

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[11] By the "missing money problem" we refer to the unrecovered fraction of the investment costs that arises when regulators impose price caps with the objective of limiting prices during scarcity situations. The term was popularized by Shanker (2003).

The exhaustive and critical review of the international experience illustrates that the design of a long-term mechanism to acquire a certain reliability product presents challenges that if not properly solved may result in the end in undesired market outcomes, see Batlle and Pérez-Arriaga (2008) or Batlle and Rodilla (2010).

The regulation design problem, not the market problem

In the light of the evidence discussed throughout this paper, one might conclude (as is often the case) that the market resulting from the reform of the electricity carried out over recent decades is not the right alternative. However, we consider that the final problem is not the market approach itself, but the lack of adequate regulatory mechanisms to deal with the complications that real life markets may present. These regulatory flaws have resurrected and encouraged numerous lines of argument in favor of a step back towards the traditional centralized (even nationalized) model; for instance, in the case of Ecuador, see Batlle et al. (2010).

But just a quick look at some electricity systems in which the market reform has not been implemented shows that they have not escaped similar or even worse problems. In this respect, the latest news from Venezuela or Mexico illustrates the fact that the formerly traditional centralized model also does not guarantee an "adequate and sufficient" functioning of the electricity system.

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