Economic Inefficiencies of Cost-based Electricity Market Designs

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ABSTRACT

Some restructured power systems rely on audited cost information instead of competitive bids for the dispatch and pricing of electricity in real time, particularly in hydro systems in Latin America. Audited costs are also substituted for bids in U.S. markets when local market power is demonstrated to be present. Regulators that favor a cost-based design argue that this is more appropriate for systems with a small number of generation firms because it eliminates the possibilities for generators to behave strategically in the spot market, which is a main concern in bid-based markets. We discuss existing results on market power issues in cost- and bid-based designs and present a counterintuitive example, in which forcing spot prices to be equal to marginal costs in a concentrated market can actually yield lower social welfare than under a bid-based market design due to perverse investment incentives. Additionally, we discuss the difficulty of auditing the true opportunity costs of generators in cost-based markets and how this can lead to distorted dispatch schedules and prices, ultimately affecting the long-term economic efficiency of a system. An important example is opportunity costs that diverge from direct fuel costs due to energy or start limits, or other generator constraints. Most of these arise because of physical and financial inflexibilities that become more relevant with increasing shares of variable and unpredictable generation from renewables.

Keywords: Electricity market design, market power, equilibrium modeling, opportunity costs

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1. INTRODUCTION

Deregulated electricity markets have been in place for nearly three decades. In the 1980s Chile and the U.K. were the first countries to divide the old vertically-integrated monopolies into private generation, transmission, and distribution companies. To date more than 30 countries and states in the U.S. rely on merchant generation firms to ensure adequate investment in new generation capacity to supply electricity at minimum cost to final consumers, with varying degrees of success (Griffin & Puller, 2009).

One feature of deregulation that is not uniform among all countries and states that have implemented competitive markets for generation is how they dispatch and price electricity in real

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time. A large group of deregulated markets allow generators to submit their supply curves (which may reflect opportunity cost) as bids to a centralized auction that is coordinated and cleared by a System Operator (SO). Some examples of such bid-based markets include the ones in PJM, California, Texas, MISO, New England, New Zealand, and Colombia. In contrast, there is another group of restructured markets where generators are not allowed to bid their supply curves. Some of these include Chile, Bolivia, Peru, Brazil, and countries in Central America (Hammons et al., 2002). In these markets, the SO or system regulator performs audits of all generation parameters (i.e., heat rates, minimum loads, ramping limits, etc.) and fuel costs to estimate each generator's direct marginal operating costs. Based on this information, the SO dispatches generators hour by hour to meet demand at minimum direct cost. The optimization of the dispatch schedules for all generators to meet demand also yields shadow prices for power on every hour and bus in the network, which, depending on the market design, might be used to settle energy purchases and sales. Hereinafter we refer to this pricing mechanism as a cost-based market design.

One issue that has received little attention in the academic literature is how cost-based markets fare when compared to bid-based ones in terms of their overall economic efficiency. In this article, we discuss several types of economic inefficiencies that can result from relying on audited information instead of on bids that typically reflect both direct and opportunity costs, to determine the optimal dispatch and prices of electricity in a power system. We make two basic arguments. First, it is incorrect to argue that forcing generators to bid their marginal fuel costs eliminates all possibilities for the exercise of market power and thereby increases the economic efficiency of the system. As we will discuss in the literature review and demonstrate with a simple example, by design cost-based markets do indeed, effectively, prevent the exercise of strategic behavior in the short-run—exactly the type of market power that regulators and final consumers are most sensitive to. However, those markets also can provide incentives for generation firms to strategically select capacities and technologies that lead to a long-run equilibrium that is distant from a perfectly competitive one, and that the resulting market inefficiency is difficult to correct through market rules if investments are deregulated.

Our second argument is that, even in the absence of strategic behavior, identifying and auditing the total marginal costs of all generators in real time is challenging and likely to lead to incorrect estimates and inefficient dispatch. Marginal costs have two components: 1) direct costs that are directly attributable expenditures on fuel, operation and maintenance (O&M), and any other variable inputs and 2) opportunity costs. The inefficient dispatch could, in theory, be avoided if generators were allowed to bid both direct and opportunity costs instead of only directly attributable costs. Furthermore, the information required to compute the opportunity costs of all generators in real time goes far beyond the responsibilities of the SO. This requires access to information concerning intertemporal generator constraints as well as on parallel markets, such as natural gas, emissions permits, and renewable energy certificates.

We organize the rest of this paper as follows. In Section 2 we discuss market efficiency and the role of information in the price formation process in competitive electricity markets. In Section 3 we discuss how market power can arise in bid- and cost-based market designs and how difficult it is to detect it. In this section we also provide a counterintuitive example where forcing spot prices to equal marginal costs in a concentrated market can result in lower investment and social welfare than under a bid-based design where generators can behave strategically in the short term. In Section 4 we enumerate and discuss specific challenges of estimating opportunity costs and how inaccurate estimates can distort market efficiency. Some examples include the opportunity costs of conventional generators with inflexible fuel contracts, opportunity costs of generators in markets with emissions and/or renewable energy policies, and intertemporal limits on starts, operating hours, and energy. Finally, in Section 5 we provide conclusions and some policy recommendations.

2. MARKET EFFICIENCY, PRICES, AND INFORMATION

There are two independent concepts that are frequently used to assess the overall economic efficiency of a market: allocative or Pareto efficiency and production efficiency. In simple terms, allocative efficiency is achieved in electricity markets where prices are equal to the marginal cost of supplying an additional unit of energy (Green, 2000). This marginal cost captures not only the incremental fuel cost, if the additional power is produced using fuel-powered plant, but also any opportunity cost incurred by a generator that supplies power to the market or, if there is scarcity, the marginal benefit of consumption. Allocative inefficiency means that too much or too little electricity is produced and consumed. On the other hand, an electricity market is said to achieve production efficiency if power is produced in a way that minimizes the total cost of producing that amount, given the generation technologies that can be chosen from and the transmission infrastructure.[1] Production inefficiency means that more cost (including opportunity costs) is incurred in production than is necessary.

In theory, a central planner (i.e., a vertically-integrated public utility that serves all customers in a geographical region) could achieve both allocative and production efficiency under the assumption of perfect and complete information concerning investment alternatives, future technology and fuel costs, and the true opportunity costs of using any resource to produce electricity at a given time and location, among many other factors. If this assumption is true, a central planner can achieve production efficiency by developing the portfolio of generation technologies that minimizes the present worth of total system costs, which can be identified by solving an optimization model such as the one described in Hobbs (1995). In addition, allocative efficiency can be achieved by later setting electricity prices equal to the Lagrange multipliers of the demand-balance constraints in the model (Wenders, 1976; Sherali et al., 1982), so as to meet any demand whose marginal benefit exceeds marginal cost.[2] Unfortunately, accessing all the needed information is impossible for a centralized authority, which can lead the system to outcomes that are neither allocative nor production efficient. This is a major reason why most generation markets around the world are structured around private, but regulated, utilities or based on deregulated markets for generation. Private firms that seek to maximize profits can have more incentive to obtain information than a central planner.[3]

Private utilities that operate as regulated monopolies have one feature in common with power systems that are centrally planned by a public utility since a single agent, the private utility, makes all investment and operational decisions. However, they differ in what Wolak (2003) refers to as the individual rationality constraint: the objective function of a private utility is to maximize its profits, not to minimize total system costs as public utility. This feature, combined with information asymmetries between the private utility and the regulator results in that *"It is virtually impossible to design a regulatory mechanism that causes a privately owned profit-maximizing firm to produce in a least-cost manner"* (Wolak, 2003, p. 14). Although allocative efficiency could be partially achieved

1. In the rest of the article we ignore transmission as a piece of infrastructure that could affect the production efficiency of an electricity market and focus solely on generation capacities and technologies.

2. This is based on the theory of peak-load pricing developed by Boiteux (1960) and later extended by a series of different authors (Crew et al., 1995).

3. For some, an even stronger argument against central planning is the independence of the electricity market from costly political agendas (Joskow, 2008).

in a system served by a regulated monopoly—under the unlikely scenario that the regulator could access all cost information of the electric utility—firms facing cost-of-service regulation have little incentive to attain production efficiency if all costs could be passed on to final consumers.

The main objective of the introduction of competition in generation has been to increase the overall economic efficiency of the system with respect to what it could be achieved through central planning by publically-owned utilities or regulated monopolies. According to microeconomic theory, if there are no barriers to entry, there is access to perfect information, and scale economies and generation firms are small relative to the size of the market—among several other assumptions—a deregulated market should yield a perfectly competitive outcome that achieves both allocative and production efficiency (Green, 2000). In other words, the best strategy for profit-maximizing firms is to select investments that minimize the average system cost and to have a supply curve that reflects the short-run marginal cost of generation, including all opportunity costs.

Depending on how they are coordinated, deregulated markets are classified as self-committed (bilateral) or centrally-committed (Poolco). In self-committed systems, equilibrium prices emerge as a result of bilateral negotiations between generation firms and retailers or consumers, and the responsibilities of the SO are limited to real-time management of imbalances and ensuring the reliable operation of the grid. In contrast, in a Poolco system, a SO clears the market through a competitive auction where generators can submit bids that reflect the minimum price they are willing to receive for producing power at a given location and time (including non-convex features of their cost structure such as start-up and no-load cost), i.e., their direct and opportunity costs. These bids are an input to the SO's optimization problem that selects dispatch schedules for all generation units and which are used to determine prices that reflect the incremental cost of supplying an additional unit of electricity at a specific time and, in systems with locational marginal pricing, in every node of the network. If information is perfect and markets are perfectly competitive, both bilateral and Poolco structures should reach the same outcome (Wilson, 2002).

Both types of deregulated markets rely on the voluntary participation of agents in the sense that generation firms are free to set the offers that best reflect their direct and opportunity costs of generation, as recommended in the ideal model for deregulation described by Joskow (2008). If generation firms believe they cannot affect the equilibrium price and they behave rationally as price takers, bidding their true direct and opportunity costs is a dominant strategy (i.e., no other bids can increase their profit), which then leads to prices that are allocative efficient in the short run and to investments that result in production efficiency in the long run (Green, 2000).[4] However, if markets are concentrated or there exist barriers to entry, generation firms can make strategic offers that will affect equilibrium prices to their benefit. This means that submitting bids above their marginal costs or withholding capacity in order to increase prices above marginal cost arises as a new dominant strategy (Cramton, 2004).

The result of such exercise of market power is likely to be a decrease in the allocative and production efficiency of the market. Allocation efficiency is harmed because some demand whose marginal benefit is less than price but greater than the marginal cost of serving it will go unsatisfied. Short-run production efficiency decreases because higher prices will encourage smaller firms to produce more power at a marginal cost near to price, partially replacing the lower cost power that larger firms have withdrawn from the market. Long-run production efficiency decreases if large efficient firms decline to expand capacity in order to maintain high prices, while costlier smaller companies partially fill the gap with more expensive investment.

4. This discussion disregards some of the complexities arising from multipart bids of nonconvex costs and the use of bid-cost recovery systems by SOs.

3. MARKET POWER IN BID- AND COST-BASED MARKET DESIGNS

"You can lead a horse to water, but you can't make it drink." —Anonymous

3.1 Theoretical and empirical evidence

In a bid-based market, generation firms have incentives to exercise market power anytime they face a less than perfectly-elastic residual demand curve. They can do so by withholding a fraction of their installed capacity in their offers or by raising their bids, particularly at times when they are pivotal suppliers (Stoft, 2002),[5] i.e., they can induce scarcity by unilaterally withholding production. Part of this behavior can be captured in a Cournot model of oligopolistic competition. The Cournot model is frequently used in electricity markets to depict the effect of strategic behavior, even when the bidding mechanism is not accurately represented by the Cournot model that assumes quantity setting. There is empirical evidence that actual prices in bid-based markets in the U.S. (i.e., California, PJM, and New England) are close to the ones predicted using a static Cournot model, particularly at times when demand is high and generation capacity is scarce (Bushnell et al., 2008). Puller (2007) states that pricing in the California market was approximately Cournot for the major firms during much of the 1998–2000 period.

The exercise of market power has been an important concern in bid-based electricity markets because it can result in potentially large wealth transfers from consumers to producers and deadweight losses. The California electricity crisis is the best example of a restructured electricity market that was gamed at the expense of consumers because market rules were not set correctly. Puller (2007) as well as Lo Prete & Hobbs (2015) analyze the behavior of the 5 largest thermal generators in the California electricity crisis and contrast it with Nash equilibrium levels as well as tacit collusion, and find statistically significant evidence of the exercise of market power. Borenstein et al. (2002) found that nearly 60% of the $6.94 billion increase in electricity expenditures from the summer of 1999 to the summer of 2000 were a direct consequence of non-competitive behavior of generation firms. Since the California crisis, the SOs and the Federal Energy Regulatory Commission (FERC) in the U.S. have implemented a series of measures to mitigate market power in restructured markets with generally satisfactory results, by essentially outlawing any form of price manipulation even if it is technically achieved through actions that are not explicitly prohibited by the tariff. In other words, any price manipulation that would have not been rational for a price taker is deemed illegal.[6]

In contrast, spot markets coordinated through cost-based dispatch and pricing mechanisms do, by design, eliminate most of the possibilities that exist in bid-based designs for generators to exercise unilateral market power. In cost-based markets, fuel costs and technical parameters are audited by the SO and generators have a "must offer" obligation, which diminishes (if not eliminates) the ability of generation firms to withhold capacity or to raise prices above marginal costs.[7] However, contrary to what many regulators believe, forcing the spot market to operate based on short-run

5. A supplier is said to be pivotal if its capacity is needed to meet demand at a specific location and time.

6. Recent actions by J.P. Morgan, abusing the Bid Cost Recovery rules in California (FERC, 2013), and by Morgan Stanley and KeySpan in New York, gaming the installed capacity market (DOJ, 2011), are examples of such behavior.

7. This is only true if the SO or regulator performs periodic revisions to cost and technical parameters of all generators in the system. However, if audits are carried out only sporadically, generation firms might have incentives to report higher fuel costs, higher technical limits, or lower levels of available capacity than the actual ones. Furthermore, some generators may have incentives to report higher than actual forced or other outage rates, which are hardly verifiable by the regulator, leading to the "sick day" problem (Harvey et al., 2004).

fuel costs can affect the production efficiency of a market, even if prices are equal to the marginal cost of generation for reasons we now explain.

The undesirable effect upon production efficiency of forcing prices to be equal to the theoretically competitive levels were first noticed in the era of regulated monopolies. Averch & Johnson (1962) demonstrated that monopolies facing a rate-of-return regulation have incentives to over-invest in capital with respect to the welfare maximizing levels in order to increase their profits, if the allowed rate of return exceeds the market's cost of capital. Currently, many regulated utilities operate under price-cap incentives, which eliminates the Averch-Johnson effect by limiting revenues rather than the return that firms get on invested capital (Braeutigam & Panzar, 1993). Joskow (1974) notes that there can also be a reverse Averch-Johnson effect if rates of return are held below market returns to capital while fuel or other operating expenses are subject to pass-through provisions, so that utilities overspend on operating costs and underinvest in capital.

Similarly, in cost-based electricity markets, firms do not necessarily have incentives to invest in the portfolio of generation technologies that minimizes cost. This issue was first demonstrated in a more general context by Kreps & Scheinkman (1983). The authors show that when firms first select production capacities and then later engage in price competition when determining short-run operating levels (Nash-Bertrand strategy), the equilibrium of that closed-loop game yields the same results of an open-loop Cournot model. In an open-loop Cournot model, firms select investment levels and production quantities simultaneously (rather than in sequence as in the closed-loop case), analogous to a system where all production is sold in long-term contracts and where there is no spot market (Murphy & Smeers, 2005).

Arellano & Serra (2007) extend Kreps & Scheinkman's result to cost-based market designs using a simple closed-loop model with only two generation technologies, peaking and baseload. The authors assume that all generation firms first select investment levels simultaneously; the dispatch and pricing of electricity is done in a later period based on audited short-run fuel costs by an independent SO. They find that under this form of market design, generation firms have incentives to increase the share of the peaking technology beyond the level that maximizes social welfare. By doing so, firms can increase the fraction of time the peaking technology sets the price, which increases the economic profits they receive from generating electricity using their baseload capacity. That solution is not, in general, the same as the open-loop Cournot model. Consequently, the theory shows that if regulators—with their best intention—try to mitigate market power by forcing prices to be equal to short-run marginal cost, producers will have incentives to invest in inefficient generation portfolios, which would ultimately reduce social welfare just like the exercise of short-run market power in bid-based markets.

However, those results do not necessarily imply that it is more desirable to allow the exercise of market power in the short-run by removing restrictions on bidding. The obvious questions therefore remain: What market design is more efficient in the long-run then? A bid-based market, where generation firms can bid strategically, or a cost-based design, where firms might have strong incentives to deviate from the welfare maximizing generation portfolio? Unfortunately, there is no unique answer to these questions. Fershtman & Kamien (1987) show that the equilibrium of a closed-loop game, where firms commit to capacities first and are free to choose productions levels later—analogous to a bid-based design—is closer to the competitive level than the one for the standard open-loop Cournot game. Murphy & Smeers (2005) reach a similar conclusion for investment and spot electricity markets with imperfect competition. The resulting prices and investment levels of the closed-loop equilibrium levels lie between the perfectly competitive levels and the ones observed in the open-loop Cournot equilibrium. Wogrin et al. (2013) compare closed-loop investment models with a generalized production stage using conjectural variations. They find that the rank ordering of closed-loop equilibria in terms of market efficiency is ambiguous and parameter dependent. Thus, the results of Fershtman & Kamien (1987), Murphy & Smeers (2005), and Wogrin et al. (2013) suggest that forcing electricity prices to be equal to short-run marginal fuel costs can be more harmful to the long-run economic efficiency of the system than letting generators exercise market power in bid-based market designs. Cramton (2004) even goes one step further and states that the exercise of market power is a desirable and necessary condition to incentivize new entry.

While we do not go as far as Cramton (2004), with the next simple illustrative example we show that forcing prices to be equal to short-run marginal cost can lead to lower market efficiency than a bid-based market. However, these results are not general and, depending on the parameters, the opposite can occur.

3.2 Market power in cost-based markets: A simple numerical example

Consider a simple system with two load periods $l \in L = \{peak, base\}$ that represent operation in a representative year. The parameter T_l denotes the duration of each period, which we define as T_{peak}=3,760 [hours/year] and T_{base}=5,000 [hours/year]. Consumers choose their demand levels d_l [MW] depending on the price of electricity p_l [\$/MWh] according to a linear demand curve $d_l(p_l) = IC_l - DS_l p_l$ (the inverse demand curve being $p_l(d_l) = IC_l / DS_l - d_l / DS_l$), where the demand intercept is IC_{peak}= 2,000 [MW] and IC_{base}=1,400 [MW] and the demand slope is DS_{peak}= IC_{peak}/250 and DS_{base}= IC_{base}/200, resulting in price intercepts of 250 and 200 [\$/MWh], respectively. There are two competing generation firms $i \in I = \{1,2\}$ in the market that select generation capacities x_i [MW] and generation dispatch levels q_{il} [MW] in order to maximize their profits. For simplicity we assume that there is only one type of technology available for investment and operation for both firms. Its annualized capital cost is K =46,000 [\$/MW-year] and its marginal cost is C =11.8 [\$/MWh].

Consider first the perfectly competitive assumption, where both firms are price takers. As we discussed earlier, the equilibrium under such ideal conditions is equivalent to the investments and dispatch levels that a central planner with perfect information would select trying to maximize social welfare (Samuelson, 1952; Mas-Colell et al., 1995). We find the perfectly competitive equilibrium solving the following optimization problem:

$$\max_{d_l, q_{il}, x_i} \sum_{l \in L} T_l \left[\frac{IC_l}{DS_l} \cdot d_l - \frac{1}{2DS_l} \cdot d_l^2 - \sum_{i \in I} C \cdot q_{il} \right] - \sum_{i \in I} K \cdot x_i \tag{1}$$

$$\text{s.t.} \ \sum_i q_{il} = d_l \quad \forall l \in L \tag{2}$$

$$q_{il} \le x_i \quad \forall l \in L \tag{3}$$

$$d_l, q_{il}, x_i \ge 0 \quad \forall i \in I, l \in L \tag{4}$$

In (1) we maximize social welfare subject to supply-demand balance (2), maximum generation limits (3), and nonnegativity (4). Next, we consider two variations of the closed-loop equilibrium models proposed in Wogrin et al. (2013): a cost- and a bid-based market. In both models generation firms first (upper level) select generation investments simultaneously and later participate in a spot market (lower level) where the dispatch and pricing of electricity is based on either audited costs (cost-based market) or on bids (bid-based market). We emulate a bid-based market using a

Cournot model, since there is empirical evidence that this setting can, approximately, capture strategic firm behavior in bid-based markets (Bushnell et al., 2008; Puller, 2007). In the lower level (spot market), given in (5), generation capacities are fixed, thus, each firm maximizes its profits subject to the (now fixed) generation capacities x_i selected in the upper-level problem:

$$\forall i \in I \left\{ \begin{array}{ll} \max\limits_{p_l, q_{il}} \sum\limits_{l} T_l \cdot (p_l - C) \cdot q_{il} & \\ s.t.\ \ q_{il} \le x_i \ \ (\lambda_{il}) & \forall l \in L \\ \quad\ q_{il} \ge 0 & \forall l \in L \end{array} \right. \tag{5}$$

where in the competitive model, p_l is viewed as a fixed parameter by firm *i,* who only optimizes over q_{il}, while in the Cournot (unconstrained bidding) model, $p_l = p_l(q_{il}, q_{-il}) = p_l\left(\sum_{j \in I} q_{jl}\right)$, and the firm optimizes over q_{il} and p_l. The variable λ_{il} represents the Lagrange multiplier of the capacity constraint. In the cost-based market, the equilibrium of the lower-level problem is equivalent to a perfectly competitive one, which means that generation firms are price takers and the conjectured price response is $\frac{\partial p_l(q_{il}, q_{-il})}{\partial q_{il}} = 0,\ \forall i \in I, l \in L$. The Karush-Kuhn-Tucker (KKT) conditions of the lower-level cost-based market equilibrium problem in complementarity form are the following:

$$0 \le q_{il} \perp T_l \cdot p_l - T_l \cdot C - \lambda_{il} \le 0,\ \ \forall i \in I, l \in L \tag{6}$$

$$0 \le \lambda_{il} \perp q_{il} - x_i \le 0\ ,\ \ \forall i \in I, l \in L \tag{7}$$

In contrast, in a bid-based market generation firms are aware that they can affect the equilibrium price since they recognize that they face a residual demand curve, i.e., price is influenced by their output so that $\frac{\partial p_l(q_{il}, q_{-il})}{\partial q_{il}} = -\frac{1}{DS_l},\ \forall i \in I, l \in L$. In a Cournot version of a bid-based model, each firm *i* views its rivals' production q_{-il} as fixed. The KKT conditions of the lower-level bid-based market equilibrium problem in complementarity form are the following ones:

$$0 \le q_{il} \perp T_l \cdot p_l - T_l \cdot \frac{1}{DS_l} - T_l \cdot C - \lambda_{il} \le 0\ ,\ \ \forall i \in I, l \in L \tag{8}$$

$$0 \le \lambda_{il} \perp q_{il} - x_i \le 0\ ,\ \ \forall i \in I, l \in L \tag{9}$$

Consumers choose their consumption levels d_l trying to maximize their surplus:

$$\max_{d_l} \frac{IC_l}{DS_l} \cdot d_l - \frac{1}{2DS_l} \cdot d_l^2 - p_l \cdot d_l \tag{10}$$

$$\text{s.t.}\ \ d_l \ge 0 \quad \forall l \in L \tag{11}$$

The KKT conditions for consumers in complementarity form are as follows:

$$0 \le d_l \perp \frac{IC_l}{DS_l} - \frac{1}{DS_l} d_l - p_l \le 0\ ,\ \ \forall l \in L \tag{12}$$

Table 1: Summary of results from three different market models.

	Cost-based market	Bid-based market	Central planner
Investments per firm [MW]	504	603	904
p_{peak} [\$/MWh]	124.0	99.4	24.0
p_{base} [\$/MWh]	56.0	74.5	11.8
Consumer surplus [Billion $]	0.6	0.617	1.38
Total profits [Billion $]	0.6	0.617	0
Total welfare [Billion $]	1.21	1.23	1.38

The producer and consumer optimization problems in each spot market are linked together by the following market clearing condition:

$$(p_l \text{ free}) \quad d_l - \sum_{i \in I} q_{il} = 0, \quad \forall l \in L \tag{13}$$

We refer to the lower-level equilibrium (spot market) of the cost-based market model as the **m**arket **e**quilibrium under **p**erfect **c**ompetition (*MEPC*) problem. The solution of the MEPC is defined by the KKT conditions (6), (7), (12), and market clearing condition (13). Similarly, we refer to the lower-level equilibrium of the bid-based market model as the **m**arket **e**quilibrium under **Co**urnot-type competition (*MECO*) problem. The solution of the MECO is defined by the KKT conditions (8), (9), (12), and market clearing (13).

We now complete the bilevel closed-loop model by adding the upper-level decision of capacity investment. In the upper level, each firm maximizes total profit (net of capital cost), subject to the short-run market equilibrium conditions (either *MEPC* or *MECO*). We formulate the bilevel equilibrium models as follows:

$$\forall i \in I \begin{cases} \max\limits_{p_l, d_l, q_{il}, x_i} \sum_l T_l \cdot \left(p_l - C\right) \cdot q_{il} - K \cdot x_i \\ \quad s.t. \quad MEPC / MECO \;. \end{cases} \tag{14}$$

The problems for all *i* must be solved simultaneously because the market clearing constraints (plus $p_l\left(q_{il}, q_{-il}\right)$ in the bid-based case) couple the firms' problems. Table 1 shows investments, equilibrium prices, consumer surplus, total profits, and total welfare for the three different equilibrium models: a) central planning, equivalent to a perfectly competitive market both in operations (*MEPC*) and investment, b) a duopoly cost-based spot market (*MEPC*) with two firms who make investments strategically, and c) a duopoly bid-based spot market (*MECO*) involving two firms behaving strategically with respect to both investment and operations.

By definition, if investments are centrally planned and bid at short-run marginal cost, the market attains the highest possible level of total welfare, which is all captured by consumers.[8] The central planner prices electricity based on its marginal cost, which yields the exact amount of revenues needed to cover both the operation and capital costs, thereby making zero profits.[9] Scarcity prices that occur when generation is operating at capacity serve as a mechanism to ration demand and provide a return to capital. This equilibrium attains both allocative and production efficiency and it is equivalent to the outcome of a perfectly competitive market in both investments and oper-

8. Note that we haven't considered the possibility of Averch-Johnson-type production inefficiency effects.
9. The zero-profit result occurs because of the linear capital and operating cost assumptions.

ations—one with many price-taking generation firms, perfect information, and no barriers to entry (Samuelson, 1952; Mas-Colell et al., 1995).

Perhaps counterintuitively, if we force the spot market to operate based on audited marginal costs (cost-based market), this does not lead generation firms to select the investment levels that would be chosen in a perfectly competitive market or by a central planner. Since generation firms are aware that the dispatch and pricing of electricity is done based on their true marginal costs in the spot market, they determine that it is optimal to strategically size their power plants below the socially-optimal levels in order to incur scarcity prices more often. The net effect is a reduction of social welfare with respect to the centrally-planned solution.

In this simple example we find that a cost-based market design leads to lower market efficiency relative to the bid-based market. Allowing for the exertion of market power in the bids allows companies to incur higher profits, which—in this particular case—also leads to higher capacity investments (603 [MW] per firm in the bid-based market). When forced to bid marginal cost, as in the cost-based market regime, capacity investments are not as profitable for private companies and hence they invest less (504 [MW] per firm in the cost-based market).

Consequently, it is not necessarily true that a cost-based market design yields a better long-run economic efficiency than a bid-based market, even if in the latter generators can behave strategically in the short term. However, we want to highlight that this result is parameter dependent. In the online Appendix A.1 we carry out a sensitivity analysis for this numerical example in order to identify when one type of market design outperforms the other.

4. THE CHALLENGE OF AUDITING OPPORTUNITY COSTS IN COST-BASED MARKET DESIGNS

Cost-based markets present an additional challenge that can create a series of production and allocation inefficiencies. In a cost-based market, the regulator or SO is responsible for estimating or verifying both the direct and opportunity costs of all generators at all hours based on audited information in order to, ideally, set dispatch schedules and prices that result in productive and allocative efficiency. However, if for some reason a generator is forced to sell its power at a price equal to its directly attributable marginal cost, but that disregards all opportunity costs then a market failure will occur because consumers will buy too much or too little of the good in question (Mas-Colell et al., 1995). Production inefficiencies can occur if a generator's actual opportunity cost is understated (overstated) by its audited cost, so it will be overused (underused) relative to other plants. We now discuss a series of settings where the opportunity costs of generators are non-zero, including dispatch with intertemporal generation constraints, inflexible fuel contracts, and tradable emissions and renewable permits.

4.1 Intertemporal limits on starts, operating hours, and energy

The operation of electric generators is subject to intertemporal constraints that give rise to opportunity costs that can greatly differ from audited fuel-based variable costs. An obvious example is hydroelectric power plants; even though water is *free*, discharging water from a reservoir today in order to generate electricity in many cases means that less water is available tomorrow to generate power then, so that the *value of water* is equal to the revenue that would be earned if energy was generated at the optimal time later on. This opportunity cost is widely recognized in power markets and is, for example, the basis of power pricing in the bulk market in Brazil (Maceira et al., 2008).

Another example whose importance has been recently recognized by SOs is the following. Many peaking generators have restrictions on the number of starts per time interval; for instance, some generators can only be started and shut down once per day because of thermal stresses or crew considerations, while for others, maintenance contracts often specify a maximum number of starts per season before a generator must be taken down for maintenance (Kumar et al., 2012). For instance, several generators in the California market have such limitations (CAISO, 2016). As a result, an opportunity cost arises as follows: if a generator is started today, it has one fewer start available over some relevant time horizon. Thus, the opportunity cost is the revenue that the generator would earn if that incremental start would instead be used later. For instance, consider a 30 [MW] peaking plant with a variable cost of 70 [$/MWh]. A start might involve a fuel cost of only $1000, but if starting the generator now precludes starting it at a later time or date when the electricity prices are 200 [$/MWh] for a four-hour peak, the generator's true start-up cost is the foregone revenue 200 [$/MWh]*30 [MW]*4 [hours], or $24,000. Assuming that this price represents the marginal value of power to the system, the SO should compare that foregone revenue with the revenue that would be earned today in order to make a rational decision about when to start the unit. It would be economically undesirable for the system to "burn" a start today under, say, prices of 100 [$/MWh], if that prevents the generator from being used during that 200 [$/MWh] period. Recognizing this, the California SO now calculates opportunity costs associated with monthly or seasonal limitations on numbers of starts, number of operating hours, and total energy production, and will allow generators to submit those costs as the start-up cost instead of fuel costs needed to start or run the unit (CAISO, 2016).

4.2 Natural gas contracts

A large number of countries rely on imports of liquefied natural gas to serve the domestic demand for the fuel using take-or-pay contracts (Creti & Villeneuve, 2004). Unlike an option contract that gives the holder the option but no obligation to buy a commodity at a pre-arranged price, a take-or-pay agreement specifies both a price and a quantity at the time of delivery, plus a clause that forces the buyer to pay a fixed penalty to the seller if the quantity of fuel taken is less than specified in the contract (Masten & Crocker, 1985). Results similar to those we are about to describe can also occur in real-time electricity markets when short-term gas imbalance penalties make it costly to deviate too far from day-ahead gas delivery quantities; this can cause generator marginal costs to be much greater—or less—than day-ahead costs (or bids) (CAISO, 2014).

These contracts create a series of difficulties for natural gas-fueled generators in power systems with large shares of variable and unpredictable generation from renewable energy resources. Since renewable resources have, in general, lower opportunity costs than natural gas, an increase in the availability of hydro, wind, or solar resources within a time window in a power system leads to a decrease in the dispatch of thermal generators. Under such a scenario, the owner of a natural gas-fueled power plant that secured its fuel through a take-or-pay agreement could find himself in a situation where the amount of procured fuel is in excess of his actual needs. In that case, the appropriate marginal cost of gas-fired generation is not the contracted price, but rather something much less, depending on the size and form of the penalty.

Consider the optimal dispatch of the following system for one hour with three available generation technologies: 100 [MW] of hydropower (Hydro), 100 [MW] of coal (Coal), and 100 [MW] of combined-cycle gas turbines (CCGT). We assume that the opportunity cost of the water in the hydroelectric power plant is 5 [$/MWh] and the marginal fuel costs for the Coal generator is 30 [$/MWh]. The CCGT signed a take-or-pay contract for a fixed amount of natural gas, which results in a (longer run) marginal fuel cost of 50 [$/MWh]. We assume that all generators act as price takers and consider two scenarios of demand: high (150 [MW]) and low (90 [MW]).

In the scenario where there is no excess of natural gas, both cost-based and bid-based markets yield the same dispatch schedule and electricity prices. In the high-demand scenario (150 [MW]), the electricity price equals the marginal fuel cost of Coal, 30 [$/MWh], and the Hydro generator makes a positive profit. In the low-demand scenario (90 [MW]) the electricity price is equal to the opportunity cost of Hydro, 5 [$/MWh]. The schedules and prices derived in the cost-based market are Pareto efficient because the only relevant costs for the CCGT are its fuel expenditures based on the take-or-pay agreement, 50 [$/MWh], an amount that is easily auditable by the SO.[10]

Let's consider now two scenarios where the CCGT faces an excess of natural gas committed in the take-or-pay agreement in a bid-based market. First, if the fuel could be re-sold by the buyer in a secondary market for the equivalent of 27 [$/MWh], this amount would define the lowest price the CCGT would be willing to receive for participating in this electricity market rather than sell the gas in the secondary one, i.e., its opportunity cost. In the high-demand scenario (150 [MW]) the CCGT would displace the generation from Coal and set the system's price, since the latter has now a higher marginal cost than the opportunity cost of natural gas. This scenario would not change the dispatch schedule or price in the low-demand case (90 MW) compared to the situation in which there is no excess of natural gas.

In the second scenario, assume now that there is no secondary market that would take the excess of natural gas committed in the take-or-pay agreement. In this case, let's assume that the CCGT faces the equivalent of a $20 penalty for every [MWh] that is not delivered using natural gas.[11] This means that the CCGT would be willing to pay customers up to 20 [$/MWh] for taking its energy from natural gas. In a bid-based market, an offer for –20 [$/MWh] would displace Hydro and give the CCGT the first place in the supply curve. In the high-demand scenario Hydro would set the electricity price, since the CCGT would be dispatched at its maximum capacity, 100 [MW]. However, in the low-demand scenario the CCGT would be the marginal unit and the efficient electricity price would not equal its fuel cost, but its opportunity cost equal to –20 [$/MWh]. These dispatch schedules and prices are Pareto-optimal since they reflect all relevant fuel and opportunity costs. However, in a cost-based market the CCGT generator would not be allowed to submit bids for its true opportunity cost that we showed in the two situations above, which would lead too little consumption of natural gas and too much of coal if the marginal cost of the CCGT cannot be changed to a value other than its long-term fuel cost, 50 [$/MWh].[12]

10. If the generator was fully using its take-or-pay contract and did not have the option of buying more than the contracted quantity at 50 [$/MWh] for the excess, then using the gas now would mean that it could not be used later. This would result in a hydro-like situation, were there would be an opportunity cost equal to the revenue that the gas would have earned in other periods. Our example here is much simpler, since we assume that the power plant has a long-term contract and also an option of buying more gas than the contracted amount at a price equal to 50 [$/MWh].

11. Note that venting natural gas off to the atmosphere is illegal. Thus, if the procured fuel is not needed, the buyer has no other alternative than to face the penalty stipulated in the take-or-pay agreement.

12. In Chile, for example, CCGTs facing an excess of natural gas can request the SO to give them a higher dispatch priority to avoid facing penalties for not taking the fuel committed in long-term contracts. In practice, the SO sets their marginal costs in the dispatch optimization program to an administrative value equal to zero. Unfortunately, this value does not

4.3 Environmental regulation and policy incentives for renewables

More than 100 countries (REN21, 2015) and 49 states in the U.S. (DSIRE, 2015) have enacted some form of environmental policy to promote generation from renewable energy resources or to reduce carbon emissions. Some of these include Renewable Portfolio Standards (RPSs), production tax credits (PTCs), feed-in tariffs, carbon taxes, and carbon cap-and-trade programs. RPSs, PTCs, and feed-in tariffs are policies that aim at pricing into the market the positive externalities caused by the production of power from qualifying renewable resources, whereas carbon taxes and cap-and-trade programs seek to price the negative externalities from the production of power from carbon-intensive generation. Since these policies are equivalent to a combination of subsidies for renewable energy and a tax on conventional technologies, they can create opportunity costs for both conventional and renewable generators participating in spot markets. In some extreme cases, renewable generators might be willing to pay customers to take their power.

The wholesale market in Texas is one example where renewable generators have submitted bids to supply their power at negative prices for several hours in a row, particularly at times when demand was low, wind resources were abundant, and transmission capacity was scarce. According to Baldick (2012), there were 4445 15-minute intervals where prices in west Texas, an area rich in wind resources, were below zero in 2010. The observed negative bids placed by wind generators were similar in magnitude to the production tax credit of approximately 30 [$/MWh]. In this case wind generators behaved rationally, since an electricity price of –29 [$/MWh] would still leave them with a 1 [$/MWh] profit, assuming negligible variable O&M costs. Since PTCs and RECs can only be accrued if a renewable resource is producing power, a competitive bid submitted by a price-taking wind generator should reflect the foregone opportunity of collecting revenues from these regulatory instruments.

In this case, negative prices are efficient and provide strong incentives for consumers to shift their consumption to those hours when renewable resources are abundant.[13] Negative prices during certain hours also disincentivize investments in more wind or solar capacity that will be mostly available within that time window. Unfortunately, in cost-based market designs, these opportunity costs are not considered as directly attributable expenditures, such as fuel or O&M costs, and must be internalized by generators, which results in dispatch schedules and prices that are economically inefficient. In Chile, for instance, there is an RPS policy with tradable Renewable Energy Certificates (RECs) and a carbon tax in place. However, the opportunity costs that result from the sales of RECs or the tax on carbon emissions are not considered in the dispatch and pricing of electricity in real time. The regulator and SO expects generators to, somehow, recover the additional costs or profits that result from these environmental policies through long-term purchased power agreements. However, this mechanism creates a distortion between long- and short-run electricity prices that ultimately affects the production and allocative efficiency of the market.

necessarily reflect the opportunity cost of the CCGTs, which should account for the option of selling the gas in a secondary market or the penalty. Therefore, this rule leads to inefficient dispatch schedules and prices as we show in the example above.

13. Another view is that negative electricity prices that result from PTCs are harmful to the economy, since they are subsidies from taxpayers to consumers of electricity. However, this inefficiency is a direct consequence of the use of taxes and subsidies in a market economy and not a failure of the electricity market. In other words, if it is true that the production of one additional MWh of power from a renewable energy source will result in economic and environmental benefits with a present worth of $30, then paying consumers up to 30 [$/MWh] to increase their consumption when renewable resources are abundant is economically efficient. However, in actual situations, the PTC can be very different from the marginal social benefit when prices are negative, and it can be more efficient to curtail renewable production (Deng et al. 2015).

5. **CONCLUSIONS**

The major goal of a market designer (or regulator) should be to ensure that a market (or a regulated monopoly) functions in the most economically efficient manner. However, this seemingly simple goal might prove quite challenging in practice since all market designs are imperfect due to information asymmetries and incentive compatibility issues (Wolak, 2003).

In this paper, we discussed some of potential inefficiencies of cost-based electricity market designs, in which investments are deregulated but the dispatch and pricing of power is conducted based on audited cost information from private generation firms. Many countries in Latin America opted for these hybrid designs at the time of deregulation with the goal of preventing the exercise of market power in the spot market (Hammons et al., 2002)—the type of strategic behavior that regulators and consumers seem most sensitive to. Elsewhere, Ireland until recently had a similar system, and several U.S. markets also require cost-based bidding when local market power is shown to exist. However, up until now, little has been said with regards to the economic efficiency of such markets and how effective they are at reducing the incentives for generators to behave strategically compared to bid-based markets, especially concerning long-term investment.

Our main arguments are that cost-based spot market designs have two main features that make them inefficient. First, the exercise of market power is still possible in concentrated markets where there are barriers to entry, since firms have incentives to underinvest or to increase the share of the peaking technology, deviating from the socially-optimal generation portfolio. We use a simple numerical example to show that the welfare loss due to the exercise of market power can be larger in a cost-based market than under a bid-based one. Thus, a bid-based design can be more efficient than a cost-based one even if firms can behave strategically in the spot market.

Nevertheless, the possible exercise of market power in the short run in a bid-based system is a real threat, particularly under stress conditions such as congestion, temporary low market liquidity, and outages of generation resources and transmission lines. To guard against such market power, U.S. markets have created market monitoring departments for SO-based markets as well as active mitigation mechanism that allow the market monitor to substitute cost-based default energy bids (DEBs) for the actual submitted bids when certain market competitiveness tests are not met. These mitigation techniques fall into two general categories: 1) Conduct and Impact Tests and 2) Structural Tests. The Conduct and Impact approach monitors if bids exhibit unusual deviations from some set norm and estimates the impact of such behavior on market prices, then triggering the DEBs if the impact exceeds a specified threshold. On the other hand, the Structural Test monitors the opportunity for the exercise of local market power due to congestion and triggers the DEBs if, for instance, the number of pivotal suppliers who can relieve congestion on a congested line is three or less. In such a case, the line is deemed noncompetitive and all bids significantly impacting such a line are replaced with DEBs. Market monitors also surveil long-term bidding patterns and relegate to FERC cases against market participants whose bidding strategies suggest that they do not behave as rational price-takers, as was the case with J.P. Morgan in California whose bidding behavior exploited the Make Whole Payment mechanism and was fined \$410M (FERC, 2013). Aggressive market monitoring and active mitigation have proven effective in suppressing market power abuse in the U.S. They are superior to enforcing cost-based bidding in all hours since, in general, the market is competitive. Annual reports by the monitor for the California market indicate that bid-based market prices most of the time fall below the simulated benchmark prices that are based on estimated cost plus 10%. Market competitiveness and the prevention of strategic withholding in the day-ahead markets are also reinforced by allowing Virtual Bidding which increases market liquidity through arbitrage between the day-ahead and real-time market by financial market participants who do not produce or consume energy. Recent studies by Jha and Wolak (2015) and by Li et al. (2015) demonstrate the efficiency gains due to virtual bidding in the CAISO bid based market.

Our second argument is that auditing the true marginal costs of generation is difficult in a market environment when firms face important opportunity costs that are not directly attributable to expenses on fuel and other out-of-pocket operations and maintenance costs. Opportunity costs can be large in situations where, for example, generators face inflexible fuel contracts, firms are subject to environmental regulations or renewable generators can obtain additional revenues from tax credits or from the sales of RECs, and where there exist intertemporal generator constraints such as ramping limits or bounds upon the number of starts over a limited period. These become more relevant in systems with increasing shares of variable and unpredictable generation from renewable energy resources.

The *engineering* approach to address the issue of opportunity costs in cost-based markets is to expand the dispatch problem of the SO to account for the constraints or parallel markets that create these opportunity costs. For instance, many cost-based markets with large shares of hydro-power use a centralized algorithm to find the socially optimal intertemporal allocation of water in all basins simultaneously (i.e., the value of water) instead of letting each firm optimize its resources independently (Hammons et al., 2002). Ramping limits, bounds on the number of starts in a period, environmental constraints, and inflexible fuel contracts can all be accounted for by introducing more variables, constraints, parameters, and assumptions (e.g., forecasts) in the centralized economic dispatch problem of the SO (Lee et al., 1994; Han et al., 2001). While there is empirical evidence that centrally-coordinated markets can increase the efficiency of a system when there are transmission externalities (Mansur & White, 2002) or nonconvexities in the dispatch (Sioshansi et al., 2008), it is not clear if larger and more complex economic dispatch problems necessarily yield accurate estimates of opportunity costs and efficient dispatch schedules for all generation units in a cost-based system. The main weakness of this approach is that it turns the SO into an accountant for all generation firms in the system that needs to be constantly auditing private information on generators' parameters, fuel contracts, and parallel markets (e.g., emissions permits, RECs, etc.). In contrast, bid-based designs rely on a *market mechanism* that addresses the issues on information asymmetries by decentralizing part of the allocation problem (Hurwicz, 1973). Consequently, in bid-based markets generators are expected to bid the opportunity costs that are not explicitly accounted for in the centralized dispatch algorithm. As we mentioned it in Section 4.1, the California SO disregards seasonal limits on the number of starts for generators in the unit commitment problem and expects firms to include these opportunity costs in their bids (CAISO, 2016).

Further research is needed to quantify the full range of economic benefits and costs of migrating from a cost-based design to a bid-based one in a real power system. As stated in Wolak (2003), most of the cost-based markets that were implemented in Latin America were justified because of the initial conditions that existed at the time of deregulation in the 1980s and early 1990s, including a small number of market participants, weak transmission systems, and largo hydro producers. In contrast to our simple numerical example in Section 3, it is possible that a cost-based approach could lead to fewer welfare losses than a bid-based design for some of those markets where these conditions still prevail. Moreover, the implementation of a bid-based mechanism, together with a well-functioning market monitoring department, might be too costly for small systems. However, it is not clear if a cost-based electricity market design is still justified in power systems that are growing both in the number of generation firms and in terms of transmission capacity, such as the Chilean market. Furthermore, there is empirical evidence that shows that firms have less incentives to behave strategically in the spot market if they hold long-term contracts (e.g., PPAs) at prices determined beforehand (Bushnell et al., 2008).

Finally, a question that is beyond the scope of this paper is how distortions in short-term dispatch schedules and prices due to disregarding opportunity costs could affect long-term contracting and investment choices. We hypothesize that short-term signals will inevitably influence long-term contract prices and, possibly, the choice of technologies, but the magnitude of this effect will depend on the risk attitudes of the generation firms present in the electricity market and the relative magnitudes of opportunity costs for different generation technologies.

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