Electricity Market Prices: An Indicator of Market Power?

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***Abstract*— Electricity market price may not always be a reference to determine the existence of market power. This paper discusses why electricity price in a day-ahead electricity market may exhibit peaks without representing market manipulation by any of the players. We use Genetic Algorithms to simulate the trading behavior of artificial agents in the spot market. Two case studies are reported and the results show that high market prices do not necessarily mean market power exercise.**

***Index Terms*—Genetic Algorithms, electricity market.**

I. INTRODUCTION

Variations in demand and fuel prices, and particularly the uncertainty among generators and their competitors can give rise to patterns of price-cost similar to those used by some analysts to support claims that the industry does not behave competitively [1]. The exercise of market power is an issue of concern to players and regulators alike, and virtually all electricity markets throughout the world have experienced it. Markets that suffer the greatest consequences are those with no or inadequate monitoring functionality. While the United Kingdom was the first to suffer, the California crisis of 2000-2001 is perhaps the best-known example, and New Zealand's present crisis is the latest.

Market power in electricity markets can appear in two forms: bidding strategies in the auction mechanism, and network management. In the first case, a power producer bids strategically based on market share by observing and predicting its competitors' actions. In the second case, a producer is able to restrict its generation because of network congestion, thus forcing the system operator to dispatch the more expensive units that drive up prices.

The relevant factors for designing and implementing effective market monitoring are defined and identified in [2]. Market efficiency is achieved by using least-cost resources. A new analytical method to compare players' bidding strategies from the viewpoint of the independent system operator is reported in [3]. The system operator can use the results produced to detect the exercise of market power. The model described in [3] simulates the electricity market and the behavior of participants to obtain a Nash equilibrium. It uses the Herfindahl-Hirschman Index (HHI), the residual supply index (RSI) and the residual dynamic analysis (RDA) to detect market power. According to [4] the majority of the empirical approaches used to detect market power in electricity markets have error of be based on standard measures. An example is when prices are significantly higher than the average variable cost of the marginal generating unit during peak demand periods. [5] describes the characteristics essential for proper monitoring and provides examples of the successes and failures in various markets worldwide.

Increasing the interconnection capacity with neighboring countries is one of the most popular market power mitigation measures. [6] studies the specific case of the typically congested interconnection capacity between France and Spain. In particular, the author evaluates the magnitude of the additional interconnection capacity that would be necessary to satisfactorily mitigate market power, and concludes that at least for this case, there must be other less expensive means of achieving the objective.

An electricity market monitoring system, which on one hand provides the references for market participants making strategic decisions, and on the other hand is able to evaluate the impacts of specific measures or market context variation, is presented in [7]. The monitoring system consists of two units: the market simulator which models the interactions between the market players via game theory and multi-agent system; and price forecast which interprets the market evolution by mathematical or artificial intelligence approaches to predict the prices. The author concludes that the regulator must understand and forecast the market evolution, as well as assess the strategy of the market players and the policies of the regulator.

This paper discusses why electricity price in a day-ahead electricity market may present peaks without representing market manipulation by some agents. Genetic Algorithm is used to simulate artificial agents trading in the markets.

The paper is organized as follows: Section II describes the spot market structure, the auction mechanism, and analytical and monitoring tools. Section III describes the economic characteristics of a Generation Company (GenCo). Fuel cost is linked with electricity price in Section IV. Two study cases are presented in Section V. The conclusions appear in Section VI.

II. ELECTRICITY MARKET

Three main models of wholesale electricity markets are proposed in the literature: centralized, decentralized and hybrid [8]. The centralized model requires market participants to share their actual costs of operation to achieve the minimization of generation costs. This model requires an independent system operator with broad authority to make decisions that guide the optimization of the operating system.

The decentralized model uses fixed costs, generation limits, and other data known only by the participants. There is no coordination of energy markets, transmission and reserves, since these operate sequentially and independently. Centralized and decentralized markets both assume perfect competition, the primal-dual equivalence of the first-best implementation where vigorous competition makes the first best incentive compatible. In practice, however, primal-dual equivalence fails since markets are never perfectly competitive. Moreover, market participants in the private market are reluctant to obey a centralized administrator, thus creating market inefficiencies. Hybrid models propose to alleviate such disagreements by simplifying networks and requiring data transparency. The trend in electricity market structure is towards decentralization. Decentralized markets are characterized by consumer price takers and companies that base their decisions on market prices [9]. Knowing the price, consumers can choose their consumption without knowing the behavior of other consumers or other resource supply/shortages. In decentralized markets the price is not sufficient to coordinate the requests and offers of private agents, because many of these agents are not price takers.

A. Auction Mechanism

In decentralized electricity markets, auction mechanisms are the easiest, efficient and most transparent way to compute the market clearing price [10]. An auction operates under an explicit set of rules adhered to by all of the players that determine resource allocations and prices based upon the bids.

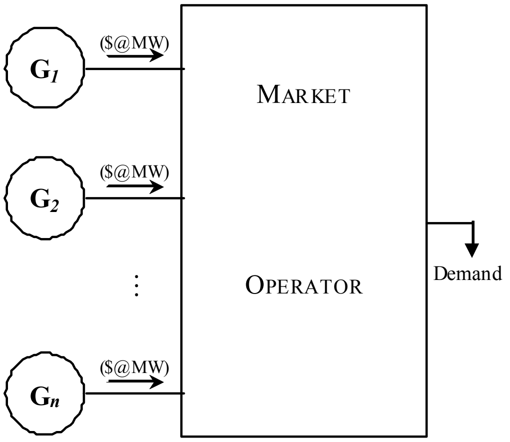

Figure 1 Model of the Market

The single-side auction is used for pricing where one of the parties offering to sell (buy) a resource is willing to receive (pay) a specified amount. Each GenCo submits a bid, which is an ordered pair ($p@q$) representing a price, p, and quantity, q. These bids are sorted in ascending order by price. They are then accepted sequentially, adding the quantity of each bid to a running total until this total meets the demand. At this point no more bids are accepted, and the last one is accepted for only the amount of remaining demand.

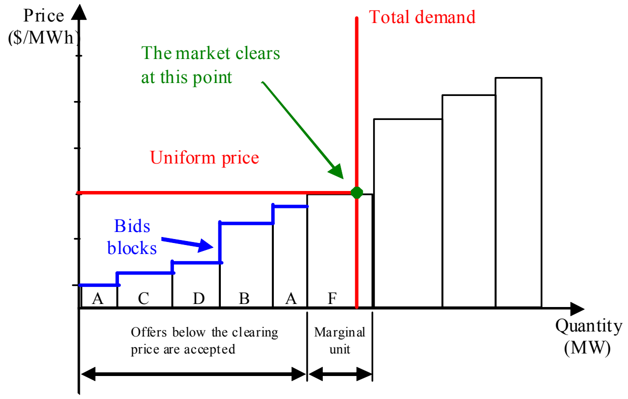

Figure 2 Single-side Auction

There are two methods for establishing the market price: Pay as Bid (PAB) and Uniform Pricing (UP). Under PAB pricing, winners pay different amounts, i.e., in the simplest case, the amount is the price they bid. In UP all “winners” (bidders whose bids were accepted) pay the same amount, i.e., in the simplest case, it is the market clearing price (the highest price that was accepted).

In a market with few players, each bidder can easily influence the outcome of the auction. In UP, this is known as the power to change the price, or market power. The most immediate effect is that bidders may cooperate to raise prices by raising their bids. Alternately, a bidder may withhold capacity to drive the price up and undercut it later.

B. Electricity market monitoring

The regulators of a spot market for electricity require the tools necessary to evaluate and monitor the behavior of participants and establish appropriate regulatory policies. Some factors used to evaluate the competitiveness of an electricity market include:

- Market concentration
- Elasticity of demand
- Number and distribution of excess capacity
- Typical contractual arrangements
- Process for setting prices
- Ease of entry and exit
- The grid

To promote market efficiency and to prevent the exercise of market power requires tools to accomplish the following tasks:

1) Monitoring blackouts
2) Monitoring market organization
3) Monitoring supply and demand conditions
4) Monitoring actual or potential exercise of market power

The market monitoring tools can be complemented by long-term models. The purpose of these models is to:

1) Evaluate the behavior of market competitiveness and efficiency

2) Identifying gaps in the market rules and procedures
3) Facilitate the modification or creation of rules

Effective, efficient and independent monitoring of market behavior requires information from internal systems and group operation, modeling of complex rules, access to confidential transactions and operational data and external data sources [11]. The components should include:

- A secure server
- An interface for communication between raw and compiled data from the system operator and the external database
- Online Analytical Processing tools
- Software management of databases and statistical analyses
- Market simulation tools
- Well-trained staff
- Transparency, including two-day bid filing requirements (example: Australia)

III. THE GENERATION COMPANY

The strategic bidding objective of market participants is to maximize economic benefits, defined as:

$$\Pi_{k,i} = PE_k * P_{G,i} - C_i\left(P_{G,i}\right) \tag{1}$$

where $\Pi_{k,i}$ represents the profits of GenCo i at period k, PE_k is the price of electricity for the period k, and $C_i(P_{G,i})$ is the cost curve of production of the *i-th* generation unit.

The input-output characteristic of a thermal unit can be defined in terms of energy requirements of heat (MMBtu/h) or total production cost ($ / h) as stated in (2).

$$C_i\left(P_{Gi}\right) = H_i\left(P_{Gi}\right) * F_i^m = \left(a_i + b_i P_{Gi} + c_i P_{Gi}^2\right) * F_i^m \qquad \left(\frac{\$}{h}\right) \tag{2}$$

where F_i^m represents the cost of fuel m to the *i-th* generator in $ / MMBtu, $H_i(P_{Gi})$ is the heat of the *i-th* generator in MMBtu/h, P_{Gi} is power generated by the *i-th* generator, and a, b and c are parameters of the input-output curve in terms of heat units of the *i-th* generator.

The incremental cost is given by:

$$F_i^m \frac{\partial C_i\left(P_{G_i}\right)}{\partial P_{G_i}} = F_i^m * \left(b_i + c_i P_{Gi}\right) \qquad \left(\frac{\$}{MWh}\right) \tag{3}$$

In liberalized markets, scheduling of a GenCo determines the expected cash flow. The GenCos must be able recover both fixed and variable costs. Two possible forms of recovering fixed costs are:

1) Fixed costs are included in the modified incremental cost curve.
2) Using the average costs of production for the calculation of bids.

The first approach would change the incremental cost curve for a factor that captures the fixed costs. This can be represented as:

$$\frac{\partial C_i\left(P_{Gi}\right)}{\partial P_{Gi}} = \alpha * \left(b_i + c_i P_{Gi}\right) * F_i^m \qquad \left(\frac{\$}{MWh}\right) \tag{4}$$

where α is a multiplication factor which includes the fixed costs.

The average cost of production is:

$$CPP_i = \frac{C_i\left(P_{Gi}\right)}{P_{Gi}} = \left(\frac{a_i + b_i P_{Gi} + c_i P_{Gi}^2}{P_{Gi}}\right) * F_i^m = \left(\frac{a_i + c_i P_{Gi}}{P_{Gi}} + b_i\right) * F_i^m \qquad \left(\frac{\$}{MWh}\right) \tag{5}$$

where CPP_i is the average cost of production of the *i-th* unit.

To understand the behavior of this equation, the limits are obtained when $P_{G,i}$ tends to *1* as tends to *1000* respectively:

$$\lim_{P_{G,i}\to 1}\left(CPP_i\right) = \lim_{P_{G,i}\to 1}\left(\frac{a_i + c_i P_{G,i}^2}{P_{G,i}} + b_i\right) * F_i^m = \left(a + c + b\right) * F_i^m \tag{6}$$

and

$$\lim_{P_{Gi}\to 1000}\left(CPP_i\right) = \lim_{P_{Gi}\to 1000}\left(\frac{a_i + c_i P_{G,i}^2}{P_{G,i}} + b_i\right) * F_i^m = \left(\frac{1}{1000} a + 1000 * c + b\right) * F_i^m \tag{7}$$

From equations (6) and (7) we observe that the lower power cost per MW is close to the value of the term independent of the cost curve, which is much greater in magnitude than the curve's parameters *b* and *c*. Moreover, for high output power, the cost per MW is close in magnitude to *b*, since the value of *a* tends to decrease considerably and the value of *c* is usually less significant.

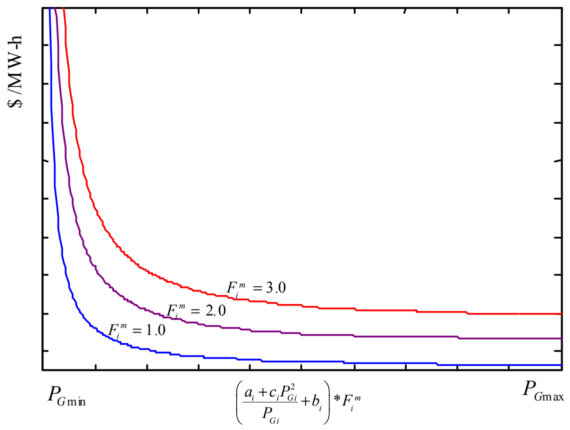

Figure 3 Average Costs for three different fuel prices

Figure 3 shows a GenCo's average costs of production for different fuel prices F_i^m, which are 1.0, 2.0 and 3.0 pu, respectively, showing that at higher prices in fuel, the cost average is greater, and when P_{Gi} is higher, the cost per MW decreases.

When a GenCo's bids are not accepted by the market, its fixed costs accumulated and it needs to recover them in subsequent periods. The GenCo has two alternatives: reduce the rate of expected return, or increase the offer price. This latter option can be accomplished by distribution in a single period or in several. The distribution in more than two terms appears more credible and also distributes the risk of the GenCo's unavailability. However, this decision will largely depend on the market information available. Mathematically this is:

$$CPP_i = \left(\frac{n\,a_i + c_i P_{G\min}}{P_{G\min}} + b_i \right) * F_i^m \qquad (8)$$

where n is the number of periods not accepted in the market for which the GenCo must recover its fixed costs.

When a GenCo is able to schedule participation at initial times in the market, it will gain the flexibility that allows it to adjust unit operations depending on market conditions. One option is to modify the expected rate of return to obtain higher profits. Figure 4 shows the CPP_i accepting n periods with varying levels of power and considering F_{im} equal to 1 \$ / MMBtu.

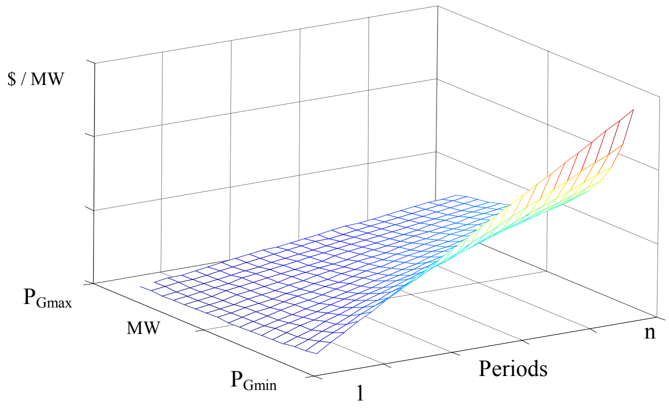

Figure 4 Average Costs

Figure 4 shows a GenCo's average costs, based on the number of periods its bids are either accepted or not accepted.

A. Behavior of the spot market

Monitoring electricity prices allows the system operator to establish bases of comparison in order to promote market efficiency and competition. Using standard, average cost pricing of variable costs also alerts regulators to prevent sales of electricity above the highest average variable cost of the generators used to provide electricity.

Figure 5 shows an example of electricity price behavior in a day-ahead market. If the GenCo offers a price that covers its actual production costs, the market price should be equivalent to a centralized unit commitment. If the expected rate of return increases in proportion to the prices of the competing GenCos, we would expect the market price to rise in proportion.

Figure 5 shows a substantial increase in market price from period 11 to period 15 resulting from the time restrictions of active maximum / minimum operation of the unit or hours of peak demand.

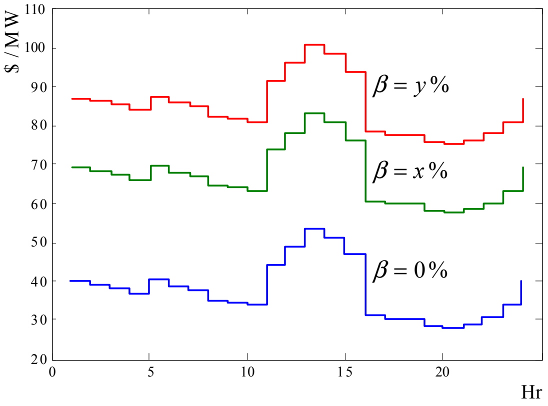

Figure 5 Price of electricity for different rates of return

IV. CASES OF STUDY AND SIMULATION

This section presents two numerical examples. In the first case, 14 units are dispatched in 24 periods, and in the second case, 13 GenCos are dispatched in 23 periods and 14 GenCos in the 24th period.

All of the agents in the marketplace simulated have different production cost curves. We use CASMM to simulate the scenarios for the populations of these artificial agents, which are modeled as GA [12].

Table I shows the cost data of our selected 14 GenCos. GenCos 1, 4, 6, 9 and 13 use natural gas, GenCos 2, 7, 8 and 14 use the Uinta Coal Basin, GenCos 3, 11 and 12 use Illinois Basin Coal, and GenCos 5 and 10 use WTI-Cushing.

TABLE I
GENCO'S COST DATA

GenCo	**Cost curve** (\$ / hr)	$P_{Gi}^{\min}$ (MW)	$P_{Gi}^{\max}$ (MW)
1	$1649.35 + 25.52 Pg_1 + 0.001627 Pg_1^2$	50	180
2	$1463.28 + 21.34 Pg_2 + 0.001143 Pg_2^2$	40	130
3	$2249.48 + 45.55 Pg_3 + 0.004627 Pg_3^2$	40	195
4	$1238.14 + 19.98 Pg_4 + 0.001002 Pg_4^2$	43	140
5	$1379.21 + 20.62 Pg_5 + 0.001392 Pg_5^2$	50	170
6	$1697.85 + 24.49 Pg_6 + 0.001932 Pg_6^2$	40	135
7	$1539.41 + 23.68 Pg_7 + 0.001732 Pg_7^2$	48	160
8	$2682.90 + 54.09 Pg_8 + 0.054905 Pg_8^2$	40	200
9	$1458.49 + 29.36 Pg_9 + 0.002332 Pg_9^2$	45	150
10	$1998.99 + 40.41 Pg_{10} + 0.040197 Pg_{10}^2$	35	198
11	$1218.72 + 18.62 Pg_{11} + 0.001032 Pg_{11}^2$	41	135
12	$1164.31 + 17.74 Pg_{12} + 0.001249 Pg_{12}^2$	32	105
13	$2241.29 + 45.40 Pg_{13} + 0.045975 Pg_{13}^2$	30	202
14	$1481.43 + 21.49 Pg_{14} + 0.002346 Pg_{14}^2$	60	195

Next, Figure 6 shows the production cost curves of the marginal units, GenCos 3, 8, 10 and 13. It can be seen that GenCo 8 has the highest costs.

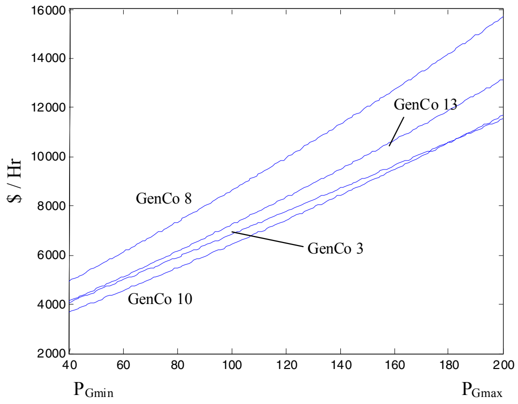

Figure 6 Production cost curves of marginal units

The pattern of demand for five days is shown in Figure 7. The ten cheaper GenCos supply base load, and the four generators with higher costs set the market price. Thus, market monitoring logically focuses on the four marginal units.

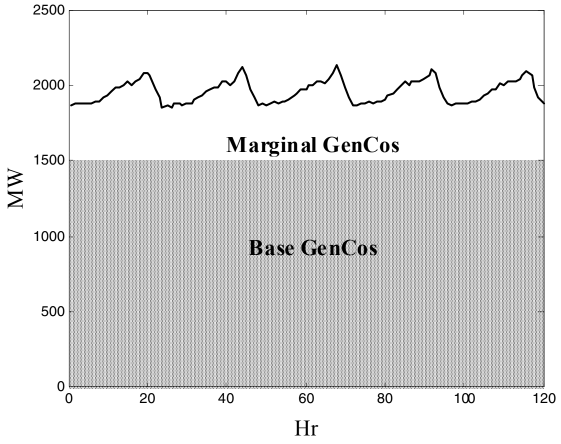

Figure 7 Five-day demand pattern

Demand time on the first day reported in the demand pattern of Figure 7 is shown in Table II.

TABLE II
HOURLY DEMAND PATTERN

Period	Demand	Period	Demand
1	1866.23	13	1991.28
2	1871.65	14	2006.44
3	1875.04	15	2018.19
4	1873.01	16	2002.37
5	1880.64	17	2025.73
6	1878.12	18	2036.81
7	1891.18	19	2085.45
8	1900.43	20	2090.15
9	1917.83	21	2067.60
10	1933.22	22	1980.09
11	1959.4	23	1916.32
12	1983.67	24	1855.41

Fuel prices are reported in Figure 8.

Table III shows the primary fuel prices; the values are taken from period 2 in Figure 8.

TABLE III
FUEL PRICES

	Illinois Basin ($/ton)	Uinta Basin ($/ton)	WTI- Cushing ($/barrel)	Natural Gas ($/1000 ft^3)
Price	84.00	$ 73.00	$ 55.95	$ 8.32

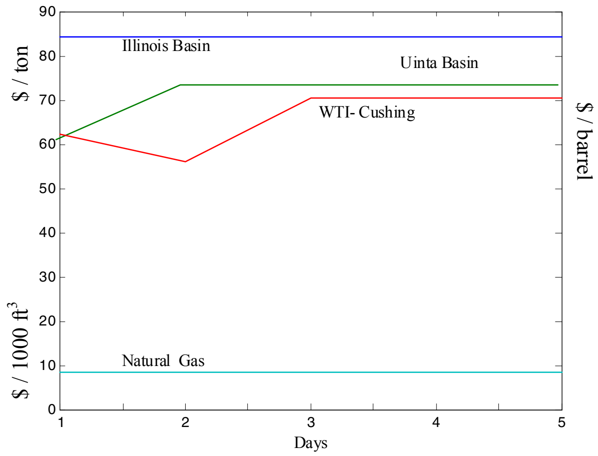

Figure 8 Primary fuel prices

A. *Case A*

GenCo 10, being the most economical offer much, even operating at full capacity in some periods. It is also noted that 3 and 13 GenCo offer about the same amount each, because production costs are very similar. The GenCo 8 is kept to a minimum of capacity in most of the time, and only during peak demand conditions of its offer is slightly increased.

Figure 9 shows marginal GenCo 4's hourly generation. We see that GenCo 10, the most economical, operates at full capacity in some periods, and that GenCos 3 and 11 have similar production costs. GenCo 8 operates at minimum capacity in most periods, and its offer increases only during periods of peak demand.

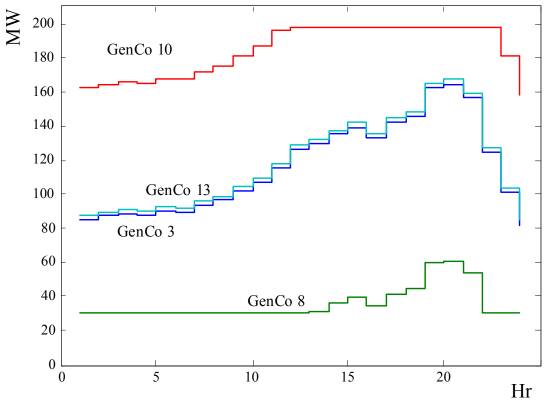

Figure 9 Case A: GenCos' power generation

GenCo 8 will determine the market price in a single-sided auction. This situation can occur while other units have sufficient capacity to supply a greater quantity of demand, since in certain periods the GenCo can block deals that do not include its full capacity, even those well above the blocks offered by the unit with the highest production costs. Including expensive units in the market could be due to reliability measures required by the system operator.

The marginal and average costs of the system are shown in Figure 10.

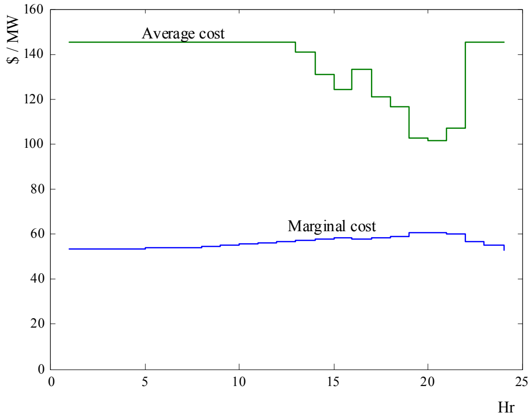

Figure 10 Case A: Market Price

Table IV shows the estimated market price via the single-sided auction in periods 5, 10 and 20, and Figure 11 is a graphical illustration.

TABLE IV
BIDS OF GENCOS

	Period 5		Period 10		Period 20	
	Block (MW)	Bid ($/MW)	Block (MW)	Bid ($/MW)	Block (MW)	Bid ($/MW)
GenCo 3	90.23	74.66	106.887	71.55	164.31	66.85
GenCo 8	30.00	145.17	30.00	145.17	60.743	101.60
GenCo 10	167.80	59.07	187.033	58.62	198	58.47
GenCo 13	92.54	73.81	109.3	70.87	167.09	66.44
$\sum P_{G,i}^{base}$	1500	<OGM*	1500	<OGM	1500	<OGM

* Less than the bid's marginal GenCos

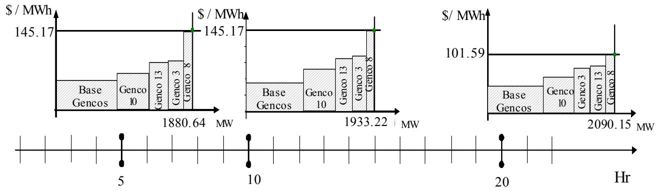

Figure 11 Market balance for periods 5, 10 and 20

GenCo 8 determines the market price for the 24 periods, yet we note that during periods 1-12 the market price is constant, because GenCo 8's offers are at a constant price, even when demand changes. GenCos 3, 10 and 13 vary in their offerings, which are cheaper for these 4 units. In period 20 GenCo 8 presents the offer at a lower price; since it increases the amount bid, the production cost drops and therefore so does the offer price.

Table V shows the profits, hour by hour, for GenCos 3, 8, 10 and 13 under the uniform pricing scheme, where CPP and CM is the market price based on bids in terms of average and marginal costs of production.

TABLE V
CASE A: PROFITS OF GENCOS 3, 8, 10 AND 13

GenCo 3		GenCo 8	GenCo 10		GenCo 13	
CPP	CM	CM	CPP	CM	CPP	CM
5944.83	-1909.92	-2750.55	13972.85	-936.15	6183.5	-1880.02
6102.3	-1896.17	-2745.78	14154.14	-910.14	6342.26	-1865.8
6200.18	-1887.37	-2742.78	14266.66	-893.62	6441.12	-1856.72
6141.47	-1892.66	-2744.58	14199.25	-903.55	6381.54	-1862.18
6362.23	-1872.72	-2737.86	14453.45	-866.26	6603.9	-1841.58
6289.37	-1879.37	-2740.08	14369.55	-878.65	6530.54	-1848.45
6666.34	-1844.32	-2728.59	14803.49	-813.79	6910.13	-1812.28
6932.44	-1818.56	-2720.46	15109.73	-766.8	7178.12	-1785.72
7430.69	-1767.94	-2705.16	15683.4	-675.89	7679.94	-1733.58
7869.19	-1720.83	-2691.63	16188	-592.81	8121.4	-1685.12
8609.88	-1635.67	-2668.62	17040.64	-445.69	8867.38	-1597.63
9616.8	-1508.27	-2637	17167.14	-237.08	9881.37	-1466.97
9343.18	-1472.15	-2628.42	16340.77	-181.24	9598.98	-1429.97
8386.86	-1407.08	-2611.82	14287.96	-83.83	8618.95	-1363.34
7798.86	-1354.74	-2597.41	13025.59	-8.19	8016.33	-1309.8
8618.89	-1424.79	-2616.49	14785.94	-109.96	8856.68	-1381.48
7474.73	-1320.35	-2587.47	12329.68	40.32	7684.19	-1274.63
7058.57	-1268.64	-2571.87	11436.38	111.6	7257.76	-1221.76
5797.45	-1025.27	-2489.51	8729.18	424.24	5965.79	-973.24
5709.11	-1000.26	-2480.32	8539.48	454.53	5875.28	-947.72
6177.82	-1117.64	-2522.35	9545.72	309.6	6355.43	-1067.51
9459.84	-1529.01	-2641.95	17167.14	-269.75	9723.26	-1488.22
7387.58	-1772.42	-2706.48	15633.7	-683.86	7636.53	-1738.19
5630.09	-1936.54	-2760.06	13610.62	-987.07	5866.54	-1907.55
173009	**-38263**	**-63827**	**336840**	**-9904.1**	**178577**	**-37339**

Table V does not show profits when the payments to the GenCos are discriminatory, because the profits are always zero. GenCo 8's profits are also omitted. Table V also shows that GenCos 3, 10 and 13 have positive returns when considering the market price as the CPP. Moreover, considering the marginal cost and market price, each GenCo has a negative return.

The calculation of GenCo 1's profit for period 1 and assuming the market price is the average cost and marginal costs respectively under uniform price mechanism can be written as:

$$G_{CPP,1} = 145.172*85.671 - \left(2249.489 + 45.559*85.671 + 0.046271*85.671^2\right) = 5944.84$$

$$G_{CM,1} = 53.487*85.671 - \left(2249.489 + 45.559*85.671 + 0.046271*85.671^2\right) = -1909.90$$

Under the discriminatory mechanism PAB are:

$$G_{PAB,1} = 75.781*85.671 - \left(2249.489 + 45.559*85.671 + 0.046271*85.671^2\right) = 0.00$$

B. *Case B*

Figure 12 shows generation accepted by the market, where the marginal unit GenCo 8 is only dispatched in period 20.

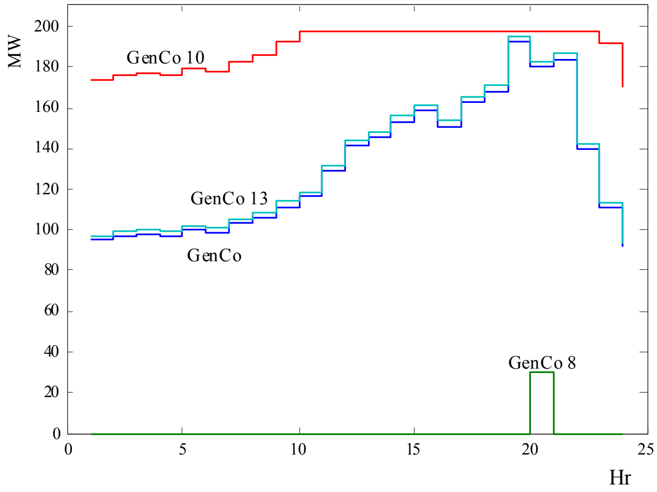

Figure 12 Case B: Economic Dispatch

The market price is again calculated period by period. Since GenCo 8 needs to recover its fixed costs for the 24 periods in a single period, which is now significantly higher the CPP in period 20 than remaining periods, this value ranges between \$63.1 and \$ 74.3/MWh as shown in Figure 13.

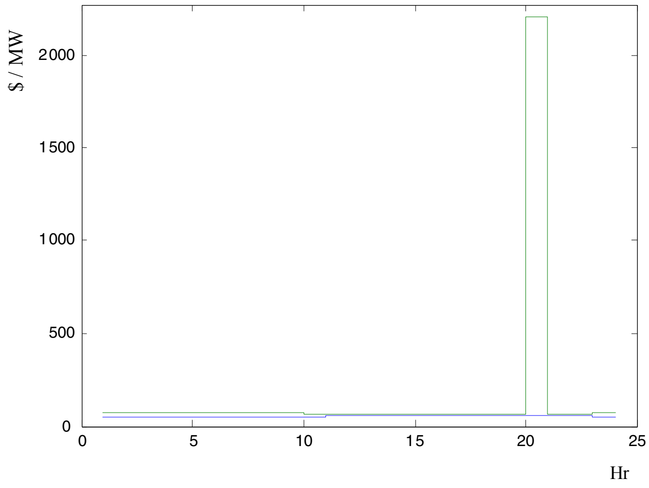

Figure 13 Case B: Market Price

It is worth mentioning that for this case the peak shown in Figure 13 tends to fall and when P_{Gi} is increased, the cost per MW decreases.

Figure 13 also shows the marginal costs, with values ranging between \$54.0 and \$63.3/MWh. They are not drastically affected by the entry of GenCo 8 in a single period. Additionally, there are no significant differences with respect to the marginal costs in Case A.

Table VI shows the profits of GenCos 3, 8, 10 and 13 under the uniform price payment mechanism, shows that the profits increase significantly when considering the scheme of payment of UP, due to the high market price caused by GenCo 8 in period 20.

TABLE VI
GENCOS' 3, 8, 10 AND 13 PROFITS: CASE B

GenCo 3	GenCo 8		GenCo 10		GenCo 13	
CM	CPP	CM	CPP	CM	CPP	CM
-1914.10	-2682.90	-2682.90	2549.44	-940.97	77.45	-1883.68
-1900.35	-2682.90	-2682.90	2527.74	-914.95	76.98	-1869.46
-1891.55	-2682.90	-2682.90	2514.63	-898.43	76.67	-1860.37
-1896.84	-2682.90	-2682.90	2522.44	-908.36	76.84	-1865.84
-1876.89	-2682.90	-2682.90	2493.76	-871.06	76.21	-1845.24
-1883.54	-2682.90	-2682.90	2503.05	-883.45	76.42	-1852.11
-1848.49	-2682.90	-2682.90	2456.91	-818.60	75.42	-1815.94
-1822.74	-2682.90	-2682.90	2426.97	-771.61	74.76	-1789.39
-1772.12	-2682.90	-2682.90	2376.16	-680.70	73.69	-1737.25
-1725.01	-2682.90	-2682.90	2336.54	-597.61	72.90	-1688.80
-1645.06	-2682.90	-2682.90	2070.99	-445.77	71.27	-1606.31
-1518.62	-2682.90	-2682.90	1887.66	-237.08	70.31	-1476.60
-1483.55	-2682.90	-2682.90	1840.26	-181.24	70.10	-1440.63
-1421.96	-2682.90	-2682.90	1757.98	-83.83	69.77	-1377.40
-1372.63	-2682.90	-2682.90	1704.13	-8.19	69.59	-1326.81
-1438.69	-2682.90	-2682.90	1778.57	-109.96	69.84	-1394.57
-1340.32	-2682.90	-2682.90	1673.66	40.32	69.51	-1293.67
-1291.87	-2682.90	-2682.90	1634.14	111.60	69.44	-1244.02
-1065.77	-2682.90	-2682.90	1521.93	424.24	69.61	-1012.59
-1011.12	61706.7	-2532.21	424431.8	454.53	389850.6	-957.91
-1151.23	-2682.90	-2682.90	1552.84	309.60	69.46	-1100.02
-1539.35	-2682.90	-2682.90	1911.51	-269.75	70.44	-1497.84
-1776.59	-2682.90	-2682.90	2380.33	-688.67	73.79	-1741.86
-1940.72	-2682.90	-2682.90	2595.81	-991.89	78.50	-1911.21
-38529.1	**0.00**	**-64238.9**	**473449.3**	**-9961.8**	**391529.6**	**-37589.5**

Additionally, losses continue to take CM as the market price because they do not include fixed costs. The returns under PAB are not displayed because they are not being considered rates of return; hence, the profits are always zero.

V. CONCLUSIONS

The marginal cost of the system, generally considered the market price, does not cover a GenCo's total costs. However, it may be the market price, provided an additional payment equal to or greater than its fixed operational cost is made to the GenCo. This paper has shown how to perform the calculation of earnings using the fixed and variable costs in the curve of a quadratic GenCo. Further, by not considering such payments' capability, it is expected that the value of deals by companies generating the CPP will increase proportionally with the higher rate of return.

System reliability plays a key role in wholesale electricity market performance, especially because such markets must consider the location and availability of suppliers. In other words, the payment for installed capacity should be based on demonstrated ability to meet, for example, energy reserves at times of shortage, and in emergency conditions. Thus, only suppliers that contribute to system reliability should be paid.

Tracking in the fuel prices used by GenCo, will always be a reference for monitoring the behavior of a spot market price of electricity.

We find that tracking the price of fuels used by GenCos functions as a benchmark reference to monitor pricing behavior in a spot market. We suggest that policy-makers and regulators can learn to correlate market behavior with specified scenarios to help evaluate player strategies and to design more effective and transparent rules.

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