Game-Theoretic Insights into the Day-Ahead Iberian Electricity Market

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***Abstract*—Electricity markets follow a marginal pricing system, where the highest-cost dispatched generator sets the clearing price for all market participants. However, instead of bidding at their marginal costs, generators strategically adjust their offers to maximize profits. This study applies game-theoretic principles to examine how hydropower owners in the Iberian electricity market strategically influence market-clearing prices through their bidding behavior. Hydropower plants, with medium marginal costs and flexible dispatch, may submit increased bids to raise the clearing price, benefiting low-cost renewable assets that remain competitive at higher prices. By analyzing historical bidding patterns and clearing price formation, this study finds that hydropower frequently acts as the marginal technology, might shape price outcomes in the market. These results highlight the limitations of the uniform-priced market, as firms with diversified portfolios can strategically optimize bids to increase revenues.**

***Index Terms*-- Electricity market, marginal pricing, bidding strategies, hydroelectric power, game theory**

I. INTRODUCTION

Access to cheap and reliable energy is a fundamental driver of economic growth, industrial competitiveness, and social well-being. A well-functioning electricity market is essential to ensuring stable energy prices, fostering investment in sustainable infrastructure, and supporting long-term economic development. High energy costs can reduce industrial productivity, limit business expansion, and increase the cost of living, ultimately hindering economic progress. Thus, ensuring market efficiency, transparency, and competition is crucial for economic stability.

In this context, the European Commission has recognized the need for structural reforms in electricity markets to enhance price stability and resilience [1]. By refining market mechanisms, policymakers aim to prevent price distortions, improve market efficiency, and encourage investments in diverse and sustainable energy sources. The goal is to create a more competitive energy landscape, where businesses and households benefit from predictable and fair pricing, reducing economic volatility and promoting long-term energy security and industrial growth.

Recognizing the risks associated with dependence on Russian gas, the European Union has accelerated efforts to diversify its energy sources, integrating a higher share of renewables and seeking alternative suppliers. While the worst effects of the crisis may now be overcome, the 2023 State of the Energy Union report [2] emphasizes that energy security remains a top priority. Energy diversification and market reforms must continue to enhance transparency, improve regulatory oversight, and increase the visibility of energy market activities. Strengthening the capabilities of regulatory bodies is essential to detecting and preventing practices that could lead to unfair price surges, ensuring long-term stability and resilience in the European energy sector.

In the Iberian Electricity Market (MIBEL), which integrates the electricity systems of Spain and Portugal, the average price in 2021 was three times higher than in 2019, the year before the pandemic. Towards the end of 2021, gas prices surged significantly, a trend that was further intensified by the war in Ukraine in 2022. As a result, 2021 and 2022 saw exceptionally high electricity prices, particularly given that a portion of the Iberian market's electricity is produced by combined cycle plants. However, the rise in electricity prices was not limited to combined cycle plants; some traditionally low- and mid-cost generators also increased their offer prices [3]. Studies have shown that, under certain conditions, a firm with significant market share may strategically reduce its production or raise its energy offer prices to influence market outcomes [4]-[5].

Game theory provides a powerful analytical framework for understanding the strategic interactions among generators in electricity markets. Various game-theoretic principles such as Nash equilibrium can be used to model the behavior of firms bidding in electricity markets [7]. These principles help explain how firms set their bids, anticipate competitors' strategies, and optimize their market positions to enhance profitability. In the Iberian electricity market, firms with a diversified portfolio that includes both hydropower and low-cost renewable energy sources (such as wind and solar) can adopt strategic bidding practices to maximize profits.

From a game theory perspective, this market can be modeled as a competition between firms with mixed portfolios and those with conventional generation. In a Nash equilibrium scenario, each firm selects a bidding strategy that optimizes its profit, considering the expected actions of others. This results in a market structure where hydropower firms exert influence over price formation while ensuring their renewable assets benefit from the elevated prices. However, such strategic bidding practices raise concerns about market efficiency and fairness. Regulatory bodies such as the European Commission and the Spanish National Commission for Markets and Competition have acknowledged the potential for market manipulation and have initiated reforms to improve monitoring and oversight [8]. These efforts aim to curtail excessive price inflation while preserving the economic viability of flexible generation assets like hydropower.

This works explores how game theory can provide strategic insights for firms aiming to optimize their profits while maintaining compliance with market regulations. The rest of this paper is structured as follows: Section II provides context for the day-ahead Iberian electricity market by briefly describing the structure of the Iberian day-ahead electricity market in 2022. Section III describes the methodology utilized to justify the generators strategy. The results are presented and discussed in Section IV and finally Section V provides the main conclusions.

II. THE DAY-AHEAD IBERIAN ELECTRICITY MARKET

The day-ahead market is a crucial pillar of the European electricity market, enabling energy transactions through buy and sell bids for the following day. Integrated with the European system since 2014, it plays a fundamental role in achieving the objectives of the European Internal Energy Market. The daily auction, held at 12:00 CET, determines electricity prices for the next 24 hours across multiple European countries, including Spain, Portugal, Germany, France, and Italy. Prices are set based on supply and demand dynamics, following a harmonized European model. In Spain and Portugal, OMIE is the designated Nominated Electricity Market Operator (NEMO), managing bids and ensuring a transparent price formation process [9]. When interconnection capacity between price zones is sufficient, electricity prices remain uniform; otherwise, price differences arise due to market congestion, governed by the market coupling mechanism.

Beyond economic efficiency, market results must also be technically viable, requiring validation by the System Operator. If necessary, adjustments are made through system constraints management, ensuring grid stability. Additionally, price limits are in place to regulate bidding behavior within the Iberian market (MIBEL), with day-ahead bid caps set between +4,000 €/MWh and -500 €/MWh. A Second Auction is triggered when prices exceed +2,400 €/MWh or drop below -500 €/MWh, helping to stabilize extreme fluctuations. Similarly, the intraday market provides flexibility, allowing participants to adjust energy schedules through three auction sessions and a continuous cross-border market. Intraday bid prices in MIBEL range from +9,999 €/MWh to -9,999 €/MWh, with additional notification thresholds to ensure efficient trading.

The intraday auction market consists of intraday capacity auctions and continuous trading, ensuring balance while managing interconnections after the final day-ahead market schedule is set. The marginal pricing model governs price formation, aligning bids with real-time supply and demand fluctuations. Twenty minutes before an auction closes, cross-border continuous trading is paused, but local transactions continue until the final bidding deadline. This structured sequence of markets—spanning from futures trading to real-time adjustments—ensures efficient electricity pricing, promotes market flexibility, and upholds grid stability, reinforcing the broader goals of European electricity integration.

In 2021, the Iberian Electricity Market (MIBEL) facilitated a total energy trade of 266.4 TWh. The day-ahead market accounted for approximately 85% of this volume, with 226.4 TWh traded. The intraday markets contributed an additional 15%, totaling 40 TWh. Furthermore, bilateral contracts represented around 27% of the total traded energy, amounting to 72 TWh. Consequently, the day-ahead electricity market alone supplied about 67% of the total energy traded within MIBEL for that year, underscoring its dominant role in price formation and energy allocation [10].

In the day-ahead market, generators submit supply offers at different prices, and consumers agents place purchase bids specifying the maximum price they are willing to pay. The market follows a merit-order principle, where the lowest-cost bids are dispatched first until total demand is met. This mechanism ensures that electricity is allocated efficiently, favoring lower-cost generation sources while setting the market-clearing price based on the highest accepted bid. Once all bids are submitted, OMIE determines the market-clearing price, which is set by the most expensive unit needed to balance supply and demand. All dispatched generators receive this uniform price, regardless of their original bid. The results of the auction define the scheduled generation and consumption for the next day, ensuring efficient price formation, transparency, and system balance across Spain and Portugal. In general, the interconnection between Portugal and Spain experiences minimal congestion on the transmission power lines, with price differences exceeding 1 €/MWh occurring in only about 3% of the hours.

In marginal pricing-based spot electricity markets, generators are expected to offer their energy at marginal cost in the short run to promote economic efficiency and market stability. Marginal cost refers to the additional cost incurred when producing one more unit of electricity, typically covering fuel expenses, variable maintenance, and operational costs, while excluding fixed or sunk costs such as capital investment [11]. By pricing electricity at marginal cost, the market functions more efficiently, ensuring that supply meets demand at the lowest possible cost. However, in imperfect markets, generators may strategically deviate from marginal-cost pricing to maximize profits, which can lead to price distortions and inefficiencies.

Deviating from marginal cost pricing can lead to significant inefficiencies—if generators bid above their marginal cost, they risk being underutilized, leading to higher market prices and inefficiencies in resource allocation. Conversely, bidding below marginal cost (e.g., at opportunity cost levels or predatory pricing) can distort market signals, potentially driving out competitors and leading to long-term price volatility and reduced investment in generation capacity. Thus, adherence to marginal cost pricing in the short run is essential for maintaining a competitive, reliable, and economically optimal electricity market.

III. METHODOLOGY

In a marginal electricity market, the clearing price is determined by the marginal generator, which is the last generator dispatched to meet demand. Several key assumptions underpin this market structure. First, it operates as a uniform-priced market, meaning that all dispatched generators are paid the same clearing price, which is dictated by the highest accepted bid. Second, generators face a risk of non-dispatch if they bid too high and are priced out of the market. Third, some firms own multiple power plants with different cost structures, allowing them to leverage market power by increasing bids from one plant to benefit others in their portfolio. Finally, there is incomplete information, as each generator does not have full knowledge of its competitors' bids but can develop expectations based on market conditions.

From a game theory perspective, generators act as rational players who must decide their bidding strategies. Each generator selects a bid price that could either reflect true production costs or be strategically inflated to increase the market-clearing price. The payoff for each generator depends on whether they are dispatched and the resulting market-clearing price. If dispatched, a generator's profit is the difference between the clearing price and its marginal cost, multiplied by the quantity of electricity supplied. However, if a generator increases its bid excessively and is not dispatched, its profit falls to zero, creating a trade-off between higher potential earnings and the risk of non-dispatch.

In a simple scenario, assuming no market power or portfolio effects, the dominant strategy for a generator would be to bid at its true marginal cost to ensure dispatch. However, the uniform-pricing rule distorts this behavior. If a firm owns multiple plants with varying cost structures, strategic bidding can increase total profits. For instance, if a firm owns both a high-cost coal plant and a low-cost renewable plant, it can bid higher for the coal plant, potentially setting a higher clearing price, which benefits the renewable plant that is still dispatched at the inflated market price. Even in the absence of explicit collusion, firms may tacitly recognize the benefits of bid inflation, leading to higher clearing prices across the market.

In imperfect markets, the concept of market power is crucial in this context, as firms that control a significant share of total generation capacity can influence the clearing price. Such firms may adopt mixed bidding strategies, adjusting bids dynamically to balance the risk of non-dispatch with the benefit of a higher clearing price. The Nash equilibrium in this setting occurs when each generator bids in a way that maximizes its expected payoff given the strategies of competitors. In equilibrium, some generators may raise bids anticipating that others will do the same, reinforcing an upward trend in prices as long as the risk of non-dispatch remains acceptable. To model this behavior formally, we consider a market setup where there are n generators, each indexed by $i=1,2,\dots,n$.

Every generator i has a marginal cost C_i per MWh of electricity produced and submits a bid price b_i. This bid may be equal to or higher than C_i. Let q_i represent the quantity of electricity that generator i offers to supply, and let D be the total market demand. The market-clearing price $P_{clearing}$ is determined by the highest accepted bid that meets total demand:

$$P_{\text{clearing}} = \max(b_i \mid \sum_i q_i \geq D) \tag{1}$$

This means that the last dispatched generator sets the market-clearing price. Each generator's profit function depends on whether it is dispatched. If dispatched, the profit π_i is:

$$\pi_i = \begin{cases} q_i \cdot (P_{\text{clearing}} - C_i), & \text{if generator } i \text{ is dispatched} \\ 0, & \text{if generator } i \text{ is not dispatched.} \end{cases} \tag{2}$$

A company with multiple plants can use strategic bidding to influence the clearing price. Consider a generator that owns Plant A (with marginal cost C_A) and Plant B (with marginal cost C_B), where C_A.> C_B The firm may raise the bid of Plant A to set a higher clearing price while ensuring Plant B is still dispatched. The firm's total profit in this case can be obtained with (3) and (4):

$$\pi_{\text{total}} = \pi_A + \pi_B \tag{3}$$

$$\pi_A = q_A \cdot (P_{\text{clearing}} - C_A) \text{ and } \pi_B = q_B \cdot (P_{\text{clearing}} - C_B) \tag{4}$$

However, if the bid for Plant A is set too high, there is a risk that it is not be dispatched, leading to a lower total profit:

$$\pi_{\text{total}} = \pi_B \tag{5}$$

This type of risk can be mitigated through the strategic use of hydropower plants with reservoirs. Unlike other generation sources, these plants have the flexibility to withhold energy from the day-ahead market and later participate in intraday markets, where prices may be more favorable. This operational advantage allows them to take calculated risks when bidding, as they can adjust their strategy based on real-time market conditions. By leveraging this flexibility, hydropower plants can optimize revenue while minimizing exposure to uncertainties in the initial bidding process.

This strategy illustrates how firms use their generation portfolio to influence the market, balancing price inflation against dispatch probability. The optimal bidding strategy is determined by maximizing the expected profit while ensuring at least one plant remains competitive. The firm thus solves (6):

$$\max_{b_A, b_B} \mathrm{E}[\pi_{total}] = \mathrm{P}(A\ dispatched) \cdot (\pi_A + \pi_B) + \mathrm{P}(A\ not\ dispatched) \cdot \pi_B \tag{6}$$

Subject to the constraints:

$b_B \le b_A$ (to ensure Plant B is dispatched),

$b_A \ge C_A$, $b_B \ge C_B$

Where: $\mathrm{E}[\pi_{total}]$ is the expected total profit of the firm, $\mathrm{P}(A\ dispatched)$ is the probability that Plant A is dispatched, $\mathrm{P}(A\ not\ dispatched)$ is the probability that Plant A is not dispatched

In order to illustrate this model, we present Fig. 1.

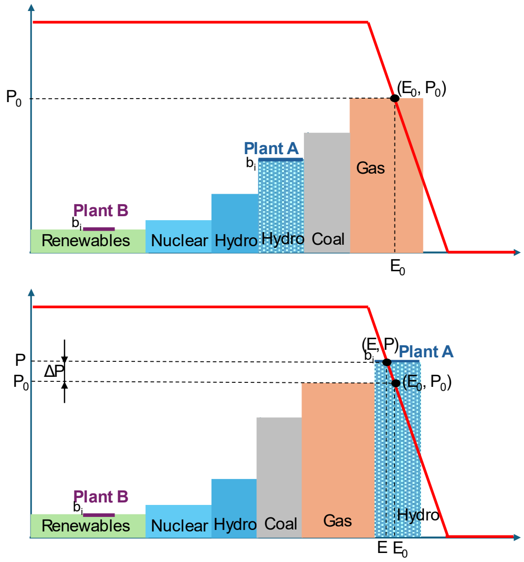

Fig. 1. Representation of the bidding strategy

The figure illustrates the merit-order principle in electricity markets, showing the interaction between generation and demand curves. The generation curve is constructed by ordering bids in ascending price from left to right, meaning that technologies with lower marginal generation costs (such as renewables and nuclear) are placed first, followed by medium-cost sources (such as hydropower), and finally, higher-cost technologies (such as coal and gas) appear on the right. The demand curve, in contrast, follows a descending order, representing the willingness of consumers (or demand agents) to purchase electricity at different price levels [12]. The market-clearing price is determined at the intersection of the supply and demand curves, setting the uniform price paid to all dispatched generators. In reality, electricity markets are more complex, as generators can incorporate additional conditions into their bids, but this description provides a simplified representation for clarity.

The figure also illustrates a strategic bidding approach modeled using game approach. It represents a company with a generation portfolio composed of a renewable plant (Plant B) and a hydropower plant (Plant A). Plant A has a medium marginal cost, positioned below fossil-fuel-based thermal plants but above renewable plants in terms of cost structure. In contrast, Plant B has a low marginal cost due to its renewable nature. Both plants submit multiple bids (b_i) into the market.

The top panel of the figure represents a standard market scenario, where both plants submit bids aligned with their respective marginal costs. The bottom panel illustrates a strategic bidding scenario, where Plant A inflates its bid above its marginal cost, and some of these higher bids are still accepted. As a result, the market-clearing price (ΔP) increases, benefiting the company overall. Despite a potential reduction in the dispatched energy from Plant A, the higher clearing price leads to an increase in total profit for the firm, as Plant B (the renewable unit) continues to be dispatched at the elevated price.

To validate this theoretical framework, an empirical analysis is conducted. We analyze data from the day-ahead Iberian market, identifying bidding behaviors that align with our theoretical framework.

IV. RESULTS

The average daily market price in the Iberian electricity market for the year 2021 was 111.93 €/MWh in Spain and 112.01 €/MWh in Portugal. That year, the electricity price tripled compared to pre-pandemic levels in 2019 and preceded the Ukraine conflict, which later triggered a surge in natural gas prices. The case of the Iberian market is particularly noteworthy, as despite having a highly diversified generation mix, high marginal cost technologies, such as combined cycle plants, accounted for approximately 13% of total energy in the day-ahead electricity market, as shown in Fig. 2. This figure also highlights that hydropower generation, which has medium marginal costs, accounted for 11% of total generation in the day-ahead market.

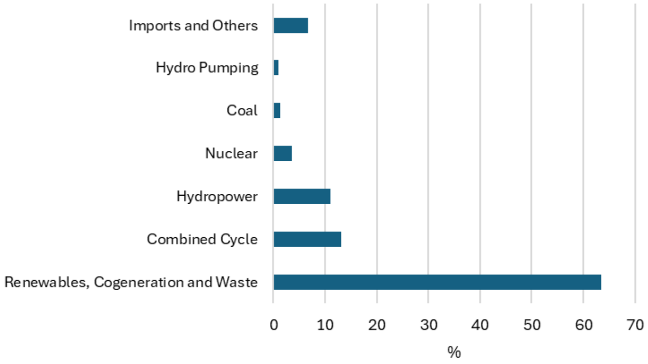

Fig. 2. Generation share (%) by technologies in 2021 (day-ahead market)

However, detailed analysis of the day-ahead market results for 2021 reveals a systematic trend, where medium marginal cost technologies regularly set the market-clearing price. This means that these technologies frequently acted as the marginal units, ultimately determining electricity prices. Fig. 3 illustrates the frequency at which different generation technologies acted as the marginal technology in the Iberian electricity market during 2021. The data confirm that hydropower was the most frequent marginal technology, setting the market-clearing price in more than 50% of the hours. This aligns with the previously discussed analysis, which highlighted the systematic role of medium marginal cost technologies in defining electricity prices throughout the year.

Other technologies, such as renewables, cogeneration, and waste, also played a significant role, setting the price in around 20% of the hours. Combined cycle plants, despite their greater relevance in the generation mix and higher marginal costs were marginal in a smaller percentage of hours.

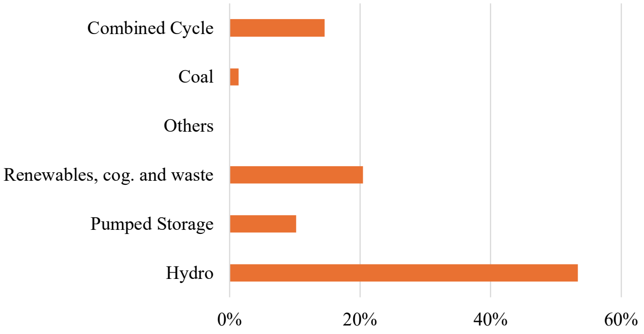

Fig. 3. Breakdown of technologies for units that were marginal in 2021

The prominence of hydropower as the marginal technology suggests that its bidding strategies had a direct influence on market prices. Given the ability of hydropower plants with reservoirs to strategically adjust their bids, this finding further supports the hypothesis that hydropower generators may engage in strategic bidding to influence market-clearing prices and maximize firm profits. Another relevant fact is that hydropower plant owners are also major players in the renewable energy sector, holding significant renewable portfolios. In 2021, five companies accounted for 89% (23.8 TWh) of the total hydropower energy cleared in the day-ahead electricity market [3]. Within these companies' portfolios, hydropower represented 30% of the total energy they supplied to the day-ahead market, amounting to 76 TWh. This concentration of hydropower generation within a few firms highlights the strategic role of hydropower in market price formation and bidding strategies, particularly given its flexibility compared to other renewable sources.

V. CONCLUSIONS

While economic theory suggests that generators should bid at their marginal costs to promote efficiency, real-world market behavior deviates due to profit-maximizing incentives, market power, and imperfect competition. Firms with diversified portfolios can leverage their assets strategically, adjusting their bids to maximize overall profitability rather than strictly following cost-reflective pricing principles.

Empirical analysis of the 2021 Iberian electricity market reveals that hydropower frequently acted as the marginal technology, meaning it often set the market-clearing price. This study demonstrates that hydropower owners strategically adjust their bids, increasing their offer prices when market conditions allow, ultimately raising the clearing price. This strategy benefits their low-cost renewable assets, which remain competitive even at higher market-clearing prices. These findings indicate that pricing decisions in electricity markets are not purely cost-driven but are influenced by firms' ability to optimize their entire portfolio's profitability.

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