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Strategic Bidding to Increase the Market Value of Variable Renewable Generators in Electricity Markets

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Abstract: The 2050 global ambition for a carbon-neutral society is increasing the penetration of the most competitive variable renewable technologies, onshore wind and solar PV. These technologies are known for their near-zero marginal costs but highly variable time-dependent generation. Power systems with major penetrations of variable generation need high balancing flexibility to guarantee their stability by maintaining the equilibrium between demand and supply. Electricity markets were designed for dispatchable technologies. Support schemes are used to incentivize and de-risk the investment in variable renewables, since actual market designs are riskier for their active participation. This study presents three strategic bidding strategies for the active participation of variable renewables in electricity markets based on probabilistic quantile-based forecasts. This case study examines the levels of active market participation for a wind power producer (WPP) in the Iberian electricity market and the Portuguese balancing markets, where WPPs are financially responsible for imbalances and operate without support schemes in the first and second stages of the Iberian market designs. Results from this study indicate that the WPP has the potential to increase its market value between 36% and 155% if participating in the tertiary and secondary balancing markets completely adapted to its design, respectively. However, considering the use of strategic bidding in actual market designs, by participating in the secondary reserve, the WPP can increase its market value by 10% and 45% when compared with perfect foresight and operational cases, respectively.

Keywords: balancing markets; electricity markets; imbalance settlement; market design; probabilistic forecasts; secondary and tertiary reserves; strategic bidding; variable renewable energy sources

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1. Introduction

Electricity market (EM) participants are diverse, autonomous entities with distinct objectives and trading strategies [1]. Typically, supply-side agents aim to maximize profits in wholesale markets, while demand-side agents focus on minimizing electricity costs before reselling it to end consumers in the retail market. Most trading strategies involve cooperation, ensuring mutual benefits for both parties [2,3]. Wholesale electricity markets operate under three primary models. Auctions represent a centralized market structure where supply and demand agents submit bids, and market prices are determined by the intersection of supply and demand curves using a marginal pricing algorithm. Bilateral contracts involve private agreements between supply and demand agents, allowing them to negotiate contract terms directly. Hybrid models combine elements of both auction-based trading and bilateral contracts, offering flexibility in market participation. Most

European Union countries operate under a hybrid market model. In this system, a day-ahead market (DAM) closes at noon in Central European Time (CET) on the day before trading, followed by intraday markets (IDMs) used for real-time bid adjustments. These intraday markets may function through multiple auction-based sessions, as seen in Iberian (MIBEL), Italian, and German markets, or via continuous intraday trading, as in most of Europe. Additionally, private bilateral contracts and participation in derivative markets provide risk management tools, enabling agents to secure fixed energy prices over extended time horizons, reducing exposure to spot market volatility. Auxiliary services, such as balancing markets (BMs), ensure grid stability by maintaining frequency and voltage, mitigating system imbalances, and enhancing overall network reliability [3–6].

The rapid growth of variable renewable energy sources (vRESs), such as wind and solar photovoltaic (PV), has introduced new challenges to electricity markets [7]. However, their intermittent nature increases supply volatility and uncertainty, leading to higher system integration costs, particularly for ancillary services [8,9]. While wind power requires substantial investment, its production costs are nearly zero. Although increased vRES penetration tends to lower spot market prices, it can drive up ancillary service costs, as deviations from expected output require balancing measures. The financial burden of these deviations is typically placed on the responsible market agents through penalties in the imbalance settlement (IS) [9–12]. In extreme cases, such as significant forecasting errors, the penalties imposed on vRES producers can exceed their spot market revenues. However, certain power systems shield vRES producers from these costs, transferring them to consumers instead. This was the case in Portugal under feed-in tariffs (FiTs) and other guaranteed tariff schemes, which provided financial stability for vRES generation [13–15]. Support schemes are a good option to de-risk investments in renewable energy sources and the volatility of electricity markets if well designed. The most common designs, such as FiTs and contracts for difference (CfDs) contributed to market distortions, such as price cannibalization, negative prices, and tariff deficit. However, with the decreasing levelized costs of energy (LCOEs) of vRESs and increasing electricity prices in Europe after the 2022 gas crisis, more competitive and well-designed support schemes, such as financing CfDs and risk-sharing contracts may contribute to de-risking the market price volatility [15–17]. Indeed, support schemes contributed for the first time negative grid access prices, reducing real-time pricing retail tariffs to values lower than wholesale prices during the gas crisis [18,19]. However, support schemes are an externality affecting the competition principle of auction-based marginal markets based on the Nash equilibrium [19,20]. So, support schemes cause market distortions by benefiting vRESs.

Given the increasing penetration of VRESs, a careful reassessment of electricity market models is necessary to determine their effectiveness in a renewable-dominated landscape [5,6]. Existing market structures were designed when dispatchable power plants dominated generation, limiting incentives for vRES participation unless coordinated with flexible generation assets [21–23]. The growing share of vRESs has led to reduced market liquidity, and, despite lower LCOEs, economic incentives—such as FiTs—remain essential for ensuring wind farm participation. While solar PV has become economically viable without subsidies, the rising costs of ancillary services highlight the need for market design reforms [5,6,24,25]. Enhancing flexibility mechanisms and appropriately compensating ancillary service providers will be critical to ensuring grid stability and efficiency in high-vRES energy systems [24–26]. vRES has the technical capability to provide balancing reserves [27]. They can use strategic bidding with or without support schemes and adapt their behavior to increase their market uptake accordingly [6,11,28–33].

Against this background, this paper evaluates the outputs of vRESs in electricity markets without support schemes using strategic bidding. This paper presents a methodology that can be adapted to all vRES technologies based on the probabilistic quantile-based forecast and price arbitrage by selecting the best quantile to increase the market uptake of vRESs. The methodology is tested using three strategies and data of MIBEL.

The remainder of this paper is structured as follows: Section 2 presents a literature review on the active participation of vRESs in electricity markets. Section 3 provides an overview of markets and reserve systems, highlighting MIBEL. Section 4 outlines the proposed methodology for the strategic participation of vRESs in markets. Section 5 presents a case study and evaluates the performance of the developed strategies. Finally, Section 6 summarizes the findings and discusses the implications for future energy markets.

2. Literature Review on the Active Participation of vRESs in Electricity Markets

This section presents a literature review on how vRESs can increase market remuneration through active participation in electricity markets [6,11,28–33]. A literature review on the different options to remunerate vRESs can be found in the study of [28]. A study analyzed how shifting to a support scheme that exposes renewables to market prices has led to increased price arbitrage by WPPs [29]. Further studies on bidding strategies in sequential markets are explored in the electricity market modeling literature [6,11,28,30–33].

A study on a wind power plant (WPP) operating in the Danish electricity market demonstrated that active participation in both the DAM and BMs resulted in a 6.5% increase in the overall wind energy value. This finding highlights the potential benefits of flexible and market-aware trading strategies, which not only improve the profitability of vRESs but also facilitate their integration into the electricity system. By leveraging multi-market participation, vRESs can reduce forecast errors, optimize revenues, and support grid stability, ultimately enhancing their economic sustainability [30].

A profitability assessment of wind power participation in Swedish BMs revealed that the most profitable strategy is engaging in both the DAM and automatic Frequency Restoration Reserve (aFRR) downward regulation. This combination can generate an additional revenue of 35% compared to participation in the DAM alone under perfect production forecasts and 22% when factoring in standard production forecast errors [31].

A study analyzed the strategic behavior of Spanish active solar PV power plants without support schemes in MIBEL. It concludes that these players used price arbitrage to offer prices higher than their near-zero marginal costs in MIBEL, increasing their market remuneration [28].

Using a stochastic optimization model applied to German electricity market data, a study finds that market participants with portfolios comprising both conventional and renewable power plants tend to prefer selling their production in the intraday market if they anticipate higher prices there compared to the DAM. As a result, they may sell nothing or even purchase quantities in the day-ahead market [32].

Considering the same WPPs and dataset of the present study, a study analyzed the participation of WPPs in the DAM and Portuguese BMs across four scenarios. The baseline scenario involved participation solely in the DAM, while Scenario A combined the DAM with the aFRR, and Scenario B combined the DAM with a manual Frequency Restoration Reserve (mFRR). Scenario C also integrated the DAM with the mFRR market but reduced the time unit to 15 min. The study found that Scenario C was the most favorable, as shorter time units increased flexibility and revenue for WPPs. Scenario A also proved more beneficial than Scenario B, with revenue increases of 4.9% and 2.2%, respectively, compared to the baseline. These findings highlight the role of WPP participation in BMs in reducing dependence on support schemes and fostering their integration as active players in electricity markets [11]. Furthermore, the appropriate design of BMs and a newly designed short-term power purchase agreement (PPA) electronic trading platform (STE) adapted to WPP's stochastic behavior may increase its market value by 25% [33]. A summary of the results obtained using the typical deterministic forecast methodology and the active participation of the WPPs in electricity markets are presented in the study of [6]. All tested scenarios increased the wind power value when compared to the baseline deterministic forecast only to the DAM.

The literature does not consider probabilistic forecasts of vRESs to handle a de-risking price arbitrage. Against this background, the presented case study analyzes the extent of active market participation by a WPP in MIBEL and the Portuguese BMs, where WPPs bear financial responsibility for imbalances and operate without support schemes in the first and second stages of MIBEL. Using probabilistic forecasts and price arbitrage, the findings indicate that, if the WPP fully participates in tertiary and secondary balancing markets tailored to its design, its market value could increase by 36% and 155%, respectively. However, under the current market framework, when strategic bidding is applied, the potential market value increase is 10% and 52% in the ideal and operational scenarios.

3. Electricity Markets

Market participants can trade electricity across five different market types [5]:

1. Spot Markets: Agents submit bids (minimum 0.1 MW) to electricity pools through day-ahead and intraday marginal auctions.
2. Continuous Markets: Trading occurs in real time, with transactions settled to 15 min before delivery.
3. Derivative Markets: Includes forwards, futures, swaps, and options, allowing hedging against spot price volatility and consumption uncertainty.
4. Non-Organized (Private Bilateral Contracts, such as PPAs): Agents negotiate directly, setting customized terms and conditions outside organized exchanges.
5. Ancillary Service Markets: Managed by Transmission System Operators (TSOs) to ensure system stability by balancing supply and demand deviations.

3.1. European Electricity Markets

In European electricity markets, the day-ahead market closes at noon (CET) the day before real-time operation (11–37 h ahead). These markets are coupled and use the EU Pan-European Hybrid Electricity Market (EUPHEMIA), a common marginal pricing algorithm that optimizes power flows between different market zones to maximize social welfare [5,34].

Energy trading also occurs in intraday markets, which consists of the following:

1. Intraday Auctions: Conducted a few hours before real-time operation.
2. Continuous Trading: Operates on a pay-as-bid basis, allowing transactions up to 15 min before real-time delivery.

In derivative markets, agents can enter financial or physical contracts via clearing houses (organized exchanges) or over-the-counter trading to hedge against spot price volatility. For non-standard agreements, private bilateral contracts allow direct negotiations between parties, such as power purchase agreements [3,16].

Since many market participants—such as retailers, energy communities and vRES generators without storage—face real-time deviations from their programmed schedules, TSOs manage balancing markets to ensure system security. Balancing Responsible Parties (BRPs) must cover the costs of their upward or downward balancing deviations, which often result in financial penalties relative to spot market prices [11,35].

European power grids must maintain a stable frequency of 50 Hz, with a secure oscillation range of ±0.1%. If deviations exceed 0.5%, outages and separations of control areas may occur. When deviations reach 0.1%, balancing reserves are automatically activated to restore stability [11,36].

Europe utilizes four main balancing mechanisms to regulate frequency deviations:

1. Frequency Containment Reserve (FCR):
    - First response mechanism, activated within 15 s to counteract frequency disturbances.
    - The European synchronous grid reserves 3000 MW for the FCR to maintain system stability.
2. Automatic Frequency Restoration Reserve (aFRR):
    - Activated within 30 s, replacing the FCR.
    - Maintains grid frequency stability for up to 15 min.
    - TSOs define a power band for each period, with symmetric band requirements set by ENTSO-E or set by each TSO according to its own methodology.
3. Manual Frequency Restoration Reserve (mFRR):
    - Used after the aFRR to support extended balancing needs.
    - Addresses medium- and long-term deviations caused by generation or load fluctuations.
    - TSOs activate 15 min market blocks, allowing generators to bid in auctions.
4. Replacement Reserve (RR):
    - Used for long-term disturbances beyond aFRR and mFRR capabilities.
    - Activated within 15 min and remain active for several hours.
    - Typically managed through bilateral agreements between TSOs and providers, rather than real-time market activations.

BMs reserves are traded directly between TSOs and providers. Upward regulation providers receive the up-regulation price, while downward regulation providers pay the down-regulation price. Imbalance settlement costs are assigned to BRPs that deviate from their scheduled dispatch. Typically, upward regulation prices exceed spot prices, while downward regulation prices are lower. In some cases, BRPs may receive compensation instead of penalties, depending on market conditions [11,37,38].

3.2. Portuguese Electricity Markets

Portugal and Spain are part of MIBEL since 2007. MIBEL oversees spot, continuous (since 2015 in the second stage of MIBEL), derivative, and bilateral markets, while ancillary services remain independent for each country and are managed by their respective TSOs. However, certain ancillary services can be traded between TSOs for system balancing. In the DAM and IDM, players can bid up to 24 bids with increasing prices per hour [5]. So, they are allowed to use price arbitrage [5,28].

Portugal follows the European frequency reserve framework for continuous balancing, with the following specifications [11,12,38–40]:

1. FCR:
    - The FCR is mandatory and non-remunerated for all technically capable generators connected to the grid.
    - Generators must reserve 5% of their nominal power under stable conditions to support the FCR.
    - Portugal contributes to the continental European synchronous grid.
2. aFRR:
    - The Portuguese TSO requires an asymmetrical aFRR power band, where up-regulation capacity is twice the down-regulation capacity.

- Historically, Portugal's aFRR power band is more used for up-regulation than down-regulation.
- To align with ENTSO-E guidelines, Portugal's TSO upscales up-regulation capacity to 60% and downscales down-regulation to 40%.
- Hourly aFRR capacity auctions are held, allowing all technically capable generators to participate.
- Generators must offer both up-regulation and down-regulation, with up capacity being twice the down capacity.
- Due to limited competition, combined cycle gas turbines (CCGTs) dominate the aFRR market.
- The price of upwards aFRR energy is regulated and set by the national regulator.

3. mFRR:
    - mFRR energy is procured through hourly auctions, with separate bids for upward and downward regulation in marginal markets.
    - Since mFRR is based on hourly auctions, it may not be sufficient for balancing long-term frequency deviations.
4. RR:
    - Based on annual marginal capacity procurement, its marginal energy procurement is defined through hourly auctions, with separate bids for upward and downward regulation.
    - RRs are activated for long-term system imbalances that cannot be resolved through aFRRs or mFRRs.
    - RRs can be activated within 15 min and remain active for extended periods.

Extraordinary reserves rely on bilateral contracts between TSOs and market participants instead of direct market bidding.

4. Strategic Bidding of vRESs in Electricity Markets

The objective of maximizing the producer's revenue is formulated as an optimization problem, which was implemented using Python. v3.7.3 (code provided in the Supplementary Materials). In this model, the decision variables represent the volumes traded in the EMs, constrained by market rules and conditions.

The following general constraints are applied:

- The schedule in the EMs is limited by the nominal power of the vRES power plant. The producer cannot sell more energy than what can be physically produced.
- The producer cannot bid more downward balancing capacity than the scheduled injection.
- Bids in the BMs are limited by the request of the TSO.

In this model, the vRES market participation decisions are interconnected through the following concepts:

- Position: The portfolio of the vRES that accounts for the bid in the DAM, increasing when selling in the IDM and decreasing when purchasing energy.
- Final offer: The position of the vRES after the capacity market and before the activation of energy bids. This represents the adjusted position based on initial bids and the balancing capacity market.
- Final schedule: After the activation of reserves by the TSO, the final schedule reflects the adjusted energy injection into the grid. It is derived from initial positions from the DAM and IDMs, increasing when upward reserves are activated and decreasing when downward reserves are called upon. This adjustment reflects the energy increased or reduced in response to the TSO's requests.

- Final deviation: The difference between the actual production and the final schedule, which will be settled during the IS period.

These concepts are crucial for understanding how the vRES's decisions evolve and impact each other across different market stages.

4.1. Ideal Case

In an ideal scenario, the producer has perfect foresight regarding both vRES production and market conditions. With this information, the producer can place bids at the optimal quantile of the distribution to maximize revenue. This participation strategy, based on the optimal quantile of vRES generation probability forecasts, has been discussed in other studies [11,41]. The revenue from the DAM is as follows:

$$R_{j,t}^{DAM} = Q_{j,t} \cdot C_t^{DAM} \tag{1}$$

where, for the hour t,

1. $Q_{j,t}$ is the quantile j, with j representing the index ranging from 1 to 21.
2. C_t^{DAM} is the DAM price.

The deviation between the observed energy, E_t^{obs}, and the quantile j for the hour t is

$$E_{j,t}^{dev} = E_t^{obs} - Q_{j,t} \tag{2}$$

Since each period t corresponds to one delivery hour, the energy volume representing the imbalance, $E_{j,t}^{dev}$, is the power deviation for that hour as given by Equation (2).

Considering the case where vRESs only participate in the DAM, after the gate closure of the DAM, any deviations are settled in the IS period. The remuneration during this period depends on the direction of the imbalance, with producers either being penalized or compensated based on whether they over- or under-deliver relative to their bid.

$$R_{j,t}^{IS} = E_{j,t}^{dev} \cdot \begin{cases} C_t^{EXC},\ if\ E_{j,t}^{dev} > 0 \\ C_t^{DEF},\ if\ E_{j,t}^{dev} < 0 \end{cases} \tag{3}$$

where, for the hour t,

1. C_t^{EXC} is the price paid to the producers with excess generation.
2. C_t^{DEF} is the price paid by producers with a deficit.

The maximum total remuneration at hour t is given by the following:

$$R_t = \max_j \left(R_{j,t}^{DAM} + R_{j,t}^{IS} \right) \tag{4}$$

The optimal quantile for each hour t, which maximizes the total remuneration, corresponds to the quantile with the index:

$$j_t^* = arg\max_j (R_t) \tag{5}$$

Considering also the participation of vRESs in intraday and balancing markets, the deviation from the DAM schedule (2) can be addressed in other markets, where the remuneration (4) depends on the market conditions and prices.

When participating in the IDMs, the producer can adjust their position after the DAM and before the IS. In the ideal scenario, any deviation can be settled in the market with a higher price in the case of a positive deviation, or a lower price if there is a deficit. The price considered for intraday continuous (IDC) is the DAM price.

Since the primary reserve is not procured in markets, only participation in the secondary and tertiary reserve (TR) were considered. Participation in the secondary reserve (SR) includes both the capacity and energy markets, as well as the IS process. In the capacity market, the producer receives C_t^{CAP} for each unit of reserve capacity sold. The offer is constrained by the TSO's requirements, meaning that the producer cannot offer a greater balancing capacity than the TSO's needs. Under first and second stage market designs, the bid for downward balancing capacity must be half of the bid for upward balancing capacity. However, under perfect forecasting, the offer for upward balancing capacity is not limited to available capacity. Producers can bid beyond their available resources and capitalize on potential negative prices in the IS.

The final offer, $E_{j,t}^{final\ offer}$, consists of the bid in the DAM, $E_{j,t}^{DAM}$, and the upward balancing capacity, $P_{j,t}^{SR+}$, assuming all energy can be activated.

$$E_{j,t}^{final\ offer} = E_{j,t}^{DAM} + P_{j,t}^{SR+} \tag{6}$$

The bid in the energy market must fall within the range set by the offer in the capacity market and is subject to TSO's requirements. The producer bids at 0 €/MWh for upward regulation and at the DAM price for downward regulation, either receiving or paying the clearing price. The producer receives C_t^{TR+} when providing upward balancing energy and pays C_t^{TR-} when required to provide downward balancing energy.

The remuneration from the energy market is as follows:

$$R_{j,t}^{EN} = \begin{cases} E_{j,t}^{SR+} \cdot C_t^{TR+}, & if\ E_{j,t}^{SR+} > 0 \\ -E_{j,t}^{SR-} \cdot C_t^{TR-}, & if\ E_{j,t}^{SR-} > 0 \end{cases} \tag{7}$$

where, for the hour t,

1. $E_{j,t}^{SR+}$ is the upward secondary balancing energy provided by the vRES.
2. $E_{j,t}^{SR-}$ represents the downward secondary balancing energy provided by the vRES, which corresponds to the energy withdrawn from the grid when requested by the TSO. The negative sign indicates the payment made by the BRP to the TSO.

The final schedule accounts for the vRES's position (which, in the ideal case, is the bid in the DAM, $P_{j,t}^{DAM}$), increasing with the upward energy provided and decreasing with the downward energy activated.

$$E_{j,t}^{schedule} = E_{j,t}^{position} + E_{j,t}^{SR+} - E_{j,t}^{SR-} \tag{8}$$

The final deviation to be adjusted in the IS is the difference between actual production and the final schedule.

$$E_{j,t}^{dev} = E_t^{prod} - E_{j,t}^{schedule} \tag{9}$$

where E_t^{prod} the observed power at hour t.

Remuneration in this market segment depends on the direction of the imbalance and includes a penalty for producers who fail to supply the allocated capacity. The penalty applied to the imbalances for each hour t is calculated as follows:

$$C_t^{penalty} = 3 \cdot \left(C_t^{DAM} - C_t^{EXC} \right) \tag{10}$$

The imbalance price for hour t is as follows:

$$C_t^{IMB} = \begin{cases} C_t^{DAM} - C_t^{Penalty}, & if\ E_{j,t}^{dev} > 0 \\ C_t^{DAM} + C_t^{Penalty}, & if\ E_{j,t}^{dev} < 0 \end{cases} \tag{11}$$

The producer faces significant penalties if they fail to fulfill their balancing service contracts. If the producer has surplus generation and the imbalance price for a positive deviation is negative, they can voluntarily curtail their excess generation to avoid incurring costs associated with overproduction. The remuneration from the IS is as follows:

$$R_{j,t}^{IS} = E_{j,t}^{dev} \cdot C_t^{IMB} \tag{12}$$

Revenue from participation in the SR is given by the sum of the three market segments:

$$R_{j,t}^{SR} = R_{j,t}^{CAP} + R_{j,t}^{EN} + R_{j,t}^{IS} \tag{13}$$

The producer can settle deviation (2) in the mFRR market. For negative imbalances, the producer can bid the deviation (2) to downward regulation and pay the price $C_t^{TR^{down}}$. For positive imbalances, the producer can receive $C_t^{TR^{up}}$. If the deviation exceeds the needs of the TSO, the remaining imbalance can be adjusted in the IDMs or through the IS, with penalties applied as described for the SR.

4.2. Operational Case

Participation in EMs involves inherent uncertainties and limited visibility into market conditions and production levels. Producers often rely on forecasts and bidding strategies to navigate these markets effectively. While minimizing forecasting errors is crucial, some level of uncertainty remains inevitable. Therefore, maintaining operational flexibility and adopting proactive planning are key to managing these challenges and optimizing performance. The bidding strategy is designed to optimize revenue by dynamically selecting the quantile offered in the DAM based on market conditions. To achieve this, the producer uses the perfect case scenario as a benchmark to identify the average DAM price when the highest quantile is the optimal bid. This threshold price, denoted as n, sets the upper limit for bids in the operational mode, ensuring that offers remain competitive while mitigating risk. Forecasts include day-ahead probabilistic quantile-based and intraday deterministic single points, which are calculated using a K-Nearest Neighbor (KNN) approach based on data from a numerical weather prediction (NWP) model [11,33,41–43]. Probabilistic forecasts are used with price arbitrage in the DAM and with quantity arbitrage in BMs. This methodology operates in real-time mode, utilizing the initial conditions provided by the Global Forecast System (GFS) model. The GFS model supplies various meteorological parameters with an hourly resolution, extending up to 48 h ahead.

The K forecast quantiles $Q_{j,t}$ are mapped to a price range from 0 €/MWh to n, with equal increments between each quantile. The highest quantile is offered when $C_t^{DAM} \geq n$.

The price interval for each of the other quantiles k from 1 to K (for $Q_{0.02}$ to $Q_{0.98}$) up to the maximum number of bids is given by the following formula:

$$Price\ Interval_k = \left[\frac{(k-1)}{K} \cdot n, \frac{k}{K} \cdot n \right] \tag{14}$$

While $Q_{0.02}$ provides a small quantity risk to the vRES at a bid price equal to 0 €/MWh, $Q_{0.98}$ provides larger risk at the highest bid price, n, de-risking the energy commitment of the vRES with lower market prices.

The quantile Q_k is the bid in the DAM, P_t^{DAM}, if the DAM price for that hour falls within the price interval as described in the following:

$$\frac{(k-1)}{K}\cdot n \leq C_t^{DAM} < \frac{k}{K}\cdot n \quad (15)$$

This dynamic price-responsive strategy ensures effective market participation while aligning bids with expected remuneration.

Deviations from the initial DAM bid are determined by updated forecasts, allowing producers to adjust their bids accordingly. Participation in the SR market is prioritized, as it offers higher remuneration potential from both the capacity and energy markets.

In addition to the previously mentioned constraints, the following rules apply in the balancing capacity market:

- The bid for upward balancing capacity cannot exceed the available capacity or the needs of the TSO.

$$P_t^{SR+} \leq min\left(E_t^{dev}, E_t^{SR_{req}^{up}}\right) \quad (16)$$

where E_t^{dev} represents the positive deviation, considering the updated vRES power forecast and the position of the vRES at the time of market.

- The bid for downward balancing capacity cannot exceed the scheduled injection or the needs of the TSO.

$$P_t^{SR-} \leq min\left(E_t^{position},\ E_t^{SR_{req}^{down}}\right) \quad (17)$$

4.3. Strategies for Participation in aFRR Market

Three strategies were simulated, each based on different market designs and varying levels of participation in the SR.

Strategy 1 (S1): Considers the first-stage design where producers adjust their position in the auction-based intraday (IDA) and bid in the SR market only when the deviation between the forecast (made between 4 and 9 h before operation) and the DAM bid is positive.

Strategy 2 (S2): Considers the second-stage market design featuring a parallel SR capacity market alongside the IDA. The IDC market is used to make necessary adjustments before the IS. Participation in the SR is limited to positive deviations in the IDA.

Strategy 3 (S3): Like S2, this strategy also follows the second-stage design but with the aFRR capacity market operating in parallel with the IDC. Participation in the SR is restricted to positive deviations.

The deviation is calculated as follows:

$$E_t^{dev} = E_t^{15min} - E_t^{position} \quad (18)$$

where

1. E_t^{15min} is the forecasted value 15 min before delivery.
2. $E_t^{position}$ is the vRES position at the time of the IDC, which can be higher than the bid in the DAM if the producer sold energy in the IDA or lower if the producer was a buyer in the IDA. The average remuneration (€/MWh) for the study period is calculated by dividing the total revenue across all hours by the total production for the same period.

$$\overline{R} = \frac{\sum_{t=1}^{T} R_t}{\sum_{t=1}^{T} E_t^{obs}} \quad (19)$$

where

1. $\overline{R}$ is the average remuneration (€/MWh).
2. R_t is the total revenue at hour t.
3. E_t^{obs} is the observed production for each hour t.
4. T is the total number of hours in the dataset.

Figure 1 illustrates the organization and structure of the market across the different strategies.

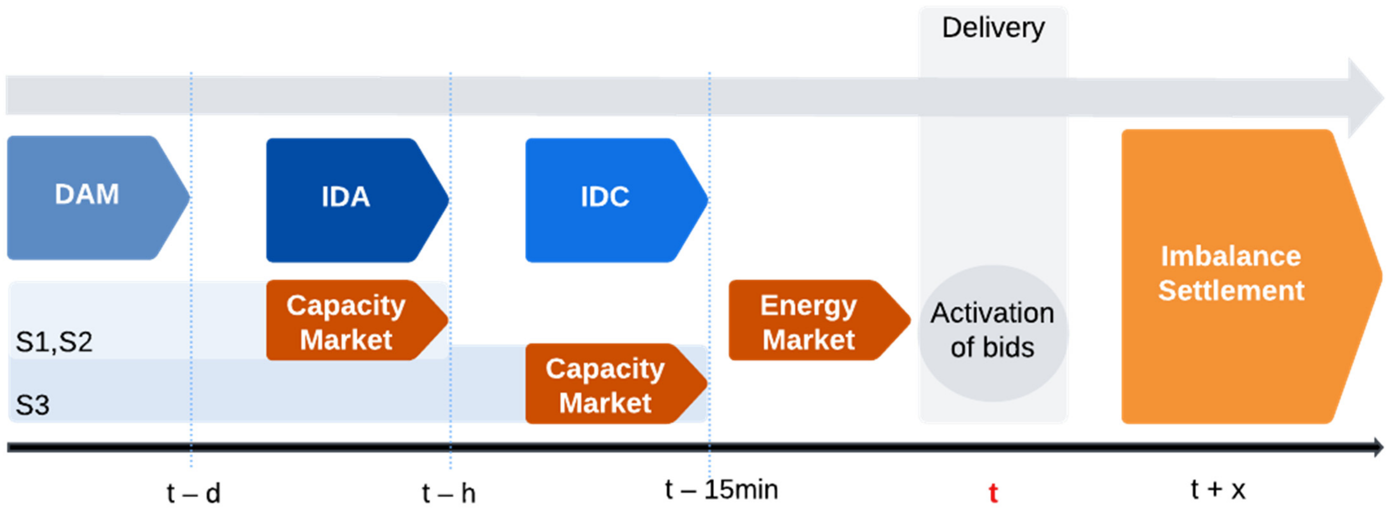

Figure 1. Market structure for the different strategies.

5. Case Study on the Active Participation of a WPP in EMs

This section presents a case study of a WPP participating in the EMs within the MIBEL framework and the Portuguese BMs during the period of 2009–2010. The analysis assumes that the WPP operates without any support schemes and is fully responsible for managing its imbalances. The objective is to maximize the producer's remuneration by optimizing market participation strategies. In this section, the dataset, methodology applied, and the developed scenarios are outlined.

5.1. Dataset and Statistics

The market data includes hourly prices for DAM, IDMs, positive and negative imbalance prices, as well as hourly prices and requirements for aFRR and mFRR.

Table 1 presents key market price statistics, such as the standard deviation (SD), highlighting significant price differences across various market segments.

Table 1. Key statistics of electricity market prices.

	DAM (€/MWh)	IDA (€/MWh)	Secondary Reserve Capacity (€/MW)	Positive Tertiary Energy (€/MWh)	Negative Tertiary Energy (€/MWh)	Positive Imbalance Price (€/MWh)	Negative Imbalance Price (€/MWh)
Min	0.00	0.00	0.00	0.00	0.00	−289.51	−160.44
Max	180.30	112.05	180.30	181.00	100.00	225.10	381.01
Median	38.18	36.52	22.57	43.20	23.00	25.86	49.23
Mean	37.30	35.09	27.12	42.40	20.15	22.74	51.82
SD	12.17	12.62	14.54	18.02	15.49	19.66	20.92

From Table 1, it can be verified that positive tertiary energy prices are higher than negative tertiary energy prices, indicating stronger financial incentives for participating in balancing markets. The Portuguese IS is symmetrical, which means that the penalty is equal for both positive and negative imbalances [40]. The difference between positive or negative imbalance prices and the DAM price is the penalty. The mean penalty is positive. However, when balancing costs are negative, the penalty can be negative, providing a positive remuneration for BRPs.

Table 1 also presents DAM, IDA, and SR capacity prices, providing further context for the broader market dynamics. The extreme fluctuations in imbalance prices underscore the market's volatility, emphasizing the importance of strategic bidding and accurate forecasting to optimize profitability and manage risks. Figure 2 illustrates the average hourly values for required aFRR capacity (a) and the energy used for aFRR and mFRR (b).

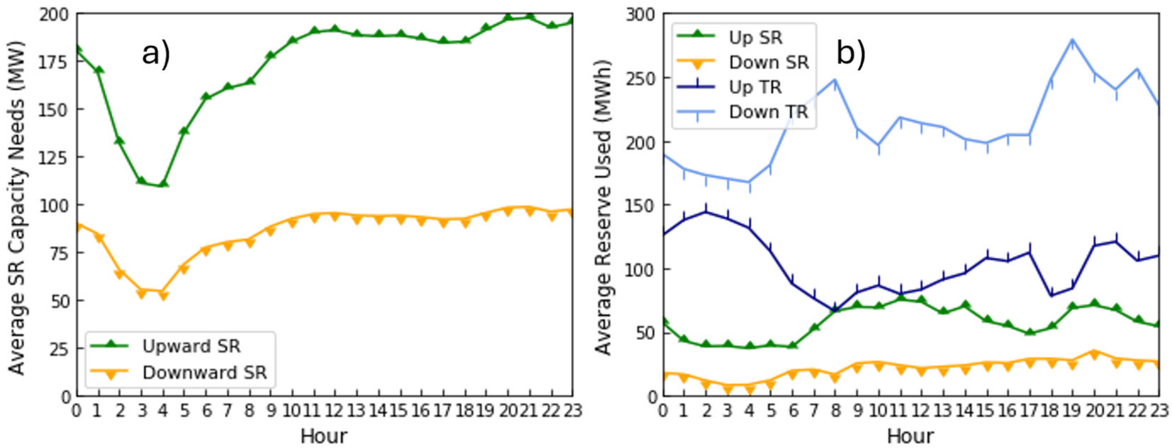

Figure 2. Mean hourly values for required aFRR capacity (**a**) and aFRR and mFRR energy used (**b**).

In Figure 2a, the upward aFRR capacity requirement is shown to be twice the downward demand, in line with Portuguese legislation. Figure 2b highlights that downward tertiary energy was the most used, reflecting the grid's reliance on manual reserves during periods of over-generation or lower demand than expected in the programming dispatches. During the period of this study, the average wind power penetration in Portugal was 16.88%. The wind data originated from an aggregator of wind power plants with a nominal capacity of 250 MW. The dataset contains both observed wind power and wind power forecasts using a KNN approach based on data from an NWP model [11,33]:

- A probabilistic quantile-based forecast used by the producer when submitting bids to the DAM.
- Two deterministic single-point forecasts are provided in the IDMs: one with a time horizon between 4 and 9 h depending on the session of IDA, corresponding to the gate closure of the IDA, and another with a 15 min time horizon, corresponding to the gate closure of the IDC.

Figure 3 illustrates the average hourly values for both observed and forecasted wind power across the 21 quantiles. These interval forecasts ranged from the 2nd to the 98th percentile of the wind power predictive distribution, corresponding to quantiles Q_1 to Q_21 for each trading period. Quantiles below the observed power can be committed without risk, and higher quantiles may require buying energy in markets or paying imbalance penalties.

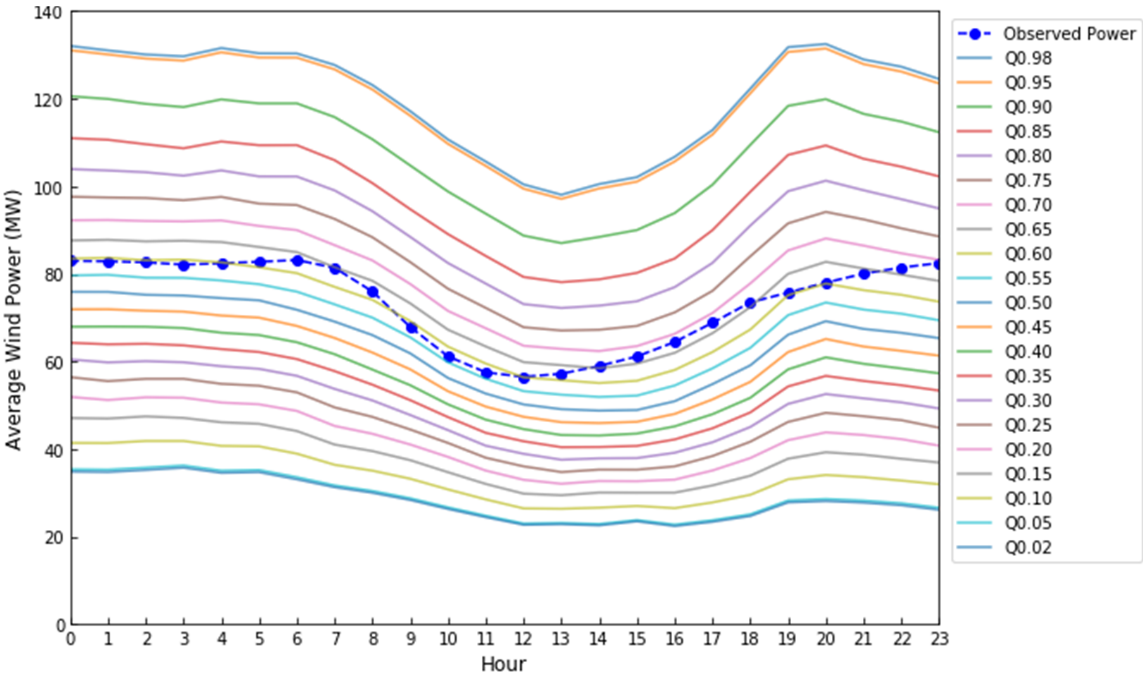

Figure 3. Average observed wind power and quantile forecasts per hour of the day.

Figure 4 presents the optimal probabilistic 21 quantiles and the average DAM prices.

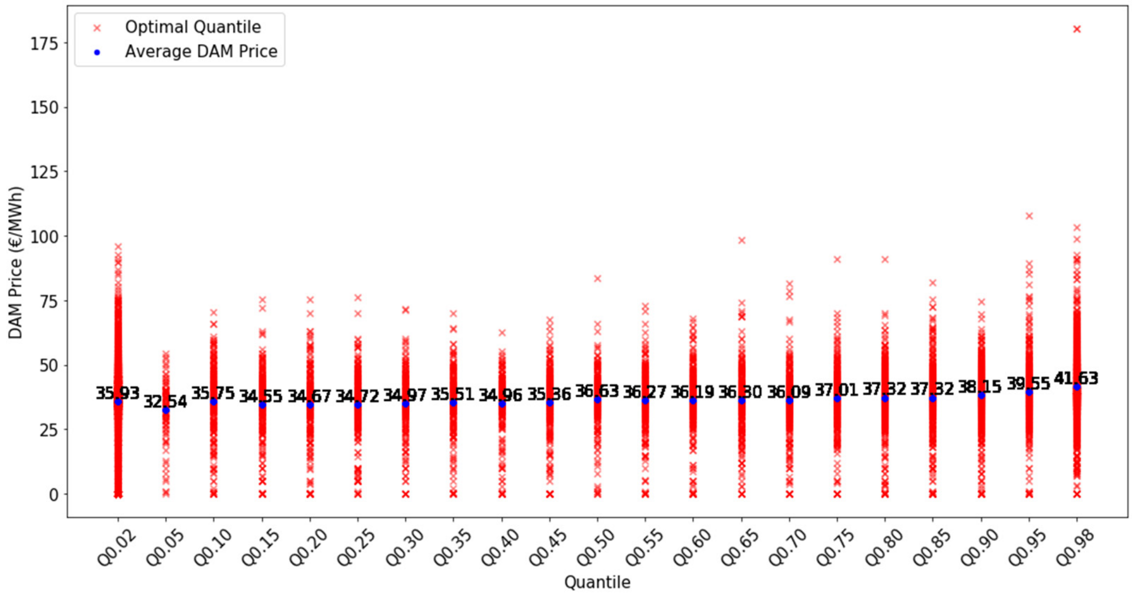

Figure 4. Optimal quantiles according to DAM prices.

Analyzing Figure 4, it is possible to verify that the optimal quantiles slightly increase with DAM prices. The output of this figure is used to define the n maximum bidding price indicated in Equations (14) and (15), presented in $Q_{0.98}$ as 41.63 €/MWh.

Figure 5 compares the average hourly values of deterministic forecasts at two different time horizons: between 4 and 9 h and 15 min before real-time operation, against the observed values. It shows that, as the forecasting horizon shortens, the deviation from the observed values decreases. Table 2 presents key statistics for the forecast deviation (forecast value—observed power) for each forecasting horizon.

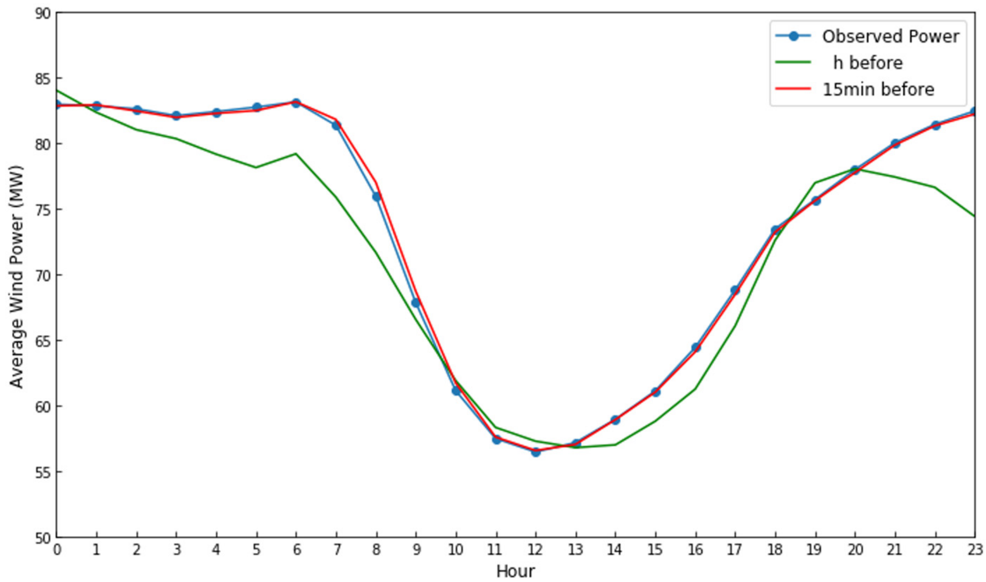

Figure 5. Average observed wind power and deterministic forecasts per hour of the day.

Table 2. Key statistics for wind power forecasts.

	4–9 h Before	**15 min Before**
Min	−143.41	−23.03
Max	114.08	24.08
Median	0.45	0.27
Mean	−2.03	0.02
SD	22.86	2.86

Analyzing Figure 5 and Table 2, the benefits of forecasts can be verified closer to real-time operation, as the IDC is important to adjust the programming schedules of vRESs, reducing imbalances.

5.2. Scenarios

This case study analyzes the active participation of the WPP across various markets, aiming to maximize revenue.

Two main cases were considered: (i) an ideal case, where the producer has perfect foresight of market prices and wind power production at the time of delivery, and (ii) an operational case, where the producer relies on forecasts and bidding strategies to navigate uncertainties in the energy markets. To highlight the evolution and improvements in EMs design, two distinct approaches were explored:

1. MIBEL first-stage design: This approach illustrates the market conditions prior to the introduction of the continuous intraday market. Under this design, the gate closure for the IDA was set a few hours before delivery. According to Portuguese legislation, bids for downward capacity must be half the amount of upward capacity offered in the aFRR market. With increasing competition from WPPs, the price of the reserve energy market was assumed instead of the regulated price to CCGTs.
2. MIBEL second-stage design: This design represents the stage after including the continuous intraday market. Existing legislation continues to impose restrictions on the procurement of downward capacity. In the simulated period, it was assumed that IDC trades have the same price as the DAM trades to overcome the lack of data in the studied period.

5.3. Results

This section presents the results of the ideal and operational cases. In the ideal case, the WPP has perfect information about its production and market prices. So, it is the case that maximizes the market value of the WPP. The operational case simulates the daily behavior of an active WPP participating in EMs.

5.3.1. Ideal Case

The outputs of the ideal case considering the WPP participation only in the DAM or also in the IDM, SR, or TR are presented in Figure 6.

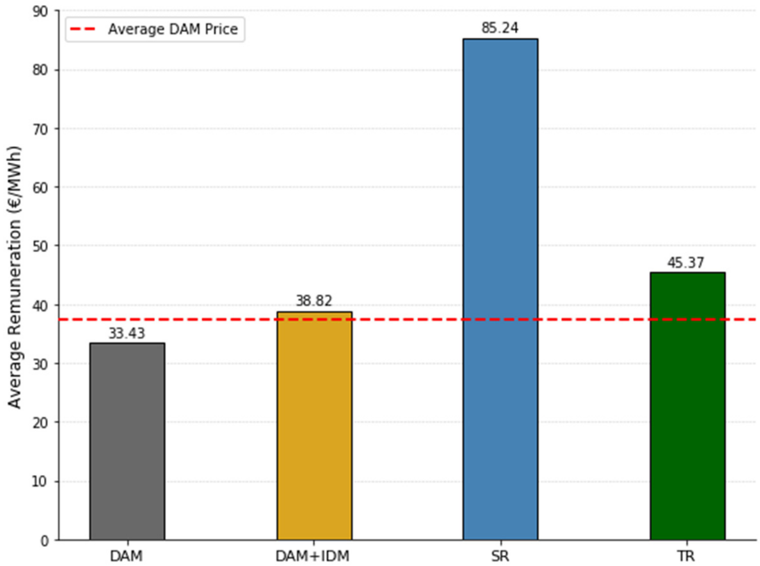

Figure 6. Average remuneration for the ideal case in different markets and market designs.

In Figure 6, it can be verified that the significant increase of 155% and 120% in the case of the WPP has perfect information when participating in the SR, when compared to participating in the DAM, or DAM + IDM, respectively. Furthermore, it can be concluded that, by participating in the SR, the WPP has the potential to increase their market value by 120% regarding its actual market options. These results indicate the potential benefits of WPPs if electricity markets are designed in adaptation to the stochastic nature of vRESs. The WPP perfectly adjusted its position in IDMs for an increase of 16% in its market value. In the case of participating in the TR, its market value increases to 36%. These results illustrate the high benefit of participating in BMs, mainly in the provision of reserve capacity, as presented in Table 3.

Table 3. Average hourly values of revenue for the different markets in the ideal case.

Market Revenue (k€)	Market			
	DAM	**IDM**	**SR**	**TR**
Day-ahead	2.54	3.04	2.23	3.26
Intraday	-	−0.19	0.18	0.01
Capacity	-	-	4.22	-
Energy	-	-	0.51	0.05
Imbalance Settlement	−0.09	−0.01	−0.89	0.01

Analyzing Table 3, it can be verified that the provision of reserve capacity in the SR is the option that provides the higher revenue to the WPPs. Indeed, with increasing levels of the vRES, as the main provider of energy, its provision of capacity is important to guarantee the flexibility from the supply side, avoiding forced curtailments in the case of energy excess. Table 4 presents the maximum market value of the WPP by introducing the IDC.

Table 4. Average remuneration for the different market designs in the ideal case.

Market Design	Stage 1	Stage 2
Average Remuneration (€/MWh)	85.24	85.77

Analyzing Table 4, it can be verified that, by considering perfect information, the introduction of the IDC only increased the wind market value by 0.62%. However, operationally, the IDC is very important for WPPs adjusting their programmed dispatches closer to real time, as the outputs of the operational case can be verified in Figure 5.

Table 5 presents average hourly values for different market designs in the ideal case.

Table 5. Average hourly values for different market designs in the ideal case.

Variables	Market Design	
	Stage 1	Stage 2
Revenue (k€)	6.26	6.29
DAM traded energy (MWh)	62.13	61.13
IDA traded energy (MWh)	14.23	9.40
IDC traded energy (MWh)	-	5.91
Allocated capacity (MW)	147.09	147.23
Activated reserve (MWh)	24.05	24.10
Imbalances (MWh)	21.12	20.69
Curtailment (MWh)	3.57	3.62

Analyzing Table 5, it can be verified that the main difference between designs is that the IDA energy is now divided between the IDA and IDC. Basically, under perfect information, the WPP is gaining from the different prices in IDA and IDC. Naturally, the IDC can reduce imbalances even under perfect information, which is more relevant in the case of the operational case presented in the next section.

5.3.2. Operational Case

In the operational case, the participation of the WPP is considered in all markets. However, the strategic bidding neglected the TR because of its competition with the SR, as SR was more economically advantageous, as indicated in Section 5.3.1.

Figure 7 presents the hourly bidding behavior of the WPP in the DAM using Equation (13) based on the optimal analysis presented in Figure 4. Each quantile represents a bid that includes price and quantity. The quantity is provided by the probabilistic quantile-based forecast and the price by Equation (13). Bids are accepted based on Equation (14).

In Figure 7, the WPP bids the quantity defined in $Q_{0.02}$ with a price equal to 0 €/MWh, receiving an average market price of 0.18 €/MWh. Prices increase with quantiles according to Equation (13) and MIBEL rules. In $Q_{0.98}$, the WPP bids the difference between the forecasted quantity obtained in this quantile and the sum of the previous bid quantities with a price equal to 41.63 €/MWh, as presented in Figure 4. In the last quantile, the WPP receives an average price of 48.69 €/MWh.

The baseline scenario considers the participation of the WPP only in the DAM using deterministic forecasts, which resulted in a wind energy value of 28.05 €/MWh [33]. The operational scenario considers the actual framework where WPPs participate in the DAM and IDM, increasing the wind energy value to 29.51 €/MWh [33].

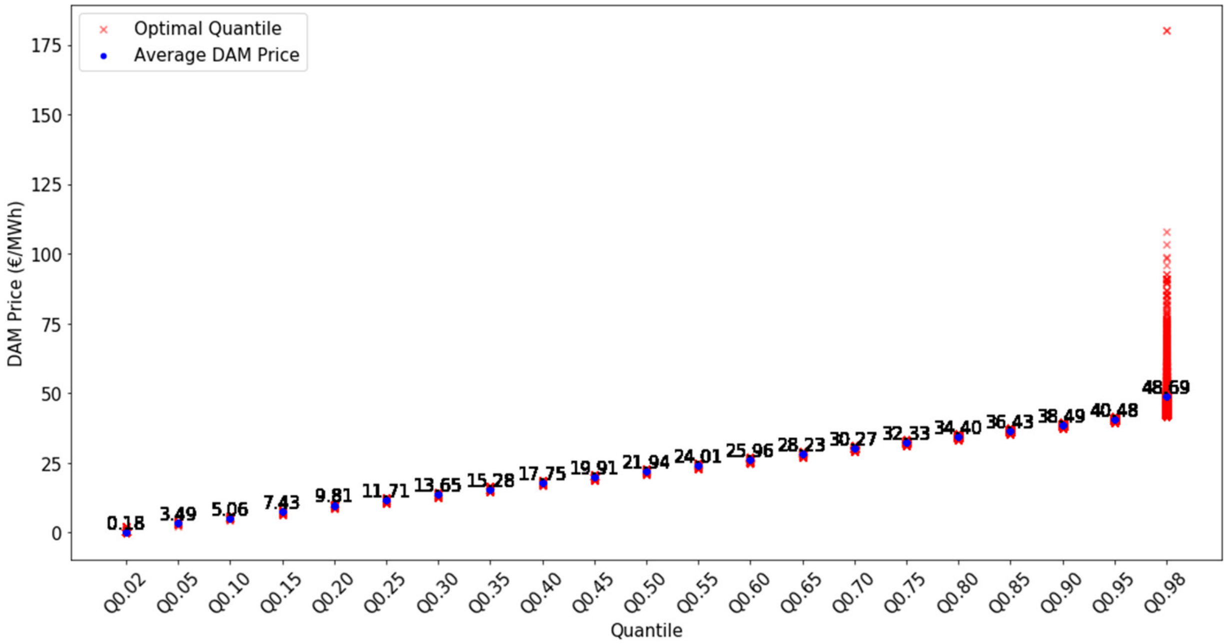

Figure 7. Employed quantile-based strategic bidding.

Figure 8 presents the outcomes of the WPP in different strategies.

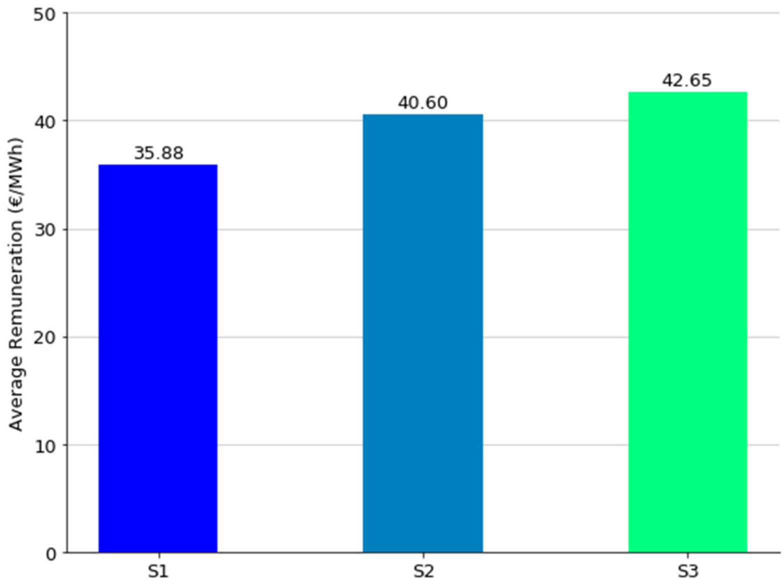

Figure 8. Average remuneration for the operational case in different strategies.

In Figure 8, it can be verified that there is a small increase of 19% in the outcomes of the WPP by using different strategic bidding. However, it is relevant to notice that S3 increases by 10% the optimal value because of the IDC (see DAM + IDM output in Figure 6). These results highlight the importance of allowing the participation of vRESs, increasing their market value and reducing their imbalances, as presented in Table 6.

Table 6. Average hourly quantities are traded for the different strategies in the operational mode.

Variables	Strategy		
	S1	S2	S3
DAM traded energy (MWh)	98.73	98.73	98.73
IDA traded energy (MWh)	36.88	22.77	22.39
IDC traded energy (MWh)	-	24.23	16.59
Capacity allocated (MW)	9.22	9.22	17.05
Upward reserve activated (MWh)	2.56	3.33	6.15
Downward reserve activated (MWh)	0.13	0.12	0.28
Imbalances (MWh)	14.79	2.26	2.84
Curtailment (MWh)	3.54	2.32	3.94

Analyzing Table 6, the benefit of strategies S2 and S3 can be verified from a technical point of view by reducing the imbalances. However, in S2, both imbalances and forced curtailments are lower, as it is the best strategy from the point of view of the system operator. So, from a technical and economic point of view, S2 and S3 are the best strategies, respectively. Table 7 presents the total revenues from each market.

Table 7. Total revenue from different markets for the different scenarios under study.

Total Revenue (M€)	Strategy		
	S1	S2	S3
DAM	64.22	64.22	64.22
IDA	−23.69	−13.50	−13.66
IDC	-	−6.99	−10.30
Upward Capacity	3.63	3.63	6.10
Downward Capacity	1.81	1.81	3.05
Balancing Energy	1.66	2.20	4.32
Positive Imbalance Cost	3.24	0.43	0.65
Negative Imbalance Cost	-5.88	-0.88	-0.90

Table 7 supports previous conclusions. While strategy S3 increases the WPP revenues because of a more significant participation in the SR capacity market, S2 has lower imbalance costs. In S2, the WPP pays more negative imbalance costs, while, in S3, it has more downward balancing energy. So, S3 has more positive imbalances because its reserved capacity is more used for downward regulation.

Considering past results with the same dataset, it can be verified that the participation of the WPP without price arbitrage in the DAM and IDA using deterministic forecasts resulted in a market value of 29.51 €/MWh, increasing to 34.31 €/MWh in the case of participating in ancillary services adapted to it [33]. Furthermore, its market value is 31.18 €/MWh in the case of participating in the TR with time intervals of 15 min [11]. These results are summarized in the study of [6], considering the baseline participation of the WPP only in the DAM using deterministic forecasts that resulted in a wind energy value of 28.05 €/MWh [33]. The participation of the WPP in 15 min STE contracts close to real-time operation increased its market value by 25% [6]. Against this background, strategy S3 increases the wind energy value by 52% considering the baseline operational scenario. Furthermore, it increases the energy value by 10% and 45% considering the optimal actual framework presented in Figure 6 and the operational framework in the study of [33], in the case where the WPP can only participate in the DAM and IDM, respectively.

The outputs support the use of quantile-based probabilistic forecasts and price arbitrage to increase the market value of vRESs and de-risk their participation in markets by considering a proportional relationship between risk and market prices in their bids.

6. Conclusions

Considering the European targets of increasing penetration of variable renewables and the decommission of fossil-fuel power plants, it is important to adapt market designs to the behavior of most of their participants (variable renewables). Indeed, the security of supply and resilient power systems depends on the balance between demand and supply. Variable renewables shall be incentivized to participate in balancing markets, increasing their market value, decreasing their forced curtailments and the need of de-risking support schemes that contribute to price "cannibalization", negative prices, and market distortions.

This study presents three strategies based on strategic bidding to increase the market value of variable renewables, enabling their market uptake without support schemes. Results from this study proved that, by allowing the participation of a WPP in the Portuguese secondary balancing market, it can increase its market value by 10% and 45% when compared with the optimal and operational situations without participating in balancing markets, respectively. Furthermore, if markets were designed according to the behavior of variable renewables, the WPP has the potential to increase its market value by 120% in the case of perfect foresight and participating in the SR. The outputs of this study highlight the need to adapt electricity market designs to the behavior of variable renewables, incentivizing new investments on them and their active participation in electricity markets without support schemes.

Future work has the goal of testing the market outcomes of variable renewables, considering new market designs and their strategic behavior on electricity markets.

Supplementary Materials: The Python code to replicate results is provided in https://github.com/hugoalgarvio/vRESBids (accessed on 13 March 2025).

Author Contributions: Conceptualization, V.S. and H.A.; methodology, V.S. and H.A.; software, V.S.; validation, V.S. and H.A.; formal analysis, V.S. and H.A.; investigation, V.S. and H.A.; resources, V.S. and H.A.; data curation, V.S. and H.A.; writing—original draft preparation, V.S. and H.A.; writing—review and editing, V.S. and H.A.; visualization, V.S.; supervision, H.A.; project administration, H.A.; funding acquisition, H.A. All authors have read and agreed to the published version of the manuscript.

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Data Availability Statement: All market data used in the simulation are available on the website of the Portuguese TSO at https://mercado.ren.pt/EN/Electr (accessed on 13 March 2025).

Conflicts of Interest: The authors declare no conflicts of interest.

Abbreviations

aFRR	Automatic-activated frequency restoration reserve
BM	Balancing market
BRP	Balance Responsible Party
CCGTs	Combined cycle gas turbines
CET	Central European Time
CfDs	Contracts for difference

DAM	Day-ahead market
EM	Electricity market
EU	European Union
EUPHEMIA	EU Pan-European Hybrid Electricity Market
FCR	Frequency containment reserve
FiTs	Feed-in tariffs
GFS	Global Forecast System
IDA	Auction-based IDM
IDC	Continuous IDM
IDM	Intraday market
IS	Imbalance settlement
KNN	K-Nearest Neighbor
LCOEs	Levelized costs of energy
mFRR	Manually activated frequency restoration reserve
MIBEL	Iberian market of electricity
NWP	Numerical weather prediction
PPA	Power purchase agreement
PV	Photovoltaic
RR	Replacement reserve
SD	Standard deviation
SR	Secondary reserve
STE	Short-term energy PPA contract
TR	Tertiary reserve
TSO	Transmission System Operator
vRESs	Variable renewable energy sources
WPP	Wind power producer
Indices	
j	Probabilistic forecast quantiles for each hour
k	Quantile
K	Number of quantiles
t	Hours
Parameters	
C_t^{CAP}	Price received for each unit of balance capacity in aFRR market
C_t^{DAM}	DAM price
C_t^{DEF}	Price paid by BRP with negative imbalances
C_t^{EXC}	Price received by BRP with positive imbalances
C_t^{IDA}	IDA price
C_t^{IMB}	Price for imbalance for BRP
$C_t^{TR^{DOWN}}$	Price for tertiary and secondary energy
$C_t^{TR^{up}}$	Price for upward tertiary and secondary energy
E_t^{15min}	Deterministic forecast 15 min before delivery in hour t
E_t^{h}	Deterministic forecast hours before delivery in hour t
E_t^{obs}	Observed energy
$E_t^{SR_{req}^{down}}$	TSO needs for downward balance in the aFRR capacity market
$E_t^{SR_{req}^{up}}$	TSO needs for upward balance in the aFRR capacity market
$E_t^{SR_{used}^{down}}$	Downward secondary energy requested by TSO
$E_t^{SR_{used}^{up}}$	Upward secondary energy requested by TSO
$E_t^{TR_{used}^{down}}$	Downward tertiary energy requested by TSO
$E_t^{TR_{used}^{up}}$	Upward tertiary energy requested by TSO
$Q_{j,t}$	Probabilistic forecast quantiles
n	Maximum price

Variables

$E_t^{curtail}$	Energy curtailed
E_t^{DAM}	Bid in DAM
E_t^{IDA}	Bid in IDA
E_t^{IDC}	Bid in IDC
E_t^{SR+}	Upward secondary energy activated
E_t^{SR-}	Downward secondary energy activated
E_t^{TR+}	Upward tertiary energy activated
E_t^{TR-}	Downward secondary energy activated
P_t^{SR+}	Upward capacity allocated
P_t^{SR-}	Downward capacity allocated

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