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Bidding Wind and Solar: A Theory of Price Premia in Sequential Electricity Markets

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Abstract

Price premia between day-ahead and intraday electricity markets are well documented and often attributed to factors such as forecast errors or market frictions. However, existing explanations provide limited insight into why these price premia can exhibit a systematic diurnal structure, as observed in the German market. This paper provides a structural explanation by linking price premia to the bidding behavior of renewable producers. I develop a stylized two-stage model in which renewable producers determine their day-ahead bids under different bidding rationales, including expected-production bidding, risk-neutral bidding, and risk-averse bidding that accounts for tail risk. Closed-form solutions for day-ahead bids and the resulting price premia are derived and evaluated using a calibration to German market data. The results show how bidding behavior interacts with supply curve convexity and forecast uncertainty to translate risk preferences of renewable producers into systematic price premia. In particular, heterogeneous bidding behavior across renewable technologies replicates the diurnal pattern of price premia observed in the German market: negative premia around midday and positive premia during morning and evening hours arise when PV producers bid expected production while wind producers follow a risk-averse strategy. The findings suggest that observed price premia reflect both risk preferences and institutional features of renewable energy marketing, which may warrant reconsideration.

Keywords: Sequential Markets, Renewable Energy Bidding, Price Premia, Risk Preferences

JEL classification: Q41, Q42, L94, D81

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1. Introduction

Electricity is predominantly traded through sequential wholesale markets. This market design allows market participants to adjust positions over time and thereby improve allocative efficiency relative to single-stage markets while simultaneously facilitating risk management. The sequential structure typically consists of forward and spot markets. Forward markets serve medium- to long-term hedging purposes, whereas spot markets determine short-term dispatch and prices close to delivery. The spot market itself is commonly organized as a day-ahead market followed by an intraday market, enabling market participants to incorporate updated information on supply and demand (Stoft 2002). Under frictionless conditions, economic theory states that prices across sequential markets should converge in expectation (Weber 1981). Empirical evidence, however, documents persistent price differences between sequential markets, commonly referred to as price premia, contradicting this convergence (Longstaff and Wang 2004; Hadsell 2008; Bowden et al. 2009).

The existing literature proposes several reasons that may explain the emergence of systematic[1] price premia between sequential markets. These include strategic behavior in the presence of market power (Ito and Reguant 2016), risk aversion (Bessembinder and Lemmon 2002), and differences in liquidity (Hagemann and Weber 2013). While these explanations focus primarily on market frictions or aggregate risk preferences, less attention has been paid to the bidding behavior of renewable producers and their risk preferences as a potential source of such systematic price premia. A first step in this direction is taken by Obermüller (2017) and Ashour Novirdoust et al. (2025), who derive optimal day-ahead bids in a competitive and non-competitive market under risk-neutral and risk-averse preferences, respectively. This perspective is specifically relevant in markets with a high share of variable renewable generation, with the German market providing a prominent example. For Germany, Schnaars (2021) and Paschmann (2017) demonstrate a characteristic diurnal pattern of price premia. While existing explanations target average price premia between day-ahead and

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[1] This work defines systematic price premia as recurring patterns that arise consistently across trading periods, rather than being driven by episodic shocks such as forecast errors or plant outages.

intraday markets, they remain largely silent on why these premia exhibit a pronounced diurnal structure, as observed in high-renewable systems such as Germany (cf. Figure 1).

Addressing this gap, this paper makes three contributions to the literature on price formation in sequential electricity markets. First, it provides a micro-founded analytical link between renewable producers' bidding behavior under uncertainty and the emergence of systematic day-ahead–intraday price premia in a perfectly competitive market setting. Second, it isolates the economic mechanism through which supply curve convexity and forecast uncertainty amplify the effect of risk preferences, thereby determining the magnitude of price premia across market stages. Third, by parameterizing a theoretical model with observed market data and differentiating bidding rationales across renewable technologies, the paper offers a novel structural explanation for the pronounced diurnal pattern of price premia observed in the German market.

To this end, this work applies a simplified two-stage model in which renewable producers choose day-ahead positions under three distinct bidding rationales: bidding expected production, risk-neutral bidding, and risk-averse bidding that accounts for tail risk. For each rationale, closed-form expressions are derived for the bids of renewable producers and for the resulting expected price premia between the two market stages. The analysis is complemented by differentiating the bidding rationales of PV and wind producers. The analytical framework is subsequently parameterized using observed market data, incorporating hourly information on demand, renewable production forecasts and their uncertainty, and supply curve price sensitivity to represent typical market situations in the diurnal cycle. This way, the analysis identifies how bidding rationales interact with time-varying supply curve convexity and forecast uncertainty, translating heterogeneous risk preferences into systematic price premia.

The remainder of this paper is structured as follows. Section 2 discusses the existing literature linked to this work. Section 3 introduces the theoretical model and analytical description of bidding rationales. Section 4 describes the parameterization of the theoretical model and compares the pattern of simulated premia to observed premia. Section 5 discusses the implications and limitations of this work, followed by a conclusion of the findings in Section 6.

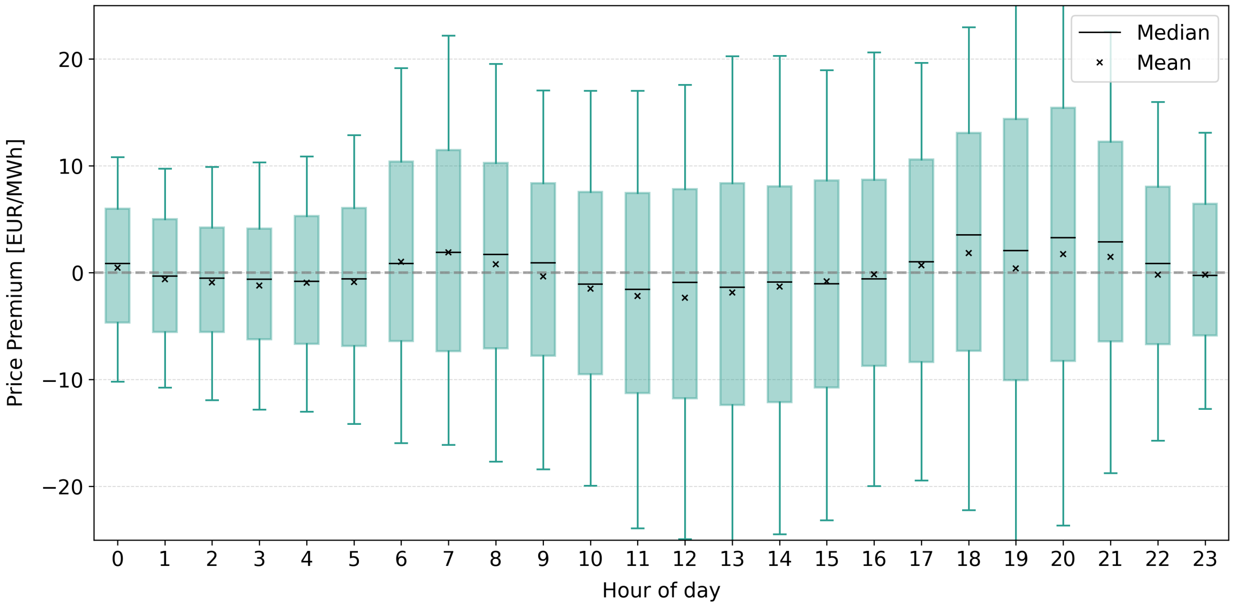


Figure 1: Hourly price premium (day-ahead – ID3) in Germany for the period January 2024 to August 2025. Boxes represent the interquartile range (25th–75th percentile), while whiskers extend to the 10th and 90th percentiles. The sample is restricted to the 1st–99th percentiles to exclude extreme outliers.

2. Literature

In the following, the present work is positioned into several strands of literature analyzing price premia in sequential electricity markets.

A first reference is the foundational work by Bessembinder and Lemmon (2002), which builds on the theory of sequential markets developed by Allaz and Vila (1993) and analyzes equilibrium pricing and optimal hedging in electricity forward markets. In their framework, forward price premia depend on the variance and skewness of expected spot prices, which determine hedging pressure by risk-averse producers and retailers. While this contribution establishes a fundamental link between uncertainty, risk preferences, and price premia, it differs from the present analysis in several ways. In particular, uncertainty arises from stochastic renewable generation rather than demand, market participants are heterogeneous regarding risk preferences, and risk aversion is modeled using a Conditional Value-at-Risk criterion, allowing for an explicit treatment of tail risks.

A second strand of the literature emphasizes strategic behavior and imperfect competition as drivers of price premia in sequential markets. Ito and Reguant (2016) develop a two-stage model with limited arbitrage and show that market power in the first market stage can generate systematic price premia even in the absence of risk aversion. Their theoretical predictions are supported by empirical evidence from the Iberian electricity market. Related analytical work by Knaut and Obermüller (2016) shows that oligopolistic renewable producers may strategically withhold supply in the first market stage, leading to higher prices. Ashour Novirdoust et al. (2025) extend this framework by introducing risk-averse renewable producers and show that mean–variance risk aversion amplifies withholding incentives and price premia under imperfect competition. In contrast to this literature, the present paper abstracts from market power and focuses exclusively on perfectly competitive settings.

Closely related are also Botterud et al. (2010) and Botterud et al. (2012), who derive day-ahead bidding strategies for wind producers under risk-seeking, risk-neutral, and risk-averse preferences. Despite relying on simplifying assumptions, most notably that prices are independent of wind realizations, their numerical results indicate that risk-averse preferences, modeled via Conditional Value-at-Risk, lead to lower day-ahead bids. Similar conclusions are reached by Bitar et al. (2012), who analytically derive optimal forward commitments of wind producers in a competitive two-settlement market. However, in their framework, imbalance prices are modeled as exogenous random variables independent of renewable realizations.

A smaller but closely related literature considers the role of supply curve characteristics and asymmetric price responses. Few studies explicitly analyze how the shape of the supply curve affects price premia. Kulakov and Ziel (2021) implicitly address this issue by modeling intraday prices as horizontal shifts of empirical day-ahead supply curves in response to wind and solar forecast errors. Because the local steepness of the merit order varies over time, their approach captures non-linear and asymmetric price responses without imposing a specific functional form. Hirsch and Ziel (2024) explicitly study how merit-order steepness affects intraday price volatility and tail behavior, finding that steep regimes are associated with higher volatility and heavier tails, although they abstract from asymmetries between positive and negative imbalances. Obermüller (2017) incorporates such asymmetries in a two-stage analytical model with a convex marginal cost curve and shows that competitive, risk-neutral renewable producers optimally withhold supply in the day-ahead market under forecast uncertainty. While empirical results suggest a positive relationship between renewable uncertainty and day-ahead–intraday price differences, the analysis does not address the pronounced diurnal pattern of price premia observed in practice. Paschmann (2017) offers an alternative explanation, arguing that non-convexities in subsets of sequential markets may also give rise to price premia.

Finally, a large forecasting-oriented strand of literature studies day-ahead and intraday price formation using econometric and statistical models (O'Connor et al. 2025). This strand primarily aims to predict prices or their distributions based on historical prices, forecast updates, trading volumes, and other market information (Narajewski and Ziel 2020; Janke and Steinke 2019; Hirsch and Ziel 2024). Some studies explicitly model day-ahead–intraday price spreads, e.g., Maciejowska et al. (2019), but typically do not treat these premia as outcomes of bidding behavior. In contrast to this literature, the present paper does not aim to forecast prices but to provide a structural explanation for the emergence of systematic price premia based on renewable producers' bidding decisions under uncertainty.

3. Theory

This chapter examines the emergence of price premia using a simplified two-stage model. First, the analytical framework is introduced. Then, the bidding rationales of renewable energy (RE) producers are discussed, followed by an analysis of how these rationales affect the expected price premia between the two market stages.

3.1. Model

The analytical model distinguishes two market stages, with the first stage representing the day-ahead market and the second stage representing the intraday market. The model captures the trading of RE producers with uncertain output, conventional producers, and retailers, and is formulated similar to the approach presented by Obermüller (2017). I assume that conventional producers are competitive and offer their production at marginal costs. Together, they form a marginal cost curve that is modeled as quadratic, thereby being convex and strictly monotonic: $MC(x) = ax^2 + bx + c$. The demand d is assumed to be deterministic and inelastic, with competitive retailers buying in the first stage. Additionally, RE producers with uncertain total production $Q \sim \mathcal{N}(\mu, \sigma^2)$ offer a quantity q in the first stage. It is assumed that total RE production must be sold in the second stage, where any deviations from the first-stage bid are balanced. RE producers are considered competitive, with symmetric production and production uncertainty. The model abstracts from pure financial arbitrage[2]. Prices in the two stages can be determined as described in Equation 1a and 1b, and the expected price premium Δp is given by Equation 1c.

$$p_1(q) = a \cdot (d - q)^2 + b \cdot (d - q) + c \tag{1a}$$

$$p_2(Q) = a \cdot (d - Q)^2 + b \cdot (d - Q) + c \tag{1b}$$

$$E(\Delta p) = a \cdot (q^2 - \mu^2 - \sigma^2) + (2ad + b) \cdot (\mu - q) \tag{1c}$$

---

[2] In practice, effective arbitrage between day-ahead and intraday markets can be limited by entry barriers for purely financial traders, transaction costs, credit limits, and the fact that physically active market participants primarily hedge their own positions and may lack complete information about RE producers' forecasts and risk exposures.

3.2. Bidding rationales

The following section investigates three distinct bidding rationales of RE producers in the first market stage, along with the expected price premia associated with these rationales. Subsequently, the bidding rationales of wind and PV producers are separated to examine heterogeneous bidding behavior and its impact on price premia. The cases under investigation are listed below:

1. Renewable producers bid the **expected production**.
2. Renewable producers bid **risk-neutrally**.
3. Renewable producers bid **risk-aversely**.
4. Separate bidding behavior:
    (a) **PV** producers bid **expected production**, while **wind** producers bid **risk-neutrally**.
    (b) **PV** producers bid **expected production**, while **wind** producers bid **risk-aversely**.

3.2.1. Expected production

An intuitive and simple bidding rationale is bidding the **expected production** μ. This rationale aims to minimize deviations in marketed quantities between the two market stages. Equation 2a formulates the bidding rationale, while Equation 2b describes the expected price premium if RE producers bid the expected production.

$$q_{ep} = \mu \tag{2a}$$

$$E(\Delta p_{ep}) = -\, a\sigma^2 \tag{2b}$$

This bidding rationale produces a negative price premium in expectation, increasing with supply curve convexity and the level of renewable production uncertainty. The premium arises from the convexity of the supply curve, which introduces an asymmetric price reaction to an imbalance in the second market stage.

3.2.2. Risk neutral

Another potential bidding rationale is the **risk-neutral bid**. A risk-neutral bidder maximizes expected profits. The aforementioned asymmetric price reaction in the second market stage must be considered in the risk-neutral bid leading to a withholding effect in the first market stage. The risk-neutral bid of competitive RE producers has been derived in Obermüller (2017) and can be described as stated in Equation 3a. If there is no uncertainty ($\sigma = 0$), the first-stage bid is equal to the expected production. However, higher uncertainty reduces the risk-neutral bid. Intuitively, if RE producers are risk neutral in a competitive market setting, the expected price premium converges to zero (cf. Equation 3b).

$$q_{rn} = d + \frac{b}{2a} - \sqrt{\left[\left(d + \frac{b}{2a} - \mu\right)^2 + \sigma^2\right]}. \tag{3a}$$

$$E(\Delta p_{rn}) = 0 \tag{3b}$$

Unlike the derivation of q_{rn} in Obermüller (2017), which relies on an equilibrium approach for individual market participants, the result can alternatively be derived using a representative agent approach. This approach aggregates the behavior of competitive market participants into a single decision-maker and assumes that market participants act as price takers in the first stage.

Formally, the representative agent's profit depends on the first- and second-stage quantity $\pi(q_1, Q)$. Let $f(q_1, Q) = d\pi/dq_1$ denote the marginal profit with respect to the first-stage bid. Then the maximum risk-neutral utility is given by the first-order condition of the utility function U_{rn}, as shown in Equation 4. From the second derivative of the utility function, it follows that $q_{rn} = q^*_{1-}$, as shown in the proof of Obermüller (2017).

$$\pi(q_1, Q) = p_1(q_1) \cdot q_1 + p_2(Q) \cdot (Q - q_1) \tag{4a}$$

$$f(q_1, Q) = \frac{d\pi(q_1, Q)}{dq_1} = p_1'(q_1) \cdot q_1 + p_1(q_1) - p_2(Q) \tag{4b}$$

$$\approx p_1(q_1) - p_2(Q) \quad \text{(representative agent)}$$

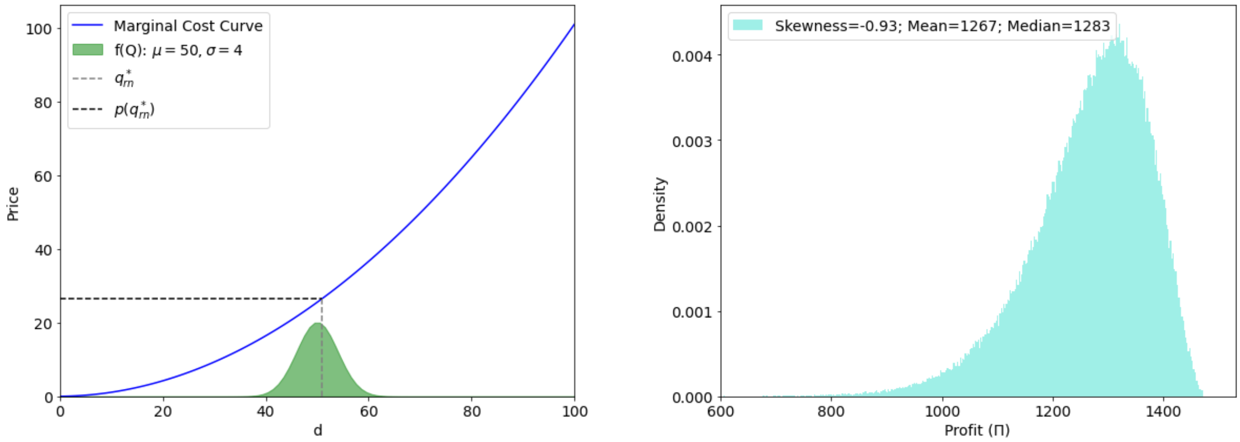
$$\frac{dU_{rn}}{dq_1} = \mathbb{E}[f(q_1, Q)] = 0 \tag{4c}$$

$$\begin{aligned}
\mathbb{E}[f(q_1, Q)] &= a \cdot (d - q_1)^2 + b \cdot (d - q_1) + c - \mathbb{E}[a \cdot (d - Q)^2 + b \cdot (d - Q) + c] \qquad (4d) \\
&= ad^2 - 2adq_1 + aq_1^2 + bd - bq_1 - [ad^2 - 2ad\mu + a \cdot (\mu^2 + \sigma^2) + bd - b\mu] \\
&= q_1^2 a + q_1 \cdot (-2ad - b) + 2ad\mu + b\mu - a \cdot (\mu^2 + \sigma^2) \\
&= q_1^2 + q_1 \cdot (-2d - \frac{b}{a}) + 2d\mu + \frac{b}{a}\mu - (\mu^2 + \sigma^2) \\
&\implies q_{1\pm}^* = d + \frac{b}{2a} \pm \sqrt{(d + \frac{b}{2a} - \mu)^2 + \sigma^2} \qquad (4e)
\end{aligned}$$

3.2.3. Risk averse

The third bidding rationale under investigation is the **risk-averse bid**. The asymmetry in the price response to imbalances in the intraday market introduces a tail to the profit distribution of RE producers. To visualize the tail risk, a Monte-Carlo-Simulation is conducted for the risk-neutral bidding rationale with a numerical example. Figure 2(a) illustrates the marginal cost curve together with uncertain RE production Q. Figure 2(b) shows the profit distribution of RE producers. Notably, the profit distribution is left-skewed, i.e., there is a risk exposure to low profits. If RE producers are risk-averse, their bidding strategies account for their aversion to tail risks. A common approach to represent risk aversion is to incorporate the Conditional Value-at-Risk (CVaR) into the utility function U of market participants. This utility function jointly maximizes expected profits $\mathbb{E}[\pi]$ and minimizes exposure to tail risks, as shown in Equation 5. The degree of risk aversion is controlled by the parameter $\lambda \in [0, 1]$. Typically, risk aversion focuses on large losses; however, in this case, it targets low profits. Therefore, the left-sided α-quantile is used, and the $CVaR$ is added to expected profits and maximized.

$$U_{ra}(\pi) = (1 - \lambda) \cdot \mathbb{E}[\pi] + \lambda \cdot \mathrm{CVaR}_\alpha(\pi), \tag{5}$$



(a) Marginal cost curve and uncertain RE output **(b)** Profit distribution of risk-neutral RE producers

Figure 2: Schematic marginal cost curve, RE production, and profit distribution of RE producers. Assumptions: a=0.01, b=0.01, c=0, d=100.

This utility function cannot be solved analytically to derive the risk-averse bid of RE producers, as the inverse cumulative density function of profits would be required. Furthermore, an approximation using higher-order moments (e.g., skewness or kurtosis) is intractable, as terms above the fifth degree would need to be solved. Despite the unknown analytical solution for the risk-averse bid, the qualitative relationship between the risk-averse and risk-neutral optimal bids can be formally established.

To demonstrate this relation, the representative agent approach is adopted, such that market participants are modeled as price takers in the first stage. For the risk-averse representative agent, the utility function additionally accounts for tail risk via the CVaR. Equation 6 states the first-order condition with respect to the first-stage bid. Evaluating the derivative of the risk-averse utility at the risk-neutral optimum $q_1 = q_{rn}$ shows that the derivative is negative, i.e., a marginal increase of q_1 reduces the utility of the risk-averse representative agent. To fulfill the first-order condition for the risk-averse utility function, the first-stage bid must be decreased relative to the risk-neutral bid. Therefore, the risk-averse representative agent would choose a lower first-stage bid relative to the risk-neutral representative agent.

$$
\begin{aligned}
U_{ra} &= (1-\lambda)\,\mathbb{E}[\pi(q_1,Q)] + \lambda\,\mathrm{CVaR}_\alpha(\pi(q_1,Q)) && \text{(6a)}\\
\frac{dU_{ra}}{dq_1} &= (1-\lambda)\mathbb{E}[f(q_1,Q)] + \lambda\,\mathbb{E}[f(q_1,Q) \mid \pi(q_1,Q) \le \mathrm{VaR}_\alpha(\pi)] = 0 && \text{(6b)}\\
\text{at } q_1 = q_{rn}: \quad \left.\frac{dU_{ra}}{dq_1}\right|_{q_{rn}} &= (1-\lambda)\,\underbrace{\mathbb{E}[f(q_{rn},Q)]}_{=0} + \lambda\,\underbrace{\mathbb{E}[f(q_{rn},Q) \mid \pi(q_{rn},Q) \le \mathrm{VaR}_\alpha]}_{<0} < 0 && \text{(6c)}\\
&\implies q_{ra} < q_{rn} && \text{(6d)}
\end{aligned}
$$

The equality $\mathbb{E}[f(q_{rn},Q)] = 0$ follows directly from the first-order condition of the risk-neutral representative agent. The inequality $\mathbb{E}[f(q_{rn},Q) \mid \pi(q_{rn},Q) \le \mathrm{VaR}_\alpha] < 0$ is proven in Equation 7.

$$
\begin{aligned}
\mathcal{T} &:= \{(q_{rn},Q) \mid \pi(q_{rn},Q) \le \mathrm{VaR}_\alpha(\pi)\} \quad \text{(lower tail of profits)}, && \text{(7a)}\\
(Q) \in \mathcal{T} &\implies Q < q_{rn} \quad \Rightarrow \quad p_1 - p_2(Q) < 0, && \text{(7b)}\\
f(q_{rn},Q) &= p_1' q_{rn} + p_1 - p_2(Q) \approx p_1 - p_2(Q) \quad \text{(representative agent)}, && \text{(7c)}\\
&\implies \mathbb{E}[f(q_{rn},Q) \mid (q_{rn},Q) \in \mathcal{T}] < 0. && \text{(7d)}
\end{aligned}
$$

Since an analytical representation of the utility-maximizing risk-averse bid is intractable, I propose an approximation of the risk-averse bid based on the information derived above. This approximation is based on the risk-factors a and σ that drive the risk-averse behavior. The approximate risk-averse first-stage bid is lower than the corresponding risk-neutral bid, with the extent of this reduction depending on the convexity of the marginal cost curve and the level of uncertainty in RE output. Equation 8a provides the approximate risk-averse first-stage bid q_{ra}, which is derived by adjusting the risk-neutral bid q_{rn} according to the parameters a and σ, and is scaled by a parameter k_λ to modulate the degree of risk aversion. Equation 8b expresses the expected price premium between the two market stages. Under a risk-averse bidding rationale, the expected price premium is positive if the supply curve is convex ($a > 0$) and renewable production is uncertain ($\sigma > 0$).

$$q_{ra} = q_{rn} - k_{\lambda} \cdot a\sigma \tag{8a}$$

$$E(\Delta p_{ra}) = k_{\lambda} a^2 \sigma \cdot (2\sqrt{\left[\left(d + \frac{b}{2a} - \mu\right)^2 + \sigma^2\right]} + k_{\lambda} a\sigma) \tag{8b}$$

3.2.4. Separate bidding rationale

The fourth bidding rationale assumes that wind and PV producers follow separate bidding rationales, introducing heterogeneity among RE producers. In the German market, a large stake of PV production is sold by transmission system operators (TSOs), who are legally obliged (§2 EEV) to minimize deviations between marketed and produced quantities (Federal Ministry of Justice, Germany 2021). In contrast, wind production is largely sold by direct marketers, who might be risk averse. The following analysis assumes that PV production is marketed in the first stage at its expected value, while wind production is marketed either risk-neutrally (*Case a*) or risk-aversely (*Case b*).

The approximated risk-averse bid derived in Section 3.2.3 is based on the risk-neutral bid with an adjustment to tail risk. To avoid an unintended "cross-hedging" that arises when risk-neutral wind producers internalize the suboptimal PV producer position, I impose an idiosyncratic risk-neutral bidding rule for wind's first-stage bid q_{rn}^{wind}. Here, the PV production is treated as a fixed parameter equal to its expected production in both market stages ($q_{pv} = \mu_{pv}$), and the wind objective takes expectations only over wind's own production uncertainty. Under this formulation, wind optimizes against its own imbalance exposure, while PV's commitments are exogenous, preventing wind from implicitly hedging PV's position, which would imply financial arbitrage. The bid is derived using the approach in Equation 4, after adjusting the problem to account for expected PV production, effectively replacing q_1 with $q_1 - \mu_{pv}$. The competitive risk-neutral first-stage bid of wind producers is stated in Equation 9a. This bid considers the expected production of both wind and PV while only considering the risk exposure of its own production (σ_{wind}). Equation 10a describes the approximated risk-averse first-stage bid of wind producers, which is based on the risk-neutral bid and adjusted to account for wind's tail risk via $k_{\lambda} a\sigma_{wind}$. Equations 9b and 10b describe the expected price premium for *Case a* and *Case b*.

$$q_{rn}^{wind} = d - \mu_{\mathrm{pv}} + \frac{b}{2a} \; - \; \sqrt{\left(\mu_{\mathrm{wind}} - d + \mu_{\mathrm{pv}} - \frac{b}{2a}\right)^2 + \sigma_{\mathrm{wind}}^2} \tag{9a}$$

$$E(\Delta p_{separate,rn}) = -2a \cdot \mathrm{Cov}(Q_{pv}, Q_{wind}) - a\sigma_{pv}^2 \tag{9b}$$

$$q_{ra}^{wind} = q_{rn}^{wind} - k_\lambda a \sigma_{wind} \tag{10a}$$

$$\begin{aligned} E(\Delta p_{separate,ra}) \; &= -2a \; \mathrm{Cov}(Q_{pv}, Q_{wind}) - a\sigma_{pv}^2 + \; a^3 k_\lambda^2 \sigma_{wind}^2 \\ &+ \; 2a^2 k_\lambda \, \sigma_{wind} \sqrt{\left(\mu_{wind} - d + \mu_{pv} - \frac{b}{2a}\right)^2 + \sigma_{wind}^2} \end{aligned} \tag{10b}$$

4. Numerical application of the theoretical model

This section applies the theoretical framework to actual market conditions. Market conditions vary substantially across hours, reflecting systematic changes in demand, renewable generation, forecast uncertainty, and supply-side price sensitivity. As a result, identical bidding rationales may lead to different price premia depending on the prevailing market environment. To capture this interaction, the theoretical model is parameterized using observed market data and simulated for an average diurnal cycle representing typical hourly market conditions. The objective is not to precisely reproduce realized price premia, but to illustrate how the interaction between market conditions and bidding behavior can give rise to diurnal patterns in expected price premia. The resulting simulated patterns are subsequently compared with observed premia to assess whether the mechanisms highlighted by the model are consistent with observed regularities, providing an indication, though not proof, of how such patterns may emerge in practice.

The section proceeds as follows. First, observed price premia are presented. Then the data used to parameterize the theoretical model are introduced. Next, the model is simulated for an average daily market profile, and the resulting price premia for various bidding rationales of RE producers are compared with observed patterns in the German market.

4.1. Observed price premia

The following section introduces observed price premia between the day-ahead and intraday market in Germany. The price premium is calculated as the difference between hourly day-ahead prices and the corresponding ID3 prices from EPEX SPOT SE (2025). The ID3 index represents the continuous intraday market and reflects the volume-weighted average price of all 15-minute transactions executed within the three hours prior to delivery. Hence, the index serves as a suitable proxy for real-time prices.

The analysis draws on recent market data covering the period from January 2024 to August 2025, comprising a total of about 16,500 hourly observations. Each hour of the diurnal cycle contains around 688 individual data points. The dataset is subsequently corrected for outliers by retaining observations of price premia within the 1st to 99th percentile range, thereby excluding extreme events and data inconsistencies. Figure 1 illustrates the distribution of hourly price premia.

The distribution of price premia reveals a distinct diurnal pattern. During nighttime and early morning hours, mean price premia hover around zero, with an interquartile range (25th–75th percentile) of approximately 10 €/MWh. A pronounced increase in premia is observed during the morning (6–8 a.m.) and evening (6–9 p.m.) hours, where mean price premia range around +2 €/MWh. In contrast, during midday hours (10 a.m.–3 p.m.), premia are predominantly negative, with average values around -2 €/MWh. A one-sample mean comparison test against zero, applied hour-wise after excluding extreme observations, indicates that price premia are statistically different from zero for all hours except 0, 1, 5, 8, 9, 15, 16, 17, 19, 22, and 23.

4.2. Data and parameterization

This section introduces the data used for the parameterization of the theoretical model. The relevant data includes renewable production and its forecast uncertainty, demand forecast, and the shape of the hourly marginal cost curve, particularly its convexity.

4.2.1. Renewable production and demand

The parameterization of the theoretical model is based on hourly means of renewable production forecast and the demand forecast. As a proxy for the ex-ante renewable production uncertainty, the standard deviation of the hourly forecast error is used. As the mean forecast error is close to zero (49 MW), the mean forecast is an unbiased predictor of mean realized production. The data are obtained from the SMARD electricity market data platform of the Federal Network Agency (Bundesnetzagentur 2024). Figure 3 illustrates the resulting mean hourly values.

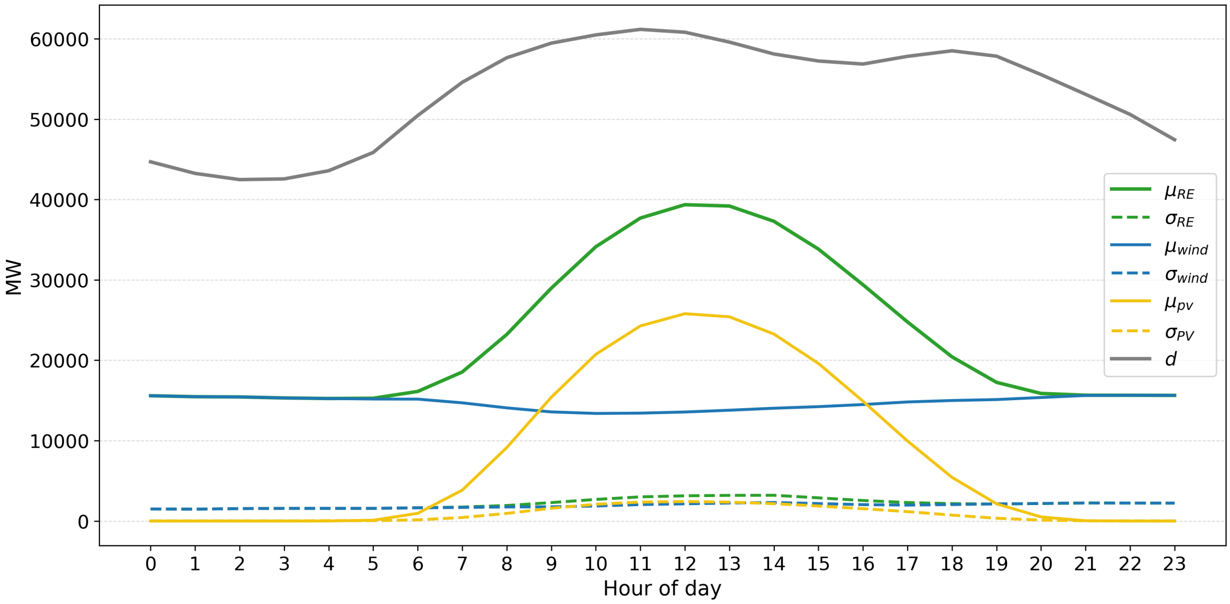
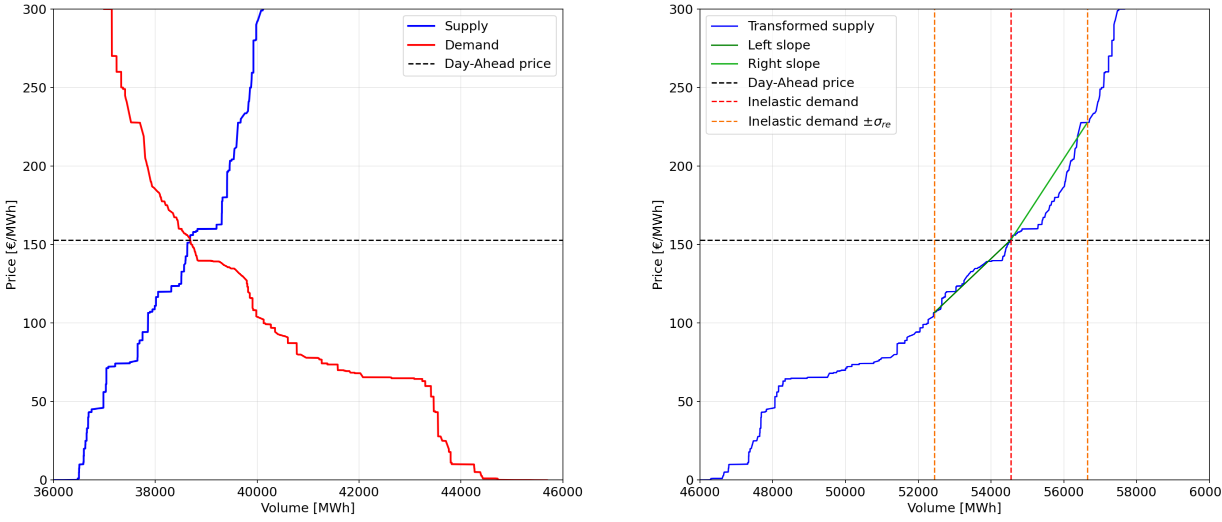


Figure 3: Hourly means of RE forecast (μ_{RE}), RE standard deviation (σ_{RE}), wind forecast (μ_{wind}), wind standard deviation (σ_{wind}), PV forecast (μ_{PV}), PV standard deviation (σ_{PV}), and load forecast (d) from January 2024 to August 2025.

4.2.2. Marginal cost curve

This section derives a numerical measure of the hourly convexity of the marginal cost curve based on observed day-ahead bid curves. To ensure that the slopes around the market-clearing point reflect supply-side price sensitivities alone, the bid curves are first transformed into a representation with perfectly inelastic demand. The transformed curves are then used to numerically derive hourly convexity measures, which serve to parameterize the marginal cost curve in the theoretical model. To approximate the convexity of the marginal cost curve, it is essential that the slope around the day-ahead clearing point reflects supply-side price sensitivities alone. However, slopes computed directly from the raw auction curves embed demand-side elasticity that is unrelated to producers' cost structures, which creates an inconsistency when such slopes are used to parameterize an analytical model with inelastic demand. To obtain a meaningful measure of hourly convexity, the day-ahead bid curves are therefore transformed into a representation with perfectly inelastic demand. This transformation was first introduced in Kulakov and Ziel (2019) and has been applied in Hirsch and Ziel (2024). The transformation preserves the original market-clearing price but reallocates the observed demand elasticity to the supply side. This reallocation is economically justified by the fact that demand-side bids in the day-ahead auction do not solely reflect short-run price responsiveness of final electricity consumers but rather the portfolio decisions and arbitrage activities of market participants who are active across multiple trading venues. In particular, utilities and trading firms can balance their positions between the day-ahead auction, intraday markets, and over-the-counter contracts, such that a buy order at a given price in the auction can equivalently be interpreted as a sell position at a slightly higher price in an alternative market. As a result, the elasticity observed on the demand side of the auction can be shifted to the supply side without altering the equilibrium outcome.

The transformed supply curve provides a representation in which local slopes around the clearing point can be interpreted as supply-side marginal price responses. This is consistent with the theoretical framework employed in this paper, where demand is assumed to be deterministic and inelastic, and producers face a strictly convex marginal cost function. Figure 4 visualizes the day-ahead bid curves for the delivery day November 18th in 2024 at 9 p.m. in their original and transformed forms. The formal approach to the transformation is described in Appendix A.



(a) Original curves

(b) Transformed curves and slopes

Figure 4: Original and transformed day-ahead bid curves from 11/18/2024 at 9 p.m. and derived slopes.

The slopes around the clearing point in the transformed day-ahead supply curve form the basis for the subsequent construction of the hourly convexity parameter used in the theoretical model. The convexity of the marginal cost curve is approximated by a^{linear}, which expresses the relationship between the left- and right-sided slopes, s^l and s^r (s. Equation 11a), originating from the market clearing point at $MC(d^{inelastic})$. The left- and right-sided gradients are computed over an interval defined by the mean hourly standard deviation of the RE forecast errors $\bar{\sigma_h}$, as stated in Equation 11c and 11b. This way, the convexity is determined on an interval of the supply curve, which is likely relevant in determining second-stage prices. To obtain a suitable convexity parameter a_h for the theoretical model, the linearly approximated convexity a^{linear} is scaled to ensure a realistic price level within the stylized marginal cost specification while preserving the observed hourly variation in convexity. Again, the dataset covers every hour of a 20-month period, from January 2024 to August 2025, and the day-ahead bid curves are based on EPEX SPOT SE (2025).

$$a_{d,h}{}^{linear} = \frac{s^r_{d,h}}{s^l_{d,h}} \tag{11a}$$

$$s^r_{d,h} = \frac{MC_{d,h}(d^{inelastic}_{d,h} + \bar{\sigma_h}) - MC_{d,h}(d^{inelastic}_{d,h})}{\bar{\sigma_h}} \tag{11b}$$

$$s^l_{d,h} = \frac{MC_{d,h}(d^{inelastic}_{d,h}) - MC_{d,h}(d^{inelastic}_{d,h} - \bar{\sigma_h})}{\bar{\sigma_h}} \tag{11c}$$

Figure 5 summarizes all linear approximations $a^{linear}_{d,h}$ of the convexity of the marginal cost curve for the time horizon under investigation.

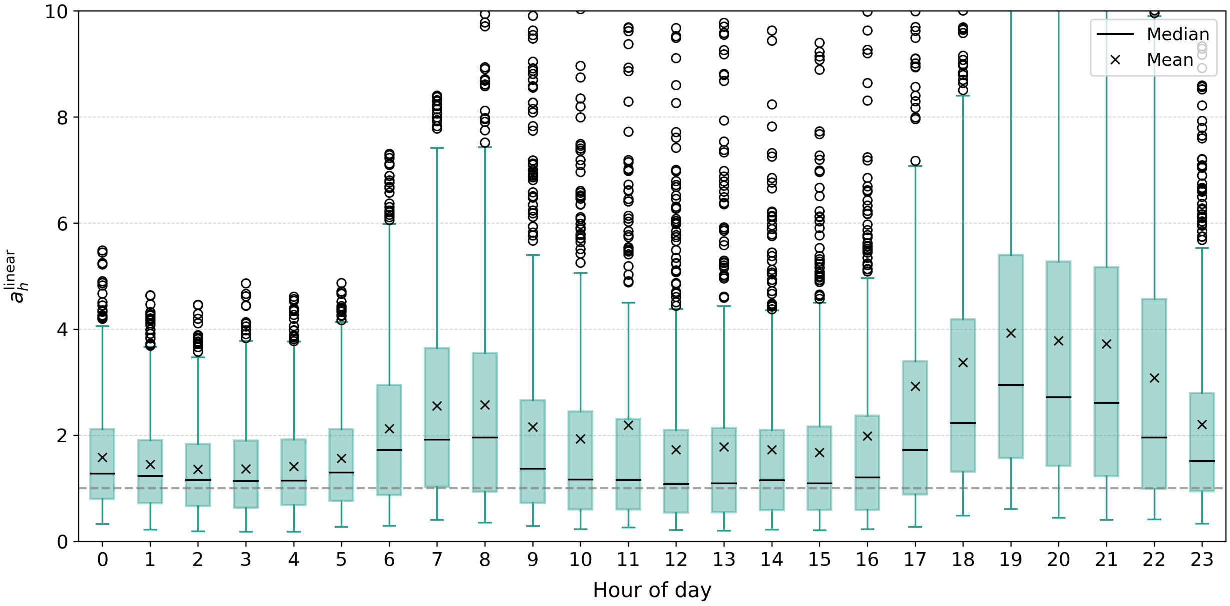


Figure 5: Hourly slope ratios a_h^{linear} from January 2024 to August 2025 of the day-ahead auction.

4.3. Simulation of price premia

This section analyzes how different first-stage bidding rationales affect the expected hourly price premium between the two market stages in the diurnal cycle and compares the pattern of simulated premia to the pattern of observed premia. The bidding rationales (cf. Section 3.2) are applied within the theoretical model (cf. Section 3.1) that is parameterized according to the data in Section 4.2. Although the marginal cost function in the theoretical model is based on observed supply curves, the empirical approximation only recovers the diurnal pattern of convexity rather than its exact magnitude. Therefore, the convexity parameter derived from the transformed day-ahead supply curves is scaled with a scalar $s = 0.2$ to obtain a realistic level of premia within the theoretical model while preserving the diurnal variation in convexity. As a result, the calibration affects only the magnitude of simulated price premia but does not impose their diurnal structure. Similarly, the degree of risk aversion of RE producers cannot be directly observed and is therefore calibrated with $k_\lambda = 0.05$. Again, altering this scalar would generally influence the magnitude but not the overall pattern in price premia. The remaining linear components of the marginal cost function are set to constant values ($b = 0.1$ and $c = 0$) , as they primarily affect the overall price level but do not influence the mechanisms determining price premia within the model.

Figure 6 illustrates the simulated hourly price premia for the three cases with homogeneous bidding rationales among RE producers, expressed relative to the average simulated day-ahead price. For a risk-neutral first-stage bid, the expected price premia are consistently zero. Risk-neutral RE producers consider both the asymmetric price reaction to RE forecast errors and the uncertainty in their expected production, resulting in expected prices that converge.

When RE producers bid their expected production, the price premia correlate negatively with the convexity of the marginal cost curve. This bidding rationale neglects the asymmetric price reaction in the second stage, causing negative expected price premia, which are particularly pronounced in hours with higher production uncertainty (cf. Figure 3) and higher convexity (cf. Figure 5) .

In contrast, risk-averse RE producers adjust their bids to account for the asymmetric price response in the second stage while also incorporating expected tail risk. As this risk increases with the convexity of the marginal cost curve and the uncertainty in RE production, the expected price premia are higher in these hours (e.g., hours 7 or 19). Notably, the systematic pattern of price premia resulting from risk-averse bidding vaguely resembles the observed pattern of actual price premia observed in market data (cf. Figure 1). However, particularly the negative price premia around midday hours cannot be explained with this homogeneous bidding rationale.

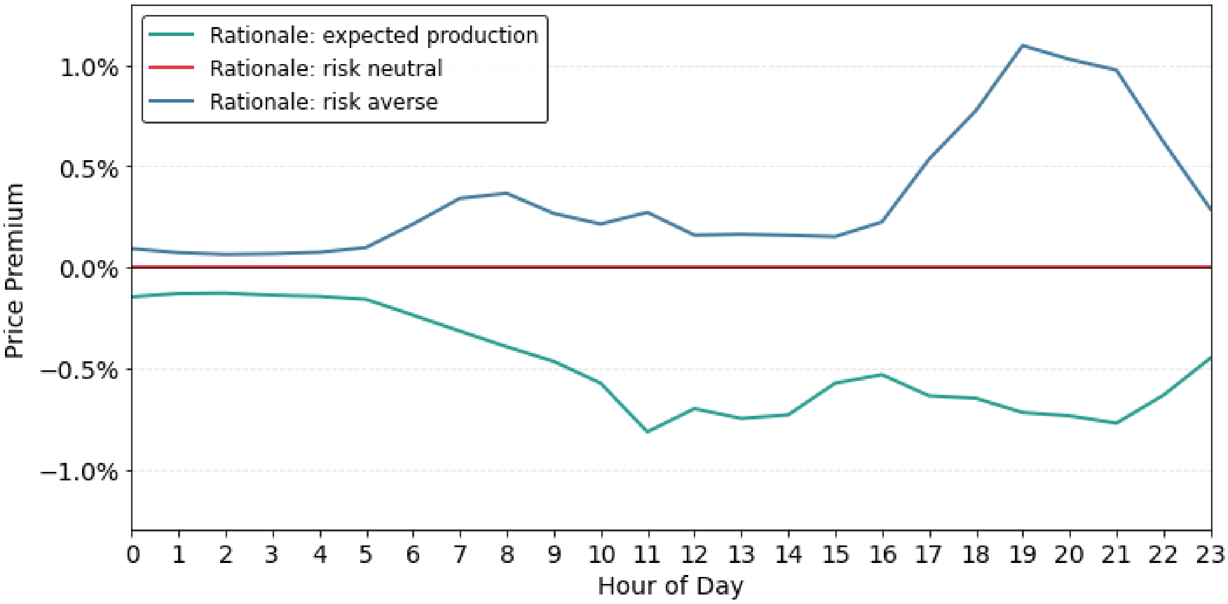


Figure 6: Simulated price premia relative to average day-ahead price for homogeneous bidding rationales among RE producers.

Subsequently, the parameterized theoretical model is computed with separate bidding rationales for wind and PV producers. Two cases are analyzed, as described in Section 3.2.4, assuming PV production to be marketed with expected production and wind production to be marketed risk-neutrally (*Case a*) and risk-aversely (*Case b*), respectively. In both cases, the expected price premium also depends on the covariance between uncertain wind and PV production (cf. Equations 9b and 10b). An analysis of PV and wind forecast errors yields a covariance close to zero; thus, its impact on expected price premia is negligible.

The results of the simulated price premia for the two cases are illustrated in Figure 7 together with observed premia. The premia are shown relative to their underlying mean day-ahead price. If PV production is zero, the risk-neutral bidding rationale of wind (*Case a*) results in a convergence of first- and second-stage prices, consistent with Equation 3b. When PV production is positive, the first-stage bid of PV ($q_{pv} = \mu_{pv}$) leads to negative expected price premia, as derived in Equation 2b. This effect intensifies with increasing PV production and is particularly pronounced around midday.

Under a risk-averse bidding rationale of wind production (*Case b*), the sign and magnitude of the expected price premium depend on which RE source dominates. The risk-averse bid of wind tends to induce positive premia, especially when the convexity of the marginal cost curve (a) is high, whereas the opposite holds for PV. Consequently, the interaction between the time-varying convexity of the marginal cost curve and the diurnal composition of wind and PV production determines both the sign and the magnitude of the expected price premium. Notably, the separate bidding rationale with risk-averse wind producers exhibits both a negative trough around midday and two peaks around morning and evening hours.

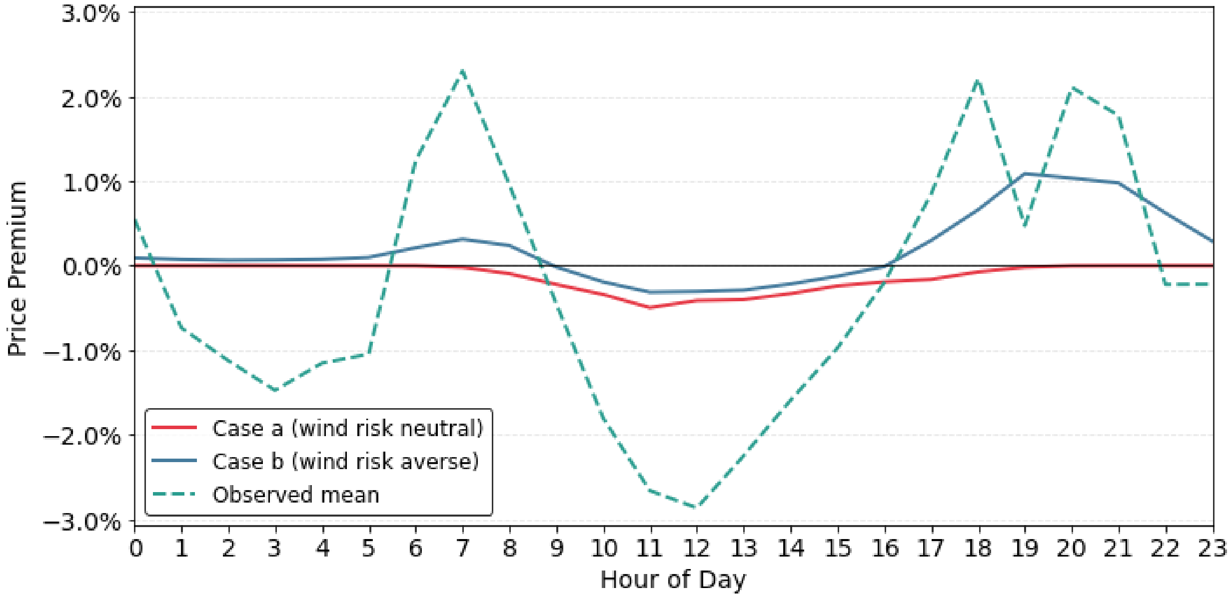


Figure 7: Simulated price premia relative to average day-ahead price for separate bidding rationales between wind and PV producers, and mean observed price premia.

A comparison with observed premia indicates that the characteristic structure of observed price premia is best explained by *Case b*. In both graphs, there is a positive premium around morning and evening hours, with a higher level in the evening hours in *Case b*, which can be explained by a higher convexity stemming from higher residual load together with higher forecast uncertainty relative to the morning peak. Moreover, *Case b* resembles the low around midday, when PV production typically reaches its high and turns out higher than wind production (cf. Figure 3). Conversely, the negative observed premia around nighttime are not resembled by *Case b* but turn out slightly positive instead. By definition of the model, when PV production is zero, price premia can only turn out positive, while actual price premia might be driven by factors beyond the scope of the model.

5. Discussion

This paper investigates the emergence of systematic price premia between the day-ahead and intraday markets as a consequence of the bidding behavior of renewable energy producers. In particular, the analysis examines how different bidding rationales translate into diurnal patterns of price premia when market conditions vary over the course of the day. To address this question, a theoretical framework is developed in which closed-form expressions for day-ahead bids are derived under different bidding rationales. The theoretical model is subsequently parameterized using observed market data from Germany and simulated for an average diurnal cycle. Comparing the resulting simulated premia with the observed pattern provides an indication of how the mechanisms highlighted by the model may contribute to the emergence of price premia in actual markets.

The discussion proceeds as follows. First, stylized facts of the German electricity market are outlined. Second, the model results are interpreted in light of these stylized facts. Third, the findings are related to the existing literature and their economic implications are discussed. Finally, limitations of the analysis and directions for future research are addressed.

5.1. Stylized facts

To structure the discussion, the following stylized facts of the German electricity market are summarized:

- **SF1 - Supply curve convexity:** The price response to renewable forecast errors is asymmetric due to convex marginal costs. This asymmetry tends to be more pronounced at times of high residual demand, when the supply curve is steeper.
- **SF2 - Renewable generation profiles:** PV generation is strongly concentrated around midday, whereas wind generation exhibits a less pronounced and more dispersed diurnal pattern.
- **SF3 - Forecast uncertainty:** Forecast errors for renewable generation increase in absolute terms with expected output and forecast horizon. As a result, periods with high renewable

generation, particularly around midday for PV, are associated with larger potential quantity deviations.

- **SF4 - Institutional setting:** A substantial share of PV generation under public support scheme is marketed by TSOs that are obligated to minimize quantity deviations between the day-ahead and intraday market, whereas wind generation is more frequently exposed to market-based and potentially risk-sensitive bidding strategies.

5.2. Economic interpretation of model results

The theoretical analysis shows that bidding rationales shape expected price premia between the two market stages. When renewable energy producers bid their expected production, expected price premia become negative due to the asymmetric price response to forecast errors in the intraday market (SF1). In this case, producers neglect that downward revisions of renewable output tend to have a stronger price impact than upward revisions. Conversely, when producers follow a risk-neutral bidding rationale, this asymmetry is fully anticipated. Producers adjust their day-ahead bids accordingly, leading to a convergence of expected prices between the two market stages.

A novel contribution of this paper is the derivation of a closed-form expression for a risk-averse bidding strategy. To derive the expression, risk aversion is modeled through a CVaR-based representation of tail risk. In this case, producers account not only for the asymmetric price response (SF1), but also for exposure to adverse outcomes with particularly low profits. The analysis shows that risk-averse bidding can give rise to positive expected price premia, as producers reduce their day-ahead positions to limit exposure to unfavorable outcomes in the intraday market. Importantly, the magnitude of these premia depends on the interaction between renewable production uncertainty (SF3) and the convexity of the marginal cost curve (SF1). In addition, the theoretical analysis derives premia that emerge from technology-specific bidding rationales that only consider idiosyncratic risk.

The application of the bidding rationales in the parameterized theoretical model, which represents changing market conditions over the course of a day, reveals distinct patterns in price premia that emerge from the interaction between bidding behavior and market conditions. Most prominently, a configuration in which PV bids its expected production while wind is marketed risk-aversely in the day-ahead market produces a pattern with positive premia during morning and evening hours and negative premia around midday. This pattern closely resembles the structure observed in market data, indicating that heterogeneity in bidding rationales across renewable technologies (SF2, SF4) can rationalize the observed diurnal structure of price premia in the German market.

5.3. Relation to the literature and economic implications

These findings contribute to the literature on price premia in sequential electricity markets. Previous analyses have identified several mechanisms that may give rise to price differences across market stages. Some contributions emphasize the role of market frictions, such as transaction costs, while others highlight the impact of market power and strategic behavior by dominant market participants that leads to persistent price premia (Ito and Reguant 2016; Ashour Novirdoust et al. 2025). A further explanation relates premia to hedging pressure among risk-averse market participants, where differences in the willingness to bear risk between producers and consumers generate equilibrium risk premia (Bessembinder and Lemmon 2002). The results of this paper identify a related mechanism through which systematic price premia can arise. Even in the absence of market power or market frictions, bidding rationales of renewable producers facing production uncertainty can generate price premia between market stages. In this sense, systematic premia do not necessarily indicate market inefficiencies but may reflect equilibrium outcomes driven by risk preferences and market structure.

From an economic perspective, the results raise the question of why such premia are not fully arbitraged away. One possible explanation is that arbitrage opportunities involve substantial exposure to price risk, which market participants may be unwilling to assume. Even if premia are partially arbitraged, risk considerations may prevent their complete elimination. In this context, the increasing deployment of storage technologies could play an important role in the future. Batteries can react to forecast errors at very short time horizons and may therefore act as a physical hedge against balancing risks faced by renewable producers (Zhao et al. 2023). A portfolio combining renewable generation and storage could allow market participants to reduce exposure to unfavorable intraday price realizations, potentially affecting bidding incentives and the resulting structure of price premia.

Further, the results have implications for the institutional design of renewable energy marketing. The analysis shows that an expected-production bidding rationale, as implied by the institutional setting in SF4, can lead to negative price premia and avoidable revenue losses. Such outcomes may increase the costs of renewable support schemes that are ultimately borne by the state. The findings therefore suggest that current renewable marketing rules may lead to suboptimal outcomes and could warrant reconsideration, particularly regarding the flexibility given to TSOs.

The analysis also highlights the importance of forecast accuracy for market outcomes. In the theoretical model, the magnitude of expected price premia increases with the variance of renewable production forecasts (SF3) under both expected-production and risk-averse bidding rationales. Improvements in forecast accuracy therefore reduce production uncertainty and weaken the role of risk considerations in day-ahead bidding behavior. In the context of the present analysis, improved forecasting would dampen the emergence of systematic price premia that arise from risk-sensitive bidding behavior. This interpretation is consistent with previous research showing that improvements in forecast quality are particularly valuable for risk-prone and risk-averse market participants, as they directly reduce the uncertainty underlying their bidding decisions (Wang et al. 2022).

Beyond forecast accuracy, the analysis also suggests that the magnitude of price premia depends on the prevailing market environment through its effect on the convexity of the supply curve. In particular, the steepness of the supply curve may change with fuel prices or the availability of flexible generation. For instance, higher gas prices or tighter capacity margins can increase supply curve convexity and thereby amplify the price response to renewable forecast errors. In the framework of this paper, such changes would lead to larger price premia, whereas additional flexibility, for example from battery storage, could dampen these effects. As a result, the magnitude of premia may vary with broader market conditions, which is relevant for understanding how structural changes in power systems can affect market outcomes.

5.4. Limitations and future research

Several limitations of the analysis should be acknowledged. First, the theoretical framework provides a stylized representation of electricity markets with two trading stages. In practice, electricity markets feature multiple trading opportunities. In particular, the risk of imbalance prices is not explicitly represented in the model. Moreover, the steepness of the marginal cost curve may change between market stages due to different participation constraints or technological response times in the intraday market. While market participants may anticipate such effects when forming expectations, these dynamics are not explicitly modeled in this work. Second, the risk-averse bidding rule derived in the theoretical model is represented by a closed-form approximation. While this approach allows for analytical insights and tractable numerical simulations, it necessarily simplifies the underlying optimization problem faced by market participants. Third, the numerical application of the theoretical model uses average diurnal market conditions. Extending the analysis to different seasons or market regimes could provide additional insights into how market conditions affect the emergence of price premia.

Future research could focus on empirically testing the mechanisms proposed in this work. While directly identifying risk preferences in bidding behavior may be challenging, empirical analyses could examine how observable risk factors, such as supply curve convexity, affect the magnitude of price premia. Extending the framework to additional electricity markets or incorporating additional trading stages could further help to assess the generality of the results.

6. Conclusion

The German electricity market exhibits a diurnal pattern in price premia between the day-ahead and intraday markets. Explaining the emergence of such temporal patterns remains challenging, as existing explanations for price premia in sequential electricity markets mainly focus on average premia rather than their diurnal structure.

This paper proposes a mechanism that links the observed pattern of price premia to the bidding behavior of renewable energy producers under production uncertainty. To this end, a stylized two-stage model is developed in which renewable producers determine their day-ahead positions under different bidding rationales. Closed-form expressions for the bids are derived and embedded in the theoretical model, parameterized with observed market data representing typical market conditions over the course of a day.

The analysis shows that different bidding rationales systematically translate renewable production uncertainty into price premia between the two market stages in the absence of complete financial arbitrage. When producers bid their expected production, the asymmetric price response to forecast errors leads to negative expected premia. Under risk-neutral bidding, producers anticipate this asymmetry, resulting in a convergence of expected prices across market stages. By contrast, risk-averse bidding under consideration of tail risk can generate positive price premia, as producers reduce their day-ahead exposure to limit unfavorable outcomes in the intraday market.

Differentiating bidding rationales across renewable technologies further shows that heterogeneous strategies between wind and photovoltaic producers can generate a pronounced diurnal pattern of price premia. In particular, a configuration in which PV bids expected production while wind producers behave in a risk-averse manner produces a pattern that closely resembles the structure observed in the German market.

The results therefore suggest that systematic price premia in sequential electricity markets do not necessarily indicate market inefficiencies but may reflect risk preferences of market participants and institutional incentives of renewable energy marketing. In the German electricity market, a large share of PV generation supported under public support schemes is marketed by TSOs who are obligated to minimize quantity deviations rather than to optimize market revenues. Such a bidding rationale can lead to negative price premia and increase the costs of renewable support schemes, suggesting that renewable marketing rules may warrant reconsideration.

At the same time, the explanatory power of this work is subject to limitations. While the model reproduces the main diurnal structure of observed premia, it does not account for the slightly negative premia observed during nighttime hours in the German market. Moreover, the theoretical framework provides a stylized representation of electricity markets limited to two trading stages. The results should therefore be interpreted as illustrating plausible mechanisms rather than providing direct empirical evidence.

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Declarations

Conflict of interest: The author has no relevant financial or non-financial interests to disclose.

Use of AI and AI-assisted technologies: During the preparation of this work the author used ChatGPT to improve the clarity, grammar, and phrasing of the manuscript. After using this tool, the author reviewed and edited the content as needed and take full responsibility for the content of the article.

Appendices

A. ***Transformation of bid curves***

This section formally describes the transformation of the day-ahead bid curves. The approach and the notation follow Kulakov and Ziel (2019).

For a given delivery day d and hour s, the aggregated day-ahead auction results can be represented by a supply curve and a demand curve. Both curves relate traded volumes to prices and are defined on a common price domain bounded by the market price limits.

Let the wholesale supply curve be denoted by

$$\mathrm{SUP}_{d,s}^{WS} : q \mapsto P, \tag{A.1}$$

and the wholesale demand curve by

$$\mathrm{DEM}_{d,s}^{WS} : q \mapsto P, \tag{A.2}$$

where $q \in (0, \infty)$ denotes the cumulative volume and $P \in [P_{\min}, P_{\max}]$ the corresponding bid price. Due to the strict monotonicity of both curves, their inverse functions exist and are given by

$$\mathrm{SUP}_{d,s}^{WS,-1} : P \mapsto q, \qquad \mathrm{DEM}_{d,s}^{WS,-1} : P \mapsto q. \tag{A.3}$$

The inverse curves map prices to cumulative quantities.

In the day-ahead auction, prices are bounded by a minimum admissible price $P_{\min} = -500$ EUR/MWh. The perfectly inelastic demand level for delivery day d and hour s is defined as the cumulative demand evaluated at the minimum price.

$$DEM_{d,s}^{\text{inelastic}} = \mathrm{DEM}_{d,s}^{WS,-1}(P_{\min}). \tag{A.4}$$

This quantity represents the total volume that is demanded at the lowest admissible price and serves as the fixed demand level in the transformed representation.

To obtain a representation with perfectly inelastic demand, the elasticity originally embedded in the demand curve is transferred to the supply side. This is achieved by combining the inverse wholesale supply curve with a mirrored version of the inverse wholesale demand curve.

The transformed inverse supply curve is defined as

$$\mathrm{SUP}^{-1}_{d,s}(P) = \mathrm{SUP}^{WS,-1}_{d,s}(P) + \left(DEM^{\text{inelastic}}_{d,s} - \mathrm{DEM}^{WS,-1}_{d,s}(P) \right) . \tag{A.5}$$

The first term corresponds to the original inverse wholesale supply curve, while the second term reflects the demand-side elasticity mirrored around the perfectly inelastic demand level. Since both inverse curves are monotonic, the transformed inverse supply curve is also monotonic.

The original day-ahead market-clearing price $P^{DA}_{d,s}$ satisfies

$$P^{DA}_{d,s} = \mathrm{SUP}_{d,s}\big(DEM^{\text{inelastic}}_{d,s} \big) , \tag{A.6}$$

such that the transformed representation preserves the original equilibrium price.

Under the transformed representation, demand is perfectly inelastic and fixed at $DEM^{\text{inelastic}}_{d,s}$. Any quantity deviation x around this demand level corresponds to an equal and opposite horizontal shift of the transformed inverse supply curve. As a consequence, price adjustments resulting from quantity deviations can be interpreted exclusively as supply-side responses.

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