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Electricity balancing as a market equilibrium: An instrument-based estimation of supply and demand for imbalance energy

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ABSTRACT

Frequency stability requires equalizing supply and demand for electricity at short time scales. Such electricity balancing is often understood as a sequential process in which random shocks, such as weather events, cause imbalances that system operators close by activating balancing reserves. By contrast, we study electricity balancing as a market where the equilibrium price (imbalance price) and quantity (system imbalance) are determined by supply and demand. System operators supply imbalance energy by activating reserves; market parties that, deliberately or not, deviate from schedules create a demand for imbalance energy. The incentives for deliberate strategic deviations emerge from wholesale market prices and the imbalance price. We empirically estimate the demand curve of imbalance energy, which describes how sensitive market parties are to imbalance prices. To overcome the classical endogeneity problem of price and quantity, we deploy instruments derived from a novel theoretical framework. Using data from Germany, we find a decline in the demand for imbalance energy by 2.2 MW for each increase in the imbalance price by EUR 1 per MWh. This significant price response is remarkable because the German regulator prohibits strategic deviations. We also estimate cross-market equilibriums between intraday and imbalance markets, finding that a shock to the imbalance price triggers a subsequent adjustment of the intraday price.

1. Introduction

In electric power systems, the consumption and production of electricity need to be balanced at every point in time for reasons of frequency stability. In European power systems, market parties such as generators and retail suppliers are balancing responsible parties (BRPs). They must trade excess generation and consumption with other BRPs ahead of time and submit the resulting schedules to transmission system operators (TSOs). Firms that are out of balance—where physical volumes deviate from schedules—receive imbalance energy from TSOs. The net sum of all individual deviations of BRPs within one balancing area is called the "system imbalance".

TSOs physically redress the system imbalance by activating balancing reserves (automatic and manual frequency restoration reserve [FRR]), which they procure from balancing service providers. They can also import balancing energy from neighboring systems through the International Grid Control Cooperation. This results in costs that TSOs pass on to BRPs through the imbalance price.

The imbalance (settlement) price, also known as the imbalance charge or cash-out price, is applied to the difference between scheduled and physically metered production and consumption. This is the price of imbalance energy. It can have a positive or a negative sign such that a BRP may either send or receive a payment for receiving imbalance energy. Across Europe, countries use quite different approaches to determine the imbalance price. Some, including Germany, apply the same imbalance price for negative and positive deviations across all firms; others use dual-price systems and may discriminate between generators and loads (ENTSO-E, 2019). The temporal granularity of imbalance settlement varies between 15 min (as in Germany) and 60 min but is set to be harmonized at 15 min across the entire European Union (ENTSO-E, 2019). Germany's imbalance price is calculated as the net cost of reserve activation divided by the net activated balancing energy. Then, a range of corrections, price floors, and price ceilings are applied that attempt to (a) avoid very high prices at times of low system imbalances to reduce price risk for the BRP and (b) avoid too low prices at times of large system imbalances to reflect the high cost of a potential blackout (Amprion, 2020).

In some European countries, the balancing system is essentially *the* short-term electricity market. Other countries, including Spain, Italy, and Germany, have liquid intraday wholesale electricity markets that

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serve as the central mechanism to match demand and supply after the day-ahead auction. Intraday markets are intimately linked to balancing systems: firms can trade in these markets to avoid (or provoke) imbalances (i.e., to close or open positions). Many European intraday markets are organized as continuous trading, in contrast to day-ahead markets, in which only one auction is conducted per day (Ocker and Jaenisch, 2020). Germany's EPEX SPOT, the largest intraday trading platform, allows for trading until five minutes before delivery.

Regulators, policy makers, and system operators often understand electricity balancing as a "linear" process. In this view, exogenous stochastic shocks, such as unexpected weather changes that impact wind and solar generation or the technical outages of power plants, cause deviations in the demand or supply of electricity. The aggregate of such individual deviations, the system imbalance, is resolved physically through the activation of balancing reserves by TSOs and settled financially at the imbalance price. From this viewpoint, the system imbalance is the result of a random process that is determined by technical parameters, such as the quality of weather forecasts and the failure rates of power plants. There is no feedback from imbalance prices to market party behavior.

This linear perspective is also in line with the legal situation in many European countries. In Germany, the regulator insists that market parties minimize imbalances regardless of imbalance prices (Bundesnetzagentur, 2020a, 2020b).[1] With this perspective in mind, long-term trends in the system imbalance must be caused by structural changes, such as a shift in the generation mix, improved equipment reliability, or enhanced weather forecasting, a view that is also widespread in the academic literature (Hirth and Ziegenhagen, 2015; Ocker and Ehrhart, 2017; Joos and Staffell, 2018).

Others have long acknowledged the existence of feedback from the imbalance price on the behavior of market parties (Fig. 1). Several authors have shown theoretically that firms can increase profits by intentionally deviating from their schedules, depending on the imbalance price (Möller et al., 2011; van der Veen et al., 2012; Chaves-Ávila et al., 2014; Just and Weber, 2015; Lisi and Edoli, 2018).

Such behavior exploits the spread between the imbalance price and the electricity price in short-term intraday markets. The profit earned is determined by the "imbalance price spread" (Koch and Hirth, 2019):

$$\text{imbalance price spread}_t = \text{imbalance price}_t - \text{intraday price}_t \tag{1}$$

If the imbalance price spread is positive, it is beneficial for market parties to take a long position—that is, to buy energy on the intraday market with the intention to "sell" it through the imbalance system. This can be done by actively buying on the intraday market (opening a long position) or by abstaining from selling excess energy (avoiding closing a long position). Similarly, firms can make a profit by going short if the imbalance price spread is negative. This is essentially trading between two stages of the electricity market.

To trade on the imbalance price spread, BRPs need to compare the imbalance price and intraday price. While the intraday price can be directly observed from open bids in order books, imbalance prices are published only after the intraday gate closure. In some countries, such as the Netherlands and Belgium, this is done within minutes; in others, such as Germany, only about a month later (Datencenter der deutschen Übertragungsnetzbetreiber, 2020). In any case, traders need to predict the imbalance price (Just and Weber, 2015; Koch, 2021). One approach to doing so is to observe or predict the system imbalance, given that system-stabilizing behavior is usually rewarded financially. Lisi and Edoli (2018) showed that forecasting the sign of the system imbalance is possible, and strategic deviations on this basis are economically viable in Italy. Note that intraday and imbalance prices are not necessarily equal due to the uncertainty related to the imbalance price, and strategic trading is different from risk-free arbitrage trading.

Deliberately taking an open position in the balancing system to exploit the imbalance price spread has earlier been referred to as *passive balancing* (Chaves-Ávila et al., 2014; Hirth and Ziegenhagen, 2015; Koch and Maskos, 2019). In this paper, we depart from this terminology for two reasons. First, *balancing* suggests that these actions always reduce the system imbalance, which is usually, but not always, the case. Koch and Maskos (2019) found that stabilizing behavior is financially rewarded 90–95% of the time, but 5–10% of the time, incentives are perverse in the sense that stressing the system is profitable. Second, the attribute *passive* depends on the perspective. If market parties respond to price incentives and thereby reduce the system imbalance, TSOs can remain passive—they do not need to activate balancing reserves. The market parties engaging in speculation, however, are not passive at all. They need to actively conduct analysis, assess risk, make decisions, and conduct transactions. We therefore use the term *taking a position* for the deliberate decision of firms to open (or not close) a gap between commercial schedules and metered quantities and *strategic deviations* for the resulting differences.

Earlier studies found empirical evidence for strategic deviations. Geographically, this literature is biased toward Germany, Benelux, and Italy. These countries have in common that TSOs mostly activate reserves based on the actual system imbalance (curative strategy), while TSOs in other countries stronger rely on forecasts and manual reserve products to prevent future imbalances (proactive strategy) (Håberg and Doorman, 2016). In the German market, Möller et al. (2011) identified systematic patterns in the system imbalance during 2003–09, which provided opportunities for taking strategic positions. Just and Weber (2015) suggested that a simple strategy of going short at high spot prices and going long at low spot prices yielded, on average, profits during 2009–10. They reported a correlation between spot prices and the system imbalance, which they interpreted as evidence for strategic deviations. Such systematic opportunities gradually disappeared in the German market after 2011 (Hirth and Ziegenhagen, 2015), which Koch and Hirth (2019) construed as the result of increased market efficiency. Koch and Maskos (2019) empirically demonstrated a significant relationship between intraday trades and the most recent information about the system imbalance during 2016–18, which they attributed to firms taking positions. Röben and de Haan (2019) analyzed historical data on the system imbalance in several countries and found more pronounced evidence for strategic deviations in Belgium and the Netherlands than in Germany, which is in line with a higher data transparency in real time in the former two countries. Table 1 summarizes the relevant publications to date that discuss the feasibility of engaging in such strategic position taking, propose trading strategies, and provide empirical evidence that position taking actually occurs.

Our contribution to the literature is three-fold. First, we develop a comprehensive and consistent framework to study electricity balancing as a market. The equilibrium price (imbalance price) and quantity (system imbalance) are determined by the intersection of the supply and demand curves. TSOs supply imbalance energy by activating reserves or importing balancing energy. Market parties demand imbalance energy by, deliberately or not, deviating from schedules. We assume rational, profit-maximizing firms that respond to incentives while taking price and legal risk into account. Second, we explicitly address the interlink between balancing and intraday markets and study those markets as a dynamic equilibrium across market stages. Third, we estimate the demand curve for imbalance energy empirically—that is, the responsiveness of the system imbalance to changes in the imbalance price. To overcome the classical identification problem in market equilibriums, we use instrumental variables. To the best of our knowledge, we are the first to do so when it comes to electricity balancing.

Using data from Germany from 2018 to 2019, we find robust evidence that firms take positions toward the imbalance price. The resulting volume impact on the system balancing is large: on average, a EUR-1-per-MWh increase in the imbalance price causes a reduction in the system imbalance by nearly 2.2 MW. A further consequence of a EUR-1-

[1] Wessling (2021) argues that this position of the German regulator is inconsistent and contradicts the prevailing European Balancing Guidelines (European Commission, 2017).

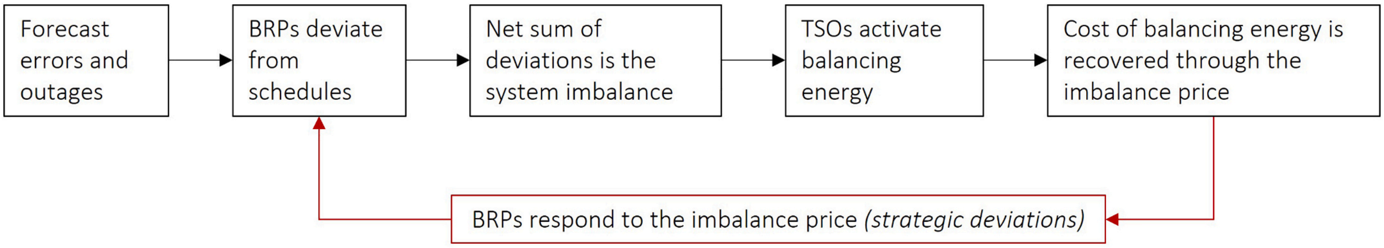

Fig. 1. Feedback perspective on the balancing system: BRPs respond to the imbalance price.

Table 1
Literature on strategic deviations.

Theoretical potential	Strategies	Evidence
• Lisi and Edoli (2018): ITA	• Koch (2021): GER	• Koch and Hirth (2019): GER
• Just and Weber (2015): GER	• Koch and Maskos (2019): GER	• Koch and Maskos (2019): GER
• Chaves-Ávila et al. (2014): GER, NLD, BEL, DNK	• Lisi and Edoli (2018): ITA	• Röben and de Haan (2019): GER, NLD, BEL
• van der Veen et al. (2012): independent of specific regulation	• Just and Weber (2015): GER	• Just and Weber (2015): GER
• Möller et al. (2011): GER	• Chaves-Ávila et al. (2013): NLD	

per-MWh increase in the imbalance price is an increase of the intraday price by EUR 0.10 per MWh.

2. Analytical framework

While many observers seem to understand the system imbalance as the result of exogenous stochastic processes, such as forecast errors and outages, we interpret the balancing system as a market for "imbalance energy." As in any other market, the equilibrium quantity (system imbalance) and price (imbalance price) emerge from the intersection of the demand and supply curves (Fig. 2). Like in other electricity markets, these curves may shift at high frequency.

Within our market framework, we distinguish positive and negative system imbalances. We use the following sign convention in this paper: a positive system imbalance means a net undersupply in the system (the system is short of energy), and a negative sign implies a net oversupply in the system (the system is long). For simplicity, we focus on short systems first and subsequently extend the framework to long systems.

While being related, it is important to differentiate *imbalance* energy from *balancing* energy. Imbalance energy, for which we consider the supply and demand curves in our model, is the energy by which BRPs deviate from their schedules and for which they pay or receive the imbalance price. Imbalance energy is settled between the BRPs and TSOs. By contrast, balancing energy is provided by the balancing service providers (i.e., reserve plants) previously contracted by TSOs. Therefore, balancing energy is traded between these balancing service providers and TSOs. The system imbalance, which is the net sum of the imbalance energy, is mainly compensated for through the activation of balancing energy. In addition, TSOs take other balancing actions, including imbalance netting with neighboring countries and emergency measures in the case of high imbalances.

Abstracting from the details of imbalance pricing, the supply curve of imbalance energy, and thereby the imbalance price, depends on the cost of activating balancing reserves. Because TSOs activate balancing reserves in increasing order of energy prices, the supply curve has a positive slope[2]: at higher system imbalances, more balancing reserves are activated, hence more expensive suppliers are needed, leading to higher prices. Note, however, that the energy price that balancing reserves receive upon activation may differ from the imbalance price (e.g., in Germany, balancing reserves are compensated based on their individual bids).

The demand for imbalance energy results from the net sum of the individual imbalances of all market parties in a balancing area. The slope of the demand curve reflects the responsiveness of BRPs to the imbalance price (i.e., the price elasticity of demand).[3] This curve would be vertical if imbalances were the result of exogenous stochastic processes and hence independent from the imbalance price. In particular, this would be the case if BRPs respected the legal balancing obligation. Economically speaking, the demand for imbalance energy would be perfectly price-inelastic. Otherwise, if BRPs respond to changes in the imbalance price, the curve will be downward sloped: the higher the imbalance price, the lower the remaining system imbalance after strategic deviations. It is the shape of the demand curve in which we are particularly interested in this paper.

Both the demand and supply curves are subject to frequent shocks (Fig. 2). On the supply side, TSOs counteract the system imbalance through the activation of balancing energy, international imbalance netting, and emergency measures. The activation costs of balancing reserves result from the process of balancing procurement for specific delivery periods. In Germany, for instance, balancing energy has been procured in daily auctions during four-hour periods on the day prior to delivery since July 2018. The energy bids submitted by the reserve providers vary over time because of changes in the opportunity costs of power plants, fuel and CO_2 costs, water value for pumped hydro storages, operational cycling constraints, auction design, and collusive behavior. The varying costs of balancing energy activation constitute a supply shifter: the higher this cost, the higher the imbalance price for the same system imbalance. In addition, imbalance netting can be interpreted as a supply shifter; the more balancing energy is substituted by netting with neighboring power systems, the lower the imbalance price for the same system imbalance. Note that such netting is not exogenous because its activation depends on the sign and magnitude of the system imbalance.

[2] Intuitively, one would expect a comparatively flat supply curve because agents can maximize profits by submitting bids close to the clearing price in repeated pay-as-bid auctions (Kahn et al., 2001). In balancing service auctions, however, prices for balancing energy activation are heterogenous because the position in the merit order curve has a strong impact on the activation probability (utilization) (Müsgens et al., 2014; Ocker et al., 2018).

[3] Demand for "imbalance energy" must not be confused with demand for "energy". For the example of a short system, BRPs can reduce demand for imbalance energy by reducing actual consumption but will much more frequently do so by generating additional electricity. Furthermore, as we discuss in the following, demand for imbalance energy can be reduced through buying electricity in the intraday market (taking long positions). Hence, this paper does not provide empirical insights into the question of the short-term elasticity of electricity demand.

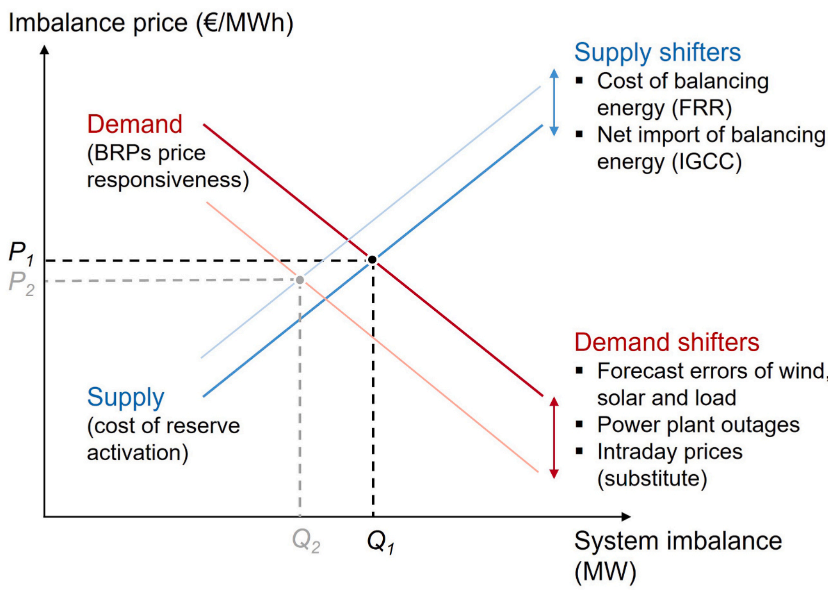

Fig. 2. The imbalance system as an equilibrium determined by the intersection of the supply and demand of imbalance energy curves (schematic). The figure depicts the equilibriums at two exemplary times t_1 and t_2 .

In the short term, the demand curve is shifted by forecast errors of wind energy, solar energy and load, and power plant and interconnector outages. Ceteris paribus, larger (net) forecast errors lead to a higher system imbalance for any given imbalance price. For example, surprisingly cloudy skies will decrease solar electricity generation, shifting the demand curve to the right and increasing the system imbalance. In the long term, it is plausible to assume that forecast accuracy is also, to some extent, endogenous to the price: at lower imbalance prices, companies may downsize intraday trading units and put less emphasis on correcting forecast errors. Conversely, firms have a stronger incentive to invest in better forecasting models at higher imbalance prices.

If BRPs respond to economic incentives, the intraday price can be considered an additional demand shifter. At higher intraday prices, the economic incentive to sell (or avoid buying) electricity at the intraday market is stronger, which will increase the system imbalance. In economic terms, buying energy at the intraday market (paying the intraday price) is a substitute for buying at the "imbalance market" (paying the imbalance price). However, if market parties respond to the imbalance price, the intraday price will not be an exogenous shock. Instead, a higher imbalance price will cause traders to take long positions and thereby lead to a subsequent increase in the intraday price. Therefore, intraday and imbalance prices should be thought of as the results of an equilibrium across both market stages.

Above, we have outlined our analytical framework for short systems. It can be symmetrically applied to oversupplied (long) systems (Fig. 3). In this case, the negative system imbalance can be interpreted as the demand for negative imbalance energy. In other words, one can think of two different markets for two different products: positive and negative imbalance energy. This aligns with the procurement of balancing reserves, which is often organized in separate auctions for upward (positive) and downward (negative) reserves. These different types of reserves have diverging opportunity costs. For instance, the market for negative reserves sometimes yields negative energy prices—a payment from balancing service providers to TSOs (Hirth and Ziegenhagen, 2015).[4] As a result, the supply curve for positive imbalance energy is shifted by the activation price of upward reserves, while the supply curve for negative imbalance energy is shifted by the activation price of downward reserves. All other shifters apply equally to short and long systems.

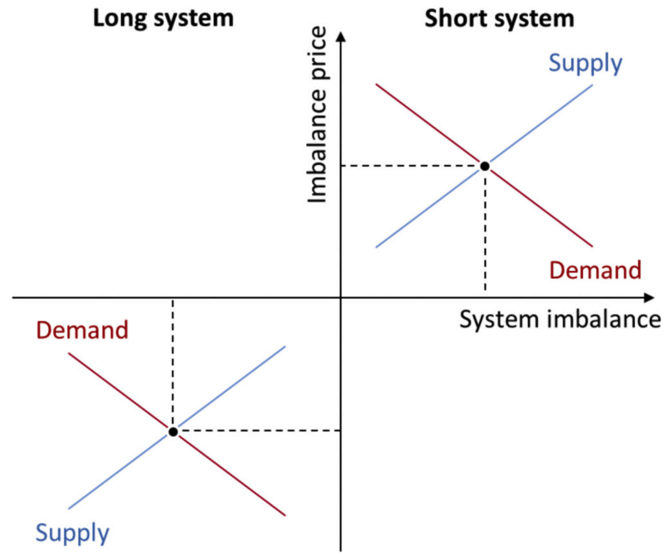

Fig. 3. The market equilibrium is established where the demand for and supply of imbalance energy intersect. It is often helpful to think of two distinct markets for positive and negative imbalance energy.

This economic framework of an "imbalance market" helps clarify and test the implications of balancing incentives. Of course, and in contrast to wholesale electricity markets and reserve procurement auctions, the imbalance pricing mechanism is not designed as a marketplace in which BRPs and TSOs explicitly agree on prices and quantities in bilateral trades or through an organized auction. Instead, BRPs deviate from their schedules, and TSOs have no choice but to balance the net sum of these deviations. In this sense, this market is fictive. However, TSOs charge a quantity-dependent price, the imbalance price, and BRPs may choose their deviations based on their expectations of this price. Therefore, the economic forces of demand and supply determine these prices and

[4] Providers of negative reserves decrease generation or increase electricity consumption. Negative reserve prices imply that service providers are willing to pay for providing this service, reflecting their benefit from producing less (saved variable cost) or consuming more (increased product output).

quantities. This holds empirically true even in countries where responding to balancing incentives is prohibited, such as Germany, as we show in the following.

3. Empirical methodology

We tested our framework by applying it to the German electricity market. We are particularly interested in how the demand for imbalance energy responds to the imbalance price. In our framework, this price responsiveness appears as the slope of the demand curve. While the intersection of the demand and supply curves can be directly observed as the equilibrium price (the imbalance price) and quantity (the system imbalance), the curves themselves, including their slopes and shifters, cannot. This is a classic econometric identification problem (Koopmans, 1949), which we address by using instrumental variables and estimating both curves simultaneously (MacKay and Miller, 2018). Our model and data are presented in the following.[5]

3.1. Identification strategy and econometric model

The above-introduced framework can be translated into a causal graph (Fig. 4). At the core of this graph is the interplay between the imbalance price and the system imbalance. If BRPs respond to balancing incentives, a supply-driven increase in the imbalance price will lead to a decrease in the system imbalance. On the other hand, a demand-driven increase in the system imbalance results in higher imbalance prices because more expensive reserves need to be activated. Moreover, as discussed above, the intraday price will be endogenous to the market equilibrium if strategic deviations are happening: high intraday prices incentivize short positions, which increase the system imbalance and, with it, the imbalance price. Vice versa, the expectation of a high imbalance price, which may be based on the prospect of a high system imbalance, incentivizes long positions and leads to an increase in the intraday price. Similarly, international imbalance netting endogenously depends on the system imbalance.

The endogeneity of price and quantity is problematic when estimating the price responsiveness of demand because the two opposing causal effects interfere. To overcome this classical endogeneity problem, we use instrumental variables (IV). This approach has been adopted before when estimating the demand response in wholesale electricity markets (Lijesen, 2007; Bönte et al., 2015). Here, we use the FRR price as an instrument for the imbalance price while controlling for the day-ahead price. By contrast, we do not control for the intraday price and imbalance netting because they are endogenous to the causal relationship between imbalance price and system imbalance. The intraday price also mediates part of the causal relationship. The effect we determine between the imbalance price and the system imbalance aggregates two causal paths: the direct effect of the imbalance price on the system imbalance and the indirect effect via the intraday price.

Similarly, we estimate the supply-side relationship between price and quantity using forecast errors of wind and solar generation and electricity consumption as instruments. While a separate estimation of the demand and supply relationships yields consistent results, a simultaneous estimation may improve the model's efficiency (Lin, 2011).

This identification strategy translates to equations for demand (Eq. 2) and supply (Eq. 3). In this system of equations, the imbalance price and the system imbalance are both explanatory and outcome variables. For simplicity, we assume linear demand and supply curves. Additional explanatory variables, or covariates, are the supply and demand shifters (MacKay and Miller, 2018). As discussed in Section 2, these are exogenous shocks, which affect the position of the curves. Based on Brijs et al. (2017), we use forecast errors as covariates for the demand equation. The supply curve is different for short and long systems (Section 2), for which we account with dummy variables. As a covariate for the supply equation, the weighted average of the energy prices of positive and negative FRRs is employed. We assume a linear relationship for all covariates. Data sources and descriptive statistics are presented in Section 3.3.

$$Q_t = \alpha_1 \cdot P_t + \alpha_2 \cdot DA_t + \alpha_3 \cdot err_{load,t} + \alpha_4 \cdot err_{solar,t} + \alpha_5 \cdot err_{wind,t} + S_t \cdot \alpha_{0S} + L_t \cdot \alpha_{0L} + \varepsilon_t \tag{2}$$

$$P_t = \beta_1 \cdot Q_t + S_t \cdot \left(\beta_{2S} \cdot FRR_t^+ + \beta_{0S}\right) + L_t \cdot \left(\beta_{2L} \cdot FRR_t^- + \beta_{0L}\right) + \mu_t \tag{3}$$

where, Q = System imbalance (MW); P = Imbalance price (€/MWh); DA = Day-ahead price (€/MWh); err_{load} = Load forecast errors (MW); err_{solar} = Solar generation forecast errors (MW); err_{wind} = Wind generation forecast errors (MW); $FRR^{+/-}$ = Weighted frequency restoration reserve price (upward: + / downward: -) (€/MWh); S, L = Dummy variables for short (S) and long (L) systems; α_1 = Price responsiveness of the demand for imbalance energy (MW per €/MWh); $\alpha_{2\ldots5}$ = Effect of explanatory variables on the system imbalance (MW per €/MWh or per MW); β_1 = Effect of the system imbalance on the imbalance price (€/MWh per MW); β_2 = Effect of the FRR price on the imbalance price (€/MWh per €/MWh); α_0, β_0 = Constants (€/MWh and MW); ε, μ =Error terms (€/MWh and MW).

At the core of our analysis is the effect of the imbalance price on the system imbalance. This is included in Eq. (2) as α_1. If the estimate of this coefficient differs significantly from zero, this will indicate price sensitivity and hence strategic deviations of the BRPs. Note that a simple regression on Eq. (2) will lead to a biased estimate of this price responsiveness (Appendix, Table A.1) because of the endogeneity of price and quantity.[6]

The IV approach yields the following first-stage equations: a regression of the imbalance price on the FRR prices as instruments (Eq. 4), which is used in the demand function (Eq. 2) and a regression of the system imbalance on the forecast errors as instruments (Eq. 5), which is used in the supply function (Eq. 3).

$$P_t = S_t \cdot \left(\gamma_{1S} \cdot FRR_t^+ + \gamma_{0S}\right) + L \cdot \left(\gamma_{1L} \cdot FRR_t^- + \gamma_{0L}\right) + \sigma_t \tag{4}$$

$$Q_t = \delta_1 \cdot err_{load,t} + \delta_2 \cdot err_{solar,t} + \delta_3 \cdot err_{wind,t} + S_t \cdot \delta_{0S} + L_t \cdot \delta_{0L} + \tau_t \tag{5}$$

where, γ_1 = Effect of instruments on the imbalance price (€/MWh per €/MWh); $\delta_{1\ldots3}$ = Effect of instruments on the system imbalance (MW per MW); γ_0, δ_0 = Constants (€/MWh and MW)σ; τ =Error terms (€/MWh and MW)

We simultaneously estimate the system of equations using the Generalized Method of Moments (GMM) system estimator (Arellano and Bover, 1995; Sheppard, 2020). Compared to the statistically more efficient three-stage least squares approach, the GMM estimator allows for the heteroscedasticity in the input data, which we find in Subsection 3.3.

3.2. Relevance and exclusion restrictions of instruments

To be valid instruments, the explanatory variables in Eqs. (4) and (5) must fulfill the relevance and exclusion restrictions. The relevance of instruments (i.e., their strong first stage) is theoretically explained in Section 2: the instruments used are supply and demand shifters. Ordinary least squares regressions empirically confirmed the relevance of all instruments (Appendix Table A.1). To satisfy the exclusion restriction, instruments must not explain variations of the dependent variable except through the replaced endogenous variable, which we discuss in the following section.

Wind and solar forecasts are based on meteorological models that are

[5] Our Python code is made available on Github and can be accessed at: https://github.com/anselm-eicke/electricity_balancing

[6] Technically, the error terms of Eqs. (2) and (3) correlate with the endogenous explanatory variables, violating the strict exogeneity condition.

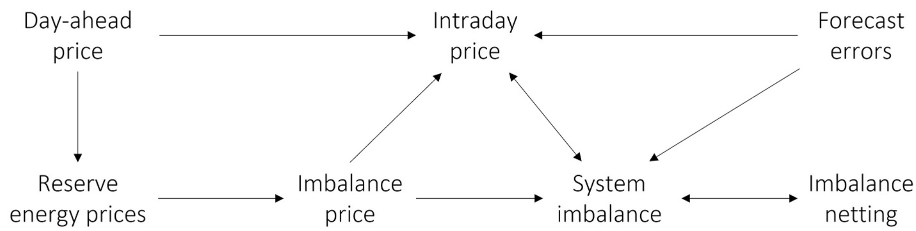

Fig. 4. Causal effects in the imbalance market equilibrium.

used for general weather forecasting, and the imbalance price does not impact the outcome of these models in the short term. Load forecasts stem from standardized load profiles based on historical data for small electricity consumers and account for the production plans of large consumers. We cannot think of any way these forecast errors could impact the imbalance price in the short term, other than through the demand for imbalance energy. Only in the long run could high imbalance prices theoretically incentivize improvements in the quality of forecasts. Given that weather forecasts are used for multiple purposes, we deem this effect unlikely.

The applied FRR prices are a proxy for the activation cost of balancing reserves—that is, the energy price that suppliers of balancing reserves receive. We calculate this proxy as the average of all winning bids of the automatic and manual FRR auctions, weighted with the dispatch probability depending on their position in the merit order of balancing reserves (reserves with low energy price bids are activated with a higher probability). We argue that this indicator does not affect the system imbalance other than through the imbalance price. Because the dispatch probability is calculated over a time span of 14 months, this proxy for FRR prices is unaffected by system imbalances in specific quarter hours. As depicted in Fig. 4, the day-ahead price can influence both the FRR prices and the system imbalance. This is because the providers of balancing energy will consider the (expected) day-ahead prices as opportunity costs in their submitted bids. On the other hand, day-ahead prices affect intraday prices, which drive the system imbalance in the case of strategic deviations. To close this causal backdoor path, we controlled for the day-ahead price. Otherwise, we found no evidence of chains of interaction between FRR prices and the system imbalance.

3.3. Data

We calibrated the model with German data between July 12, 2018 and September 29, 2019. The start date was set to the day when automatic FRR auctions first took place on a daily basis for four-hour periods. The end date was set to the latest day for which we could obtain publicly available intraday price data from the EPEX SPOT website. The dataset covers 41,553 quarter hours. Within the period of investigation, there were two major regulatory changes: first, the introduction and later, the abolishment of a new winner selection rule in the auctions for balancing reserves.[7] These regulatory changes mainly affected FRR prices and are hence captured in our model through this supply shifter.[8]

Data on the imbalance price and system imbalance are depicted in Fig. 5; the color indicates the density of observations. The plot reveals

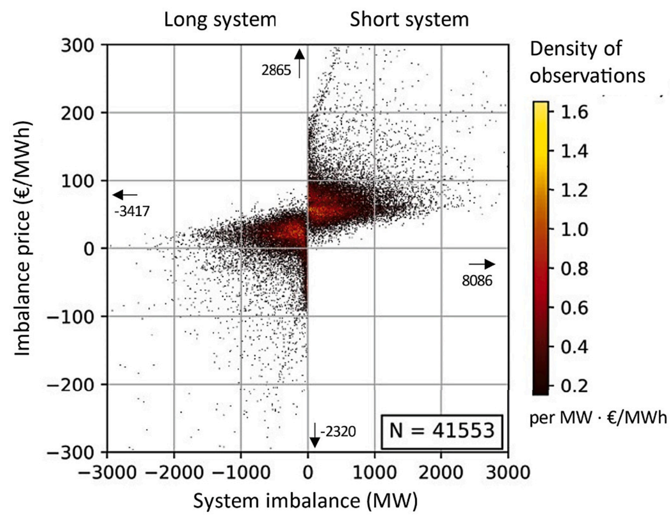

Fig. 5. Historical observations of quarter-hourly imbalance price and system imbalance from July 2018 to September 2019 (arrows indicate the maximum values, which are beyond the figure's scope).

heteroscedasticity in the input data: the variance in the imbalance price depends on the system imbalance and vice versa.

Based on the system imbalance, we grouped the dataset into short and long systems (Section 2). From the resulting two subsets of data, we excluded all observations with system imbalances below 500 MW in absolute terms. We did so because, for smaller absolute imbalances, the assumption of a linear supply curve is questionable due to peculiarities in the way imbalance prices are calculated. In principle, the imbalance price in each quarter hour is the ratio between the reserve activation costs and the average system imbalance. If both positive and negative reserves are activated within the same quarter hour,[9] this can result in high costs for a low net volume, leading to extraordinarily high imbalance prices, with a discontinuity between high positive prices for slightly positive system imbalances and high negative prices for slightly negative ones (see Fig. 5). To avoid this, the German regulator introduced a price cap for absolute imbalances smaller than 500 MW (visible in e Fig. 5). To sum up, the supply curve for small system imbalances is hyperbolic, downward-sloping rather than upward-sloping, discontinuous, and capped by regulation. We therefore dropped these cases, reducing the number of observations to 13,450 (32% of the initial dataset). A sensitivity analysis for the threshold above which observations are included in the analysis shows that smaller thresholds of 300 MW and 400 MW lead to similar results (Appendix, Table A.4).

Day-ahead prices, which serve as demand shifters, are taken from

[7] This different procurement system with the German name “Mischpreisverfahren” was in place from October 16, 2018 to July 31, 2019 (Ehrhart and Ocker, 2021).

[8] Note that, in the beginning of our observation period, the energy price of reserve bids was capped at 9999 €/MWh (this was introduced on January 5, 2018). With the introduction of the different procurement system, this cap was (re-)increased to 99,999 €/MWh. This change is also captured in our model through FRR prices.

[9] The continuous imbalance may vary between positive and negative values within the quarter-hourly settlement period.

EPEX SPOT, the largest power exchange in Germany. We also retrieved intraday prices from this source, which we used as a dependent variable in a modified version of our model (Subsection 4.3). While the day-ahead auction results in one single price per delivery period, the continuous nature of the intraday market implies different prices for each transaction. If BRPs strategically deviate, the relevant intraday prices will be those shortly before gate closure, when most information about the (uncertain) system imbalance and imbalance price is available. We therefore use the ID1 price index, which is the volume-weighted average price of all trades taking place within Germany 60 min to 30 min before delivery. Note that further trade is possible within control areas until five minutes before delivery such that the ID1 is an imperfect indicator. Nevertheless, the ID1 index reflects about 30% of intraday trades (EPEX SPOT, 2020a), and we assume it is strongly correlated with the prices of succeeding trades.

We define forecast errors as the difference between forecasted and actual values. We employ forecast errors for solar and load based on day-ahead forecasts, which are publicly available. For wind, we use non-public intraday forecast errors, which are available to traders shortly before intraday gate closure. We expect these intraday forecasts to better explain the system imbalance compared to day-ahead forecasts. A comparison with day-ahead wind generation forecasts confirms this expectation but shows that the effect on the overall results is small (Appendix,

As a supply shifter, we use the average of the energy prices of accepted automatic and manual FRR bids, weighted with the activation probability depending on their position in the merit order of balancing reserves. We derive the activation probability of the different FRR types during the entire investigation period from quarter-hourly activation time series, conditional on a system imbalance above 500 MW for positive reserves and below −500 MW for negative reserves.[10] Table 2 provides an overview of all parameters, their sources, and their mean value for the two subsets.

4. Results and discussion

This section presents and discusses the results of the econometric model. We found a significant price response of BRPs to balancing incentives, which we interpret and quantify. Against this background, we discuss whether strategic deviations are problematic.

4.1. Evidence for and quantification of strategic deviations

We estimate three variants of our model: one in which short and long systems are combined (1) and two in which short (2) and long (3) systems are treated separately. The separate estimation reflects our interpretation of distinct markets for positive and negative imbalance energy (Section 2). The combined model accounts for the difference between short and long systems through specific coefficients for positive and negative FRR prices. In contrast to the separate models, all other coefficients are the same by assumption.

Table 3 summarizes the results for these three models. Nearly all the results are significant at a p-level of 0.1%, and all coefficients have the expected sign. Furthermore, all coefficients are similar across the three models.

For our analysis, the coefficient of the imbalance price is most interesting. According to our combined model, an increase in the imbalance price by EUR 1 per MWh causes a decrease in the absolute system imbalance by about 2.18 MW.[11] This indicates that the demand for imbalance energy is indeed price-elastic and that BRPs respond to changes in the imbalance price: high imbalance prices incentivize BRPs to reduce individual shortages or to deliberately take long positions. The fact that the coefficient of the imbalance price is statistically significantly different from zero is by itself an important piece of evidence: it suggests that at least some BRPs engage in strategic deviations and flags the role of the imbalance price in balancing the system. This finding aligns with Koch and Maskos (2019), who also found evidence of the occurrence of strategic deviations in the German market.

The validity of our model is supported by the fact that all other coefficients in Table 1 have the expected sign and are of plausible size. Load forecast errors have a negative impact, while generation forecast errors have a positive impact on the system imbalance. This is as expected: the system becomes longer through positive load forecast errors (i.e., the load is lower than predicted) and shorter at positive generation forecast errors (i.e., generation is lower than predicted). The fact that the coefficient of the day-ahead price has a positive sign supports our hypothesis that it influences the system imbalance through the intraday price: higher day-ahead prices will be positively correlated with higher intraday prices, which incentivize short positions, summing up to a higher system imbalance. Interestingly, the coefficient of the day-ahead price is much larger than that of the imbalance price. This is reasonable, given that the intraday price, through which the day-ahead price affects the system imbalance, is known, but the imbalance price is (highly) uncertain at the time of strategic trading. In addition, the effect of the FRR price is as anticipated: positive FRR reserves are activated in short systems. Higher prices for these reserves cause higher costs for reserve activation, thus increasing the imbalance price. In long systems, the activation of more costly negative reserves (further) reduces the (often negative) imbalance price.

The similarity of coefficients across the three models suggests robust estimates. The model results are also robust against changes in the data set. Reducing the threshold value for data exclusion to ±300 MW and using day-ahead wind forecast errors instead of intraday data has little impact on the model results (Appendix, Table A.3 and Table A.4). In the following discussion, we focus on the combined model.

Table A.1 in the Appendix compares our estimates to a regression on the demand curve without instrumental variables (Eq. 2). It shows that ignoring the endogeneity induced through the simultaneity of price and quantity massively biases the estimated effect. In fact, the coefficient of the imbalance price has a flipped sign, suggesting that a higher imbalance price *increases* the system imbalance. This confirms our theoretical argument that estimating the price elasticity in imbalance markets without an IV approach can be highly misleading (Section 3.1).

Fig. 6 visualizes our findings. It shows the observed market equilibria (dots) and the demand and supply curves estimated with the combined model (1) for one hypothetical moment in which all shifters are at average values. Independent of the position, the responsiveness of BRPs to the imbalance price is reflected in the slope of the (red) demand curve, which is linear by assumption.

The occurrence of strategic deviations in the German regulatory context is remarkable for two reasons. First, BRPs in Germany are legally obliged to minimize their imbalance (regardless of price), which implicitly prohibits such strategic behavior. Second, the imbalance price can only be predicted at the time of trading because it is published 20 working days after delivery. The predictability of the imbalance price is further complicated by the fact that the system imbalance and the activation of reserves are also published after delivery.[12] This lack of

[10] Technically, we calculate the complementary cumulative distribution function of reserve activation (i.e., the probability of FRR activation exceeding a certain threshold). The underlying time series are retrieved from Regelleistung.net (2020).

[11] An increase in the imbalance price reduces a positive system imbalance and increases a negative system imbalance.

[12] Notice that such a late publication of imbalance prices favors players participating in the reserve market, which therefore possess additional information on the state of the system.

Table 2
Parameter description, mean values, and sources.

Parameter	Description	Mean (short system)	Mean (long system)	Source
System imbalance	Net imbalance in the Germany electricity system (net sum of all four TSOs)	897 MW	−841 MW	TenneT (2020)
Imbalance price (*German: reBAP*)	Charge (or compensation) that BRPs pay (or receive) for deviations of physical positions from schedules.	79 €/MWh	3 €/MWh	TenneT (2020)
Intraday price (ID1)	Weighted average price of all trades executed in the last hour before delivery	57 €/MWh	29 €/MWh	EPEX SPOT (2020b)
Load forecast error	Difference between forecasted and realized volume (forecast minus	−2053 MW	−768 MW	ENTSO-E (2020)
Wind forecast error	realized). We employ (public) day-ahead forecasts for load and solar, and (non-public) ID forecasts for wind.	298 MW	−324 MW	ENTSO-E (2020) (for DA data)
Solar forecast error		178 MW	−213 MW	ENTSO-E (2020)
FRR^{+} price (upward)	FRR energy prices reflecting the activation cost of balancing reserves; average of accepted automatic and manual FRR bids, weighted with	124 €/MWh	n/a	Regelleistung.net (2020)
FRR^{-} price (downward)	their probability of activation.	n/a	152 €/MWh	Regelleistung.net (2020)

Table 3
GMM estimation of coefficients for the combined model and for the separate models of short and long systems.

	(1) Combined model	(2) Short system	(3) Long system
Demand curve			
Outcome variable: System imbalance (MW)			
Instruments:	FRR^{+} and FRR^{-} prices	FRR^{+} price	FRR^{-} price
Imbalance price (€/MWh)	−2.18**	−1.56**	−1.20*
Day-ahead price (€/MWh)	5.84**	4.65**	4.30**
Load forecast error (MW)	−0.02**	−0.03**	−0.01
Wind forecast error (MW)	0.10**	0.13**	0.07**
Solar forecast error (MW)	0.10*	0.14*	0.03*
Constant (MW)	605** | −1099**	536**	−1903**
Supply curve			
Outcome variable: Imbalance price (€/MWh)			
Instruments: Load, wind, and solar forecast error			
System imbalance (MW)	0.05**	0.07**	0.01
FRR^{+} price (€/MWh)	0.31**	0.25*	–
FRR^{-} price (€/MWh)	−0.03*	–	−0.05*
Constant (€/MW)	−6.3* | 47.6*	−11.3	3.27

** significant at $p < 0.001$, * significant at $p < 0.05$, Controlled for month, hour of day, quarter hour within hours, and business days.

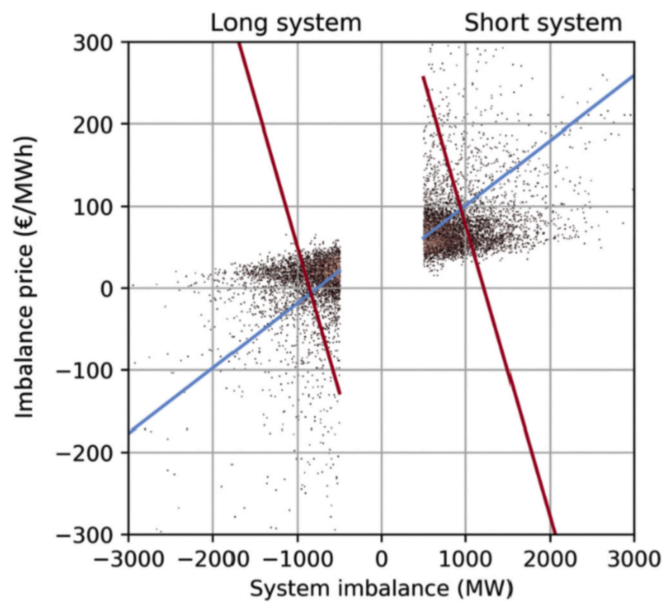

Fig. 6. Supply and demand curves for imbalance energy based on the model results of Section 4 (exemplary curves for average values of supply and demand shifters).

transparency of the German regulator has the purpose of impeding strategic deviations. Against this background, our estimate of the price responsiveness is idiosyncratic to German regulation. We would expect a higher price responsiveness if strategic deviations were allowed or if more real-time information on the balancing system was published, both of which are the case in other countries, such as the Netherlands.

4.2. *Effect of strategic deviations on the imbalance market equilibrium*

This section illustrates the role of strategic deviations in the imbalance market equilibrium. To this end, we consider an exemplary equilibrium to which we apply supply and demand shocks.

A supply shock changes the imbalance price for equal system imbalances. Such a shock may occur due to a regulatory change. We discuss the effect of a EUR 10 per MWh price shock, which corresponds to an upward shift of the supply curve. Based on our estimated price response to the demand, this would lead to a decline in the system imbalance by around 21.8 MW. However, as the demand for imbalance energy decreases, the imbalance price also declines because less costly reserves are activated, partly compensating for the initial EUR 10 per MWh shock (Fig. 7, left). A new equilibrium emerges, where the imbalance price is only EUR 8.6 per MWh higher than before, and the system imbalance decreases by 18.8 MW.[13] This example highlights the endogeneity of the imbalance price and system imbalance. As a practical example, consider the change in the winner selection criterion in Germany's balancing procurement auctions between 2018 and 2019 (see Subsection 3.3). This change reduced FRR prices, shifting the supply curve downward and lowering equilibrium imbalance prices by, on average, EUR 49 per MWh in significantly short systems.[14] Based on our model and neglecting changes in other exogenous variables, we can estimate that the system imbalance increased in these quarter hours by about 107 MW due to the price responsivity of demand.

Equivalently, we can analyze the effect of a shock on the demand curve. For example, consider a wind forecast error of 100 MW, meaning that wind generation is lower than forecasted. This shifts the demand curve to the right and thereby increases the system imbalance (Fig. 7,

[13] This can be calculated using the estimated coefficients of $\alpha_1 = -2.18$ MW per €/MWh and $\beta_1 = 0.05$.

[14] Note that this underestimates the true decline of the imbalance price due to the threshold of data selection (system imbalance $\geq$ 500 MW) before and after this regulatory change.

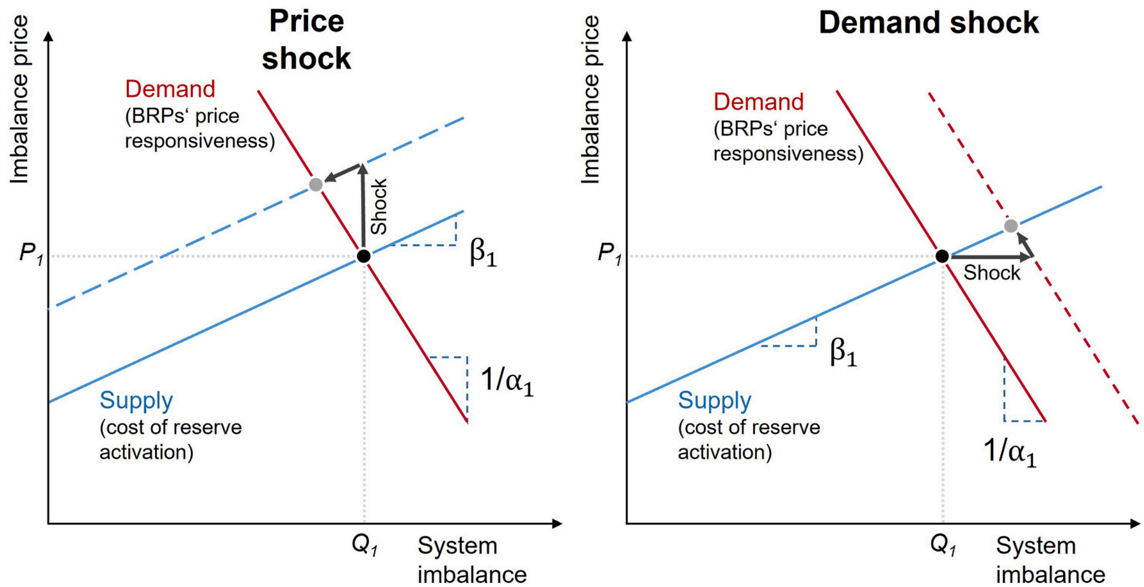

Fig. 7. Effect of a price (left) and demand shock (right) on the balancing market. The resulting equilibrium emerges at the new intersection of the supply and demand curves.

right). In this case, the downward-sloping demand curve for imbalance energy partly counterbalances the increasing system imbalance. Based on our empirical results, the system imbalance in the new equilibrium will be only 90 MW larger than in the original equilibrium. Accordingly, the imbalance price at equilibrium increases by EUR 4.5 per MWh.

4.3. Strategic deviations and equilibrium across intraday and imbalance markets

So far, we have focused on how the imbalance price affects the system imbalance and have shown that electricity balancing can be understood as an equilibrium in the imbalance market. We now extend this perspective and characterize the role of the intraday price in this equilibrium. More precisely, we estimate the impact of the imbalance price on the intraday price. To do so, we modify Eq. (2) of our IV-GMM model by replacing the system imbalance with the intraday price as the outcome variable. As before, the imbalance price is the endogenous variable for which we use FRR prices as an instrument (Eq. 4). In this model, the causal effect of the imbalance price on the intraday price is transmitted on a direct path and on an indirect path via the system imbalance as a mediator (Fig. 4).

The results of this model show a significant effect of the imbalance price on the intraday price: an increase in the imbalance price of EUR 1 per MWh causes the ID1 price to increase by EUR 0.09 per MWh (Table 4). This finding quantifies how the intraday market is interlinked with the imbalance market through strategic deviations: an increase in the (expected) imbalance price incentivizes long positions, and the resulting trades of market parties then increase the intraday price. Intuitively, one could expect that market parties are buying electricity at the intraday market until the increase in the intraday price matches the increase in the imbalance price and all arbitrage opportunities have been exploited. This would imply a coefficient of one. This, however, ignores uncertainty and legal risk: while the intraday price is known, the imbalance price is not. Furthermore, taking active positions is a violation of the German balancing obligation, which carries the risk of penalties.

For illustration, reconsider the EUR 10 per MWh price shock on the supply curve from Subsection 4.2. As discussed above, the new intersection between the supply and demand curves leads to a new equilibrium in which the system imbalance is 18.8 MW lower and the

Table 4
Estimating the impact of a change in the imbalance price on the ID1 price (IV-GMM model).

Outcome variable: ID1 (€/MWh) Instruments: FRR^{+} and FRR^{-} prices	
Imbalance price (€/MWh)	0.09**
Day-ahead price (€/MWh)	0.98**
Load forecast error (MW)	−0.00*
Wind forecast error (MW)	0.00**
Solar forecast error (MW)	0.01**
Constant (MW)	−4.53**

Controlled for month, hour of day, and business days.

imbalance price is EUR 8.6 per MWh higher. This rise in the imbalance price allows us to determine the new intraday price, which will increase by EUR 0.8 per MWh.[15] Note how the imbalance price spread (Eq. 1) increases by EUR 7.8 per MWh compared to the equilibrium before the shock.

This example highlights the shortcoming of considering the imbalance price spread as the (ex-ante) driver for position taking, as described in previous literature (Hirth and Ziegenhagen, 2015; Koch and Hirth, 2019). By definition, the spread is calculated ex post. At the time of trading and dispatch decisions, the imbalance price is unknown to firms, but intraday prices can be observed. Therefore, the new equilibrium with a larger imbalance price spread may still be arbitrage-free once risk is factored in. While the imbalance price spread does not reflect the uncertainty associated with the imbalance price, our empirical model helps to better understand the resulting market equilibria.

4.4. Are strategic deviations a problem?

We find that strategic deviations do occur in the German system. Whether such deviations are problematic depends on the direction and magnitude of the economic incentives to which BRPs are responding. Our results quantify the BRPs' price response in relative terms—per change in

[15] Actual imbalance price increase of EUR 8.6 per MWh times estimated coefficient of 0.09.

the imbalance price. However, we cannot directly infer the absolute effect of these strategic deviations. While our results illustrate how the imbalance price spread characterizes the ex-post incentive, which does not account for uncertainty at the time of the decision, it remains helpful to assess the harmfulness of strategic deviations. In our empiric sample, the imbalance price spread rewarded a behavior that relieved the system imbalance in more than 90% of all analyzed quarter hours. Therefore, it is highly likely that strategic deviations lowered, on average, the demand for imbalance energy—otherwise, BRPs would have systematically lost money through this behavior. The likely decrease in the demand for imbalance energy would reduce the activation of balancing reserves on average and thereby lower activation costs.

The prospect of strategic deviations that reduce the activation of balancing reserves and their related costs appears promising. However, this will only be cost-efficient if electricity can be contracted from less expensive generators on the intraday market. By contrast, when intraday prices are very high, it may be cost-efficient to employ cheaper balancing reserves instead. BRPs would cost-efficiently solve this trade-off through strategic deviations if intraday and imbalance prices reflected the marginal cost of electricity generation. BRPs would then have the incentive to open and close individual positions until a cross-market equilibrium is reached, in which the marginal cost for doing so equals the expected marginal cost of reserve activation. This is not the case in Germany, where the imbalance settlement price reflects the average, not marginal, activation cost of balancing reserves. In this setting, the (absolute) imbalance price is always below the marginal cost of reserve activation.

Of course, the main purpose of balancing energy regulation extends beyond cost-efficient dispatch: its primary aim is to ensure security of supply and avoid costs of supply interruptions. In the past, strategic deviations occasionally aggravated system imbalances in extreme situations, such as on June 12, 2019, when perverse economic incentives rewarded stressing the system imbalance close to a system collapse. Therefore, whether strategic deviations are beneficial to the security of supply strongly depends on the design of the respective economic incentives.

5. Conclusion

In this paper, we propose a framework for interpreting the balancing system as a market. We apply this framework to empirical data on the German balancing system and find robust evidence that firms respond to balancing incentives. Our results suggest that the demand for imbalance energy declines by 2.2 MW for an increase in the imbalance price by EUR 1 per MWh. Such strategic deviations support system stability if and only if economic incentives are adequately set.

Interpreting the balancing system as a fictive marketplace for imbalance energy also offers new insights into the relationship between intraday markets and imbalance prices. It illustrates that the imbalance price spread, while being a useful ex-post metric, is unknown at the time of trading, and taking a position is hence a risky undertaking rather than risk-free arbitrage trading. Our empirical results suggest that risk and legal constraints play an important role in reducing the responsiveness of firms to imbalance prices.

Because strategic deviations happen despite their prohibition, regulators should ensure that the underlying incentives encourage a behavior that enhances system stability and reduces system costs. We see two different strategies to enhance the incentive design. One approach is to reduce imbalance price spreads that reward BRPs for stressing the system imbalance. This aim was pursued by the German regulator, who revised the price coupling mechanism in 2020 to ensure that the imbalance price is always higher (lower) than the intraday price for short (long) systems (BNetzA, 2020). Alternatively, regulation can aim for more cost-reflective balancing incentives, which would imply that the profit-maximizing behavior of market participants reduces overall system costs. Important steps for this second approach are imbalance prices reflecting the marginal costs of balancing reserves, the higher transparency of the imbalance price, and the legalization of strategic deviations. While this is not the strategy of the German regulator, these steps are taken in other countries, such as the Netherlands.

The interpretation of the balancing mechanism as a market allows us to apply a system of equations with instrumental variables, an econometric method that has previously been used to characterize market equilibria. The empirical evidence for the price responsiveness of the system imbalance supports the proposed equilibrium framework. Our results also underline the importance of endogeneity between prices and quantities in this fictive market.

The economic framework developed in this paper could be exploited further by advancing the econometric model. One important extension may be to allow for nonlinear or stepwise estimations of the supply and demand functions. In particular, it would be interesting to focus on extreme situations, such as time periods of very high system imbalances that exhaust balancing reserves and put system security into jeopardy. In addition, the framework could be used to study the effects of different pricing rules and balancing procurement auction designs. This could be done across countries or over time, exploiting regulatory reforms. Finally, the model could be refined by adding more or better data. Power plant outages, reported as urgent market messages on transparency platforms, could serve as (another) exogenous source of variation. Rather than using the ID1 intraday price index, alternative price indices could be explored, including the ID_{AEP} index (which has the additional advantage of being publicly available for longer times). Better data could also be collected for solar and load forecast errors. Load forecast errors might constitute a particular area of concern when studying extreme situations, which are often triggered by extreme temperatures.

The economic framework itself could also be developed further. Here, we focus on the equilibrium in the imbalance market and interactions with the intraday market. This could be extended to other market stages. For example, one could think of the balancing reserves procurement auctions, as well as the newly introduced balancing energy bids, as endogenous parts of the framework. As a result, firms would optimize not only between intraday and imbalance prices but also balancing reserve and energy prices, leading to an equilibrium across all market stages.

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Anselm Eicke and Oliver Ruhnau contributed equally to this work.

Declaration of Competing Interest

The authors declare no competing interests.

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Appendix A

Table A.1
Estimation results without instruments.

	(1) Combined model	(4) Demand without instruments	(5) Supply without instruments
Demand curve (Instruments: positive and negative FRR price)			
Dependent variable: System imbalance (MW)			
Imbalance price (€/MWh)	−2.18**	0.90*	
Load forecast error (MW)	−0.02**	−0.01**	
Wind forecast error (MW)	0.10**	0.07**	
Solar forecast error (MW)	0.10*	0.08**	
Constant (MW)	615** | −1089**	669** | −877**	
Supply curve (Instruments: load, wind, and solar forecast error)			
Dependent variable: Imbalance price (€/MWh)			
System imbalance (MW)	0.05**		0.04**
FRR^{+} price (€/MWh)	0.31**		0.33**
FRR^{-} price (€/MWh)	−0.03*		−0.02**
Constant (€/MW)	−7 | 48**		0.3 | 40**

** significant at $p < 0.001$, * significant at $p < 0.05$; Controlled for month, hour of day, quarter hour within hours, and business days.

Table A.2
Relevance of instruments (OLS regressions).

Dependent variable: System imbalance (MW)	R-squared: 0.816 F-statistic: 14910
Load forecast error (MW)	*−0.02***
Wind forecast error (MW)	*0.07***
Solar forecast error (MW)	*0.08***
Constant positive | negative (MW)	*818*** | *-816***
Dependent variable: Imbalance price (€ / MW)	R-squared: 0.279 F-statistic: 1732
FRR+ price (€/MWh)	*0.31***
FRR- price (€/MWh)	*−0.02***
Constant positive | negative *(€ / MW)*	*41.8*** | *6.6***

** significant at $p < 0.001$.

Table A.3
Sensitivity analysis: Day-ahead vs. intraday forecast errors.

	(1) Combined model Intraday wind forecast error	(6) Combined model Day-ahead wind forecast error
Demand curve (Instruments: positive and negative FRR price)		
Dependent variable: System imbalance (MW)		
Imbalance price (€/MWh)	−2.18**	−2.13**
Load forecast error (MW)	−0.02**	−0.02**
Wind forecast error (MW)	0.10**	0.05**
Solar forecast error (MW)	0.10*	0.09*
Constant (MW)	615** | −1089**	646** | −1049**
Supply curve (Instruments: load, wind, and solar forecast error)		
Dependent variable: Imbalance price (€/MWh)		
System imbalance (MW)	0.05**	0.02*
FRR^{+} price (€/MWh)	0.31**	0.29**
FRR^{-} price (€/MWh)	−0.03*	−0.03*
Constant (€/MW)	−7 | 48**	−18 | 25*

** significant at $p < 0.001$, * significant at $p < 0.05$; Controlled for month, hour of day, quarter hour within hours, and business days.

Table A.4
Sensitivity analysis: Varying the thresholds of data selection (combined model).

	(1)	(7)	(8)	(9)
Data selection (SB: System balance)	SB > 500 MW or SB < −500 MW	SB > 400 MW or SB < −400 MW	SB > 300 MW or SB < −300 MW	SB > 200 MW or SB < −200 MW
Number of observations	13,450	17,322	22,116	27,876
Demand curve (Instruments: positive and negative FRR price)				
Dependent variable: System imbalance (MW)				
Imbalance price (€/MWh)	−2.18**	−2.58**	−2.92**	−3.24**
Load forecast error (MW)	−0.02**	−0.02**	−0.02**	−0.03**
Wind forecast error (MW)	0.10**	0.11**	0.12**	0.12**
Solar forecast error (MW)	0.10**	0.10**	0.10*	0.10*
Constant (MW)	615** | −1089**	575** | −971**	517** | −870**	458** | −774**
Supply curve (Instruments: load, wind, and solar forecast error)				
Dependent variable: Imbalance price (€/MWh)				
System imbalance (MW)	0.05**	0.05**	0.05**	0.05**
FRR^+ price (€/MWh)	0.31**	0.26**	0.17*	−0.15*
FRR^- price (€/MWh)	−0.03*	−0.02*	−0.02*	−0.02*
Constant (€/MW)	−7* | 48**	−1 | 42**	15 | 40**	−21 | 36**

** significant at p < 0.001, * significant at p < 0.05 Controlled for month, hour of day, quarter hour within hours, and business days.

Table A.5

	(1) Combined model	(4) Demand without instruments	(5) Supply without instruments
Demand curve (Instruments: positive and negative FRR price)			
Dependent variable: System imbalance (MW)			
Imbalance price (€/MWh)	−2.18**	0.90*	
Load forecast error (MW)	−0.02**	−0.01**	
Wind forecast error (MW)	0.10**	0.07**	
Solar forecast error (MW)	0.10*	0.08**	
Constant (MW)	615** | −1089**	669** | −877**	
Supply curve (Instruments: load, wind, and solar forecast error)			
Dependent variable: Imbalance price (€/MWh)			
System imbalance (MW)	0.05**		0.04**
FRR^+ price (€/MWh)	0.31**		0.33**
FRR^- price (€/MWh)	−0.03*		−0.02**
Constant (€/MW)	−7 | 48**		0.3 | 40**

** significant at p < 0.001, * significant at $p < 0.05$; Controlled for month, hour of day, quarter hour within hours, and business days.

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