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Impact of short-term market sequences on bidding behavior of market participants

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Abstract

This study provides insights into the consequences of market actors' bidding strategies depending on market design changes, particularly the sequence and timing of different marketplaces. Balancing market bidding represents a complex decision problem for prequalified market participants as they could profit not only from reserving capacity but also from increasing or decreasing their output. At the same time, they face opportunity costs due to trading options in the wholesale markets. The bidding decisions are affected by the planned splitting of balancing capacity and balancing energy markets. Other factors that influence actors' strategies is the introduction of voluntary balancing energy bids and the gate closure time of the balancing capacity auction with respect to the day-ahead market. We investigate the impact of these changes by developing a theoretical bidding calculus for participants in multiple markets based on decision theory. We study the effect in which markets close and clear using three market design options. The business-as-usual option with a joint market is compared to split balancing capacity and energy markets with clearing for balancing capacity before or after the closure of the day-ahead market. The possibility of submitting voluntary balancing energy bids is explicitly considered in the bid formulation.

We find that the effect of splitting balancing capacity and energy markets will be marginal unless the timing of the balancing capacity market is also adjusted and voluntary balancing energy bids are introduced. From a theoretical standpoint, the procurement of balancing capacity day-ahead ensures that balancing providers with low opportunity costs are allocated to the balancing market leading to an efficient market equilibrium. The effect of the introduction of voluntary bids is twofold. It will on the one hand reign in high balancing energy prices but also create higher opportunity costs and, ergo, higher balancing capacity prices as bidders will attempt to compensate for the foregone profits from balancing energy by bidding higher for balancing capacity. Thereby the optimal bidding strategies between bidders using the regular combination of balancing capacity and balancing energy bid and bidders using solely voluntary bids differ.

1. Introduction

At present, European balancing markets are undergoing far-reaching reforms [1]. These auction-based markets need to cope efficiently with the changing system reality such as increasing volumes of variable renewable energy sources (vRES). On the other hand, new resources, such as flexible loads and distributed generation, are penetrating the system and the markets. Another important driver is the progressive integration of European electricity markets, which requires an adaptation of national marketplaces towards coordinated European marketplaces and a harmonized market design [1]-[3].

Market participants have a number of options to generate profits in liberalized electricity markets. They may trade energy at the spot markets, i.e. day-ahead (DA) market and intraday (ID) market, or offer flexibility in the balancing market to aid the transmission system operator (TSO) to keep generation and load in balance. From the perspective of market design, a crucial factor that determines the performance of balancing markets is the timing for the procurement of balancing capacity (BC) and balancing energy (BE). Timing changes in the spot markets have an effect on the balancing market and vice versa [4], [5]. The reason for this is that balancing service providers (BSPs) face tradeoffs when participating in the balancing markets or in the spot markets. Thus, the order of markets affects participants' cost structures and creates interdependencies between their strategies in different markets with regard to bid volumes and prices (e.g. [6], [7]).

In most European countries, BC and BE are procured jointly in a single auction ahead of the DA market[1] [9], [10]. A separate market for BE must be implemented in European balancing markets for automatically activated Frequency Restoration Reserve (aFRR) no later than 2021, pursuant to the EU Electricity Balancing Guideline (EBGL), the main EU regulation guiding the future balancing market design [1]. Furthermore, so-called voluntary BE bids must be introduced [1]. This implies that market participants who did not participate or were not awarded in the BC market may still submit BE bids without receiving remuneration for capacity. In this way, BSPs do not necessarily reserve their capacities in advance but aid system balancing on a more *ad hoc* basis, which is expected to improve market efficiency and boost competition [1].

Given the novelty of this regulatory change, to our knowledge, its implications have not yet been examined in the literature. Additionally, most balancing-market-related studies focused on BC reservation alone while the procurement of balancing energy was not investigated in its own right (e.g. [9], [11-[14]). To analyze the effect of the changes in the balancing market design on BSPs' bidding strategies, we pose three research questions in this study:

- What is the effect of splitting BC and BE markets on bidders' cost structures and bids in these markets?
- The EBGL only prescribes the temporal position of the BE market, yet the position of the BC market is not fixed. What effect does the position of the BC market with respect to the spot markets have on the cost structures of the bidders?
- What is the effect of the introduction of voluntary bids on BSPs' optimal bidding strategies in the balancing market?

In order to answer these questions, we contrast the presently most common balancing market design with several options for split BC and BE markets. We analyze the optimal bidding strategies that result from these options and discuss which option best fulfills the above-stated policy goals. We develop a theoretical bidding calculus for participants in

[1] One of the few exceptions to this rule is the Dutch balancing market design where BE is procured separately from BC. In the Nordic countries, in contrast, a BE-only product exists for mFRR, i.e., no BC is reserved in advance [8].

multiple markets based on a decision-theoretical approach. We present a BSP's bidding calculus for each market design option and derive the profit maximizing bidding strategy.[2]

2. Market design and market actors' cost structures

The fundamental goal of each market is different: the DA market is the primary market for energy trade, the ID market serves as the final option for "last-minute" schedule adjustments, the BC market represents an option market for possible future activation, and the BE market is the actual physical contribution for stabilizing system frequency. The BE market and the ID market serve similar purposes, i.e., addressing system imbalances: in the ID market, market participants attempt to minimize deviations from their submitted schedules (e.g. due to an updated forecast from renewables or unforeseen changes in demand), while in the BE market, the TSO alleviates system imbalances by BE activation.

The availability of different marketplaces determines the number of trading options for market actors and consequently their prospects for profit. This is illustrated in Figure 1 and discussed in the following. Market actors can be characterized by two important factors. Firstly, not all wholesale market participants can place bids in the balancing market due to the technical prequalification required for market entry. Prequalified market participants, BSPs, must decide whether to sell their capacities on one of the spot markets, where only energy delivery is remunerated, or on the balancing market, where profits from both the reservation of BC and the delivery of BE can be generated.

Secondly, based on their short-term marginal costs, a distinction is made between inframarginal and extramarginal market participants. Inframarginal participants' variable costs are lower than the marginal price in a given market. In contrast, variable costs of extramarginal participants are higher (e.g. [16]). This characteristic determines in which markets actors can offer their available capacity profitably as well as their cost structures. Considering the high observed empirical balancing prices [17], a market actor with high variable costs, e.g. a gas-fired power plant, is likely to be extramarginal in the spot markets but inframarginal in the BE market (see also [18]). In contrast, market actors operating coal-fired power plant, which is likely inframarginal in the DA market, must consider expected profits in different markets when formulating their trading decision ([6], [16], [18]). Finally, market actors with short-term flexibility (e.g. vRES) tend to bid in the ID market as they are most often not allowed to participate in the balancing market [19].

If the system is undersupplied, positive BE bids are required to increase generation (or reduce load) whereas in the case of undersupply negative BE bids are needed to lower generation levels (or increase load) in order to restore system balance. Following the merit-order in the positive and negative balancing market, bids are activated from the lowest to the highest bid. In the latter, a BSP generates savings by reducing its generation level, so in this market BE bids with the highest variable costs should be activated first. Figure 1 shows that the bids for the two regulation types imply different cost structures, which may or may not include opportunity costs.

Unlike technology-related costs, opportunity costs are largely dependent on a market sequence applied and limit market actors' strategy space. Market sequence also plays a role in determining whether BSPs that were not awarded in the balancing market can still offer their capacity in one of the spot markets. Their order is defined by a number of timing-related design variables, such as:

- the bidding frequency, i.e. how often a specific auction takes place,

[2] Note that we do not apply a game-theoretical analysis. This would exceed the scope of this paper. For a game-theoretical model of the current Austrian-German and future harmonized European aFRR auction please refer to [15].

- the bidding period, i.e. the timeframe when the order book is open, starting with gate opening time (GOT) and ending at the gate closure time (GCT) when no bids can any longer be modified or any new bids submitted and
- the frequency of market clearing, i.e. how often the market operator builds a respective merit order and determines the market clearing price.

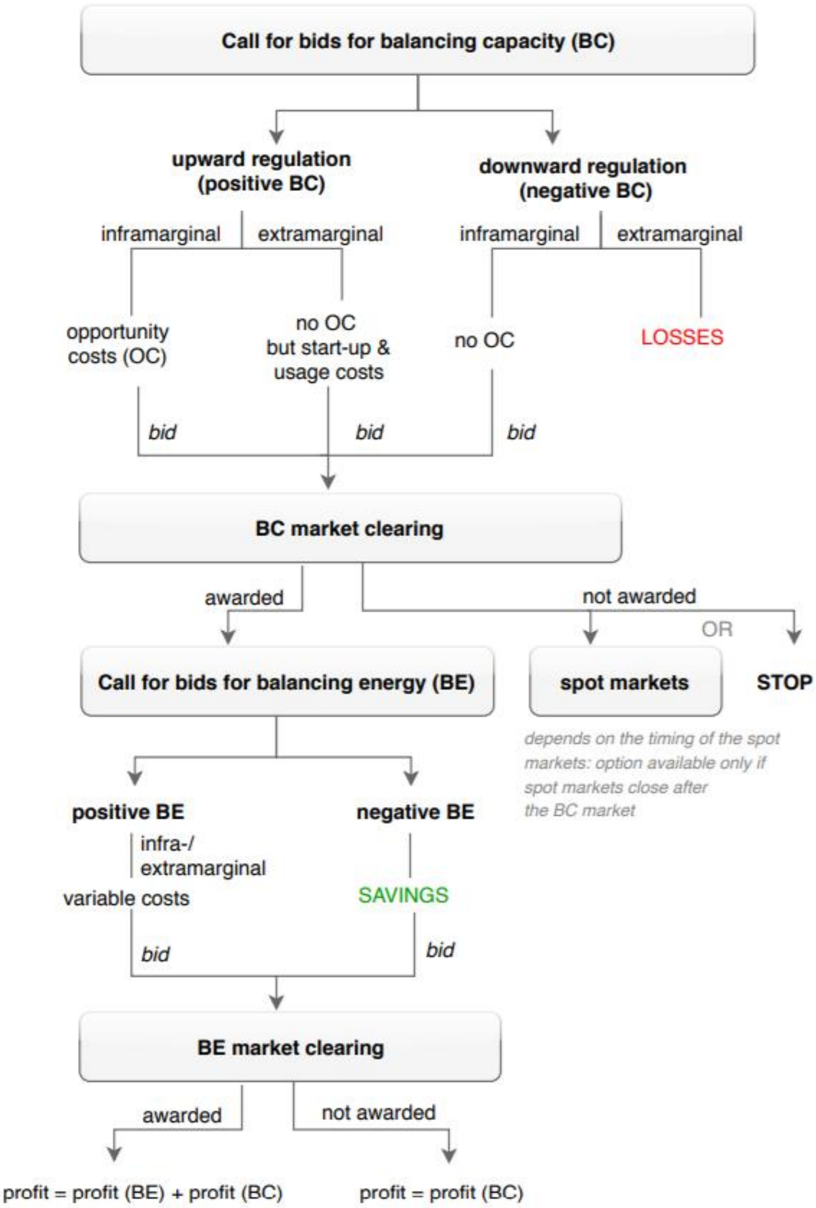

Figure 1. Trading options and associated costs for prequalified BSPs in the balancing market

Depending on the frequency of bidding, BC can be reserved for potential activation for different periods of time so that the reservation period during which BE can be activated can vary from a year to an hour or even less [10], [19]. Unlike the DA market and the ID market, in the balancing market bidding and clearing times can differ. For instance, if bids for BC and BE are submitted only once a week, i.e., the capacity market is cleared once a week, the energy market may be cleared every 15 minutes based on real-time system imbalances. Currently, fifteen minutes is the shortest settlement period applied in the European markets [9]. In contrast, if the two markets, for BC and for BE, are split, the frequency of bidding of BC and BE are not identical.

The spot markets and balancing market can be cleared either sequentially, a preferred way in the ENTSO-E area [9], [20], or simultaneously, for instance, as implemented in some US markets (e.g. PJM or CAISO). The markets are further characterized by different lead times, i.e., the time between GCT and bid execution, e.g. one day for the DA market and 60 to 5 minutes for the ID market (e.g. [21]). Finally, the markets in a sequence can be more spread out with longer time periods in between respective bidding periods or positioned compactly within a short timeframe, e.g. a day.

Cost Structures

The underlying cost structures are crucial for the formulation of the bidding calculus. They consist of costs of capacity reservation (henceforth capacity costs) and costs of energy activation (henceforth calling costs).

Capacity Costs

Capacity costs include all costs of a BSP for reserving BC for the balancing market and are included in the BC bid in Euro/MW. For positive BC, the operator of an inframarginal power plant needs to consider opportunity costs. These arise due to sequential market clearing of the balancing and the spot markets so that the capacity committed to the balancing market cannot be sold in these other markets during the reservation period. The opportunity costs are given by the margin between the relevant market price and the variable costs, multiplied by the length of the reservation period (Figure 1). For negative BC, inframarginal power plants do not face opportunity costs: all the produced energy is sold at a profit because the operator must run the plant on a certain minimum load. For the operator of an extramarginal power plant several cost components are included in the capacity costs, such as start-up costs, usage costs or maintenance costs when providing upward regulation (Figure 1). However, these cost components are highly dependent on a specific power plant and, thus, are not considered in our theoretical analysis.

Calling Costs

Calling costs are assigned to the BE bid in Euro/MWh. The TSO incurs these costs in case BE is called. For positive BE and both inframarginal and extramarginal power plants, these costs are equal to the variable costs of generation. For negative BE, these costs are actual savings (Figure 1). The reason is that BSPs are still remunerated with the relevant market price. Recall, if negative BE is needed, there is too much energy supplied to the power system. Thus, a BSP does not need to produce traded energy with her power plant and also saves costs by reducing the load level of her power plant. Therefore, a BSP may be willing to pay the TSO for the delivery of negative BE, where the maximum willingness to pay is determined by the variable costs of the BSP's power plant.

3. Analysis of market design options

Current design: Joint market for BC and BE

This option is most frequently used in the European balancing markets (cf. [9]). BC bids and BE bids are submitted in the same bidding period, while the joint market is cleared only for BC. The scoring rule, i.e. the determination of winning bids, comprises solely BC bids. The BE bids in the merit order remain the same for the duration of the reservation period (from the GCT to real time). The GCT of the DA market and ID market take place after the GCT of the balancing market. Finally, the BE market is currently cleared every 15 minutes to one hour close to real time (Figure 2).

Figure 2: Joint market for BC and BE clearing before the DA market

The BSP's objective is to maximize her (expected) profit, which depends on her capacity costs c and calling costs k. The BSP's probability of being accepted with her BC bid b_C is described by function $H(b_C)$, which has a negative derivative, $h(bc) \leq 0$. A BSP's probability of being called for the delivery of BE on the basis of her BE bid b_E, is described by function $G(b_E)$. Since the calling probability $G(b_E)$ decreases with b_E, its derivative is less or equal to zero, $g(b_E) \leq 0$. The probabilities $G(b_E)$ and $H(b_C)$ are based on BSPs' subjective beliefs. The reservation period in hours is denoted by d and a BSP's capacity offer by q (i.e., her prequalified capacity). For the purpose of this analysis, we assume that a BSP submits only one BC bid and only one BE bid. If a BSP is awarded, her expected profit is given by (see also [14])

$$\pi(b_C, b_E) = H(b_C) \cdot q \cdot [(b_C - c) + (b_E - k) \cdot d \cdot G(b_E)]\,. \tag{1}$$

The first-order conditions for the maximization of (1) with respect to both bids b_C and b_E lead to the following conditions for optimal BC and BE bids b_C^* and b_E^*:

$$b_C^* = c - (b_E^* - k) \cdot d \cdot G(b_E^*) - \frac{H(b_C^*)}{h(b_C^*)}, \tag{2}$$

$$b_E^* = k - \frac{G(b_E^*)}{g(b_E^*)}. \tag{3}$$

The optimal BC bid b_C^* depends on the capacity costs c. The term $(b_E - k) \cdot d \cdot G(b_E^*)$ in (1) reflects the expected profit of the BE bid per megawatt (MW) $\pi(b_E^*)$. That is, the expected profit of the optimal BE bid b_E^* is considered in the calculation of the optimal BC bid b_C^*. Since the term $H(b_C^*)/h(b_C^*)$ is negative, its absolute value is added to c. In our model the price rule pay-as-bid (PaB) is applied, i.e., awarded BSPs are remunerated with the bid figures they submitted.[3] This markup is due to the PaB rule and corresponds to a markdown in sale auctions, which is called "bid-shading" [23]. The optimal BE bid b_E^* is independent of the optimal BP bid b_C^* because the BC bid must be accepted first before any profits can be generated with the BE bid. The calling costs k are the basis of the optimal BP bid, to which – due to the PaB rule – the absolute value of $G(b_E^*)/g(b_E^*)$ is added as a markup.

From a theoretical perspective, this market sequence ensures overall market efficiency, i.e., minimizing overall costs. The reason for this is that winner determination is based on the submitted BC bids: BSPs with the highest variable cost and, thus, lowest opportunity cost incorporated in the BC bid, are awarded for the balancing market. This yields the efficient allocation that BSPs with low variable cost are not selected in the balancing market but run continuously on the spot market, while BSPs with high variable costs are selected for the balancing market in which they are activated discontinuously (based on the system imbalance) [16], [18].

Under the current design, the expected capacity costs c are given by

$$c = \max((p_{DA} - VC) + \varepsilon_{DA}; (p_{ID} - VC) + \varepsilon_{ID})\,, \tag{4}$$

[3] The authors are aware that [1] foresees pay-as-cleared (uniform pricing) as price rule in the future, harmonized balancing markets. However, we decided to apply pay-as-bid in our analysis for three reasons. Firstly, the aim of this paper is the examination of effects on bidding strategies based on different market sequences, not based on different price rules. For an analysis of different price rules refer to [6], [22]. Secondly, [1] allows using pay-as-bid in balancing markets if it is proven that its application leads to a higher efficiency than pay-as-cleared. Thirdly, the theoretical analysis is more complex and less intuitive with pay-as-cleared as price rule (see [6], [26], i.e. exceeding the scope of this paper.

where *VC* denotes the costs of power generation p_{DA} denotes the (expected) price of the DA market, and p_{ID}denotes the (expected) price of the ID market. Note that BSPs form beliefs about future DA and/or ID market prices since those are not known at the time of BC bid submission. To capture this price uncertainty of BSPs, we use the variables ε_{DA} and ε_{ID}, which can be interpreted as risk premiums with regard to expected opportunity costs. According to (4), capacity costs represent the maximum of the price spread of the DA market and a BSP's variable cost and the price spread of the ID market and a BSP's variable costs.

The magnitude of BSPs' expected opportunity costs is affected by how big the temporal gap between the GCT of the balancing market and that of the spot markets is. The farther the time of bid submission is from real time, the less precisely the expected opportunity costs can be estimated. As a result, market participants are more likely to place BE bids as close as possible to the maximum expected spot market prices to reduce the extent of missing out on profits from the spot markets [24]. A greater uncertainty produces higher risk premiums ε_{DA} and ε_{ID} as well as a risk for market inefficiency due to a higher probability of a distorted assignment of BSPs to the spot markets and balancing market. The size of the risk-premium depends also on the volatility of the spot market prices, i.e., the higher the volatility of the prices, the higher are the BSPs' risk premiums [25].

Thus, information availability largely depends on the time horizon of the balancing market. According to EBGL, "the contracting should be performed for not longer than one day before the provision of the balancing capacity and the reservation period shall have a maximum period of one day" ([1], Art. 5.9). Frequent bidding opportunities make it easier to evaluate the options closer to real time. However, the compression of GCTs may also lead to liquidity issues, particularly for daily timeframes [26], and to a much higher price volatility [5], thus increasing the magnitude of risk premiums ε_{DA} and ε_{ID}.

Alternative market design options: Split markets for BC and BE

Split markets for BC and BE imply that the BE market is independent of the BC market and both market clearing times and bidding frequencies differ. Furthermore, an additional factor is modelled: voluntary BE bids. As a result of their introduction, the bid components for existing BSPs change: an additional voluntary BE bid b_{VE} is added.

In our model, two distinct bidding options are considered. Firstly, if a BSP is awarded with the BC bid b_C, she submits her regular BE bid b_E, and if a BSP is not awarded with the BC bid, she can still submit her voluntary BE bid b_{VE}. Secondly, a BSP that did not participate in the BC market now also can still submit a voluntary BE bid (e.g. vRES plants that cannot reserve capacity upfront).

Note that in the first option the bidding strategy for the BC bid and the regular BE bid is not independent of the bidding strategy for the voluntary BE bid. The reasons for this is that bidders still have the chance to submit their voluntary BE bid if not awarded with the BC bid. This is not the case in the second bidding option: if a BSP did not participate in the BC market, she submits a voluntary BE bid exclusively. Further note that we assume that regular and voluntary BE bids form part of a single merit order.

<u>Split BC and BE market with DA market cleared after BC market</u>

In this design option capacity reservation takes place ahead of the DA market whereas the GCT of the DA market takes place prior to the opening of the market for BE, as is shown in Figure 3. Importantly, even if the BC and BE markets are formally split; bidders who commit their capacity in the first one will inevitably take the expected profit from the latter into account. In contrast to BC bids, different BE bids can be submitted each 15 minutes. The capacity costs correspond to (4).

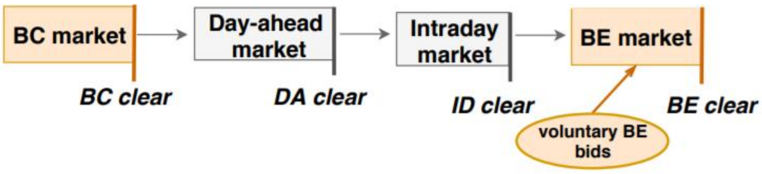

Figure 3. DA market cleared after BC market and before BE market

If voluntary bids are allowed, an additional element is considered in the expected profit function as the BSP who participates in the BC market takes both options for BE bid submission, regular and voluntary, into account. The expected joint profit is given by

$$\pi(b_C, b_E, b_{VE}) = H(b_C)\cdot q\cdot[(b_C - c) + (b_E - k)\cdot d\cdot G(b_E)] + \\ + \big(1 - H(b_C)\big)\cdot G(b_{VE})\cdot(b_{VE} - k)\cdot d\,. \tag{5}$$

The BSP is awarded with the BC bid b_C with probability $H(b_C)$ and, thus, generates profits with the BC bid and the regular BE bid, while with the probability $\big(1 - H(b_C)\big)$ a BSP is awarded with the voluntary BE bid b_{VE}. For maximizing (5), we compute the first-order conditions for the optimal BC bid b_C^*, regular BE bid b_E^* and voluntary BE bid b_{VE}^*, which lead to the following conditions:

$$b_C^* = c - (b_E^* - k)\cdot d\cdot G(b_E^*) - \frac{H(b_C^*)}{h(b_C^*)} + (b_{VE}^* - k)\cdot d\cdot G(b_{VE}^*), \tag{6}$$

$$b_E^* = k - \frac{G(b_E^*)}{g(b_E^*)}, \tag{7}$$

$$b_{VE}^* = k - \frac{G(b_{VE}^*)}{g(b_{VE}^*)}\,. \tag{8}$$

Compared to (2), the optimal BC bid in (6) includes an additional markup corresponding to the opportunity costs given by the expected profit of voluntary BE bid. The optimal voluntary BE bid has the same structure as the optimal BE bid: the basis are the calling costs k plus the absolute value of the markup.

If the BSP did not participate in the BC market and is then awarded with the voluntary energy bid, her expected profit is given by

$$\pi_{VE}(b_{VE}) = G(b_{VE})\cdot(b_{VE} - k)\cdot d\cdot q\,. \tag{9}$$

Note that in the case of non-acceptance with the voluntary BE bid, a BSP does not generate a profit at all because the DA market and ID market already cleared. The first-order condition for maximizing (9) leads to the condition for the optimal the voluntary BE bid b_{VE}^*:

$$b_{VE}^* = k - \frac{G(b_{VE}^*)}{g(b_{VE}^*)}\,. \tag{10}$$

Note that the voluntary BE bid is identical with the term in (8).

<u>Split BC and BE market with DA market clearing before the BC market</u>

In this option, BC is procured on a daily basis after the GCT of the DA market and BE is auctioned after the GCT of the ID market, as is illustrated in Figure 4.

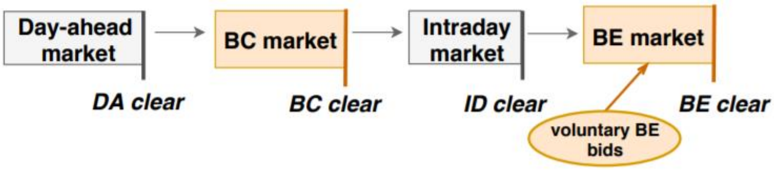

Figure 4. BC and BE markets clearing after the DA market

The opportunity cost reflect the expected foregone profit of the ID market:

$$c = (p_{ID} - VC) + \varepsilon_{ID}\ . \tag{11}$$

For both bidding options, the expected profit function is identical as in (5) and (9) and the first-order conditions for the optimal bids are identical as in (6)-(8) and in (10).

In practice, a BSP with a portfolio of units can allocate different portfolio shares to each market depending on their variable costs and, thus, maximize profits. Given that BSPs have the chance to generate higher profits in the subsequent balancing market, the DA market price now incorporates balancing market opportunity cost. Depending on the extent of which the DA price is influenced by these opportunity costs, the higher the DA market price, the less attractive is the balancing market option, and vice versa.

Yet, both from a theoretical standpoint (e.g. [15]) and confirmed by empirics [17], the balancing market offers higher profits, even as close as a day-ahead of delivery. Notably, in the BC market where capacities are reserved, BSPs do not face variable costs, unlike the DA market where participants incur costs for actual energy generation. Market participants, both those extramarginal in the DA market but also inframarginal, are thus incentivized to provide the maximum of their prequalified capacities as BC, potentially driving volumes away from the DA market.

Although technically feasible, this sequence is unpopular because of system security concerns, that is, if BC market is following the DA market, a supply shortage is more likely, endangering the system. The ultimate goal of system balancing consists in stabilizing frequency deviations, as a result, insufficient capacity available for activation would cause power outages. Therefore, safeguards such as a second auction or mandatory provision in case of danger to system stability must be in place. Another concern is that moving the balancing market so close to real time may affect market liquidity. This, however, should not necessarily be the case due to an offsetting effect of entry of renewables and distributed providers of flexibility into the market, which becomes possible thanks to shorter timeframes and improved forecasting.

Introduction of voluntary BE bids

If we set $G(b_E^*) = G(b_{VE}^*)$ for (5) to (8), two interesting observations can be made: firstly, the optimal regular BE bid and the optimal voluntary BE bid are identical, and secondly, the term for the optimal BC bid reduces to $c - H(b_C^*)/h(b_C^*)$. However, is it reasonable for a BSP to assume the same calling probability beliefs for both the regular BE bid and the voluntary BE bid? We argue that this is not the case. Recall that in the market equilibrium those BSPs are awarded with BC bids who have the lowest opportunity costs and, thus, (relatively) high variable costs. If a BSP is not awarded with the BC bid, she gains the additional information that her variable costs are lower than all of the variable costs of the BSPs who were awarded with the BC bid, i.e. those BSPs who form the initial merit-order of BE bids. This means that a BSP who was not awarded with the BC bid learns that she will compete with relatively "expensive" competitors for the positions in the merit order of BE bids. A rational BSP will include this information when formulating her voluntary BE bid: she will include a higher markup $G(b_{VE}^*)/g(b_{VE}^*)$ on her variable cost basis k and, thus, submit a higher voluntary BE bid compared to the regular BE bid.

The actual magnitude of the markup is a trade-off between additional profits and the position in the BE bid merit order: if a BSP exaggerates her markup, the BE bids of BSPs who were initially awarded with the BC bid, might still be lower than the voluntary BE bid. This would then result in a high position in the BE merit-order and, consequently, the BSP would deliver BE in a reduced number of cases. An additional factor that may limit her markup is that a number of voluntary bids that did not take part in the BC market will be placed in the BE market. These can be RES or small-scale producers whose bids will not necessarily have high variable costs and whose added volume it will be difficult to estimate. In other words, although BSPs that previously took part in the BC market obtain an information advantage, they do not get a similar advantage in the BE market as the bidding timeframe is the same for regular and voluntary bids and all the bidders are informed about the results of the BE market only *ex post*. Besides, according to the EBGL, no BE bids may be adjusted after the gate closure time of the BE market (Art. 24, [1]).

The empirical benefits of voluntary bids from the market perspective are illustrated by the experience from the Dutch market, where voluntary bids are already used. It shows that although the number of BC providers is very limited and they participate in the market repeatedly over an extended period of time, the balancing market still shows an efficient outcome as more BE providers take part in the market through voluntary bids (e.g. [21], [26]). Furthermore, opportunistic or collusive behavior that can arise from repeated BC auctions with a limited number of participants can be mitigated with the help of voluntary bids that seem to "cap" unreasonably high BE bids. As a result, voluntary bids can increase market liquidity and allocative efficiency making sure that the most cost-efficient units are used for the service.

4. Conclusion

By applying a decision-theoretical bidding calculus, we showed that the sequence in which markets close and clear has an effect on market actors' cost structures and their optimal bidding strategies. An additional change is introduced if standalone voluntary BE bids, as mandated by the EBGL, are implemented. We analyzed these effects by comparing three balancing market designs.

An important conclusion from this study is that the splitting of BC and BE markets alone does not change BSP's optimal bidding strategy unless the timing for the BC market is adjusted and voluntary BE bids are introduced. If these two aspects are disregarded, the effect of splitting will be marginal. The reason for that is that BSPs will still consider their costs and profits from both markets and the same bidders awarded in the BC market participate in the subsequent BE market. The additional short-term trading option in the form of voluntary BE bids generates additional opportunity costs, which leads to even higher BC prices. Especially if the BC market is situated far ahead of DA market, this can provoke substantial costs of capacity reservation borne by consumers. Thus, conducting the auctions for balancing capacity close to the DA market or even after its closure is likely to improve overall market efficiency.

Through voluntary BE bids, actors with short-term flexibility and low variable costs, e.g. new market entrants such as operators of renewables not participating in the BC market, can also compete for BE profits in the future. We show that their bidding strategy will differ from the one of incumbent BSPs that may use voluntary bids as a second chance to enter the merit order in the BE market. The introduction of voluntary bids in separate BE markets is likely reign in very high BE prices. A potential downside could be that the balancing market becomes so competitive that profit levels in the BE market as compared to the expected profits in the spot markets decrease to such an extent that it no longer appears profitable, driving capacities out of the balancing market.

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Appendix 1

List of abbreviations

aFRR	automatically activated frequency restoration reserve
BC	balancing capacity
BE	balancing energy
BSP	balancing service provider
DA	day-ahead
EBGL	Commission Regulation (EU) 2017/2195 of 23 November 2017 establishing a guideline on electricity balancing (also known as 'Guideline on Electricity Balancing')
ENTSO-E	European Network of Transmission System Operators for Electricity
FCR	frequency containment reserve
GCT	gate closure time
GOT	gate opening time
ID	intraday
ISO	independent system operator
MCP	marginal clearing price
MW	megawatt
mFRR	manually activated frequency restoration reserve
PAB	pay-as-bid (pricing rule)
TSO	transmission system operator
vRES	variable renewable energy source

Notation used in this paper

π	BSP's (expected) profit [Euro].
VC	variable costs of a power station [Euro/MWh]
c	capacity costs [Euro/MW]
k	calling costs [Euro/MWh]
b_C	BC bid [Euro/MW]
b_E	BE bid [Euro/MWh]
b_{VE}	voluntary BE bid [Euro/MWh]
$H(b_C)$	BSP's probability of being awarded with BC bid
$h(b_C)$	derivative of the "acceptance probability"
$G(b_E)$	BSP's probability of being called for the delivery of BE based on BE bids
$g(b_E)$	derivative of the "calling probability"
d	reservation period [h]
q	BSP's power offer [MW]
p_{DA}	(expected) price of the DA market [Euro/MWh]
p_{ID}	(expected) price of the ID market [Euro/MWh]
ε_{DA}	price uncertainty related to the DA market
ε_{ID}	price uncertainty related to the ID market