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Balancing Power Markets in Germany: Timing Matters

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Balancing Power Markets in Germany:

Timing Matters[1]

by

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Abstract:

This paper analyzes timing issues on the German balancing power market. We focus the analysis on the length of the bidding period, i.e. the length of the time period a supplier has to provide balancing power capacities, and the question of how far before the beginning of a bidding period the auction should be carried out. We show that different load levels require different plants for the optimal provision of balancing power. In a longer bidding period, the power plants that have the lowest average cost in the bidding period are unlikely to be efficient in all hours of the bidding period. Hence, shortening bidding periods can increase efficiency. Furthermore, we show that an early commitment on a power plant's mode of operation (when uncertainty about resulting spot prices is still relatively high) also reduces efficiency. This suggests that the auction should be held relatively close to the beginning of the bidding period. Furthermore, we discuss some advantages of a liquid real time market.

Key words: Electricity Markets, Balancing Power, Market Design

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INTRODUCTION

Balancing power is required to balance short term deviations from the desired grid frequency in electricity systems. In the German balancing power market, the four TSOs procure balancing power capacities in auctions. In these auctions, different balancing power products are procured. Firstly, primary control power, secondary control power and minutes reserve are distinguished. These products reflect different qualities especially because they have to be available after an increasing activation time (30 seconds for primary control power, 5 minutes for secondary control power and 15 minutes for minutes reserve). Secondly, positive and negative balancing power are distinguished. Positive balancing power corrects a drop in the frequency by either providing additional generation or reducing load. Negative balancing power corrects a rise in the frequency by either reducing production or increasing consumption. Thirdly, the different qualities have different lengths of the bidding periods. As of today, both primary and secondary control power have a bidding period of one month. Minute reserve has a bidding period of 4 hours.

The design of such markets has different components. Two important aspects are the settlement and the scoring rule. In the German balancing power market, the settlement rule is pay-as-bid. This is often controversially discussed (see e.g. Kahn et al. 2001 for a discussion in the context of California's electricity market). The scoring rule is also subject to ongoing debates (see e.g. Chao and Wilson 2002 for a mathematical analysis). Based on this and other previous work, the settlement and the scoring rule in the German balancing power markets are discussed in Müsgens, Ockenfels and Peek 2011.

This article concentrates on timing issues in balancing power markets. Furthermore, we compare the current situation in Germany to the proposed design and give specific recommendations for improvements where appropriate. One crucial timing aspect in balancing power markets is the length of the bidding period, i.e. the length of the time period a supplier has to provide balancing power capacities. Another crucial aspect we address is the question of how far before the beginning of a bidding period the auction should be carried out. Last but not least we discuss some advantages of a liquid real time market in this connection.

THE ROLE OF TIMING

Müsgens, Ockenfels and Peek 2011 outline the economics of balancing power markets by analyzing the rules and economic algorithms that channel the incentives of players in the balancing power markets. Furthermore, they show that bids in a competitive market depend on capacity costs (that is, opportunity costs for reserving capacity) and variable costs. This paper demonstrates, that timing issues significantly affect the suppliers' costs, and so also affect bidding, prices and overall efficiency of balancing power markets.

In the following, we will concentrate on three different timing areas in balancing power markets. The first is the length of the bidding periods. The second is the time period between the bidding and the settlement, which depends on the frequency of the tendering process as well as on the length of the bidding period. We will show that shorter bidding periods and higher frequencies of the tendering process can significantly reduce capacity cost on balancing power markets. The third topic concerns the promotion of a real time market. We will present arguments that the system operator should be allowed to buy additional balancing power on this market. This would open new sources for balancing power and increase the integration of real time and balancing power markets.

The bidding periods on Germany's balancing power markets are different for secondary control power and minutes reserve. For the former, a bidding period lasts one calendar month and contains either HT[2] periods or NT periods.[3] Auctions are performed about two weeks before the beginning of the respective month. For minutes reserve, a bidding period lasts four hours of a single day. All six different products for one day are auctioned the day before at 11 a.m.

Both, the auction for secondary control power and the auction for minutes reserve are different from the regular day-ahead electricity auctions performed at the EEX. In this auction hourly contracts are traded for the 24 hours of the following day. The results of the daily electricity market auctions are published after 12 a.m. Hence, both the time of bidding and the times and lengths of the bidding periods are different from the ones for balancing power. We will show that this leads to uncertainties, which in turn influences capacity costs. Moreover, the length of the bidding period – in particular for secondary control power – leads to varying capacity costs during this bidding period. On top of that, potential suppliers of balancing power need to determine how to operate their power plant during the bidding period far in advance. This causes a loss of flexibility of operating power plants and increases overall costs of the suppliers.

Length of the Bidding Period

The length of a bidding period for minutes reserve is four hours. With secondary control power, the length of a HT bidding period adds up to between 228 and 276 hours and to between 432 and 516 hours for NT bidding periods.[4] The prices of electricity on the day-ahead wholesale electricity market are different in each hour of the bidding periods.

A power plant can be either inframarginal or extramarginal in hour *t*. Hence, taking into account the volatility of the electricity price[5] during a bidding period and following the

2 HT is a specification of a certain bidding period for secondary control power, which covers the hours from 8 a.m. to 8 p.m. from Monday to Friday except national holidays. Note that this differs slightly from the EEX peak definition, as the latter includes national holidays. NT includes all other ours.

3 The German regulatory authority, the BNetzA, has decided to shorten the time periods for both primary (BNetzA 2011a) and secondary control power (BNetzA 2011b) from monthly to weekly. These changes were discussed and decided after we finished our research, which provides a rationale for these changes. However, our results seem to suggest to shorten bidding periods even further.

4 This depends on the number of working days and public holidays in the respective month.

5 We will discuss the implications of the associated uncertainty below.

derivations in Müsgens, Ockenfels and Peek 2011, the capacity cost[6] [CC] in hour t of the bidding period is:

$$CC^{\text{Reserve}}(t) = \begin{cases} \left(VC - p^{DA}(t)\right) \cdot \dfrac{CAP^{Min}}{CAP^{\text{Reserve}}} & ,\text{if } VC > p^{DA}(t) \\ p^{DA}(t) - VC & ,\text{if } VC \le p^{DA}(t) \end{cases}.$$

In that equation, VC denotes a power plant's variable generation costs, p^{DA} is the day-ahead electricity price, CAP^{Min} is the power plant's minimum load, and $CAP^{Reserve}$ is the amount of reserve capacity provided. Overall capacity costs per MW/h of a power plant providing balancing power are the average of the capacity costs in each hour, i. e.

$$CC^{\text{Reserve}} = \frac{\sum_{t=1}^{T} CC^{\text{Reserve}}(t)}{T},$$

where T is the number of hours in the corresponding bidding period. If there was one constant electricity price only within a bidding period, an efficient allocation rule would favor power plants with variable costs close to the electricity price over power plants with variable costs differing significantly from this price. If the electricity price varies within such a period, a single allocation cannot be efficient anymore, because the difference between electricity price and variable cost varies too within a bidding period.

Without considering the balancing power market, the electricity price at the wholesale market is a market signal indicating which power plants should run to cover demand. Since costs for procuring balancing power are directly linked to the electricity price – both for inframarginal and for extramarginal power plants – the electricity price assures an efficient allocation of power plant capacities between the electricity market and the balancing power market (see Chao and Wilson 2002, and Müsgens, Ockenfels and Peek 2011 for more detailed analyses and illustrations). The costs of procuring balancing power increase as the difference between electricity price and variable cost increases. In an efficient allocation, this assures that inframarginal power plants with low variable costs are used to generate electricity. The generation from inframarginal power plants with high variable costs is decreased. Within their technical limits these power plants are partly used for procuring balancing power and additional energy from these power plants is being called when needed. Since the probability of being called is less than 100%, this assures that overall variable costs are minimized.

An analogous argument holds for extramarginal power plants. When these are used to procure balancing power, they cause extra costs, because they generate electricity at minimal technical load on the electricity market and replace cheaper (inframarginal) power plants.

[6] For the sake of simplicity, only the effects on capacity costs are illustrated in the following analyses. Thus, we implicitly assume a probability of being called of 0 %. A larger probability would not change the fundamental results regarding the efficiency of the selection of power plants for procuring balancing power.

Extramarginal power plants with higher variable costs cause higher total costs than extramarginal power plants with lower variable costs.[7]

However, if several hours are combined to one bidding period leading to a constant allocation of capacities during that period, efficiency automatically decreases in case of price volatility. During hours with low electricity prices, too many power plants with high variable costs are used to generate electricity and replace more suitable power plants, i.e. those with lower variable costs. During hours with high electricity prices, too many power plants with low variable costs are used to procure balancing power. This causes losses in overall efficiency and additional costs in comparison to the case where bidding periods are more homogenous with regard to the electricity price. These efficiency losses result both from increased costs on the balancing power markets and on the electricity wholesale market.

Example Illustrating the Effects of the Length of a Bidding Period

In the following, the effects of the length of a bidding period are illustrated for the simple case when two hours are combined to one bidding period. We assume that in both hours the set of power plants is the same and that variable costs do not change. However, variable costs are different for different qualities of power plants.

In this example, two different load levels are assumed. In the first hour, demand is supposed to be comparably high and the electricity price corresponds to the variable cost of a CCGT. In the second hour, the demand is supposed to be lower and the electricity price corresponds to the variable cost of a hard coal power plant. This is shown in figure 1. In the upper part of the figure, the electricity price equals the variable cost of a CCGT. The (opportunity) cost for procuring balancing power from the marginal power plant is zero. To the left of this, capacity costs of all inframarginal power plants are shown, which increase as the difference between variable costs and electricity price increases. To the right of the CCGT, capacity costs of extramarginal power plants are shown, which also increase as the difference between variable costs and electricity price increases. In the lower part of figure 1, the electricity price corresponds to the variable cost of a hard coal power plant. Here, this hard coal power plant has no capacity cost. Again, as the difference between variable costs and electricity price increases, capacity costs increase both for inframarginal and extramarginal power plants.

Efficiency requires that power plants with the lowest capacity costs are used on the balancing power market. If the two hours are treated independently, the power plants below the blue bars in the figure, i.e. the ‘efficient suppliers’, should be used in an efficient allocation on the balancing power market. In the first hour, these are almost only CCGT power plants, whereas in the second hour, mainly hard coal power plants are used to cover demand on the balancing power market.

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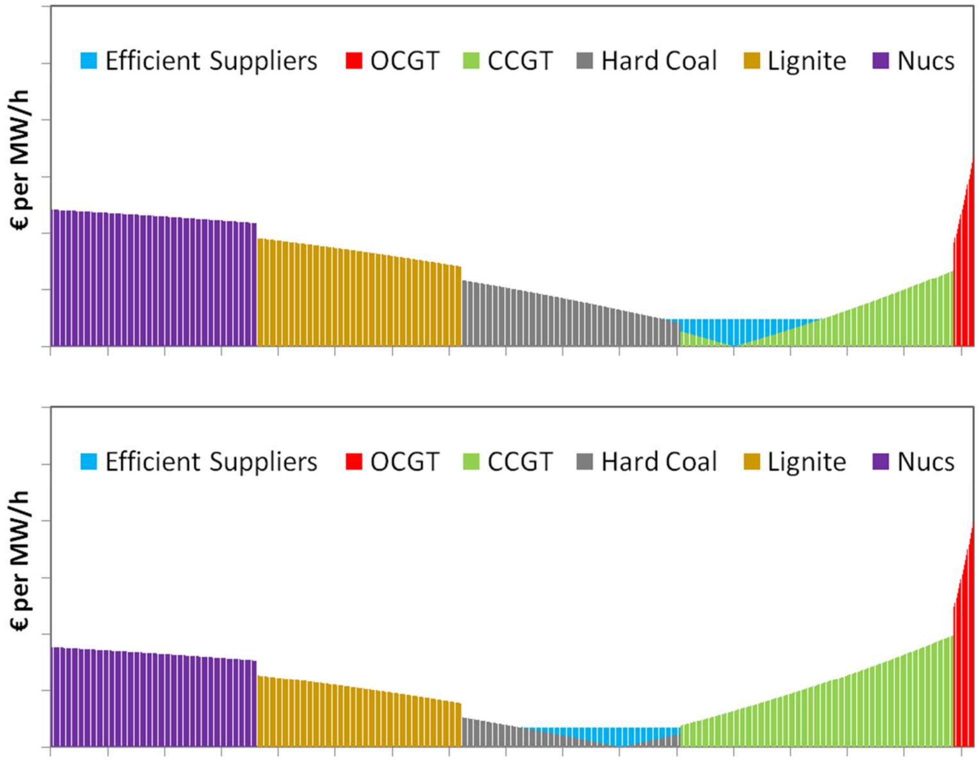
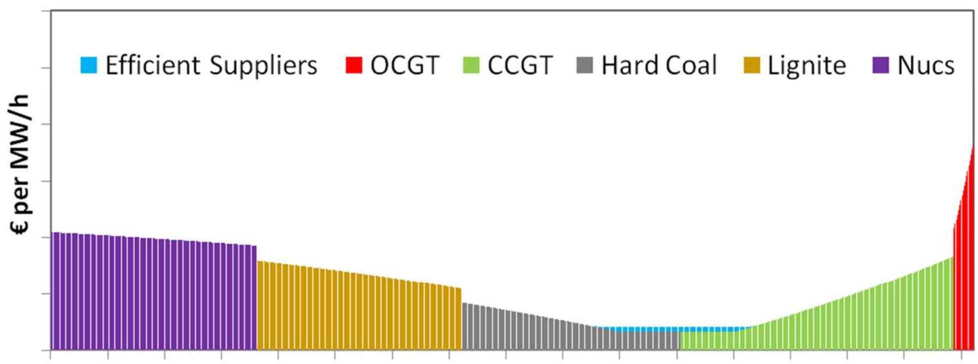
[7] While this might not be true when minimal load and/or load gradients for different technologies differ significantly, the general idea could be augmented to include this effect without changing the basic results.

Figure 1: **Capacity cost of spinning reserve depending on the electricity price at the wholesale market**



When combining the two hours, the costs for procuring balancing power in both hours have to be considered. Average capacity costs of the power plants are shown in figure 2. As the figure shows, no power plant has capacity costs of zero. This is because for each power plant the difference between the variable cost and the electricity price is larger than zero in at least one hour. The efficient suppliers for a bidding period of two hours consist of about half CCGTs and half hard coal power plants. Compared to the former case, in the first hour too many hard coal power plants and in the second hour too many CCGTs are used for procuring balancing power capacities. This increases overall costs.

Figure 2: **Capacity cost of spinning reserve in a bidding period of two hours**



Time between Auction and Beginning of the Bidding Period

This section deals with the uncertainty about the electricity price on the day-ahead market. In the last section we assumed that the electricity price in the bidding period is known to suppliers. This is approximately fulfilled for minutes reserve. Here we will focus on uncertainty regarding the electricity price in the case of positive secondary control power.

The day-ahead electricity price in a bidding period is a fundamental factor for capacity costs of balancing power. With a monthly auction, suppliers have to estimate this price far in advance. The forward price for the upcoming month is an estimator for the expected electricity price within that month.[8] However, uncertainty increases with time to delivery. In other words, the standard deviation of the difference between forward price (expected spot price) and realized spot price increases with the time span between the point in time of the auction and the point in time of the delivery. We will show by way of example that this uncertainty reduces efficiency because power plants have to commit to a state of operation when offering balancing power.

Assume that at the time of the auction the forward price for electricity for the bidding period is 30 € per MWh. For the sake of simplicity, it is furthermore assumed that the electricity price does not vary within the bidding period, i.e. the length of the bidding period is one hour. If there is no uncertainty regarding the realized electricity price, a supplier with variable cost of 30 € per MWh has a capacity cost of 0 € per MW and hour, because he has no opportunity cost on the spot market. If now uncertainty is taken into account, the supplier loses the power plant's optionality, i.e. the value of flexibility in operating the power plant. The reason is that the supplier has to commit to a state of operation (namely production with at least minimal technical load) when offering balancing power. This, however, causes opportunity costs: Suppose there are three possible realizations of the electricity price, 25, 30 and 35 € per MWh, which all occur with a probability of one third. Assuming that the supplier does not bid on the balancing power market, he conditions the actual production on the actual electricity price. If the day-ahead market comes out at 25 € per MWh, the supplier does not produce electricity. The resulting contribution margin is zero. At 30 € per MWh, the supplier is indifferent, the contribution margin is zero either way. With an energy price of 35 € per MWh, however, the supplier earns a positive contribution margin of 5 € per MWh by electricity generation with nominal load. The expected profit arising from the power plant's optionality therefore corresponds to 1.66 € per MWh, because with a probability of 66.7 % no profit is made and with a probability of 33.3 % a profit of 5 € per MWh is gained.

Suppose now the supplier offers half of the nominal capacity of the power plant as positive balancing power[9] and the power plant has a minimal technical load of 50 % of the nominal

[8] There may be a difference between expected spot and forward prices due to risk aversion of market participants. Under risk neutrality, the forward price should be an unbiased estimator of the expected spot price.

[9] We assume that the power plant's ramp rate is sufficient to offer the difference between minimal technical load and maximum load as balancing power. Otherwise, a small fraction of the power plants optionality remains. The only difference is a small reduction of the order of magnitude of the effect described in this section.

capacity. In this case, the power plant's optionality is reduced to zero. Regardless of the electricity price on the day-ahead market, the power plant must be operating at minimal technical load. With a realized electricity price of 25 € per MWh, the electricity price does not cover variable costs. Thus, the power plant suffers a loss on the spot market of 5 € per MWh multiplied with the amount of electricity generation in minimal technical load. If the day-ahead auction comes out at 30 € per MWh, no additional capacity costs arise, because variable costs are exactly covered by the electricity price. If the realized electricity price is 35 € per MWh, the power plant earns a profit contribution of minimal technical load (MW) times 5 € per MWh because the spot price exceeds variable costs. In total, the power plant loses money on the day-ahead market at a price of 25 € per MWh and earns the same amount if the price is 35 € per MWh. The probability weighted expected profit from the day-ahead market is zero. Hence, the difference to the situation where the plant did not provide balancing power is 1.66 € per MW nominal capacity and hour. Considering the minimal load condition (the plant can offer only 50% of nominal capacity on the balancing power market), the supplier's expected capacity costs are 3.33 € per MW balancing power capacity due to the uncertainty

The supplier will provide positive balancing power only if the expected overall profit under uncertainty, i.e. the expected profit on the day-ahead market plus the profit on the balancing power market, is at least equal the profit made when selling electricity on the day-ahead market only. Hence, the profit decrease on the day-ahead market of 1.66 € per MW nominal capacity due to an offer of positive balancing power is priced in as opportunity costs in the capacity bid on the balancing power market.

However, without uncertainty, there were no such commitment costs that would increase the capacity costs. If we assume a continuous supply function, three different plants would provide balancing power: a plant with variable cost of 25 € per MWh at a day-ahead electricity price of 25 € per MWh, a plant with variable cost of 30 € per MWh at a day-ahead electricity price of 30 € per MWh and a plant with variable cost of 35 € per MWh at a day-ahead electricity price of 35 € per MWh. Respective capacity cost would be zero in all three cases.

Our example shows that uncertainty regarding the electricity price at the time a bid is submitted increases costs for suppliers of balancing power.[10] If a supplier is uncertain about the price outcome on the day-ahead market, submitting a bid for balancing power leads to commitment costs: the supplier cannot adjust generation to the actual price on the day-ahead market.

Hence, the costs for balancing power procurement for a single power plant on the day-ahead market increase, especially when the plant's variable cost is close to the price on the day-ahead market. Efficiency in the market is reduced as well. The effect is similar to the one described in the last section. In both cases, an efficient adjustment of the allocation of power plant capacities between the day-ahead market and the balancing power market on actual prices on the day-ahead market is not possible. In the case of bidding periods with different

[10] This is especially relevant for suppliers 'at the margin' who are usually the most efficient suppliers of balancing power.

electricity prices on the day-ahead market this is due to fixing the balancing power capacities for several hours. In the case of uncertainties this is due to fixing balancing power capacities at a point in time when the electricity price is still uncertain. Regarding the resulting electricity price, different units would have been optimal.

The effect gets reinforced by the winners' curse: the costs of suppliers all depend on the expected day-ahead market price such that winning the auction implies that others are probably less optimistic regarding the expected profit on the balancing power market compared to the expected profit on the day-ahead market. In such cases, even risk neutral bidders would often adjust their bid in order to take into account that winning reveals information about others' spot price estimates ('winning is bad news'). As a result, uncertainty about the relevant spot price may increase bids and thus procurement costs for purely strategic reasons (see Ockenfels 2009 and the references cited therein for more details about the winners' curse effect).

There are other likely inefficiencies due to the timing of the balancing power markets. A long time between the auction and the bidding period can cause suppliers to reduce their offered generation capacities or even constitute a barrier to entry for small players. A supplier has to assure that accepted generation capacity is available during the whole bidding period. For example, if planned plant revisions lie within a bidding period, a supplier cannot bid for this plant’s capacity during the whole period. Similar problems occur for power plants whose maximal available generation capacity depends on the outdoor temperature, such as gas turbines, or for power plants which are used for district heating. In these cases, the ‘worst case’ scenario during the whole bidding period has to be taken into account for the calculation of possible offered balancing power capacities. To ensure the requirement of a work availability of 100 %, additional capacities to back up the accepted capacities in case of non-availability can be required. The shorter the bidding period is, the lower is this firmness of bids problem.

To sum up, we recommend to shorten the time between auction and bidding period. In combination with the results from the last section (shorter bidding periods), it seems natural to have more auctions for secondary control power held closer to bidding period, e.g. adapting the current design for minutes reserve in that respect. Both measures increase the efficiency in the balancing power market and facilitate the market entry of new competitors to enhance the degree of competition on the secondary control power market in particular. In addition, our suggested changes would lay the foundation for an improved integration of renewable energy sources into the electricity system. In the long run, accompanying changes in the legal framework may even enable generation from non-dispatchable renewable energy sources such as wind power to offer e.g. negative minutes reserve. Furthermore, the TSOs could calculate necessary amounts for balancing power capacities conditional on feed-in forecast for renewable energies.

Strengthening the 'Real Time' Market

Balancing power markets are closed after the end of the respective balancing power auction. This means that balancing power is only called from suppliers whose bids were accepted in the balancing power market. However, in principle it is also conceivable to give pre-qualified suppliers the opportunity to submit additional bids after the respective balancing power auction has ended. We propose that these bids would only consist of an energy price bid.

This could be done in two different ways. Firstly, already existing bilateral intra-day trades in Germany could be used. In the current form, these are insufficient to provide the services needed. Nonetheless, this trading could be expanded and adapted to the grid operators' needs. More precisely, a new product would have to be established, where a bidding period is not one hour long but only 15 minutes. Moreover, the time gap between purchasing balancing power and delivering the energy would have to be shortened.

Because of the more restrictive technical requirements, such a real time market seems not appropriate for secondary control power. In this case it is more adequate to allow pre-qualified suppliers to offer additional balancing power capacities directly to the system operator. Besides the energy price, a supplier could also choose the bidding period freely. The system operator would only have to define a minimal length of such a period, which depends on technical and organizational issues. This way, today's balancing power market would be extended by a 'real time' market for balancing power. This would lead to both increased competition and increased efficiency on the balancing power energy market.

Also, if there is a low auction frequency and bidding periods are comparably long, suppliers could benefit from such a 'real time' market. This is especially relevant for suppliers whose capacity price varies significantly during the bidding period because of volatile energy prices on the day-ahead market. Furthermore, it would reduce inefficiencies resulting from false predictions about this day-ahead energy price. And suppliers who could not submit bids because of planned revision times during for example some part of the bidding period could participate in this 'real time' market for the remaining bidding period.

Another advantage is that costs for spinning reserve would decrease during the very off-peak hours. A significant number of power plants are not shut down in these hours, even if they are 'out of the money'. Reasons for this can be start-up and shut-down costs as well as minimal idle and run times. Shut-down and start-up costs can be higher than the negative contribution margin caused by running at minimal technical load. During such a period of time, these power plants can provide balancing power with capacity cost of zero. Hence, their generation capacity could be bid in the real time market with an energy price corresponding to their variable cost. This would increase both competition and efficiency in the balancing power market.

When introducing such a real time market, trade-offs between potential advantages arising from both a higher degree of competition and increasing efficiency and disadvantages because of additional organizational requirements need to be considered. Especially if bidding frequencies stay on a low level and bidding periods are kept long – as for instance with secondary control power – one might expect a significant number of potential suppliers in this real time market.[11]

CONCLUSION

This article investigates various timing issues in balancing power markets. We argue that efficiency can be increased in the German balancing power market by reducing the length of the bidding periods, especially in the market for secondary control power. Currently, inefficiency arises from combining different hours in one bidding period. We show that different load levels require different plants for an optimal (cost minimal) provision of balancing power. In a bidding period of e.g. one month, the power plants that have the lowest cost in the average of the month are unlikely to be efficient in all hours of the months – even if the differentiation of HT and NT eases this problem slightly. In addition, the commitment to provide balancing power during one whole month might serve as a barrier to entry especially for smaller players. Firstly, if they provide balancing power, they have to produce during all HT (or NT) hours of the month – regardless of the electricity price. This might mean incurring losses during numerous hours. Secondly, it is more likely that a given plant fails to deliver balancing power if the commitment to deliver covers a whole month. Hence, we conclude that a reduction of the length of bidding periods on the German balancing power market could increase efficiency and the degree of competition on both the market for minutes reserve and the market for secondary control power. This is especially relevant on the market for secondary control power.

We also analyze the time between the auction and the bidding period. We show that an early commitment on a power plant's mode of operation (when uncertainty about resulting spot prices is still relatively high) also reduces efficiency. Hence, the auction should be held relatively close to the beginning of the bidding period.

Finally, we discuss the possibility of embedding parts of the balancing power trading into the real time market in Germany. So far, this market is rather illiquid. However, suppliers of balancing power, TSOs and the competitiveness of balancing power trading could profit significantly from strengthening this market if the right products (e.g. concerning the length of bidding periods) were traded.

[11] Another advantage of a stronger real time market is improved scarcity pricing, which in turn improves investment decisions and thus long run reliability of electricity markets (see Cramton and Ockenfels 2011).

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