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Tender Frequency and Market Concentration in Balancing Power Markets

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Abstract

Balancing power markets ensure the short-term balance of supply and demand in electricity markets and their importance may increase with a higher share of fluctuating renewable electricity production. While it is clear that shorter tender frequencies, e.g. daily or hourly, are able to increase the efficiency compared to a weekly procurement, it remains unclear in which respect market concentration will be affected. Against this background, we develop a numerical electricity market model to quantify the possible effects of shorter tender frequencies on costs and market concentration. We find that shorter time spans of procurement are able to lower the costs by up to 15%. While market concentration decreases in many markets, we – surprisingly – identify cases in which shorter time spans lead to higher concentration.

Keywords: Balancing Power, Market Design, Market Concentration, Tender Frequency, Provision Duration, Mixed Integer Programming

JEL classification: D47, L94

1. Introduction

In electricity markets supply and demand need to be equal at all times and commonly transmission system operators (TSOs) are in charge of balancing supply and demand. Due to unbundling policies TSOs are not allowed to own generation assets and need to procure short-term flexibility from operators of power plants. These power plants need to be able to adjust their production on short notice to balance supply and demand.

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In Germany, balancing power is currently procured on a weekly basis for primary and secondary balancing power. Operators that offer for example positive balancing power therefore need to withhold production capacities over the time span of a whole week and can not sell their full capacity into the spot market. The costs that arise from balancing power provision are thus based on the opportunity costs with respect to selling the capacity in the spot market, namely the foregone profits from spot market operation.

In this paper, we take a closer look at the German balancing power markets with a special focus on two problems that may arise from the current (weekly) market design. First, the weekly procurement leads to inefficiencies as operators need to withhold capacities for a whole week and can not fully participate in the hourly spot market. There is a missing market for hourly balancing power products that could be solved by an hourly procurement of balancing power. Secondly, we observe that large players with a broad portfolio of power plants are able to provide balancing power at lower costs, especially in a weekly auction. These economies of scale for large players may lead to highly concentrated markets and the possible abuse of market power.

Whereas in theory it is well understood that shorter time spans lower costs and may increase market concentration, the magnitude of a change in market design towards shorter time spans remains unclear. In order to assess the possible impact, we develop a numerical model that accounts for the operator structure in the balancing power market and considers different time spans for balancing power procurement. Based on the model we are able to quantify the effects of different market designs (weekly, daily, hourly) on system costs and market concentration.

The modeling of balancing power markets is complex, as it is driven by the opportunity costs of operators. Just and Weber (2008) started to write down this problem analytically and solved the simplified model numerically. Later the methodology was again applied by Just (2011) to analyze the implications of different tender frequency on the procurement costs but without considering the operator structure. Richter (2012) bases his analysis on the model developed by Just and Weber (2008) and is able to show the existence of a competitive simultaneous equilibrium in spot and balancing power markets that is unique and efficient. He finds out that the bids of the capacity providers form a u-shaped bidding function around the spot demand. This work shows that the integrated modeling of spot and balancing power markets in a fundamental model as it is done in the analysis at hand yields meaningful results. In addition, the equilibrium of the spot and balancing power market was further analyzed by Müsgens et al. (2014) in the context of the German market design.

The procurement of balancing power is commonly organized via auctions. A special characteristic of the balancing power procurement process is that the cost structure of participants can be divided into two parts. One part is fixed for a period and stems from withholding capacity for balancing purposes. The second part are variable costs for the supply of energy in the case of being called during operation. Bushnell and Oren (1994) were the first to analyze the auction design of balancing power markets. Their work was later extended by Chao and Wilson (2002) in order to design incentive compatible scoring and settlement rules. They found that incentive compatible auctions can be designed by considering only the capacity bid for scoring in a uniform price auction. Nevertheless many of the implemented auction designs in Europe differ from their proposals.

The auction design of balancing markets was also studied by Müsgens et al., who analyzed the importance of timing and feedback (Müsgens and Ockenfels, 2011; Müsgens et al., 2012). The development in the tertiary reserve market and the change in rules was analyzed by Haucap et al. (2012). They find that the cooperation of the four TSOs in Germany decreased costs for the procurement of tertiary reserve.

Whereas previous literature focuses on the efficient design, high market concentrations are an additional issue in balancing power markets with few big operators. In 2010, Growitsch et al. (2010) analyzed the operator structure in the tertiary balancing power market. They find high market concentration in certain situations of the tertiary balancing power market. Heim and Götz (2013) looked at the market outcomes in the German secondary reserve market based on exclusive data provided by the BNetzA and find that the price increase in 2010 can be traced back to the bidding behavior of the two largest firms.

While the general effects of a design change towards shorter spans is well understood, the empirical importance is less clear. To contribute to filling this gap, we simulate a design change for the German balancing market. We compare simulation results for the current market design to simulation results for shorter time spans. From the comparison of the results, we derive a difference of 15% balancing cost in favor of shorter time spans. With respect to concentration, our model results indicate that an hourly market design for balancing power leads to periods with higher market concentration. This means that in some hours market concentration could increase by a change of market design from weekly to hourly and policy makers should be aware of this.

The paper is organized as follows: In Section 2 we focus on the background information which include, among others, the general electricity market structure, bidding behavior for balancing power and the concepts of market concentration indices. Section 3 introduces the methodology, namely a unit-commitment model for electricity markets and the model specifications to account for the balancing power markets. Section 4 presents the modeling results as to the system costs and the market concentration indices. Section 5 concludes.

2. Background

2.1. On the Functioning of the Balancing Power Market

The balancing power market is an additional market for electricity generators, besides the classic spot markets like the day-ahead and intraday market and is divided into products depending on the urgency and the direction of power provision. In Germany, the markets are divided into primary, secondary and tertiary balancing power provision which differ mainly in reaction time. In the primary balancing power market, power plants need to be able to adjust their output in both directions (upward and downward). Secondary and tertiary balancing power markets are divided into products for positive and negative balancing power. The secondary balancing power market is further divided into a peak and off-peak product. Additional information on the current market design can also be found in Hirth and Ziegenhagen (2015).

Because the balancing of imbalances has to occur in very short time periods before physical delivery, providers of balancing power have to reserve capacity for balancing purposes (save fuel costs in case of negative balancing purposes). This means for example that an operator for positive balancing power cannot sell all her production capacity into the spot market and needs to operate power plants below the maximum capacity level. When being called for the supply of balancing power, the power plant needs to increase its output. For the case of negative balancing power provision, operators need to run their plants above their minimum production capacity and when negative balancing power is called, these plants have to be able to decrease their electricity production.

The cost structure of participants in the balancing power market is thus different compared to the spot market. On the one side, participants must account for opportunity costs that arise from the opportunity of marketing the spare capacity in other power markets (such as day-ahead and intraday) and on the other side participants need to pay fuel costs in case that their plants are being called for balancing purposes. The opportunity costs for capacity provision mainly depend on the type of power plant and the prices that are being observed in the markets where the power could also be sold. For example, a power plant that has marginal generation costs a bit lower than the spot market price, has very low opportunity costs for positive balancing power provision. If this power plant decreases its spot market production in order to offer positive balancing power, the income from the spot market is only slightly lowered. The opportunity costs for the provision of positive balancing power are thus close to zero.[1] In contrast to this, if the power plant

[1]This holds only true if efficiency losses due to partial load operation are neglected.

has very low marginal costs of production compared to the spot price, the opportunity costs for positive balancing power provision are very high, as the forgone spot market profits are very high. Figure 1 shows the opportunity costs for different ranges of the merit order.

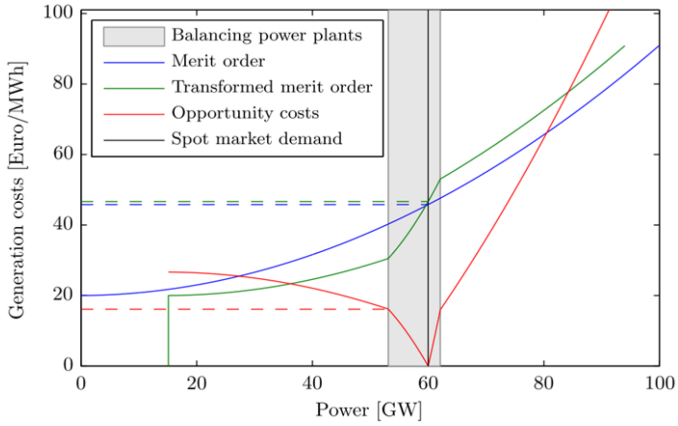


Figure 1: Capacity bidding behavior for balancing power markets is theoretically based on an opportunity cost strategy to the spot market (here: positive balancing power)

The demand of electricity depends mainly on the time of consumption and fluctuates throughout the day. Therefore prices fluctuate as well. This means opportunity costs of single power plants are constantly changing and providers of balancing power need to take this into account. For the case of operators owning multiple power plants with a well diversified portfolio this effect is not as severe because in the best case they are always operating a power plant with marginal costs close to the spot price that has very low opportunity costs. This makes it obvious that bigger power plant portfolios may have significant cost advantages compared to small players.

In order to illustrate the effect of the portfolio on the opportunity costs, we consider the following example which is visualized schematically in Figure 2: Let us assume that there are three power plants A, B, and C with the same capacity but different marginal costs of 10, 20 and 30 EUR/MWh. With an ordering according to the marginal costs, we derive the simplified spot market merit order. The spot market clearing price is thus the intersection of the demand function with the merit order. The opportunity costs for positive balancing power arise by the difference of the power plants' marginal costs to the spot market clearing price. Thus, the opportunity costs are dependent on the spot market demand situation. Now, let us consider two demand situations: A low and a high spot market demand situation. In the low demand situation, the demand is lower than the total capacity of plant A. Hence, the cheapest power plant A can satisfy the total spot market demand resulting in a spot market clearing price of 10 EUR/MWh. This leads to opportunity costs of 0, 10 and 20 EUR/MWh for A, B and C respectively[2] (shown in Figure 2 on the lower y-axis part). In the high demand situation, the demand exceeds the joint capacity of plant A and B. Therefore, plant C determines the spot price of 30 EUR/MWh, which results in opportunity costs of 20, 10 and 0 EUR/MWh for A, B and C respectively. If we assume that power plants need to provide the positive

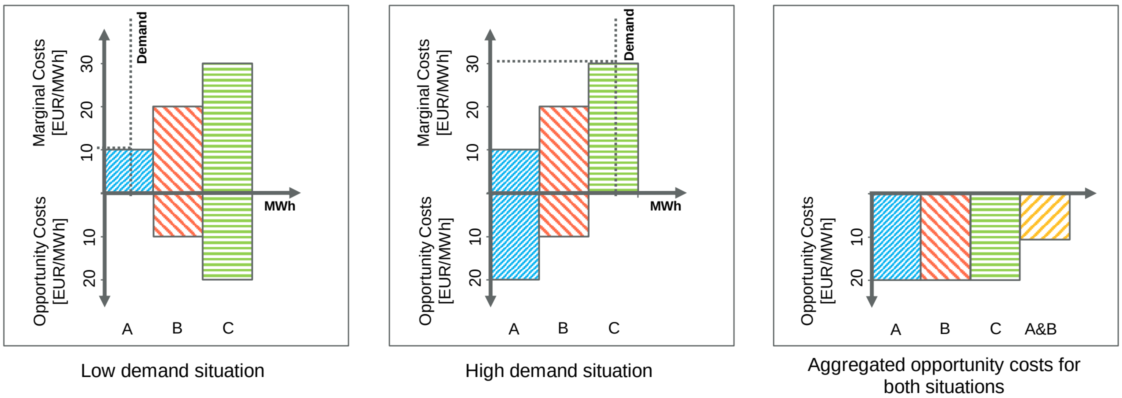


Figure 2: Schematic situation of the portfolio effect

balancing power for both situations, the opportunity costs in each situation sum up for each power plant:

$$TotalOpportunityCosts(p) = \sum_{i=low,high} OpportunityCosts_i(p) \qquad , \forall p \in \{A, B, C\} \tag{1}$$

This results in total opportunity costs of 20 EUR/MWh for each power plant. A coalition of two power plants could reduce the joint opportunity costs. Power plants A and B could cooperate, e.g. belong to the same operator. Then, in each situation the operator can provide balancing power by her power plant with the lowest opportunity costs. She would use plant A in the low demand situation, and plant B in the high demand situation. The joint opportunity costs for power plant A and B for both situations is 10 EUR/MWh, which is lower than the individuals' 20 EUR/MWh. For the negative balancing power, this portfolio effect does not hold in general. The opportunity costs are 0 for inframarginal power plants and usually monotonically increasing for extramarginal power plants. This leads to monotonically increasing opportunity costs in each demand situation. The sum of monotonically increasing functions is still monotonically increasing. Thus, the cheapest power plants to provide negative balancing power are always in the left segment of the merit order and there is no possibility to get better off with a coalition with another power plant. Note that we assumed no part load efficiency and attrition costs in this example. Furthermore, we assumed the balancing

[2]We assume that power plants need to run in order to provide positive balancing power (e.g. due to minimum load or ramping constraints). If plants B and C would not need to run, their opportunity costs would be 0 EUR/MWh.

power demand to be small such that the marginal power plant can fully provide the balancing power demand.

The portfolio effect only occurs if balancing power is procured over a long time horizon that differs from the hourly spot market tender frequency. Here, large players may have significant cost advantages because they can provide balancing power at lower costs from their portfolio. For shorter time periods of balancing power procurement, the portfolio effect is reduced.

In Figure 3, an exemplary merit-order for Germany divided into the main operators is shown. Power plants that do not belong to the largest five companies are considered as power plants of a fringe.[3]

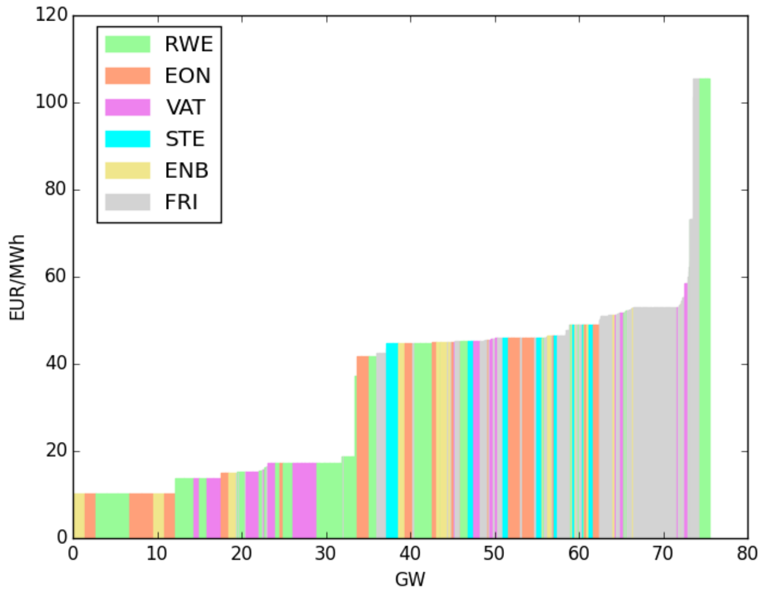


Figure 3: Merit Order in Germany colored as to the operators

As previously explained, opportunity costs in the balancing power market do strongly depend on the intersection of supply and demand in the spot market. Therefore, to investigate market concentration, we need to consider the power plant portfolio of all operators in the merit order (cf. Figure 3). We can see that several ranges are covered by only a few operators. Especially, in the left part of the merit order, there are only two to three operators covering a range of up to several Gigawatts. These are operators owning nuclear and lignite power plants with high investment costs and low marginal costs.[4] Those ranges with few operators tend to favor market concentration. By incorporating the operators and their power

[3]Throughout the paper we use the following abbreviation for the operators: RWE (RWE), E.ON (EON), Vattenfall (VAT), STEAG (STE), EnBW (ENB), fringe (FRI).

[4]Note that the fringe at the right of the merit order does not cause higher market concentration, because those plants do not belong to a single firm.

plant portfolio into our modeling, we are able to show the effect of different provision duration on market concentration.

2.2. Market Concentration

In order to compare different levels of market concentration, we apply typical market concentration indices from the economic literature. Those indices are the Herfindahl-Hirschmann-Index (HHI, Hirschman (1964)) and the residual supplier index (RSI).[5]

The HHI uses the market shares of operators as an indicator for market concentration. It is defined as

$$HHI := \sum_{i=1}^{n} {MS_i}^2 \tag{2}$$

where MS_i is the market share of operator i in % and n the total number of operators.[6] Note, that we use the decimal representation of the market shares (50% = 0.5). Therefore, our HHI index is in the range between 0 and 1. Comparable high market shares have an higher impact to the HHI due to the squared functional representation. If we would have only five operators in the electricity market, the HHI could not be lower than 0.2 which would be the case of equally shared capacity. Since we also consider a fringe in our numerical analysis, these lower bounds are not necessarily holding. Based on the described indices we are able to compare the effects of different market designs on market concentration.

The RSI for operator x measures the remaining capacity without supplier x's capacity to fulfill the demand. It is defined as

$$RSI(x) := \frac{\text{TotalCapacity} - \text{Capacity}_x}{\text{demand}}, \tag{3}$$

where Capacity_x is the the capacity of operator x (cf. Twomey et al. (2006)). In our analysis, we account only for active capacity which means capacity that is already operating. Non-operating capacities cannot provide balancing power in time or have additional start-up costs which make the opportunity costs non competitive. For comparison reasons, we focus on the inverse value, i.e. RSI^{-1}. Thus, similar to HHI, a higher value indicates higher market concentration

The HHI represents a market concentration index based on the market share while the RSI represents

[5]We do not focus on the pivotal supplier index (PSI), since the non-binary RSI is a refinement of the binary PSI. Furthermore, we do not investigate market concentration indices which involve prices, e.g. Lerner-Index (Elzinga and Mills, 2011) Because we are applying a mixed-integer model, prices cannot be easily derived from the results due to the convexity problem (cf. (Bjørndal and Jörnsten, 2008; Ruiz et al., 2012)). Technical restrictions like minimum load or start-up costs in mixed-integer problems lead to non-convexities. Therefore, the marginal of the supply-demand-equilibrium cannot directly be interpreted as an estimator for electricity prices. Power plant specific variable costs can be above the system marginal costs of mixed-integer problems.

[6]The HHI is broadly applied in energy economics, see for instance Hogan (1997) and Twomey et al. (2006). A general discussion on concentration indices can be found in Green et al. (2006).

a market concentration index based on the residual supply (remaining capacity). Both measures therefore give different insights on the level of market concentration.

3. Methodology

In this section, details of the basic modeling approach as well as data and assumptions are presented.

3.1. Modeling Approach

The analysis is performed with a unit-commitment model for the German power market.[7] The basic model formulation is based on the work by Ostrowski et al. (2012) and Morales-España et al. (2013) and is extended for the modeling of balancing power provision.

In this article, we explain the general modeling approach for unit-commitment models but abstract from the detailed formulation that can be found in the literature on unit-commitment models (e.g. Ostrowski et al. (2012) and Morales-España et al. (2013)). The focus is set on the introduction of additional equations that account for the characteristics of balancing power markets.

The overall goal of the unit-commitment model is to derive the cost minimal production schedule of power plants to satisfy the demand for electricity. Power plants are modeled blockwise on an hourly time resolution. Power plant blocks are denoted by index p and hourly timesteps by index t. The objective function of the unit-commitment model is to minimize the total costs of electricity production and can be expressed as

$$\min TotalCosts = \sum_{t,p} \left(VarCosts(t,p) + StartUpCosts(t,p) \right). \tag{4}$$

StartUpCosts arise if a power plant is not producing in time step t but produces electricity in time step $t+1$. The actual *StartUpCosts* are dependent on the power plant p as well as on the non-production duration (time steps since last time operating). Power plants produce electricty to satisfy the demand. This essential constraint is represented as

$$\forall sm: \qquad \sum_{p_{sm}} production(p_{sm}) + import(sm) - export(sm) = demand(sm) \tag{5}$$

and holds for every time step t and every spot market sm. Here, p_{sm} are the power plants in spot market sm, *import* considers the electricity flow from other countries (spot markets) to the respective one and vice

[7] The model builds on the modelling framework **MORE** (**M**arket **O**ptimization for Electricity with **R**edispatch in **E**urope) that was developed at *ewi Energy Research and Scenarios gGmbH* and is written in GAMS (further information can be found at http://www.ewi.research-scenarios.de/en/models/more/).

versa for *exports*.[8] The exogenous demand is assumed to be perfectly inelastic.[9]

Technical characteristics of power plants are modeled via different constraints. An important modeling aspect of unit-commitment models is that it accounts for different states of power plants that can be incorporated by using binary variables. This makes the model a mixed-integer model. For example, each power plant has a range of feasible production which can be described by

$$production(p) = 0 \qquad \text{or} \tag{6}$$

$$minload(p) \leq production(p) \leq capacity(p). \tag{7}$$

Additional technical constraints of power plant blocks can also be incorporated, such as part load efficiency losses, load change rates, combined heat and power operation and start up times.

The basic model is extended to account for the unique characteristics of balancing power markets. These characteristics are essentially given by (i) different provision intervals and (ii) operator structures. We therefore need to map the hourly timesteps to the balancing provision intervals as well as the different power plant blocks to operators.

Set	
BPi	interval for balancing power provision, e.g. week, day or hour
op	operator
t	hour
p	powerplant
t_BPi	set of hours that are in the respective interval for balancing power provision
p_OP	set of plants that belong to respective operator
FRI	Fringe operators
Parameters	
D(BPi)	balancing power demand in interval
Variables	
BP_O(BPi, op)	balancing power provision by operator in interval
BP(t, p)	balancing power provision by plant and hour
BP_F(BPi, p)	balancing power provided by fringe operators in the interval

Table 1: Overview of sets, parameters and variables

Table 1 gives an overview of the sets, parameters and variables used for the modeling of balancing power. In the following, the equations of the model will be discussed.

[8]In the analysis at hand, only the German spot market is considered. Imports and exports are given exogenously as explained later.

[9]If this assumption would be relaxed, we expect a similar outcome with respect to balancing power provision, since the intersection point of demand and supply curve at the spot market, and hence the relevant opportunity costs would not change.

The total demand for balancing power during a provision interval must be satisfied by the sum of the provision of all operators:

$$\forall \quad BPi: \sum_{op} BP\_O(BPi, op) = D(BPi). \tag{8}$$

The balancing power provision of all operators during a provision interval is constituted by the provision of the plants of the operators in each hour:

$$\forall \quad BPi, \quad t \in t\_BPi, \quad op: \sum_{p \in p\_OP} BP(t,p) = BP\_O(BPi, op). \tag{9}$$

The balancing power provision of the fringe during the provision interval is constituted by the fringe power plants without the option to pool:

$$\forall \quad BPi: \sum_{p \in p\_OP(\text{“}FRI\text{”})} BP_F(BPi, p) = BP\_O(BPi, \text{“}FRI\text{”}). \tag{10}$$

The power plant specific balancing power provision of fringe power plants is fixed in each hour of the provision interval:

$$\forall \quad BPi, \quad t \in t\_BPi, \quad p \in p\_OP(\text{“}FRI\text{”}): \quad BP_F(BPi, p) = BP(t,p). \tag{11}$$

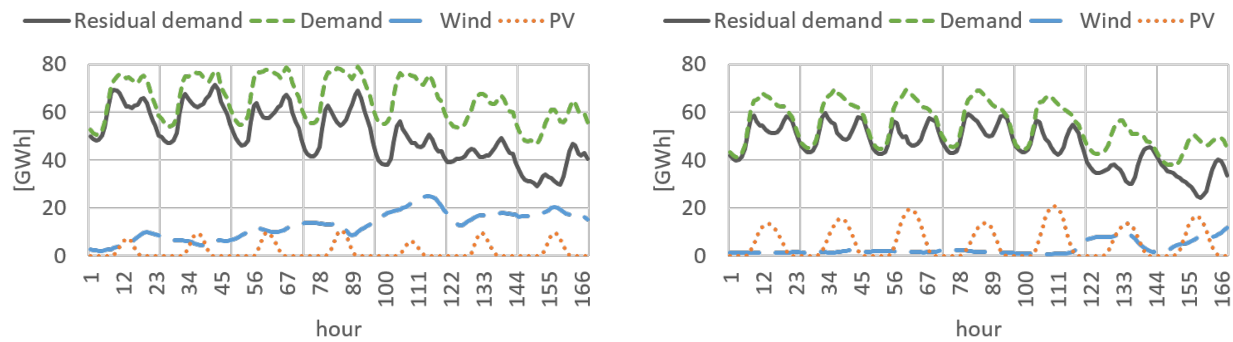
Thus, the model allows the fundamental modeling of power plants that provide balancing power accounting for the operator structure. However, calls of balancing power are not modeled. Model outputs are the hourly production per power plant, as well as, balancing power provision by operator and power plant. In combination with the operator structure, we can evaluate market concentration indices in an ex-post analysis.

3.2. Input Data and Assumptions

We model two representative weeks in 2014, i.e. a winter week and a summer week. Figure 4a shows the demand, residual demand, solar feed-in and wind feed-in during the winter week. This winter week represents a typical situation of high demand in the early evening hours combined with no or very few solar radiation during the day. Especially at the beginning of the week, the wind production is low as well. As a result, there are situations with a residual demand of up to 71.2 GW in which the conventional power plant fleet (nuclear and fossil power plants, pumped storage plants) is utilized up to 69.3%. In the last three days of the week, the residual demand is low due to low demand during the weekend and high wind feed-in. In such a situation of low residual demand, the base load power plants supply a large share of the spot market demand. Since the base load plants are owned by the large operators, situations with low demand may show a high market concentration in the spot market. This has implications for the market concentration on the balancing power markets as well.

Figure 4b shows the demand, residual demand and renewable feed-in in the summer week. It can be seen that there is a contrast to the conditions of the winter week. The demand in summer is typically low and there is high solar radiation during the day. This combination leads to a reduced utilization of the power plant fleet and therefore to lower prices. Here, even base load and mid load German power plants (lignite and hard coal power plants) reduce their production. Wind feed-in is on a relatively low level (below 10 GW in every hour), but increases during the weekend when the demand is already especially low. This leads to a low residual demand of only 24.3 GW on the Sunday.

Typical weeks during spring and autumn can be interpreted as a combination of the situations in those weeks. The varying demand and renewable feed-in in every single hour of those weeks cover a broad range of situations and therefore reflect also average situation with medium demand and/or renewable feed-in.



(a) Winter Week (Monday-Sunday)

(b) Summer Week (Monday-Sunday)

Figure 4: Demand, Residual Demand, Solar Feed-In and Wind Feed-In

The assumptions on power plant capacities are based on Bundesnetzagentur (2014). Only German power plants are modeled. Imports and exports are exogenously given based on ENTSO-E data. Fuel costs and CO_2 prices are based on historical data. Installed capacities, fuel costs and techno-economic parameters of power plants can be found in the Appendix.

Power plants are also constrained in their balancing power provision. We consider primary and secondary balancing power in our model, but abstract from tertiary balancing power provision.[10]

[10]We do not consider tertiary balancing power since (i) technical restrictions are lower for the tertiary market and it tends to be compensated by the intraday-market (30 min before physical delivery), (ii) the current market design of tertiary balancing

We assume that all running plants can provide a certain share of their capacity as balancing power. For the fossil and nuclear power plants, this share is derived by information about the ramping speeds multiplied by the time duration until the power adjustment needs to be realized. The ramping speed deviates by the year of construction of the technology. Furthermore, we assume that the capacity (share) for positive balancing power is the same as for negative balancing power. Table 2 shows the maximum allowed share of the capacity to provide balancing power for different power plant technologies.[11] We assume that

	primary balancing power	secondary balancing power
CCGT	2.50 - 4.00%	25.00 - 40.00%
Coal	1.00 - 2.50%	5.00 - 12.5%
Lignite	1.00 - 2.50%	5.00 - 12.50%
Nuclear	2.00 - 2.50%	10.00%
OCGT	5.00 - 12.50%	50.00 - 60.00%
Oil	2.00%	20.00%
Pumped Storage	10.00%	15.00%

Table 2: Share of total capacity that can be used for balancing power provision

power plants that are not running have high starting costs, e.g. due to attrition and fuel consumption, and thus are not competitive in offering balancing power.[12] We do not consider balancing power provision by renewables and demand side management, because those technologies were not important for the balancing power market in 2014 (Dena, 2014).

There is only one product that is procured for primary balancing power. However, in the case of secondary balancing power, we consider a positive and negative product for peak and off-peak times, respectively. Additionally we investigate the cases of shorter tendering times, namely daily and hourly. In the case of a weekly provision, the peak time are working days between 8 am and 8 pm. All other hours (night and weekends) are off-peak time. In the case of a daily provision, the peak time is the time between 8 am and 8 pm on every day (including weekends). In an hourly auction, the distinction between of peak and off-peak products disappears.

We map the information about the ownership to each power plant. We consider the German power

power has already a high tender frequency (provision duration of four hours), and (iii) there are many competitors in the tertiary market which reduces the risk of market power. Therefore, primary and secondary balancing power are in the focus of our analysis.

[11] Pumped storage plants have a high ramping speed. Therefore, they have a high technical potential to provide balancing power (up to 30 % of the capacity for the primary balancing power, and up to 45% for the secondary balancing power for a single plant). However, due to multiple bidding strategies and prequalification requirements, we assume that not all pumped storage plants are bidding their total technical potential into the balancing power markets.

[12] Start-up costs for a cold start can be up to 60.000 Euro for e.g. a 500 MW CCGT or OCGT power plant with 2010 cost data (Schill, 2016). These costs would have to be reimbursed by the revenue in the balancing power markets. Additionally, a faster start-up than usually increases the attrition and has a higher consumption of equivalent operating hours (EOH).

plant operators E.ON, RWE, EnBW, Vattenfall and STEAG in our model. All other power plants are mapped to the fringe. We obtain information about ownership of plants from a list of the German regulator Bundesnetzagentur.[13]

E.ON, RWE, EnBW, Vattenfall and STEAG can use pooling to provide balancing power over a time period, e.g. they can offer a certain volume of balancing power during the provision period and use different power plants within their pool to fulfill their commitment. The fringe is not allowed to pool meaning that each power plant of the fringe has to provide the balancing power of the whole provision period. This is the most restrictive assumption for the pooling of the fringe. Indeed, there are several pooling companies which aggregate smaller producers to a virtual power plant and therefore allow for pooling for subsets of the fringe. However, if we allow that the whole fringe may use pooling effects, the fringe would operate as an additional big producer. Therefore, we expect that the general results for market concentration hold and only the absolute level of market concentration deviates.[14]

4. Results

In this section, we present the model results for a weekly, daily and hourly provision duration. The weekly provision duration represents the status quo which is currently in opertation in Germany. Daily and hourly provision duration are currently discussed as alternative market designs for the German balancing power market. We analyze the balancing power provision in three dimensions. First, we focus on the efficiency gains by a shortened provision duration which are captured in the total system costs. Second, we analyze the balancing power provision by technology and operator which enables us to shed light onto the level of market concentration for the different provision duration using the indices HHI and RSI^{-1}.[15]

4.1. System Costs

Power system costs of different model configurations are a benchmark for the efficiency of the market design. In order to assess the costs of balancing power provision, we additionally model the electricity system without balancing power provision. The difference between this baseline run and the model runs with balancing power provision can thus be considered as the extra costs of balancing power provision.[16]

[13]Each power plant is mapped to only one owner. This corresponds to the assumption that even if several owners have shares in one plant, only one owner is responsible for marketing balancing power.

[14]Furthermore, fringe power plants are typically gas fired power plants. Therefore, the effect on market concentration affects only situation with high residual demand as to the opportunity cost bidding strategy and the merit order.

[15]Note that we use RSI^{-1} instead of RSI. Thus, a higher value of RSI^{-1} indicates higher market concentration, similar to the interpretation of HHI.

[16]When referred to balancing power in this section, primary and secondary balancing power is meant.

Table 3 gives an overview of the total system costs in the simulated summer and winter week with different designs of the balancing power markets. Irrespective of if and how balancing power is provided, it can be seen that the system cost in the winter is more than EUR 50m higher than in the summer.

in mio. Euro	no provision	hourly	daily	weekly	weekly (no pooling)
Winter	175.6	176.7	176.8	177.0	178.0
Summer	124.6	125.1	125.2	125.2	125.6

Table 3: Total System Cost in Reference Scenario in Million Euros

As outlined above, the major power plant operators are allowed to pool their portfolio in order to provide balancing power. In order to quantify the efficiency gain resulting from pooling, a sensitivity with weekly balancing power provision in which pooling is not allowed is simulated additionally to a weekly configuration with pooling and hence included in Table 3.

The difference between the system costs without balancing power provision and the system costs of a configuration with hourly / daily / weekly balancing power provision can be understood as the respective costs of balancing power provision. Figure 5 illustrates those costs. It can be seen that not only the total modeled system costs are higher in winter, but also the costs of balancing power provision. This is expected given the higher residual demand levels in the winter.

If pooling would not be allowed, the cost of balancing power provision would be EUR 2.361m in the winter week and EUR 0.995m in the summer week. The modeled costs of the current weekly market design (with pooling of major operators) amount to EUR 1.328m in the winter week, and EUR 0.677m in the summer week. The cost difference between the weekly configuration with pooling and without pooling, that can be interpreted as the efficiency gain of pooling, is EUR 1.033m in the winter and EUR 0.319m in the summer.[17]

The difference between the system costs of a configuration with weekly balancing power provision and a configuration with hourly balancing power provision (from now on we only consider configurations with pooling) can be interpreted as the maximum efficiency gain from shortening the provision duration. This cost difference is EUR 222k in the winter week, and EUR 96k in the summer week.[18] The system costs of the daily balancing power provision are between the system costs for the hourly and weekly balancing power provision. Compared to the efficiency gain from pooling, this further efficiency gain by a shortened provision duration is small.

[17] An additional sensitivity analysis not included in figure 5 in which pooling of all fringe operators in one common fringe pool would be allowed shows no significant further efficiency gain.

[18] Due to solver inaccuracies (difference between current best integer solution and optimal value of LP relaxation), we cannot resolve the exact effect. However, we can be sure about the order of magnitude of the effect.

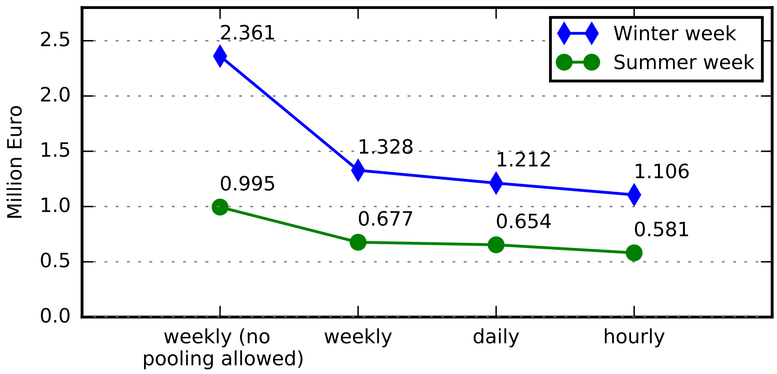


Figure 5: Costs of primary and secondary balancing power (compared to no provision)

The level of renewable feed-in can influence those results. Therefore, we consider a sensitivity in which we double the values of the historically observed renewable feed-in in the simulated weeks. The detailed results are shown in AppendixB. A higher renewable feed-in leads to higher costs of balancing power provision especially in the summer week compared to the configuration with less renewables. For instance, in the case of weekly provision in the summer, the balancing power costs increase by EUR 559k if the renewable feed-in doubles. Due to the lower residual demand, more power plants have to be operational only in order to provide balancing power. The order of magnitude of the efficiency gain from pooling, however, remains unchanged by doubling the renewable feed-in.

The German expenses for the provision of primary and secondary balancing power was EUR 331m in 2014 (Bundesnetzagentur, 2016) corresponding to average expenses of EUR 6.37m per week.[19] This means that the average real expenses were higher than the simulated costs for the balancing power market with the weekly market design (EUR 1.328m in the winter and EUR 0.677m in the summer). Our model calculates *total costs* for power plants to provide balancing power under perfect competition and foresight. Those can be interpreted as a lower bound for producers' costs for the balancing power provision. The Bundesnetzagentur publishes the *total expenditures* for the balancing power provision. These expenditures also include producers' surplus. If every operator would bid their real costs in the pay-as-bid auction (under perfect foresight and perfect information), both results should be the same. However, since it is profit maximizing for the operators to estimate and bid the system marginal costs instead of own marginal costs (see for instance Müsgens et al. (2014)), the real expenditures are higher than the modeled costs for provision. Furthermore,

[19]This figure is calculated based on capacity bids, not energy bids. This is consistent with our modeling approach in which we consider only provision and not calling of balancing power.

the exercise of market power (e.g. withholding of volumes) could even lead to higher system marginal costs and hence higher producers' surplus. Effects like strategic bidding between capacity and electricity bid or sub-optimal behavior due to information asymmetries could further increase the cost difference between real expenditures and the model results. Additionally, uncertainty for e.g. residual demand, prices, and power plant shortages of the next week are included in the bids which increase costs. These aspects are not considered by the cost minimizing model under perfect foresight. Therefore, we would expect our results to be a lower bound for the possible cost reductions.

4.2. Provision of Balancing Power

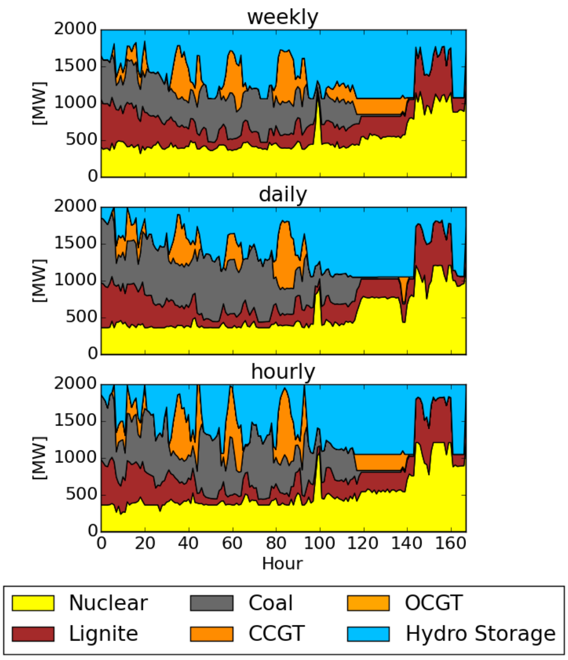
Balancing power is provided by different types of power plants within the portfolio of operators. Depending on the portfolio of operators and the pooling within the portfolio, the balancing power provision by technology changes from hour to hour. This effect can be observed in the graphs in Figure 6a for different provision durations at the example of positive secondary balancing power in the winter week.

For the weekly provision, we see a strong hourly fluctuation within the technologies although operators are restricted to a weekly provision duration. This indicates that the operators make significant use of the pooling option. The operators can freely select the power plants that shall provide balancing power in certain hours of the week. Therefore, the operators choose those power plants in their portfolio which have the lowest opportunity costs with respect to the spot market. Here, obviously, operators with a large portfolio have an advantage compared to small operators. For primary balancing power as well as for the case of the summer week, the fluctuation of balancing power providing technologies are similar to the Figure 6a.

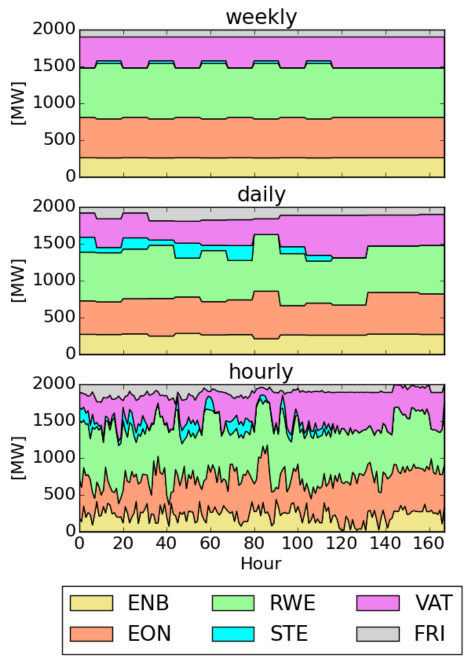
If we take a look at the provision by technology for daily or hourly provision duration, we find a surprisingly similar structure to the weekly provision duration. However, small differences in the diagrams can be identified. CCGT (in orange), for instance, have a more important role in peak hours with the hourly provision compared to the outcomes with longer provision duration. In the daily configuration, coal power plants (in grey) provide more often balancing power compared to the other configurations. The hourly provision duration can be expected to be the efficient benchmark where the owner structure of power plants does not matter. This means that the most cost efficient power plants in each hour provide balancing power. Since the capacity provision by technology of the weekly and daily cases are similar to the hourly benchmark, we conclude that the pooling possibilities allow a provision pattern that is close to the most efficient outcome. Even with a weekly provision duration, almost the same cost efficient technologies provide balancing power as in the case with an hourly provision.[20] This interpretation is in line with the results presented

[20]This result does not only hold for the case of positive secondary balancing power, but also for the other investigated

in Section 4.1 where the efficiency gain from pooling was quantified to be EUR 1.382m in the winter week whereas the respective efficiency gain from shortening the provision duration from a weekly to an hourly market design was found to be EUR 0.222m.



(a) Provision by technology



(b) Provision by operator

Figure 6: Comparison of the technologies (left) and operators (right) providing positive secondary balancing power for the weekly, daily and hourly provision duration in the winter week (model results)

Figure 6b shows the modeled capacity provision by operator for positive secondary balancing power for a weekly, daily and hourly provision duration. Compared to the modeled provision by technology, the modeled provision by operators differs more significantly for the three market designs. The fluctuation of market shares becomes higher with a shorter provision duration.

The capacity provision by operator can be considered as a first indicator for the market concentration indices. Therefore, we expect stronger fluctuation of the market concentration indices for shorter provision duration. Drivers for this are:

- the absolute residual demand level at a given time point in the time frame,
- the volatility of the residual demand level in the provided time frame,

products.

- the steepness of the marginal cost function of the power plants and therefore the steepness of the opportunity cost function,
- the operator structure of the opportunity cost function, i.e. whether operators capacities are in blocks or spread in the opportunity costs merit order.

Thus, the capacity provision by operator is typically dependent on the specific market circumstances, e.g. the product definition, the annual season, and the provision duration. Hence, we investigate the different market designs based on market concentration indices in detail to derive further insights.

4.3. Market Concentration

Based on the balancing power provision by operator observed in Figure 6b we compute market indices for the three balancing power products, primary, secondary positive and secondary negative balancing power. The indices vary depending on the market design and provision duration. In order to assess the different ranges of market concentration indices, we analyze the model results in histograms for the HHI (cf. Figures 7, 9 and 10). Those diagrams show the HHI values in the weekly market design as a red line. In the case of secondary balancing power, two red lines are present due to the two contract durations (HT and NT, as described in Section 2). For the hourly provision duration, 168 different products are defined and hence 168 HHI values. The histograms show the distribution of those hourly HHI values. Similar histograms for the RSI^{-1} are evaluated (cf. Figures 8, C.12 and C.13).[21]

For the interpretation of the results, we also add dotted lines into the histograms which indicate threshold values for high market concentration. For the HHI, a strong market concentration exists at a value of 25% according to US Department of Justice, Federal Trade Commission (2010, §5.3) and at 20 % (with further restrictions) as to EUR-lex (2004, 19. and 20.). In the case of the RSI^{-1} we consider a threshold value of 1.11 (which corresponds to a threshold value of 0.9 for the original RSI definition).

The indices are no absolute measures in which one index would be sufficient to indicate market concentration. Nevertheless, high market concentration is more likely if both discussed indices point to a critical level.

4.3.1. Market Concentration for Primary Balancing Power Provision

For the modeled provision of primary balancing power, the HHI values are displayed in Figure 7. We observe that the summer seems to be slightly more concentrated in balancing power provision than the

[21] Additionally, an analysis for the concentration indices CR1 and CR3 was conducted. The CR for m firms is defined as $CR(m) := \sum_{i=1}^{m} MS_i$ where MS_i is the market share of operator i in % for the m largest firms. The analysis for CR1 and CR2 did not lead to different conclusions compared to the analysis based on HHI and RSI^{-1}.

winter. The reason for this lies in the different demand profiles and the increasing production of solar generation (cf. Figure 4a). In the summer, a lower electricity demand and higher solar generation lead to less demand of generation from conventional power plants and therefore there are less power plants available (i.e. running) that are able to provide primary balancing power. This is also indicated by high values of the RSI^{-1} that can be seen in figure 8.

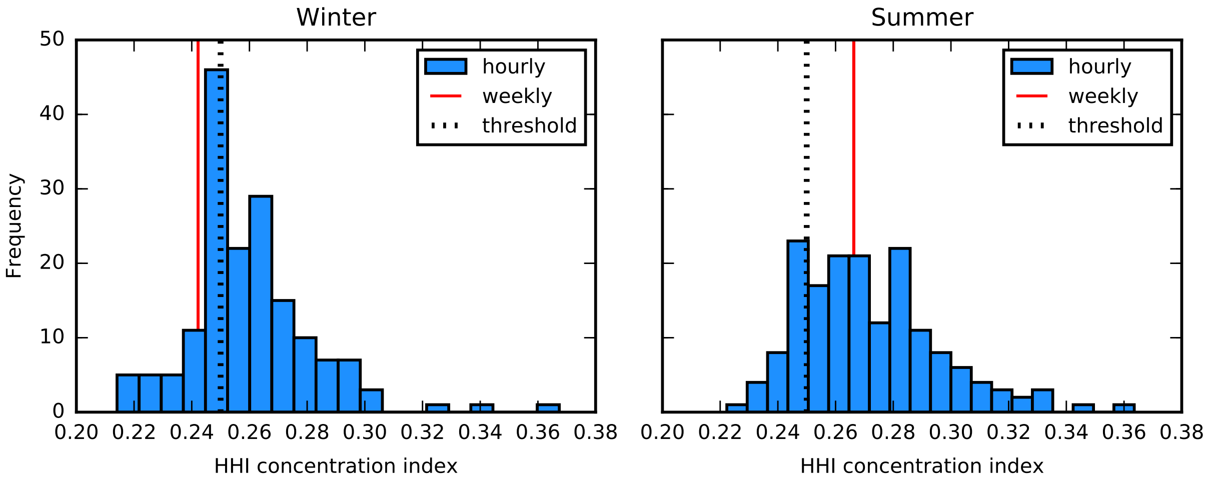


Figure 7: Histogram of the hourly HHI values for primary balancing power in winter week (left) and summer week (right)

Based on the model results we can infer that the primary balancing power market is prone to high market concentration. When the market design is changed from weekly provision to hourly provision we observe that the indices take on a broader range of values. This means there are hours in which market concentration is increased and hours when market concentration is lowered. An increase in market concentration may occur if the level of demand is at a level where only few operators are close to the marginal production level. As previously explained in Section 2 and shown in Figure 3, there are intervals in the merit order where only some operators own power plants. This is for example the case for lignite power plants that are owned by Vattenfall and RWE. When demand is low and lignite power plants are marginal in their production, they can provide balancing power at lowest cost. Since this effect only depends on one single demand period in the hourly provision case instead of multiple demand periods in the weekly design, the modeled market concentration increases in some hours. In addition, market concentration is higher in the summer because of lower demand levels and therefore less conventional power plants that are operating. These baseload power plants which are still operating are owned by fewer operators, which increases market concentration.

There is no clear trend observable to conclude whether shorter provision duration structurally mitigates or favors market concentration. The RSI^{-1}, however, that can be seen in Figure 8, decreases in average with shorter provision duration especially in the winter week. This means that the average market concentration is reduced because there is more active capacity that could provide balancing power. Nevertheless, there are some hours when the RSI^{-1} indicates a slightly higher concentration compared to the weekly provision. The number of hours with critically high values can be significantly reduced if the market design is changed to an hourly balancing power provision. In the winter this leads to RSI^{-1} values below the threshold. In the summer, however, the RSI^{-1} can only be decreased below the threshold in some hours. Based on the model results, the primary balancing power market seems to be highly concentrated such that even in the case with an hourly balancing power provision the average market concentration in the summer is still modeled as critically high.

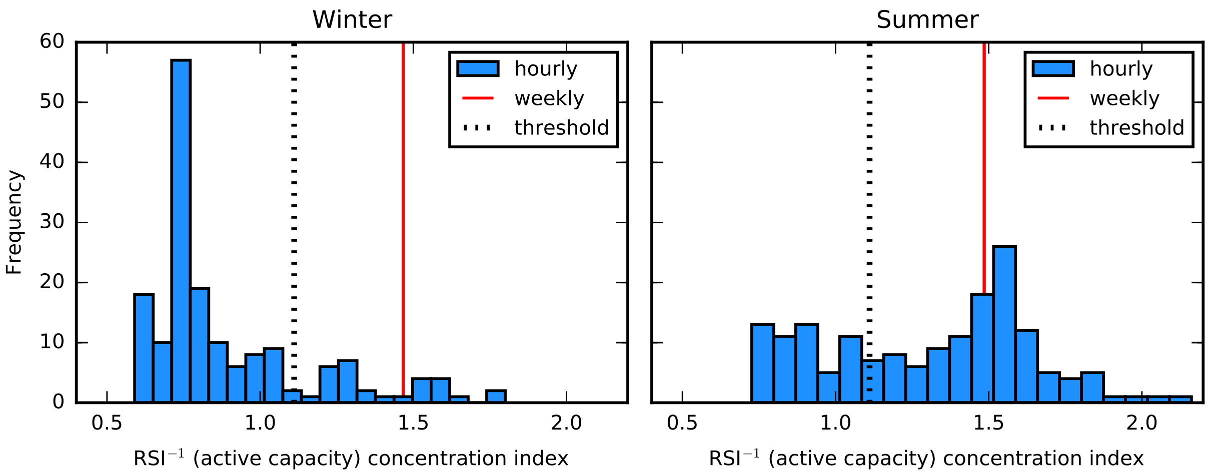


Figure 8: Histogram of the hourly concentration index RSI^{-1} for primary balancing power in winter week (left) and summer week (right)

4.3.2. Market Concentration for Positive Secondary Balancing Power Provision

Whereas primary balancing power is mostly provided by baseload power plants that are able to increase and decrease their generation, secondary balancing power is divided into positive and negative balancing power. In the case of positive balancing power, power plants provide the ability to increase their generation when being called. For the winter we see the respective technology and operator mix in Figure 6. The result for the summer week is similar which is the reason why it is not shown additionally. The main difference is that more lignite power plants are providing balancing power instead of CCGTs than in the winter week. Especially the high provision of balancing power from lignite power plants leads to a high market share by

RWE and Vattenfall.

The market concentration indices in Figure 9 show a high market concentration based on the HHI. Here, again, concentration seems to be higher in the summer compared to the winter. Nevertheless, the story is a bit different compared to the provision of primary balancing power because in the case of positive secondary balancing power there is a larger proportion of active power plants that could potentially provide balancing power. The respective RSI^{-1} indicates that the market is not too concentrated because the providing power plants could be replaced by the provision from power plants that are currently not delivering balancing power (the histogram for the RSI^{-1} can be found in the Appendix). Therefore the market can be considered as not as concentrated compared to the primary balancing power market. When the provision duration is lowered to an hourly level, the average modeled market concentration based on the RSI^{-1} is further reduced. In the case of the HHI, there is, however, no clear evidence for a reduction in average market concentration by reducing provision durations. There are single hours with very high modeled market concentrations in the hourly case.

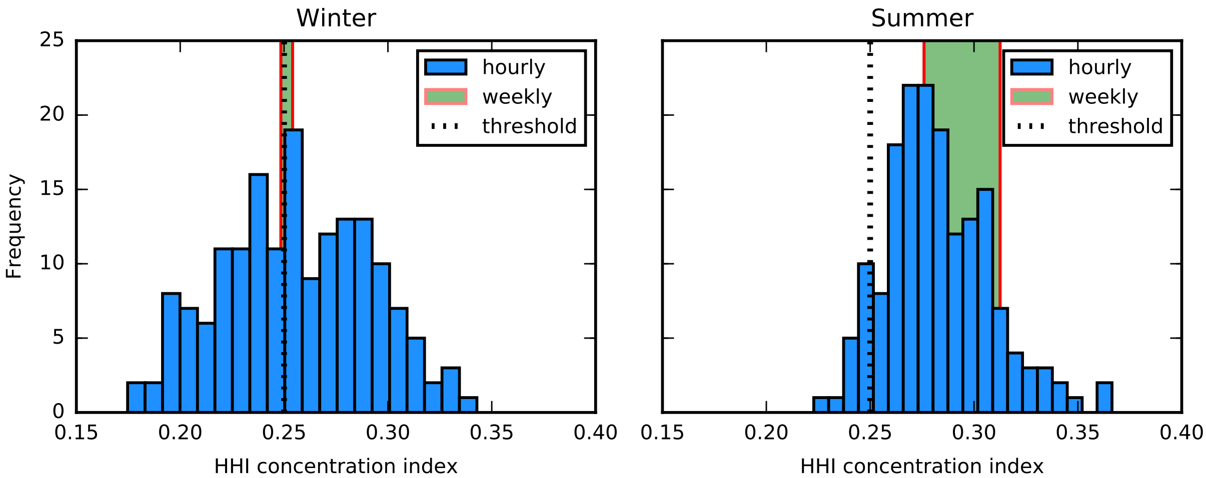


Figure 9: Histogram of the hourly HHI values for positive secondary balancing power in winter week (left) and summer week (right)

4.3.3. Market Concentration for Secondary Negative Balancing Power Provision

The HHI values for secondary negative balancing power that can be seen in Figure 10 have similar characteristics as the values for the positive secondary balancing power. Nevertheless, in the negative secondary balancing power market, we would expect no abuse of market power even with a high market concentration. The rational for this is as follows: As to Section 2, the costs for capacity bids for balancing power are driven by opportunity cost compared to the spot market. Thus, for one hour, all operating power plants have zero costs for offering negative balancing power. For a longer provision duration, the costs would increase if the power plant would not be inframarginal all the time. However, due to pooling effects, operators can choose power plants which are operating in a specific situation. Therefore, the opportunity costs for each provider can be assumed to be (almost) zero. Many fringe operators can potentially participate in the auction, since e.g. wind producers could also provide negative balancing power. This means that the resulting supply curve for negative balancing power is very flat. If operators would try to withhold quantities in an attempt to increase prices, fringe operators with similar small costs would provide the balancing power. Hence, prices of (almost) zero for negative balancing power should be the consequence. Note that in reality, there is uncertainty (e.g. power plant outages) which leads to slightly positive capacity bids. With our model, we can find the cost minimal provision of balancing power but we would expect fierce competition. Therefore, even high shares of market concentration that can be observed in the model results should not lead to the abuse of market power because all providers face the same low level of opportunity costs.

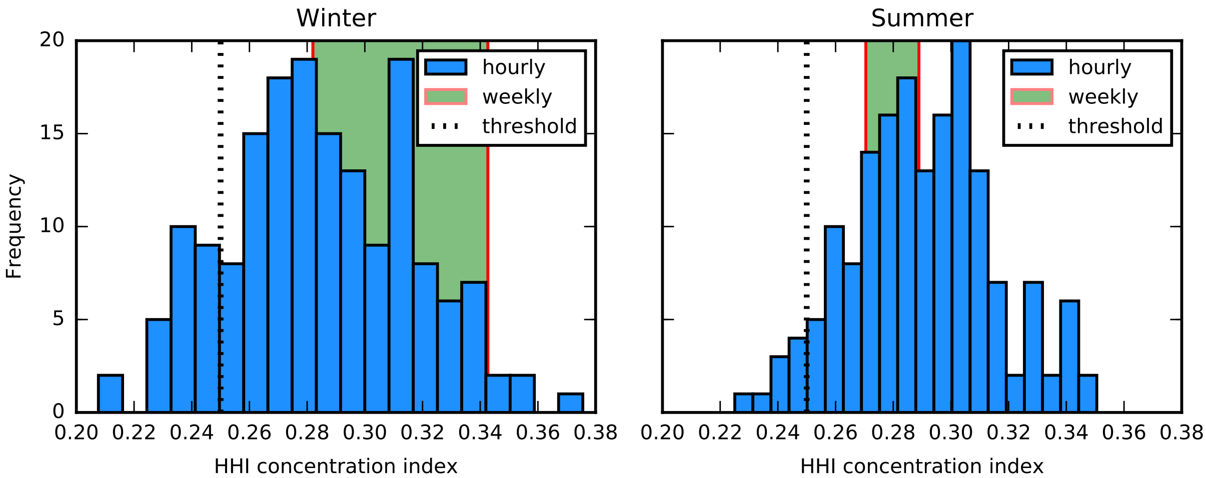


Figure 10: Histogram of the hourly HHI values for negative secondary balancing power in winter week (left) and summer week (right)

5. Conclusion

Currently, the German primary and secondary balancing power markets have a weekly tender frequency. In a weekly market design, large power plant operators make use of pooling within their portfolio in order to provide balancing power. Fringe operators, however, do not have pooling options and need to withhold the capacity of their plants from the spot market for a whole week to provide balancing power which can lead to inefficiencies. Hence, fringe operators could potentially benefit from a shortened provision duration. The analysis at hand focuses on (1) efficiency gains from a shorter provision duration in primary and secondary balancing power markets, and (2) market concentration in market designs with different provision duration. Since it is known from the literature that simultaneous equilibria in spot and balancing power markets are efficient and unique (Richter, 2012), our methodology is based on a cost minimizing unit-commitment model for the electricity market in which we account for the ownership of power plants.

We quantify the efficiency gain from allowing pooling in a weekly market design to be EUR 1.033m in a winter week and EUR 0.139m in a summer week. Compared to this, the further efficiency gains that can be realized by shortening the provision duration from a week to an hour are small. An hourly market design would lower the costs of balancing power provision by EUR 222k in a winter week and EUR 96k in a summer week. Relative to the total simulated cost of balancing power provision in the weekly market design with pooling, the efficiency gain is 17% in the winter week, and 14% in the summer week.

Besides the efficiency gains, we identify effects on the market concentration. Here, we investigate the HHI and RSI^{-1} indices which are based on the market share and the residual supply, respectively. According to the model results, we see the potential for high market concentration in the primary balancing power market due to the technical requirements power plants need to fulfill in order to participate in this market. In the market for positive secondary balancing power, the model results indicate less concentration because there is more available capacity that could potentially replace the providing power plants. For the negative secondary balancing power, our results are quantitatively similar to the other products. However, we consider concentration in the market for negative balancing power not to be an issue due to the low opportunity costs for providing negative balancing power. Based on the model results, we find a higher market concentration in the summer than in the winter in all considered markets. The higher market concentration in the summer is driven by a lower level of demand, which reduces the number of active power plants and also the number of operators that are providing balancing power.

Our results reveal a tendency towards decreasing average market concentration by shortening the provision duration. However, the market concentration indices take on a broader range of values in the case of a shorter provision duration depending on the residual demand level and its volatility. There are single provision periods with a very high market concentration in the hourly and daily market design that could favor the potential for market power abuse.

Although market concentration can be an indicator for market power, it does not necessarily identify market power. The characteristics of the supply curve for balancing power determine the potential for market power abuse. If high market concentration is found in a flat segment of the supply curve, prices cannot be raised significantly. The goal of further research should be to comprehensively understand market imperfections in balancing power markets. Besides market concentration, aspects like e.g. strategic bidding between capacity and energy bid and uncertainty about the renewable feed-in or demand should be considered.

As a policy implication, we recommend to monitor market concentration and price levels carefully after a change of the market design in the balancing power market. In specific situations, single operators may have a cost advantage compared to their competitors.

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AppendixA. Input Data for Modeling

Since we model the year 2014, we are able to use realistic data according to public available sources. Assumptions that are made are inline with typical assumptions for modeling the electricity generation sector. The installed power plant capacities of different fuel types are shown in Table A.4 and are based on Bundesnetzagentur (2014).[22]

	[GW]
Nuclear	12.1
Lignite	21.3
Coal	25.5
Gas	26.9
Oil	2.4
Pumped Storage	6.4
PV	32.7
Wind onshore	31.4
Wind offshore	0.4
Biomass	7.5
Hydro	4.4
Others	1.0

Table A.4: Installed capacity in Germany for 2014

The assumptions on fuel costs are shown in table A.5.

	[EUR/MWh]
Nuclear	3.6
Lignite	1.5
Coal	13.2
Gas	22.8
Oil	49.4
Biomass	31.8
Others	22.8

Table A.5: Fuel costs for 2014

The CO_2 emission certificate costs are assumed to be 6.20 EUR/t CO_2. We assume those costs to be static over the whole year.

Table A.6 shows the assumed technical power plant parameters (particularly dependent on the year of construction).

[22] The actual input of installed capacities is further separated as to the year of construction: This gives further technical characteristics and parameters like full load and part load efficiency. The newer a power plant, the better are its technical parameters.

	Net efficiency	FOM-costs	Availability	Start-up time	Minimum part-load
	[%]	[EUR/kW/a]	[%]	[h]	[%]
Coal	37 - 46	36 - 54	84	4 - 7	27 -40
Lignite	32 - 47	43 - 65	86	7 - 11	30 - 60
CCGT	40 - 60	28	86	2 - 3	40 - 70
OCGT	28 - 40	17	86	0.25	40 - 50
Nuclear	33	97	92	24	45
Biomass	30	165	85	1	30

Table A.6: Techno-economic parameters for conventional power plants

AppendixB. Robustness Checks

As a robustness check, a model run is considered in which the values of renewable feed-in is doubled. Table B.7 gives an overview of the total system costs, and Figure B.11 illustrated the costs for providing primary and secondary balancing power compared to a model run without balancing power provision.

in mio. Euro	no provision	hourly	daily	weekly	weekly (no pooling)
Winter	131.6	132.8	132.9	133.0	134.1
Summer	102.4	103.5	103.5	103.6	104.3

Table B.7: Total system cost in scenario with doubled renewable feed-in in million Euros

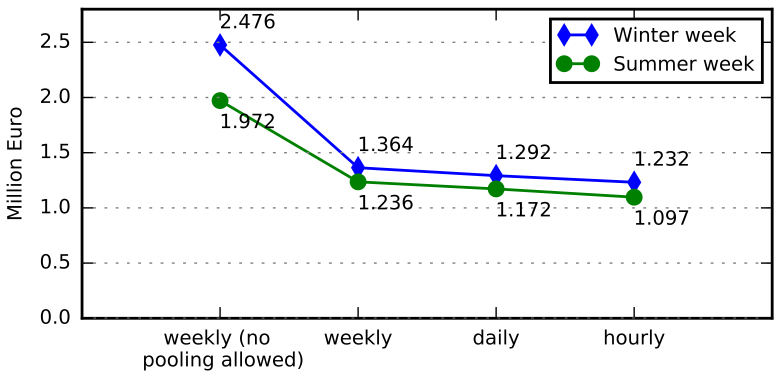

Figure B.11: Costs of primary and secondary balancing power (compared to no provision) in scenario with doubled renewable feed-in

AppendixC. RSI concentration index for secondary balancing power

Figure C.12 and C.13 show the RSI^{-1} market concentration indices for secondary balancing power (positive and negative, respectively).

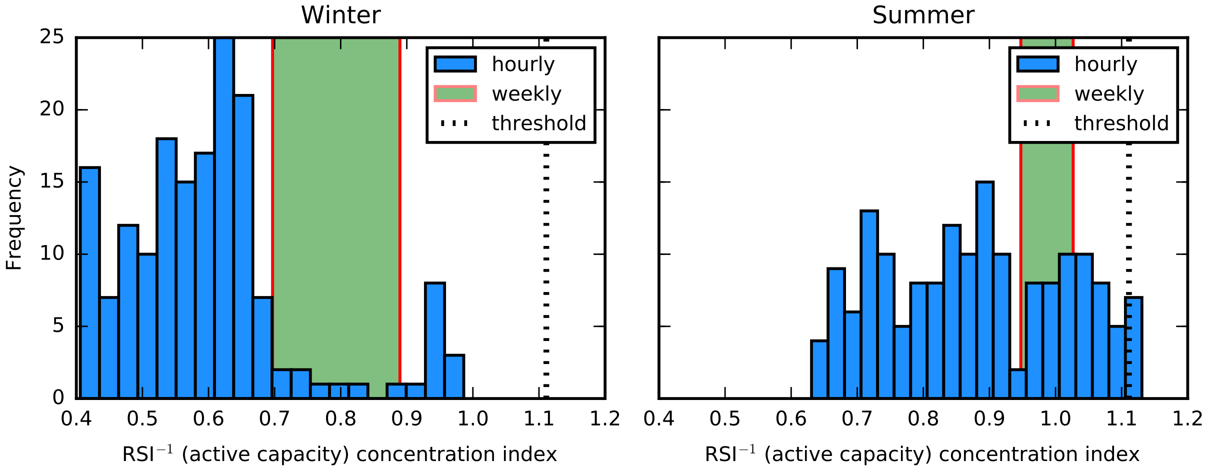

Figure C.12: Histogram of the hourly concentration index RSI^{-1} for positive secondary balancing power in winter week (left) and summer week (right)

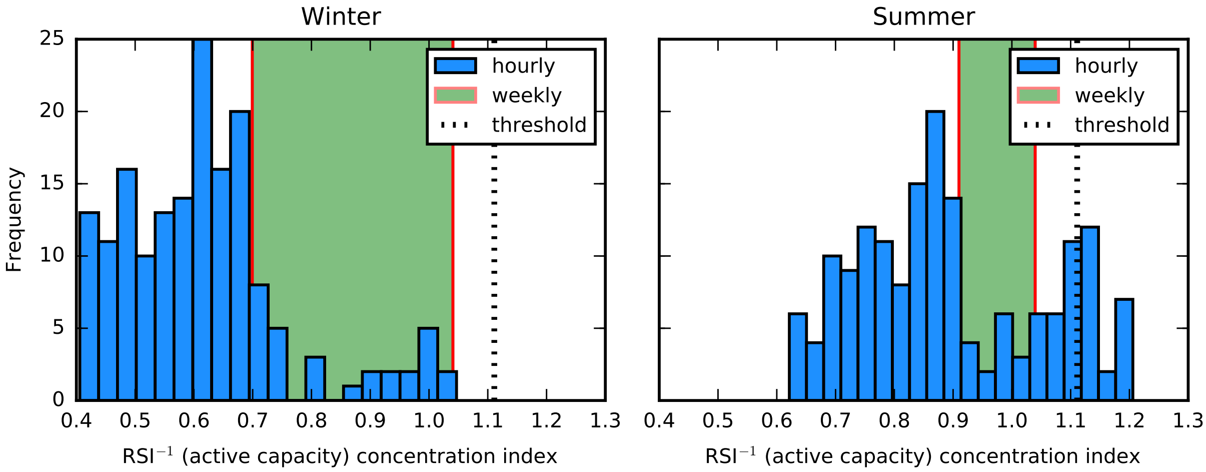

Figure C.13: Histogram of the hourly concentration index RSI^{-1} for negative secondary balancing power in winter week (left) and summer week (right)