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Beyond the day-ahead market – effects of revenue maximisation of the marketing of renewables on electricity markets

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Abstract

The proportion of renewable energy has rapidly increased in many countries during the last few years. Due to the specific characteristics of variable renewables, this development influences the price on electricity markets as well as flexibility requirements in the electricity system. New developments regarding market liberalisation and support schemes for renewables encourage the active participation of renewables in the electricity market. This paper analyses the effects of such a participation of renewables in different electricity market segments. In particular, we investigate how the active marketing of renewables on the day-ahead, intra-day, balancing and futures markets dampen their effects on markets and systems. Using German data for 2013, we determine the effect of direct marketing on average market price levels and price volatility, the possible contribution of renewables to balancing, the profitability of flexible generation from biomass, and the additional revenues that renewables can generate from participating in different markets. Price effects of shifting renewables between markets, and limits in intra-day market liquidity are included in the assessment.

Keywords

Renewables, electricity markets, revenue opportunities, price volatility, merit-order effect, direct marketing

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Introduction

The proportion of renewable energy has rapidly increased in many countries over the last few years. Due to the specific characteristics of variable renewables (i.e. reneswable which may fluctuate rapidly over day time, in particular wind and solar PV), this development influences the price on electricity markets as well as flexibility requirements in the electricity system.

The low marginal costs of variable renewables generate the merit-order effect which describes the fact that, at least in the short term, electricity prices decrease with a rising share of renewable energy.[1,2] Furthermore, the stochastic generation profile of wind and solar increases price volatility in electricity markets as well as the need for power system flexibility.[a,3–11] Flexibility can be provided through different options including grid extension, storage, demand-side measures and flexible power plants. The need for more flexible power plants becomes more apparent as full load hours of conventional plants decrease.

In the past, many countries across the world began to use feed-in tariffs to support the expansion of renewable technologies. Under such tariffs, renewable plant operators receive a fixed remuneration for each unit of electricity they produce. This type of support is very effective in increasing renewables penetration in electricity systems at comparatively low costs due to the low risk involved for investors.[12] As plant operators are not concerned by price developments in the electricity market, however, a fixed feed-in tariff means that renewables plant generates electricity at the maximum possible level without considering the demand situation. This leads to biomass plant being operated in a very inflexible manner and solar and wind plants generating electricity even when demand is low and prices on the electricity market have turned negative.[13]

Support schemes allowing for an active participation of renewables in electricity markets, rather than a passive generation-maximizing feed-in subsidy, can alleviate the adverse impact of renewables on electricity markets and systems. Such schemes include capacity payments, feed-in premiums or quota schemes. They can also serve as a means to increase power system flexibility in general.[b] In addition, it is possible that the active marketing of renewables on different markets can increase the revenues generated and thus decrease support costs. The increased risk for plant operators and the capital costs involved might, however, dampen this effect.

This paper aims to analyse the effects of an active participation of renewables in electricity markets when compared to their behaviour under a fixed feed-in tariff. It seeks to determine the extent to which a corresponding change in the support regime for renewables and the market regulations can induce benefits regarding system operation, support costs, power prices and flexibility requirements. The question is answered through a simulation study based on German data from 2013.

The remainder of the paper is structured as follows. In the background section, hypotheses regarding the potential effects of active market participation of renewables are formulated and existing results from literature are assessed. An explanation of the methodology for the case study conducted based on German data from 2013 follows. Subsequently, input data and results are presented and discussed. The paper ends with a conclusion.

Effects of active trading of electricity generated from renewables on different electricity markets

Increasing shares of renewables influence electricity prices and the electricity system in a number of ways. The impact cannot be avoided even if the electricity generated is not directly sold on the market, but is supported by a fixed tariff. The effects include lower than average wholesale prices, higher price volatility and reduced full-load hours for conventional power plants.[14] Therefore, high proportions of renewables make the occurrence of the "missing money" problem (investments that cannot be recovered) more likely, and might therefore pose a threat to the security of supply especially in energy-only electricity markets.[c,15]

In addition, increasing shares of variable renewables require additional system flexibility not only to balance demand fluctuations but also to generate fluctuations in variable renewables.[3–5] Flexibility in liberalised electricity markets is provided based on economic considerations. Large differences between base and peak prices help generate investments in flexibility options such as storage, demand-side flexibility or flexible power plants. In addition, balancing markets, organised mostly by grid operators, ensure the compensation of short-term deviations from schedule. Power plants contracted for balancing services need to be in operation in order to quickly react when needed; traditional balancing markets are one major reason for "must-run" capacities (i.e. capacities that cannot be easily switched off as they are required in certain circumstances) and thus lower system flexibility.[16]

Furthermore, as shares of renewables increase, the market value of electricity from renewables decreases since variable renewable generation is self-reinforcing.[d,17–19] This implies higher support expenditures due to the rising difference between revenues and generation costs.

This paper investigates the extent to which active trading of renewables and individual revenue maximisation reduce the impacts described above. More precisely, the following hypotheses are tested:

Hypothesis 1 (H1)

The increase in price volatility and the reduction of the average wholesale price caused by growing renewable shares can be reduced by enabling active trading of renewables.

Hypothesis 2

If active trading of electricity generated from renewables is allowed for, the need for further flexibility options is decreased.

Subhypothesis 2.1 (H2.1). Renewables contribute to fulfilling balancing requirements. As a consequence, conventional "must-run" capacities can be reduced.

Subhypothesis 2.2 (H2.2). Active trading encourages flexible biomass power generation.

Hypothesis 3 (H3)

Revenues from renewables increases with active trading and thus might encourage the reduction of support expenditures.

There is much literature regarding the development of the merit-order effect in different jurisdictions, as well as some studies investigating the effect of higher renewable shares on price volatility.[6,7,20,8–11] However, literature investigating the effect of different support systems or marketing strategies on price levels and volatility is scarce. Winkler et al.[13] find that support systems linked to lower opportunity costs for curtailment (i.e. capacity-based schemes or feed-in premiums) lessen the price-decreasing and volatility-increasing effect of renewables but to a limited extent.

The potential contribution of renewables to system flexibility in terms of more flexible generation and a contribution to providing balancing services have been analysed in a few papers. Olson et al.[21] show that curtailment can contribute to system flexibility based on a case study for California. The more flexible operation of biomass plants is often given as one option for flexibility in power systems with low carbon emissions. Barchmann[22] shows that for Germany, given different support systems, a more flexible operation is profitable under specific conditions, for example, for existing plants that receive an additional premium for capacity extensions. Tafarte et al.[23] find that biomass could contribute substantially to balancing variable renewables, but costs and profitability are not assessed. Szarka et al.[24] draw the same conclusion including an assessment of costs and benefits. The potential of variable renewables to provide balancing services is analysed by Jansen.[25] He concludes that photovoltaics (PV) and wind resources can profit from providing negative balancing, but positive balancing is not a realistic option.

A number of authors have analysed the development of renewable market values based on the day-ahead market. They come to differing conclusions on the future profitability of renewables on the market, but agree that rising renewable energy shares, given that everything else is equal, reduce revenues per unit of electricity.[17–19,26] Other authors have explored the benefits of active trading of renewables in different markets compared to day-ahead trading alone. Most concentrate on wind energy and assess either the balancing markets or the intra-day market. For single wind plants, additional revenue opportunities for intra-day markets are found to be up to 5% compared to day-ahead trading alone.[27–30] Speculative behaviour further increases possible revenues, but also trading risks.[31] Depending on assumed uncertainties, De Vos et al.[28] show that for Belgian data, intra-day market participation does not necessarily generate increased profits. In addition, it was revealed that intra-day markets can cause a decrease in risks and an increase in the optimal energy offered on day-ahead markets.[32] Also, intra-day market participation can possibly reduce imbalance penalties.[33] A much wider range is found regarding additional revenues from balancing. While Saiz-Marin et al.[34] and Hochloff and Braun[35] only determine small additional profits for wind, based on Spanish data, and biogas based on German data, other authors estimate much higher revenue opportunities of up to 34.5% for wind plants in California or Denmark.[36,37] Taking into consideration price effects of higher market penetration, Zugno et al.[38] calculate additional profits of between 1.96% (25% penetration) and 7.58% (10% penetration). Regarding the futures market, only one study was found in which an optimal bidding curve for wind park participation in the forward market is derived.[39]

In contrast to existing studies, the analysis conducted here includes all market segments and technologies to allow for more general conclusions not only regarding the impact of active trading on the income from renewables, but also on market price and system flexibility. In addition, the impact of the merit-order effect and limited intra-day market liquidity are included in the calculations.

The formulated hypotheses are tested in the following paragraphs. To do this, an algorithm is developed to analyse the revenues of renewables and other effects of active trading based on real data. The algorithm is run using German data from 2013. Sensitivities are included regarding two important factors influencing the effects, and especially the revenue development, of renewables. These are intra-day market liquidity and the extent of the merit-order effect. The exact methodology is described in the following section.

Methodology

The algorithm used in this paper simulates a trader maximising revenues by selling renewable electricity and capacity on different markets. Revenues on each market are computed for relevant combinations of prices and quantities. The generation profile and electricity production for the calculation period are used as input data for variable renewables. For dispatchable technologies, calculations are based on installed capacities and energy produced. Generation can be moved freely between the hours of the day depending on prices, with installed capacity setting a cap on the maximum hourly generation. Price effects from moving renewable generation or capacity between hours and markets are considered on all markets. The impact of limited intra-day market liquidity is also assessed.

It is assumed that support for renewables does not interfere with the trading and bidding behaviour of the renewables trader.[e] This assumption is made in order to show the effects of participation in different markets without the distortions of the current support. The exclusion of the market premium from the analysis has four consequences for the case study results: first, the calculated values can be compared to the levelised costs of generation in order to assess the profitability of renewable plants without support; second, the profitability of providing balancing services can be evaluated based on market conditions, as opportunity costs of participating in the balancing market are reduced by the additional income from the support scheme; third, optimal curtailment based on market conditions is derived and shows whether free market participation would considerably reduce renewable generation; fourth, results are more extreme when compared to a system with the market premium in place as reduced opportunity costs due to foregone support incentivise plant operators to react more directly on market price signals. Volume shifting between day-ahead and intra-day markets is, however, not affected, as the German market premium is paid for by trading on both markets.

In order to keep the algorithm manageable, some simplifying assumptions were made: The main simplification is the assumption of perfect information, i.e. traders do not face uncertainties regarding weather conditions or market prices and therefore do not need to handle trading risks. This simplification also excludes the effects of forecast accuracy from the analysis which tends to increase the positive effects of direct market participation. A second simplification is the assumption of uniform pricing for the entire portfolio. When the algorithm is used for big portfolios, this simplification can lead to an overestimation of the price-reducing effect of renewables. Both assumptions tend to increase the observed effects and therefore results in most cases needing to be interpreted as maximum values.

The algorithm includes day-ahead market, intra-day market, negative and positive secondary and tertiary balancing as well as the futures market. Maximum possible revenues are calculated separately for day-ahead and intra-day trading, balancing markets and futures markets.

Day-ahead and intraday market

For dispatchable and variable renewables, the trader compares hourly prices on intra-day and day-ahead markets. As long as intra-day market prices are above day-ahead market prices, incremental units of electricity are moved to the intra-day market in order to profit from the higher price. For dispatchable plants, two generation profiles are considered. The first one assumes constant generation, while the second is based on optimised marketing on the day-ahead market. Curtailment is applied during hours with negative prices or prices below fuel costs.

Two restrictions are taken into account. First, the intra-day market is typically less liquid than the day-ahead market. Figure 1 shows the hourly price differences between the day-ahead and the intra-day market and the corresponding trading volumes for all hours with intra-day prices above day-ahead prices. Intra-day volumes are clearly below day-ahead volumes for all hours. The highest intra-day volume in these hours is 9.0 GW which is below installed renewable capacity. Consequently, market participants seeking revenue maximisation on the day-ahead and intra-day markets, risk not finding a trading partner.

Limited intra-day market liquidity is implemented in a simplified way by limiting the share of the hourly market volume that can be moved between the day-ahead and the intra-day market. The parameter *ms* (moveable share) determines the percentage of the overall market volume that can be transferred between the day-ahead and the intra-day market. The maximum tradable volume on the day-ahead and the intra-day market is determined based on equations (1) and (2), respectively. An $ms = 0$ implies that trading on

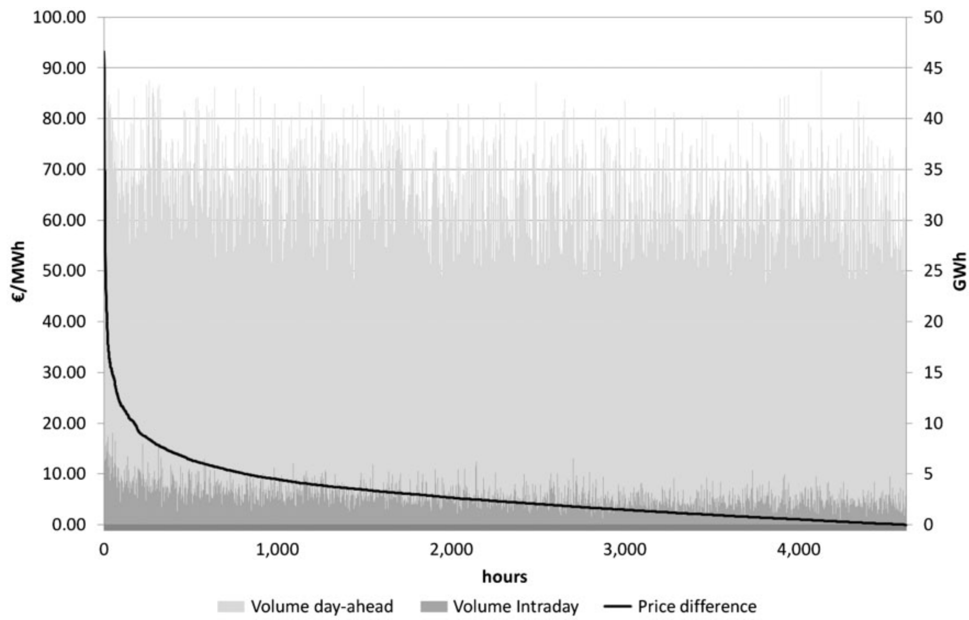

Figure 1. Hourly price difference between day-ahead and intra-day market and corresponding day-ahead and intra-day market volumes for hours with intra-day prices above day-ahead prices.
Source: EPEX Spot[40]

the intra-day market is possible but restricted by the actual trading volume[f] in the respective hour. To show the effect of market liquidity, *ms* is varied between 0 and 1 in the scenario calculations. Higher market liquidity typically leads to higher revenues as more generation can be moved to the intra-day market if prices are high.

$$[volume]_{(\max_{\text{intra}}-day,\,h)} = \min\left[volume_{(\text{intra}-day,\,h)} + ms \times (volume_{(\text{intra}-day,\,h)} + volume_{(day-ahead,\,h)}),\, volume_{(\text{intra}-day,\,h)} + volume_{(day-ahead,\,h)}\right] \tag{1}$$

$$[volume]_{(\max_{day}-ahead,\,h)} = \min[volume_{(day-ahead,\,h)} + ms \times (volume_{(\text{intra}-day,\,h)} + volume_{(day-ahead,\,h)}),\, volume_{(\text{intra}-day,\,h)} + volumeday - ahead, h] \tag{2}$$

Here, volume $\max_{\text{intra-day,h}}$ is maximum trading volume at the intra-day market in a certain hour; volume $\max_{\text{day-ahead,h}}$ is maximum trading volume at the day-ahead market in a certain hour; $\text{volume}_{\text{intra-day,h}}$ is current trading volume at the intra-day market in a certain hour; $\text{volume}_{\text{day-ahead,h}}$ is current trading volume at the day-ahead market in a certain hour and ms is moveable share.

Second, the level of renewables sold on the market influences the market price, resulting in a higher renewable shares leading to a lower price ("merit-order effect").[g] In the algorithm, the merit-order effect is calculated using equation (3). To determine the relevant merit-order effect, an estimate for a certain year ($\text{MOE}_{\text{baseyear}}$) and the respective annual generation from renewable energy sources ($\text{RG}_{\text{baseyear}}$) are required. For the market or hour when less energy than the input data is sold, the merit-order effect is added to the resulting price and vice versa. A higher merit-order effect is typically linked to lower revenues as less energy can be moved to the intra-day market before prices on both markets are equalised.

$$MOE_h = \frac{\Delta volume_h \times M0E_{base\ year} \times 8760}{RG_{base\ year}} \tag{3}$$

where MOE_h is hourly merit-order effect in year of calculation (€/MWh); Δ volume_h is change of hourly volume in year of calculation compared to the base year (MWh); $\text{RG}_{\text{baseyear}}$ is annual renewable generation in the base year (MWh) and $\text{MOE}_{\text{baseyear}}$ is estimated merit-order effect in the base year (€).

The merit-order effect is implemented as a linear function. This ignores the fact that the intra-day merit-order profile is steeper than that of the day-ahead merit-order resulting in a more pronounced price effect as well as differences between hours due to a lack of available data.[41,42] In the case study, the merit-order effect is applied based on Sensfuß[1] with data from 2012 as the baseline and data from 2010 and 2007 as maximum and minimum values. These estimates are in the same range as others for Germany according to Würzburg et al. (see Table 1)[2]

Balancing market

Balancing markets in Europe are typically divided into three categories – primary, secondary and tertiary. The main difference between these is the requirement regarding reserve activation times. Primary balancing reserves (also called spinning reserves) need to be available immediately and are mostly used to balance short-term frequency alterations. Secondary and tertiary reserves have longer activation times of 5 and 15 min, respectively. Secondary and

Table 1. Merit-order effect according to Sensfuß.[1]

Year	$RG_{baseyear}$ (TWh)	$MOE_{baseyear}$ (Mrd. €)	MOE per additional MWh of renewables (€/TWh)
2007	62.5	5.83	0.0110
2008	69.3	6.09	0.0953
2009	76.1	5.27	0.0829
2010	83.5	8.72	0.0659
2011	102	8.91	0.0843
2012	105	5.83	0.0870

Table 2. Overview of German balancing market rules.

	Secondary balancing	*Tertiary balancing*
Length of product period	Seven days	4 h
Auction period	Wednesday of previous week	Day ahead
Award criterion	Capacity price	Capacity price
Call criterion	Energy price	Energy price
Minimum offer size	5 MW	10 MW
Activation time	$\leq$5 minutes	$\leq$15 minutes
Pricing rule	Pay-as-bid	Pay-as-bid

tertiary balancing each include separate markets and resources for positive and negative balancing. In that regard, positive balancing means that production resources contracted need to able to be increased or electricity demand decreased in order to balance shortages of supply in the system. Negative balancing reserves are required to decrease generation or increase demand to smooth the access to electricity.

The algorithm in this paper includes positive and negative secondary and tertiary balancing. Primary balancing is excluded from the analysis as the delivery of this reserve type by renewable sources, at least in the short term, seems very challenging and is currently unlikely. Prequalification requirements for balancing in Germany currently exclude variable renewable from all balancing markets. However, discussions are ongoing on how they should be included. Unresolved challenges include reliability, and the measurement of additional or reduced electricity compared to planned feed-in.[25,43] In this study, it is assumed that there is full access of variable renewables to secondary and tertiary balancing.

The implementation of balancing markets largely follows the current German balancing market rules (see Table 2). Apart from the activation time, there are differences between secondary and tertiary balancing regarding the length of the product period, the auction periods and the minimum offer size. Secondary balancing reserves are auctioned weekly on the Wednesday before the product period begins, i.e. plant operators and demand resources need to guarantee their availability for a complete week some days in advance. Tertiary balancing reserves have a much shorter product period of 4 h and are contracted day-ahead. Both these conditions favour the participation of variable renewables in tertiary, rather than secondary balancing. The reasons are twofold. First, variable renewables do not typically

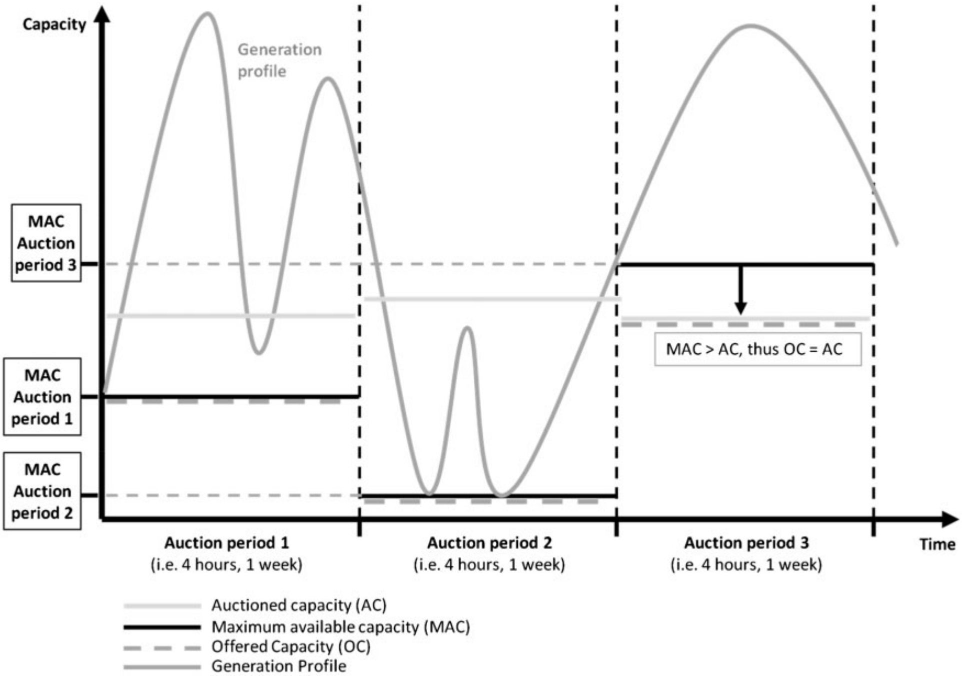

Figure 2. Determination of maximum available capacities for balancing auction periods.

have a constant generation profile and thus cannot provide reliable availability for a long time period. Second, forecast accuracy of variable renewables increases substantially over the most recent days, and even hours, before delivery and thus availability is much more certain for the day ahead than 5–12 days ahead. Due to the assumption of perfect information, the modelling only considers the first constraint. As stated above, ignoring the importance of forecast quality tends to result in greater market integration than that experienced in reality.

The first step in calculating the maximum possible income from balancing in the algorithm is deriving the maximum available capacity (MAC) for each balancing auction period by assessing the minimum hourly generation in this time period (see Figure 2). In product periods with an MAC above the auctioned volume, the auctioned capacity sets a cap on the offered capacity (OC). The maximum available capacity and offered capacity are formally defined in equations (4) and (5), respectively.

$$MAC_{product\ period} = \min_{h=1\ldots,n}[gen_h] \tag{4}$$

Here MAC is maximum available capacity per product period (MW); h is hour in product period; n is number of hours in product period and gen is electricity generation from renewables in respective hour.

$$OC_{product\ period} = \min[MAC_{product\ period}, AC_{product\ period}] \tag{5}$$

In this equation, OC is offered capacity per product period (MW); MAC is maximum available capacity per product period (MW) and AC is auctioned capacity per product period (MW).

For negative balancing, the optimised generation profile from the day-ahead and intraday market is used. For positive balancing, the original feed-in profile is applied for variable renewables, while a constant generation profile is implemented to maximise MAC for dispatchable renewables.

In a second step, the maximum income from each balancing auction in secondary and tertiary balancing is determined by taking into consideration the price-reducing effect of higher renewable capacities in balancing auctions. The optimal OC, generating the maximum income is determined by replacing original bids; it is assumed that the renewables trader uses a uniform offer price for his entire portfolio and pushes offers out of the market by bidding just below the original offer price. The assumption of a uniform offer reduces the impact of the assumption of perfect information by limiting the possible revenues.

Figure 3 shows a stylised example of the optimal bidding strategy for the renewables trader. Three offers were successful for a certain product period in the original auction without the participation of the renewables trader. One of the successful bidders offered 20 MW at 50 €/MW, the second bidder offered 10 MW at 40 €/MW and the last bidder 30 MW at 25 €/MW. The renewable trader has identified an MAC of 45 MW for the period under considerations. Given the assumptions made, the renewables trader now has three options. The first option is to offer 20 MW at 50 €/MW, the second option to offer 30 MW at 40 €/MW and the third option to sell 45 MW at 25 €/MW. The possible revenues under each option are derived by multiplying the offered capacities by the respective price.

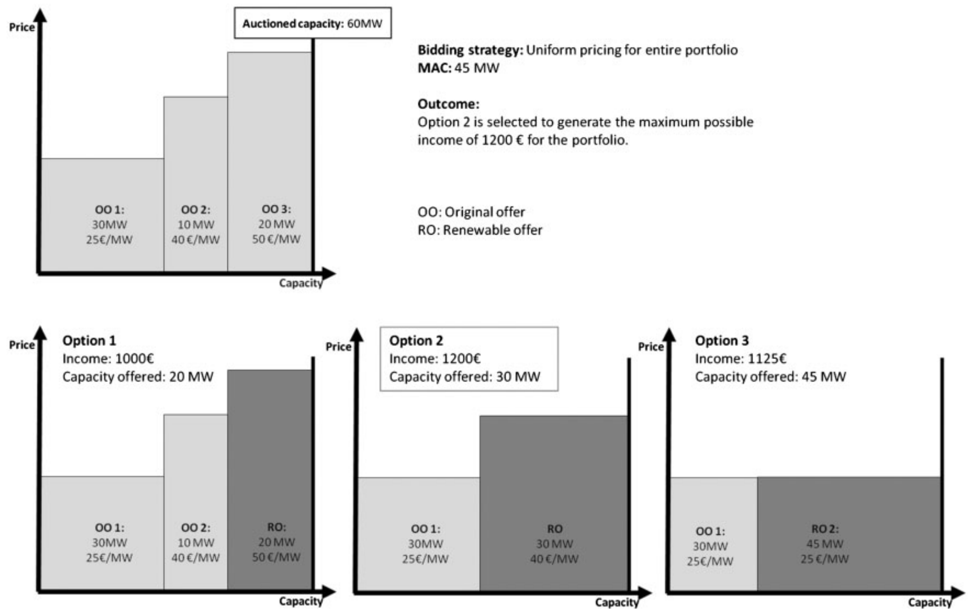

Figure 3. Determination of optimal offered capacity and calculation of maximum possible income.

The calculation reveals that the optimum strategy for the renewable trader would be to sell 30 MW at 40 €/MW with a revenue of 1200 €. The remaining capacity or corresponding energy should be traded in another market segment for revenue maximisation.

For positive reserves, the optimisation of revenues from capacity payments is followed by the maximisation of revenues from activation. The maximum profit from activation is calculated analogously as the product of the assumed energy price and activated energy.

Subsequently, the optimal combination of secondary and tertiary reserves is identified on a weekly or four-hourly basis depending on the length of the product period. If, in any period, capacity remains that could not be marketed on the balancing market with higher profits, it is sold on the other market.

In the case of positive balancing, opportunity costs arise from foregone revenue from the day-ahead market. In the algorithm, these costs are calculated by multiplying the capacities for providing reserves with the respective hourly day-ahead prices. Opportunity costs do not influence resulting prices which are solely determined by the replacement of original bids. After the optimisation, possible revenues are compared to opportunity costs to analyse whether the maximum possible revenue renders the participation in balancing markets profitable.

Futures market

The Phelix Base Year Future is used for modelling the futures market as it is the futures product with the highest trading volume and consequently seen as representative for futures price developments. The MAC for the whole year is first determined in order to optimise futures trading. For dispatchable renewables, a constant generation profile is assumed. The option of selling energy on the futures markets and buying from the spot market if plants are not available, is prohibited in the algorithm. Consequently, income from the futures market cannot be generated by PV due to its feed-in characteristics. The trader uses one uniform offer for the entire capacity offered, and the maximum income together with the optimal trading volume is calculated as for the balancing markets. Trading risks of selling futures and benefits of different hedging strategies are not considered.

Input data and results

Input data

The analysis considers three portfolios representing the entire capacity and generation from PV, onshore wind and biomass. In 2013 about 35.9 GW of PV, 34.7 GW of wind and 8.1 GW of biomass generating 30.0 TWh, 53.4 TWh and 47.9 TWh of electricity, respectively, were installed.[44] The biomass portfolio does not distinguish between solid, liquid and gaseous biomass. Hourly feed-in profiles for wind and PV are taken from ÜNB.[45]

Tables 3 and 4 give an overview of prices and volumes of the day-ahead, intra-day and futures market in Germany 2013. Futures prices were highest followed by intra-day and day-ahead prices. Intra-day volatility was above day-ahead and futures volatility possibly implying a higher trading risk. Compared to previous years, prices on both intra-day and day-ahead markets were significantly lower in 2013. The high price on the futures market, however, cannot be interpreted as a general attribute of futures prices but is probably caused by the unexpectedly low prices on the day-ahead and intra-day markets.[h] Trading volumes on the futures market are greater than volumes on the day-ahead market and substantially

Table 3. Comparison of 2013 prices on day-ahead, intra-day and futures market.

€/MWh	Day-ahead	Intra-day	Phelix Base Year Future
Average market price	37.78	38.58	53.59
Standard deviation	16.62	17.36	3.75
Maximum price	130.27	155.61	60.87
Minimum price	−100.03	−83.25	45.07

Note: The average market price on the intra-day market is based on volume-weighted hourly average prices. Data for Phelix Base Year Future include contracts realised in 2010–2012 with maturity in 2013.

Table 4. Comparison of 2013 volumes on day-ahead, intra-day and futures market.

	Day-ahead	Intra-day	Phelix Base Year Future
Overall (TWh)	246	16 (6.63% of day-ahead volume)	547
Average volume per hour (GWh)	28	2	62
Maximum (GWh)	45	9	62
Minimum (GWh)	18	0	62
Standard deviation (GWh)	4	2	0

Note: Data for Phelix Base Year Future include contract realised in 2010–2012 with maturity in 2013.

Table 5. Overview of capacity prices on the German markets for the positive secondary and tertiary reserve in 2013 (accepted offers).

€/MW/week	Negative tertiary reserve	Negative secondary reserve	Positive tertiary reserve	Positive secondary reserve
Average	1,023.61	918.46	202.96	636.88
Median	470.19	848.00	58.80	694.00
Maximum	21,709.34	20,001.00	17,220.00	2440.00
Minimum	0.00	239.00	0.00	26.00
Coefficient of variation	1.59	0.81	3.10	0.48

Note: Prices for the secondary reserve are converted to weekly prices. Source: ÜNB.[46]

exceed intra-day trading volumes. Intra-day hourly volumes are much more volatile than day-ahead volumes. Tables 5 to 7 give an overview of prices and volumes on the markets for the secondary and tertiary reserve. Both capacity and energy prices vary considerably over time. Capacity prices for the negative reserve exceed prices for the positive reserve. The positive secondary reserve is generally more profitable than the positive tertiary reserve while the differences between secondary and tertiary reserve are less clear regarding capacity prices for the negative reserve. Energy prices are analysed based on the offered prices – realised prices are lower due to a low activation rate. On average, 6.7 GW was contracted as positive and 6.8 GW as negative secondary and tertiary reserve in 2013.

Table 6. Overview of energy prices on the German markets for negative the secondary and tertiary reserve in 2013 (all offers).

€/MWh	*Negative tertiary reserve*	*Negative secondary reserve*	*Positive tertiary reserve*	*Positive secondary reserve*
Minimum	−4800	−33	0	−90
Median	90.	10	333	133
Maximum	15,000	6001	9999	2500
Average	301	199	478	217
Coefficient of variation	2	4	1	1

Source: Own calculations based on ÜNB.[45]

Table 7. Overview of volumes auctioned and activated on the German markets for the secondary and tertiary reserve in 2013.

	Negative tertiary reserve	*Negative secondary reserve*	*Positive tertiary reserve*	*Positive secondary reserve*
Average capacity auctioned [MW]	2562	4205	2437	4267
Average capacity activated [MW]	52	264	28	166
Maximum capacity activated [MW]	2716	2234	2447	2125
Energy activated 2013 [GWh]	458	2314	244	1458

Source: Own calculation based on ÜNB.[45]

Results

This section discusses how far revenue maximisation behaviour of renewables on electricity markets impacts on the electricity system and the potential revenues of renewable plants. When interpreting the results of the simulation, it is, however, important to bear in mind the restriction of the algorithm and especially the underlying assumption of perfect information. The presentation and discussion of results is structured along the hypotheses developed above.

Changes in price volatility and average market prices. To assess the changes in price volatility and average prices, changes in intra-day and day-ahead market prices are calculated for an optimised feed-in of constant biomass generation, flexible biomass generation, PV, onshore wind and a combination of constant biomass, PV and onshore wind. Price changes are assessed in comparison to the actual prices observed in 2013. It is assumed that the base case implies a feed-in of onshore wind and PV following the historic generation profile without curtailment. For biomass, a constant generation profile is assumed for the baseline. These assumptions do not fully reflect reality, as in 2013 direct marketing of renewables already existed in Germany and participating in balancing markets was already possible for biomass. However, as the level of renewables active in intra-day trading and balancing is estimated to be small, this deviation is not considered to interfere with the validity of the results.

Generation can be adapted to demand needs and market prices for dispatchable renewable plants. For variable renewables, curtailment is the only option to avoid negative prices. Both kinds of plant can make use of the intra-day markets to maximise their market revenues. The impacts of revenue maximisation behaviour of renewables on the day-ahead and intra-day markets are assessed in the following paragraphs.

Four sensitivities are implemented regarding the degree of intra-day market liquidity with ms set to 0, 0.2, 0.5 and 1, respectively. Due to the lower generation and installed capacity of the German biomass and PV portfolios, $ms = 1$ is not considered as an ms of 0.5 already enables the full effects for these technologies. Three levels of the merit-order effect are used as described above. In a fourth scenario group, the merit-order effect is ignored. For biomass, two different scenarios are considered. In the first one, electricity is generated constantly during the year from biomass unless prices are below fuel costs (estimated at 30 €/MWh based on Kost et al.[47]) on both electricity markets in which case generation is reduced. In the second scenario, biomass is modelled as flexible. Plant is assumed to be able to ramp up to full production within one trading period. Generation is limited through installed capacity. In reality, solid biomass plants are less flexible than assumed; biogas plants can provide a high degree of flexibility but only with adaptations in the production process or additional biogas storage. Higher flexibility for biomass plant is costly – according to Szarka et al.,[24] costs for increased flexibility for biogas plant is between 10 and 30 €/MWh. These costs need to be considered when interpreting the result. Table 8 gives an overview of factor variations and sensitivities considered.

Changes in average market prices. Figure 4 shows the baseline results for the development of average day-ahead electricity prices under direct marketing assuming a medium MOE and medium intra-day market liquidity. Figures 5 and 6 show the results for different assumptions on MOE and ms. Active marketing of onshore wind, PV, biomass with a constant generation profile and a combination of these three portfolios (all) lead to higher than average prices on the day-ahead market if the merit-order effect is considered. If intra-day trading is allowed for, with increasing intra-day market liquidity and a more pronounced merit-order effect, average day-ahead electricity prices increase to a greater degree. This is

Table 8. Overview of factor variations for optimised intra-day and day-ahead marketing of renewables.

Technology	*Generation profile*	*Intra-day market considered*	*Merit-order effect (MOE)*	*Moveable share (**ms**)*
Biomass	Constant	No	No	0.0
	Flexible	Yes	2012 (base)	0.2
PV	Original profile with curtailment	No	2010 (min)	0.5
Onshore wind		Yes	2007 (max)	0.0
All (Combination of PV, onshore wind and constant biomass				0.2
				0.5
				1.0

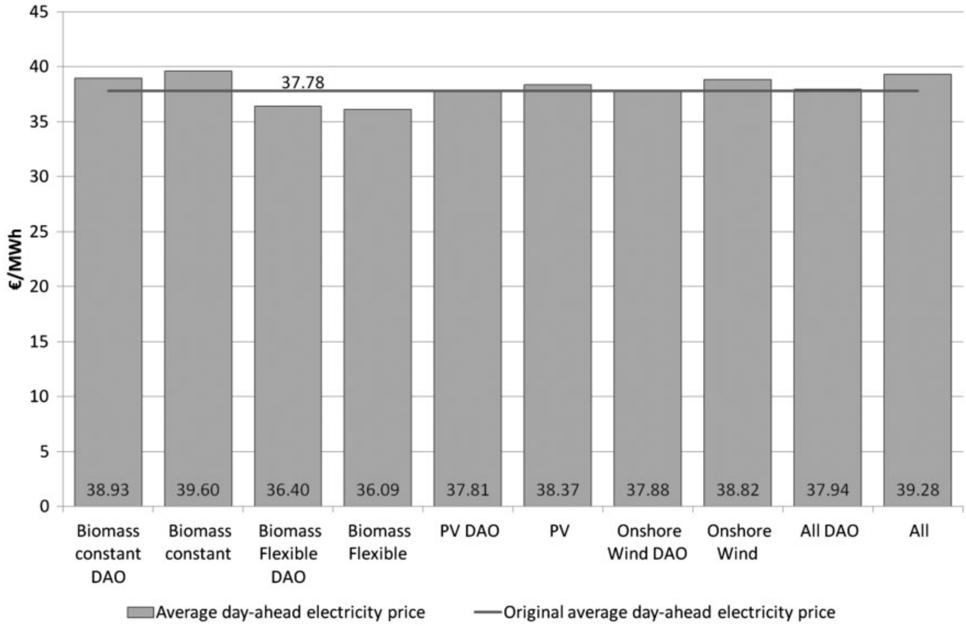

Figure 4. Effects of different marketing strategies for biomass, PV, onshore and a combination of technologies (all) on average day-ahead electricity prices (moveable share = 0.2 and MOE = base). DAO: day-ahead only.

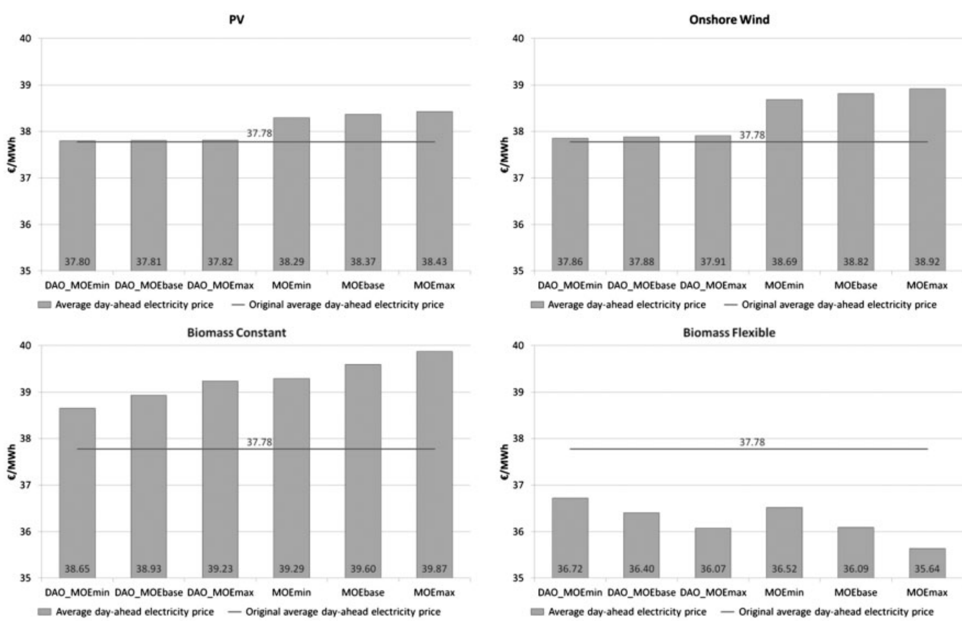

Figure 5. Effects of different degrees of the merit-order effect on average day-ahead electricity prices for different technologies and trading strategies.

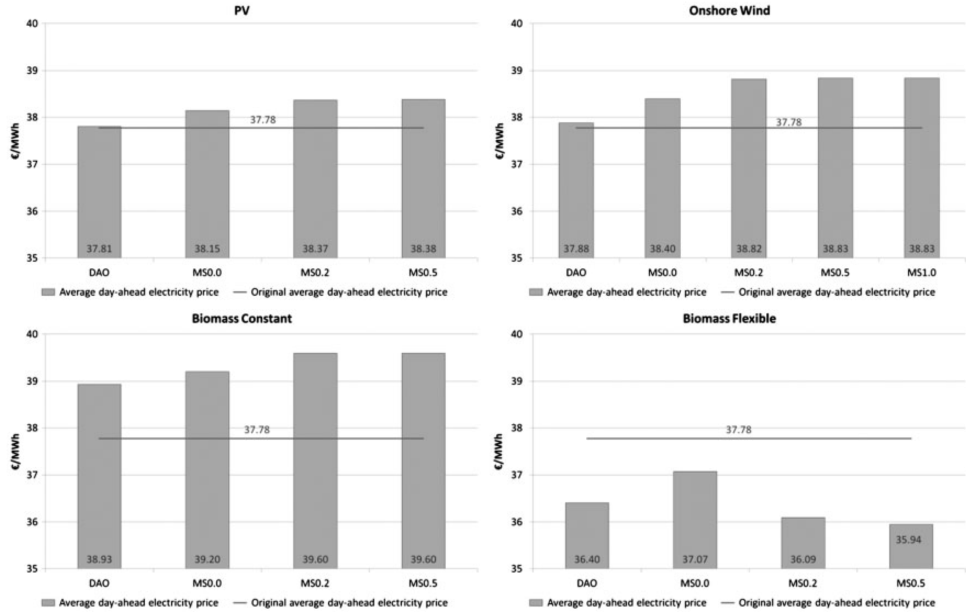

Figure 6. Effects of different degrees of intra-day market liquidity on average day-ahead electricity prices for different technologies and trading strategies.

due to the fact that less energy from renewables at low marginal costs is sold on the day-ahead market and therefore the original merit-order effect is reduced. These results correspond to expectations.

For flexible biomass generation, however, the average day-ahead electricity price is lower than the observed price in 2013. This is because, under flexible generation, power from biomass is only generated in hours with high electricity prices. In these hours, generation is higher than that of the baseline of constant generation indicating that the merit-order effect leads to lower prices in these hours. The reduction of generation does not fully balance this effect under the chosen settings. In reality, as described in previously, the merit-order effect is more pronounced in hours with a higher level of consumption. If this is considered when looking at flexible biomass generation, the results might slightly change.

A higher merit-order effect implies stronger effects of direct marketing and revenue optimisation of average electricity prices (see Figure 5). The same is true for higher degrees of intra-day market liquidity (compare Figure 6). In general, however, the effect is rather moderate. The maximum increase of the average day-ahead electricity price equates to 2.09 €/MWh or 5.5% of the 2013 average price. Also, as shown by the example of flexible biomass generation, revenue-optimising marketing strategies of renewables do not necessarily cause a decrease on their reducing impact on the electricity market price level.

Effects on the intra-day market contrast with those of the day-ahead market as with the opening of intra-day markets for electricity generated from renewable sources, electricity sold on this market increases and therefore prices decrease in the respective hours. The resulting intra-day electricity prices for the base case (MOE = base and $ms = 0.2$) are depicted in Figure 7.

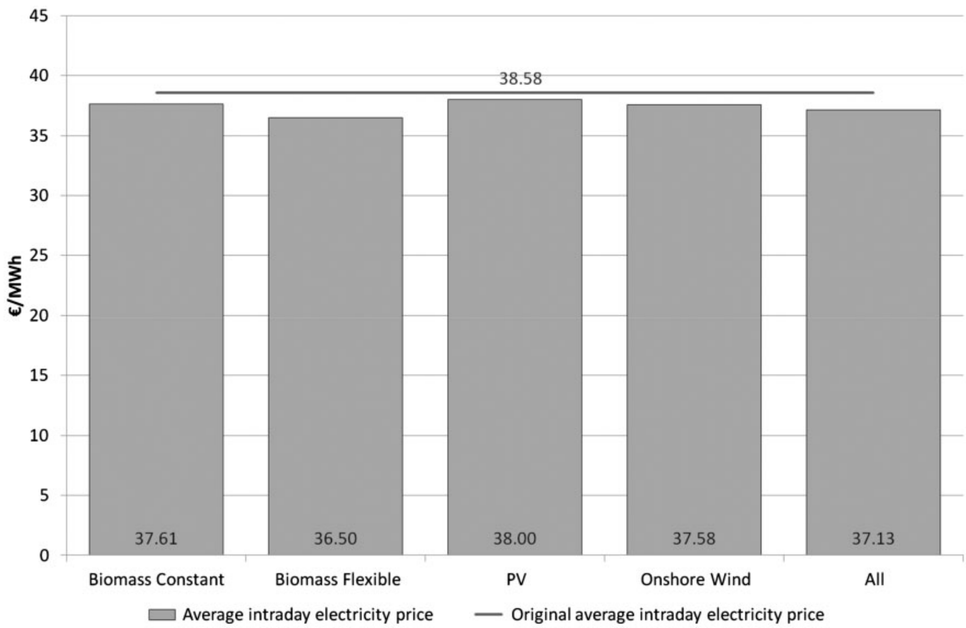

Figure 7. Effects of different marketing strategies for biomass, PV, onshore and a combination of technologies (all) on average intra-day electricity prices (moveable share = 0.2 and MOE = base).

As can be seen, flexible generation and revenue maximisation of marketing of electricity from biomass have the most pronounced impact on the average intra-day market price as under this setting most electricity moves from the day-ahead to the intra-day market. As for the day-ahead market, a higher merit-order effect and higher intra-day market liquidity increase effects. The maximum effect equates to a reduction of 2.79 €/MWh, corresponding to 7.2% of the original average intra-day market price caused by flexible biomass operation with a maximum merit-order effect and full intra-day market liquidity.

Changes in volatility of market prices. Figures 8 and 9 show the impact of revenue maximisation of the marketing of electricity generated from renewable sources on day-ahead and intra-day market price volatility respectively. The figures illustrate that revenue maximisation of marketing of renewable electricity reduces price volatility in almost all cases. This is due to the fact that renewable curtailment in hours with negative prices or prices below fuel costs for biomass leads to a price increase in hours with low prices. In addition, high prices on the intra-day market are reduced, due to the shifting of renewable generation to this market. In the case of PV, the shifting of generated electricity often occurs in hours with high prices on the day-ahead market which are then further increased leading to a slight increase in day-ahead market price volatility.

Also on the intra-day market, price volatility is reduced by the revenue maximisation trading behaviour of renewable plant operators. This result is less straightforward than the reduction of volatility on the day-ahead market. Shifting of electricity from the day-ahead to the intra-day market is realised in hours when intra-day prices are above day-ahead prices. As a consequence, the prices on the intra-day market in these hours are reduced due to the

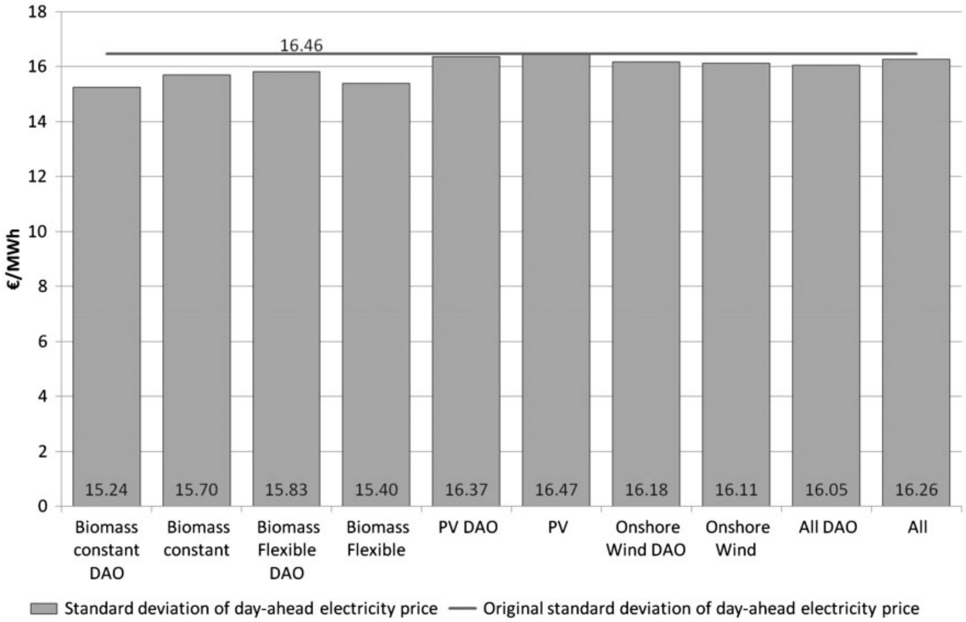

Figure 8. Effects of different marketing strategies for biomass, PV, onshore and a combination of technologies (all) on volatility of day-ahead electricity prices (moveable share = 0.2 and MOE = base).

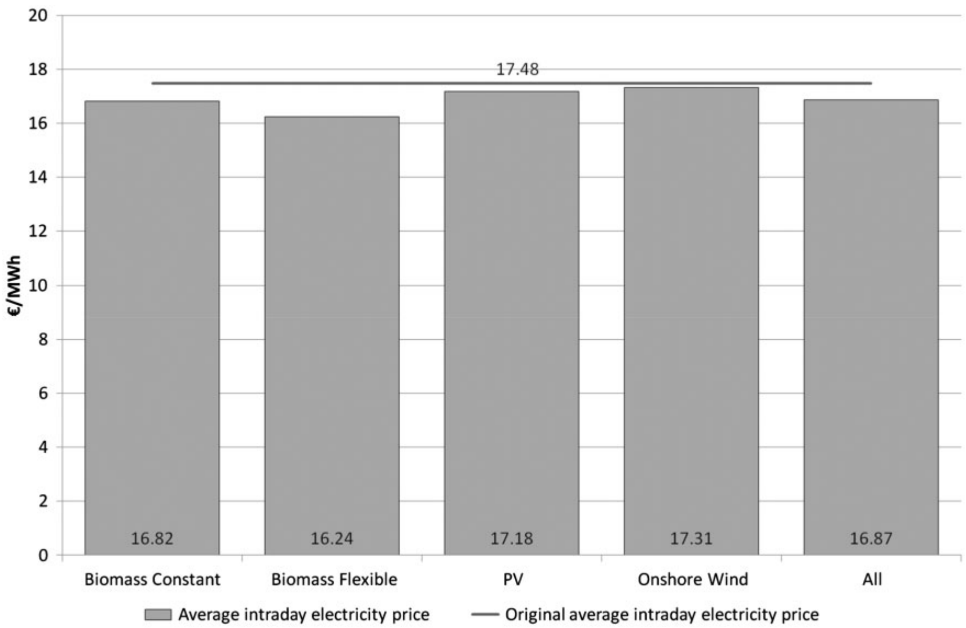

Figure 9. Effects of different marketing strategies for biomass, PV, onshore and a combination of technologies (all) on volatility of intra-day electricity prices (moveable share = 0.2 and MOE = base).

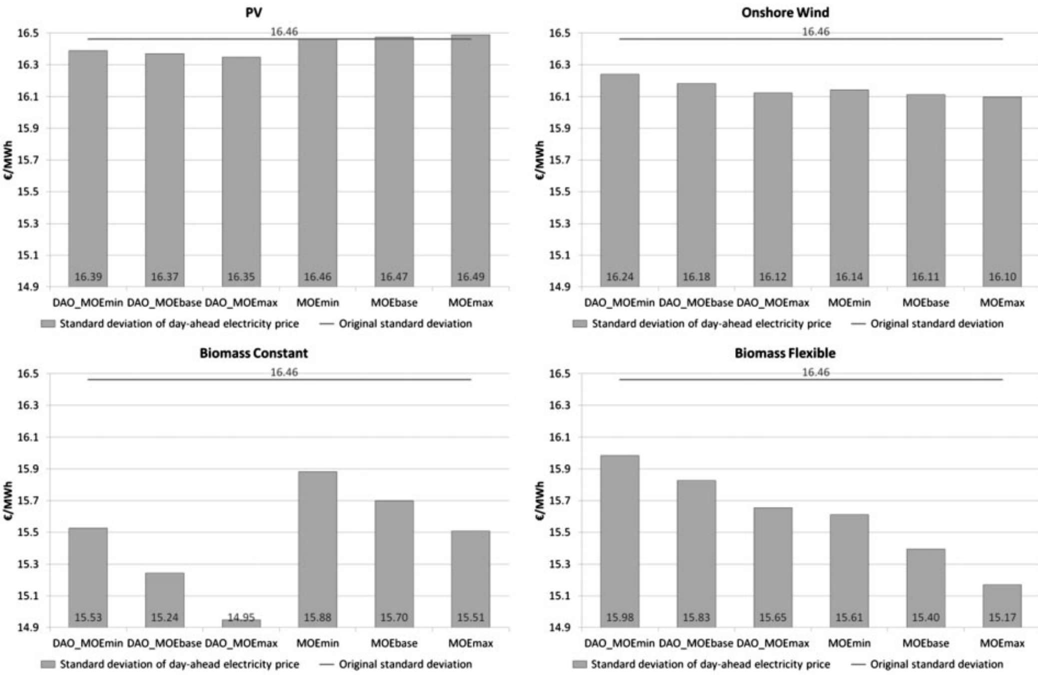

Figure 10. Effects of different degrees of the merit-order effect on day-ahead electricity price volatility for different technologies and trading strategies.

increased electricity supply. This leads to lower price volatility if the hours when the shift occurs originally had higher than average prices. Indeed, this was the case for prices in 2013, with an average intra-day electricity market price in hours with prices above day-ahead prices of 47.12 €/MWh, compared to 30.58 €/MWh in hours with prices below day-ahead prices. This relationship also confirms a theoretical argument, as scarcity on the day-ahead market and thus high prices, tends to increase over the day and therefore leads to higher intra-day market prices. Thus, while results rely heavily on the nature of the relationship between day-ahead and intra-day market prices, the situation observed in 2013 is typical and a generalisation might therefore be valid.

As for the effects on average prices, the impact is augmented by higher intra-day market liquidity and a higher merit-order effect (see Figures 10 and 11 as examples of day-ahead market price volatility). On the day-ahead market, price volatility is reduced by a maximum of 1.34 €/MWh or 8.2%. On the intra-day market, the maximum reduction is 1.60 €/MWh or 9.1%. The extent of the effects observed in the simulation is non-negligible. However, one needs to bear in mind that the assumption of perfect information generates greater movement between the markets than under real world conditions. Thus, in reality, the effects of active renewable trading on market prices are expected to be lower.

Summary and evaluation of hypotheses. According to the first hypothesis (H1), when making allowances for active trading or renewables, both cause electricity prices to increase and price volatility to decrease. The results of the simulation conducted here only partially confirm

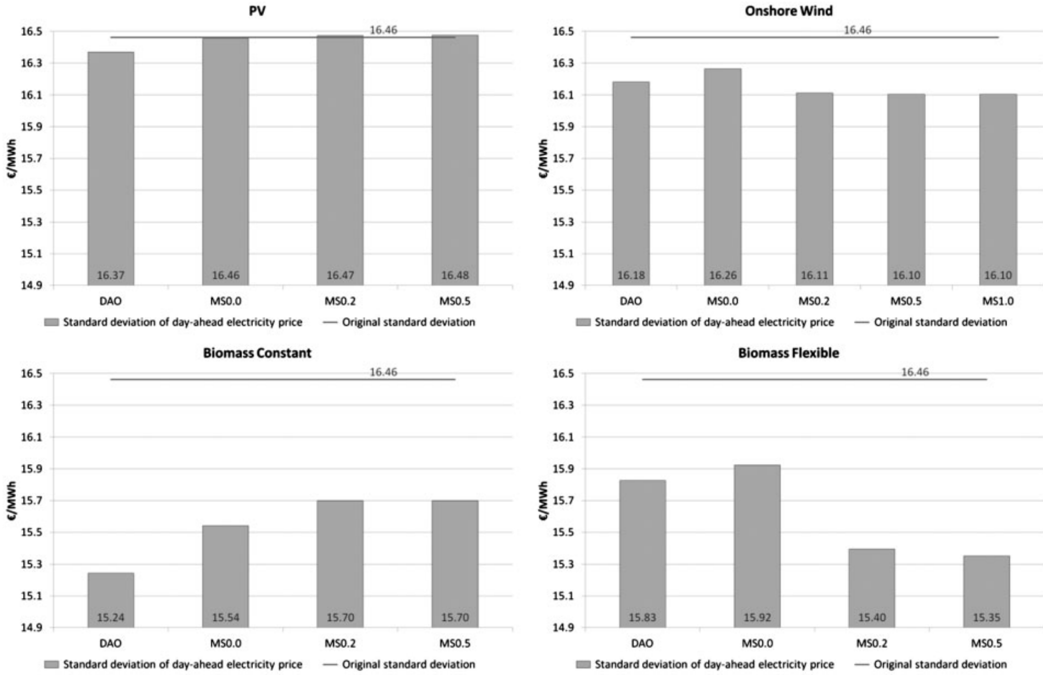

Figure 11. Effects of different degrees of intra-day market liquidity on day-ahead electricity price volatility for different technologies and trading strategies.

this hypothesis. While active marketing of renewables almost always decreases price volatility, the effect on average market prices is less clear. The direct marketing of onshore wind, PV and the constant biomass portfolio leads to an increase in day-ahead prices. However, a flexible operation of biomass plants leads to a further decrease of average day-ahead market prices under the given assumptions. Also, on average, intra-day market prices decrease due to the shifting of renewables to this market.

Contribution of renewables to system flexibility. Increasing shares of variable PV and onshore wind or non-flexible biomass require the remaining electricity system to be more flexible. However, in certain aspects, renewables can also contribute to system flexibility and thus limit the additional flexibility needs. This is of special importance as it affects the provision of balancing services and thereby the reduction of conventional "must-run" capacities and the flexible operation of biomass plant. In the following, the impact of a revenue maximisation behaviour of renewables on flexibility needs is assessed.

Balancing and "must-run" capacities. To analyse the effects on balancing requirements, the participation of renewables in balancing markets is evaluated. In principle, renewables can participate in both positive and negative balancing as far as market rules allow for such participation. In Germany, currently only biomass plants are admitted to balancing markets, but discussions are ongoing regarding the participation of variable renewables. For the purposes of this study, a full opening of secondary and tertiary balancing to variable renewables is assumed. In the following assessment of the contribution to balancing, only constant biomass generation is included. This generates a higher biomass contribution than the flexible generation curve. The reason for this is that flexible biomass leads to a more volatile generation profile which makes biomass less available for balancing.

As price effects are considered in the analysis, the contributions shown here do not represent maximum contributions, but the contribution leading to maximum revenues for each technological portfolio. This also implies that the distribution between the tertiary and secondary reserve in a specific slot is based on both the plant availability and the price difference between the two markets.

Potential contribution of renewables to balancing needs shows that renewables may substantially contribute to balancing requirements. Even though technologies are investigated separately, in some hours positive balancing is fully provided, and negative balancing almost fully provided, by biomass or wind plant.

Due to the relatively long product period of one week for secondary balancing, PV cannot participate in this market under current conditions. However, even PV plants provide on average 21% of negative tertiary reserves and 18% of positive tertiary reserves. The most important contribution to balancing requirements stems from biomass plant delivering up to 100% (on average 65%) of negative and up to 99% (on average 67%) of positive reserves. In hours with negative balancing prices, there is no contribution from biomass. This occasionally occurred in 2013. The share of balancing provided by renewables can be directly translated into a reduction of conventional "must-run" capacities unless such plant is also involved in primary balancing. When it comes to positive reserves, the biomass contribution never sinks below 1.4 GW, implying a very clear "must-run" reduction (compare Table 9). However, opportunity costs of positive balancing are not considered in this analysis so that the real contributions, especially of wind and PV, will be lower.

Flexibility of biomass generation. Under the assumptions made, biomass plant will run in flexible mode if this is profitable given the additional costs linked to more flexible operation. As mentioned above, these costs are estimated to be in the range between 10 and 30 € /MWh.[24] In addition, technical restrictions apply for plant flexibility.

Figures 12 and 13 illustrate that the net revenues for the MWh originally generated (i.e. total revenues minus fuel costs, divided by baseline electricity generation) are higher for flexible generation than constant generation and curtailment. However, additional revenues are lower than costs for flexible operation in all scenarios. This means that flexible biomass plant operation was not profitable under 2013 market conditions. When actual electricity generation is considered, this becomes even clearer; curtailing occurs more often in scenarios without flexible generation while electricity generation over the year is higher with a more flexible generation (see Figure 14). Revenues from MWh actually generated are therefore lower with higher flexibility.

Consequently, at least under 2013 market conditions, the hypothesis that revenue-maximising trading of electricity from renewable sources enhances flexible biomass operation cannot be confirmed.

Summary and evaluation of hypotheses. Simulation results show that renewables can contribute substantially to both positive and negative balancing requirements when allowed and thus hypothesis H2.1 can be confirmed based on German data from 2013. Hypothesis H2.2 cannot, however, be confirmed as flexible generation from biomass plant was found not

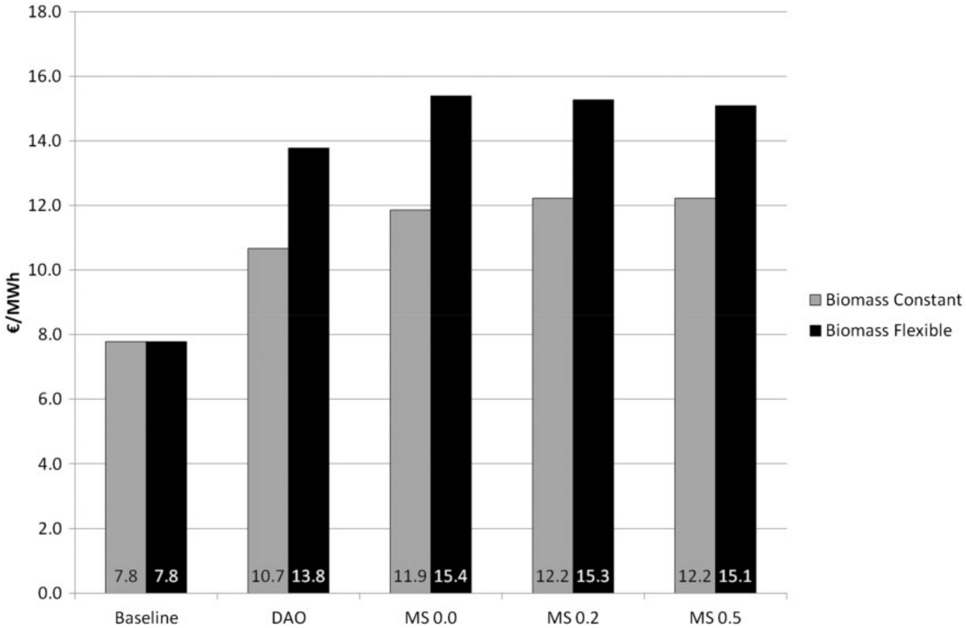

Figure 12. Net revenues (excluding fuel costs) of constant vs. flexible biomass generation per originally generated MWh of electricity for day-ahead only trading and different degrees of intra-day market liquidity (MOE = base).

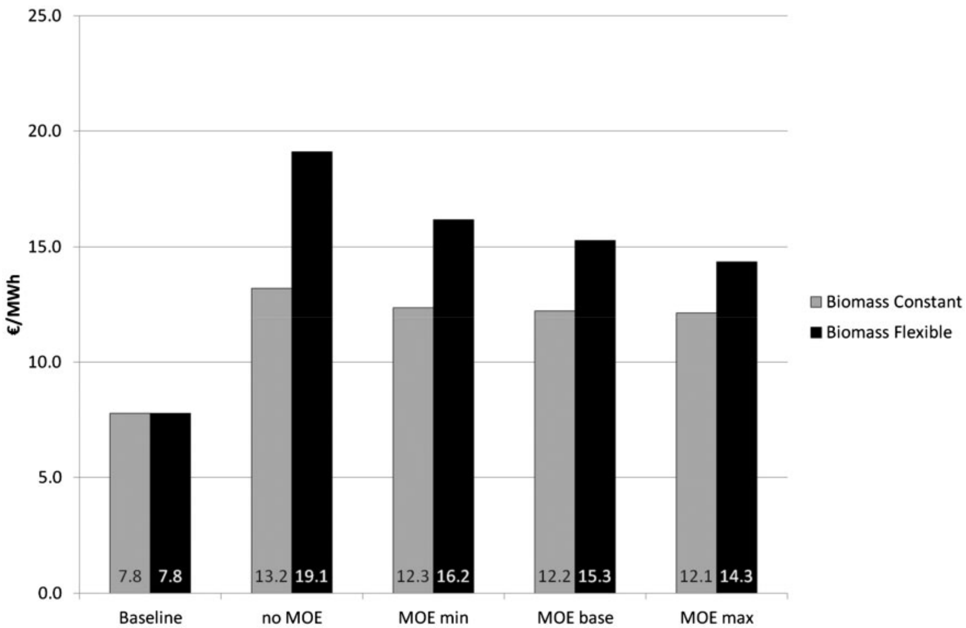

Figure 13. Net revenues (excluding fuel costs) of constant vs. flexible biomass generation per MWh of electricity originally generated for day-ahead only trading and different assumptions regarding the extent of the merit-order effect ($ms = 0.2$).

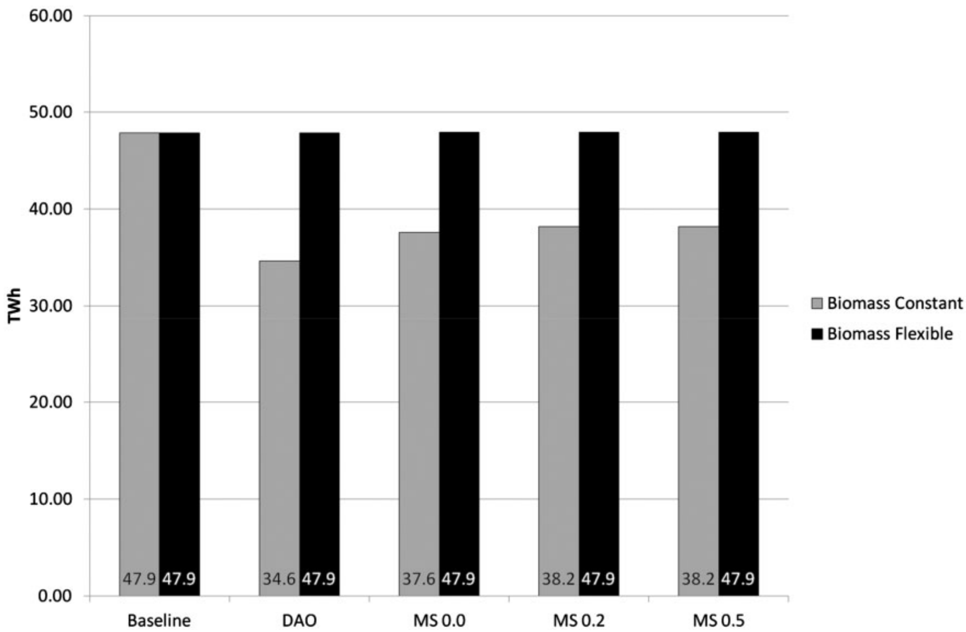

Figure 14. Electricity generation from biomass with and without flexibility for day-ahead only trading and different degrees of intra-day market liquidity (MOE = base).

to be profitable. This result can be explained by the fact that spreads in the German spot market are currently very low indicating a high level of installed capacity and sufficient flexibility. In the future, with increasing renewable shares and lower availability of conventional plant, this might change unless storage and demand-side assets fill the gap at a lower price than biomass plant.

Revenues of renewable electricity. To assess the potential for creating additional revenues from electricity markets other than the day-ahead market, the intra-day markets, secondary and tertiary balancing and the futures market are assessed for biomass, PV and wind onshore. Selling all electricity generated without curtailment on the day-ahead market is used as a baseline.

Spot market. Figures 15 to 18 show additional revenues generated from revenue-maximising trading under different settings regarding the merit-order effect and intra-day market liquidity for PV, onshore wind, and constant and flexible biomass.

In general, revenue maximisation of marketing creates moderate additional revenues of 7% (ranging between 1% and 11%) for both PV and onshore wind. Biomass achieves substantial revenue gains (excluding fuel costs) of 57% (range 37–70%) for constant generation and 96% (range 71–145%) for flexible generation. The results shown correspond to an increase in revenue of 2.52€/MWh for PV (range 1.64 €/MWh to 4.17 €/MWh); 2.21 €/MWh for onshore wind (range 0.33 €/MWh to 3.60 €/MWh); 4.47 €/MWh for constant biomass (range 2.90 €/MWh to 5.42 €/MWh) and 14.26 €/MWh (range 5.51 €/MWh to 18.63 €/MWh) for flexible biomass generation. The optimal curtailment rate remains below

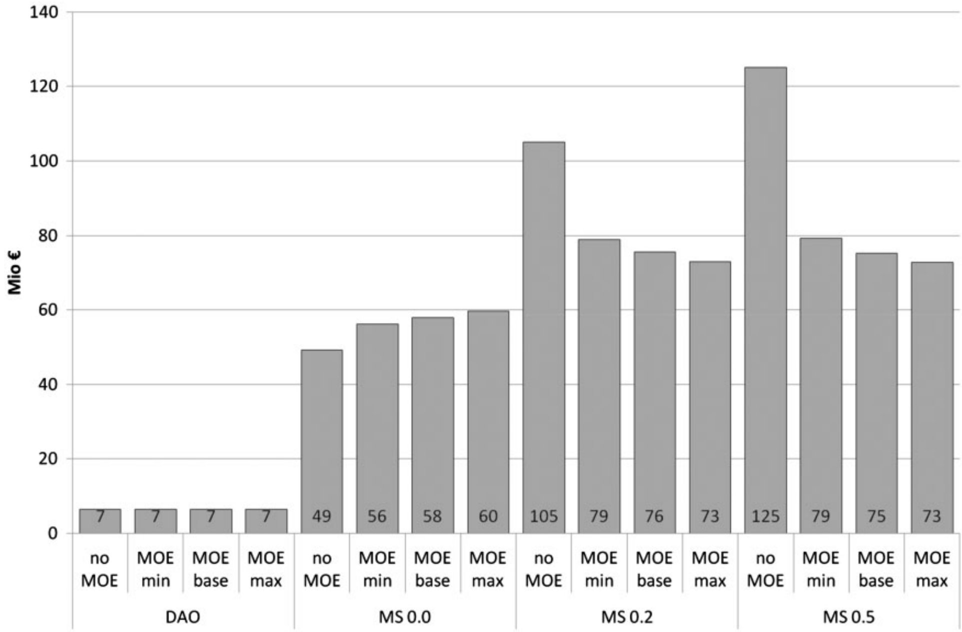

Figure 15. Additional revenue of PV plants under optimised marketing on spot markets depending on intra-day market liquidity and degree of merit-order effect.

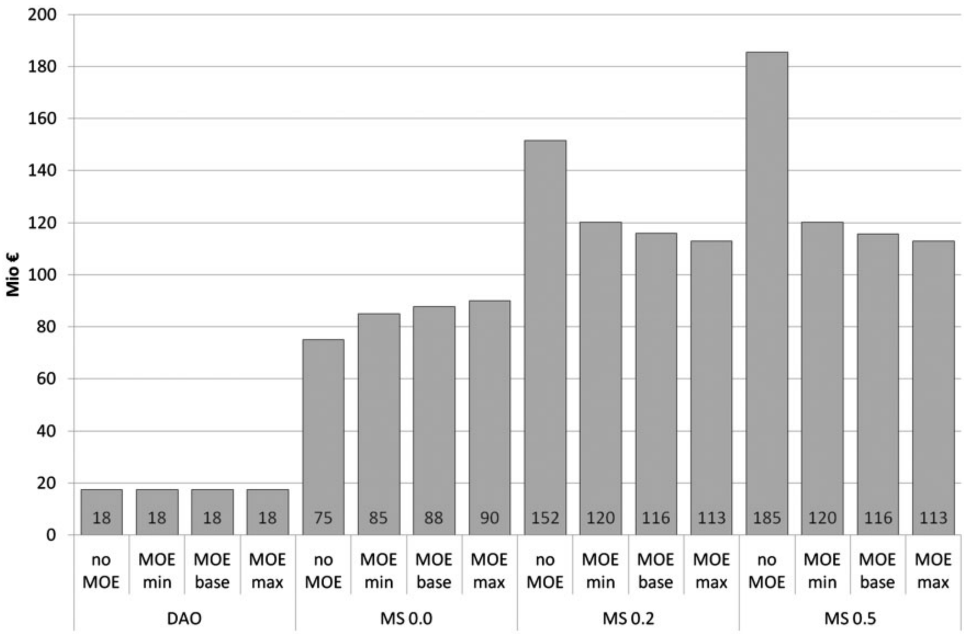

Figure 16. Additional net revenues of wind onshore plants under optimised marketing on spot markets depending on intra-day market liquidity and degree of merit-order effect.

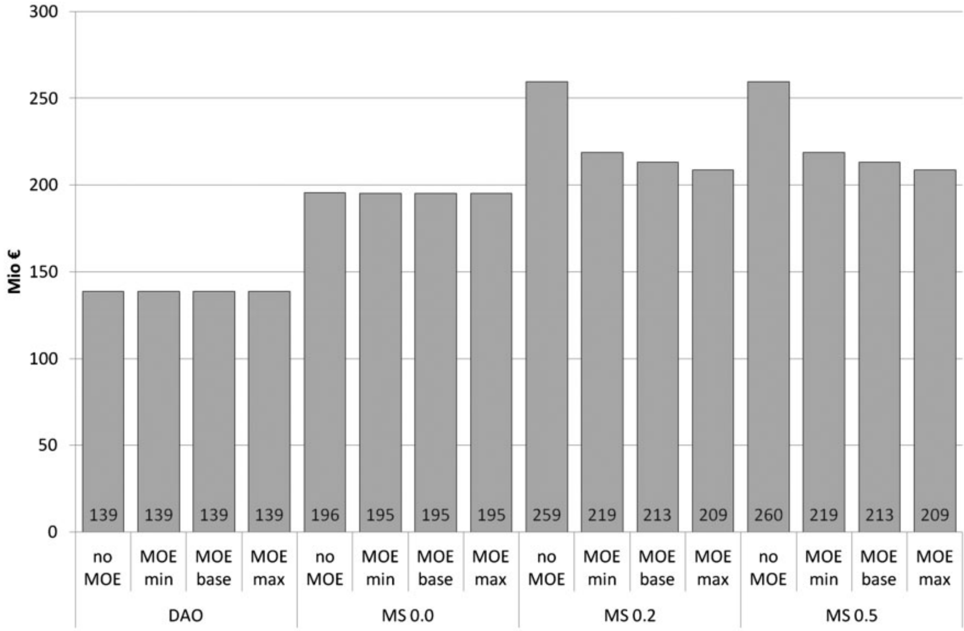

Figure 17. Additional net revenues (excl. fuel costs) of biomass plants (constant generation) under optimised marketing on spot markets depending on market liquidity and MOE.

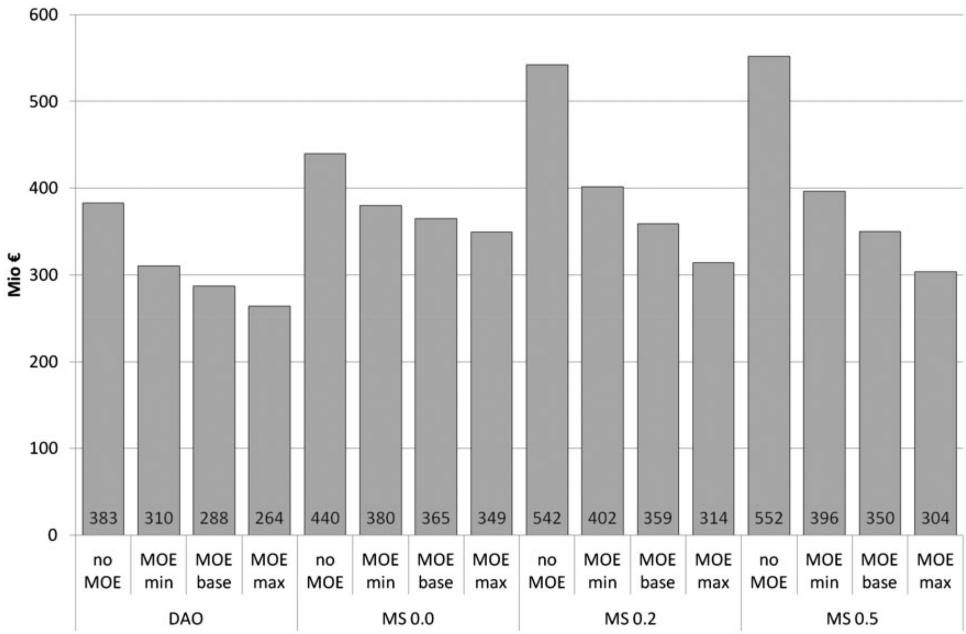

Figure 18. Additional net revenues (excl. fuel costs) of biomass plants (flexible generation) under optimised marketing on spot markets depending on market liquidity and MOE.

1.5% in all cases for PV and below 2.5% for wind. For biomass, the assumption of fuel costs of 30 €/MWh leads to high curtailment under constant generation between 20% and 28% to avoid losses. Flexible biomass generation completely avoids curtailment.

Low intra-day market liquidity and a higher merit-order effect are in general linked to lower revenues. However, when intra-day market liquidity is low, in some cases a high merit-order effect results in higher revenues. This is due to the fact that in the calculation, the merit-order effect is applied symmetrically to intra-day and day-ahead markets. When electricity is moved from the day-ahead to the intra-day market, the price on the intra-day market decreases and the price on the day-ahead market increases to the same extent. If the amount that can be moved to the intra-day market is restricted, the capacity remaining on the day-ahead market is substantial. In the case of a high merit-order effect, this remaining capacity profits from a greater increase of the day-ahead market price compared to a lower merit-order effect. As the merit-order effect on the intra-day market is even more pronounced than on the day-ahead market, this situation could also occur in reality. Thus, the relationship between the merit-order effect and intra-day market liquidity needs to be considered to develop an optimal trading strategy.

Balancing market. When offering positive balancing, plant operators face opportunity costs due to foregone revenues from selling electricity on the day-ahead market. Consequently, the contribution of variable renewables (wind and PV), to positive balancing, proves to be non-revenue-maximising even without considering risks of non-availability and non-perfect information. Reducing the product period to one hour increases revenues from balancing for PV and wind due to higher sales volumes, but it also results in higher foregone revenues from the day-ahead market (see Figure 19). Consequently, only biomass would contribute to positive balancing requirements under the premise of revenue maximisation as the biomass portfolio generates an additional revenue of 70.8 Mio € (corresponding to 1.47 €/MWh per MWh or 19.0 % of original revenues excluding fuel costs). Depending on the risk assessment of plant failures and costs for non-availability on the balancing markets, the provision of positive balancing might be a profitable option for biomass plants.

Negative balancing does not imply restrictions to selling electricity on other markets. Costs arise from trading as well as from uncertainties and the risk of non-availability. However, these are not considered in the analysis. Consequently, participating in negative balancing is profitable for all renewable portfolios. Figure 20 shows the additional revenues per MWh. Biomass earns a higher revenue from negative balancing if a constant generation profile is assumed rather than the flexible profile arising from the constant availability of balancing capacity. The reduction of the product period to 1 hour is beneficial, especially for the revenues from flexible biomass generation, which increase fivefold. PV and wind also profit substantially. Constant biomass generation benefits from a better possibility to sell secondary and tertiary balancing in the same slot and thus revenue also increases slightly.

Futures market. Due to the choice of the futures product (Phelix Base Year Future) and the precondition of fulfilling the contract without additional trading on other markets, it is only possible for wind and biomass to participate in this market. While the entire biomass portfolio can be sold on the futures market, the wind sales are restricted to firm capacity which in 2013 made up 2.3% of the entire generation (141 MW per hour). As prices on the futures market were high compared to other markets in 2013, trading on this market was very

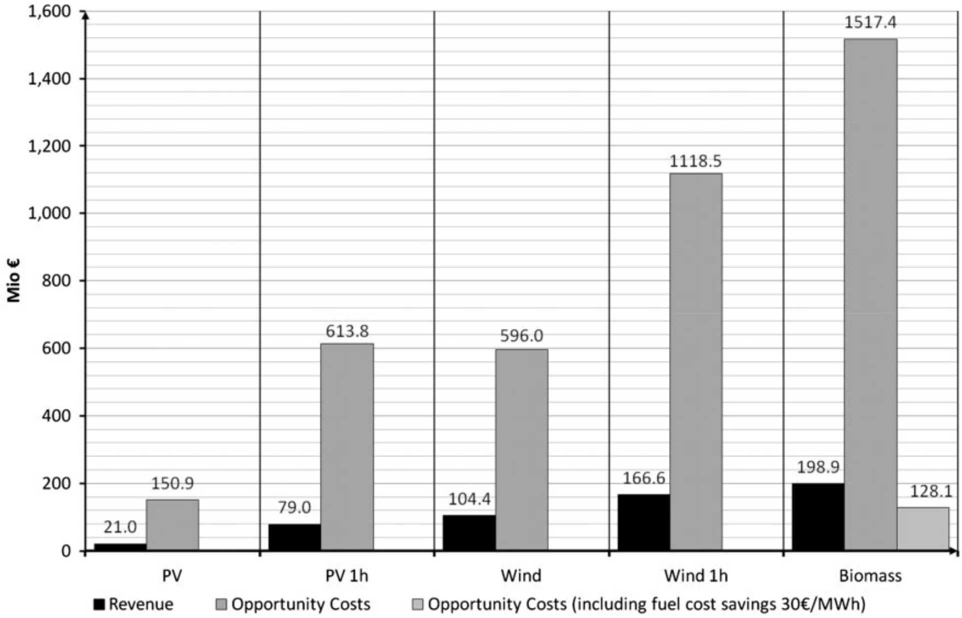

Figure 19. Additional revenues and opportunity costs from active trading on the market for positive secondary and tertiary reserves depending on technology and product period.

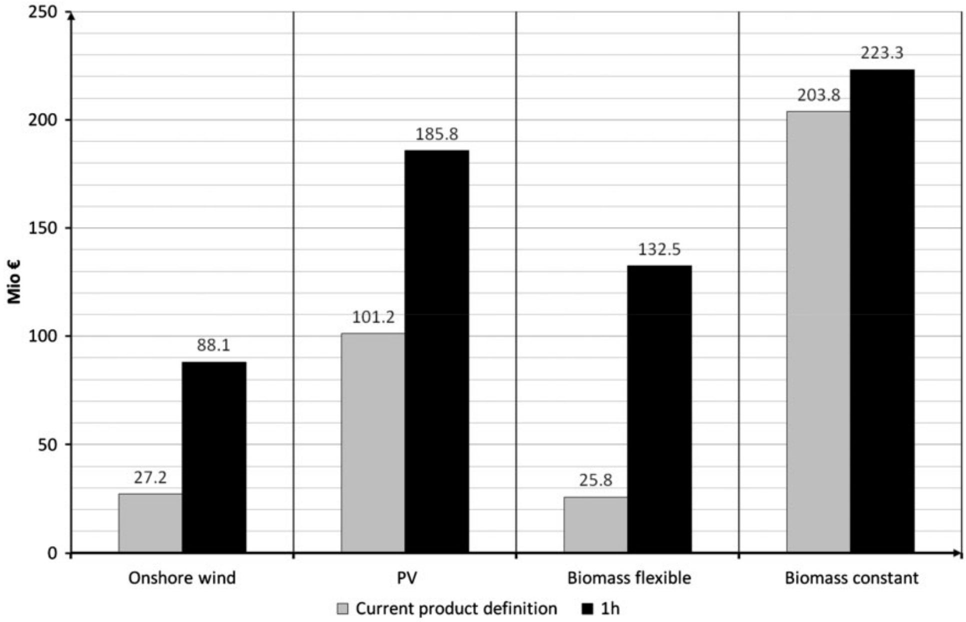

Figure 20. Additional revenues from active trading on the market for negative secondary and tertiary reserves depending on technology and product period.

Table 9. Potential contribution of renewables to balancing needs.

	PV	*Onshore wind*	*Biomass*
Negative balancing			
Secondary reserve			
Average contribution (MW/%)	0 0%	305 7%	1661 65%
Maximum contribution (MW/%)	0 0%	2555 59%	4178 99%
Minimum contribution (MW/%)	0 0%	0 0%	0 0%
Number of slots with full balancing provision	0	0	0
Tertiary reserve			
Average contribution (MW/%)	530 21%	1519 59%	1661 64%
Maximum contribution (MW/%)	2725 >100%	3242 >100%	3242 >100%
Minimum contribution (MW/%)	0 0%	0 0%	0 0%
Number of slots with full balancing provision	18	54	34
Total			
Average contribution (MW/%)	530 8%	1824 27%	4393 65%
Maximum contribution (MW/%)	2725 72%	4915 >100%	6573 >100%
Minimum contribution (MW/%)	0 0%	0 0%	0 0%
Number of slots with full balancing provision	0	3	3
Positive balancing			
Secondary reserve			
Average contribution (MW/%)	0 0%	778 18%	3291 77%
Maximum contribution (MW/%)	0 0%	4107 99%	4295 >100%
Minimum contribution (MW/%)	0 0%	142 3%	1458 34%
Number of slots with full balancing provision	0	0	336
Tertiary reserve			
Average contribution (MW/%)	432 18%	1049 42%	1226 49%
Maximum contribution (MW/%)	2558 >100%	2597 >100%	2597 >100%
Minimum contribution (MW/%)	0 0%	5 0%	5 0%
Number of slots with full balancing provision	12	36	44
Total			
Average contribution (MW/%)	432 6%	1826 27%	4508 67%

(continued)

Table 9. Continued

	PV	*Onshore wind*	*Biomass*
Maximum contribution (MW/%)	2558 37%	6416 97%	6736 99%
Minimum contribution (MW/%)	0 0%	160 2%	1463 22%
Number of slots with full balancing provision	0	0	0

profitable – the revenue per MWh was 57.64 €/MWh for biomass and 60.25 €/MWh for wind and thus 8.4 €/MWh and 24.5 €/MWh above the highest calculated revenue (without MOE) from spot trading. However, the results for the futures market depend even more heavily on the assumption of perfect information regarding prices and plant availability than for the other markets assessed. Furthermore, in the long run, prices on the futures market tend to equal prices on the spot market. Otherwise, arbitrage opportunities between these markets would exist to reduce the gap between the prices. Thus, the suitability of a trading strategy with a focus on the futures market is uncertain in the long run even if spreading the sales between several markets can decrease trading risks and therefore increase revenues given real world uncertainties.

Summary and evaluation of hypotheses. Based on the analysis of German data for 2013, the hypothesis that revenue maximisation of marketing leads to higher revenues and can therefore reduce support costs for renewables can be partially confirmed.

In the case of onshore wind and PV, participating in the intra-day market created moderate additional revenues. However, one needs to consider that these revenues were obtained assuming perfect information and do not include any risks or associated trading costs. In the case of balancing, possible gains will probably outweigh additional costs. Therefore, support cost requirements might be reduced, especially by allowing variable renewables to participate in negative balancing.

For biomass however, a different picture was shown. Optimised spot trading and especially curtailment of generation at prices below fuel costs substantially increase overall revenues. Therefore, revenue maximisation of the marketing of biomass might lead to lower support expenditures in the future. However, even if flexible plant operation is not more profitable than constant operation, it avoids curtailment and thus generates the additional capacity requirements needed to achieve generation-based renewable extension targets. Biomass plant can also profit moderately from participating in positive and negative balancing. Negative balancing, however, requires lower curtailment rates.

With respect to the futures market, prices were high in 2013 and thus futures trading was exceptionally profitable. However, due to the high risks regarding price development and non-availability of plant, selling the maximum possible capacity on the futures market is certainly not advisable.

Summary and conclusions

New developments regarding market liberalisation, and support schemes for renewables, encourage the active participation of these technologies in the electricity market.

This paper analyses the effects of such a participation of renewables on different electricity market segments. Based on 2013 data from Germany and perfect information, and without considering opportunity costs arising from the chosen support scheme, three hypotheses regarding these effects were investigated.

The first hypothesis implies that revenue maximisation of marketing of electricity generated from renewables contributes to higher than average electricity prices and decreases price volatility. This hypothesis was partially confirmed by the data. It was shown that revenue-maximising marketing of renewables under most settings assessed decreases price volatility. The effect on average market prices was, however, less clear. Day-ahead market prices indeed increased, except in the case of flexible biomass operation. Intra-day prices, however, decreased due to the shifting of electricity from the day-ahead to the intra-day market. Therefore, the overall effect on average market prices remains ambiguous and also depends on the share of renewables traded in different market segments.

The second hypothesis states that revenue maximisation of marketing of renewable electricity contributes to system flexibility as renewables provide balancing services, and the operation of flexible biomass plant reduces flexibility requirements. The analysis confirmed that renewables can contribute substantial shares of balancing needs. In the case of negative balancing, this is also profitable for all technologies considered, while due to the opportunity costs arising, positive balancing is only attractive for biomass. However, the analysis showed that, at least under German market conditions in 2013, the flexible operation of biomass plant was, in most cases, not profitable. This was due to the additional costs linked to operating the plant more flexibly and restricted revenue potentials because of low price spreads. This result might however change under a different set of assumptions, for example regarding costs of more flexible operation.

The third hypothesis suggests that revenues from renewables are expected to increase by trading on different electricity markets. In the medium term, this might lead to a decrease in support expenditures and could be partially confirmed based on the research in this paper. In the case of PV and onshore wind, participation in negative balancing is linked to substantial additional revenues while intra-day trading is probably not profitable considering the additional trading costs and risks. Biomass plant, however, could generate substantially increased revenues from trading by curtailing generation when prices are above fuel costs. Furthermore, the participation in both positive and negative balancing generated moderate revenues for biomass plant.

The analysis conducted in this paper partially confirmed the hypothesis regarding the benefits of an active participation of renewables in electricity markets. It shows that the introduction of more market-oriented support instruments could be beneficial in some cases but policy-makers should not expect dramatic changes regarding plant behaviour or costs. The analysis also showed that considering price effects of shifting renewable electricity between markets and market liquidity is crucial for results. In order to generalise the results from this analysis, further research is necessary; for example, it could be based on data for other years and countries or based on models with more extreme data assumptions. Future revenue gains might substantially increase with rising price spreads due to lower capacity margins. In addition, uncertainties regarding prices and generation should be included in the assessment to investigate, among others, the impact of forecast accuracy. Also, differences between the simulation approach used here and a full revenue optimisation should be analysed.

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Notes

a. A flexible power system is able to quickly react to expected and unexpected changes in demand or supply. While in the past, changes in electricity demand and plant outages were the main reasons for system flexibility needs, the increase of electricity generation from variable renewables requires additional flexibility.
b. The three mechanisms mentioned entail different degrees of market distortion. Under capacity payments, market distortion is minimised as it is only electricity market prices which determine plant operators' dispatch decisions. Under feed-in premium and quota schemes, opportunity costs of foregone revenues from the support scheme are also considered. A detailed analysis of these differences, also including the effects of feed-in tariffs, can be found in Winkler et al.[13]
c. In energy-only electricity markets, only generated electricity is paid for. The alternative are markets in which installed capacity or availability of plants is also remunerated. This can be organised in the form of a capacity market or capacity payments, among others. Hybrid forms also exist, for example when the regular electricity market is complemented by a strategic reserve. An overview of capacity mechanisms and their advantages and disadvantages can be found in Finon and Pignon.[48] In Germany, plant availability and capacity are currently only rewarded in the balancing markets. However, a strategic reserve will be introduced in the near future to guarantee security of electricity supply.
d. That is, if the wind or solar resources are low/strong, the more wind/solar is installed, the more this phenomenon is enhanced and the less value is added by additional variable generation capacity.
e. This assumption corresponds to a system where renewables are either not supported or support is organised in the form of a capacity payment. This implies that dispatch decisions are taken solely based on electricity market prices and no distortion occurs due to generation-based support.
f. The actual trading volume in this paper is defined as the trading volume realised in the respective hour or trading period in 2013.
g. A summary of relevant literature on the merit-order effect can be found in Würzburg et al.[2]
h. The low prices are to some extent attributed to the high share of renewables in combination with low CO_2 prices. The economic crisis and increasing European market integration also play a role. For systematic differences between spot and futures prices, and risk premiums in the German and Nordic future market, see Benth et al.,[49] Botterud et al.,[50] Huisman and Kilic,[51] Pietz,[52] Viehmann,[53] and Weron and Zator.[54]

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