Merit order effect of flexibility options

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***Abstract*—Due to increasing amounts of variable renewable generation, additional flexibility in the German electricity market is necessary. Potential revenues for flexibility options like battery storage systems or demand side management can be calculated based on historic prices. However, additional flexibility in the system also affects future prices.**

In order to approximate this effect, bid curves of the EPEX SPOT day-ahead market are used. New flexibility options may be considered to be functional storages; this allows simulating the assumed operation by linear optimization. By adjusting the bid curves according to demand or supply by the additional flexibility option, a new time series of prices can be determined. Using this, potential revenues and operation of another flexibility option is simulated. Iteratively repeating this method yields continuously decreasing revenues for additional flexible power in the market. At about 2.5 GW the reduction is 50 %.

Keywords-flexibility, merit order, spot market, demand side management

I. Introduction

Due to the expansion of installed renewable energy capacity in Germany (up to 141 GW in 2025 according to the latest network development plan [1]), flexibility is becoming increasingly important for integrating fluctuating production into the energy system. In today's market setting, flexibility demand which cannot be covered by flexible power plant operation or importing and exporting energy is mainly provided by storage systems. Spreads between high and low spot prices enable revenues by buying electricity at low prices and selling at high prices. The size and frequency of those price spreads determine the profitability of storage systems. In the future, new flexibility options like residential or industrial demand side management can provide this flexibility and can therefore be considered functional storages. Additional functional storage units also affect spot prices due to their participation in the market. Adding means of flexibility to the system thus entails decreasing prospects of revenues for further functional storage systems.

The necessity for additional flexibility is illustrated in fig. 1. It shows mean PV generation in Germany in 2015 compared with mean electric load for the same year, both normalized to a daily sum of 1. The curves evince considerably different characteristics: the expected PV peak around noon in contrast to the morning and evening peaks of the load. Additional flexibility in terms of e. g. storage or load shifting can help to match these curves.

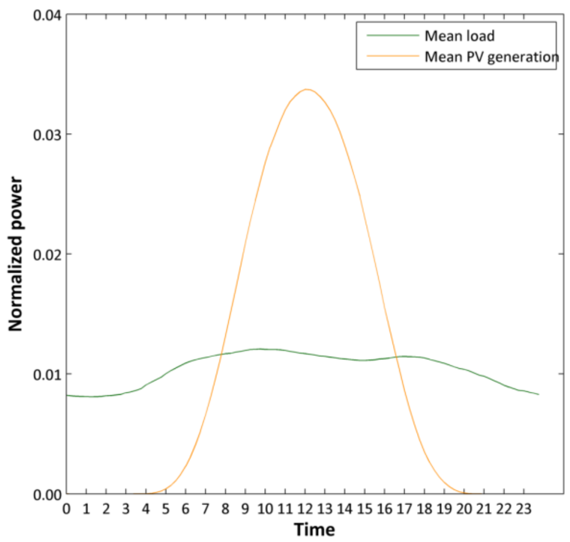

Figure 1. Comparison of PV generation and load

The mean EPEX SPOT day-ahead price curve for the year 2015, depicted in fig. 2, shows similar features as the load curve in fig. 1. This indicates a relevant effect of PV generation on price formation. Therefore, market-driven flexibility options help to integrate additional PV energy in today’s market setting. As stated previously, this may change with market entry of new flexibility options due to their impact on prices.

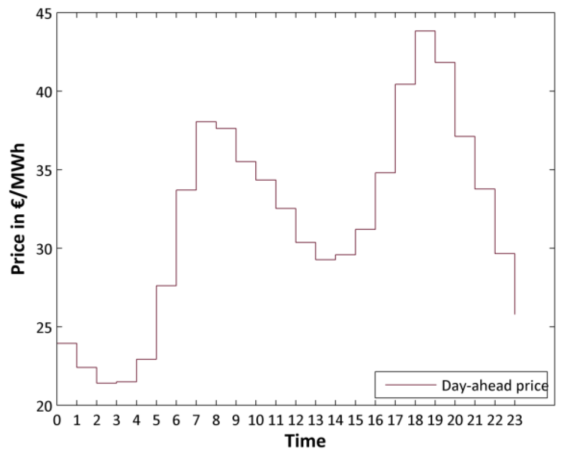

Figure 2. Mean hourly day-ahead price 2015

II. Methods

For modelling of spot market prices with additional flexibility in the market, bidding curves from EPEX SPOT are used [2]. These data and the model for potential prices and revenues for flexibility options are described in the following sections.

A. Data

At the day-ahead-market of EPEX SPOT, every participant can place buy or sell bids for every hour of the following day. One bid is characterized by price and volume. All the bids received by EPEX SPOT for a specific hour are combined and form two curves: the demand curve (all buy bids in order) and the supply curve (all sell bids in order), where the demand curve does not necessarily reflect the actual demand [3]. An example for one hour of 2015 is depicted in Fig. 3. The supply curve starts at the minimum price of –500 €/MWh and ends at the maximum price of +3 000 €/MWh. The demand curve shows the reverse order.

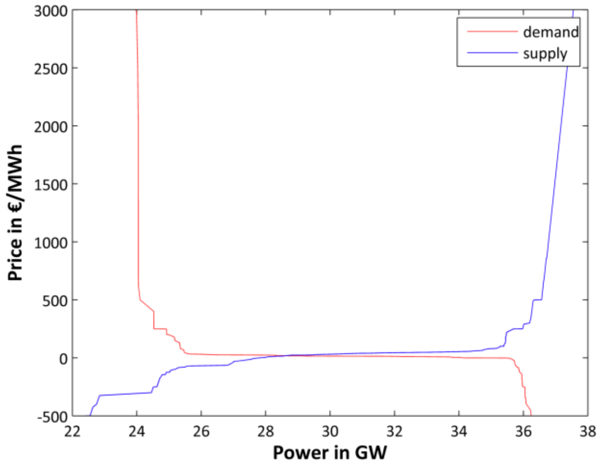

Figure 3. Demand and supply curve for one hour

The intersection of these curves defines the market clearing price as well as the traded volume. This is illustrated by an enlarged version of the above example in Fig. 4. The resulting market clearing price in this case is 18.1 €/MWh at a trading volume of 28.6 GW.

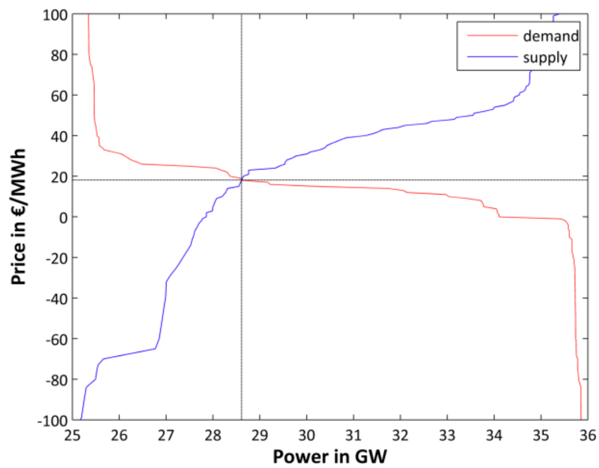

Figure 4. Determininig the market clearing price

These curves are published daily by EPEX SPOT since January 1st, 2011. This allows using data for five full years in the following computations.

B. Optimization

As explained above, flexibility options in general can be considered as functional storages. This means that they are “charged” at low prices and “discharged” at high prices to generate revenues. In order to identify the optimal operation of a given flexibility option to achieve this goal, linear optimization is applied to determine optimal hours for charging and discharging.

The optimization model uses hourly prices as inputs. A functional storage with the capacity to charge at maximum power for 1 hour and an efficiency of 80 % is assumed. Maximum charging and discharging power are identical. The objective of the model is to maximize the revenues. Taxes and fees for the different types of functional storages are neglected. These calculations only consider the day-ahead spot market. Additional revenues from intraday and control power markets are excluded, but can potentially multiply the result [4].

Fig. 5 shows the exemplary result of the described optimization process for one day. Negative operation means charging the flexibility option, whereas positive values represent discharging. As expected, low prices are used to charge and high prices to discharge. Due to the assumed efficiency of 80 %, more energy is charged than discharged.

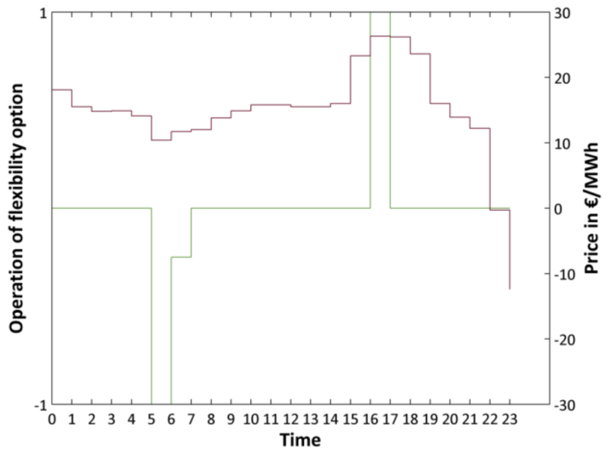

Figure 5. Optimized operation of flexibility option

C. Modelling of prices

The hourly prices at EPEX SPOT are given by the intersection of demand curve and supply curve. To calculate this intersection, linear interpolation is applied. This is necessary because the curves are defined in discrete steps as given by individual bids.

The original hourly curves can be used to determine the time series of prices. These are used in the first step to simulate the optimal operation of a flexibility option. This yields the charging or discharging power (which can be zero) for each hour of the year, which can be represented as additional demand or supply in the bid curves for the respective hours:

- Additional demand is added to the demand curve with maximum price, which means this demand will always be fulfilled.
- Additional supply is added to the supply curve with minimum price, therefore this will also be fulfilled.

The effect of adding additional demand is illustrated graphically in Fig. 6. Since the intersection point also changes, this yields a new price. Even though the bids of additional flexibility options are inserted at maximum or minimum prices, their revenues are still calculated based on the market clearing price, accordingly to the market system.

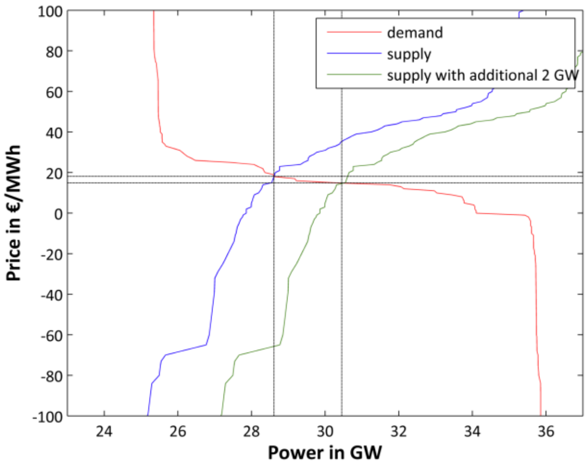

Figure 6. Adjustment of the demand curve

In this example, by introducing 2 GW of additional bids to the supply curve, the price drops to 14.9 €/MWh whereas the trading volume increases to 30.5 GW.

By performing the optimization again with these new prices, the potential revenues of an additional flexibility option can be calculated. This result will be lower than for the first one, since the first one is already part of the modelled market and causes reduced price spreads. Due to the lower prices spreads the frequency of storage cycles can also decrease between two optimizations runs.

Iteratively repeating this price modelling and subsequent optimization for new prices allows calculating the potential revenues for flexibility options after a certain amount of flexible power already entered the market. The whole process is depicted in fig. 7.

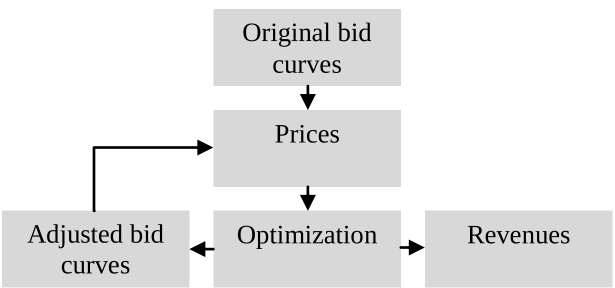

Figure 7. Flowchart of the calculation process

Fig. 8 illustrates the results of these calculations based on the price curve from fig. 5. Adding additional flexibility options with a power of 5 GW in steps of 50 MW to the system according to the described methodology yields the prices displayed in the figure. As expected, peaks in both directions are smoothed, since flexibility is applied to balance hours with high prices and hours with low prices. Therefore, spreads between high and low prices are reduced and the possible revenues for additional flexibility options decrease.

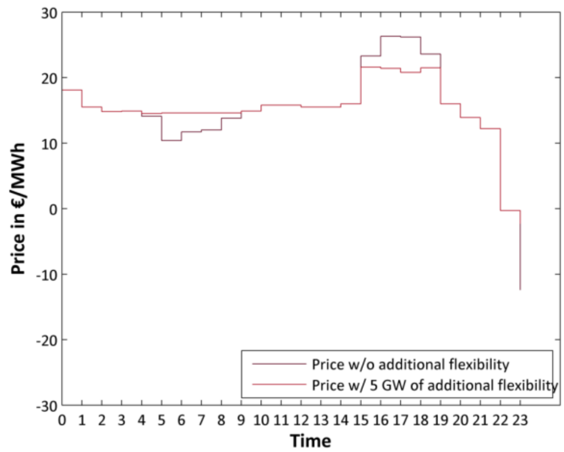

Figure 8. Effects of additional flexibility on prices

The result of the next optimization step is displayed in fig. 9. Due to the smoothed price curve, the optimal operation of an additional flexibility option changed compared to the original prices. This illustrates the necessity of optimizing again at each step in order to achieve reliable results.

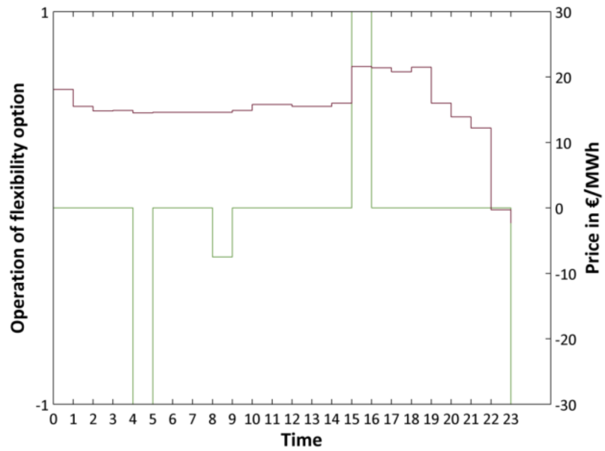

Figure 9. Optimized operation of flexibility option with adjusted prices

III. Results

A. *Step size of iteration*

The power of the additional flexibility option in each iteration step, e. g. the amount of supply or demand to add in the respective curves, affects the result. Different step sizes lead to different results, as for example adding 1 MW in the first iteration and adding another 1 MW in a second iteration yields different operation of the functional storage than adding 2 MW in the first step. Therefore, minimal step size leads to highest accuracy, but needs maximum computing time. Therefore, a reasonable step size has to be found.

Fig. 10 shows the integration of additional flexible power up to 100 MW in 2015, calculated with step sizes from 1 MW to 100 MW.

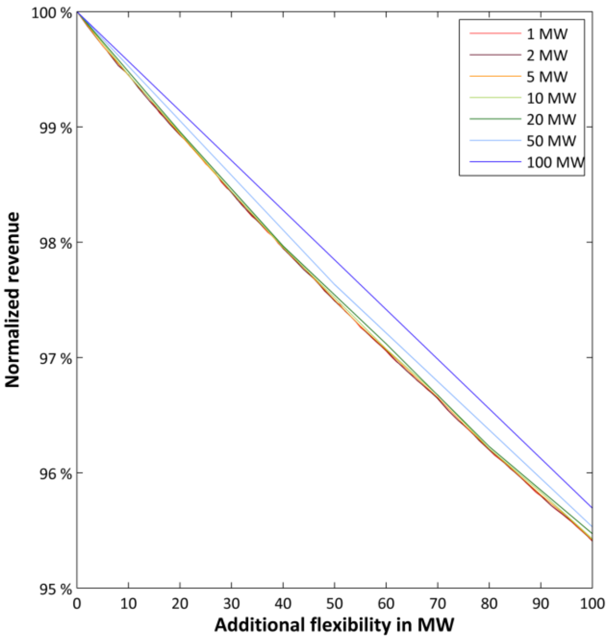

Figure 10. Comparison of step sizes

All step sizes cause a reduction of around 4 % by introduction of additional 100 MW to the market. Closer investigation of the results at 100 MW, which are also given in Table I, shows that step sizes of 20 MW and above cause noticeable deviations, whereas 10 MW can be considered sufficiently exact. Therefore, a step size of 10 MW is applied in the following simulations.

TABLE I. COMPARISON OF STEP SIZES

Normalized revenues at 100 MW additional flexibility						
1 MW	***2 MW***	***5 MW***	***10 MW***	***20 MW***	***50 MW***	***100 MW***
95.4 %	95.4 %	95.4 %	95.4 %	95.5 %	95.5 %	95.7 %

B. Comparison of total revenues by year

Applying the described optimization model to unadjusted time series of prices yields potential profits of flexibility options. Fig. 11 compares these values in normalized form for the five available years (100 % = five years average).

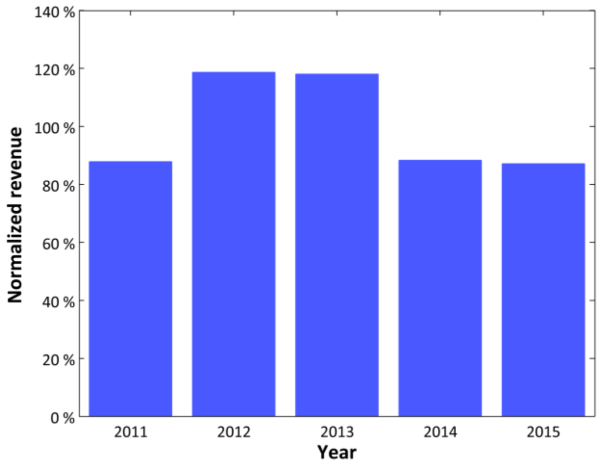

Figure 11. Normalized revenues of flexibility options by year

These results show that the potential revenues for flexibility options in the German market increased significantly in 2012 and 2013 compared to 2011. This might be a consequence of a steeper Merit-Order induced by e.g. increasing volatile renewables in the system or changes by the fuel prices. However, 2014 and 2015 show a drop again back to about the same level as 2011 (cf. [5]).

Since there are quite large differences between the years, the results of the following evaluations are normalized per year. This means that the potential revenues without any adjustment of bid curves are considered to be 100 % in each year for easier comparison.

C. Reduction of revenues by additional flexibility

Application of the method presented above with the determined step size of 10 MW and up to 5 GW of additional flexible power yields the results depicted in fig. 12. It can be observed that all five years evince a similar shape of decreasing revenues. The years 2011 to 2013 show quite similar values. This means that additional flexibility options introduced in the market setting of one of these years would have caused similar reductions of price spreads, although the absolute values of potential revenues differ, as discussed before.

For 2014 and 2015, a trend to smaller reductions can be assumed. This can be caused by the fact that there already was additional flexibility in the market compared to the years before, which reduced the absolute revenues as stated before. Reduced absolute revenues mean that the flexibility is used less and therefore has less influence to spot market prices.

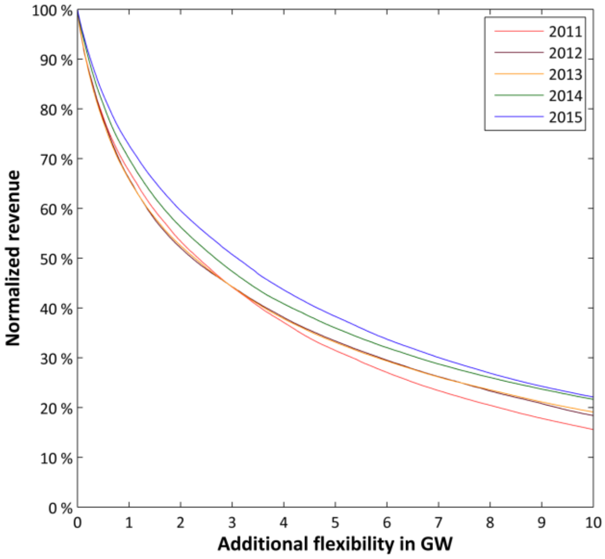

Figure 12. Normalized decrease of revenues by year

For easier comparison of the years, Table II shows the amount of additional flexibility that can enter the market until the potential revenues for following flexibility options drops below a threshold of 75 % or 50 %.

TABLE II. COMPARISON OF YEARS

Revenues below	**Additional flexibility in GW**				
	2011	***2012***	***2013***	***2014***	***2015***
75 %	0.6	0.6	0.6	0.7	0.9
50 %	2.4	2.2	2.3	2.7	3.1

This confirms the observation of similar results in the years 2011 to 2013 and slower decrease for the two subsequent years. Additional flexible power of 0.6–0.9 GW already reduces the revenues by one fourth; at around 2.5 GW it drops to one half of the initial value.

IV. DISCUSSION

Additional demand or supply by flexibility options change the bid curves at the spot market. This leads to different prices, which in turn reduce the potential profitability of new flexibility options and therefore reduces incentives to invest in flexibility for integration of solar power. This effect can be investigated using historic market data.

The evaluations show that the effect of reduced revenues with increasing flexibility in the market is crucial when evaluating the profitability of flexibility options. To illustrate the effect of different flexibility options which might be in the market in the future, Fig. 13 shows their potential and/or planned power for comparison to the calculated decrease curve. Here, only the results for 2015 are displayed, since these are the most recent data available and therefore give most reliable results.

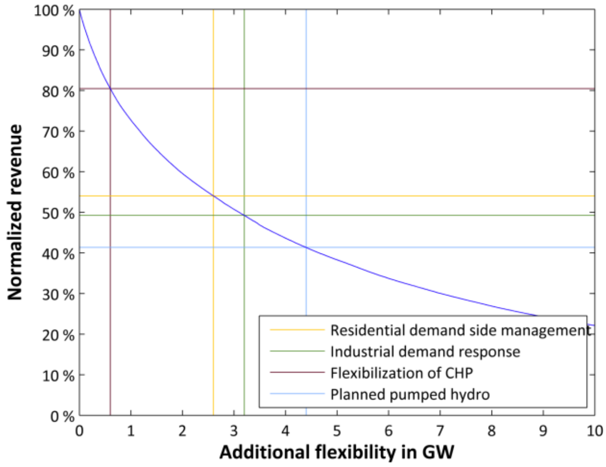

Figure 13. Comparison with different flexibility options

The potential for residential demand side management is estimated with 2.6 GW in Germany [6]. This amount of additional flexible power causes a reduction of potential revenues by 46 %. For industrial demand response, recent evaluations state a potential of 3.2 GW flexible power [7]. If this was utilized in today's market setting, the revenues for flexibility options would decrease by 51 %. The installation of thermal storages at cogeneration plants yields additional flexible power of 0.6 GW [8], which causes a reduction to 80 %. Current plans of new pumped-storage plants with a cumulative power of 4.4 GW [9] in Germany would reduce revenues for additional flexibility options to 41 %.

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