Reduction of Curtailment by Residential Demand-Side Management – Secondary Effects on Electricity Markets

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Abstract:

Variable electricity rates can pose an incentive for residential customers to adapt their consumption behavior to external requirements. Due to increasing installed capacities from volatile renewables, this flexibility can be utilized to integrate more renewable generation in the system. This can be quantified by the reduction of necessary curtailment. Therefore, variable rates are designed to cause load shifting to intervals with active curtailment measures.

Load shifting alters the total load and therefore potentially affects the resulting market prices in the electricity market. In order to quantify the expected impact, two approaches are compared: An energy system model, which allows deducing resulting market prices from marginal costs of power plants, and the adjustment of real bid curves from EPEX SPOT, which can be used to model hypothetical additional bids.

The evaluations show that the first approach is not suitable, since it fails to plausibly represent the effects of minor changes to the simulated load curve. However, the second one evinces reasonable results, as differences in the resulting prices can be observed. Therefore, it is recommended to apply this method for similar investigations. Nevertheless, these differences remain relatively small, so the effects on market prices are not considered to be a substantial aspect in the design of variable rates.

Keywords: variable electricity rates, demand-side management, spot market, bid curves

1 Introduction

The ongoing expansion of renewable energy in Europe leads to growing requirements for curtailment in order to ensure stable grid operation. Flexibility options like residential demand-side management provide means to reduce these curtailment measures by increasing their consumption in times of excess production of renewables [1]. Appropriate incentives for residential customers are necessary and can be implemented by variable electricity rates [2]. Since this approach naturally alters the total residual load within the considered area, it also affects wholesale prices for electric energy. These effects can be quantified by simulation of residential DSM based on measured load curves and real curtailment data. Two methods are compared with a focus on the German day-ahead spot market.

2 Methodology

The DSM potential for residential customers can be calculated by a pattern recognition algorithm which allows identifying individual appliances within the measure load curve [3]. Based on that, shifting of the operation times of these appliances according to grid requirements, i.e. dependent on curtailment in the respective region, can be simulated [4]. This yields adjusted time series of residential energy consumption per simulated household and can be aggregated on local or regional level.

However, individual shifting processes in individual households will not be considered here, since aggregate calculations are sufficient to demonstrate the general methodical approach and the feedback effects on spot market price formation. Therefore, the overall methodology consist of three parts: analysis of curtailment data and deduction of rate structures, simulation of load-shifting measures based on aggregate load profiles and computation of the effects on market prices, where two different approaches are examined. These steps are explained in the subsequent sections.

2.1 Rate Structures for Curtailment Reduction

Curtailment of renewables in Germany is a measure, which is mostly applied to wind energy, whereas it is rarely applied in regions with high installed PV capacity. In order to represent both types of renewable plants, different regions are considered for the calculations.

2.1.1 Data Basis

Curtailment data for five different distribution system operators (DSOs) in Germany are available for the calculations [5]. Most of the DSOs do not publish their data publicly, so a comprehensive data set is almost impossible to achieve. Therefore, these regions are to be considered examples for the whole methodology, but no conclusions for an extrapolated potential on the national level can be drawn. The yearly sums of curtailed energy in the year 2017 in these grid regions are given in Table 1. The numbers show that the available data cover both regions with very little curtailment and regions with a high amount of curtailed energy.

On an aggregate level, i.e. curtailed energy summed over the described five grid regions per hourly interval, the yearly pattern in 2017 is displayed in Figure 1. This shows that the demand for curtailment is almost independent of seasonal influences. Moreover, detailed analysis of the resulting curve shows that there is no single day in the entire year 2017 without any curtailment.

Table 1: Total curtailed energy by grid region in 2017

DSO	Curtailed Energy in GWh
Avacon	174.1
Bayernwerk	0.9
E.DIS	382.6
Schleswig-Holstein Netz	2 062.4
Stadtwerke Prenzlau	1.0

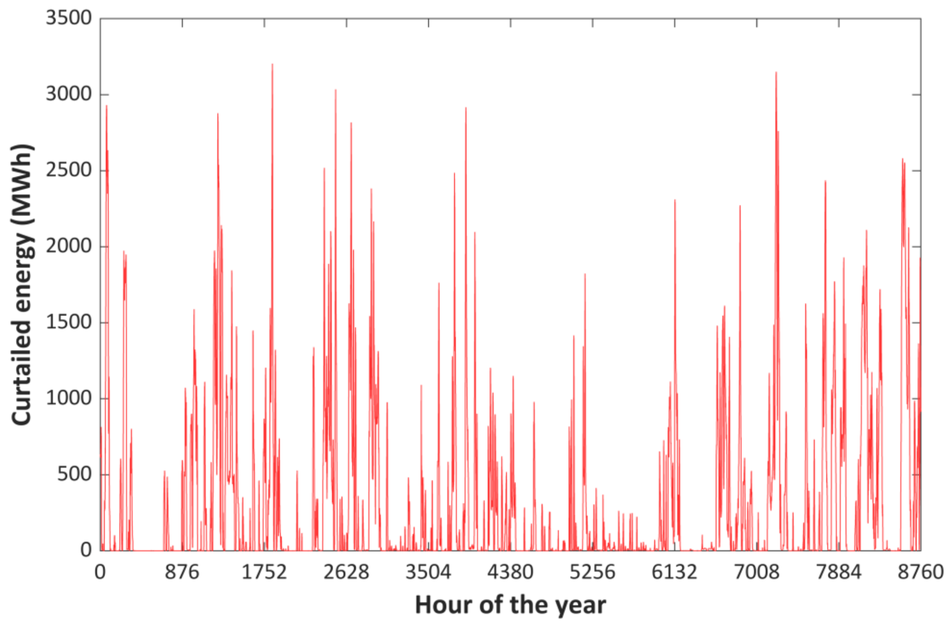

Figure 1: Sum of curtailed energy per hour in 2017

2.1.2 Rate Structures

Previous work shows that a vast majority of curtailment measures is caused by congestion on the transmission grid level [6]. Thus, the grid within the DSO regions is neglected for the following evaluations, which also avoids the problem of grid data availability.

Therefore, the calculations are based on the assumption that an increase of consumption within a DSO region reduces the curtailed energy by the same amount. This increase in consumption is incentivized by low energy prices in time intervals with active curtailment and high energy prices with no curtailment.

Households are expected to reduce their energy consumption in intervals with high prices and compensate this by additional consumption in the remaining time. Therefore, load shifting to time intervals with curtailment is achieved. Surveys show that residential customers prefer electricity rates with hourly structure to rates with sub-hourly price adjustment [7]. Thus, the rate considered here is defined for every hour according to the system described above (cf. Figure 2).

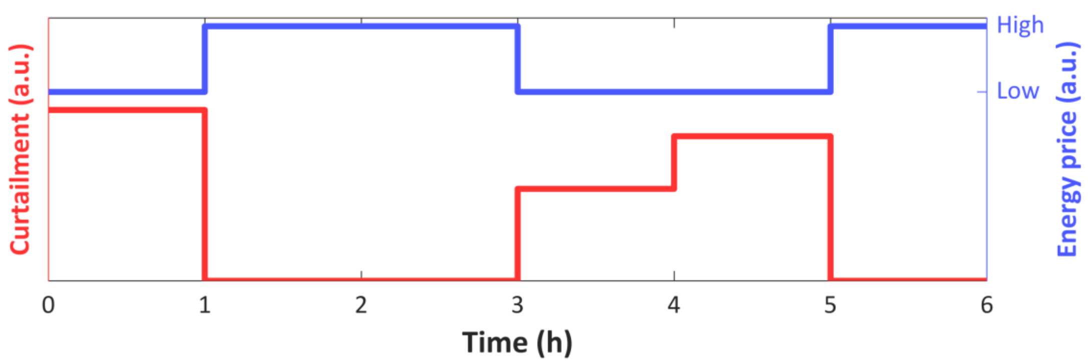

Figure 2: Exemplary representation of the assumed rate structure

2.2 Effects on Load Curves

Time-resolved electricity consumption is represented by load profiles deduced from measurements. The resulting load curve can be adjusted according to a variable rate and the assumed willingness of consumers to react to external price signals.

2.2.1 Load profiles

In order to model the total energy consumption of the residential sector in Germany, measurements of electrical load at local substations in residential areas in different regions of Germany are utilized [8],[1]. 13 measurement points were recorded for at least six months, which yields a sufficient data basis for the calculation of representative normalized load profiles. These are structured according to the usual standard load profile model, so three types of days (working day, Saturday, Sunday) in three seasons (winter, spring/fall, summer) are modelled.

This profile is applied to construct a yearly load curve by concatenation of daily load curves. The yearly load curve is modelled in hourly resolution, since the rate structure also adheres to an hourly grid and therefore, the calculations are performed with this resolution. Since the load curve is also applied in energy system modelling (cf. Section 2.3.2), it has to be slightly adapted so that the sum of all sectoral curves meets the published total load curve [9]. As as last step, it is scaled to the total yearly consumption of the residential sector in the respective region, so it can be applied both on a national level and on DSO level. Since This leads to the consumption pattern depicted in Figure 3.

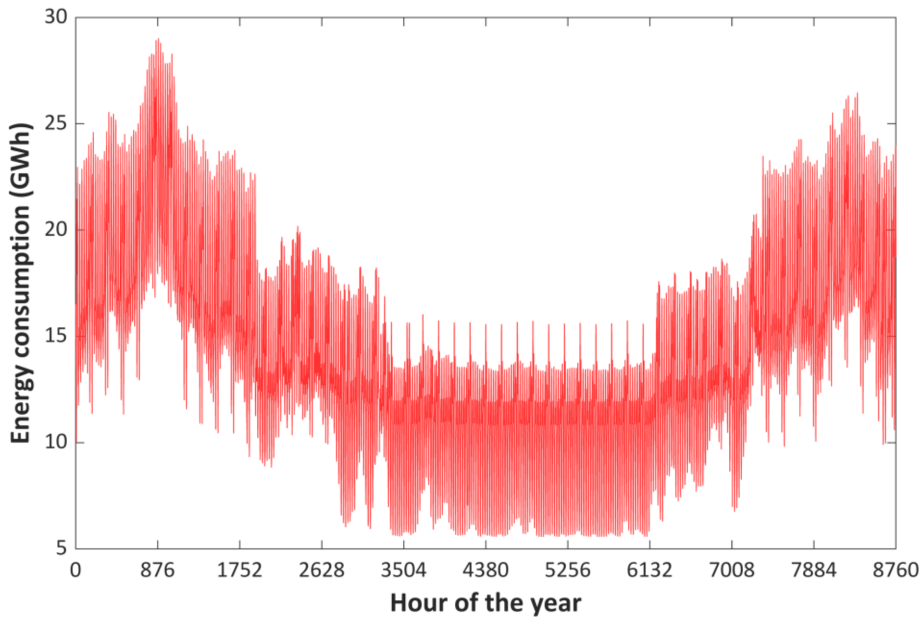

Figure 3: Modelled total consumption of the residential sector in Germany

2.2.2 Simulation of load shifting measures

As previously explained (cf. Section 2.1.2), a variable rate with two price levels is assumed. This is expected to cause load shifting processes from high prices to low prices and therefore, from time interval without curtailment to time intervals with curtailment.

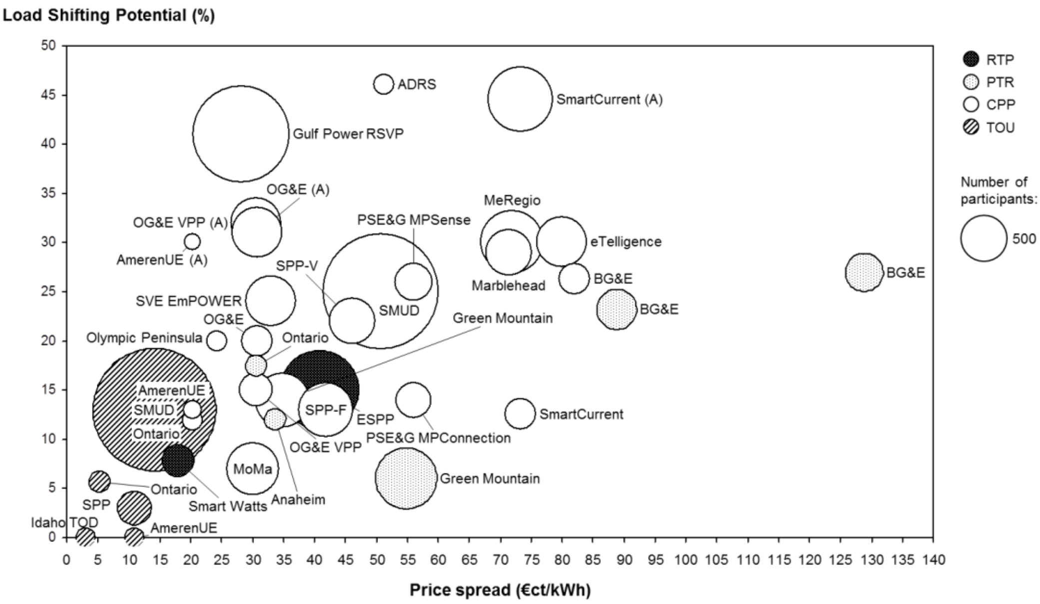

Figure 4: Load shifting potential dependent on price spread in various projects

The general potential for load shifting in households is dependent on a variety of external and internal influences: the level of automation, the price spread between high and low prices, the intrinsic motivation of participants etc. Since no individual appliances are modelled here, the amount of energy to be shifted is represented as a fraction of the total consumption in the respective time interval. This value has been determined in various previous projects and studies; an overview is displayed in Figure 4.

In order to better quantify this value and the general acceptance of variable rates with residential customers, a survey has been conducted [7]. In general, dishwashers, washing machines, dryers, freezers and fridges are considered to be suitable for flexible operation. Since the total consumption of freezing and cooling devices is comparably low [10], only the first three appliance types are considered here.

The survey results allow estimating the willingness of customers to adjust the operation times of their appliances under the assumption that the shifting processes are automated. Considering the share of these appliances of total energy consumption in a typical household [11],[12], this leads to a load shifting potential of 10.8 %.

This means that 10.8 % of the consumption in the hours with curtailment, i.e. with high energy price, is shifted to the remaining hours of the day. Only shifting processes within a day are modelled. The shifted amount of energy is evenly distributed to the hours of the day with low prices. This procedure is applied in on the regional level, so high and low price intervals are defined per DSO region. This means that for each of the five DSOs, the load shifting is calculated separately, followed by a subsequent aggregation of the load curves.

For comparison and to determine a maximum estimation regarding the effects on spot market prices, the high price level is assumed to apply to the twelve hours with highest prices and the low price level to the remaining twelve hours with lower prices and vice versa. This is expected to yield a magnitude of price changes near the theoretical maximum and thus, it is applied as a worst-case estimation.

2.3 Effects on Market Prices

Price formation at the day-ahead spot market works by finding the intersection of two bid curves for demand and supply. This can be modelled based either on real market data or by employing an energy system model, which simulates scheduling of power plants dependent on the load situation. Both approaches allow incorporating changes to the load curves and calculating the resulting effects on the prices.

2.3.1 Energy System Modelling

The first approach utilizes the model “ISAaR”, which represents the energy system in form of a linear optimization, including the sectors electricity, district heating, gas, hydrogen, synthetic fuels and biomass. Generators, storages, distribution and consumers for all these sectors are modelled. Additionally, the electrical coupling of Germany to neighboring European countries is simulated. The model optimizes the total costs of the system and allows deducing market prices from the power plants’ marginal costs [13],[14],[15]. The consumption of electric energy in the residential sector is modelled via the load profiles described previously (cf. Section 2.2.1). The simulation scenario represents the year 2020, which defines the available assets, consumption curves in all sectors, expansion of renewables etc. Therefore, the resulting load curve for the residential sector is adapted slightly to match this scenario [8]. The load shifting is represented as described in Section 2.2.2 and therefore, it yields an adjusted load curve, which is used as an input to the model and finally yields a new time series of calculated market prices.

2.3.2 Market Data Adjustment

The EPEX SPOT day-ahead market allows placing bids for every hour of the following day. These bids are either buy or sell bids and are characterized by volume and price. All bids for a specific hour are combined and sorted and form two bid curves, exemplarily displayed in Figure 5.

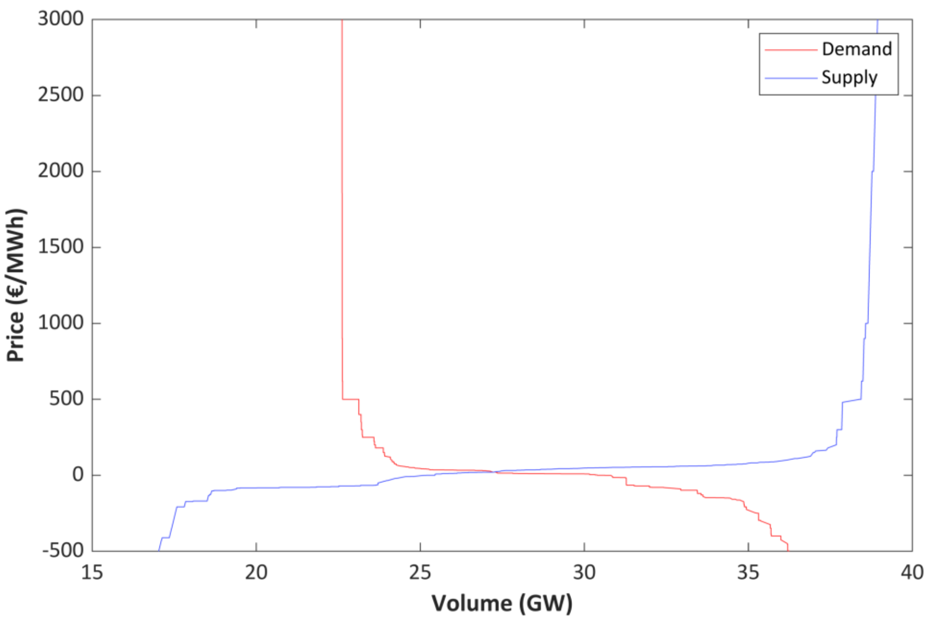

Figure 5: Demand and supply curve for one exemplary hour

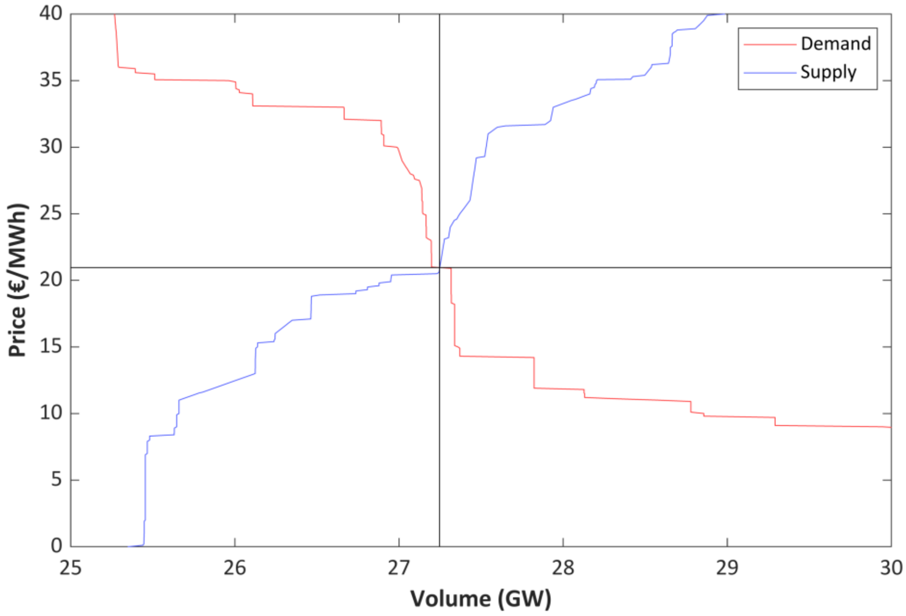

Figure 6: Demand and supply curve for one exemplary hour, enlarged at intersection

The market price is defined by the intersection of the curves, illustrated in Figure 6 in an enlarged version. The traded volume can also be deduced from this intersection point, since all bids up to this threshold are executed. Additional supply or demand can be taken into account by inserting it into the respective bid curve with minimum (supply) or maximum (demand) price [16]. This approach results in a "shifted" curve and therefore, in a different intersection of demand and supply. Figure 7 illustrates this for an adjusted supply curve with 1 GW of additional bids. This shows that the market price decreases due to additional supply, whereas the traded volume increases. Both effects are as expected and confirm the plausibility of the approach. The calculations use market data from the year 2017 [17].

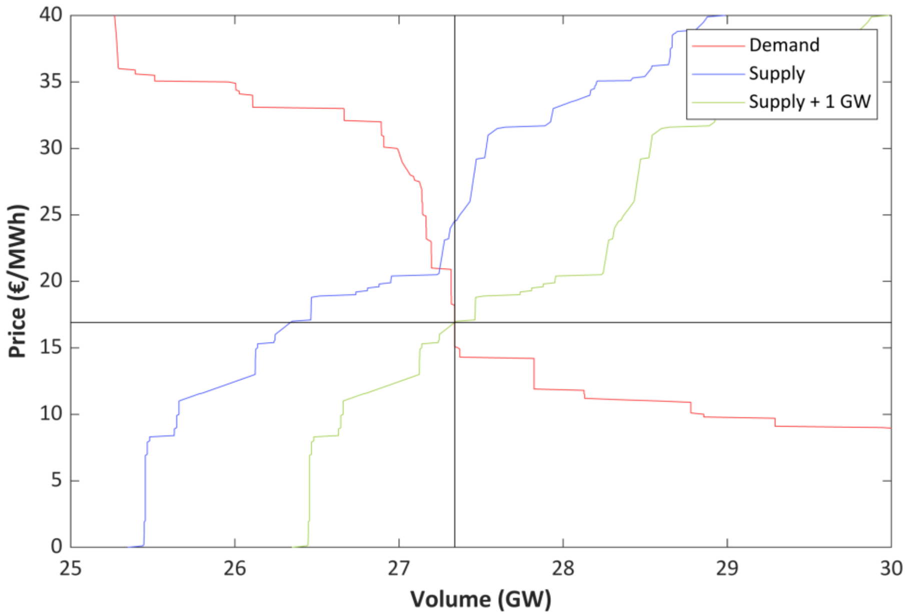

Figure 7: Demand and supply curve for one exemplary hour, supply adjusted by 1 GW

3 Results

Both described approaches allow simulating the effects of adjusted load curves on the resulting market prices. In order to better understand the results, the changes to the residential share of the total load in Germany are analyzed first. In the subsequent sections, price effects are quantified.

3.1 Load Curves

As already explained in Section 2.2.2, the effects of curtailment-driven load shifting are modelled by moving a share of consumption from intervals without curtailment to intervals with curtailment. This scenario is called C. For sensitivity analyses, in addition to the aforementioned 10.8 %, varying load shifting potential is also considered. This yields the scenarios C− und C+ with a 50 % decrease or increase in potential, respectively. Finally, the described maximum estimation scenarios are denoted by L for load shifting from high to low prices, and by H for the opposite case. These are compared to the base case B with respect to different key figures in Table 2.

Table 2: Key figures for resulting load curves

Scenario	B	C−	C	C+	L	H
Yearly sum (TWh)	124	124	124	124	124	124
Total shifted energy (TWh)	–	0.116	0.212	0.318	7.04	6.39
Maximum daily load spread (GW)	13.5	13.5	13.4	13.5	16.5	16.4
Mean daily load spread (GW)	9.16	9.15	9.14	9.14	9.34	11.3
Minimum daily load spread (GW)	5.20	5.18	5.16	5.14	4.64	6.89

As a simple plausibility check, the total year sum is evaluated. This confirms that all shifting processes work as expected, since no change to the overall consumption is observed.

For scenario C, the total shifted energy throughout the year according to the model is 212 GWh. This accounts for only 0.2 % of the total consumption, which is caused by two effects: firstly, due to data availability, load shifting is only simulated for five DSO regions, and secondly, load shifting only occurs within days with active curtailment. The sensitivity scenarios C− and C+ lead to an approximate change of 50 % of the value in both directions, which shows that an increase in potential is almost fully converted to increased load shifting. By contrast, L and H evince shifted volumes over 5 %, which is near the theoretical maximum for the assumed potential and therefore, can be considered a maximum estimation as intended.

For all C-scenarios, the changes in daily load spreads are almost negligible. Therefore, the changes to market prices are expected to be rather low, which will be examined in the following section. For the maximum scenarios, the maximum spreads are increased considerably by about 22 %. The differences regarding minimum spreads are lower, leading to an overall increase in the mean spreads, even for scenario L, which could be expected to reduce spreads by shifting from high to low prices, and consequently in most cases from higher to lower load levels.

3.2 Market Prices

The calculated load curves are applied to model the effects on market prices. Besides the absolute results, the comparison between the two described approaches of price modelling is analyzed here.

3.2.1 Curtailment Scenarios

For the following discussion of results, the two approaches are denoted by M for the energy system model and P for the adjusted bid curves. Due to the slightly different reference years, both approaches are evaluated with respect to the prices that stem from the same approach, i.e. the modelled prices without load shifting for 2020 for M and the real prices for 2017 for P. Table 3 shows a comparison of the resulting price characteristics.

Table 3: Key figures for market prices in the base case

Scenario	MB	PB
Mean price (€/MWh)	42.39	34.20
Standard deviation (€/MWh)	8.88	17.66
Maximum daily price spread (€/MWh)	38.05	114.69
Mean daily price spread (€/MWh)	12.78	30.57
Minimum daily price spread (€/MWh)	0.00	8.13

The figures show substantial differences between the two approaches. The values for mean prices and standard deviation already evince considerably different characteristics of the time series, and the price spreads confirm this observation. The energy system model cannot reliably represent the intraday patterns of spot market prices. Since intraday load shifting mainly affects these patterns, the results indicate that this approach is not suitable to quantify these effects.

In order to confirm this, Table 4 shows the same key figures for the curtailment-driven load shifting scenarios. Here, no changes are observed within the given accuracy of three or four significant digits. This supports the previous conclusion that the approach is not appropriate for the problem, since the amount of shifted energy in Table 2 leads to the expectation of corresponding price changes. The resulting prices can be explained by the model structure, which outputs price based on marginal prices of modelled power plants. Therefore, changes to the input data that do not change scheduling cause almost no changes to the calculated prices.

Table 4: Key figures for resulting market prices (based on the energy system model)

Scenario	MB	MC−	MC	MC+
Mean price (€/MWh)	42.39	42.39	42.39	42.39
Standard deviation (€/MWh)	8.88	8.88	8.88	8.88
Maximum daily price spread (€/MWh)	38.05	38.05	38.05	38.05
Mean daily price spread (€/MWh)	12.78	12.78	12.78	12.78
Minimum daily price spread (€/MWh)	0.00	0.00	0.00	0.00

Table 5: Key figures for resulting market prices (based on bid curves)

Scenario	PB	PC−	PC	PC+
Mean price (€/MWh)	34.19	34.19	34.19	34.19
Standard deviation (€/MWh)	17.66	17.65	17.63	17.62
Maximum daily price spread (€/MWh)	114.69	115.55	116.41	117.35
Mean daily price spread (€/MWh)	30.57	30.44	30.35	30.28
Minimum daily price spread (€/MWh)	8.13	8.13	8.13	8.13

For comparison, Table 5 lists the analogous evaluations for prices calculated via bid curves. By contrast to the previous results, an effect of the load shifting measures is observed. Despite the virtually constant mean price, standard deviation is reduced slightly for scenarios with adjusted load characteristics. Therefore, the load shifting from intervals without curtailment to intervals with curtailment is slightly smoothing the resulting price curve, indicating that curtailment correlates with lower prices. This can be examined by calculation mean prices in hours with curtailment (32.23 €/MWh) compared to hours without curtailment (42.59 €/MWh). The decreased value of the mean daily price spread also supports this conclusion, but the analysis of the maximum daily spread shows that this does not hold for all days. Nevertheless, the results show that the described approach yields more plausible results than the previous one, which is also confirmed by the fact that the respective effect on each figure is stronger for higher assumed potential, i.e. for scenarios C− up to C+. Thus, the adjustment of bid curves is the recommended method for quantifying the approximate effect of small changes to the total load curve.

3.2.2 Maximum Scenarios

Since the observations in the previous section show that approach M is not suitable, only the values for approach P are evaluated here. For the maximum scenarios L and H, these are given in Table 6. The comparison of mean prices show that even under these very strong assumptions, the mean prices do not change by much. However, the direction of changes can be considered another plausibility check, since L reduces the prices, whereas H causes an increase. The same holds for all other figures, since all indicate that H leads to higher fluctuations, while the opposite is observed for L. Despite the minor effects regarding mean prices, the price characteristics would change considerably under the given assumptions, as can be seen from the differences regarding standard deviation and the evaluated price spreads.

Table 6: Key figures for resulting market prices in the maximum scenarios

Scenario	PB	PL	PH
Mean price (€/MWh)	34.19	33.78	35.24
Standard deviation (€/MWh)	17.66	15.01	25.74
Maximum daily price spread (€/MWh)	114.69	112.23	217.22
Mean daily price spread (€/MWh)	30.57	22.02	47.54
Minimum daily price spread (€/MWh)	8.13	4.51	13.08

However, even with nationwide implementation of the described variable rate structure, the full effect is not to be expected, since this would require all DSO regions to evince curtailment at the same hours, and at the same time, these hours would have to be either all cheap or all expensive ones. Therefore, the overall effect on spot market prices by curtailment-based variable rates and resulting load shifting is expected to be rather small to negligible.

4 Conclusion

The presented analyses show that two approaches can be applied in order to quantify the potential effects of residential load shifting on spot market prices. Load shifting is considered to be incentivized by variable rates, which are considered to be designed with the objective of increase integration of renewables. This is represented by the reduction of curtailment of renewables, which can be modelled via published data from German DSOs.

The first approach of modelling price effects based on an energy system model does not prove useful, since it does not represent the effects of minor changes in the load data due to the inherent model structure. The second one utilizes publicly available bid curves from EPEX SPOT and plausibly reflects the expected changes in prices and price characteristics. Nevertheless, it leads to the conclusion that load shifting in the residential sector only slightly affects the resulting spot market prices under reasonable assumptions, and even in the maximum scenario, mean prices hardly change. Therefore, feedback to market prices is not considered a crucial aspect for a potential future implementation of the described rate structure.

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Funding

The described work is conducted within the project C/sells by Forschungsgesellschaft für Energiewirtschaft mbH and funded by Bundesminsterium für Wirtschaft und Energie (BMWi) in the SINTEG funding program (funding code: 03SIN120).