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Tim Janke, Bastian Brindley, Tobias Rodemann, Florian Steinke

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Incentivizing the adoption of local flexibility options: A quantitative case study

(Tim Janke, Bastian Brindley, Tobias Rodemann, Florian Steinke)
Anonymous Institution
Anonymous Department
Anonymous City and Country
(Email: tim.janke@eins.tu-darmstadt.de)

***Abstract*—Energy systems with a large share of generation from renewable sources require a flexible behavior of the demand side. Office buildings can technically contribute by the installation of local generation and storage in combination with energy management systems. However, businesses will only consider the adoption of flexibility options if there is a clear monetary benefit. We evaluate different combinations of flexibility options for a typical medium sized office campus in Germany regarding the incentives provided by different electricity pricing models. We model the campus using a mixed integer linear programming (MILP) formulation and assume perfect foresight. We find that even for the traditional static pricing model the adoption of flexibility options is beneficial. Dynamic pricing models, however, provide substantially larger incentives.**

***Index Terms*—Demand-side management, Energy management, Smart grids**

I. Introduction

The increasing share of generation from renewable energy sources (RES) and the associated natural fluctuations demand a flexible and intelligent behavior from consumers and prosumers in today's and, even more, in future energy systems. Smart energy management systems which can utilize local generation and energy storage are a way to mitigate negative effects from the volatile generation from RES and promote the goal of an integrated energy system efficiently.

The potential and incentives for demand side management has been researched especially for energy intensive industries, see e.g. [1], [2]. However, also office buildings have untapped potential to shift demand using smart energy management systems. The impact on the aggregated load curve from load shifting by offices and residential buildings was shown in [3]. However, those systems demand a substantial monetary investment up front. Hence, a wide spread adoption, especially among small and medium sized businesses, will only occur if there are obvious monetary incentives. We aim to quantify these incentives for a real, medium sized office complex located in Offenbach, Germany using demand and energy price data from 2016.

Using the facility's time series data for the electrical and thermal demands, we evaluate three different configurations for the campus' energy supply system as well as four different pricing models. We consider the (current) static tariff, where the price is time-invariant, a dynamic scheme, where the price equals the actual spot price plus levies, an amplified dynamic pricing scheme with a dynamic Renewable Energies Act (EEG) surcharge, and a dynamic model without EEG surcharge. For a literature review on dynamic electricity prices see [4]. For each pricing model and configuration, we compute the optimal schedule assuming perfect foresight and quantify the annual energy cost. We also give an estimate for the net present value (NPV).

We find that the adoption of flexibility options is financially beneficial even for the static pricing model. However, dynamic pricing models provide larger incentives. Interestingly, the pricing model without the EEG surcharge and therefore prices closer to the wholesale price, renders investments in local generation and storage unprofitable. We contribute to the literature by breaking down the theoretical discussion about the effectiveness of pricing models to a concrete, quantitative example and thereby provide practical insights for regulators.

The paper is structured as follows. In Section II we describe the office complex under study, its demand for energy as well as the examined configurations of the energy supply system. Section III describes the considered pricing models. The mathematical model of the campus is presented in Section IV. We present our results in Section V and briefly discuss our findings in Section VI together with some proposals for future work.

II. The office complex

The investigated office complex is modeled based on data from an R&D campus in Offenbach, Germany. The total annual energy consumption, including electricity, cooling, and heating, was 5,92 GWh in 2016. The campus has an hourly average demand for electrical and thermal energy of 335 kWh and 340 kWh, respectively.

The demand for electrical energy exhibits a daily, weekly and seasonal pattern. Throughout the year, there is a constant base demand for electricity. On business days the demand increases during the morning and declines in the evening. This pattern is not present on weekends and holidays. The energy consumption of the cooling system increases with the ambient temperature resulting in a higher electrical demand during summer. Throughout the year, distinct spikes in the demand are caused by an electric vehicle charging station (EVC). The EVC's maximum demand in 2016 was 84 kW. In combination with a high demand around noon, the peak demand for

TABLE I

Considered campus configurations and investment cost. Sizes for the High Flex configuration were chosen in relation to average hourly (PV and battery) and daily demands (heat and cooling storage). Investment according to [6], [7], [8], [9]. (Investment for small heat storage is 18 €/$\mathrm{kWh_{th}}$)

Component	No Flex	Current	High Flex	Investment
CHP	-	199 $\mathrm{kWh_{el}}$	199 $\mathrm{kWh_{el}}$	433,000 €
PV	-	10 kW	335 kW	1300 €/kW
Heat stor.	-	70 $\mathrm{kWh_{th}}$	8174 $\mathrm{kWh_{th}}$	12 €/$\mathrm{kWh_{th}}$
Cooling stor.	-	-	1884 $\mathrm{kWh_{th}}$	12 €/$\mathrm{kWh_{th}}$
Battery	-	-	335 kWh	250 €/kWh

electricity can reach up to 700 kW on hot summer days. The thermal demand pattern is rather smooth and exhibits a daily, weekly, and seasonal pattern with a higher demand during cold days and working hours and low demand on weekends and in summer. We use time series data generated by a detailed model of the facilities which reproduces the electrical and thermal demands as well as the photovoltaic (PV) system's output with high accuracy [5].

For our analysis we consider three different configurations for the campus' energy supply system (see Table I). As a baseline scenario, we examine a campus with no flexibility options or local generation at all. Thus, this campus covers the demand for electricity and heat entirely by the grid and a gas heating, respectively. We refer to this campus as "No Flex". Second, we model the current campus set-up including a 199 kW combined heat and power plant (CHP), a 10 kW PV system, and a 70 $\mathrm{kWh_{th}}$ heat storage. And third, we evaluate a highly flexible campus which is equipped with the 199 kW CHP, a heat storage, and a cooling storage with the capacity of the average daily demand for heat and cooling, respectively. Furthermore we assume a much larger 335 kW PV system, which corresponds to the average electricity demand of the campus, and a battery with a capacity of 335 kWh. We refer to this campus as "High Flex".

III. Pricing models

We consider four different electricity pricing models (see Table II). The current energy cost of the campus can be divided into the cost for gas, consumed by the heating and the CHP, and the cost for electricity bought from the grid. The cost for gas are made up of an annual basic charge and a time-invariant consumption specific unit price. The cost for electricity originate from a annual basic charge, a price for the annual peak load (76.45 €/kW), and a time-invariant specific unit price. We assume this unit price to be the mean of the 2016 EPEX day-ahead price, which is 0.0289 €/kWh. Additionally, surcharges and taxes which are levied as a fixed amount per kWh consumed have to be paid. In 2016 the EEG surcharge was 0.0635 €/kWh and the electricity tax was 0.0205 €/kWh. Other miscellaneous duties accounted for 0.0125 €/kWh. Thus, the total specific unit price adds up to 0.1245 €/kWh. We assume a feed-in tariff for energy from the battery and PV system of 0.085 €/kWh. We will refer to the traditional pricing model just described as "static pricing". Obviously, this pricing model does not create an incentive to adapt to the current supply and demand situation on the market. It does, however, provide an incentive to keep the peak load low and thereby acting grid friendly.

Alternatively, we evaluate an electricity pricing model where the unit price equals the time varying day-ahead spot price plus taxes and surcharges. We also assume a time varying feed-in tariff that equals the corresponding spot price. The gas price, basic charges, and peak load price are equal to the static pricing model. We refer to this pricing model as "dynamic pricing". It creates an incentive to adapt to the current market situation and should increase the value of flexibility options. However, the original price signal is dampened by additional levies, predominantly by the EEG surcharge.

This motivates the idea of the "amplified pricing" model as proposed in [10], [11]. The idea is to introduce a dynamic EEG surcharge, i.e. the current spot price is multiplied by a constant factor instead of adding a fixed value. This amplifies the price signal as a higher price will become even higher by adding a larger absolute amount. If the price approaches zero, the surcharge will become small and is set to zero if the price becomes negative. Given the average spot price of 0.0289 €/kWh and the EEG surcharge of 0.0635 €/kWh for 2016, choosing a factor of 2.197 results in an average value identical to the fixed EEG surcharge. Therefore, shifting demand to low price hours will result in an increased reduction of the financial burden from the EEG surcharge. The reasoning is that the increased volatility creates an additional incentive for the demand side to act flexibly. On the other hand, the created incentives might be too large and thereby promoting investments where they are not economically efficient. For a detailed discussion we refer to the literature [10], [11].

Finally, we consider a "market pricing" model where the consumer pays the spot price plus taxes and levies but no EEG surcharge. Hence, the market signal is biased much less. In this case, the government will have to levy the lost revenue from the waived EEG surcharge otherwise and the campus' annual expenditures will clearly be significantly lower compared to the other pricing models. However, it is still interesting to observe how the optimal behavior changes if the consumer price was close to the wholesale price.

IV. Optimization model

Assuming perfect foresight, i.e. all demands, prices, and the PV output is known in advance, we use the following MILP formulation to model the energy system of the campus.

For all energy forms, we denote powers as P, demands as D, energy content in the storage as E, prices as p, and costs as C. The energy form is indicated by the superscripts el and th for electrical energy and thermal energy, respectively. The subscripts $B, HS, CS, GH, chp, EVC, grid$ denote the battery, the heat storage, the cooling storage, the gas heating, the CHP, the EVC, and the electrical grid, respectively. The subscripts min and max denote minimal and maximal values.

For buying electricity from grid at time t_i, the price $p_{grid}(t_i) = p_{unit}(t_i) + p_{EEG}(t_i) + p_{tax}$ has to be paid which is composed of the unit price, the EEG surcharge, and a fixed price for other taxes and duties. For the maximum power

TABLE II
Overview for the different pricing models.

pricing model	unit price	EEG surcharge	other levies	peak price	feed-in tariff	gas unit price	basic charges
static	0.0289 €/kWh	0.0635 €/kWh	0.033 €/kWh	76.34 €/kW	0.085 €/kWh	0.026 €/kWh	39,360 €
dynamic	$p_{spot}(t_i)$	0.0635 €/kWh	0.033 €/kWh	76.34 €/kW	$p_{spot}(t_i)$	0.026 €/kWh	39,360 €
amplified	$p_{spot}(t_i)$	$2.197 p_{spot}(t_i)$	0.033 €/kWh	76.34 €/kW	$p_{spot}(t_i)$	0.026 €/kWh	39,360 €
market	$p_{spot}(t_i)$	-	0.033 €/kWh	76.34 €/kW	$p_{spot}(t_i)$	0.026 €/kWh	39,360 €

drawn from the grid $P^{el}_{grid,max}$ one has to pay p_{peak}. Finally, there is a annual basic charge $p_{fix,grid}$ to be paid. Thus, the cost for buying electricity from the grid is given by

$$C_{grid} = \sum_{t_i} P^{el}_{grid}(t_i)\ p_{grid}(t_i)\ \Delta t + P^{el}_{grid,max}\ p_{peak} + p_{fix,grid}. \tag{1}$$

Furthermore, there are cost resulting from the use of the gas heater and the CHP:

$$C_{gas} = p_{gas}\Delta t \sum_{t_i} P^{gas}_{chp}(t_i) + \sum_{t_i} p_{mt} u(t_i) + p_{gas}\Delta t \sum_{t_i} \frac{1}{\eta_{gh}} P^{th}_{gh}(t_i) + p_{fix,gas}. \tag{2}$$

One has to pay a unit price p_{gas} and again a annual basic charge $p_{fix,gas}$. The binary variable $u(t_i)$ indicates whether the CHP is switched on or off. The gas consumption of the CHP is denoted as P^{gas}_{chp}. A fixed amount for maintenance cost $p_{mt} = 1.075$ € has to be paid if the CHP is running. $\eta_{gh} = 0.95$ denotes the efficiency of the gas heating.

The campus obtains a revenue by selling power (denoted by the subscript $sell$) produced by the PV system or from the battery for the feed-in tariff $p_{feed-in}$. Furthermore, electricity is sold via the EVC at the current price plus a fixed premium $p_{prem} = 0.25$ €/kWh:

$$C_{sell} = \sum_{t_i} \left[P^{el}_{PV,sell}(t_i) + P^{el}_{B,sell}(t_i)\right] p_{feed-in}\Delta t + \sum_{t_i} P^{el}_{EVC}(p_{grid} + p_{prem})\Delta t. \tag{3}$$

The optimal solution is then found by minimizing the objective function

$$\min_{\boldsymbol{\theta}} C = C_{el} + C_{gas} - C_{sell} \tag{4}$$

with respect to

$$\boldsymbol{\theta} = \{P^{el}_{chp}(t_i), u(t_i), P^{el}_{grid}(t_i), P^{el}_{PV,sell}(t_i), P^{el}_{B,sell}(t_i), P^{el}_{B,in}(t_i), P^{el}_{B,out}(t_i), P^{th}_{HS,in}(t_i), P^{th}_{HS,out}(t_i), P^{el}_{CS,in}(t_i), P^{el}_{CS,out}(t_i) : t_i = 1, ..., 35040\}.$$

Thus, in each time step, the utilization of the CHP, the amount of power bought from and sold to the grid, and the usage of the storage have to be chosen.

At all times the electrical and thermal power balances given by

$$D^{el}(t_i) = P^{el}_{grid}(t_i) + P^{el}_{chp}(t_i) + P^{el}_{PV}(t_i) - P^{el}_{PV,sell}(t_i) + \Delta P^{el}_{B}(t_i) + \Delta P^{el}_{CS}(t_i) \tag{5}$$

$$D^{th}(t_i) = P^{th}_{chp}(t_i) + P^{th}_{gh}(t_i) + \Delta P^{th}_{HS}(t_i) \tag{6}$$

must be considered. The electrical demand is the sum of the general demand, the cooling demand, and the demand by the EVC: $D^{el}(t_i) = D^{el}_{gen}(t_i) + D^{el}_{cool}(t_i) + D^{el}_{EVC}(t_i)$.

The amount of energy stored in the battery, the heat storage, and the cooling storage is constrained by the maximum capacity, the efficiency of the in-feed (η), the storage losses (δ), and the maximum power of the battery:

$$0 \le E_j(t_i) \le E_{j,max} \tag{7}$$

$$E_j(t_i) = (1-\delta_j)E_j(t-1) + [\eta_j P_{j,in}(t_i) - P_{j,out}(t_i) - P_{j,sell}(t_i)]\Delta t \tag{8}$$

$$P^{el}_{B,in}(t_i) + P^{el}_{B,out}(t_i) + P^{el}_{B,sell}(t_i) \le P^{el}_{B,max}, \tag{9}$$

for $j \in \{B, HS, CS\}$. We set $\eta_j = \{0.9, 1.0, 1.0\}$, $\delta_j = \{1.344 \cdot 10^{-5}, 1.0 \cdot 10^{-3}, 1.0 \cdot 10^{-3}\}$, and $P^{el}_{B,max} = 100$ kW.

The power sold from the PV system and the battery have to be positive and smaller than the available PV power and the energy available from the battery, respectively:

$$0 \le P^{el}_{B,sell}(t_i)\Delta t \le E_B(t_i) \tag{10}$$

$$0 \le P^{el}_{PV,sell}(t_i) \le P^{el}_{PV}(t_i). \tag{11}$$

The running CHP has a base gas consumption per hour $P^{gas}_{chp,base} = 318\ \mathrm{kWh_{gas}}$ and a variable gas consumption which depends linearly on the output of electric power constrained by the minimum $P^{el}_{chp,min} = 100$ kW and maximum output $P^{el}_{chp,max} = 199$ kW:

$$P^{gas}_{chp}(t_i) = [P^{gas}_{chp,base} u(t_i) + \epsilon_{gas/el}(P^{el}_{chp}(t_i) - P^{el}_{chp,min})] \tag{12}$$

$$P^{el}_{chp,min} u(t_i) \le P^{el}_{chp}(t_i) \le P^{el}_{chp,max} u(t_i). \tag{13}$$

$\epsilon_{gas/el} = 2.3737\ \frac{\mathrm{kWh_{gas}}}{\mathrm{kWh_{el}}}$ denotes the ratio of gas consumption to electrical energy produced. The generation of heat from the CHP is given by

$$P^{th}_{chp}(t_i) = P^{el}_{chp}\epsilon_{th/el}, \tag{14}$$

where $\epsilon_{th/el} = 1.4724\ \frac{\mathrm{kWh_{th}}}{\mathrm{kWh_{el}}}$ denotes the ratio of thermal to electrical power output for the CHP.

We used GAMS [12] to model and solve the described optimization problem.

V. Results

Fig. 1a - d shows the optimized electrical consumption and generation for the High Flex campus and all four pricing models for the time from March 30 to April 3 2016. The spot price for electricity as well as the true price to be paid for electricity is shown on the right axis. During these days, the spot price was very low on March 30, but approached 50 €/MWh only a day later, which is well above the annual average. Depending on the pricing model, the optimal schedule for the supply of electrical energy changes.

In the static pricing model (Fig. 1a), the CHP is used at all times, even when the spot market price approaches zero. In the morning and the evening, the low production of the PV system and a high electrical demand coincide leading to increased amount of power drawn from the grid. These peaks in the demand line up with the price peaks of the spot price. The dynamic pricing model (Fig. 1b) induces a more adaptive behavior. At night the battery and cooling storage are loaded. During the price spikes in the morning and evening the stored energy is used to shift a part of the demand to low price hours. The amplified pricing (Fig. 1c) increases the use of the storage, which are now loaded even during the low price periods around noon. Also, the use of the CHP is no longer optimal when the price is very low, e.g. during March 30. Finally, the market pricing leads to a similar use of the storage options and the lower price level causes a reduced utilization of the CHP, e.g. during March 30.

Fig. 2 shows the composition of the annual expenses for electrical and thermal energy as well as the revenue from the EVC and from selling energy to the grid. A feed-in to the grid happens very rarely as it is more profitable most of the time to consume the electricity internally. Therefore, the revenue is largely attributable to the EVC. The change in cost composition for the different energy system configuration is similar for all pricing models. For the static, dynamic, and amplified pricing model, the current campus configuration reduces the annual expenses by 11 % to 12 % (see Table III) compared to the No Flex campus. This is attributable to the use of the CHP and the thereby reduced amount of electricity bought from grid. This also results in a reduced burden from taxes and surcharges. Because of the low demand for heat and the small heat storage, the use of CHP is infeasible in summer, i.e. there is no possibility to reduce the expenses for the peak load. For the market pricing model, the cost reduction is only 3 %. This is because the gap between the price paid for electricity from grid and the price for electricity produced by the CHP is much smaller. For all pricing models, the High Flex campus reduces the expenses considerably. The larger heat storage makes the use of the CHP feasible also in hours of low heat demand. In combination with the PV system, the battery, and the storage, the expenses for electricity bought from the grid and thereby the expenses for taxes and surcharges reduce substantially. Also, the cost for the peak load decreases by around 50 %. The overall cost reduction for the High Flex campus in the amplified model is 34 %. For the

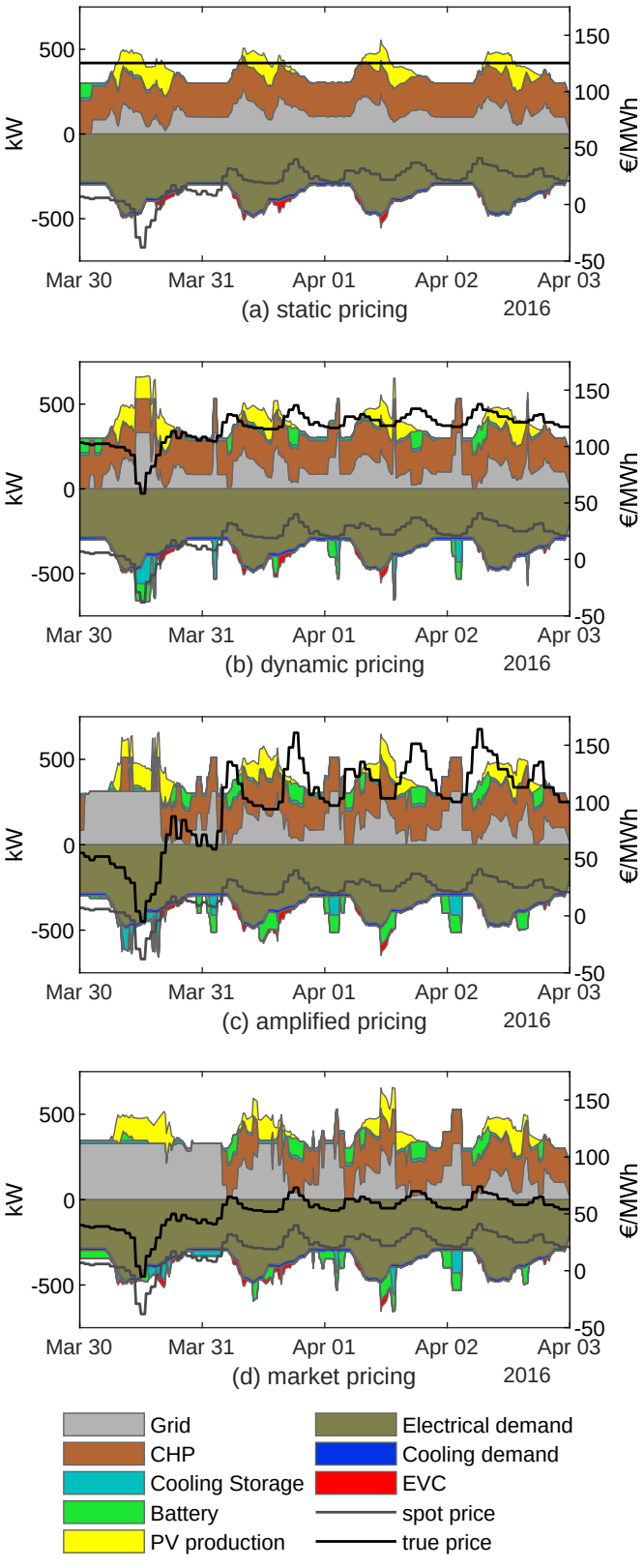

Fig. 1. *The figure shows the optimal demand and production schedules (left axis) as well as the spot price and the "true" end customer price time series (right axis) for the different pricing schemes for the time from March 30 to April 3 2016 in 15-minute resolution.*

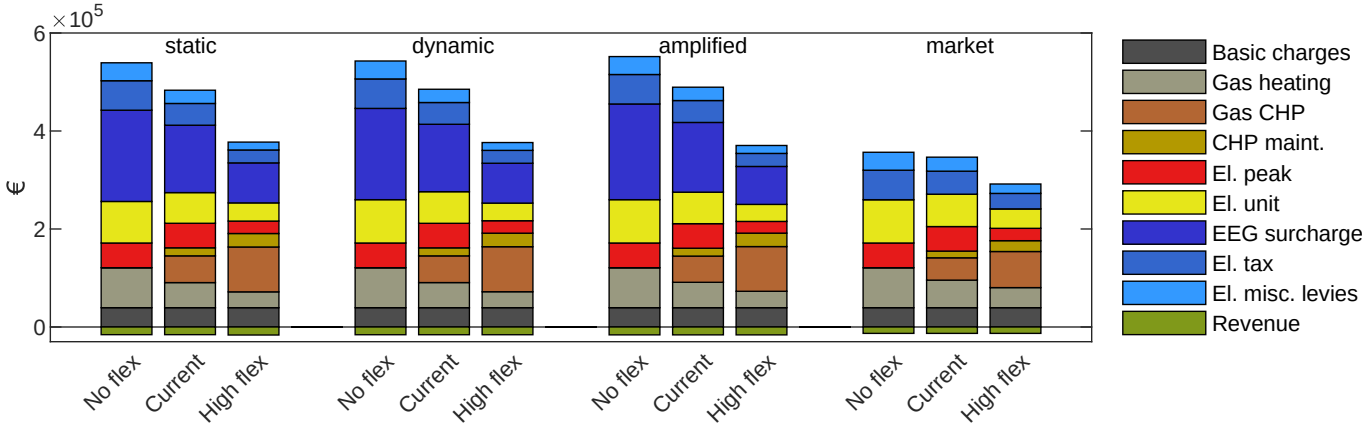

Fig. 2. *Annual expenses and revenues for different campus configurations for each pricing model.*

TABLE III

Financial performance indicators for different configurations compared to the No Flex campus for each pricing model. The NPV was estimated as the sum of discounted cash flow from the annual cost advantage assuming an interest rate of 5 %.

configuration	financial performance	static	dynamic	amplified	market
No Flex	annual cost	523,510 €	527,051 €	535,807 €	343,535€
Current	investment	447,260 €	447,260 €	447,260 €	447,260 €
	annual energy cost	467,547 €	469,386 €	473,303 €	333,538 €
	annual cost advantage	-55,962 € (-11 %)	-57,664 € (-11 %)	-62,503 € (-12 %)	-9,997 € (-3 %)
	NPV after 10 years	-15,133 €	-1,991 €	35,375 €	-370,061 €
	payback period (years)	11	11	10	> 15
High Flex	investment	1,055,990 €	1,055,990 €	1,055,990 €	1,055,990 €
	annual energy cost	360,959 €	360,647 €	354,362 €	278,769 €
	annual cost advantage	-162,550 € (-31 %)	-166,403 € (-32 %)	-181,444 € (-34 %)	-64,766 € (-19 %)
	NPV after 10y	199,183 €	228,932 €	345,076 €	-555,881 €
	payback period (years)	9	8	8	>15

static and dynamic pricing it is 31 % and 32 %, respectively. For the market pricing model the relative advantage is only 19 %. Again, this is because of the lower price for electricity from the grid. While the relative reduction for expenses related to the electricity unit price, the peak price, and duties are similar to the other pricing models, the value of flexibility options diminishes because of the missing gains by the reduced payments for the EEG surcharge.

Table III provides an overview of financial performance indicators. The amplified model increases the incentive for the adoption of flexibility options most strongly. After ten years the NPV of the High Flex campus is about 146,000 € larger compared to the static pricing model and 116,000 € larger compared to the dynamic model, which results in a shorter payback period. This is because the amplified pricing raises the cost for the No Flex and Current configuration and lowers the cost for the High Flex campus. The annual cost reduction in the market pricing model is too low to pay off the high investments.

VI. Conclusion

We presented a case study for a typical medium sized office campus in Germany to quantify the monetary incentives for the adoption of local flexibility options considering different electricity pricing models. We find that the amplified pricing model effectively improves the business case for the adoption of flexibility options. Most of the savings are attributable to savings on surcharges and taxes. An elimination of the EEG surcharge in combination with a dynamic pricing model would render investments in local generation and storage unprofitable. This contradicts the common theme of a decentral energy transition and should be further investigated. Our work could be extended in many ways. We assumed perfect foresight and an optimal mode of operation and did not include the aging and maintenance costs of system components. We also analyzed only one full year and did not account for uncertainty of future prices and investments. Furthermore, the component sizes could be chosen optimally.

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