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**Working Paper**

## How the design of retail prices, network charges, and levies affects profitability and operation of small-scale PV-battery storage system

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# How the design of retail prices, network charges, and levies affects profitability and operation of small-scale PV-Battery Storage System

HEMF Working Paper No. 03/2019

*by*

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 **Fraunhofer**  
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ESSEN

*Open-Minded*

# How the design of retail prices, network charges, and levies affects profitability and operation of small-scale PV-Battery Storage Systems

by Jessica Thomsen and Christoph Weber

## Abstract

We assess how the design of retail prices, network charges and levies for household prosumers affect the attractiveness and resulting operation of small-scale photovoltaic battery storage systems (PVBSS), using a detailed modeling approach applied to a case study of six households in Germany. The selected pricing schemes and reform proposals are evaluated regarding the investment attractiveness for the prosumer and the impact on system-oriented operation, considering both market and grid integration. We show that currently the business case for PV as well as PVBSS only exists since it allows avoiding grid offtake and thus avoiding paying taxes and levies on consumed electricity. Introducing time-variable pricing schemes or price components increases the value of PVBSS for the customer and the market, but leads to less grid-friendly operation. It is shown that the term “system-oriented operation” should be defined carefully since market value and grid-friendly operation do not necessarily go hand in hand so that one incentive cannot inherently contribute to both objectives at the same time. The tariff design, as well as the design of single tariff components have a considerable impact on the attractiveness and the resulting system integration of PVBSS and should be evaluated thoroughly to avoid unintended outcomes.

Keywords: photovoltaic battery storage systems; tariff design; system integration; grid integration

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# 1 Motivation

With increasing shares of fluctuating renewable energy (RE) generation, the need for storage technologies rises (Denholm and Hand, 2011). In many countries, increasing the share of RE generation and storage technologies has been proclaimed as a political target. To achieve this, the desired technologies have to be attractive to the potential investor, which has led to establishing a variety of financial support schemes in a number of countries (Abolhosseini and Heshmati, 2014; Couture and Gagnon, 2010; del Río and Mir-Artigues, 2014; Haas et al., 2011a; Haas et al., 2011b; Jenner et al., 2013). These support schemes for RE generation or storage systems are a result of societal and political choices. Thus, their design is set by politics and is part of the framework that determines the profitability of RE generation plants and storage systems. The costs for such support schemes are often recovered via levies included in the electricity retail prices (Bourgault et al., 2016). In consequence, this means their design affects the price signal customers receive and hence the resulting demand response.

From a customer perspective, investment and operational decisions with respect to renewable and storage systems are driven by the overall structure of retail prices. In order to achieve policy objectives, policy makers have therefore to consider the interplay between the pure retail energy price and the various levies and taxes. E.g. a widely discussed reform proposal, at least in Germany, has been to replace the current static RE levy by a variable one, which would be linked to the wholesale market price, cf. notably (Frontier Economics Ltd. and BET, 2016; Nabe and Bons, 2014). Yet an isolated consideration of one particular levy is insufficient since the electricity retail prices usually include various components covering a wide range of aspects, from RE levies to support for combined heat and power plants to network costs. As for the pure energy price and the RE levy, the design of the network charges influences the demand response as well as the attractiveness of business models for local self-generation based on avoided electricity purchases. With increasing shares of distributed generation that is based on business models minimizing electricity purchase from the grid and growing consciousness for energy efficiency, demand from the electricity grid decreases. However, as especially network costs are mainly fixed costs, decreasing electricity consumption requires also an adaptation in the design of network tariffs to ensure efficient and adequate cost recovery (Brunekreeft et al., 2011; Brunekreeft et al., 2005; Pérez-Arriaga et al., 2016; Rochlin, 2015; Wood et al., 2016). One major objective thereby is to efficiently allocate costs to all grid users. Additionally, with rising shares of distributed generation, it also has to be ensured that these costs are not distributed evenly and not at the expense of those customers without self-generation that cannot reduce or avoid consumption from the distribution grid. (Khalilpour and Vassallo, 2015) Different options

to distribute fix costs via network tariffs have been discussed and evaluated (Abdelmottaleb et al., 2017; Pérez-Arriaga and Bharatkumar, 2014; Wood et al., 2016).

When looking specifically at photovoltaic (PV) plants and PV battery storage systems (PVBSS), one also finds that many business models are based on avoiding electricity purchases as stated above. I.e. they are specifically designed for so-called prosumers who are consumers with some self-generation of electricity. In effect, this frequently also leads to avoid paying taxes and levies on the corresponding electricity consumption. Currently, around 50% of newly installed PV systems in Germany are installed as PVBSS (Kairies et al., 2016). For single-family homes, they are the easiest technology option to generate own electricity, since they require little maintenance and a low amount of active operation control and can be fitted from single-family houses to large industrial consumers. This is one of the reasons PVBSS have been subject to scientific research. So far, most studies focus on best operation modes and optimal system sizing under current regulatory framework conditions (Battke, 2012; Dennenmoser et al., 2013; Eyer and Corey, 2010; Feilmeier, 2016; Hanser et al., 2017; Hoppmann et al., 2014; Kanngießner, 2014; Kaschub et al., 2016; Khalilpour and Vassallo, 2016; Linssen et al., 2017; Lorenz and Schröder, 2014; Merei et al., 2016; Möller et al.; Moshövel et al., 2015; Mulder et al., 2013; Ranaweera and Midtgård, 2016; Ren et al., 2016; Sani Hassan et al., 2017; Tjaden et al.; Weniger et al., 2014a; Weniger et al., 2014b). (Parra and Patel, 2016) investigate PVBSS operation under different retail price schemes, including a constant energy price, a time-of-use tariff and a real-time price, but only from the household perspective. The design of various price components is not considered.

As applied research to date has focused on optimizing PVBSS against given retail pricing schemes, it has yet to be analyzed how incentives for investment and operation change depending on the design of various price components. Especially the incentives for households and their resulting response in residual demand shall be the focus of this work. Additionally, most published papers concentrate on the optimization of PVBSS operation for the prosumer only, so the value of the operating scheme from a system perspective is not part of the consideration. However, the optimum for the prosumer might not be the best operation scheme in a system view. Thus, the second question is what is the systemic value of the resulting operation scheme and how is this influenced by retail price design.

In order to answer the identified research questions, the present paper examines the incentives for investment and operation of PVBSS in households under different retail pricing schemes and the resulting impacts. The focus is thereby not to design optimal pricing schemes but rather to illustrate the likely impacts in a detailed case study considering current reform proposals. Such a case study has obviously to be embedded in a systematic reflection of objectives for policy reforms and indicators to be used for measuring the effectiveness of reform proposals. Yet it

provides demonstrative evidence, why certain “well-intended” reform proposals will only have limited effects and what the key drivers for the effectiveness of those proposals are. Thereby, we focus on the effects of so-called real-time-pricing along with changes in two key components of retail prices, namely the network charges and the surcharge used to finance renewable support payments. The evaluation is first undertaken from the household or prosumer perspective and then from a systemic perspective to answer the two main research questions.

The remainder of this paper is structured as follows: Section 2 discusses methodological aspects and relevant assumptions. The results of an empirical case study are presented and discussed in section 3, followed by a conclusion in section 4.

## **2 Methodology**

The following sections first discuss key aspects of the design and impact of network charges and other components of retail electricity prices. Then a short overview of the model used for the empirical assessment is given followed by a discussion of the model adaptations. Finally, the case study is presented including the scenarios considered as well as the assumptions and data input used to model an exemplary application case.

### **2.1 Key design elements and key effects of retail electricity prices, network charges, and renewable levies**

The structure of electricity retail prices and their components have steadily evolved over time. The introduction of competitive markets has led to a separation of grid-related cost components from the energy-related ones – at least in European markets where zonal pricing and retail competition are rather the rule than the exception. Moreover, various surcharges and taxes are applied in many legislations, inter alia to finance renewable support schemes or to incentivize energy efficiency through a specific energy or electricity tax.

In view of the intended decarbonization and transformation of the electricity system, the structure of network charges and other levies plays an important role. Besides the traditional objective of providing financial means for grid infrastructure and (possibly) renewable expansion, the design of network charges and renewable levies is also expected to facilitate the grid integration of RE and to provide adequate incentives for a system-oriented operation of flexible units such as demand-side flexibilities or storage systems (cf. e.g. (Brown et al., 2015; eurelectric, 2016, 2013; Hinz et al., 2018; Rodríguez Ortega et al., 2008)). Another element that is expected to incentivize demand-side flexibilities is real-time-pricing (cf. e.g. (Allcott, 2011; Borenstein, 2005)).

Overall, five major objectives for the design of grid charges and renewable levies may be distinguished. Three of them are rather conventional:

- 1) Incentivize the efficient use of grid infrastructure
- 2) Induce efficient investment in grid infrastructure
- 3) Enable the recovery of the investment and operational costs of the electricity grid infrastructure

Besides, two new objectives gain importance in the context of a transition to a low-carbon economy:

- 4) Enable the recovery of the investment and operational costs for renewables
- 5) Provide adequate incentives for the investment into renewable and flexible installations

Also, the first objective may be somewhat reformulated in the presence of new types of grid users including prosumers and storage systems – which are frequently characterized by the flexibility they purportedly include:

1A) Provide adequate incentives for the system-oriented operation of existing and new flexibilities.

These different objectives raise the question to what extent existing proposals for a reform of network charges and other parts of the retail electricity price will contribute to the achievement of these partly conflicting goals. Before answering this question, first, it must be clear how the achievement of these goals can be measured. This will be outlined in section 2.1.1. In section 2.1.2, we discuss the various elements of the current reform proposals in order to identify key aspects to be considered further in the analysis.

### **2.1.1 Indicators for measuring the impact of reforms in retail pricing**

In order to measure the impact of reforms in network charges and other components of retail electricity prices on the aforementioned objectives, adequate indicators need to be defined.<sup>1</sup> In order to reduce the complexity of the evaluation task, we subsequently focus (almost) exclusively on proposals where the cost recovery for grid and renewable investments is achieved. I.e. we do not need indicators to measure the impact on the objectives 3) and 4), rather we adjust the reform proposals so that these objectives are met. Also, the objective 2) of incentives for adequate grid investments is not at the core of the present study. It has to be achieved mostly through

---

<sup>1</sup> Obviously, one may also question whether some objectives are well-posed and appropriate. Notably in the vein of mainstream environmental economics, incentives for renewable investments should not be an objective on its own. It is rather the decrease in greenhouse gas emissions that should be retained as primary objective. Yet this debate is beyond the scope of this paper (cf. e.g. Frondel et al. (2014), van der Ploeg and Withagen (2014) for contributions to that debate). We rather take the formulated objectives as given and are interested in the question to what extent price structure reforms can contribute to attain them.



appropriate incentive regulation for grid operators; whereas the focus here is on pricing structures for grid users.

Hence, the focus is on appropriate metrics for objective 5) and the modified objective 1A). For objective 5), i.e. the incentives for investments, a straightforward indicator is to consider the *net present value (NPV) for typical investment alternatives* under the different reform proposals.

In view of objective 1A), one has to clarify what is meant by system-oriented operation. In fact, this should be related back to the question what are the boundaries of the system under scrutiny. This may range from the local low voltage grid passing by the higher level distribution grid up to the overall interconnected (European) electricity system. Correspondingly, at least three indicators are needed, one for each system boundary considered.

For the European electricity system, the degree of system-oriented operation may be assessed by looking at the *value of the flexibility operation* when valued *at market prices*. Since market prices (should) reflect scarcities in the system, high positive market values should describe strong contributions to system stress reduction and vice versa. At the local and intermediate grid level, no specific market prices are available – at least in the current European framework. Yet grid costs are largely driven by maximum capacity requirements and thus changes in *maximum grid load or infeed levels* are retained as indicators to measure the degree of system-oriented operation at lower levels. A dimensionless quantity to measure the efficient use of grid capacity is the *coincidence factor* (the inverse of the diversity factor), which describes the ratio of the maximum load at a certain grid level to the sum of the maximal individual loads.

With respect to the different indicators used to assess system-oriented operation one may state in a somewhat different vein: the indicators measure on the one hand how the reform proposals incentivize flexibility operation in view of market integration of renewables (*market value of flexibility operation*) and on the other hand their grid integration (*maximum load/infeed and coincidence factors*).

### **2.1.2 Dimensions of price structure, network charges, and levy reforms**

From a grid user perspective, the use of existing operational flexibilities will be driven by the overall electricity price, i.e. the sum of the energy component of the retail price, the grid charges, the renewable levies and possibly further charges (e.g. electricity tax or so-called concession fee). As long as load or generation are (considered as) inflexible in their operation, the structure of the price components is irrelevant. Only the annual sum of the different components is relevant when it comes to comparing various investment alternatives since they will affect the NPV. For flexible loads, storage or generation, the structure of price components matters at least in three respects: 1) their differentiation in fix (lump sum), capacity dependent (maximum load/infeed) and energy

dependent parts, 2) their variability over time, and 3) a possible differentiation between price components for grid offtake vs. prices for grid infeed. Especially storage operation will be affected notably by aspects 2) and 3) since time variability is a prerequisite for value generation through time arbitrage and price discrimination between offtake and infeed provides incentives for self-consumption.

Besides the time variability and direction-based differentiation of the energy component of retail prices, also the structure of network charges and possible modifications in the renewable levies and other charges will affect storage or combined PVBSS systems, at least when it comes to investment decisions. To assess the investment incentives appropriately, a detailed modeling of the operation is yet required in order to identify the revenue (or avoided cost) potential that comes along with an optimized use of the storage flexibility. Computing thereby the optimal usage of the flexibility provides an upper bound to the revenues of a prosumer – especially under the (common) assumption of perfect foresight with respect to solar infeed and prices. Such a computation – done on concrete examples of reform proposals and for concrete households – may hence provide a benchmark in terms of investment incentives offered to the consumer. At the same time, this also gives insight into the achievable gains from a system perspective.

## **2.2 Modeling Approach**

The chosen model DISTRICT (Thomsen, 2017) covers the aspects discussed above and requires only slight adaptations to be fully adequate for the present research questions. The following sections provide a short overview of the model followed a discussion of the model adaptations as well as the assumptions and data input used for the present analysis.

### **2.2.1 General Modelling Approach**

The model DISTRICT targets a cost minimal operation of a regionally bounded energy system. Within the system borders, the model is divided into model areas, where the demand and distributed generation is located. Electricity distribution between the areas is represented by a transport model approach. The model takes into account renewable generation technologies such as photovoltaic and wind energy, storage technologies and demand-side management at the prosumer level. Within each model area, electricity can be generated, consumed directly, stored and/or fed into the grid. Remaining electricity demand can be covered by withdrawing electricity from the grid. It offers the possibility to trade electricity outside of the system border, i.e. to participate in the day-ahead or reserve markets. For a detailed formulation of the model, refer to (Thomsen, 2017).

## 2.2.2 Model Adaptations

The original objective function for the aggregated optimization, as shown in the following equation, had to be adapted to allow determining the optimum for each household instead of the system optimum. The total cost ( $TC$ ), consisting of variable ( $VC$ ) and fix ( $FC$ ) operation cost as well as a trade balance for the spot market ( $R^{spot}$ ) participation, are minimized. For the presented assessment, reserve market participation is not considered and has therefore been left out in the objective function.

$$TC = VC + FC - R^{spot} \quad 2.2.1$$

For the present assessment, each model area represents a single household and thus a single prosumer. Each prosumer has a PVBSS. For each model area, the demand ( $DEM_{a,t}$ ) has to be equal to the generation ( $GEN_{a,pp,t}$ ) in that region plus electricity discharged ( $DCH_{a,stor,t}$ ) and grid withdrawal ( $WD_{t,a}$ ) minus storage charge ( $CH_{a,stor,t}$ ) and grid infeed ( $FI_{t,a}$ ), as stated in equation 2.2.2. For the detailed description of all conditions regarding generation, transport and storage of electricity, please refer to (Thomsen, 2017).

$$DEM_{a,t} = \sum_{pp} GEN_{a,pp,t} + \sum_{stor} DCH_{a,stor,t} - \sum_{stor} CH_{a,stor,t} + WD_{t,a} - FI_{t,a} \quad 2.2.2$$

In order to determine the optimal decisions from the household perspective instead of a system optimum in an aggregator perspective, the withdrawal and feed-in of each household (corresponding to an area of the original model) are given a local price signal. To achieve this, the following equation is used, where the costs of offtake and infeed are accounted for. The cost of electricity purchase is calculated by multiplying the power withdrawn from the grid connection  $WD_{t,a}$  by the length of the time-step  $\Delta t$  and the electricity price  $p_t^{buy}$ . The revenue is calculated by multiplying the electric power fed into the grid  $FI_{t,a}$  by the length of the time-step and the price received for selling electricity  $p_t^{sell}$ . Additionally, the fix part of grid fees ( $f^{grid}$ ) is added as annual sum and multiplied by the local connection capacity of each house  $CAP_{a,transformer,t}$ . To account for the possibility of working with different numbers of time-steps or different time-step lengths, the term is multiplied by  $\frac{\Delta t \cdot n}{8760}$ ,  $n$  being the number of time-steps considered. This allows considering the fixed grid fee only partially if the optimization is done only for a fraction of a year.

$$C_a^{area} = \sum_t (WD_{t,a} \cdot \Delta t \cdot p_t^{buy}) - \sum_t (FI_{t,a} \cdot \Delta t \cdot p_t^{sell}) + f^{grid} \cdot CAP_{a,transformer,t} \cdot \frac{\Delta t \cdot n}{8760} \quad 2.2.3$$

The equation does not consider additional taxes for self-consumption within the area since the present analysis concentrates on single-family buildings with PV capacities up to 10kW where no taxes apply. Since the perspective of the household instead of the aggregator is taken, expenses and revenues from trades at the spot market are additionally set to zero.

$$R^{spot} = -\sum_t \left( E_t^{bought} \cdot \Delta t \cdot (p_t^{spot} + tf) \right) + \sum_t \left( E_t^{sold} \cdot \Delta t \cdot (p_t^{spot} - tf) \right) = 0 \quad 2.2.4$$

This leads to the following objective function for the individual household optimization:

$$TC = VC + FC - R^{spot} + \sum_a C_a^{area} \quad 2.2.5$$

## 2.3 Case Study

In order to assess the effects of possible reforms in the retail pricing structure numerically, one has to select specific reform proposals for investigations (cf. section 2.3.1) and then also to specify a concrete application context (cf. section 0).

### 2.3.1 Investigated Scenarios

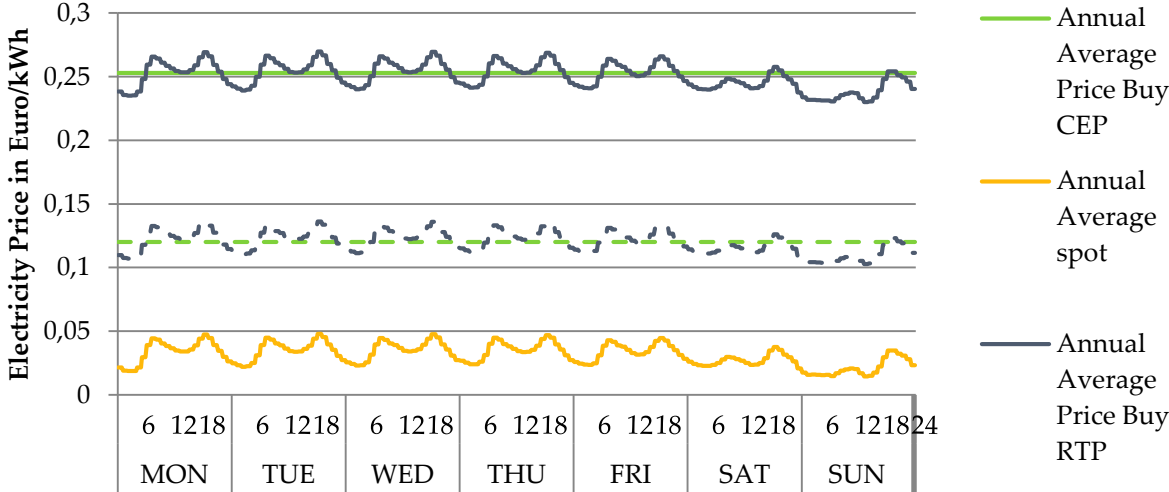
Following the considerations outlined in section 2.1.2, a first set of basic scenarios is defined, which differ with respect to the time-variability of the retail energy price and the discrimination between offtake and infeed prices. In a subsequent step, these basic scenarios are then complemented by three specific policy reform scenarios.

The first basic scenario reflects the current practice, i.e. a constant electricity price (CEP) for consumed electricity and a constant electricity price for electricity fed into the grid aligned on current German data. The second scenario takes the pure spot perspective. It is based on strictly different answers to the two main issues raised in section 2.1.2: ad 2) Retail clients are confronted with time-varying prices along the principles of “real-time-pricing” and ad 3) There is no price differentiation between offtake and infeed prices. In this vein, the second scenario takes the spot market price for both, energy consumption from the grid as well as remuneration for the electricity feed-in. It is hence labeled “spot” scenario<sup>2</sup>. The third basic scenario, called “real-time-pricing scenario” (or RTP for short), describes a version of real-time-pricing that is more likely to be put into practice. It provides a synthesis of the two aforementioned scenarios by considering

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<sup>2</sup> In view of actual policy making, this is not a realistic scenario. Yet it reflects the assumptions underlying most so-called energy system models (e.g. Di Leo et al. (2015); Eggers and Stryi-Hipp (2013); Palzer and Henning (2014); Saad Hussein (2017); Sgobbi et al. (2016); Simoes et al. (2015); Simoes et al. (2013)) which are frequently used to advise policy makers on optimal long-term system development. Since such a pricing scheme also is the first-best choice in view of a system-oriented operation in the absence of local congestions, it is retained here as a kind of benchmark scenario.

the spot market price plus all fees also included in the conventional retail price for electricity purchases. On the sales side, this is combined with the so-called “direct marketing” support scheme for renewable infeed, consisting of the spot market price plus a market premium as revenue for electricity feed-in. All price patterns are illustrated in Figure 1.



**Figure 1 Pricing schemes for the three basic scenarios**

The basic scenarios one and three include a gap between the procurement and sale price that is induced by policy choices. This gap consists of a number of taxes and levies, used to recover certain costs related to the energy system, such as grid costs, technology specific support schemes or value-added tax. The design of these taxes and levies not only impacts the mentioned gap between the two prices but could also affect the variation over time. To gain a closer look on the effects that come with political design choices, the design of the grid fees as well as the RE levy, are examined in more detail in additional scenarios, called “policy reform scenarios”.

First, a changed structure of the grid fees towards a higher capacity based component, as discussed in various reform proposals, is considered. Second, a variable RE levy, frequently called “dynamic RE levy” in the German policy debate, instead of a flat RE levy is considered (cf. section 2.1 for details). Third, the changed grid fee scheme is combined with the dynamic RE levy. All policy reform scenarios are applied to the CEP and RTP price schemes. As a result, six policy reform scenarios as displayed in Table 1 are considered in addition to the three basic scenarios.

**Table 1 Policy reform scenarios based on the CEP and RTP price schemes**

Policy Reform Scenario 1	Policy Reform Scenario 2	Policy Reform Scenario 3
Changed scheme on grid fees	Dynamic RE levy	Dynamic RE levy plus changes scheme on grid fees
<b>Adapted to the constant electricity price (CEP) and real-time pricing (RTP) tariff scheme:</b>		
CEP_CapChargGrid	CEP_dynRELevy	CEP_combined
RTP_CapChargGrid	RTP_dynRELevy	RTP_combined

### 2.3.2 Case study

For the case study, six households with different demand characteristics, summarized in Table 2, are included. These six households are set as a closed system with a connection to the superior grid, enabling the analysis of the criteria elaborated in section 2.1. The demand data is obtained from SynPro (Fischer et al., 2015; Härtl et al., 2014) and represents individual load profiles for single households (HH).

**Table 2 Characteristics of the considered single-family buildings**

	HH 1	HH 2	HH 3	HH 4	HH 5	HH6
<b>Number of occupants per household</b>	4	4	2	2	2	4
<b>Number of full time working occupants</b>	1	2	2	1	0 (retired)	1 (family with small children)
<b>Sum of annual demand [kWh]</b>	5,376.10	4,070.12	2,347.89	2,360.14	2,552.31	3,881.34
<b>Maximum annual load [kW]</b>	7.08	5.76	3.73	4.72	3.29	4.73
<b>Minimum annual load [kW]</b>	0.09	0.08	0.04	0.06	0.05	0.05
<b>Annual electricity cost without own generation at usual HH-tariff [Euro]</b>	1,504.27	1,147.35	676.67	680.02	732.54	1,095.75

Installed capacities and cost assumptions are summarized in Table 3. Since (Dietrich and Weber, 2018) show that economies of scale also exist for small-scale PV systems and NPVs under current regulations are best for large systems, all capacities are fixed to 10kWp for the PV system. For the BSS, the values are set to 5kW/5kWh.

**Table 3 Cost assumptions for the considered technologies**

Technology	Installed capacity in kW	Fix operation cost in € per kW	Variable operation cost in € per kWh	Net investment cost in € per kW	Lifetime in a	Weighted average cost of capital WACC
<b>Photovoltaic</b>	10	15.18 <sup>a</sup>	0	1356 <sup>a</sup>	25	0.035 <sup>b</sup>
<b>Battery</b>	5	20 <sup>c</sup>	0	500 + 300 for replacement <sup>c</sup>	10	0.035 <sup>b</sup>

<sup>a</sup>(Dietrich and Weber, 2018), <sup>b</sup>(Kost et al., 2013), <sup>c</sup> own assumption based on (Dietrich and Weber, 2018; Moshövel et al., 2015)

Concerning spot market prices, data from 2015 are used as a basis since current future base prices maintain around the same value until 2020. The values for the RE levy and grid fees are current values from 2017.

As a policy reform proposal with respect to the structure of grid charges, we assume that instead of most costs being paid on energy consumption, 70% of the costs are paid on the connection capacity and only 30% is paid as a surcharge on energy consumption. This is an example for a shift towards more capacity based grid fees, without losing the energy component altogether as proposed e.g. by (eurelectric, 2013) and already observable in Germany (Jahn and Graichen, 2018), with exemplary proportions for the capacity and energy-based part of the tariff. Calibrating on equal revenues for the grid operator based on the case study data, we obtain the values stated in Table 4.

**Table 4 Assumptions for grid fees and their payment scheme excluding value-added tax**

	<b>Variable grid fee [€/kWh]</b>	<b>Fixed grid fee [€/kW]</b>
<b>Current tariff scheme (own calculation of fixed and variable part based on average German grid fee in (BDEW Bundesverband der Energie- und Wasserwirtschaft e.V., 2017))</b>	0.065	2.41
<b>New tariff scheme – 70% fixed and 30% variable grid fee</b>	0.0226	12.46

For the reform proposal of a dynamic RE levy, we follow the concepts presented by (Nabe and Bons, 2014), who couple the RE levy to the spot market price by a constant factor. This proposal has also been evaluated by (Frontier Economics Ltd. and BET, 2016) as the currently most prominent concept in public debate. The effect is that the levy increases with rising prices and decreases with decreasing prices, while the total revenue from the levy stays the same. The motivation behind this dynamic design is to incentivize behavior that reduces demand in high price periods and increases demand in low price periods. The dynamic RE levy is calculated as follows (Frontier Economics Ltd. and BET, 2016):

$$\sum_t dynRELevy_t \cdot demand_t = \sum_t statRELevy \cdot demand_t \quad (1)$$

$$dynRELevy_t = p_t^{spot} \cdot f \quad (2)$$

$$f = \frac{\sum_t (statRELevy \cdot demand_t)}{\sum_t (p_t^{spot} \cdot demand_t)} \quad (3)$$

For the present assessment, the sum of all households included in the case study and the spot market prices of 2015 are used, which gives a factor of 1.8383.

For all price data, RE levy, variable grid fee as well as additional charges such as value-added tax and electricity tax are included in  $p_t^{buy}$ .  $p_t^{sell}$  is either set equal to the spot market price, the spot

market price plus the EEG based market premium (0.0883€/kWh) or equal to the feed-in-tariff of 12 ct€/kWh.

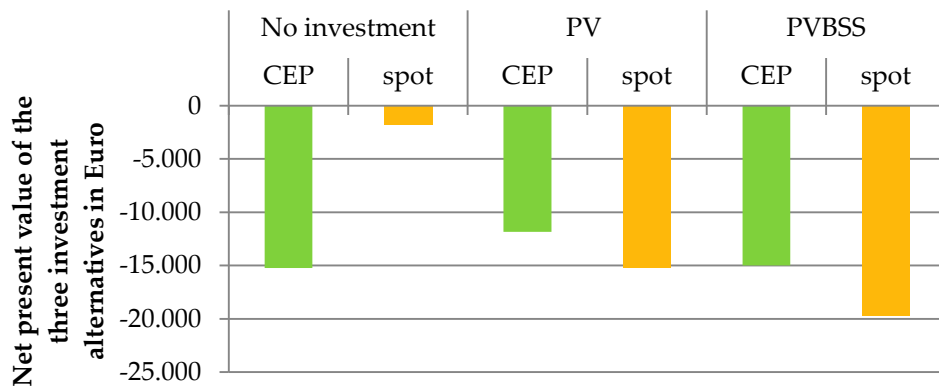
### **3 Results and Discussion**

In the following, the results are shown for HH 2 only, whose annual sum of demand is closest to the sample average. The results for all households can be found in the appendix. The differences between the scenarios show the same tendencies for all households, except where noted otherwise, so the focus is on one household simply to facilitate comparison. In the following, first, the investment and operational incentives are assessed from the household perspective. Second, the system impact is discussed.

#### **3.1 Economic evaluation of PVBSS operation from the household perspective**

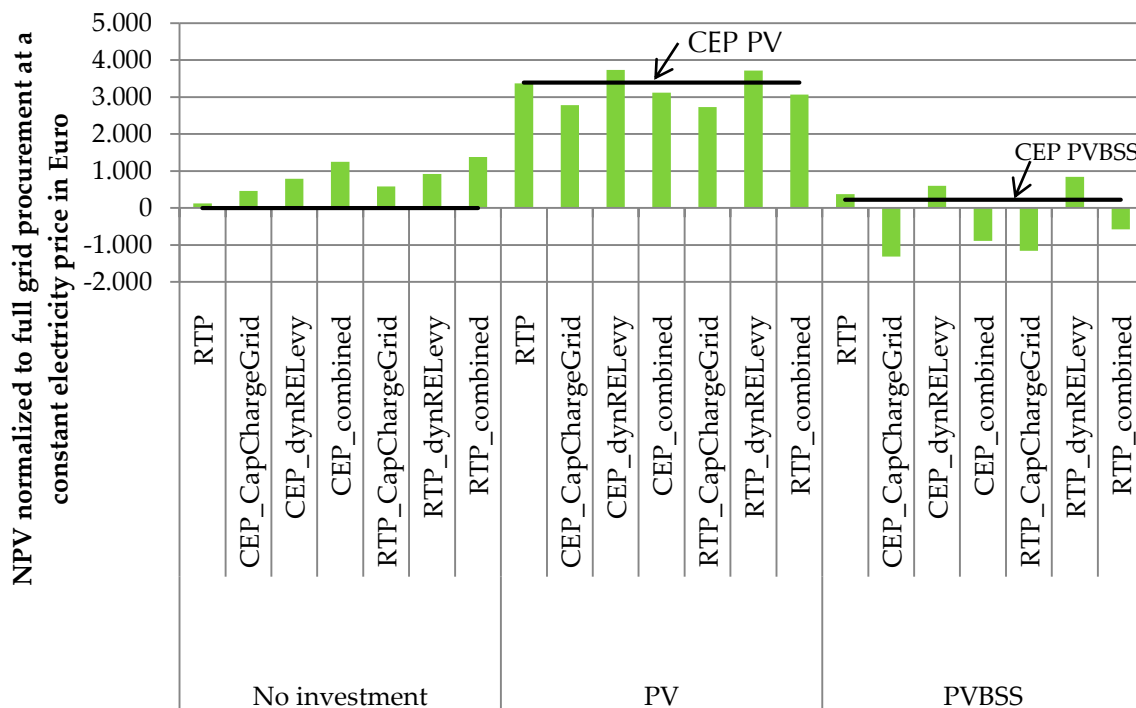
As discussed in section 2.1.2, we use the NPV as an indicator to assess whether objective 5) can be achieved with the reform proposals. Figure 2 displays the NPVs of the three options at hand: Not undertaking any investment and relying only on external electricity procurement, investing into a PV plant or investing into a PVBSS. For the two investment options, remaining electricity demand is covered by external procurement and excess generation is remunerated with the prices given in the scenario definitions. Figure 2 displays the results for the two basic scenarios *CEP* and *Spot*. It can be seen that for the *CEP* scenario the NPV increases (it gets less negative) when investing in a PV plant. Hence, the PV investment is profitable, whereas it is clearly unprofitable for the *Spot* scenario. For PVBSS, the NPV is lower than the NPV for PV in both scenarios. Thus, none of the basic scenarios provides sufficient incentives for installing BSS at the assumed prices. This is in line with other study results such as (Dietrich and Weber, 2018). When considering spot prices only, the NPV for both investment options is significantly lower compared to the no investment alternative. This shows that the gap between the offtake and infeed price is a decisive factor when examining business models for household-scale PV or PVBSS.





**Figure 2 NPV of the three investment alternatives no investment, PV plant only and PVBSS for the two basic scenarios with either constant energy prices or spot market prices**

Figure 3 displays the difference between each NPV and the CEP NPV without investment. Thus, the value shows whether this option is more or less profitable than external electricity procurement at the assumed constant electricity price. A more profitable option signifies that there are incentives to invest in a PV system or PVBSS. To enable an easier comparison between the reform proposals, the value for the corresponding CEP scenario is displayed as a line, i.e. the value for *CEP PV* for the PV scenarios and *CEP PVBSS* for the PVBSS scenarios. The prices for *CEP* and *RTP* are calibrated so that without investment the NPV is nearly identical.



**Figure 3 NPV of all scenarios except those displayed in Figure 2 above**

Without investment, all reform proposals lead to a better outcome, implying that the incentive to consider an investment decreases. In those scenarios with a higher capacity charge in grid fees, this effect does not show up for all households. The distributional effects of the reform in the grid

fee structure imply that households with higher demand are better off whereas negative normalized NPVs arise for households with lower demand, compare Table 8 in the appendix. Except for this effect, observable in all *\_CapChargeGrid* and *\_combined* scenarios, the changes between the scenarios are similar for all households so that examining the results for one household is sufficient to compare the effects of the different reform proposals.

It can be observed that without an investment the household is better off with the dynamic RE levy. With the demand patterns used, the dynamic RE levy actually reduces electricity cost at full external procurement, i.e. traditional, inflexible household electricity consumers benefit from a reform that is intended to support new flexible consumption (and production/storage) patterns. This indicates that the examined demand patterns already have a negative correlation with the spot market prices with demand peaks during the day at low spot market prices and a second demand peak in the evening at high spot market prices. The demand during the day seems to outweigh the higher charges for the RE levy in the evening peak, leading to a better result for the household. This is surprising and may raise doubts about the stringency of the reform proposal. However, as the results from (Andersen et al., 2014) show, this might change when different years are considered for the wholesale prices.

Generally, the incentive to invest into a PV system is higher than to invest into a PVBSS, regardless of the pricing scheme and reform proposal. An *RTP* pricing scheme does not affect the profitability for PV but improves the NPV of the PVBSS. With a BSS, the introduced price fluctuations can be utilized by optimizing the residual load, leading to a better result for the PVBSS in the *RTP* scenario than in the *CEP* scenario.

For both investment options, the dynamic RE levy leads to a better result for *CEP\_dynRELevy* and *RTP\_dynRELevy*. Whereas for the PV plant, the difference between *CEP\_dynRELevy* and *RTP\_dynRELevy* is less than 50€ for the normalized NPV, this difference exceeds 600€ for PVBSS. This is due to the same effect as the improvement in the *RTP* scenario. In the *RTP\_dynRELevy* scenario, the price fluctuations are highest leading to the highest NPV for PVBSS.

Without investment, the changed grid fee scheme leads to a better result for the household in both scenarios *CEP\_CapChargeGrid* and *RTP\_CapChargeGrid* since the considered household has an above average consumption. However, when undertaking an investment to generate own electricity, a higher capacity charge leads to a decrease in NPV. This effect is more pronounced for PVBSS than for PV and less pronounced in the *combined* scenarios. When switching from pure energy to more capacity based grid charges while reducing the residual load, the annual sum for grid costs increases and thus reduces the NPV. This is also a primary intention of this reform proposal: reducing the detrimental effect of PV installations on grid revenues which are not backed by corresponding cost reductions in the grid. Consequently, the decrease in residual

load through PV installations does not lead to a similar cost reduction for the household as in the *CEP* scenario since the impact of fix costs remains, reducing the incentive to invest into an own plant. This effect is reduced when combined with the dynamic RE levy as the fluctuating component offers additional opportunities to optimize self-generation with a PVBSS. I.e., in order to obtain the same investment incentive for a PVBSS as in the reference case, higher capacity charges would have to be accompanied by a fluctuating price scheme or fluctuating price component.

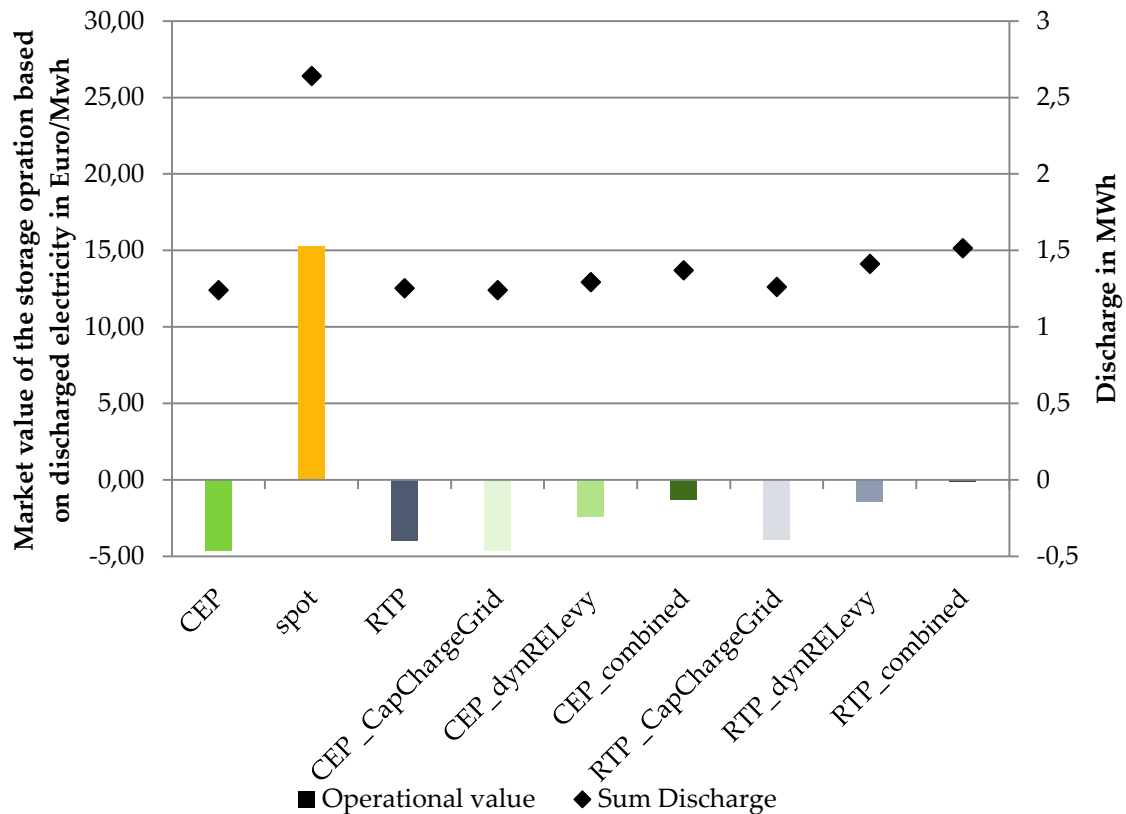
Taking a closer look at PVBSS, it can be seen that with the assumed prices PVBSS are only profitable in the *CEP*, *RTP*, *CEP\_dynRELevy* and *RTP\_dynRELevy* scenario compared to no investment at *CEP*. Comparing the NPVs to the corresponding reform proposal scenario without investment, it has to be stated that PVBSS are only profitable in the *CEP* and *RTP* scenario. From the results presented thus far, it can be stated that the tariff design and especially taxes and levies play a crucial role in current business models for PVBSS. The applied pricing scheme determines the value of self-consumption and thus the NPV achievable by self-optimization.

### **3.2 Systemic evaluation of PVBSS operation under different regulatory reforms**

As discussed in section 2.1, the impacts on a system-oriented operation of existing and new flexibilities are evaluated using the indicators *market value of flexibility operation*, *maximum load/infeed* and *coincidence factors*.

To determine the market value (Figure 4), the storage charge and discharge are valued with the spot market price and divided by the sum of discharged electricity. This leads to the market value the storage would generate in the determined operation mode. A positive market value indicates that the storage generates an additional value for the system.

The *Spot* scenario obviously yields the highest market value and even the only positive one. Hence, this is the only scenario where storage operation utilizes price spreads to generate additional revenues. The operation in this scenario is purely driven by the spot market price and less by self-consumption, which leads to significantly higher amounts of charging and discharging. Under this price scheme, self-consumption does not have any added value so that utilizing price spreads is preferred over increasing self-consumption, leading to a high market value.



**Figure 4 Market value of storage operation in Euro/MWh, determined by the difference between the charge and discharge, both valued at the corresponding spot market price, and based on the sum of discharged electricity**

*CEP* and *CEP\_CapChargeGrid* show the lowest market values of all considered scenarios. Both scenarios have constant price signals, leading to PVBSS operation being driven by optimizing self-consumption and selling excess electricity whenever necessary. The resulting timing of operation does not fit to market signals. When introducing a time-variable price or price component, the market value improves, but none of the scenarios reaches any value close to the *Spot* scenario's value.

At the same profit margin to the household as the *CEP* scenario, the *RTP* price scheme provides a slightly higher market value. With similar quantities being charged and discharged, we conclude that the *RTP* scheme incentivizes a more system-oriented PVBSS operation. It is favorable for the household to adapt operation to price fluctuations additionally to adapting it to PV generation and own demand.

A more capacity based grid fee only affects the market value for the *RTP\_CapChargeGrid* scenario, increasing it by 2%, whereas it has no effect for the CEP based scenario *CEP\_CapChargeGrid*. Thus, the market value is not strongly affected by flat price components. The observed small effect in the *RTP* scheme can be explained by slightly higher relative fluctuations since the time-invariant energy component of the grid fee is reduced.

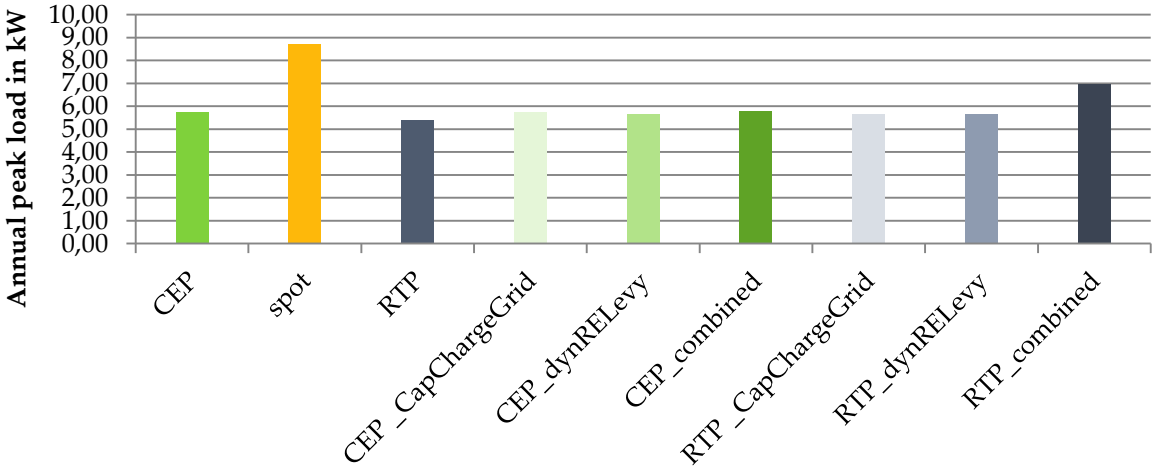
Changing the RE levy increases the market value for all households. The selected household shows an improvement by 48% (*CEP\_dynRELevy*) and 69% (*RTP\_dynRELevy*) compared to the *CEP* scenario. Additionally, the sum of discharged electricity increases. This indicates a higher usage rate and a more system-oriented operation, although the effects are rather small. For both policy reforms, the relative increase in the market value is higher than the relative increase in the sum of electricity charged and discharged. This means that the utilization of price differences is improved, leading to an improved PVBSS operation in terms of system orientation.

In the combined price schemes, the market value increases further. In the *RTP\_combined* scenario the market value increases to -0.14€, which is the highest value of the reform scenarios. Reducing the overall value of procured electricity while increasing the relative fluctuation of the procurement price induces a more system-oriented operation since the household has the opportunity to increase its savings and revenues when adapting to the price signal. I.e. the value of self-consumption becomes time-dependent with time-varying price signals. The sum of electricity discharged increases in both *combined* scenarios, with higher values for the *RTP\_combined* scenario. As the *RTP* scenario has a time-variable sales price, one could have expected higher market values. However, *CEP\_dynRELevy* shows a better market value than *RTP* although the sales price remains constant. The market value increases even further in the *RTP\_dynRELevy*, without changing the sales price. These observations indicate that the variation in the purchase price has a higher influence on the market value than the variation in the sales price.

As the chosen time-variable price signals (*RTP* and *dynRELevy*) are coupled to the spot market price, they incentivize a more system-oriented operation, thereby increasing the market value. With fluctuating price signals whose fluctuations are not in line with the spot market price, the market value would be inferior to those shown. However, even the chosen scenario layout does not achieve positive market values in any scenario where taxes and levies on the purchase price are considered. This means that the system-orientation can be improved but self-consumption being the main priority hinders high market values.

The second aspect of systemic value is grid usage, beginning with the consumer peak load displayed in Figure 5. It can be seen that the *Spot* scenario shows the highest peak load, which is due to the low spot market prices, making optimized electricity purchases from the grid more attractive. The other way around this means a higher stress on the distribution grid. The individual peak load is not affected by introducing a capacity based grid fee as the capacity charge is

imposed on the rated capacity of the connection<sup>3</sup>. Introducing a dynamic RE levy increases the peak load for all households except for the selected household, cf. Table 11 in the appendix. This indicates that the time-variable purchase price tends to increase stress in the grid or at least does not reduce it compared to the *CEP* scenario. The combined scenarios show a further increase in peak load, indicating that the storage system is used to a further extent to adopt demand in order to benefit from a varying price signal. The effect seems more pronounced when both price signals, offtake, and infeed, are time-variable rather than when only the offtake price shows a temporal variability (*CEP\_dynRELevy* and *CEP\_combined*).

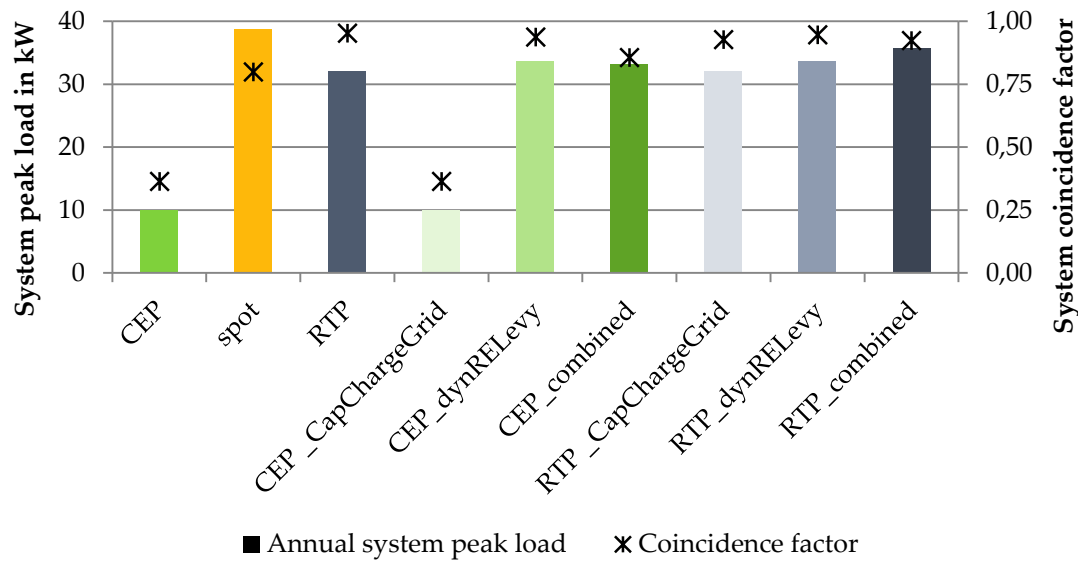


**Figure 5 Annual peak load in kW for PVBSS in each scenario**

The coincidence factor and system peak load are displayed in Figure 6. It can be observed that the lowest coincidence factor and peak load to the superior grid occur in the *CEP* and *CEP\_CapCharGrid* scenarios. This means a reduced stress on the local grid compared to the other scenarios. Due to the completely constant price signals, the households do not have any incentives to shift their peak demand. All scenarios that consider a time-variable price signal show significantly higher system peak loads and coincidence factors, implying a higher stress on the grid. The increase in the coincidence factor indicates that the peak demand of individual households converge to the same time-steps with low electricity prices as one expects for spatially uniform prices with a temporal variation. The increased system peak load means that in the long-run, network infrastructure has to be reinforced to accommodate the changed demand behavior.

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<sup>3</sup> Capacity charges can either be imposed on rated capacity or annual peak load. Both has its merits, however, as essentially the installation of the network infrastructure is the cost driver of grid costs, the present case study uses grid costs on contracted capacity. However, capacity charges on peak load can be used to incentivize a certain customer behavior, cf. e.g. Brown et al. (2015); Hinz et al. (2018); Pérez-Arriaga and Bharatkumar (2014); Rodríguez Ortega et al. (2008) for contributions to the discussion.



**Figure 6 System coincidence factor and peak load to the superior grid for the system of six households**

Within those scenarios with time-variable price signals, the *Spot* scenario shows the highest peak demand. Interestingly, the coincidence factor in the *Spot* scenario is lower than in all other scenarios with a time-variable price signal. The incentive to shift peak load to the same time-step seems to be reduced as the value of self-consumption decreases due to the low offtake prices. Thus, there is a higher offtake from the grid with less coordinated individual peaks. This might also increase the temporal diversity of peak loads, while in scenarios with a higher value of self-consumption peak load is more concentrated in the same, low priced time-steps (e.g. in the *RTP* scenario). The high system peak load in the *Spot* scenario means a considerable stress on the grid that contradicts system-oriented operation.

The reduced value of self-consumption might also cause the more grid-friendly values in the *CEP\_combined* scenario compared to the *CEP\_dynRELevy* scenario. *CEP\_dynRELevy* shows the same system peak load than the *RTP\_dynRELevy* scenario, but a lower coincidence factor. Since the fluctuations in the *RTP\_dynRELevy* are more pronounced, we conclude that larger fluctuations lead to a more pronounced temporal convergence of peak loads.

Although the *RTP* scenario does not dispose of the highest price fluctuation, it shows the highest coincidence factor, followed by the *RTP\_dynRELevy* scenario. However, they do not show the highest system peak loads. I.e. the individual peak loads occur almost simultaneously, but the resulting system peak load is lower than in the *Spot* or *RTP\_combined* scenario. In the *RTP\_CapChargeGrid* scenario, the peak load maintains the same value as in the *RTP* scenario but the coincidence factor decreases slightly. As the purchase price and, hence, the value of avoided grid offtake decreases, the incentive to shift peak load to a certain time-step is also lower. This results in a slightly lower coincidence factor.

The demand to the superior grid has additionally been valued with a current grid tariff in Germany (NetzeBW, 2017), cf. Table 14 in the appendix. This cost estimation shows that the cost per household at least double once the offtake price includes a time-variable component. For the spot scenario, the costs even exceed the quadruple of the *CEP* cost. Although this valuation can only be considered a rough estimation of grid costs and is subject to future changes, it may serve as an indication for the magnitude of cost and cost changes in comparison the cost components already presented.

Although the grid load is the standard measure for grid dimensioning, in the present case peak infeed is considerably higher and would thus determine the required grid capacity. As the observable effects are similar to those for the system load, the results for the system infeed are included in section 6.4 in the appendix.

The analysis shows that the two objectives within the target of a system-oriented operation contradict each other in several cases. While the market value benefits from a time-variable price signal, local demand simultaneously increases the stress on the grid infrastructure. Thriving for an operation that is more driven by time-varying price signals leads to peak values converging in time, effectively requiring higher capacities in grid components to handle this impact. This suggests that further thoughts should be spent on possible reform proposals. In order to avoid local grid overload due to a market-oriented operation, a capacity grid fee based on measured maximum offtake/infeed may be one solution. Another one would be to provide the grid operator with a right to limit offtake or infeed in case of local grid congestion. Hence, the results shown provide first insights into the relevant effects on the actual operation of PVBSS and which aspects drive a system-wide optimal operation.

## 4 Conclusions and Policy Implications

The present paper examines the influence of regulatory reforms on the attractiveness of investments into PV or PVBSS and their effects on the system integration of PVBSS. We have shown that the often used term “system-oriented operation” has to be defined thoroughly in this regard, as market value and grid-friendly operation do not always match each other and cannot inherently be achieved with the same incentive. Therefore, we have defined several indicators in order to evaluate the different dimensions of system-oriented operation as well as the investment incentives. In **Fehler! Verweisquelle konnte nicht gefunden werden.**, a monetary evaluation of these indicators is provided. Each indicator is valued against the CEP pricing scheme, displaying only the difference.



Table 5 Summary of changes in cost compared to the CEP scenario for each indicator

Indicator	CEP (reference)	Spot	RTP	CEP_CapChargeGrid	CEP_dynRELevy	CEP_combined	RTP_CapChargeGrid	RTP_dynRELevy	RTP_combined
<b>Investment incentives (including savings from avoided grid withdrawal)</b>									
Annualized NPV PV	-	-238.5	-1.4	-43.3	24.2	-19.3	-46.6	23.0	-22.9
Annualized NPV PVBSS	-	-330.2	10.6	-107.9	26.7	-78.1	-97.0	43.7	-56.0
<b>Systemic value PVBSS</b>									
Market value storage operation	-	46.0	0.7	0.0	2.6	3.9	0.8	3.7	5.5
HH load valued at pure LV grid tariff	-	-137.8	3.6	0.0	0.5	-5.0	1.1	-1.4	-23.4
HH infeed valued at pure LV grid tariff	-	-134.2	0.1	0.0	-0.3	-3.4	0.1	-46.2	-53.7
System load from superior grid valued at corresponding grid tariff	-	-219.8	-70.4	0.0	-76.8	-79.1	-60.8	-70.5	-79.0
System infeed into superior grid valued at corresponding grid tariff	-	-178.7	0.2	0.0	-0.6	-3.8	4.5	0.1	-3.8

Comparing PV and PVBSS to not undertaking any investment (not displayed in the table but in Figure 2 and Figure 3) shows that there is only a business case as long as taxes and levies are considered in the electricity procurement price. The analyses also illustrate that a PV plant shows considerably higher NPVs than PVBSS for all tariff schemes. NPVs of PVBSS improve with time-variable price signals as summarized in **Fehler! Verweisquelle konnte nicht gefunden werden..** This is true for RTP pricing schemes as well as introducing another time-variable component to a former constant electricity price, such as a dynamic RE levy. Increasing capacity charges and thereby reducing the energy component in the grid tariff reduces the NPV since avoiding grid offtake becomes less valuable to the prosumer.

Regarding the system-integration of PVBSS, the market value indicates the market benefits and the peak loads/infeeds, as well as the coincidence factors, are a measure of grid integration. Given current wholesale prices and future quotations, the computed market value is a rather robust estimate that is not likely to change drastically over the next couple of years. The estimated grid costs, however, are subject to larger uncertainty due to local conditions and should be considered as a first rough monetization. The market value only is positive for the *Spot* scenario; all other price schemes including taxes and levies in the purchase price have negative market values.

However, time-variable price signals lead to an improvement in the market value: the higher the relative variations of the purchase price, the higher the market value. Furthermore, time-variable price signals lead to higher storage utilization, marked by higher sums of electricity charge and discharge. Thus, an improvement can be observed for all considered scenarios compared to the *CEP* reference, except the *CEP\_CapChargeGrid*, which also includes only time-invariant price signals. However, both effects are only valid if time-variable price components are coupled to the spot market price. Price signals with other variations might not generate higher but lower market values.

An improved grid-orientation of the resulting operation does not necessarily come along with high market values. The monetization given in Table 5 values the individual household peak load/infeed at the pure low voltage (LV) power price and the sum of energy taken from/fed into the grid at pure LV energy price, as explained in more detail in the appendix. The system peak load/infeed and the sum of electricity taken from/fed into the superior grid level are valued at the low/medium voltage transformation power and energy price. As can be seen in Table 5, the induced cost changes are considerably higher for the demand since the variation in infeed is much smaller between the scenarios. Due to the high infeed, the absolute values are nevertheless considerably higher for the infeed than for the demand. Moreover, the cost changes for the grid impact are of a similar magnitude than changes in NPV, whereas all other system indicators show noticeably smaller cost differences. When comparing the NPV for PVBSS and the grid costs for system load, it has to be noted that for the latter, the direction of cost changes is similar for all scenarios, whereas there are pricing schemes that induce an improvement in NPV. Comparing those pricing schemes, it has to be noted that the improvement in NPV is inferior to the worsening in grid cost associated with system load increases. Given the numerical uncertainties, this result should not be overinterpreted. Moreover, this trade-off has to be weighted at the political level and choices are necessarily also reflective of political preferences and priorities. Yet it may be worth investigating further regulatory reform proposals that allow a better simultaneous achievement of policy goals than those currently under discussion.

Our analyses have shown that the tariff design, as well as the design of single tariff components, has a considerable impact on the attractiveness as well as the resulting system integration of PVBSS. Regarding the political targets identified as relevant for this assessment: 1A) Provide adequate incentives for the system-oriented operation of existing and new flexibilities and 5) Provide adequate incentives for the investment into renewable and flexible installations, it has to be stated that the regulatory reforms investigated here do not allow satisfying both policy objectives simultaneously. This makes a prioritization of objectives necessary and calls for further search for better policy reform proposals.

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## 6 Appendix

### 6.1 Net present values for all households

Table 6 Net present values without any investment normalized to the net present value at CEP without any own generation in Euro

	CEP	spot	RTP	CEP_ CapChargeGrid	CEP_ dynRElevy	CEP_ combined	RTP_ CapChargeGrid	RTP_ dynRElevy	RTP_ combined
HH 1	-	17,507	190	1,396	1,085	2,481	1,586	1,275	2,671
HH 2	-	13,383	126	459	790	1,249	585	916	1,375
HH 3	-	7,972	74	-778	459	-319	-703	533	-244
HH 4	-	8,006	70	-769	452	-317	-699	521	-248
HH 5	-	8,624	92	-631	519	-112	-539	611	-20
HH 6	-	12,797	129	323	769	1,092	452	898	1,221

Table 7 Net present values for PV systems normalized to the net present value at CEP without any own generation in Euro

	CEP	spot	RTP	CEP_ CapChargeGrid	CEP_ dynRElevy	CEP_ combined	RTP_ CapChargeGrid	RTP_ dynRElevy	RTP_ combined
HH 1	4,549	4,479	4,047	4,412	4,977	5,210	4,343	4,967	5,476
HH 2	3,420	2	3,398	2,773	3,815	3,540	2,751	3,855	3,854
HH 3	2,034	2,041	-5,360	674	2,318	1,337	680	2,391	1,680
HH 4	2,351	2,346	-5,327	880	2,602	1,507	877	2,661	1,841
HH 5	2,524	2,522	-4,724	1,127	2,805	1,781	1,126	2,866	2,117
HH 6	3,460	3,429	-591	2,662	3,799	3,371	2,633	3,830	3,677

Table 8 Net present values for PVBSS normalized to the net present value at CEP without any own generation in Euro

	CEP	spot	RTP	CEP_ CapChargeGrid	CEP_ dynRElevy	CEP_ combined	RTP_ CapChargeGrid	RTP_ dynRElevy	RTP_ combined
HH 1	1,353	-426	1,491	328	1,844	870	754	471	2,110
HH 2	222	-4,471	372	-1,312	601	-889	-509	-1,158	843
HH 3	-1,341	-9,833	-1,225	-3,501	-1,171	-3,290	-2,023	-3,383	-994
HH 4	-1,146	-9,799	-1,051	-3,359	-1,012	-3,182	-1,793	-3,262	-855
HH 5	-907	-9,195	-807	-3,080	-749	-2,878	-1,480	-2,977	-584
HH 6	203	-5,063	346	-1,453	533	-1,078	116	-1,306	777

## 6.2 Market value for all households

Table 9 Market Value of all examined PVBSS – household combinations in Euro/MWh

	CEP	spot	RTP	CEP_ CapChargeGrid	CEP_ dynRElevy	CEP_ combined	RTP_ CapChargeGrid	RTP_ dynRElevy	RTP_ combined
HH 1	-3.90	15.24	-2.76	-3.90	-0.54	0.52	-2.55	0.56	1.39
HH 2	-4.62	15.26	-3.99	-4.62	-2.41	-1.32	-3.90	-1.42	-0.14
HH 3	-6.55	15.23	-6.13	-6.55	-5.12	-4.35	-6.14	-4.68	-2.63
HH 4	-7.35	15.29	-6.05	-7.35	-5.63	-4.74	-5.96	-4.47	-2.51
HH 5	-7.09	15.33	-5.94	-7.09	-5.24	-4.41	-5.89	-4.27	-2.51
HH 6	-4.31	15.30	-3.68	-4.31	-2.01	-0.84	-3.56	-0.90	0.20

### 6.3 Peak loads for all households for PV only and PVBSS

Table 10 Peak loads of all households using a PV system for self-consumption in kW

	CEP	spot	RTP	CEP_ CapChargeGrid	CEP_ dynRElevy	CEP_ combined	RTP_ CapChargeGrid	RTP_ dynRElevy	RTP_ combined
<b>HH 1</b>	6.72	6.72	6.72	6.72	6.72	6.72	6.72	6.72	6.72
<b>HH 2</b>	5.76	5.76	5.76	5.76	5.76	5.76	5.76	5.76	5.76
<b>HH 3</b>	3.73	3.73	3.73	3.73	3.73	3.73	3.73	3.73	3.73
<b>HH 4</b>	4.46	4.46	4.46	4.46	4.46	4.46	4.46	4.46	4.46
<b>HH 5</b>	3.29	3.29	3.29	3.29	3.29	3.29	3.29	3.29	3.29
<b>HH 6</b>	4.73	4.73	4.73	4.73	4.73	4.73	4.73	4.73	4.73

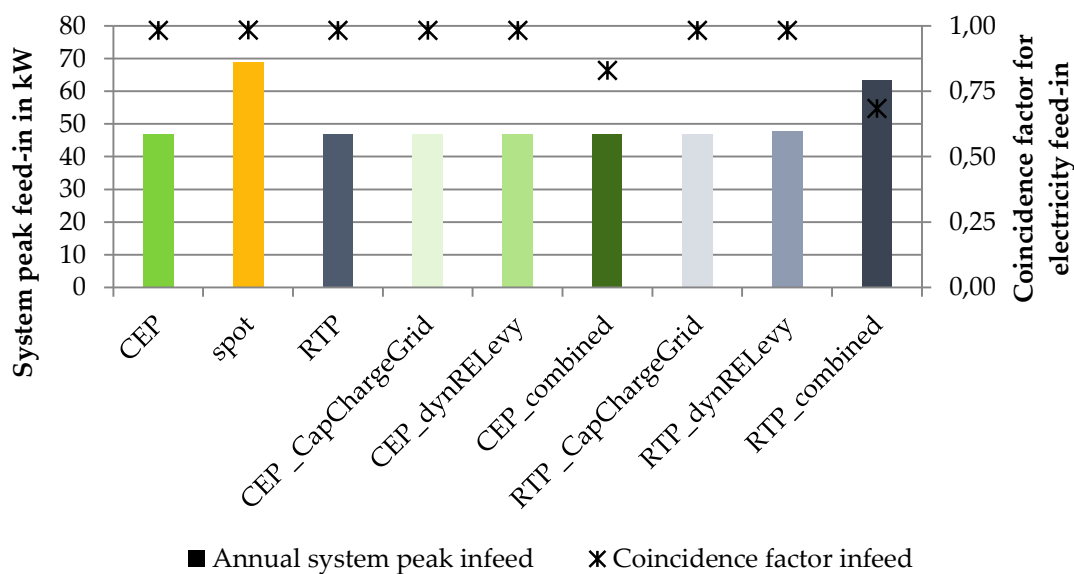
Table 11 Peak loads of all households using a PVBSS for self-consumption in kW

	CEP	spot	RTP	CEP_ CapChargeGrid	CEP_ dynRElevy	CEP_ combined	RTP_ CapChargeGrid	RTP_ dynRElevy	RTP_ combined
<b>HH 1</b>	6.72	9.13	6.72	6.72	6.81	6.81	6.72	6.81	8.93
<b>HH 2</b>	5.76	8.71	5.41	5.76	5.64	5.81	5.64	5.64	6.97
<b>HH 3</b>	2.95	7.64	5.23	2.95	5.34	5.47	5.23	5.44	6.49
<b>HH 4</b>	4.46	7.78	5.22	4.46	5.25	5.59	5.22	5.51	5.59
<b>HH 5</b>	2.54	7.10	5.43	2.54	7.15	7.15	5.43	7.15	6.74
<b>HH 6</b>	4.73	8.16	5.51	4.73	5.75	7.87	5.51	5.94	7.87

## 6.4 System peak infeed to the superior grid for all scenarios

For the considered households, the peak values for the electricity feed-in considerably exceed the peak load values. Thus, the analogous factor for the coincidence of feed-in is determined and displayed in **Fehler! Verweisquelle konnte nicht gefunden werden.**. It can be seen that for the feed-in, the coincidence factor significantly differs from the load coincidence factor. There is less variation in the temporal distribution of electricity feed-in than in peak load, leading to high coincidence factors in all scenarios except the combined scenarios. The feed-in seems mainly driven by excess PV generation as it shows such a high coincidence in most scenarios.

In the *Spot* scenario, the system peak infeed is the highest infeed of all scenarios. Due to the completely spot market-driven operation and low offtake prices, there is no incentive to optimize self-consumption and to reduce the amount of electricity fed into the grid. Additionally to the high peak infeed, the coincidence factor for the infeed is as high as in the other scenarios, making it the most stressful scenario for the grid infrastructure.



**Figure 7 Peak infeed into the superior grid and the corresponding coincidence factor for the system of six households**

Both combined scenarios are the only scenarios with lower coincidence factors. While the peak infeed in the *CEP\_combined* scenario is similar to the majority of scenarios, *RTP\_combined* shows a considerably higher peak infeed. Increasing relative temporal fluctuations and reducing the gap between offtake and infeed price in the combined scenarios seems to favor a higher temporal coincidence in the infeed. Hence, the most system-oriented scenario in this regard is the *CEP\_combined* scenario. However, the higher relative price fluctuations in the *RTP\_combined* scenario increase the peak infeed and thus the stress in the grid. Combined with the lower coincidence factor, this indicates that individual peak loads are higher than in the other scenarios and that a higher infeed takes place in more time-steps than in the other scenarios. This

considerably increases the stress on the grid infrastructure and thus the need for reinforcements in the long-term. Higher relative fluctuations in the offtake price combined with a varying price signal for the infeed hence lead to a remarkably worse result than a varying offtake price combined with a flat infeed price in regard to grid load.

Since the absolute values for feed-in are higher than for the system load, the feed-in would be the determining factor in grid dimensioning. Since it is argued that more and more grid congestions will occur in the distribution grid and the need for reinforcements will increase (Agricola et al., 2012), this should be considered as a systemic aspect for the evaluation of the regulatory reform proposals and their effects alongside with the indicators for peak demand. The relevance of the local infeed is also indicated by the grid cost estimation, given in Table 14, as the costs for infeed into the superior grid are two to seven times higher than the grid usage cost for the demand from the superior grid.

## 6.5 Cost estimation for local electricity feed-in and offtake

To estimate the grid cost for the individual households load and infeed, the following calculation was done. To derive the pure LV grid tariff, the MV tariff multiplied with the coincidence factor of the considered system of 0.37 was subtracted from the gross LV tariff. This gives the following tariff values:

$$\text{Power price} = 17.59\text{€/kW} - 0.37 \cdot 19.07\text{€/kW} = 10.50\text{€/kW}$$

$$\text{Energy Price} = 0.0451\text{€/kWh} - 0.37 \cdot 0.0391\text{€/kWh} = 0.0311\text{€/kWh}$$

The household peak load/infeed was then valued with the power price of 10.50€/kW and the sum of household grid offtake/infeed valued with the determined energy price of 0.0311€/kWh. The results are displayed in the following tables (Table 12 and Table 13). The corresponding value for the system load to the superior grid level, displayed in Table 14 is valued at the LV/MV tariff of 19.07€/kW and 0.0391€/kWh.

Table 12 Net grid cost for electricity withdrawal <sup>a</sup>

	No invest	PV	PVBSS								
	CEP	CEP	CEP	spot	RTP	CEP_CapChargeGrid	CEP_dynRElevy	CEP_combined	RTP_CapChargeGrid	RTP_dynRElevy	RTP_combined
HH 1	- 241.37	- 171.31	- 132.76	- 263.29	- 132.96	- 132.76	- 134.91	- 138.34	- 133.05	- 137.08	- 166.42
HH 2	- 186.93	- 139.25	- 100.72	- 238.52	-97.16	- 100.72	- 100.19	- 105.71	-99.66	- 102.14	- 124.17
HH 3	- 112.11	-87.23	-44.08	- 197.64	-68.12	-44.08	-69.70	-75.06	-68.16	-72.62	-92.35
HH 4	- 122.89	-90.05	-57.63	- 194.64	-65.74	-57.63	-66.46	-74.13	-65.79	-71.16	-80.65
HH 5	- 113.84	-80.94	-39.26	- 190.79	-69.72	-39.26	-88.28	-92.40	-69.75	-90.15	-94.33
HH 6	- 170.25	- 121.88	-84.58	- 225.80	-92.96	-84.58	-96.09	- 122.10	-93.02	- 100.08	- 127.95

<sup>a</sup> using the prices for consumers with recorded power measurement stated in (NetzeBW, 2017) and explained in the calculation above

Table 13 Net grid cost for electricity feed-in <sup>a</sup>

	No invest	PV	PVBSS								
	CEP	CEP	CEP	spot	RTP	CEP_CapChargeGrid	CEP_dynRELevy	CEP_combined	RTP_CapChargeGrid	RTP_dynRELevy	RTP_combined
HH 1	-	377.25	311.89	441.27	311.79	311.89	312.24	322.80	311.80	348.33	362.54
HH 2	-	395.85	329.07	463.28	328.96	329.07	329.37	332.43	328.96	375.23	382.77
HH 3	-	419.53	358.83	488.04	358.65	358.83	359.14	377.04	358.67	393.93	412.15
HH 4	-	413.18	356.46	483.04	356.20	356.46	356.79	378.66	356.23	400.57	410.07
HH 5	-	411.67	351.98	479.65	351.75	351.98	352.33	383.93	351.77	386.24	400.05
HH 6	-	394.64	332.44	462.52	332.34	332.44	332.78	359.72	332.34	374.40	382.81

<sup>a</sup> using the prices for consumers with recorded power measurement stated in (NetzeBW, 2017) and explained in the calculation above

Table 14 Summary of economic values of all indicators in absolute numbers as basis for Table 5

Indicator	(reference) CEP	spot	RTP	CEP_CapChargeGrid	CEP_dynRELevy	CEP_combined	RTP_CapChargeGrid	RTP_dynRELevy	RTP_combined
<b>Investment incentives (including savings from avoided grid withdrawal)</b>									
NPV PV (annuity)	238.7	0.1	237.3	195.4	262.8	219.3	192.0	261.6	215.7
NPV PVBSS (annuity)	15.6	-314.6	26.2	-92.3	42.3	-62.5	-81.5	59.3	-40.4
<b>Systemic value PVBSS</b>									
Market value storage operation	-5.7	40.3	-5.0	-5.7	-3.1	-1.8	-4.9	-2.0	-0.2
HH load valued at pure LV grid tariff	-100.7	-238.5	-97.2	-100.7	-100.2	-105.7	-99.7	-102.1	-124.2
HH infeed valued at pure LV grid tariff	-329.1	-463.3	-329.0	-329.1	-329.4	-332.4	-329.0	-375.2	-382.8
System load from superior grid valued at corresponding grid tariff <sup>b</sup>	-67.6	-287.3	-137.9	-67.6	-144.4	-146.7	-128.4	-138.0	-146.6
System infeed into superior grid valued at	-469.4	-648.1	-469.2	-469.4	-470.0	-473.2	-464.9	-469.3	-473.3



<b>corresponding grid tariff<sup>b</sup></b>									
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<sup>b</sup> using the prices for transformation from LV to MV for consumers with recorded power measurement stated in (NetzeBW, 2017)