Flexible Electricity Tariffs: Power and Energy Price Signals Designed for a Smarter Grid

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Abstract

Renewable energy is increasingly replacing carbon-based technologies worldwide in electricity networks. This increases the challenge of balancing intermittent generation with demand fluctuation. Demand response (DR) is recognized as a way to address this by adapting consumption to supply patterns. By using DR technology, grid withdrawal of demand side management (DSM) devices such as heat pumps, electric vehicles or stationary batteries can be temporally shifted. Yet, the development of an accurate control and market design is still one of the greatest remaining DR challenges.

We present a range of flexible price signals that can address this by acting as effective demand control mechanisms. The different tariffs consist of combinations of flexible energy and power price signals. Their impact on the unit commitment of automatable DSM devices is tested for a set of German households. The financial outcome for the respective stakeholders are quantified. Our results suggest flexible power pricing can reduce overall demand peaks as well as limit simultaneous grid withdrawals caused by real time pricing incentives. Furthermore, we prove that inefficient designs of flexible power pricing can lead to undesired bidding of automatable devices. We propose a specific tariff design that shows robust network performance and reduces energy procurement costs.

Keywords: Electricity tariff, flexible power pricing, demand response, residential storage, residential energy management

1. Introduction

Important energy transformations must occur in order to mitigate anthropogenic climate change. The electrical power system requires energy intensity improvement, electrification of other energy sectors (e.g. heat and transport) and radical decarbonisation with renewable energies [1]. This transition is already increasing the incorporation of distributed energy resources (DER) such as photovoltaics, smart meters, batteries and smart appliances throughout distribution networks. Electrical power systems in industrialized nations are subsequently shifted from wholly centralized and vertically integrated to decentralized and more dynamic systems [2]. Decentralized insertion of renewables is technically challenging both because of their variable and non-dispatchable nature and the higher proportion of generation fed into low and medium voltage grids. Furthermore, electrification of personal transportation and residential heat supply leads to a significant increase of electric consumer power at the distribution level [3]. These devices can either be considered as an unpredictable threat on system stability or as an opportunity to deal with the decentralized and variable renewable insertion given the right incentives are provided [4].

An acknowledged way to influence demand is through tariff systems. However, residential customers are historically charged with a fixed electricity tariff that is calculated by averaging the costs of the supply chain during electrical energy provision. Under flat tariffs, market signals such as varying wholesale energy prices are not passed on to customers, who have therefore no incentive to adapt their behaviour in a cost-reflective way [5, 6]. But their participation in a supply-dependent load management is especially meaningful because of their high potential for flexibility. In fact, household potential for load reduction is similar to those from the manufacturing and tertiary sector and the potential for transient load increases can even reach one or two orders of magnitude higher than these other sectors because of the high peak load of washing equipment, boilers and space and water heaters [7]. DR programs are valuable since they integrate the user as an influenceable entity in order to contribute to system efficiency [8]. These programs change the normal consumption pattern of end-use customers in response to flexible prices or incentive payments [9]. A more active role of consumers not

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only increases possibilities for cost savings through a lower utilization of peak plants and an efficient integration of renewable energy resources [10]. The involvement of consumers also ensures higher system reliability by improving adaptation to variable generation with load-shifting abilities [11].

A high market penetration of smart meters in industrialized countries, thanks to recent roll-outs, allows affordable communication and monitoring of household consumption profiles. More importantly, however, they provide an effective control of load-shifting potentials through DR program deployment [4, 12]. Although load shifting can be achieved through customer behaviour responding to incentives, providing signals to specific DSM devices that can automatically alter their function is a more preferred DR practice. These devices lower the burden on consumers who adapt their demand patterns much stronger [13] and ensure a higher predictability of the extent of the signal's response [4]. Together with an information and communication technology infrastructure, these devices can receive signals from electricity markets and act accordingly based on pre-established optimization parameters [14, 15].

Several classifications of DR programs can be found in the literature based on signal type or control method [16, 17, 18]. Some of the standard price-based signals and flexible billing methods used are time of use (TOU), critical peak pricing (CPP) and real time pricing (RTP) in order of increasing complexity and flexibility. TOU rates have fixed prices per different blocks of time in a day. CPP apply extra high rates throughout a pre-specified limited number of hours and can be combined with TOU or flat rates. RTP varies on an hourly basis in relation to the wholesale market price.

Even with different programs already deployed, the development of an accurate control and market framework is still the greatest remaining challenge for DR programs to achieve full potential [4]. In particular, establishing an effective demand control mechanism through price signals is considered an outstanding challenge. In order to address this issue, this study designs and tests smart and controllable DR price signals by deconstructing residential tariffs into three components: an energy component, a power component and a levy and tax component. Different types of billing schemes are applied to each of these components, allowing for their possible combinations to yield an array of several tariffs. The unit commitments of automatable devices of numerous households are systematically evaluated for a period of one year given these various tariff designs. Both technical influences and financial outcomes are quantified:

We prove that certain kinds of electricity tariff designs can lead to undesired opportunistic bidding of automatable devices. Furthermore, we propose a tariff with a robust network performance that either reduces households' demand peaks or limits simultaneous grid withdrawals to a desired level using a real time pricing incentive. We evaluate the economic outcome of different electricity tariffs by discriminating the specific effects to all tariff stakeholders involved such as households, network operators, retailers and tax agencies.

We build on previous work which explores similar dynamics in DR designs but that we consider do not address the full scope of the outstanding issue. The energy management of private households pertaining to different electricity tariffs is addressed in several papers [19 - 23]. These papers evaluate the financial effects of different tariffs from the household perspective, but do not discriminate the effects on the other stakeholders.

In [19], an RTP tariff with and without a peak power limiting strategy for an electric vehicle and energy storage system is evaluated. The power limitation is controlled by a fixed physical limit. We investigate this further by applying tariffs with different power components to dynamically charge the amount of power that is withdrawn, which would allow but financially de-incentivize higher demand. In [20] an optimal and automatic residential energy management framework is proposed where an RTP tariff is combined with a power component that applies a two-step inclining block rate. This tariff combination is presented as being specifically beneficial for automatable flexible loads. The future uptake of PV and battery storage is tested in [21] for several electricity tariffs, based on flat, TOU and CPP designs. The daily and monthly peak electricity demand is used as settlement for costs of power. In our paper we build on [20, 21] to investigate various power mechanisms and a larger sample of households. In [22], a power-based tariff in combination with both a fixed and flexible energy component is analysed and compared to a fully fixed electricity tariff. The research is focused on the cost recovery of electricity tariffs and extended in [23]. The authors design and present a framework to assess the interaction between tariffs and user reactions, and conclude that further research should include the comparison of different tariff designs such as capacity and energy based tariffs. We specifically address this outstanding issue. Both [4] and [24] note that the use of global signals for DR can increase simultaneous demand, leading to new peaks with potential network congestions. We specifically design electricity tariffs that can address this dynamic.

This paper is organized as follows. Section 2 describes the overall experimental setup and the theoretical basis for the design of household configurations and tested tariffs. Section 3 describes the data sources, covers detailed specification of the parameterizations applied and describes the modelling of the optimization problem. Section 4 provides the simulated results of the incidence of our designed tariffs on household demand peaks and economic impacts to all the major stakeholders involved within the electricity pricing. Finally, section 5 concludes on the major observations and provides a discussion for further research.

2. Design of electricity tariffs and experimental setup

Retail electricity tariffs are used to invoice three different cost components of the energy supply chain. The energy component covers utility's costs for generating, purchasing and selling energy. The power component is charged to cover network infrastructure and power supply operation. A levy and tax component is the last part of the electricity tariff, which covers additional system costs and is a source of state income. Additionally, consumers often pay a fixed fee for billing and metering. The total costs of each component is usually summed up and billed as an average price per kWh-usage, multiplied by the value added tax vat, even though different individual demand patterns cause different costs. Equation 1 describes the total electricity costs C_h^{tot} of a household $h \in H$:

$$C_h^{tot} = \left[\sum_{t \in T} \left(C_{h,t}^{eng} + C_{h,t}^{pow} + C_{h,t}^{ltc} \right) + c^{bas} \right] \cdot vat \; , \tag{1}$$

where $C_{h,t}^{eng}$ are the costs associated with the energy component, $C_{h,t}^{pow}$ with the power component and $C_{h,t}^{ltc}$ with the levy and tax component for all time steps t of the billing period T. To determine the total costs of the overall system, C_h^{tot} in equation 1 has to be summed up over all households.

2.1. Cost reflective electricity tariffs

In order to design electricity tariffs that are more cost-reflective and dynamic in nature, a distinction between fixed and variable cost components within the tariffs are proposed. The levy and tax component is usually not dependent on the household's demand profile and thus not suitable for flexible pricing. Fixed costs of both the grid operator and the utility, such as staff costs, write offs or rental costs, also represent the fixed share of the electricity tariff. Therefore, the potential for a flexible component, adaptable to

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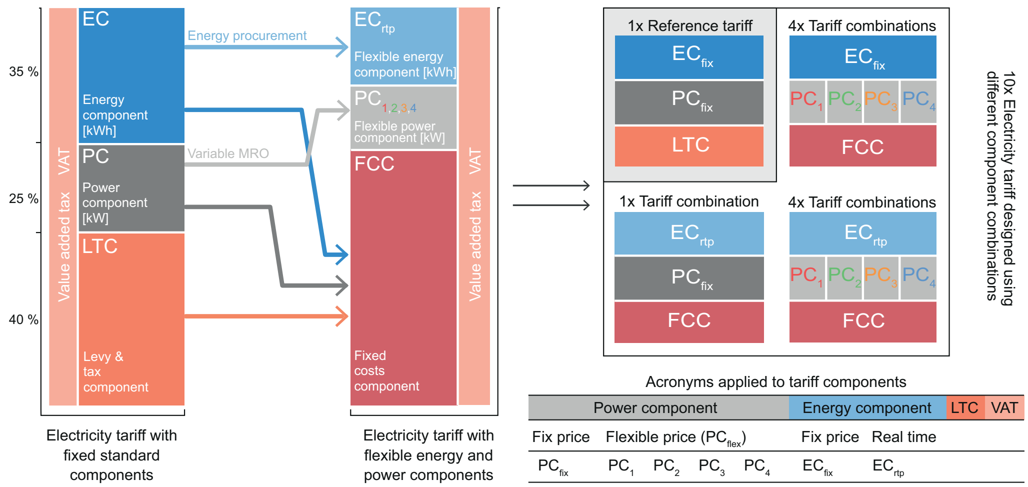

Figure 1: Elements of an average German retail electricity tariff and its partitioning into a flexible energy component (EC_{rtp}), a flexible power component ($PC_{1,2,3,4}$) and combined fixed costs.

a user's dynamic demand profile, lies in the energy procurement cost and the grid usage (see Fig. 1).

The left side of Fig. 1 shows the elements of the electricity tariff for households in Germany (1st April 2013) [25]. Without taking into account the value added tax,

- 35% of the total costs are charged for the energy component (Purchasing energy, sales, profit)
- 25% for the power component (Grid fees, billing, metering point operation, profit)
- 40% for the levy and tax component (Concession fee, electricity tax, EEG-levy, etc.)

The value added tax is a percentage surcharge of 19% on each of these tariff components. These standard components are deconstructed to discriminate an overall fixed cost component and two flexible components corresponding to energy and power:

- Flexible energy component: Purchasing energy at spot market

- Flexible power component: Variable Costs for maintenance, repair and operations (MRO) in the short-term and investment costs for grid expansion in the long-term

- Fixed cost component: Sales, billing, metering point operation, levy and taxes, profit

The costs of each component have to be multiplied by the value added tax. In this paper, we assume that the utility is able to influence household demand in order to optimize purchasing costs according to spot market prices. Since the hourly spot price is passed-on to customers, we call the flexible energy component of this RTP approach EC_{rtp}. In order to define a suitable flexible power component that can meet the criteria for the intended dynamic retail tariff, four different billing mechanisms $PC_{1,2,3,4}$, collectively termed PC_{flex}, are designed and compared. Details of the PC_{flex} designs are introduced in section 2.2.

The right side of Fig. 1 shows how the different components have been combined into an array of ten different electricity tariffs. EC_{fix} and EC_{rtp} are each combined with PC_{fix} (two combinations) and PC_{flex} (eight combinations).

2.2. Design of flexible power component

Four different mechanisms for flexible billing of the power component PC_{flex} have been designed, which represent the summand $C^{pow}_{h,t}$ in equation 1. All PC_{flex} are designed and parameterized in a way that the total costs over all households are equivalent for a baseline configuration with photovoltaic (PV) panels (termed H_{cp} and defined in section 2.3). The average net costs are 25 ct/kWh. However, the cost of an individual household is dependent on its demand profile and can therefore be reduced by an optimized energy management.

The different PC_{flex} charge a household's load profile in different ways. Fig. 2 provides a visualization and description of the power component designs and their general behaviour. For PC_{fix}, PC_1, PC_2 and PC_3, the total and average grid costs are plotted against the withdrawal power per time step. PC_4 is linearly dependent on the daily demand peak of each household and thus cannot be visualized in this graph.

The net load $P^{nl}_{h,t}$ is defined as the difference of the power of all consuming and generating units within each household. We call the net load withdrawal power $P^{wp}_{h,t}$ if it is greater than or equal to zero.

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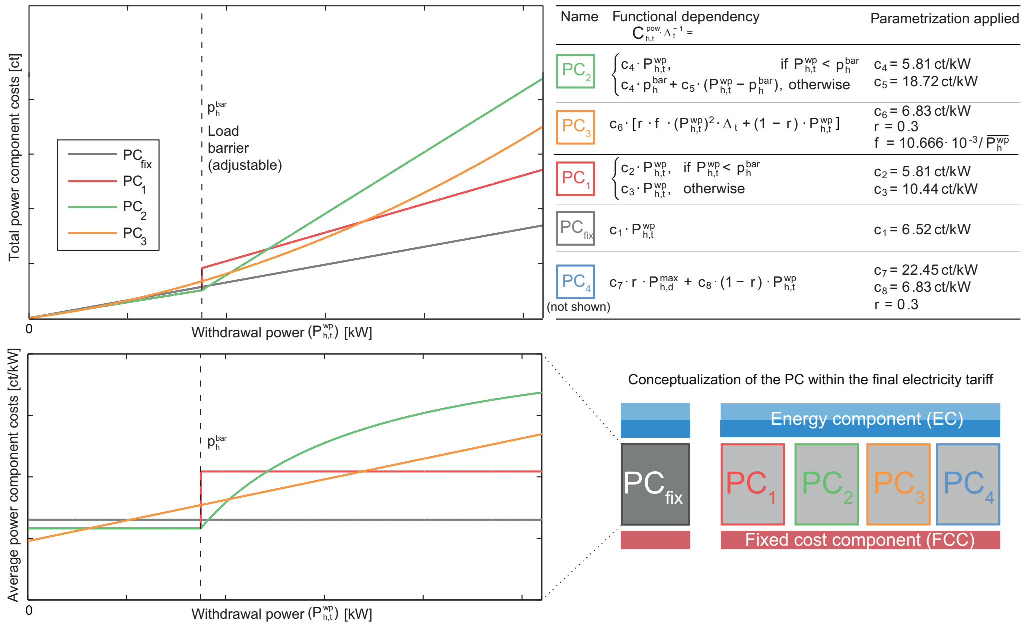

Name	Functional dependency $C^{pow}_{h,t} \cdot \Delta_t^{-1} =$	Parametrization applied
PC$_2$	$\begin{cases} c_4 \cdot P^{wp}_{h,t}, & \text{if } P^{wp}_{h,t} < p^{bar}_h \\ c_4 \cdot p^{bar}_h + c_5 \cdot (P^{wp}_{h,t} - p^{bar}_h), & \text{otherwise} \end{cases}$	$c_4 = 5.81$ ct/kW $c_5 = 18.72$ ct/kW
PC$_3$	$c_6 \cdot [r \cdot f \cdot (P^{wp}_{h,t})^2 \cdot \Delta_t + (1 - r) \cdot P^{wp}_{h,t}]$	$c_6 = 6.83$ ct/kW $r = 0.3$ $f = 10.666 \cdot 10^{-3} / \overline{P^{wp}_h}$
PC$_1$	$\begin{cases} c_2 \cdot P^{wp}_{h,t}, & \text{if } P^{wp}_{h,t} < p^{bar}_h \\ c_3 \cdot P^{wp}_{h,t}, & \text{otherwise} \end{cases}$	$c_2 = 5.81$ ct/kW $c_3 = 10.44$ ct/kW
PC$_{fix}$	$c_1 \cdot P^{wp}_{h,t}$	$c_1 = 6.52$ ct/kW
PC$_4$ (not shown)	$c_7 \cdot r \cdot P^{max}_{h,d} + c_8 \cdot (1 - r) \cdot P^{wp}_{h,t}$	$c_7 = 22.45$ ct/kW $c_8 = 6.83$ ct/kW $r = 0.3$

Figure 2: Design and parameterization of the power component.

2.2.1. Description of power components (see section 3.2.2 for further details)

- PC_{fix}: The average grid costs are constant. The total costs are linearly dependent on $P^{wp}_{h,t}$, which represents the usual billing method.

- PC_1: Two price steps are offered to the customers based on a specific load barrier p^{bar}_h. The high price step is paid for the total consumption if the demand is above p^{bar}_h. Therefore, the average and the total grid costs increase sharply at the barrier.

- PC_2: Two price steps are offered to the customers based on the same load barrier as for tariff PC_1. The high price step, however, is paid only for the share of consumption that is above p^{bar}_h. Therefore, the transition at the barrier is smoother but the slope of the total grid costs above p^{bar}_h is eventually higher than for PC_1.

- PC_3: 30% of the power costs are quadratically and 70% linearly dependent on the withdrawal power.

- PC_4: 30% of the power costs are linearly dependent on the daily peak of the withdrawal power ($P^{max}_{d,h}$) and 70% are linearly dependent on the withdrawal power.

2.2.2. Design of load barrier for PC_1 and PC_2

The price steps and load barriers p_h^{bar} used for PC_1 and PC_2 are intended to reward a demand below and disincentivize a demand above the barrier. The maximum value of the accumulated withdrawal power of all households within the year (a value which is termed peak of sum (PoS) [22]) should not increase with the flexible tariff structure. Therefore, the sum of all barriers has been set to equal the value of this peak of sum (PoS). For this specific group of 33 households under a baseline configuration with PV panels (H_{cp}, see section 2.3), the PoS is 44.5 kW. Since the average withdrawal power of the 33 households is 8.5 kW, the individual barrier is then set to:

$$p_h^{bar} = 44.5 \cdot \frac{\overline{P_h^{wp}}}{8.5} = 5.2 \cdot \overline{P_h^{wp}}, \tag{2}$$

where $\overline{P_h^{wp}}$ is the average withdrawal power of each household within the year under review. The individual barriers are listed in table A.2.

2.3. Experimental setup

The proposed designs of flexible tariffs are tested as effective DR signals by applying them to a set of 33 households under different DER installations. The simulation framework RedSim, in combination with the solver IBM ILOG CPLEX (see section 3.5), is used to determine the optimized unit commitment of the DSM devices. The overall experimental setup is illustrated in Fig. 3.

Three different household configurations are shown in the left of Fig. 3. The household which is solely consuming according to the measured fixed profiles is named H_c. The household with additional PV generation, which is used as the baseline configuration, is termed H_{cp}. The household setup with consumption, PV panels and DSM devices is called H_{cpd}. These three household configurations and the 10 combinations of electricity tariffs lead to 30 possible scenarios for each of the 33 households which are used as an input of the optimization. However, only 10 scenarios include dispatchable DSM devices (H_{cpd}) that are scheduled by the optimization.

The configurations H_c and H_{cp} have a static demand pattern with no potential for an optimized energy shift, but are used to evaluate and contrast technical and financial influences of the electricity tariff. The DSM devices

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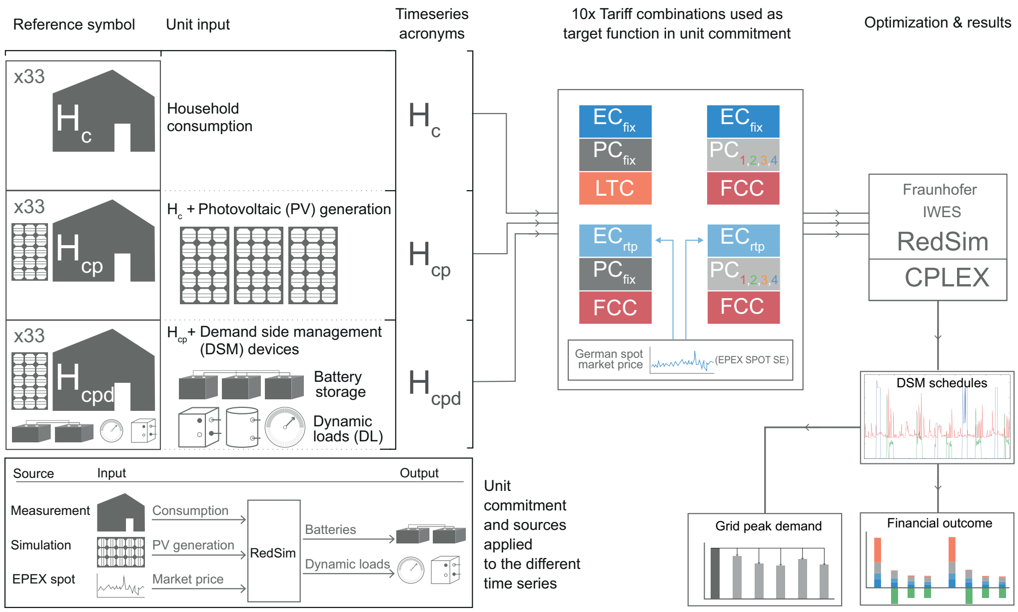

Figure 3: Graphical abstract: Overview of experimental setup.

of configuration H_{cpd} can be scheduled according to the load profile, the PV generation and the market prices. The DSM schedules are an output of the optimization (see bottom left of Fig. 3). The parameters and boundaries used to perform the DSM optimization are described in section 3.4. The sources of the time series, listed in the bottom left of Fig. 3, are described in section 3.1.

3. Modelling and calculations

The following subsections describe the data input of the optimization, the parametrization of the investigated electricity tariffs and the mathematical formulation of optimization problem.

3.1. Data sources

Residential load measurement data in 15 minutes time intervals are obtained from selected households during a field test [26]. The data of 33 households from July 1st 2011 until May 31st 2012 are used in this experimental setup. The annual consumption of the households is listed in Tab. A.2.

The annual power generation of virtual photovoltaic panels is simulated in time intervals of 15-minutes [27]. Three arbitrary sets of eleven households each are given different generation-to-consumption ratios $r_h^{gen/con}$ of 2:3, 1:1 and 4:3 , respectively (see Tab. A.2). Therefore, the nominal power of the PV panels $p_h^{pv,nom}$ is varied in ratio to the household consumption (see Tab. A.2):

$$r_h^{gen/con} = p_h^{pv,nom} \cdot \frac{\sum\limits_{t \in T} P_o^{gen,norm}}{\sum\limits_{t \in T} P_{h,t}^{con}} \ , \tag{3}$$

where $\sum\limits_{t \in T} P_o^{gen,norm}$ is the generation time series of a PV panel with a nominal power of 1 kW either oriented south or east-west. Two thirds of the households are simulated with southward facing PV and one third is simulated with both east- and westward facing PV. This panel orientation is designed based on the fact that even though southward facing panels usually have higher annual performance, installation of east- and westward facing panels has seen increasing use given the improved hourly correlation between PV generation and daily peak demand (here: $\sum\limits_{t \in T} P_{o=south}^{gen,norm} = 1029\ kWh$ and $\sum\limits_{t \in T} P_{o=eastwest}^{gen,norm} = 759\ kWh$).

Assuming that the suppliers procure all the energy for their balancing group the day before the physical delivery, the day ahead spot market auction price for Germany determined by EPEX SPOT SE is used as the real time pricing time series for EC_{rtp}. Before December 2014, only 60-minute units were tradable in the day ahead auction. However, since all other time series are available in 15 minutes time intervals we generated a 15 minute resolution version of the 60 minute trades by simply repeated the hourly value 4 times each hour.

3.2. Parameterization of electricity tariffs

As introduced in section 2.1, the total costs of electricity consist of an energy component, a power component and a levy and tax component. The parameterization of these cost components of the newly designed electricity tariffs are summarized in Tab. 1 and further described in this section.

3.2.1. Costs for energy component

The costs of EC_{fix} are described by:

$$C_{h,t}^{eng,fix} = c^{eng,fix} \cdot P_{h,t}^{wp} = (\overline{mp} + gm) \cdot P_{h,t}^{wp} \ . \tag{4}$$

Component	Fixed billing Value $[ct/kWh]$	Symbol	Flexible billing Value $[ct/kWh]$	Symbol
Energy	8.46	$c^{eng,fix}$	$mp_t + 3.55$	c_t^{eng}
Power	6.52	$c^{pow,fix}$	* 6.83	
Levy and tax	9.71	c^{ltc}	9.71	c^{ltc}
Net sum	24.69		* 25.00	
Value added tax	4.69		* 4.75	
Gross price	29.38		* 29.75	
Feed-in tariff	13.88	c^{feedin}	13.88	c^{feedin}

Table 1: Parameterization of fixed and flexible tariff components. The marked values (*) are average values of all households under the baseline configuration H_{cp}.

The demand weighted costs factor $c^{eng,fix}$ is 8.46 ct/kWh in German retail prices in 2013 [25]. It is split into the retailer's gross margin gm and the demand-weighted average spot market price $\overline{mp}$, which is defined as:

$$\overline{mp} = \frac{\sum\limits_{h \in H} \sum\limits_{t \in T} mp_t \cdot P_{h,t}^{wp}}{\sum\limits_{h \in H} \sum\limits_{t \in T} P_{h,t}^{wp}} \ . \tag{5}$$

Under H_{cp} the $\overline{mp}$ is 4.91 ct/kWh. The retailer's gm is then 3.55 ct/kWh which is used as the fixed cost of EC_{rtp}. The costs of the flexible energy component are defined as:

$$C_{h,t}^{eng} = c_t^{eng} \cdot P_{h,t}^{wp} = (mp_t + gm) \cdot P_{h,t}^{wp} \ . \tag{6}$$

with the gross margin as the fixed share, and a flexible share which is immediately billed according to spot market prices mp_t. Thus, it is assumed that the retailer's savings, when minimizing procurement costs according to the spot market price opportunities, are passed on to the customer.

3.2.2. Costs for power component

The functional dependencies and the parameterization of the power components are listed at the top right of Fig. 2. Under PC_{fix} the specific cost factor for grid fees $c^{pow,fix}$ is 6.52 ct/kWh, which is charged for the withdrawn energy [25]. The costs of the fixed power component are:

$$C_{h,t}^{pow,fix} = c^{pow,fix} \cdot P_{h,t}^{wp} \; . \tag{7}$$

By definition, for all PC_{flex} the costs are dependent on the withdrawal power and thus the specific household, but they are parameterized in such a way that the total annual electricity costs of all households are the same for H_{cp}. The annual average charge of all households for the power component is set to 6.83 ct/kWh, which corresponds to an annual income of the grid operator of 5112 €(6.83 $ct/kWh \cdot 74687 \; kWh = 5112$ €). The higher costs in comparison to PC_{fix} are charged to limit losses in revenue of the grid operator since the revenues can be reduced by an optimized energy management of the households. They can be interpreted as a compensation for a greater measurement and billing effort.

PC_1 and PC_2 have pre-established load barriers dividing the price steps, as explained in section 2.2 and further detailed in the parameterization at the top right of Fig. 2. The specific cost factor of both tariffs up to the individual barrier p_h^{bar} (see Tab. A.2) is set to 5.81 ct/kWh, which corresponds to a reduction of 15% from the annual average charges. Based on this, the equations at the top right of Fig. 2 allow to calculate the specific cost factors above the barrier. Since the total annual costs for all tariffs are preset to 5112 € for H_{cp}, which has a fixed withdrawal, all other factors of these equations are known except the costs above the barrier. As a result, for PC_1, 10.44 ct/kWh is paid for the total consumption if the demand is above the barrier, whereas in PC_2 18.72 ct/kWh is paid only for the share of consumption above the barrier.

PC_1 and PC_2 are given by the two piecewise defined functions at the top right of Fig. 2. For both power component designs, the share of the costs that are charged for the withdrawal power above the barrier (second piece of the functions) amounts to 22% of the total costs. These charges are incurred for the few particularly high withdrawal peaks above the barrier. To penalize high withdrawal peaks for PC_3 and PC_4 similarly strong than for PC_1 and PC_2 the flexible billed share is set to 30% since for these tariff designs the shares result from all withdrawal powers and not only the particularly high ones.

Both for PC_3 and PC_4, 70% of the costs are linearly dependent on the withdrawal power with a cost factor equal to the annual average charge of 6.83 ct/kWh. For PC_3, 30% of the total costs are quadratically dependent on the withdrawal power. A specific factor of $10.666 \cdot 10^{-3}/\overline{P_h^{wp}}$ is applied to achieve equivalent costs to all other PC_{flex} under H_{cp} as described above. In the case of PC_4, 30% of the cost is determined by a specific charge of 22.45 ct/kW for the daily peak of the withdrawal power $P_{d,h}^{max}$. Again, given the requirement that the total costs for all flexible tariffs are equal (5112 €) and that demand profiles are fixed under H_{cp}, both of the specific factors can be determined using the equations at the top right of Fig. 2.

The shares of 22% for PC_1 and PC_2 as well as 30% for PC_3 and PC_4 are valid for the average consumption of all households given configuration H_{cp} but vary from household to household because different demand pattern cause different costs. Therefore, by applying the tariffs with flexible power components, households with an unsteady utilization of the grid are generally charged with a higher average rate.

3.2.3. Costs for levy and tax component

The specific costs of the levy and tax component c^{ltc} are 9.71 ct/kWh both for a flexible and a fixed tariff [25]. The total costs of the levy and tax component are:

$$C_{h,t}^{ltc} = c^{ltc} \cdot P_{h,t}^{wp} \ . \tag{8}$$

3.2.4. Feed-in tariff

The feed-in tariff for PV generation is set at 13.88 ct/kWh according to German feed-in tariff on December 2013 for PV installations of less than 10 kWp [28]. In order to use the support program of the German Bank for Reconstruction for battery storage (programme 275 [29]), the criteria has to be met that only 60% of the nominal power of the PV panels $p_h^{pv,nom}$ can be fed into the grid. Surpluses above this amount that cannot be consumed or stored have to be curtailed.

3.3. Modelling of objective function

Under the tariff approach there is no interaction or communication between the households. In the following, the functional dependency of the equations are not marked with the individual household notation h anymore since their optimization can be performed individually.

Positive and negative net loads are composed by positive $P_{s,t}^{nl+}$ and negative load segments $P_{s,t}^{nl-}$ in order to simulate the different electricity tariff levels in the optimization. These segments can be filled successively up to a specific amount and are multiplied by different cost factors ($C_{s,t}^{nl+}$ and $C_{s,t}^{nl-}$)

implying power and other cost components. The constraints of the load segments are described in Appendix B. The objective function is the minimization of household's total costs:

$$min \sum_{t \in T} \left[\Delta_t \cdot \left(\sum_{s \in S^+} P^{nl+}_{s,t} \cdot C^{nl+}_{s,t} + \sum_{s \in S^-} P^{nl-}_{s,t} \cdot C^{nl-}_{s,t} \right) + \right.$$
$$\left. \sum_{n \in N} \left(B^{start}_{n,t} \cdot c^{start}_{n} \right) \underbrace{+ B^{add}_{t} \cdot c^{add} \cdot \Delta_t}_{\text{only for PC}_1} \right] \underbrace{+ \sum_{d \in D} P^{max}_{d} \cdot c^{peak}}_{\text{only for PC}_4} , \quad (9)$$

The first term describes the payments for grid consumption, whereas $C^{nl+}_{s,t}$ is individually defined for each electricity tariff in Appendix B as well as the last two terms of equation 9. The second term stands for the feed-in tariff. It holds:

$$\sum_{s \in S^-} P^{nl-}_{s,t} \cdot C^{nl-}_{s,t} = -c^{feedin} \cdot P^{nl-}_{s=1,t} , \quad (10)$$

where the width of the first segment of S^- is limited to $P^{nl-}_{s=1,t} \leq 0.6 \cdot p^{pv,nom}_{h}$ (see section 3.2.4). The factor c^{feedin} is defined in section 3.2. The start-up costs for switching on the rectifier and the inverter c^{start}_{n} as well as the binary variable $B^{start}_{n,t}$ (third term in equation 9) are defined in Appendix C. The interval length Δ_t in equation 9 is set to 0.25 hours according to the temporal resolution of the data.

3.4. Modelling of DSM devices

Stationary batteries and dynamic loads (DL) are considered demand side management (DSM) devices in this paper. Dynamic loads (DL) allow a shift in energy demand during a specific time period without major energy losses. Batteries on the other hand allow a shift in energy supply without affecting the consumer behaviour, and generally without any temporal limits. DSM devices can be used to increase the self-sufficiency rate of PV panels and reduce costs of grid consumption if flexible electricity tariffs are applied. The DSM schedules are an output of the unit commitment and are scheduled in order to minimize the objective function (equation 9).

The model for the battery system consists of a rectifier, an inverter and Li-ion cells. It is assumed that for each household the maximum input power of the rectifier $p^{rec,max}$ and the maximum output power of the inverter $p^{inv,max}$

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equals $p^{pv,nom}$. Furthermore, the maximum usable capacity of the storage is given by multiplying $p^{pv,nom}$ by two hours. The mathematical formulation of the stationary battery is described in Appendix C.

Based on demonstration projects with flexible tariffs [30] it is assumed that 20% of the total consumption in each time interval is flexible and can be shifted for up to two hours. The mathematical formulation of the DL is described in Appendix D.

3.5. Simulation framework

The optimization problem is implemented in RedSim (Renewable Energy Dispatch Simulation). RedSim is a simulation framework developed at Fraunhofer IWES that allows setting up mixed-integer linear optimization problems for different combinations of units, such as generators, consumers and storage systems in Matlab. Technical specifications like characteristic curves, minimal downtimes or start-up costs are implemented for various technologies. The system of equations can be set up for different target functions considering the specific market conditions. The optimization problem is solved with the use of IBM ILOG CPLEX Optimization Studio 12.4. and processed by RedSim [27, 31].

Because of the high complexity of the optimization problem including numerous binary variables, the annual simulations for this research are not performed instantaneously but with the aid of rolling planning. Therefore, the unit commitment is determined every 24 hours for a period of 48 hours. The first 24 hours are used for the final schedules of the DSM devices. The solution for the last 24 hours is replaced by the unit commitment calculated during the following day. Initial values of each optimization step, such as storage levels and shifted loads, are obtained from the previous optimization period.

4. Results and discussion

Section 4.1 describes the effects of the electricity tariffs on consumer's peak load, section 4.2 addresses the financial outcome and section 4.3 discusses the impact of these results on the implementation of the tariff in a real system.

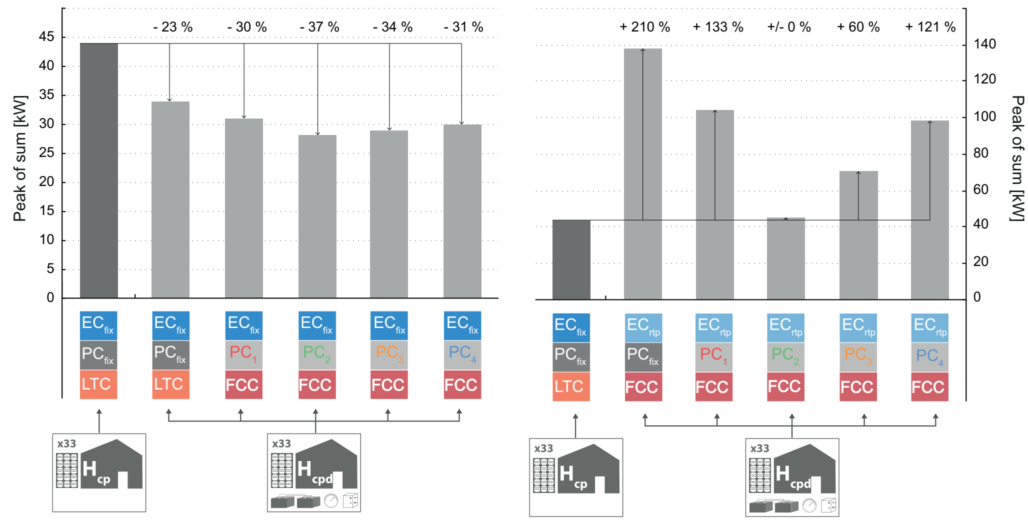

Figure 4: Comparison of peak of sum of households with DSM (H_{cpd}) under various flexible electricity tariffs in relation to a system without DSM (H_{cp}).

4.1. Impact of designed tariffs on grid requirements

First, the operational modes of DSM devices in households (H_{cpd}) are optimized using electricity tariffs with all four PC_{flex} but with EC_{fix} as the energy pricing scheme. Results are described in section 4.1.1 and include the baseline configuration H_{cp} under fixed charges in both power and energy as reference (PC_{fix} and EC_{fix}). Second, EC_{rtp} is applied to the different PC_{flex} with results shown in section 4.1.2.

In Fig. 4 the maximum value of the accumulated withdrawal power of all 33 households during the year, which is termed peak of sum (PoS) [22], is evaluated and compared for the range of configurations.

4.1.1. Flexible power and fixed energy pricing

The PoS of H_{cpd} and their change in relation to the baseline configuration H_{cp} are shown in the left part of Fig. 4. The PoS decreases by 23% if PC_{fix} is applied and by 30 - 37% depending on the flexible power component design. The reason for the decrease under PC_{fix} is due to DSM devices maximizing household self-sufficiency, given the feed-in tariff is lower than the costs for energy withdrawn from the grid. Therefore, the morning and evening peak of withdrawal power is shifted to the period of self-generated energy surplus at midday, which reduces the PoS without needing any PC_{flex} incentive.

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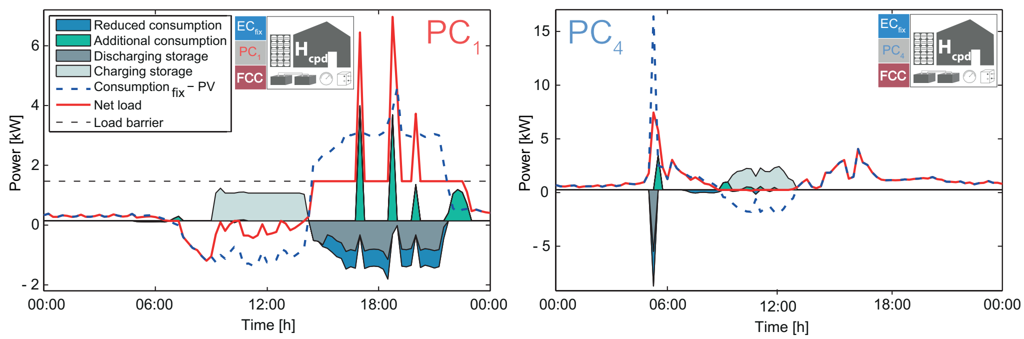

Figure 5: Daily profile of individual households under PC_1 (left) and PC_4 (right) showing potentially detrimental results for the overall system.

Results suggest that all PC_{flex} mechanisms cause similar energy management behaviour when combined with EC_{fix}. However, from the perspective of the overall system both for PC_1 and PC_4 specific adverse events and a potentially detrimental operation of DSM devices is observed. Fig. 5 shows two different household profiles using PC_1 (left) and PC_4 (right) for an exemplary day.

On the specific example with PC_1, a household consumption minus generation is higher than the load barrier for more than seven hours. The DSM devices cannot reduce the withdrawal power below the level of the barrier for the entire period and, as a consequence, steep rebound peaks are produced at specific times to satisfy the high demand. The storage output is reduced but does not reach zero when the peaks occur due to the start-up energy costs of the inverter (see equation C.1). Under this operating mode, the higher tariff rate has to be paid four times during the whole day. In general, these peaks do not occur simultaneously in several households but random occurrence of individual peaks at the same time could lead to network congestions.

The right side of Fig. 5 shows the energy management profile of one household using PC_4 for an exemplary day. In this example, the highest daily peak in demand occurs in the morning in a specific anomalous event, probably given by simultaneous use of several high-powered household appliances. Even though DSM devices are able to reduce the size of the peak, PC_4 yields an undesired behaviour: under this electricity tariff the daily peak determines the power charges, so no financial incentive exists to shave the afternoon peak irrespective of whether a PoS of the overall system occurs or not.

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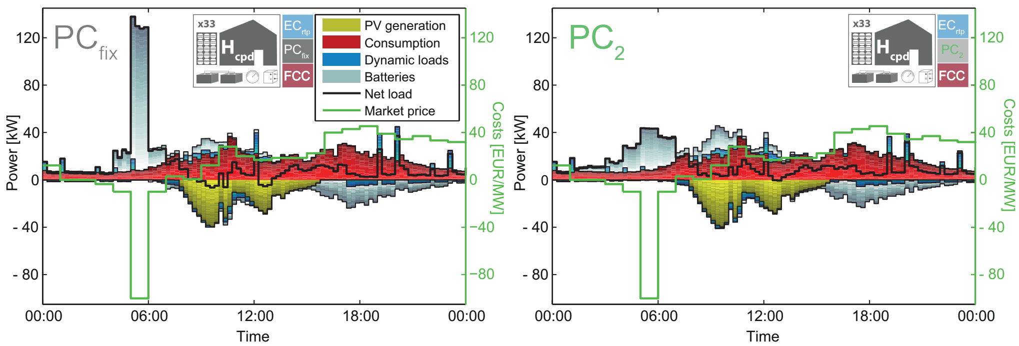

Figure 6: Accumulated profile comparing EC_{rtp} effect under PC_{fix} (left part) and PC_2 (right part) on January 22nd 2012.

4.1.2. Combined flexible power and energy pricing

The PoS of the 33 households under tariffs with both flexible power and energy charges and their comparison to H_{cp} are summarized in the right part of Fig. 4. The indicator increases significantly for all tariffs except for PC_2. In fact, the PoS is almost tripled under PC_{fix}, and more than doubled for PC_1 and PC_4.

Responsible for this observed behaviour is a specific market event on January 22nd 2012 where the minimum spot market price reached -100 €$/MWh$. The energy component of the tariff at this point in time has such a negative value that the penalty charge for PC_1, PC_3 and PC_4 is not high enough to avoid this high peak which, furthermore, occurs synchronized for all 33 households. The energy management profile corresponding to this specific event for all households under a tariff with PC_{fix} is shown on the left part of Fig. 6. Given this specific market opportunity, all of the household's batteries are simultaneously charged between five and six o'clock am when the market price is negative, producing a single spike.

Although a tariff with PC_2 produces a withdrawal peak between five and six in the morning, it is not as steep as with the other tariffs (right part of Fig. 6). The incremental costs for power are higher for PC_2 above the barrier than for all other tariffs [1] (see Fig. 2). As withdrawal increases the

[1]The costs of PC_3 are higher than for PC_2 at high withdrawal power because of the quadratic increase of the cost function, but they are lower in the region closer to the load barrier.

power cost eventually counteracts the negative energy price and thus avoid withdrawal peaks from the DSM. This dynamic makes the charging phase of batteries to be temporally distributed rather than abrupt.

The avoidance of high peaks in demand, however, cannot be guaranteed only by using tariff PC_2. Additional conditions have to be fulfilled. In general, a withdrawal power above the barrier is never beneficial if the gap between the maximal and minimal spot market price is smaller than the penalty payment for exceeding the barrier:

$$c^{pow}_{s=2} - c^{pow}_{s=1} > mp^{max} - mp^{min} \tag{11}$$

Therefore, using the parameterization of PC_2 in Fig. 2, the difference should never be higher than 12.91 ct/kWh.

However, inequality 11 is a sufficient but not a necessary condition for the avoidance of high withdrawal peaks. On January 22nd 2012 a price gap of 14.54 ct/kWh can be observed without exceeding load barriers. This results from the fact that energy costs between 4 and 5 am, as well as between 6 and 7 am, are only 9.00 ct/kWh more expensive than the price minimum in between. Since only a finite amount of energy can be stored, it is more cost efficient to distribute the charging phase over time and avoid the penalty that has to be paid if demand exceeds the barrier.

4.2. Households costs and financial outcome of electricity tariffs

The following section is primarily focused on the financial evaluation of PC_2 and its comparison with PC_{fix} since PC_2 is identified as the only effective power component in section 4.1.

4.2.1. Household electricity prices

The left part of Fig. 7 shows the average net electricity costs per kWh under H_c, H_{cp}, H_{cpd}, combined with both flexible and non-flexible tariff components.

The baseline configuration (H_{cp}) leads to equivalent costs of 25 ct/kWh for each PC_{flex} which are 0.31 ct/kWh higher than for PC_{fix} as intended by the tariff parameterization (see section 3.2). In comparison to energy consuming households (H_c) these average costs are about 0.04 ct/kWh higher for PC_1, PC_2 and PC_3 and 0.47 ct/kWh for PC_4. This occurs because PV generation reduces the average withdrawal power during times when consumption is generally low, and therefore when PC_{flex} costs are also low.

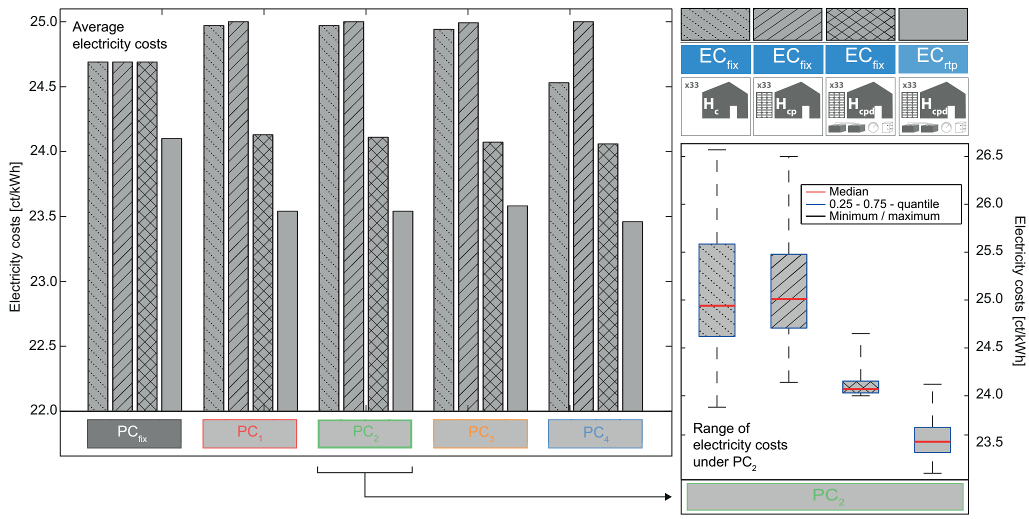

Figure 7: Average net electricity costs of households (left part) and price ranges under PC_2 (right).

Since the ratio of high versus low power charges becomes higher, the average price increases. Adding DSM devices to households (H_{cpd}) lowers the costs approximately by 0.9 ct/kWh and applying EC_{rtp} by another 0.6 ct/kWh. The resulting costs under configuration H_{cpd} are almost equal for all PC_{flex} and overall lower than for PC_{fix}.

The distribution range for the average cost per kWh considering all households under PC_2 are shown in the right side of Fig. 7. The dispersion of the costs decreases when the system has DSM. This is due to the fact that households with higher costs from exceeding the load barrier proportionally more often, have more potential for cost savings through DSM devices than households with cheaper demand profiles.

4.2.2. Financial outcome for stakeholders

The total annual electricity payments for all households under the different configurations are calculated for tariffs with PC_{fix} and PC_2 and shown in Fig. 8, including the impact of EC_{rtp}. The results show how each component of the tariff and thus its stakeholder (household, supplier, network operator, tax agencies) is affected.

The greatest reduction in the households' net payments is achieved by applying a PV system (H_{cp}) to H_c considering both the reduction in grid

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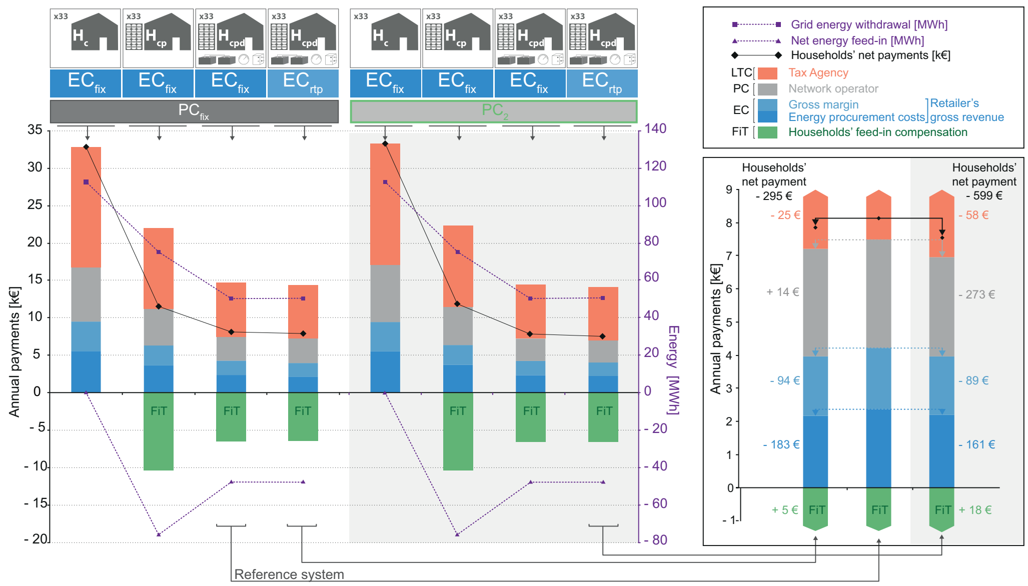

Figure 8: Total yearly outcome of all households payments, comparing PC_{fix} and PC_2 (left). Detailed financial impact for selected tariff and households configurations (right).

demand and feed-in income. This reduction amounts to 65% for PC_{fix} and 64% for PC_2. Adding DSM devices (H_{cpd}) reduces net payments by 75% and 76% respectively in comparison to H_c and by 76% and 77% if EC_{rtp} is offered. This shows that the financial influence of using the flexible power component is relatively small.

A detailed comparison of H_{cpd} is done between the fixed tariff and EC_{rtp} tariffs with PC_{fix} and PC_2. Results of these three configurations are shown on the right side of Fig. 8. This comparison is particularly meaningful since households that invest in PV panels and DSM devices currently receive fixed charges. If a flexible energy billing (EC_{rtp}) is provided to the customers instead, this component could either be combined with PC_{fix} or PC_2 by which the maximum peak loads would be affected as described in section 4.1.2.

In the case of EC_{rtp} with PC_{fix}, households reduce their net payment by 295 € p.a. due to lower energy, levy and tax costs as well as a higher income from feed-in. From the supplier's perspective, the energy procurement cost decreases by 183 € p.a. but the gross margin is negatively affected and reduced by 94 € p.a. Since this optimization lowers grid consumption in the late afternoon and early evening, where the demand-weighted average spot market price is relatively high ($\overline{mp}(H_{cpd}) \leq \overline{mp}(H_{cp})$, see equation 5 for definition of $\overline{mp}$), the average energy procurement cost is lowered as well. In the case of EC_{fix}, this cost reduction increases the supplier's gross margin but the benefit is not shared with the customer, who pays a fixed charge per kWh (equation 4). When EC_{rtp} is applied to configuration H_{cpd}, however, the reduced procurement costs are passed on to the customer since the supplier has a fixed gross margin per kWh sold (equation 6).

The gross revenue of the network operator under EC_{rtp} and PC_{fix}, increases slightly by 14 € p.a. for two reasons. First, more energy is consumed by households to compensate efficiency losses of DSM devices. Second, more power is withdrawn from the grid on specific days such as January 22nd 2012 (see Fig. 6) leading to higher payments for grid utilization but overall energy cost reduction.

Although lower spot market costs are achieved with DSM devices under EC_{rtp} and PC_{fix}, an increase of the PoS is produced by this tariff as discussed in section 4.1.2. The high withdrawal peaks can produce constraints to the overall system, which is why avoiding them by applying tariff design PC_2 is of specific interest. The economic impact to stakeholders when using PC_2 and EC_{rtp} is shown on the far right of Fig. 8. Under this scenario the household's net payments are further reduced by 304 € p.a. This is associated with lower network demand and thus lower network costs, which also reduces the revenue of the grid operator. Network optimization from PC_2 can yield significant savings by avoiding grid expansion, but this benefit cannot be quantified in this setup since it's directly influenced by the local grid topology.

4.3. Considerations to implement tariff in real system

This section discusses three significant obstacles that should be considered when implementing the flexible tariffs in a real case scenario. Namely, we address the design of the load barrier, the potential reduction in grid operators' revenues and the comparatively small savings in energy procurement costs.

Tariffs with PC_2 show an optimized grid performance by using a load barrier, which activates a higher price step for the share of consumption above this barrier. The sum of the designed barriers is set to equal the original PoS (Maximum value of the accumulated withdrawal power of all households within the year) and is then linearly distributed among the households depending on their average power consumption (see section 2.2). In a real system, the sum of the barriers could be designed based on the physical structure and capacity of the local grid. The sum of the barriers could be equated with the limiting factor of the grid such as the power of the low-voltage transformer minus a safety reserve. Furthermore, the barrier of households with heat pumps or electric vehicles could be raised disproportionately in comparison with other households if subsidization or other incentives are applied by policy.

Section 4.2.2 shows that the flexible power component can reduce revenues of grid operators. In this experimental setup, the gross price of all flexible tariffs is set to 29.75 ct/kWh for configuration H_{cp} (see section 3.2). If grid operators need to be compensated, the gross price could be increased and therefore the rate below or above the barrier. Higher revenue, however, could also occur by only applying the tariff to a real system without any further modifications. Since, in practice, demand and PV generation data would be affected by uncertainties, the household's unit commitment may not be as optimized as presented here and therefore produce higher costs. Furthermore, in the long-term, the electrification of heat supply and transportation may increase the amount of energy and power that has to be withdrawn from the distribution network. Since the application of PC_2 can lead to a more efficient use of the network and may even avoid grid expansions, the higher volume of power delivered under the same infrastructure would reduce the operators' grid costs per kWh and thus increase profitability.

The detailed economic analysis of section 4.2.2 shows that absolute savings from the optimization of spot market procurement cost with EC_{rtp} are comparatively low in this paper. This might suggest that such dynamic pricing system might not be justified. However, observed market tendencies might progressively increase these savings. For example: i) with an increase in electrical consumption from electric vehicles and heat pumps, ii) from higher penetration of variable generators along with a low price elasticity of demand, yielding an increase in spot market price gaps of hourly and quarter-hourly contracts and iii) if legislators directly increase saving potentials by, for example, adopting flexible billing of the electricity tax according to energy and capacity payments.

5. Conclusion

DR programs can help integrate variable renewable energies and DER in the energy supply system, yet the development of an accurate control and

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market framework is still one of the greatest remaining DR challenges. Our paper presents flexible price signals that can address this by acting as effective demand control mechanisms. The different tariffs, with combinations of flexible energy and power price signals, are tested on the unit commitment of automatable DSM devices from a set of households and the financial consequences to the respective stakeholders are quantified.

The use of flexible power components on the proposed tariffs results in reductions of annual peak demands. This may suggest that in lieu of expensive network expansions, grid operators could apply these signals and incentives to prevent network congestion and enhance grid efficiency. On the other hand, by testing a flexible energy component with RTP, this paper shows that although energy procurement costs can be reduced, annual peak demand can in fact increase. Such new peaks might negatively affect grid requirements and thus electricity prices, or even lead to unforeseeable network congestion. The paper proposes a solution to this, however, by showing that applying a specific combination of flexible power and energy components can achieve both the energy procurement optimization and stable peak demand.

Out of the four different designs of flexible power components, only one provides robust results while the other three trigger demand peaks from spot price opportunities. The successful PC_2 uses a load barrier, linearly dependent on the average power consumption of each household, which activates a higher price step for the share of consumption above the barrier. In order to implement PC_2 effectively in a real system, the barriers could be designed based on the physical limitations and capacity of the local grid, as mentioned in section 4.3. Economic analysis of stakeholder impact show that flexible power components can reduce revenues of grid operators. To prevent these losses, the costs of the two price steps could be adapted leading to smaller savings in households electricity costs.

Further research could then include the empirical testing of the system proposed here, considering realistic uncertainties in load predictions have not been factored into our simulations. Furthermore, an important milestone in order to implement the tariff in a real system would be the validation of the functionality of the tariff design in a pilot project under real conditions. Such projects should take into account the exchange of data between the stakeholders, the intensity of customer reactions to the provided incentives and the technical influences on a lower time scale than 15 minutes.

Acknowledgment

M.S. designed and developed the experiment, set up and implemented the optimization problem and performed the simulations. All authors contributed substantially to the analysis and interpretation of the results. M.S. and M.W. drafted the article. All authors contributed to its critical revision.

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Nomenclature

Indexes and sets

$d \in D$	Days within test year, day change at 00:00 UTC
$h \in H$	Set of 33 households
$n \in N$	Devices of households
$s \in S^{+}$, $s \in S^{-}$	Positive / negative net load segments
$t \in T$	Time intervals within test year, 15-minutes time resolution

Constants and parameters

Δ_t	Interval length
$\Delta_{shift,max}$	Maximum shifting period of DSM
c^{add}	Specific factor of additional costs
c^{bas}	Basic costs and meter charge
$c^{eng,fix}$, c_t^{eng}	Specific cost factor of fixed / flexible energy component
c^{feedin}	Specific cost factor of feed in power
c^{ltc}	Specific cost factor of levy and tax component
c^{peak}	Specific cost factor of daily peak in demand
$c^{pow,fix}$	Specific cost factor of fixed power component
c_n^{start}	Start-up cost of unit

c_s^{pow}	Specific cost factor for power component per load segment
gm	Gross margin of the retailer
mp^{min}, mp^{max}	Minumum / maximum spot market price
mp_t, $\overline{mp}$	Spot market price, demand-weighted spot market price
p_h^{bar}	Load barrier
$p_h^{pv,nom}$	Nominal power of photovoltaic panel
$r_h^{gen/con}$	Generation-to-consumption ratio of household
s^{max}	Number of segments
vat	Value added tax
w^{seg}	Width of segments

Variables

B_t^{add}	Binary variable that indicates additional costs for PC_1
$B_{n,t}^{start}$	Binary variable that indicates start time of unit
$C_{h,t}^{eng,fix}$, $C_{h,t}^{eng}$	Costs of fixed / flexible energy component
$C_{h,t}^{ltc}$	Costs of levy and tax component
$C_{s,t}^{nl+}$, $C_{s,t}^{nl-}$	Costs of positive / negative net load
$C_{h,t}^{pow}$	Costs of power component
C_h^{tot}	Total electricity costs
P_t^{aux+}, P_t^{aux-}	Positive and negative auxiliary variable of net load
$P_{h,n,t}^{con}$, $P_{h,n,t}^{gen}$	Power of consuming / generating units
$P_{s,t}^{nl+}$, $P_{s,t}^{nl-}$	Power value of the positive / negative net load segment
$P_{h,t}^{nl}$, $P_{d,h}^{max}$	Net load / maximum daily net load
$P_{i,j}^{shift}$	Shifting power vectors
$P_{h,t}^{wp}$, $\overline{P_h^{wp}}$	Withdrawal power / average withdrawal power
$\sum_{t\in T} P_o^{gen,norm}$	Standardised generation time series of PV panel either oriented south or east-west

Appendix A. Parametrization of households

Tab. A.2 shows the annual energy consumption E^{con}, the annual withdrawn energy under H_{cp} E^{wp}, the annual generation-to-consumption ratio $r^{gen/con}$ (arbitrary), the nominal power of the PV panels $p^{pv,nom}$ and their orientation as well as the load barrier p^{bar} of the households.

h	E^{con} $[kWh]$	E^{wp} $[kWh]$	$r^{gen/con}$	$p^{pv,nom}$ $[kW]$	orient.	p^{bar} $[kW]$
1	4061	2875	0.67	2.7	S	1.70
2	2930	1960	1.00	3.9	E-W	1.16
3	2267	1352	1.00	3.0	E-W	0.80
4	2521	1724	1.33	3.3	S	1.02
5	3537	2478	1.33	4.6	S	1.47
6	3620	2335	1.00	3.6	S	1.38
7	4312	2792	1.33	5.6	S	1.65
8	4252	3154	0.67	3.8	E-W	1.87
9	3981	2452	1.00	5.3	E-W	1.45
10	3121	2242	1.00	3.1	S	1.33
11	4832	2864	1.33	8.5	E-W	1.70
12	4396	2788	1.33	5.7	S	1.65
13	5334	3912	0.67	3.5	S	2.32
14	1572	1085	0.67	1.1	S	0.64
15	2274	1568	1.00	3.0	E-W	0.93
16	3410	2337	0.67	2.3	S	1.38
17	5909	3557	1.00	5.8	S	2.11
18	3386	2145	1.33	6.0	E-W	1.27
19	2524	1719	0.67	2.3	E-W	1.02
20	5859	3572	1.00	5.7	S	2.11
21	3297	1988	1.33	4.3	S	1.18
22	2766	1857	1.33	4.9	E-W	1.10
23	2522	1944	0.67	2.3	E-W	1.15
24	3500	2454	0.67	2.3	S	1.45
25	3073	2129	1.00	3.0	S	1.26
26	2210	1423	1.00	3.0	E-W	0.84
27	3687	2349	1.33	4.8	S	1.39
28	1805	1337	0.67	1.2	S	0.79
29	5323	4025	0.67	3.5	S	2.38
30	2074	1540	1.00	2.1	S	0.91
31	1782	1436	0.67	1.2	S	0.85
32	3595	2254	1.33	4.7	S	1.33
33	2251	1353	1.33	3.0	S	0.80

Table A.2: Parameterization of households

Appendix B. Modeling of electricity tariffs

Positive and negative net loads equal sums of positive or negative load segments respectively, which can be filled up to a specific level (equation B.1 and B.2). These segments are used to settle costs for different tariff levels individually. Auxiliary variables are subtracted from the sums which do not affect the target function.

$$P_t^{nl} = \sum_{s\in S^+} P_{s,t}^{nl+} - P_t^{aux-} \tag{B.1}$$

$$-P_t^{nl} = \sum_{s\in S^-} P_{s,t}^{nl-} - P_t^{aux+}\ . \tag{B.2}$$

The first term in objective function 9 describes the payments for grid consumption. The set of segments S^+ and the costs per segment $C_{s,t}^{nl+}$ are individually defined for each tariff in the following subsections.

Appendix B.1. Specification of PC_{fix}

It holds that $S^+ = \{1\}$ and $C_{s,t}^{nl+} = c_t^{eng} + c^{pow,fix} + c^{ltc}$ (see Tab. 1).

Appendix B.2. Specification of PC_1

It holds that $S^+ = \{1, 2\}$ and $C^{nl+}_{s,t} = c^{eng}_t + c^{pow}_s + c^{ltc}$, where c^{eng}_t and c^{ltc} are defined in Tab. 1. Furthermore, $c^{pow}_{s=1} = c_2$ and $c^{pow}_{s=2} = c_3$ (see Fig. 2). Since the lower tariff level is only paid if the demand is below the barrier, the power of the first segment in equation 9 is limited by $P^{nl+}_{s=1,t} \leq p^{bar}$. Thus, the lower tariff level is charged for the amount of power below and the higher tariff level for the amount of power above the barrier. Since the higher tariff level has to be paid for the whole amount of power if the barrier is exceeded, additional costs are introduced. These additional costs equal the difference of the costs for the higher and the lower tariff level multiplied by the width of the first segment which equals p^{bar}. Therefore, the additional costs c^{add} in equation 2 equal $(c_3 - c_2) \cdot p^{bar}$. Equation B.3 is introduced which ensures that the binary variable B^{add}_t in equation 9 equals 1 (additional costs are activated) if the second tariff segment is not empty:

$$-(p^{nl,max} - p^{bar}) \cdot B^{add}_t + P^{nl+}_{s=2,t} \leq 0\,. \tag{B.3}$$

Appendix B.3. Specifications of PC_2

It holds that $S^+ = \{1, 2\}$ and $C^{nl+}_{s,t} = c^{eng}_t + c^{pow}_s + c^{ltc}$, where c^{eng}_t and c^{ltc} are defined in Tab. 1. Furthermore, $c^{pow}_{s=1} = c_4$ and $c^{pow}_{s=2} = c_5$ (see Fig. 2). The power of the first segment in equation 9 is limited by $P^{nl+}_{s=1,t} \leq p^{bar}$.

Appendix B.4. Specifications of PC_3

It holds that $S^+ = \{1, 2, ..., s^{max}\}$ and $C^{nl+}_{s,t} = c^{eng}_t + c^{pow}_s + c^{ltc}$, where c^{eng}_t and c^{ltc} are defined in Tab. 1. The quadratically increasing cost function is approximated by a linear function. The method is explained in detail in [27]. The number of positive load segments s^{max} is limited by:

$$s^{max} \cdot w^{seg} \geq p^{nl,max}\,,$$

where the width of the load segments w^{seg} equal $0.25\,kW$. The capacity costs of segment $s \in S^+$ are defined as:

$$c^{cap}_s = c^{quad} \cdot w^{seg} \cdot (s^2 - (s-1)^2) + c^{lin} \cdot (1 - r)\,,$$

where $c^{quad} = c_6 \cdot r \cdot f$, $c^{lin} = 6.83$ and $r = 0.3$ (see Fig. 2).

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Appendix B.5. Specifications of PC_4

It holds that $S^+ = \{1\}$ and $C^{nl+}_{s,t} = c^{eng}_t + c^{pow} + c^{ltc}$, where c^{eng}_t and c^{ltc} are defined in Tab. 1. Furthermore, $c^{pow} = c_8 \cdot (1 - r)$ (see Fig. 2). The maximum daily peak P^{max}_d is defined as:

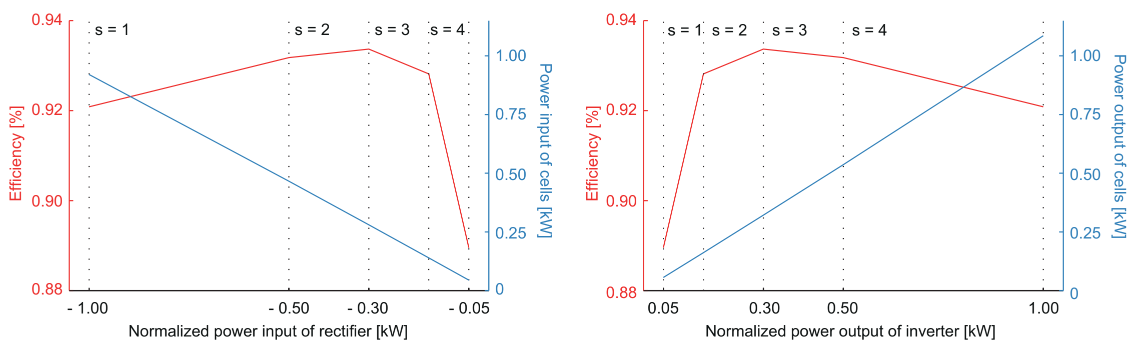
$$P^{nl+}_{s=1,t} \leq P^{max}_d \,,\, \forall d \in D,\, t \in \left[(d-1) \cdot \frac{24}{\Delta_t} + 1, d \cdot \frac{24}{\Delta_t}\right] . \tag{B.4}$$

c^{peak} in the objective function 2 equal $c_8 \cdot r$ (table 3).

Appendix C. Battery

The battery systems consist of a rectifier, an inverter and Li-ion cells. An efficiency of 96% is assumed for both charging and discharging the Li-ion cells [32]. The efficiency of the rectifier and inverter is derived from the commercial product SUNNY ISLAND 8.0H by SMA. It is assumed that the efficiency losses noted in the data sheet [33] are equally distributed over the rectifier and inverter.

The efficiency and performance curves are approximated by piecewise linear functions with four grid points (see figure C.9). The multiple choice model [34] is used to model the performance curves.



	Segment s			
	1	2	3	4
Intercept	0.0109	0.0014	- 0.0016	- 0.0029
Slope	- 0.9099	- 0.9290	- 0.9392	- 0.9475
Lower boundary	- 1.0	- 0.5	- 0.3	- 0.15
Upper boundary	- 0.5	- 0.3	- 0.15	- 0.05

	Segment s			
	1	2	3	4
Intercept	0.0035	0.0019	- 0.0016	- 0.0128
Slope	1.0540	1.0647	1.0764	1.0987
Lower boundary	0.05	0.15	0.3	0.5
Upper boundary	0.15	0.3	0.5	1.0

Figure C.9: Approximation of efficiency and performance curves of rectifier and inverter.

The power output of the inverter is limited by the fixed demand per time step to ensure that stored energy is not feed into the grid and compensated by the feed-in compensation for PV generation. Low but positive start-up costs (equation C.1) shall encourage a continuous charging and discharging phase instead of a frequently switching on and off.

$$c^{start} = p^{pv,nom} \cdot 0.01\, ct \tag{C.1}$$

Appendix D. Modeling of demand side management

A set of i shifting power vectors $P_{i,j}^{shift}$ is defined as

$$P_{i,j}^{shift} \begin{cases} \leq \infty, & \text{if}\, i \leq j \,\text{and}\, i + \frac{\Delta_{shift,max}}{\Delta_t} \geq j \\ = 0, & \text{otherwise} \end{cases}, \tag{D.1}$$

where $\Delta_{shift,max} = 2h$ and $i, j \in T$. The original, flexible consumption $P_t^{con'}$, which is 20 % of the total consumption, is defined in equation D.2. The factor 1/1.001 is a small standby consumption which shall encourage that consumption is only shifted if a financial gain can be achieved. The new consumption P_t^{con} is defined in equation D.3.

$$P_t^{con'} = P_{i=t,j=t}^{shift} + \sum_{j \in T} P_{i=t,j}^{shift} \cdot \frac{1}{1.001} \tag{D.2}$$

$$P_t^{con} = \sum_{i \in T} P_{i,j=t}^{shift} \tag{D.3}$$

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