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AUTHORS

Cosima Jägemann

Simeon Hagspiel

Dietmar Lindenberger

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Institute of Energy Economics at the University of Cologne (EWI)

www.ewi.uni-koeln.de

Institute of Energy Economics
at the University of Cologne (EWI)

Alte Wagenfabrik
Vogelsanger Straße 321
50827 Köln
Germany

Tel.: +49 (0)221 277 29-100
Fax: +49 (0)221 277 29-400
www.ewi.uni-koeln.de

CORRESPONDING AUTHOR

Cosima Jägemann
Institute of Energy Economics at the University of Cologne (EWI)
Tel: +49 (0)221 277 29-300
Fax: +49 (0)221 277 29-400
Cosima.Jaegemann@ewi.uni-koeln.de

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The economic inefficiency of grid parity: The case of German photovoltaics

Cosima Jägemann[a,*], Simeon Hagspiel[a], Dietmar Lindenberger[a]

[a] *Institute of Energy Economics, University of Cologne, Vogelsanger Strasse 321, 50827 Cologne, Germany*

Abstract

Since PV grid parity has already been achieved in Germany, households are given an indirect financial incentive to invest in PV and battery storage capacities. This paper analyzes the economic consequences of the household's optimization behavior induced by the indirect financial incentive for in-house PV electricity consumption by combining a household optimization model with an electricity system optimization model. Up to 2050, we find that households save 10 % - 18 % of their accumulated electricity costs by covering 38 - 57 % of their annual electricity demand with self-produced PV electricity. Overall, cost savings on the household level amount to more than 47 bn €$_{2011}$ up to 2050. However, while the consumption of self-produced electricity is beneficial from the single household's perspective, it is inefficient from the total system perspective. The single household's optimization behavior is found to cause excess costs of 116 bn €$_{2011}$ accumulated until 2050. Moreover, it leads to significant redistributional effects by raising the financial burden for (residual) electricity consumers by more than 35 bn €$_{2011}$ up to 2050. In addition, it yields massive revenue losses on the side of the public sector and network operators of more than 77 and 69 bn €$_{2011}$ by 2050, respectively. In order to enhance the overall economic efficiency, we argue that the financial incentive for in-house PV electricity consumption should be abolished and that energy-related network tariffs should be replaced by tariffs which reflect the costs of grid connection.

Keywords: Grid parity; Photovoltaic; Battery storage; Optimization model; Excess costs; Redistributional effects;

JEL classification: C61, Q28, Q40

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*Corresponding author
Email address: `Cosima.Jaegemann@uni-koeln.de, +49 22127729300` (Cosima Jägemann)

1. Introduction

In Germany, the consumption of self-produced electricity is exempt from paying taxes, levies and surcharges. Moreover, electricity consumers pay energy-related rather than capacity-related network tariffs, i.e., electricity consumers pay a fixed network tariff for each kWh purchased from the grid (see Figure 1). Both facts incentivize the consumption of self-produced instead of grid-supplied electricity. This paper analyzes the economic consequences of this indirect financial incentive for the case of residential photovoltaic (PV) systems – both from the single household's and the total system perspective.

Besides the exemption from taxes, levies and surcharges as well as the allocation of grid costs via energy- rather than capacity-related network tariffs, the government currently promotes investments in renewable energy technologies via a feed-in tariff system in which eligible renewable energy producers receive a fixed payment for the amount of electricity fed into the grid (over a period of 20 years). The additional costs associated with the promotion of renewable energies are passed on to electricity consumers via the renewable energy surcharge. Under the current feed-in tariff system, households typically maximize their profits by

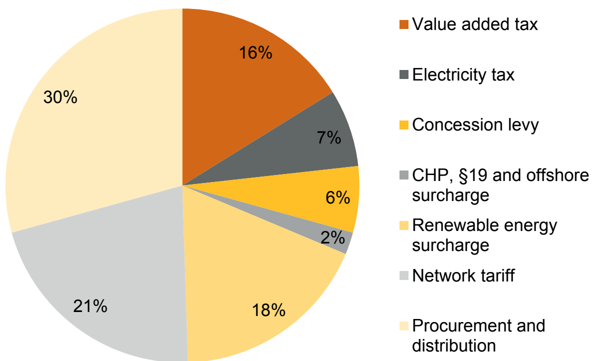

Figure 1: Composition of Germany's flat residential electricity tariff in 2013 based on BDEW (2013)

maximizing the amount of PV electricity fed into the electricity grid. However, in 2012, the German government decided to stop the direct financial incentives for PV electricity generation (feed-in tariff) once a cumulative capacity of 52 GW is reached (Germany Parliament (2012)), which corresponds to the German NREAP target for 2020.[1]

Meanwhile, 'PV grid parity' was recently reached on the household level in Germany (as a consequence of increasing residential electricity tariffs and falling PV system prices), which marked the point in time at which the levelized costs of electricity (LCOE) of rooftop PV systems have reached the level of the residential

[1]By the end of October of 2013, total installed PV capacity amounted to 35.3 GWp in Germany (BNetzA (2013)).

electricity tariff (Perez et al. (2012)).[2] Since then, the LCOE of rooftop PV systems (14 €ct/kWh - 16 €cent/kWh, Kost et al. (2012)) have fallen well below the flat residential electricity tariff (28.5 €ct/kWh, BDEW (2013)).

Both (i) the decrease of PV electricity generation costs below the flat residential electricity tariff and (ii) the exemption from taxes, levies and surcharges as well as the allocation of grid costs via energy- rather than capacity-related network tariffs in Germany, have made the consumption of a self-produced kWh cheaper than the consumption of a grid-supplied kWh from the single household's perspective. Hence, households are given a financial incentive to install rooftop PV systems, even without receiving any feed-in tariff.

If the residential electricity tariff further increases and the price of PV system further decreases, the financial incentive will also continue to increase in the years to come. Similary, the price of small-scale battery storage systems, such as lithium-ion batteries, is expected to further decrease, allowing an increased share of PV electricity generation to be consumed in-house. Overall, households will soon be able to significantly reduce their electricity costs by consuming self-produced PV electricity instead of grid-supplied electricity, rendering investments in rooftop PV systems combined with small-scale battery storage systems economically viable from the single household's perspective.

This paper analyzes the consequences of exempting in-house PV electricity consumption from taxes, levies and surcharges and allocating grid costs via energy- rather than capacity-related network tariffs from 2020 onwards – both from the single household and the total system perspective.[3] In a case study for Germany, a household optimization model is applied that minimizes the single households' electricity costs by determining (among others) the cost-optimal dimensioning of the combined PV and battery storage system, the amount of PV electricity generation consumed in-house or sold to the grid as well as the dispatch of the battery storage system. To best reflect the current situation, it is assumed that households pay a flat (time-independent) residential electricity tariff for the amount of electricity purchased from the grid. Moreover, households are assumed to receive the (time-dependent) wholesale electricity price for the amount of surplus PV electricity generation fed into the grid.

Our analysis complements a growing body of literature addressing the economic performance of both

[2]Several studies have tried to identify the point in time at which PV grid parity will be reached in different countries (e.g., Bhandari and Stadler (2009) for Germany, Ayompe et al. (2010) for Ireland, and Denholm et al. (2009), Reichelstein and Yorston (2013) and Swift (2013) for the United States). An analyis of factors influencing the LCOE of PV (and thus the point of time at which PV grid parity is reached) is, for example, provided by Branker et al. (2011), Darling et al. (2011), Singh and Singh (2010) and Hernandez-Moro and Martinez-Duart (2013).

[3]Although investments in PV systems for in-house PV electricity consumption may already be economically viable today, we choose 2020 as starting year in our analysis as investments in PV systems are expected to be driven by the feed-in tariff until 2020, which will be paid until the target of 52 GW is achieved. Moreover, by 2020, the price of lithium-ion batteries is expected to have significantly fallen in comparison to today, rendering investments in small-scale storage capacities (to increase the amount of in-house PV electricity consumption) economically viable.

residential and commercial PV systems from the single customer's perspective. Darghouth et al. (2013), Ong et al. (2010), Mills et al. (2008) and Borenstein (2007) analyze the impact of the retail electricity tariff structures on the economic viability of residential PV systems from the customer's perspective. These papers find that time-varying retail tariffs (such as time-of-use rates or real-time prices), which reflect the utility's cost of generating and/or purchasing electricity on the wholesale electricity market, lead to higher electricity bill savings from in-house PV electricity consumption than flat retail tariffs.[4] This is due to the generally positive correlation between the hourly solar power generation profile and the hourly wholesale electricity price profile in scenarios with low solar power penetration. However, as explained by Darghouth et al. (2013), electricity bill savings under time-varying retail tariffs may decrease with increased solar power penetration, as high amounts of PV electricity generation may cause the temporal profile of the hourly wholesale electricity price to become negatively correlated with the hourly PV electricity generation profile. More specifially, the more PV capacity is installed, the larger the short-term merit-order-effect becomes. PV electricity supply, having (almost) zero variable generation costs, reduces the wholesale electricity price and, as such, the (time-varying) retail tariff during sunny hours.[5] However, in Germany (and many other European countries), residential customers are traditionally charged a flat retail electricity tariff for the electricity taken form the grid – independent of the time of day that the electricity is used.

The applied household optimization model extends the modeling approach of recent analyses. While Colmenar-Santos et al. (2012), McHenry (2012), Ayompe et al. (2010) and Hernandez et al. (1998) analyze the profitability of investments in grid-connected PV systems (with an exogenously given capacity) from the single household's perspective, Ren et al. (2009) determine the cost-optimal capacity of a grid-connected PV system by minimizing the annual electricity costs of a given residential electricity consumer. Castillo-Cagigal et al. (2011), in contrast, abstract from costs and evaluate the supplementary installation of both a battery storage system and active demand side management in order to maximize the in-house consumption of self-produced PV electricity. Only Colmenar-Santos et al. (2012) and Castillo-Cagigal et al. (2011) analyze the option to install a battery storage system in combination with the PV system. However, none of the papers cited above jointly optimizes the size of the PV and battery storage system from the single household's perspective by minimizing the household's annual electricity costs.

Moreover, to the authors' knowledge, our analysis is the first to account for feedback effects of the single

[4]While time-of-use rates set various prices for different periods (e.g., daytime vs. nighttime), real-time pricing forsees prices to change on an hourly basis depending on the hourly wholesale electricity price (Darghouth et al. (2013)).

[5]The effect of renewable energy penetration with no variable generation costs on the wholesale electricity price (short-term merit order effect) is, for example, analyzed in Gil et al. (2012), Jonsson et al. (2010), Munksgaard and Morthorst (2008), G. Saenz de Miera and P. del Rion Gonzalez and I. Vizcaino (2008) and Sensfuß et al. (2008).

household's optimization behavior on the rest of the electricity system (and vice versa). In particular, an increased penetration of PV systems on the household level causes changes in the residual load (both in volume and structure), which in turn affects both the wholesale electricity price (via a change in the provision and operation of power plants and storage technologies on the system level) and the residential electricity tariff (primarily via changes in the wholesale electricity price and the renewable energy surcharge). We account for these feedback effects by running an iteration between the household optimization model and an electricity system optimization model. Finally, we are the first to quantify both redistributional effects and excess costs associated with the indirect financial incentive for in-house PV electricity consumption.

We find that households are able to reduce their electricity costs by investing in PV and storage battery capacities to meet part of their demand with self-produced electricity. However, while households reduce their annual electricity costs by consuming self-produced instead of grid-supplied electricity, this indirect financial incentive yields two economic consequences:

Firstly, we find that the indirect financial incentive distorts competition of technologies, which causes excess costs to be born by the society. Due to the exemption from taxes, levies and surcharges for the amount of in-house PV consumption and the allocation of grid costs via energy- rather than capacity-related network tariffs, households are incentivized to undertake investments in small-scale PV and battery storage systems that are inefficient from an economic perspective, causing total system costs to rise.

Secondly, we find that the indirect financial incentive for the consumption of self-produced instead of grid-supplied electricity leads to a redistribution of financial resources. For example, as a consequence of an increased in-house PV electricity consumption on the household level, the amount of electricity purchased from the grid decreases. However, since the additional costs of promoting renewable energies are currently apportioned to the amount of electricity purchased from the grid, the renewable energy surcharge (to be paid by the residual electricity consumers) increases with the amount of in-house PV electricity consumption on the household level. Hence, the financial burden for residual electricity consumers rises in order to favor the electricity bill savings of households that meet part of their electricity demand with self-produced PV electricity.

In order to incentivize a cost-efficient development of the German electricity system, we argue that the consumption of self-produced electricity should be treated in the same manner as the consumption of grid-supplied electricity, i.e., the exemption from taxes, levies and other surcharges for the amount of self-produced PV electricity consumed in-house should be abolished. Alternatively, the residential electricity price could be reduced to the 'true' costs of electricity procurement. Moreover, since grid costs are primarily fixed costs, the traditional (energy-related) grid tariffs should be replaced by cost-reflecting tariffs that correspond primarily to grid connection capacity.

The remainder of the paper is structured as follows: Section 2 presents the applied methodology used to analyze the consequences of indirect financial incentives for in-house PV electricity consumption in Germany. Section defines the scenarios und Section 4 summarizes the model results. Section 5 concludes and provides an outlook on possible further research.

2. Methodology and assumptions

In the following, we first explain the general logic of the applied methodological approach (Section 2.1), before the household optimization model (Section 2.2) and the electricity system optimization model (Section 2.3) are described in more detail.

2.1. Modeling approach

The general logic of the applied modeling approach used to analyze the consequences of the indirect financial incentive for in-house PV electricity consumption can best be described by defining two agents, each characterized by a specific optimization behavior. Agent A minimizes the single household's accumulated and discounted electricity costs subject to techno-economic constraints. Agent A can choose between meeting the single household's electricity demand with electricity supplied by the grid or with self-produced PV electricity. More specifically, he minimizes the single household's electricity costs by determining the optimal decisions with respect to the dimensioning of the combined PV and storage systems and the use of self-produced PV electricity. Hence, Agent A decides not only on the optimal size of the combined PV and storage capacities installed but also on the optimal dispatch of the single household's battery storage systems and the optimal amount of PV electricity generation that is to be consumed in-house or sold to the grid.

Agent B, in contrast, minimizes total system costs by making optimal investment and dispatch decisions with respect to generation and storage technologies on the system level. Accumulated and discounted system costs are minimized subject to techno-economic constraints, such as the necessity to meet the electricity demand at each point in time. Given the assumption of a price-inelastic electricity demand, the cost-minimization problem of Agent B corresponds to a welfare-maximization approach.

Moreover, both agents minimize costs under the assumption of perfect foresight.

As shown in Figure 2, the optimization behavior of Agent A influences the optimization behavior of Agent B and vice versa. The more PV and storage system capacities Agent A builds on the household level, the more PV electricity is produced and either consumed in-house or fed into the grid. As a consequence,

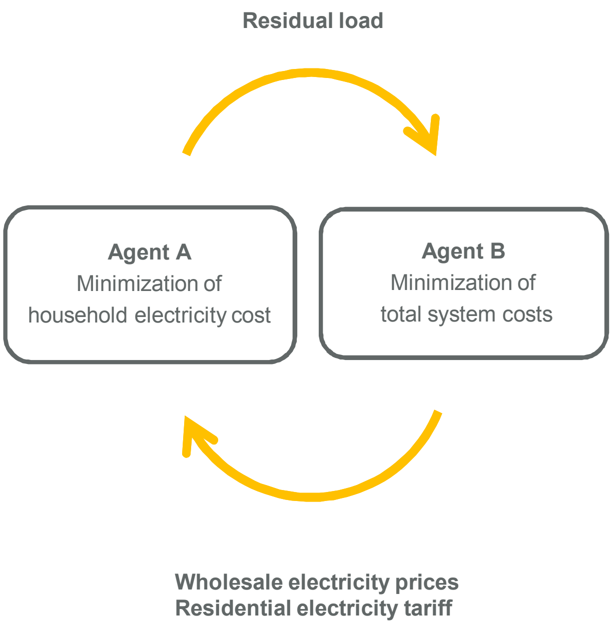

Figure 2: Interaction of the agents' optimization behaviors

the residual load to be supplied by generation and storage technologies on the system level changes (both in volume and structure). Agent B subsequently adapts the provision and operation of power plants and storage technologies on the system level to the new residual load, which in turn leads to changes in the wholesale electricity price and the residential electricity tariff. Changes in the wholesale electricity price and the residential electricity tariff, in turn, affect the single household's optimization behavior. This is due to two facts: Firstly, we assume that households pay a fixed, i.e., time-independent, residential electricity tariff for each kWh purchased from the grid, as currently employed in Germany. Secondly, we assume that the amount of surplus (not self-consumed) PV electricity generation, which is sold to the grid, is remunerated by the wholesale electricity price.

Agent A and Agent B are assumed to determine their investment and dispatch decisions given the investment and dispatch decisions of the other agent. Hence, both agents adapt their optimal invest and dispatch decisions in response to the other agent's decision until the equilibrium is reached. In the equilibrium, Agent A no longer has an incentive to change his behavior, given the exogenously given behavior of Agent B and vice versa.

In order to determine the equilibrium solution, an iterative approach with two linear optimization models, (i.e., a linear household optimization model (Agent A) and a linear electricity system optimization model (Agent B)), is applied. Each model minimizes the respective agent's costs. The equilibrium is derived by iterating all interrelated variables (such as the wholesale electricity price, the renewable energy surcharge and the residual load) until convergence of results is reached. For this, a convergence criterion must to be defined. A natural possibility is to stop when the relative change in the interrelated variables is sufficiently small.

The linear programming environment has been proven to be suitable for solving large-scale problems such as these ones, which involve millions of variables that require extensive calculations. In fact, there are very effective algorithms which can efficiently and reliably solve large linear programming problems, such as the Simplex algorithm (e.g.,Boyd and Vandenberghe (2004), Todd (2002) or Murty (1983)).[6] An alternative approach would be to formulate a non-linear optimization model that minimizes the sum of the respective agent's costs. In this case, however, the target function would become non-linear and thus the optimization problem may become difficult to solve since the algorithms for large-scale non-linear optimization problems are typically far less effective than the algorithms for linear optimization problems (Boyd and Vandenberghe (2004)). Another alternative would be to formulate an equilibrium model that solves each agent's optimization problem simultaneously within a complementarity system. However, just like in the case of the non-linear optimization model, the large complexity of the problem structure suggests that the model may be rather difficult to solve via a mixed complementarity problem algorithm (Li (2010)).

In the following, the household optimization model (Section 2.2) and the electricity system optimization model (Section 2.3), which are iterated to determine the market equilibrium, are described in more detail.

2.2. Household optimization model

The household optimization model determines (among others) the optimal investment in combined PV and storage systems from the single household's perspective by the year 2020 and calculates the optimal dispatch of the battery storage system in 5-year time steps up to 2050, i.e., over the entire lifetime of the PV system (which is assumed to be 30 years). Moreover, the model determines the optimal share of PV electricity to be consumed in-house, stored in the battery storage system or sold to the grid.

2.2.1. Model equations

The objective of the linear household optimization model is to minimize the accumulated discounted electricity costs of one- and two-family houses in Germany, given hourly solar radiation profiles, hourly household electricity consumption profiles, PV and battery storage system investment costs, hourly wholesale

[6] Applications of iterative procedures to compute market equilibria can, for example, be found in Greenberg and Murphy (1985) and Wu and Fuller (1996). Specifically, the iterative procedure pursued in this paper is comparable to the PIES (Project Independence Evaluation System) algorithm, which essentially applies a combination of a linear programming model and econometric demand equations to determine valid prices and quantities of fuels (Ahn and Hogan (1982) and Hogan (1975)).

electricity prices and the residential electricity tariff. Table 1 lists all sets, parameters and variables of the household optimization model.

The accumulated discounted electricity costs of one- and two-family houses in Germany ($THHC$), as defined in Equations (1) - (6), are the sum of the single household's annualized PV system investment costs ($C^P_{y,i,b}$), the annualized storage system investment costs ($C^S_{y,i,b}$), the annual operation and maintenance (O&M) costs ($M_{y,i,b}$) and the annual costs for the amount of electricity purchased from the grid ($P_{y,i,b}$). Investment costs are annualized with a 5 % interest rate for the depreciation time, i.e., the technical liftetime of the PV and battery storage systems. O&M costs account for the replacement of the inverter. In addition, the electricity costs are decreased by the revenue acquired from selling surplus (not self-consumed) PV electricity to the grid ($R_{y,i,b}$), which is assumed to be remunerated by the wholesale electricity price ($p_{y,h}$).

$$\min THHC = \sum_{i \in I} \sum_{b \in B} \sum_{y \in Y} disc_y \cdot (C^P_{y,i,b} + C^S_{y,i,b} + M_{y,i,b} + P_{y,i,b} - R_{y,i,b}) \cdot \frac{z_{i,b}}{x} \tag{1}$$

s.t.

$$C^P_{y,i,b} = c^P \cdot AD^P_{y,i,b} \cdot an^P \tag{2}$$

$$C^S_{y,i,b} = c^S \cdot AD^S_{y,i,b} \cdot an^S \tag{3}$$

$$M_{y,i,b} = fc^P \cdot K^P_{y,i,b} + fc^S \cdot K^S_{y,i,b} \tag{4}$$

$$P_{y,i,b} = \sum_{h \in H} (ECI^G_{y,h,i,b} + ESB^G_{y,h,i,b}) \cdot ret_y \tag{5}$$

$$R_{y,i,b} = \sum_{h \in H} ((ESG^P_{y,h,i,b} + ESG^S_{y,h,i,b}) \cdot p_{y,h}) \tag{6}$$

$$K^P_{y,i,b} \cdot \omega \cdot (\frac{a_{h,b}}{\overline{a}}) = ECI^P_{y,h,i,b} + ESB^P_{y,h,i,b} + ESG^P_{y,h,i,b} \tag{7}$$

$$d_{y,h,i,b} = ECI^P_{y,h,i,b} + ECI^S_{y,h,i,b} + ECI^G_{y,h,i,b} \tag{8}$$

$$L^S_{y,h,i,b} \leq K^S_{y,i,b} \tag{9}$$

$$L^S_{y,h+1,i,b} - L^S_{y,h,i,b} = ((ESB^P_{y,h,i,b} + ESB^G_{y,h,i,b}) \cdot \eta) - ECI^S_{y,h,i,b} - ESG^S_{y,h,i,b} \tag{10}$$

$$ESB^P_{y,h,i,b} + ESB^G_{y,h,i,b} = l = K^S_{y,i,b} \cdot n \tag{11}$$

$$ECI^S_{y,h,i,b} + ESG^S_{y,h,i,b} = l = K^S_{y,i,b} \cdot n \tag{12}$$

The accumulated discounted electricity costs are minimized subject to several techno-economic con-

Table 1: Sets, parameters and variables of the household optimization model

Abbreviation	Dimension	Description
Model sets		
$h \in H$		Hour of the year, H = [1, 2, ..., 8760]
$y \in Y$		Year, Y = [2020,...,2050]
$i \in I$		Number of residents living in the household, I = [1,2,3,4,5]
$b \in B$		Region, B = [Northern Germany, Central Germany, Southern Germany]
Model parameters		
$a_{h,b}$	W/m^2	Solar irradiance on tilted PV cell
$\overline{a}$	W/m^2	Solar irradiance under standard test conditions
an^P		Annuity factor for PV investment costs
an^S		Annuity factor for storage investment costs
c^P	€$_{2011}$/kW	PV investment costs
c^S	€$_{2011}$/kWh	Battery storage investment costs
$d_{y,h,i,b}$	kWh	Household electricity demand
$disc_y$		Discount factor
fc^P	€$_{2011}$/kW	PV fixed operation and maintenance costs
fc^S	€$_{2011}$/kWh	Battery storage fixed operation and maintenance costs
n	1/h	Relation of storage capacity [kW] to storage volume [kWh]
$p_{y,h}$	€$_{2011}$/kWh	Wholesale electricity price
ret_y	€$_{2011}$/kWh	Residential electricity tariff
t^P	years	PV lifetime
t^S	years	Battery storage lifetime
η	%	Efficiency of the battery storage
u	%	Interest rate for annuity and discount factor [an^P, an^S and $disc_y$]
$z_{i,b}$		Total number of one- and two-family houses
x		Sample households with residents i in region r
ω	%	PV performance ratio
Model variables		
$AD^P_{y,i,b}$	kW	Commissioning of new PV systems
$AD^S_{y,i,b}$	kWh	Commissioning of new battery storage systems
$C^P_{y,i,b}$	€$_{2011}$	Annualized PV investment costs
$C^S_{y,i,b}$	€$_{2011}$	Annualized battery storage investment costs
$ECI^P_{y,h,i,b}$	kWh	Electricity consumed in-house supplied by the PV system
$ECI^S_{y,h,i,b}$	kWh	Electricity consumed in-house supplied by battery storage system
$ECI^G_{y,h,i,b}$	kWh	Electricity consumed in-house supplied by the grid
$ESG^P_{y,h,i,b}$	kWh	Electricity sold to the grid supplied by the PV system
$ESG^S_{y,h,i,b}$	kWh	Electricity sold to the grid supplied by battery storage system
$ESB^P_{y,h,i,b}$	kWh	Electricity stored in the battery system supplied by the PV system
$ESB^G_{y,h,i,b}$	kWh	Electricity stored in the battery system supplied by the grid
$K^P_{y,i,b}$	kW	Installed PV system capacity
$K^S_{y,i,b}$	kWh	Installed battery storage volume
$L^S_{y,h,i,b}$	kWh	Storage level
$M_{y,i,b}$	€$_{2011}$	Annual O&M cost
$P_{y,i,b}$	€$_{2011}$	Annual costs of purchasing electricity
$R_{y,i,b}$	€$_{2011}$	Annual revenue from selling electricity
$THHC$	€$_{2011}$	Total HH electricity costs
Model variables calculated ex-post		
HHC_y	€$_{2011}$	Scaled costs of PV and battery storage capacities
$HHD_{y,h}$	MW	Scaled amount of household electricity demand
$HHES_{y,h}$	MW	Scaled amount of electricity sold to the grid
$HHGD_{y,h}$	MW	Scaled amount of grid-supplied electricity consumed in-house
HHI_y	€$_{2011}$	Scaled revenue from selling surplus PV electricity
$HHSC_{y,h}$	MW	Scaled amount of self-produced electricity consumed in-house

straints.

Power generation constraint (Eq. (7)): The power output of the single household's PV system, which depends on the solar radiation on the tilted PV cells ($a_{h,b}$) and the performance ratio of the PV system (ω), can either be directly consumed in-house ($ECI^P_{y,h,i,b}$), stored in the battery storage system ($ESB^P_{y,h,i,b}$) or sold to the electricity grid ($ESG^P_{y,h,i,b}$).

Power balance constraint (Eq. (8)): The single household's electricity demand ($d_{y,h,i,b}$) needs to be met by electricity supplied by the PV system ($ECI^P_{y,h,i,b}$), the battery storage system ($ECI^S_{y,h,i,b}$) or the electricity grid ($ECI^G_{y,h,i,b}$).

Battery storage constraints (Eqs. (9), (10), (11) and (12)): The maximum storage level of the single household's battery system ($L^S_{y,h,i,b}$) is determined by the storage volume ($K^S_{y,i,b}$). Moreover, the hourly change in the storage level of the single household's battery system depends on the storage operation and the losses during the charging process. Note that the stored PV electricity may not only be used to meet the household's electricity demand ($ECI^S_{y,h,i,b}$) but also be fed into the electricity grid ($ESG^S_{y,h,i,b}$). Likewise, the battery storage system may not only be charged using electricity supplied by the PV system ($ESB^P_{y,h,i,b}$) but also using grid-supplied electricity ($ESB^G_{y,h,i,b}$).

Equations (13) - (18) quantify all variables calculated ex-post, which then serve as input parameters for the electricity system optimization model.

$$HHES_{y,h} = \sum_{i \in I} \sum_{b \in B} (ESG^P_{y,h,i,b} + ESG^S_{y,h,i,b}) \tag{13}$$

$$HHSC_{y,h} = \sum_{i \in I} \sum_{b \in B} (ECI^P_{y,h,i,b} + ECI^S_{y,h,i,b}) \tag{14}$$

$$HHGD_{y,h} = \sum_{i \in I} \sum_{b \in B} ECI^G_{y,h,i,b} \tag{15}$$

$$HHD_{y,h} = \sum_{i \in I} \sum_{b \in B} d_{y,h,i,b} = \sum_{i \in I} \sum_{b \in B} (HHGD_{y,h} + HHSC_{y,h}) \tag{16}$$

$$HHC_y = \sum_{i \in I} \sum_{b \in B} (C^P_{y,i,b} + C^S_{y,i,b} + M_{y,i,b}) \tag{17}$$

$$HHI_y = \sum_{i \in I} \sum_{b \in B} R_{y,i,b} \tag{18}$$

The total calculation time of the household optimization model amounts to 20 hours.

2.2.2. Numerical assumptions

All country- and year-specific input parameters of the household optimization model (such as the solar radiation profiles, the single household's electricity demand profiles or PV and storage system investment costs) have been defined according to German levels.

Solar radiation profiles: The household optimization model considers three hourly solar radiation profiles (8760 h) for Northern, Central and Southern Germany (based on historical solar radiation data of the year 2008 taken from EuroWind (2011)), which were converted from the horizontal to the tilted surface. The solar cells were assumed to be oriented to the south (azimuth of 180°) and tilted with an optimized angle of 37° in Southern Germany and 35.3° in Northern and Central Germany.[7] Given these rather optimal conditions, a conservative performance ratio of 70 % was chosen to capture losses due to soiling and partial shadowing of rooftop PV systems. As a result, rooftop PV systems were assumed to exhibit a yield of 868 kWh/kWp per year in Northern Germany, 923 kWh/kWp in Central Germany and 1,022 kWh/kWp in Southern Germany.[8]

Household's electricity demand profiles: The household optimization model accounts for 250 individual electricity demand profiles for 8760 h of the year, which were derived using a model developed by Richardson et al. (2010). The model creates synthetic electricity demand data for 24 h (with one-minute resolution) by simulating domestic appliance use dependent on the number of residents living in the house, the day of the week and the month of the year.[9] Deriving individual electricity demand profiles for 8760 h of the year – instead of using standard load profiles – is of major importance in order to adequately determine the cost-optimal PV and battery storage capacities from the single household's perspective. Individual electricity demand profiles account for both the high variability of the individual household's electricity demand and peak load situations. Standard load profiles for residential customers, in contrast, are based on statistical average values. Hence, taking standard load profiles as an input parameter for the household

[7] The chosen orientation and angle was derived via a PV electricity optimization model that maximizes the total annual electricity generation of the PV system depending on their location in Europe (in this case in Northern, Central or Southern Germany) developed by the authors.

[8] The impact of the orientation of the PV system on both the total annual electricity generation and the daily profile of PV electricity supply is, for example, discussed in Tröster and Schmidt (2012), Blumsack et al. (2010), Mehleri et al. (2010) and Mondol et al. (2007). Note that the electricity generation output during the morning and evening can be increased by splitting the orientation of the PV panel arrays for an east-west orientation rather than a fixed southern orientation, as explained by Blumsack et al. (2010). This may be advantageous for residential electricity consumers if the electricity generation profile of the east-west orientated PV system matches more closely to the customer's demand profile. Such an orientation, however, assumes that the customer's goal is to maximize the in-house consumption of PV electricity generation. In contrast, if electricity consumers were to maximize revenues from net metering, they would need to consider the correlation between the PV systems electricity generation profile and the wholesale electricity price when deciding on the optimal orientation of the PV system (Blumsack et al. (2010)).

[9] The basic version of the domestic electricity demand model is distributed under https://dspace.lboro.ac.uk/2134/5786 and documented in Richardson et al. (2010).

optimization problem would not adequately represent the variability of individual household's demand and thus distort the results.

The domestic electricity demand model is configured to simulate the use of domestic appliances in Germany based on data from DESTATIS (2012a), DESTATIS (2012b), DESTATIS (2012c) and Statista (2012) for 8760 h of the year. The assumed proportions of households equipped with domestic appliances are shown in Table A.16 of the Appendix.

The model is used to simulate 250 electricity demand profiles, differing with regard to the number of residents living in the household (1-5 residents) and the household's configuration of domestic appliances, which are randomly assigned in the domestic electricity demand model (according to the assumptions shown in Table A.16 of the Appendix).[10] The average annual electricity demand of these consumption profiles is presented in Table 2.

Table 2: Average annual household electricity demand [kWh]

	min	max	average
1 Resident	1,840	5,649	2,888
2 Residents	2,086	6,556	3,871
3 Residents	2,539	9,217	4,200
4 Residents	3,057	8,698	4,519
5 Residents	3,339	10,379	4,833

By combining the 250 electricity demand profiles with the three different solar radiation profiles, we obtain 750 individual housholds each differing with regard to the number of residents living in the house (1-5 residents), the equipment (domestic appliances) and the location of the house. In the model, the 750 sample households are scaled-up by the actual number of one- and two-family houses in Germany, $z_{i,b}$ (see Table 3), in order to analyze the potential consequences of the indirect financial incentive for in-house PV electricity consumption for the case in which a large share of residential electricity consumers invests in combined PV and storage systems. In specific, only 90 % of the one- and two-family houses are used in scaling the results of the household optimization model, accounting for the fact that part of the rooftop PV potential of one- and two-family houses will already be used to achieve Germany's NREAP target for PV (52 GW).[11]

[10] Specifically, 50 electricity demand profiles were generated for each of the five household types (with 1-5 residents), each of which differing with regard to the configuration of domestic appliances.

[11] By scaling up the results of the household optimization model by the number of one- and two-family-houses located in Germany, market imperfections such as informational asymmetry, transaction costs or uncertainty are neglected. In particular, the scaling-up procedure abstracts from the so-called 'landlord-tenant' problem (Jaffe and Stavins (1994)), which describes the barriers for landlords in ensuring appropriate investment returns by including investment costs in the rent. The chosen scaling

Note that scaled-up annual household electricity demand covered by the household optimization model amounts to 56 TWh. This corresponds to 9 % of the gross electricity demand assumed in the electricity system optimization model for Germany in 2020 (612 TWh).

Table 3: Number of one- and two-family houses located in Germany (90 %) based on data by DESTATIS (2008) and DESTATIS (2010)

	Northern Germany	Central Germany	Southern Germany
1 Resident	835,086	1,817,500	1,176,311
2 Residents	1,261,675	2,462,942	1,562,837
3 Residents	528,596	1,016,977	643,481
4 Residents	491,342	942,537	596,034
5 Residents	171,152	326,388	206,157

Wholesale electricity prices and residential electricity tariff: The wholesale electricity price and the residential electricity tariff are taken from the electricity system optimization model (described in Section 2.3), which determines both input parameters based on optimal investment and dispatch decisions on the system level.

Other input parameters: All other input parameters of the household optimization model are listed in Table 4. In particular, PV system investment costs (c^P) are assumed to amount to 1,200 €$_{20112011}$/kWp in 2020 (based on Agora Energiewende (2013) and Prognos AG (2013)). Moreover, stationary battery storage units are assumed to have investment costs (c^S) of 400 €$_{20112011}$/kWh and a technical lifetime (ts) of 15 years, which reflects expectations for lithium-ion batteries (see, e.g., Bost et al. (2011)).

2.3. Electricity system optimization model

The electricity system optimization model used in this analysis is a deterministic dynamic linear investment and dispatch model for Europe, incorporating conventional thermal, nuclear, storage and renewable technologies. The model is an extended version of the long-term investment and dispatch model of the Institute of Energy Economics (University of Cologne) as presented in Richter (2011). The possibility of endogenous investments in renewable energy technologies has been added to the investment and dispatch model, as described in Fürsch et al. (2013), Jägemann et al. (2013) and Nagl et al. (2011).

In the following, an overview of the applied electricity system optimization model is given. The model has been adapted to accurately incorporate the feedback effects of the single households optimization behavior

procedure serves the purpose of deriving the maximum potential of PV and battery storage systems that may be optimally deployed on top of one- and two-family-houses in Germany. Because the scaling-procedure includes all one- and two-family houses, the results should be interpreted as upper bound estimates and not as most likely estimates.

Table 4: Input parameters of the household optimization model for 2020

Input parameter	Unit	
c^P	€$_{20112011}$/kWp	1,200
c^S	€$_{20112011}$/kWh	400
m^P	€$_{20112011}$/kWp p.a.	11
m^S	€$_{20112011}$/kWh p.a.	6
n	1/h	0.6
t^P	years	30
t^S	years	15
η	%	95
u	%	5
x		50
ω	%	70
$\overline{a}$	W/m^2	1,000
ω	%	70

on the residual electricity system and to quantify the redistributional effects associated with the indirect financial incentive for in-house PV electricity generation.

2.3.1. Technological resolution

The model incorporates investment and generation decisions for all types of technologies: conventional (potentially equipped with carbon capture and storage (CCS)), combined heat and power (CHP), nuclear, renewable energy and storage (pump, hydro and compressed air energy (CAES)). In contrast to investments in generation and storage capacities, the extension of interconnector capacities, which limit the inter-regional power exchange, is exogenously defined. Today's power plant mix is represented by several vintage classes for hard coal, lignite and natural gas-fired power plants. With regard to renewable energy technologies, the model encompasses onshore and offshore wind turbines, roof and ground based PV systems, biomass (CHP-) power plants (solid and gas), hydro power plants, geothermal power plants and concentrating solar power (CSP) plants (including thermal energy storage devices).

2.3.2. Regional resolution

The model is configured to cover all countries of the European Union, except for Cyprus, Malta and Croatia, and includes Norway and Switzerland. To account for local weather conditions, the model considers 47 onshore wind, 42 offshore wind and 38 PV subregions, each differing with regard to both the level and the structure of the wind and solar power generation (based on historical hourly meteorological wind speed and solar radiation data from EuroWind (2011)). Given the focus of the analysis, the simulation was run for Germany and seven neighboring European market regions that were considered most relevant for dispatch and investment decisions in Germany (Figure 3).

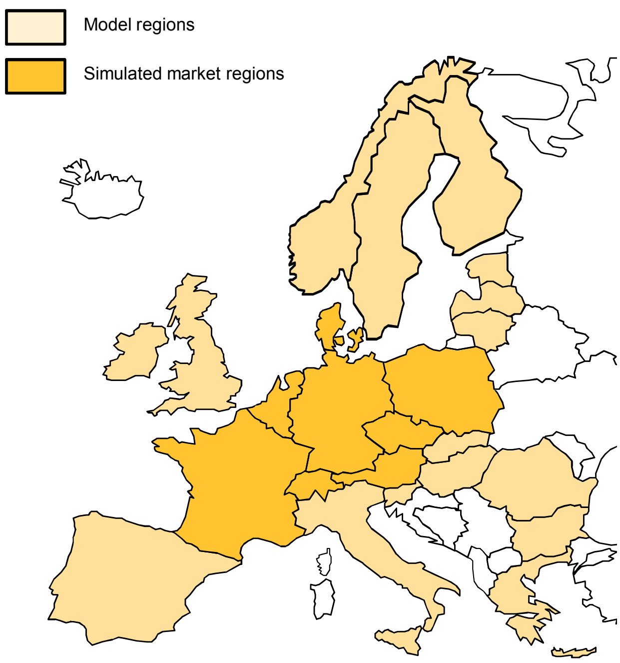

Figure 3: Simulated market regions

2.3.3. *Temporal resolution*

For our analysis, the simulation is carried out as a two-stage process: In the first step, investments in generation and storage capacities are simulated in 5-year time steps until 2050 by the investment and dispatch model. For reasons of computational efforts, the dispatch of generation and storage capacities is calculated in this step for eight typical days per year, which are then scaled to 8760 h in the model. Each typical day defines the electricity demand per country for 24 hours (h) of the day. Moreover, each typical day determines the hourly water inflow of hydro storages and the hourly electricity feed-in of wind and solar power plants per subregion (in $MW/MW_{installed}$). For each of the years simulated, the model determines both investments in new capacities and decommissionings of existing capacities. Moreover, the dispatch of power plants and storage technologies is simulated for each typical day and scaled to 8760 h of the year. In the second step, the capacity mix is fixed for each year and a (high resolution) dispatch is simulated. Instead of typical days, the dispatch is simulated on the basis of hourly load profiles (based on historical hourly load data by ENSTO-E (2012)) as well as the hourly electricity generation profiles of hydro, wind (on- and offshore) and solar power (PV and CSP) technologies for 8760 h per year (based on historical hourly wind and solar radiation data by EuroWind (2011)).

2.3.4. Model equations

An overview of all model sets, parameters and variables is given in Table 5.

The objective of the model (Eq. 19) is to minimize accumulated discounted total system costs which include investment costs, fixed O&M costs, variable generation costs and costs due to ramping thermal power plants.

Investment costs arise from new investments in generation and storage units ($\mathrm{AD}_{y,a,c}$) and are annualized with a 5 % interest rate for the depreciation time.[12] The fixed operation and maintenance costs (fc_a) represent staff costs, insurance charges, rates and maintenance costs.[13] Variable costs are determined by fuel prices ($\mathrm{fu}_{y,a}$), the net efficiency (η_a) and the total generation of each technology ($\mathrm{GE}_{y,h,a,c}$). Depending on the ramping profile, additional costs for attrition occur (ac_a). Combined heat and power (CHP) plants can generate revenue from the heat market, thus reducing the objective value. More specifically, the generated heat in CHP plants ($\mathrm{GE}_{y,h,a,c} \cdot \mathrm{hr}_a$) is remunerated by the assumed gas price divided by the conversion efficiency of the assumed reference heat boiler (hp_y), which roughly represents the opportunity costs for households and industries. However, only a limited amount of generation in CHP plants is compensated by the heating market.[14]

Accumulated discounted total system costs are minimized, subject to several techno-economic constraints:

Power balance constraint (Eq. (20)**):** The match of electricity demand and supply needs to be ensured in each hour and country, taking storage options and inter-regional power exchange into account. In specific, the sum of a country's electricity generation ($GE_{y,h,c,a}$), net imports ($IM_{y,h,c,c'}$) and electricity lost in storage operation ($ST_{y,h,s,c}$) needs to equal demand ($d_{y,h,c}$).

Capacity constraint (Eq. (21)**):** The maximum electricity generation by dispatchable power plants (thermal, nuclear, storage, biomass and geothermal power plants) per hour ($GE_{y,h,a,c}$) is restricted by their seasonal availability ($\mathrm{av}_{d,h,a,c}$), which is limited due to unplanned or planned shutdowns (e.g., because of repairs).[15] Unlike dispatchable power plants, the availability of wind and solar power plants is given by the maximum possible electricity feed-in per hour. The maximum transmission capability per hour between two neighboring countries is given by the net transfer capacities.

[12] Note that the interest rate level significantly influences capital cost. However, the impact of the actual interest rate level (i.e., 3, 5 or 7 %) on the optimal investment mix is only minor.

[13] For CCS power plants, fixed operation and maintenance costs include fixed costs for CO_2 storage and transportation.

[14] We account for a maximum potential for heat in co-generation within each country, which is depicted in Table A.20 of the Appendix.

[15] The availability of dispatchable power plants is the same for each country, year and hour, but differs for each season. The infeed of storage technologies is additionally restricted by the storage capacity in use at a particular hour.

Table 5: Sets, parameters and variables of the electricity system optimization model

Abbreviation	Dimension	Description
Model sets		
a ∈ A		Technologies
s ∈ A	Subset of a	Storage technologies
r ∈ A	Subset of a	RES-E technologies
c ∈ C (alias c')		Market region
h ∈ H		Hours
y ∈ Y		Years
Model parameters		
ac_a	€$_{2011}$ /MWh_{el}	Attrition costs for ramp-up operation
an_a		Annuity factor for technology specific investment costs
$\mathrm{av}_{h,a,c}$	%	Availability
$\mathrm{d}_{y,h,c}$	MW	Total demand
disc_y		Discount factor (5 % discount rate)
cc_y	t CO_2	Cap for CO_2 emissions
ef_a	t CO_2 /MWh_{th}	CO_2 emissions per fuel consumption
fc_a	€$_{2011}$/MW	Fixed operation and maintenance costs
$\mathrm{fu}_{y,a}$	€$_{2011}$/MWh_{th}	Fuel price
$\mathrm{fp}_{y,a,c}$	MWh_{th}	Fuel potential
hp_y	€$_{2011}$/MWh_{th}	Heating price for end-consumers
hr_a	MWh_{th}/MWh_{el}	Ratio for heat extraction
ml_a	%	Minimum part load level
$\mathrm{nr}_{y,r,c}$	MW	National technology-specific RES-E targets
$\mathrm{pd}_{y,h,c}$	MW	Peak demand (increased by a security factor of 10 %)
$\mathrm{sp}_{r,c}$	km^2	Space potential
sr_r	$\mathrm{MW/km}^2$	Space requirement
st_a	hours	Start-up time from cold start
η_a	%	Net efficiency (generation)
$cr_{y,h,a,c}$	%	Securely available capacity
$\alpha_{a,h}$	%	Capacity factor
ϵ	%	Share of privileged end consumer
$RESpc$	€$_{2011}$/kWh	Renewable energy surcharge for privileged end consumers
Model variables		
$\mathrm{AD}_{y,a,c}$	MW	Commissioning of new power plants
$\mathrm{CU}_{y,h,a,c}$	MW	Capacity that is ramped up within one hour
$\mathrm{CR}_{y,h,a,c}$	MW	Capacity that is ready to operate
$\mathrm{GE}_{y,h,a,c}$	MW_{el}	Electricity generation
$\mathrm{O}_{s,y,h,i}$	MW	Consumption in storage operation
$\mathrm{IM}_{y,h,c,c'}$	MW	Net imports
$\mathrm{IN}_{y,a,c}$	MW	Installed capacity
$\mathrm{ST}_{y,h,s,c}$	MW	Consumption in storage operation
TSC	€$_{2011}$	Total system costs
Model variables calculated ex-post		
$CI_{y,h}$	€$_{2011}$	Revenues from the reserve market
REC_y	€$_{2011}$	Renewable energy compensation
RES_y	€$_{2011}$/kWh	Renewable energy surcharge
CP_y	€$_{2011}$/kWh	Back-up capacity payment
$dCONSR_y$	€$_{2011}$	Difference in consumer rents
$dPROSR_y$	€$_{2011}$	Difference in rents of 'HH producers and in-house consumers'
$d\pi_y$	€$_{2011}$	Difference in producer profits
dW_y	€$_{2011}$	Difference in sectoral welfare (excess costs)
Shadow variables		
$\mu_{y,h}$	€$_{2011}$/MW	Wholesale electricity price (shadow variable of the power balance constraint)
$\kappa_{y,h}$	€$_{2011}$/MW	Capacity price (shadow variable of the security of supply constraint)

$$\min \ TSC = \sum_{y \in Y} \sum_{c \in C} \sum_{a \in A} (disc_y \cdot (AD_{y,a,c} \cdot an_a + IN_{y,a,c} \cdot fc_a \tag{19}$$

$$+ \sum_{h \in H} (GE_{y,h,a,c} \cdot (\frac{fu_{y,a}}{\eta_a}) + CU_{y,h,a,c} \cdot (\frac{fu_{y,a}}{\eta_a} + ac_a) - GE_{y,h,a,c} \cdot hr_a \cdot hp_y)))$$

s.t.

$$\sum_{a \in A} GE_{y,h,a,c} + \sum_{c' \in C} IM_{y,h,c,c'} - \sum_{s \in A} ST_{y,h,s,c} = d_{y,h,c} \tag{20}$$

$$GE_{y,h,a,c} \leq av_{d,h,a,c} \cdot IN_{y,a,c} \tag{21}$$

$$GE_{y,h,a,c} \geq ml_a \cdot av_{h,a,c} \cdot IN_{y,a,c} \tag{22}$$

$$CU_{y,h,a,b} \leq \frac{IN_{y,a,c} - CR_{y,h,a,c}}{st_a} \tag{23}$$

$$CR_{y,h,a,c} \leq av_{h,a,c} \cdot IN_{y,a,c} \tag{24}$$

$$\sum_{a \in A} (cr_{y,h,a,c} \cdot IN_{y,a,c}) \geq pd_{y,h,c} \tag{25}$$

$$\sum_{r \in A} sr_r \cdot IN_{y,r,c} \leq sp_{r,c} \tag{26}$$

$$\sum_{h \in H} \frac{GE_{y,h,a,c}}{\eta_a} \leq fp_{y,a,c} \tag{27}$$

$$\sum_{a \in A} (\sum_{c \in C} \sum_{h \in H} \frac{GE_{y,h,a,c}}{\eta_a} \cdot ef_a) \leq cc_y \tag{28}$$

$$IN_{y,r,c} \geq nr_{y,r,c} \tag{29}$$

Minimum load constraint (Eq. (22)**):** The minimum electricity generation per hour ($GE_{y,h,a,c}$) of dispatchable power plants (thermal, nuclear, storage, biomass and geothermal power plants) is given by their minimum part-load level (ml_a).

Ramp-up constraints (Eqs. (23) **and** (24)**):** The start-up time (st_a) of dispatchable power plants limits the maximum amount of capacity ramped up within an hour.

Security of supply constraint (Eq. (25)): Equation 25 captures system reliability requirements by ensuring that the historically observed peak demand level of each country is met by securely available capacities. Due to the simplification of the annual dispatch to eight typical days, potential peak demand is not considered as a dispatch situation in the investment part of the model. To nevertheless ensure security of supply at all times, i.e., also during times of low solar radiation and low wind infeed, the peak-capacity constraint is implemented in the model. Whereas the securely available capacity ($cr_{y,h,a,c}$) of dispatchable power plants within the peak-demand hour is assumed to correspond to the seasonal availability, the securely available capacity of onshore (offshore) wind power plants within the peak-demand hour (capacity credit) is assumed to amount to 5 % (10 %). Hence, 5 % (10 %) of the total installed onshore (offshore) wind power capacities within a region are assumed be securely available within the peak demand hour. In contrast, PV systems are assumed to have a capacity credit of 0 % due to the assumption that peak demand occurs during evening hours in the winter.[16] The modeled capacity market simply ensures that sufficient investments in back-up capacities are made to meet potential peak demand situations.[17]

Space potential constraint (Eq. (26)**):** The deployment of wind and solar power technologies is restricted by area potentials in km^2 per subregion ($sp_{r,c}$).

Fuel potential constraint (Eq. (27)**):** The fuel use is restricted to a yearly potential in MWh$_{th}$ per country($fp_{y,a,c}$), with different potentials applying for lignite, solid biomass and gaseous biomass sources.

In addition to techno-economic constraints, politically implemented restrictions are also modeled:

CO_2 emission constraint (Eq. ((28)**):** Equation (28) states that the accumulated CO_2 emissions of all modeled market regions may not exceed a certain CO_2 cap per year (cc_y). The approach of modeling a quantity-based regulation (CO_2 cap) rather than a price-based regulation (CO_2 price) ensures that the CO_2 emissions reduction target within Europe's power sector is met in all scenarios simulated – which allows the results to be compared to one another.

Renewable capacity constraint (Eq. (29)): Equation (29) formalizes the politically implemented restriction that each country must achieve the technology-specific RES-E targets ($nr_{y,r,c}$), as prescribed by the EU member states' National Renewable Energy Action Plans (NREAP's) for 2020.

The total calculation time of the electricity system optimization model amounts to two hours.

The most important assumptions of the electricity system optimization model (such as the gross electricity demand, investment costs and techno-economic parameters of conventional, storage and renewable technologies as well as fuel prices) are listed in Tables A.17 - A.25 of the Appendix.

3. Scenario definitions and quantification of redistributional effects

To capture the impact of the single household's optimization behavior on the residual electricity system, we iterate the household optimization model in conjunction with the electricity system optimization model

[16]This assumption is based on a detailed analysis of historical electrical load data (based on ENSTO-E (2012) and historical solar radiation data based on EuroWind (2011)) for all EU member states for the years 2007-2010 (Ackermann et al. (2013)).
[17]However, such investments could also be triggered in an energy-only market in the event of price peaks.

until convergence of results is achieved. The results of the last iteration step represent the 'Grid Parity Scenario'. A more detailed description of the iterative approach and the convergent behavior of the interrelated variables can be found of the Appendix A.3.

Moreover, to quantify the overall economic consequences of the single household's optimization behavior (such as redistributional effects and excess costs), we compare the results of the 'Grid Parity Scenario' with the results of a 'Reference Scenario', which assumes that the indirect financial incentive for in-house PV electricity consumption is abolished (Table 6). More specifically, households are assumed to meet their electricity demand with grid-supplied electricity in the 'Reference Scenario'. However, the NREAP targets for 2020 are achieved in both scenarios.

Table 6: Scenario definitions

	Grid Parity Scenario (GP)	Reference Scenario (REF)
Household optimization	Yes	No
Iterative approach	Yes	No
Achievement of 2020 NREAP targets	Yes	Yes
Achievement of CO_2 reduction targets	Yes	Yes

Redistributional effects of the household's optimization behavior are quantified for three different actors: (i) (pure) electricity producers, (ii) (pure) electricity consumers and (iii) household electricity consumers who meet part of their electricity demand with self-produced PV electricity generation in the 'Grid Parity Scenario', referred to as 'HH producers and in-house consumers' in the following. Note that in the 'Reference Scenario', the (former) 'HH producers and in-house consumers' become pure consumers, i.e., they no longer own a combined PV and battery storage system and meet their total electricity demand with grid-supplied electricity. Since we apply a linear electricity system optimization model with a price-inelastic electricity demand function, no absolute values for the consumer rent can be quantified. Instead, we focus on the change of the consumer rent as a consequence of the single household's optimization behavior, i.e., the difference in the consumer rent between the 'Grid Parity Scenario' and the 'Reference Scenario'. Welfare losses or excess costs due to the single household's optimization behavior are given by the accumulated change in the consumer rent, the rent of 'HH producers and in-house consumers' and the producer profit.

In the following, all parameters are discussed which are used to quantify redistributional effects.

Wholesale electricity prices: The shadow variable of the power balance (Equation (20)) serves as a proxy for the hourly wholesale electricity price in Germany ($\mu_{y,h}^{GP}$,$\mu_{y,h}^{REF}$).

Producer compensation for providing back-up capacity: The shadow variable of the security of supply constraint ($\kappa_{y,h}$) serves as a proxy for the capacity price which producers receive for their efforts in ensuring security of supply. More specifically, they are assumed to be compensated for providing back-up capacities. Equations (30) and (31) define the revenue which producers receive from the reserve market by offering securely available capacity ($CI^{GP}_{y,h}$, $CI^{REF}_{y,h}$).

$$CI^{GP}_{y,h} = \sum_{a \in A} (\alpha_{a,h} \cdot IN^{GP}_{y,a} \cdot \kappa^{GP}_{y,h}) \tag{30}$$

$$CI^{REF}_{y,h} = \sum_{a \in A} (\alpha_{a,h} \cdot IN^{REF}_{y,a} \cdot \kappa^{REF}_{y,h}) \tag{31}$$

Back-up capacity payment: The costs for providing back-up capacities are assumed to be apportioned to electricity consumers and 'HH producers and in-house consumers'. Specifically, for each kWh electricity purchased from the grid, a capacity payment (CP_y) is incurred.

$$CP^{GP}_{y} = \frac{\sum_{h \in H} CI^{GP}_{y,h}}{\sum_{h \in H} (d_{y,h} - HHSC_{y,h})} \tag{32}$$

$$CP^{REF}_{y} = \frac{\sum_{h \in H} CI^{REF}_{y,h}}{\sum_{h \in H} d_{y,h}} \tag{33}$$

Producer compensation for providing renewable energy capacities: As prescribed by Equation 29, Germany is expected to achieve national, technology-specific renewable energy targets by 2020 (NREAP targets). To reflect the current renewable energy promotion system in Germany (feed-in tariff), we assume that renewable energy producers receive the additional costs, i.e., the difference between annual costs and revenue from selling renewable energy electricity on the wholesale market (REC^{GP}_{y}, REC^{REF}_{y}).[18] This compensation is assumed to be granted over a period of 20 years for renewable capacities built up to the year 2020.[19]

[18]The annual costs include annualized investment costs, fixed O&M costs and variable generation costs (for biomass technologies).

[19]The quantification of the producer compensation for providing renewable energy capacities and of the renewable energy surcharge builds on the data of EWI (2012).

$$REC_y^{GP} = \sum_{r \in R}(AD_{y,r}^{GP} \cdot an_{y,r}^{GP} + IN_{y,r} \cdot fc_r) + \sum_{h \in H}\sum_{r \in R}(GE_{y,h,r}^{GP} \cdot (\frac{fu_{y,r}}{\eta_r}) - \mu_{y,h}^{GP}) \quad (34)$$

$$REC_y^{REF} = \sum_{r \in R}(AD_{y,r}^{REF} \cdot an_{y,r}^{REF} + IN_{y,r} \cdot fc_r) + \sum_{h \in H}\sum_{r \in R}(GE_{y,h,r}^{REF} \cdot (\frac{fu_{y,r}}{\eta_r}) - \mu_{y,h}^{REF}) \quad (35)$$

Renewable energy surcharge: The difference between the producers' annual costs and their revenue from selling renewable energy electricity on the wholesale market is assumed to be apportioned to electricity consumers via the renewable energy surcharge (RES_y), which (non-privileged) electricity consumers pay for each kWh purchased from the grid (Eqs. 36 and 37). [20]

$$RES_y^{GP} = \frac{REC_y^{GP} - \epsilon \cdot \sum_{h \in H} d_{y,h} \cdot RESpc}{(1-\epsilon) \cdot \sum_{h \in H} d_{y,h} - \sum_{h \in H} HHSC_{y,h}} \quad (36)$$

$$RES_y^{REF} = \frac{REC_y^{REF} - \epsilon \cdot \sum_{h \in H} d_{y,h} \cdot RESpc}{(1-\epsilon) \cdot \sum_{h \in H} d_{y,h}} \quad (37)$$

Residential electricity tariff: The residential electricity tariff is comprised of endogenous and exogneous components. The base price (i.e., the average wholesale electricity price), which serves as a proxy for the average costs of electricity procurement, the renewable energy surcharge and the back-up capacity payment are the endogenous components, which are outputs of the electricity system optimization model.[21] The assumptions regarding exogenous components are listed in Table 7.

After having defined the parameters, the quantification of the redistributional effects is explained in the following.

Change in producer profit: The difference in producer profits ($d\pi_y$) between the 'Grid Parity Scenario' and the 'Reference Scenario' is defined by Equation (38). Producers are assumed to earn revenue for providing electricity, heat and securely available generation capacities. Moreover, producers receive a

[20] This reflects the current situation in Germany, where the additional costs for promoting renewable energy investments via a fixed feed-in tariff scheme are apportioned to (non-privileged) electricity cosumers via the renewable energy surcharge. Note that the fixed feed-in tariff, which is granted over 20 years, corresponds approximately to the technology-specific electricity generation costs of renewables. Moreover, the share of priviliged electricity consumers (ϵ = 15 %) pays a lower renewable energy surcharge ($RESpc$).

[21] Note that in reality, the average costs of electricity procurement do not exactly correspond to the base price. This is due to the fact that electricity supplied by conventional and renewable capacities is not only marketed via the wholesale electricity market but also via mid- and long-term contracts. Furthermore, unlike in the electricity system optimization model, market participants do not have perfect foresight in reality.

Table 7: Composition of the residential electricity tariff (ret_y) based on 50Hertz, Amprion, Tennet and Transnet BW (2012b), 50Hertz, Amprion, Tennet and Transnet BW (2012a), BNetzA (2012) and BDEW (2013) [in €ct/kWh]

Base price Renewable energy surcharge Back-up capacity payment Value-added tax of 19 % [€ct/kWh]	Endogenous					
		2020	2025	2030	2040	2050
Concession levy	Exogenous	1.79				
Offshore liability surcharge	Exogenous	0.25		-		
Distribution (margin included)	Exogenous	2.11				
Electricity tax	Exogenous	2.05				
CHP surcharge	Exogenous	0.31				
§19 surcharge	Exogenous	0.33				
Network tariff	Exogenous	7.18	8.12	9.19		

renewable energy compensation payment. Producer profits are determined by deducting the annualized investment costs, fixed O&M costs, variable generation costs, additional variable costs for ramping operations and costs for pumping electricity into storage units from the sum of producer revenues.

$$\begin{aligned}
d\pi_y = {} & \sum_{a\in A}\sum_{h\in H}(\mu^{GP}_{y,h}\cdot GE^{GP}_{y,h,a,c}) + \sum_{a\in A}\sum_{h\in H}(GE^{GP}_{y,h,a}\cdot hr_a\cdot hp_y) + CI^{GP}_{y,h} + REC^{GP}_y \\
& - \sum_{a\in A}(AD^{GP}_{y,a}\cdot an^{GP}_a) - \sum_{a\in A}(IN^{GP}_{y,a}\cdot fc^{GP}_a) - \sum_{a\in A}\sum_{h\in H}(GE^{GP}_{y,h,a}\cdot(\frac{fu_{y,a}}{\eta_a}) \\
& - \sum_{a\in A}\sum_{h\in H}(CU^{GP}_{y,h,a}\cdot(\frac{fu_{y,a}}{\eta_a}+ac_a)) - \sum_{s\in S}\sum_{h\in H}(O^{GP}_{s,y,h}\cdot\mu^{GP}_{y,h}) \\
& - \Big[\sum_{a\in A}\sum_{h\in H}(\mu^{REF}_{y,h}\cdot GE^{REF}_{y,h,a,c}) + \sum_{a\in A}\sum_{h\in H}(GE^{REF}_{y,h,a}\cdot hr_a\cdot hp_y) + CI^{REF}_{y,h} + REC^{REF}_y \\
& - \sum_{a\in A}(AD^{REF}_{y,a}\cdot an^{REF}_a) - \sum_{a\in A}(IN^{REF}_{y,a}\cdot fc^{REF}_a) - \sum_{a\in A}\sum_{h\in H}(GE^{REF}_{y,h,a}\cdot(\frac{fu_{y,a}}{\eta_a})) \\
& - \sum_{a\in A}\sum_{h\in H}(CU^{REF}_{y,h,a}\cdot(\frac{fu_{y,a}}{\eta_a}+ac_a)) - \sum_{s\in S}\sum_{h\in H}(O^{REF}_{s,y,h}\cdot\mu^{REF}_{y,h})\Big]
\end{aligned} \tag{38}$$

Change in consumer rent: The difference in the consumer rent ($dCONSR_y$) between the 'Grid Parity Scenario' and the 'Reference Scenario' is defined by Equation (39) as the difference in the consumers' expenditures for meeting their electricity demand. Since the costs for ensuring security of supply and for promoting renewables are apportioned to electricity consumers via energy-related payments, consumers' expenditures do not only include the costs for buying electricity on the wholesale market but also the costs for being provided with both securely available and renewable capacities.

$$\begin{aligned} dCONSR_y = (-1) \cdot \Bigg[& \sum_{h \in H} (\mu_{y,h}^{GP} \cdot (d_{y,h} - HHD_{y,h})) + \sum_{h \in H} (d_{y,h} - HHD_{y,h}) \cdot CP_y^{GP} \\ & + \epsilon \cdot \sum_{h \in H} d_{y,h} \cdot RESpc \\ & + ((1-\epsilon) \cdot \sum_{h \in H} d_{y,h} - \sum_{h \in H} HHD_{y,h}) \cdot RES_y^{GP} \\ & - \Bigg[\sum_{h \in H} (\mu_{y,h}^{REF} \cdot d_{y,h}) + \sum_{h \in H} d_{y,h} \cdot CP_y^{REF} + \epsilon \cdot \sum_{h \in H} d_{y,h} \cdot RESpc \\ & + (1-\epsilon) \cdot \sum_{h \in H} d_{y,h} \cdot RES_y^{REF} \Bigg] \Bigg] \end{aligned} \tag{39}$$

Change in the rent of 'HH producers and in-house consumers': Equation (40) defines the difference in the rent of 'HH producers and in-house consumers' ($dPROSR_y$) between the 'Grid Parity Scenario' and the 'Reference Scenario' as the difference in expenditures that households need to make in order to meet their electricity demand. As opposed to the 'Reference Scenario' in which households meet 100 % of their electricity demand ($HHD_{y,h}$) with grid-supplied electricity, households meet part of their electricity demand with self-produced PV electricity in the 'Grid Parity Scenario'. Note that in the 'Grid Parity Scenario' households pay investment and fixed O&M costs for their PV and battery storage capacities, but also earn revenue from selling surplus PV electricity generation.

$$\begin{aligned} dPROSR_y = (-1) \cdot \Bigg[& \sum_{h \in H} (\mu_{y,h}^{GP} \cdot HHGD_{y,h}^{GP}) + \sum_{h \in H} HHGD_{y,h} \cdot (CP_y^{GP} + RES_y^{GP}) \\ & + HHC_y^{GP} - HHI_y^{GP} \\ & - \Bigg[\sum_{h \in H} (\mu_{y,h}^{REF} \cdot HHD_{y,h}) + \sum_{h \in H} HHD_{y,h} \cdot (CP_y^{REF} + RES_y^{REF}) \Bigg] \Bigg] \end{aligned} \tag{40}$$

Welfare loss: The welfare loss or excess costs associated with the single household's optimization behavior are defined by Equation (41) as the accumulated change in the consumer rent, the rent of 'HH producers and in-house consumers' and the producer profit between the 'Grid Parity Scenario' and the 'Reference Scenario'.

$$dW_y = d\pi_y + dCONSR_y + dPROSR_y \tag{41}$$

4. Scenario results

The changes in the optimal capacities of PV and storage systems which take place during the iterative process are shown in Figure A.11 of the Appendix A.4. Convergence of results is achieved after nine iteration steps.[22] In the following sections, the results of the household and the electricity system optimization models of the last iteration step are analyzed, which are referred to as the results of the 'Grid Parity Scenario'. These results are then compared to the results of the 'Reference Scenario', which assumes that the indirect financial incentive for in-house PV electricity consumption is abolished and thus total system costs are minimized.

4.1. Household level

4.1.1. Cost-optimal PV and battery storage capacities

The average cost-optimal PV and battery storage capacities (as shown in Table 8) increase with the number of residents living in the household and the annual full load hours of the PV system, i.e., the further south the house is located, the larger the average cost-optimal PV and battery storage capacities become. Specifically, cost-optimal PV capacities built in 2020 vary between 1.7 kWp and 3.6 kWp, and cost-optimal battery storage capacities between 2.1 kWh and 5.3 kWh.[23]

Due to their lower technical lifetime of 15 years, battery storage capacities need to be replaced in 2036. The fact that the optimal average battery storage capacities are lower in 2036 than in 2020 illustrates the diminished economic value of battery storage capacities from the single household's perspective over time.[24]

4.1.2. PV electricity in-house consumption and grid feed-in

Table 9 shows the average share of the single household's annual PV electricity generation that is consumed in-house and the average share of the single household's annual electricity demand that is covered by self-produced PV electricity in 2020.[25]

[22] To demonstrate the robustness of results the iteration is repeated for alternative starting values, as shown in Figures A.12 and A.13 of the Appendix A.5.

[23] As explained in Section 2, for each of the five household types (with 1-5 residents), 50 different electricity demand profiles were generated and taken as input parameters for the household optimization model. The results of each household type (with 1-5 residents) present the average values over 50 samples.

[24] The battery storage investment costs in 2036 are assumed to be the same as in 2020, i.e., 400 €$_{2011}$/kWh.

[25] The average shares achieved in the years 2025-2050 differ only marginally from the shares in 2020.

Table 8: Average cost-optimal PV and battery storage capacities in the 'Grid Parity Scenario'

	Northern Germany	Central Germany	Southern Germany
	Average cost-optimal PV capacities [kWp]		
1 resident	1.7	1.9	2.1
2 residents	2.3	2.6	2.9
3 residents	2.5	2.8	3.2
4 residents	2.8	3.1	3.4
5 residents	3.0	3.3	3.6
	Average cost-optimal storage capacities [kWh] (replaced in 2036)		
1 resident	2.1 (1.8)	2.6 (2.3)	3.0 (2.8)
2 residents	3.0 (2.5)	3.6 (3.2)	4.1 (3.9)
3 residents	3.4 (2.9)	4.1 (3.7)	4.6 (4.4)
4 residents	3.7 (3.2)	4.4 (4.0)	5.0 (4.7)
5 residents	3.9 (3.4)	4.7 (4.2)	5.3 (5.0)

Table 9: Average PV in-house consumption and self-supply shares in the 'Grid Parity Scenario' (2020)

	Northern Germany	Central Germany	Southern Germany
	Average share of annual PV electricity consumed in-house		
1 resident	75%	75%	73%
2 residents	75%	75%	72%
3 residents	76%	75%	73%
4 residents	76%	76%	73%
5 residents	76%	76%	74%
	Average share of annual household electricity demand supplied by PV electricity		
1 resident	38%	46%	54%
2 residents	39%	46%	56%
3 residents	40%	48%	57%
4 residents	40%	48%	57%
5 residents	41%	48%	57%

Due to the optimal dimensioning of the single household's PV and storage system capacities, the average shares of the single household's annual PV electricity generation that is consumed in-house lie within a high and relatively narrow range between 72 % and 76 % for all configurations. Hence, only 20 - 24 % of the (average) annual PV electricity generation by households is fed into the grid.[26]

Moreover, given the cost-optimal dimensions of the PV and battery storage capacities, households cover on average between 38 % and 57 % of their annual electricity demand by self-produced PV electricity that was either directly consumed (at the moment of production) or supplied by the battery storage system at a later point in time. Hence, the annual amount of electricity purchased by the single household from the grid decreases on average by 38 - 57 %. However, over the course of the year, the average share of the household's electricity demand that is met using self-produced PV electricity significantly varies. As shown in Table 10, households cover 76 - 85 % of their electricity demand in June, but only 6 - 22 % in December due to the lower PV electricity generation and higher household electricity demand in the winter.

Table 10: Share of monthly household electricity demand met by self-produced PV electricity

	Northern Germany	Central Germany	Southern Germany
January	6%	12%	31%
February	25%	40%	57%
March	39%	43%	45%
April	56%	54%	61%
May	73%	78%	78%
June	76%	84%	85%
July	74%	79%	81%
August	58%	75%	80%
September	47%	59%	61%
October	27%	39%	57%
November	10%	15%	35%
December	6%	11%	22%

Figure 4 and Figure 5 show exemplaric electricity demand and supply profiles of a household with three residents in Central Germany for a rather extreme week in June and December 2020, respectively. In June, the household covers most of its electricity demand by self-produced PV electricity ('PV in-house consumption'). Moreover, a significant amount of the overall PV electricity generation is neither directly consumed in-house nor stored in the battery system, but instead fed into the electricity grid ('PV grid feed-in'). Given the high solar PV electricity generation and the possibility to store surplus electricity in the battery system, the amount of electricity purchased from the grid ('Electricity purchased') in June is comparatively small. Only during some night hours is part of the household's electricity demand met by

[26] Average storage losses lie between 3 % and 4 % of the average annual household PV electricity generation.

using grid-supplied electricity. In December, in contrast, households meet almost all of their electricity demand with grid-supplied electricity due to very limited solar power generation. Moreover, all of the (very limited) PV electricity generation is consumed in-house. Hence, no PV electricity is fed into the grid by the household in this sample week in December.

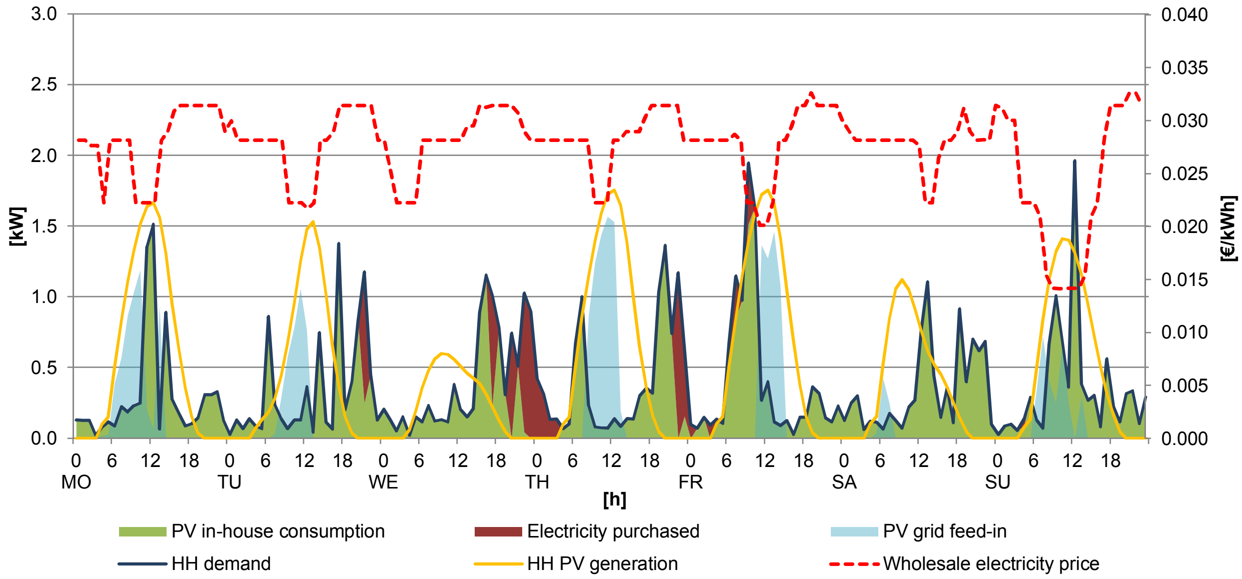

Figure 4: Sample week in June (2020): Profiles of a household with 3 residents in Central Germany

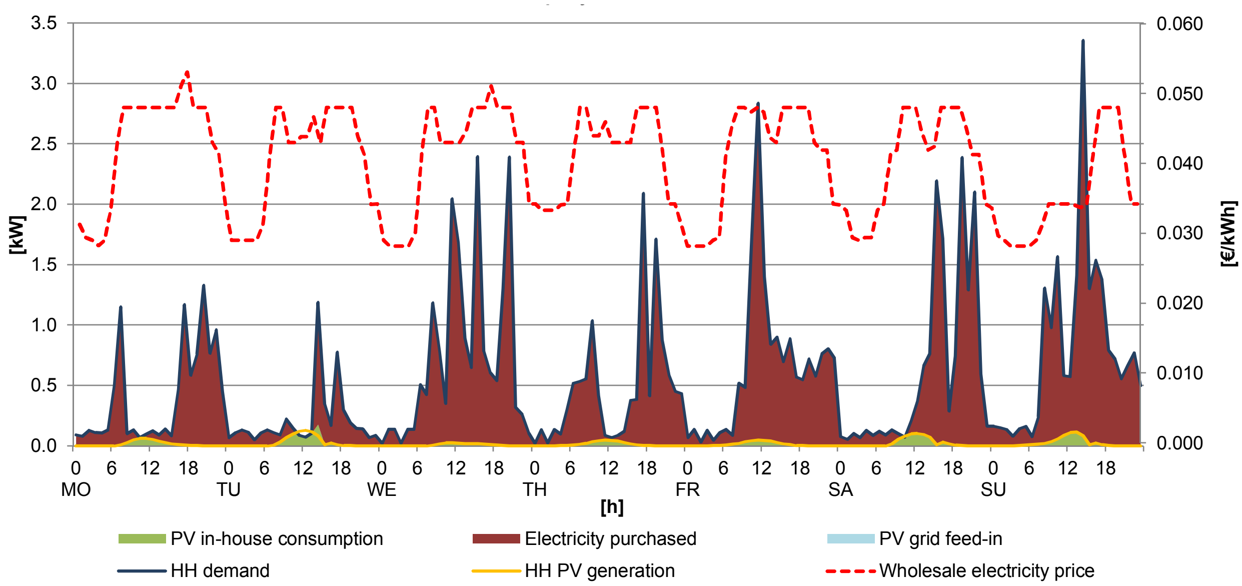

Figure 5: Sample week in December (2020): Profiles of a household with 3 residents in Central Germany

4.1.3. Investment costs

Depending on the average cost-optimal PV and battery storage system capacities, total overnight investment costs to be paid by the households lie between 2,853 €$_{2011}$ and 6,485 €$_{2011}$ in 2020 (Table 11). On average, PV system costs account for more than two thirds (68 %) of total overnight investment costs.

Note that the upfront investment costs may pose a challenge for some households and may thus form an obstacle to the wide-scale deployment of PV and battery storage systems on the household level. As argued by R. Schleicher-Tappeser (2012) and Yang (2010), even if cost-effectiveness of PV systems on the household level is achieved, the commercial competitiveness may not be guaranteed for reasons of high upfront investment costs and unfamiliarity with the technology.

Table 11: Overnight investment costs of the average cost-optimal PV and battery storage capacities in the 'Grid Parity Scenario' (2020)

	Northern Germany	Central Germany	Southern Germany
	PV investment costs [€$_{2011}$]		
1 resident	2,006	2,249	2,514
2 residents	2,786	3,085	3,485
3 residents	3,042	3,414	3,801
4 residents	3,314	3,671	4,086
5 residents	3,541	3,958	4,353
	Battery storage investment costs [€$_{2011}$]		
1 resident	847	1,059	1,208
2 residents	1,183	1,435	1,651
3 residents	1,372	1,637	1,855
4 residents	1,489	1,767	2,001
5 residents	1,573	1,876	2,132
	Total investment costs [€$_{2011}$]		
1 resident	2,853	3,308	3,722
2 residents	3,969	4,520	5,136
3 residents	4,414	5,051	5,656
4 residents	4,804	5,438	6,087
5 residents	5,115	5,834	6,485

4.1.4. Cost savings

In comparison to the 'Reference Scenario' in which households meet their total electricity demand with grid-supplied electricity, households save on average between 1,336 €$_{2011}$ and 4,012 €$_{2011}$ of their accumulated (2020-2050) and discounted (5 %) electricity costs as a consequence of the indirect financial incentive for in-house PV electricity consumption (Table 12). Hence, households avoid on average 10 % - 18 % of their accumulated discounted electricity costs over the PV system's liftime (30 years).

As can be seen in Table 12, the cost savings in the 'Grid Parity Scenario' increase with the number of residents living in the house and the annual full load hours of the PV system, i.e., the further south the house is located, the larger the potential cost savings per household become.

The cost savings demonstrate that despite the costs of installing and operating the PV and battery storage systems, households are economically better off if they meet part of their electricity demand using self-produced PV electricity instead of completely using grid-supplied electricity. This is due to the fact that the consumption of self-produced PV electricity – in contrast to the consumption of grid-supplied electricity – is exempted from the payment of taxes, levies, surcharges and network tariffs.

Table 12: Average cost savings (accumulated 2020-2050, discounted by 5 %)

	Accumulated and discounted electricity costs in the 'Grid Parity Scenario' [€ $_{2011}$]		
	Northern Germany	Central Germany	Southern Germany
1 resident	11,886	11,509	10,887
2 residents	15,863	15,375	14,502
3 residents	17,191	16,628	15,690
4 residents	18,489	17,881	16,839
5 residents	19,655	18,976	17,862
	Accumulated and discounted electricity costs in the 'Reference Scenario' [€ $_{2011}$]		
1 resident	13,222		
2 residents	17,702		
3 residents	19,160		
4 residents	20,542		
5 residents	21,874		
	Accumulated and discounted electricity costs savings [€ $_{2011}$] ([%])		
1 resident	1,336 (10 %)	1,713 (13 %)	2,335 (18 %)
2 residents	1,839 (10 %)	2,326 (13 %)	3,200 (18 %)
3 residents	1,969 (10 %)	2,532 (13 %)	3,470 (18 %)
4 residents	2,053 (10 %)	2,661 (13 %)	3,703 (18 %)
5 residents	2,219 (10 %)	2,898 (13 %)	4,012 (18 %)

4.1.5. Grid connection dimensioning

As a consequence of the in-house consumption of self-produced PV electricity, the average share of the household's annual electricity demand met by grid-supplied electricity decreases (from 100 %) to 38 % - 57 %. However, the maximum (peak) amount of electricity purchased from the grid (within a single hour) decreases by only 2 - 4 %, as shown in Table 13. Hence, if we assume that the single household's grid connection capacity was originally dimensioned to meet the household's peak demand, then the installation of the PV and battery storage capacity would not allow for the grid connection capacity to be reduced.

Table 13: Average reduction of the maximum amount of electricity purchased from the grid in the 'Grid Parity Scenario' (2020-2050)

	Northern Germany	Central Germany	Southern Germany
1 Resident	-3%	-3%	-4%
2 Residents	-3%	-3%	-3%
3 Residents	-3%	-3%	-4%
4 Residents	-2%	-2%	-3%
5 Residents	-2%	-2%	-3%

4.2. System level

As explained in Section 2.2.2, the 750 sample households are scaled-up in order to analyze the potential consequences if a large share of residential electricity consumers invests in combined PV and storage systems for in-house PV electricity consumption.

As a result of the scaling procedure, 36 GW of rooftop PV capacities are installed on one- and two-family houses in Germany by 2020 in the 'Grid Parity Scenario'. Note that these capacities are deployed in addition to the 52 GW of PV capacities already built by 2020 under the feed-in tariff promotion system. Battery storage capacities built in combination with these rooftop PV systems amount to 50 GWh, corresponding to 125 % of currently installed pump storage capacities in Germany (40 GWh in the year 2010 (Mahnke and Mülenhoff (2012))). Note that the 50 GWh storage capacities built in 2020 are decomissioned and replaced in 2036, but with a smaller total capacity of 45 GWh. Moreover, the 50 GWh (45 GWh) storage capacity correspond to a nominal output of 30 GW (27 GW).

In the following, we analyze the consequences of the single household's optimization behavior on the rest of the electricity system. This is done by comparing the results of the electricity system optimization model for the 'Grid Parity Scenario' to those of the 'Reference Scenario'.

4.2.1. Changes in the capacity and generation mix

Figure 6 displays the capacity and generation mix per decade in the 'Grid Parity Scenario', as well as a comparison to the 'Reference Scenario'. Note that in both scenarios, German NREAP targets for 2020 are achieved, including the 52 GW target for PV.

In the 'Grid Parity Scenario', an additional 36 GW of PV systems in combination with 30 GW (50 GWh) battery storage capacities are installed on households in 2020 as a consequence of the indirect financial incentive for in-house PV electricity consumption. In contrast, no additional PV and storage capacities (beyond the politically implemented target of 52 GW) are built before 2020 in the 'Reference Scenario', since these technologies are not a cost-efficient investment option from a total system perspective in 2020.

However, due to further investment cost degressions, PV capacity investments become cost-efficient by 2030 in both scenarios. In the longer run (2040-2050), more wind power capacities with comparatively higher full load hours are installed in the 'Reference Scenario' to achieve commitment with more ambitious CO_2 reduction targets. Moreover, compressed air energy storage capacities ('electricity') are expanded in both scenarios only after 2040.

Regarding the generation mix, the scenario comparison reveals that the additional PV electricity generation on the household level induced by the indirect financial incentive for PV electricity in-house consumption displaces electricity produced by coal-, gas- and lignite fired power plants in 2020 and 2030. Moreover, net electricity exports from Germany to neighboring countries significantly increase in the 'Grid Parity Scenario' compared to the 'Reference Scenario'.

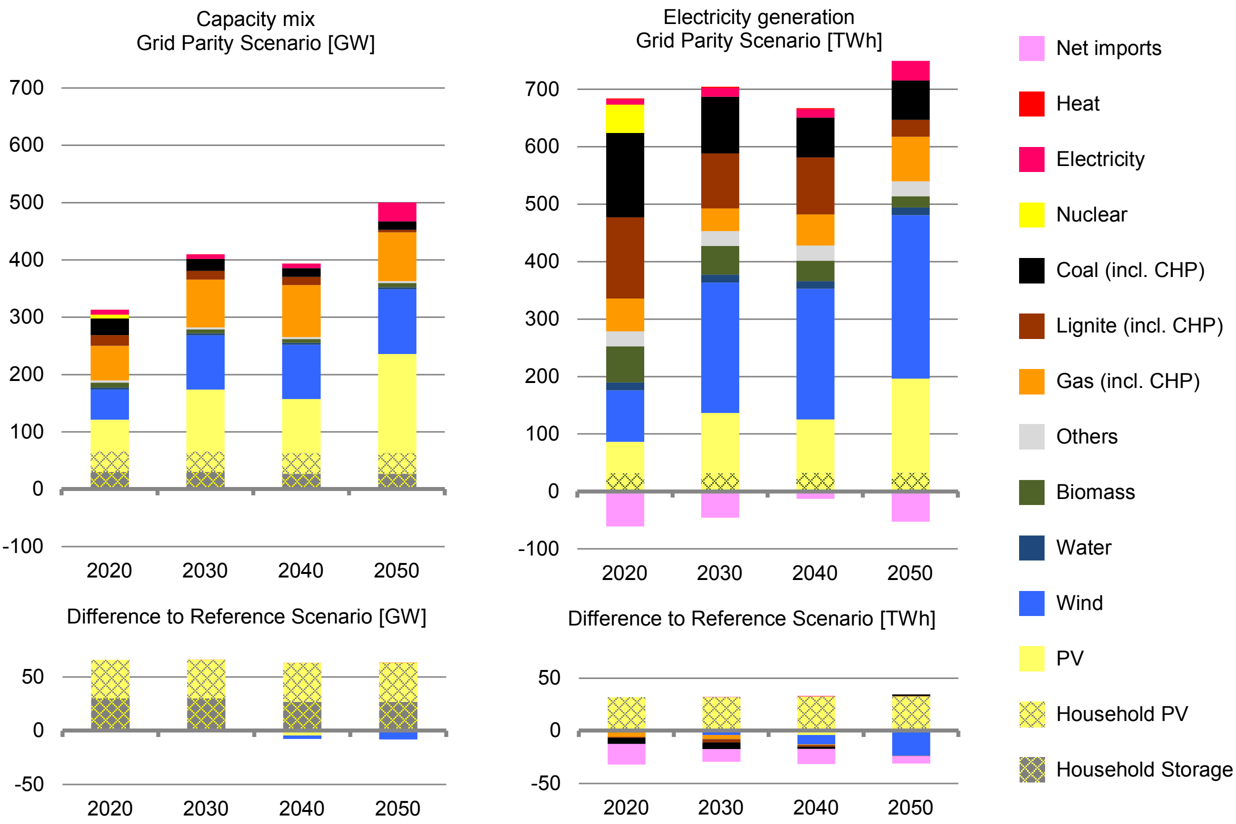

Figure 6: Capacity and generation mix in the 'Grid Parity Scenario' and difference to the 'Reference Scenario'

4.2.2. Changes in the residual load to be supplied by the wholesale electricity market

The additional PV electricity generation on the household level in the 'Grid Parity Scenario' causes significant changes in the residual load and thus in the provision and operation of power plants on the system level.[27]

Figure 7 shows the average reduction of the total electricity demand (per hour and month) in 2020 that is supplied by the wholesale market due to the additional PV electricity generation on the household level, which is either consumed in-house or fed into the electricity grid.[28] As can be seen in Figure 7, the largest reductions in total electricity demand are observed during midday in the summer (up to 19 %) when PV electricity generation on the household level is highest. However, total electricity demand in the summer also decreases significantly in the evening hours due to the consumption of PV electricity that was stored in the battery system during the day.

		Month											
		January	February	March	April	May	June	July	August	September	October	November	December
Hour	1	0%	-1%	-1%	-1%	-2%	-2%	-2%	-2%	-1%	-1%	0%	0%
	2	0%	-1%	-1%	-1%	-2%	-2%	-2%	-1%	-1%	0%	0%	0%
	3	0%	-1%	-2%	-1%	-2%	-2%	-2%	-1%	-1%	0%	0%	0%
	4	0%	-1%	-3%	-2%	-3%	-3%	-2%	-2%	-2%	-1%	0%	0%
	5	-1%	-1%	-1%	-2%	-3%	-4%	-3%	-2%	-2%	-1%	0%	0%
	6	-1%	-2%	-2%	-4%	-8%	-8%	-7%	-6%	-3%	-1%	0%	0%
	7	-2%	-4%	-5%	-8%	-13%	-13%	-11%	-9%	-8%	-5%	-1%	0%
	8	-2%	-6%	-7%	-10%	-17%	-16%	-14%	-12%	-10%	-7%	-2%	-1%
	9	-3%	-7%	-10%	-12%	-18%	-18%	-16%	-14%	-12%	-8%	-4%	-3%
	10	-4%	-7%	-8%	-12%	-19%	-19%	-16%	-15%	-12%	-8%	-4%	-4%
	11	-3%	-7%	-9%	-12%	-19%	-18%	-15%	-15%	-12%	-8%	-4%	-4%
	12	-3%	-8%	-9%	-11%	-16%	-16%	-14%	-12%	-9%	-6%	-4%	-4%
	13	-3%	-8%	-8%	-9%	-13%	-12%	-10%	-9%	-7%	-6%	-4%	-4%
	14	-3%	-8%	-7%	-8%	-11%	-10%	-9%	-8%	-7%	-5%	-3%	-3%
	15	-1%	-7%	-6%	-7%	-9%	-9%	-8%	-7%	-7%	-5%	-2%	-2%
	16	-1%	-3%	-7%	-9%	-10%	-10%	-9%	-8%	-8%	-6%	-3%	-2%
	17	-1%	-4%	-5%	-10%	-11%	-10%	-10%	-11%	-10%	-7%	-3%	-2%
	18	-1%	-3%	-5%	-9%	-11%	-10%	-9%	-11%	-9%	-7%	-2%	-1%
	19	-1%	-3%	-4%	-6%	-9%	-8%	-7%	-7%	-6%	-5%	-1%	0%
	20	-1%	-3%	-3%	-5%	-8%	-9%	-7%	-6%	-4%	-3%	-1%	-1%
	21	-1%	-3%	-3%	-4%	-8%	-9%	-8%	-6%	-3%	-2%	-1%	0%
	22	-1%	-3%	-3%	-4%	-7%	-8%	-7%	-5%	-3%	-2%	0%	0%
	23	-1%	-2%	-2%	-3%	-5%	-5%	-5%	-4%	-2%	-1%	0%	0%
	24	0%	-1%	-1%	-1%	-2%	-2%	-2%	-1%	-1%	0%	0%	0%

Figure 7: Average reduction of total electricity demand to be supplied by the wholesale electricity market (2020)

4.2.3. Changes in the residential electricity tariff and its components

As explained in Section 3, the residential electricity tariff is derived by exogenous and endogenous components (see Table 7). While the exogenous components are the same for both scenarios, the endogenous components are scenario specific. Table 14 and Figure 8 illustrate the impact of the household's optimization behavior on the endogenous components of the residential electricity tariff.

As a consequence of the additional PV electricity generation on the household level, the base price slightly decreases in 2020-2040. Specifically, as households consume self-produced instead of grid-supplied electricity, the residual load diminishes, and, as surplus PV electricity is fed into the grid, it displaces power

[27]In the following, the residual load to be supplied by the wholesale electricity market is defined as the total electricity demand in Germany minus the scaled PV electricity in-house consumption and grid feed-in.

[28]Note that the average reduction of the total electricity demand in 2020 hardly differs from the average reduction in the years 2025-2050.

Table 14: Endogenous components of the residential electricity tariff [€$_{2011}$ ct/kWh]

	'Reference Scenario'	'Grid Parity Scenario'
	Base price	
2020	3.2	3.1
2030	3.1	2.9
2040	4.1	4.0
2050	4.2	4.3
	Renewable energy surcharge	
2020	6.1	6.5
2030	2.9	3.1
2040	1.3	1.4
	Back-up capacity payment	
2020	1.6	1.7
2030	1.3	1.4
2040	1.2	1.3
2050	1.8	1.9
	Value-added tax	
2020	4.7	4.8
2030	4.4	4.4
2040	4.3	4.3
2050	4.1	4.2
	Residential electricity tariff	
2020	29.7	30.1
2030	27.4	27.6
2040	26.7	26.8
2050	25.9	26.1

plants with higher variable production costs (short-term merit order effect). Both effects cause the hourly wholesale electricity price and thus the base price to decline.[29]

At the same time, however, the renewable energy surcharge increases as a consequence of the single household's optimization behavior. This is due to two factors: Firstly, the market value of the renewable energy generation – based on renewable capacities promoted via the feed-in tariff to achieve the 2020 NREAP targets – decreases with the additional PV electricity generation (short-term merit order effect). As a consequence, the additional costs, i.e., the difference between the producers' annual costs and their revenue from selling renewable energy electricity on the wholesale market, increase. Secondly, the total amount of grid-supplied electricity purchased by (non-privileged) electricity consumers – on which the additional costs

[29]In 2050, in contrast, the base price slightly increases. This can be explained by the fact that in the 'Reference Scenario', more wind power (instead of PV power) is deployed in 2050 to achieve commitment with the long-term CO_2 reduction target (see Figure 6), which displaces conventional power plants at the steeper end of the merit-order curve (since wind generation is largest during the winter when the electricity demand is highest).

are apportioned – decreases due to the increased in-house PV electricity consumption.

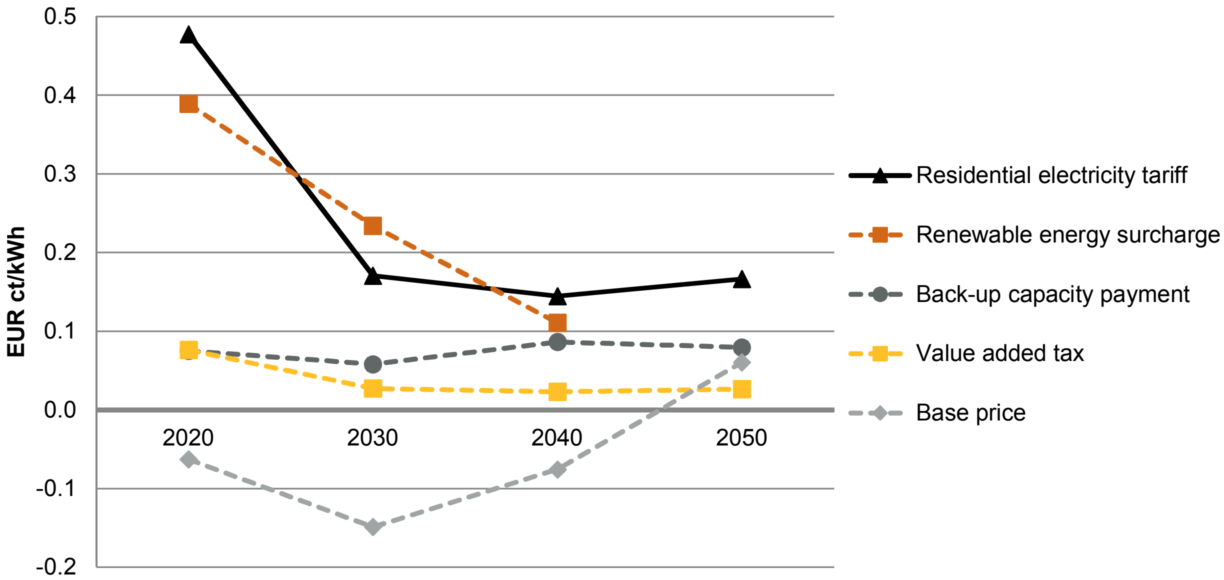

Figure 8: Impact of the single household's optimization on the residential electricity tariff [€$_{2011}$ ct/kWh]

The decrease in the total amount of grid-supplied electricity purchased from electricity consumers in the 'Grid Parity Scenario' also explains the slight increase in the back-up capacity payment. Specifically, the costs for providing securely available capacities are apportioned to a lower share of electricity consumers (i.e., a lower amount of grid-supplied electricity purchased from electricity consumers) in the 'Grid Parity Scenario'.

Finally, the value-added tax payment also increases due to the fact that the value-added tax of 19 % is levied on the sum of all components, which is larger in the 'Grid Parity Scenario' than in the 'Reference Scenario'.

In sum, the increase in the renewable energy surcharge, the back-up capacity payment and the value-added tax payments compensates the decrease in the base price (which serves as a proxy for the average costs of electricity procurement). Thus, the residential electricity tariff increases.

Notably, the increase in the residential electricity tariff due to the additional PV electricity generation constitutes a self-reinforcing effect, since a higher residential electricity tariff in turn increases the attractiveness of consuming self-produced instead of grid-supplied electricity from the single household's perspective.

4.2.4. Welfare loss and redistributional effects associated with the household's optimization behavior

After having analyzed the impact of the single household's optimization behavior on the generation and capacity mix, the residual load and the residential electricity tariff, we quantify the welfare loss and redistributional effects associated with the in-house consumption of self-produced PV electricity generation on the household level.

Figure 9 illustrates the redistributional effects associated with the household's optimization behavior. Specifically, it shows the difference in the consumer rent, the rent of 'HH producers and in-house consumers', the producer profit, the payments of consumers to the public sector and network operators, the payments of 'HH producers and in-house consumers' to the public sector and network operators as well as the revenues of the public sector and network operators between the 'Grid Parity Scenario' and the 'Reference Scenario' accumulated up to 2050 in bn €$_{2011}$ (not discounted). Table 15, moreover, shows the change in the single components of the consumer rent, the rent of 'HH producers and in-house consumers' and producer profit accumulated up to 2050 in bn €$_{2011}$ (not discounted).

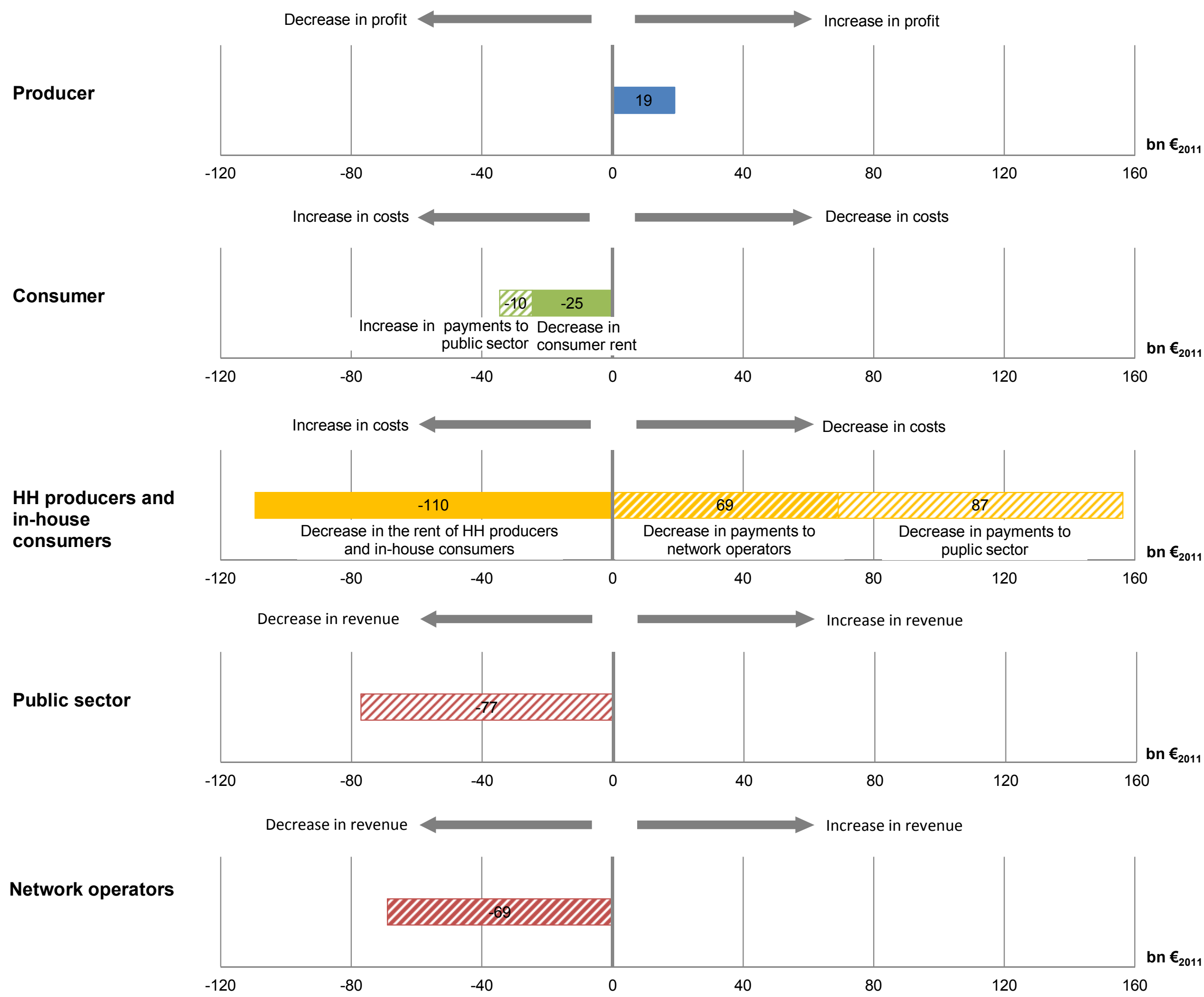

Figure 9: Redistributional effects accumulated up to 2050 in bn €$_{2011}$ (not discounted)

Table 15: Change in the single components of the producer profit, the consumer rent and the rent of 'HH producers and in-house consumers' accumulated up to 2050 in bn €$_{2011}$(not discounted)

Producer	
Decrease in the revenue for providing electricity	-25
Decrease in the revenue for providing heat	-2
Increase in the revenue for providing securley available capacities	2
Increase in the renewable energy compensation	6
Sum: Decrease in producer revenue	-20
Decrease in the annualized investment costs	22
Decrease in the variable generation costs (including fuel and CO_2 costs)	7
Decrease in the fixed operation and maintenance costs	10
Sum: Decrease in producer costs	39
Net effect: Increase in producer profit	19
Consumer	
Decrease in the costs for being provided with electricity (from the wholesale market)	9
Increase in the costs for being provided with securly available capacities	-13
Increase in the costs for being provided with renewable capacities	-21
Sum: Decrease in consumer rent	-25
HH producers and in-house consumers	
Increase in the revenue from the wholesale market	3
Sum: Increase in the revenue of HH producers and in-house consumers	3
Decrease in the costs for being provided with electricity (from the wholesale market)	26
Decrease in the costs for being provided with securely available capacities	12
Decrease in the costs for being provided with renewable capacities	13
Increase in the costs for PV and storage capacities	-163
Sum: Increase in costs of HH producers and in-house consumers	-113
Net effect: Decrease in the rent of HH producers and in-house consumers	-110

The producer rent increases by 19 bn €$_{2011}$ in the 'Grid Parity Scenario' since the decrease in the producer's costs exceeds the decrease in the producer's revenue (see Table 15). Specifically, the producer's revenue for providing electricity decreases by 25 bn €$_{2011}$, but annualized investment costs, variable generation costs and fixed O&M costs decrease by 22, 7 and 10 bn €$_{2011}$, respectively, in the 'Grid Parity Scenario'. Moreover, the producer's compensation for providing renewable energy capacity increases since the market value of the renewable energy generation (based on renewable capacities promoted via the feed-in tariff to achieve the 2020 NREAP targets) decreases (see Section 4.2.3).

The consumer rent, in contrast, decreases by 25 bn €$_{2011}$ due to the single household's optimization behavior. Although the costs of being provided with electricity from the wholesale electricity market decreases by 9 bn €$_{2011}$ due to the higher PV electricity generation in the 'Grid Parity Scenario', the costs of being provided with renewable and securely available back-up capacities increase by 21 and 13 bn €$_{2011}$, respectively, for consumers. This is due to the fact that the (residual) consumers have to bear a higher share of both the (increased) additional costs of renewable energy and back-up capacities, as the total amount of grid-supplied electricity (on which these costs are apportioned) decreases.

Besides the consumer rent, the rent of 'HH producers and in-house consumers' also decreases by more than 110 bn €$_{2011}$ in the 'Grid Parity Scenario'. This is due to the high investment (and fixed O&M) costs for the households's PV and storage capacities of 157 bn €$_{2011}$, which compensate (i) the decrease in the costs of being provided with electricity from the wholesale electricity market (26 bn €$_{2011}$), (ii) the decrease in the costs of being provided with renewable and securely available capacities (13 and 12 bn €$_{2011}$, respectively) and (iii) the revenue from selling surplus PV electricity on the wholesale market (3 bn €$_{2011}$).

In sum, the single household's optimization behavior (induced by the indirect financial incentive for in-house PV electricity consumption) reduces overall economic welfare by 116 bn €$_{2011}$.[30] The welfare loss is due to the fact that the single household's PV and storage capacities are not yet cost-efficient investment options from the total system perspective in 2020.

However, despite the decrease in the rent of 'HH producers and in-house consumers', investments in PV and storage capacities are nevertheless profitable from the perspective of 'HH producers and in-house consumers', as illustrated in Figure 9. This is due to the fact that the in-house consumption of self-produced PV electricity allows 'HH producers and in-house consumers' to reduce their payments to the public sector and network operators. Overall, 'HH producers and in-house consumers' reduce their payments to the public sector by more than 87 bn €$_{2011}$ and to the network operators by more than 69 bn €$_{2011}$. This is because of the exemption from taxes, levies and surcharges for the amount of self-produced PV electricity generation consumed in-house and the allocation of grid costs via energy- rather than capacity-related network tariffs. In contrast, the consumers' payments to the public sector slightly increase by 10 bn €$_{2011}$, which is primarily explained by the fact that the total amount of value-added tax payments increase (see Section 4.2.3).

In total, 'HH producers and in-house consumers' save 47 bn €$_{2011}$ in the 'Grid Parity Scenario' compared to the 'Reference Scenario'. The financial burden of the (residual) electricity consumers, in contrast, increases

[30]The welfare loss (excess costs) corresponds to the accumulated change in the consumer rent, the rent 'HH producers and in-house consumers' and the producer profit between the 'Grid Parity Scenario' and the 'Reference Scenario' (see Equation (41) in Section 3).

by 35 bn €$_{2011}$. Moreover, the public sector and network operators face revenue losses of 77 and 69 bn €$_{2011}$, respectively.

Note that in our analysis, we capture feedback effects of the in-house consumption of self-produced PV electricity generation for four components of the residential electricity price: the base price (which serves as a proxy for the average costs of electricity procurement), the renewable energy surcharge, the back-up capacity payment and the value added tax (see Table 7). All other components of the residential electricity tariff are, in contrast, exogenously assumed and do not differ between scenarios.[31] This assumption aims at illustrating the potential revenue loss experienced by the public sector and the network operators as a consequence of an increased consumption of self-produced (instead of grid-supplied) electricity on the household level in Germany. However, if, contrary to our assumption, the public sector would raise the taxes and levies on electricity consumption or if the network operators would raise the (energy-related) network tariffs (to cover their revenue losses of 77 and 69 bn €$_{2011}$, respectively), the financial burden of the residual electricity consumers would further increase. Moreover, just like in the case of the renewable energy surcharge, an increase in public taxes and levies or network tariffs would constitute a self-reinforcing effect since a higher residential electricity tariff increases the attractiveness of consuming self-produced (rather than grid-supplied) electricity from the single household's perspective. Hence, our quantified welfare effects (excess costs of 116 bn €$_{2011}$) may be interpreted as lower-bound estimates.

In summary, the unequal treatment of grid-supplied and self-produced electricity with respect to public taxes, levies and surcharges as well as the allocation of grid costs via energy- rather than capacity-related network tariffs constitutes a considerable distortion of competition. Accumulated up to 2050, excess costs associated with the massive expansion of combined PV and storage capacities on the household level by 2020 amount to more than 116 bn €$_{2011}$, corresponding to 0.44 % of the German gross domestic product from 2012 (DESTATIS (2013)). These significant excess costs can be explained by the fact that PV systems in Germany become efficient from 2030 only (see Figure 6), once PV investment costs may have fallen further and CO_2 reduction targets become more ambitious. Likewise, electricity storage is not a cost-efficient flexibility option before 2040, i.e., not until the share of fluctuating renewable energy technologies has further increased. However, instead of small-scale battery storage capacities (on the household level), large-scale compressed air energy storage (CAES) capacities are installed in the Reference Scenario, which are characterized by higher investment costs but significantly higher technological lifetimes, rendering CAES

[31] The exogenously assumed components of the residential electricity tariff include the concession levy, the offshore liability surcharge, the costs of distribution (margin included), the electricity tax, the CHP surcharge, the §19 surcharge and the network tariff (see Table 7).

storage a less costly flexibility option than battery storage. Moreover, while the battery storage capacities on the household level are dispatched to minimize the single household's electricity costs, the CAES capacities are optimally dispatched from total system perspective.

5. Conclusion

The paper has analyzed the consequences of exempting in-house PV electricity consumption from taxes, levies and surcharges and allocating grid costs via energy- rather than capacity-related (cost-reflective) network tariffs in a case study for Germany up to 2050.

We find that single households are able to avoid on average 10 % - 18 % of their accumulated electricity costs up to 2050 by covering (on average) 38 - 57 % of their annual electricity demand with self-produced PV electricity. In total, cost savings on the household level amount to more than 47 bn €$_{2011}$ up to 2050 in our scenario analysis. However, while the installation of PV and battery storage capacities on the household level for the consumption of self-produced instead of grid-supplied electricity is beneficial from the single household's perspective, it is inefficient from the total system perspective. In total, the single household's optimization behavior is found to cause excess costs of 116 bn €$_{2011}$ accumulated up to 2050.

Moreover, we find that the single household's optimization behavior leads to redistributional effects that may be undesirable from the overall economic perspective. Specifically, the single household's optimization behavior raises the financial burden for the (residual) electricity consumers by more than 35 bn €$_{2011}$ up to 2050. In addition, it yields massive revenue losses on the side of the public sector and network operators of more than 77 and 69 bn €$_{2011}$, respectively.

In order to enhance the overall economic efficiency, we argue that the financial incentive for in-house PV electricity consumption should be abolished. This implies that either the consumption of self-produced electricity should be burdened with taxes, levies and other surcharges, as in the case of the consumption of grid-supplied electricity, or that the residential electricity price should be reduced to the 'true' costs of electricity procurement. Moreover, since grid costs are primarily fixed costs, the traditional energy-related network tariff should be replaced by a cost-reflective tariff corresponding primarily to the grid connection capacity. As a result, competition between PV and all other electricity generation technologies would be ensured and inefficient investments avoided.

Future research could address the following issues: Firstly, the consequences of a change in the network tariff structure from energy- to capacity-related tariffs on the overall single households optimization behavior and the overall welfare effects could be quantified. Secondly, the effect of active demand side management measures could be analyzed. More specifical, the option to shift the deferrable electricity demand of households from the evening hours to the maximum PV electricity generation hours would be an interesting point of investigation. Thirdly, the implications of a time-dependent residential electricity tariff on the single household's optimization behavior could be analyzed. With increasing penetration of PV capacities, hourly solar generation and wholesale electricity prices may become negatively correlated. Thus cost savings from consuming self-produced instead of grid-supplied electricity may be lower under a time-varying residential electricity tariff (instead of a flat residential electricity tariff). All three aspects are assumed to lower the economic inefficiency associated with the indirect financial incentive for in-house PV electricity consumption.

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Appendix A. Appendix

Appendix A.1. Assumptions of the household optimization model

Table A.16: Assumed equipment of households with domestic appliances in Germany based on data from DESTATIS (2012a), DESTATIS (2012b), DESTATIS (2012c) and Statista (2012)

Domestic appliance type	Proportion of households equipped with appliance
Chest freezer	19 %
Fridge freezer	59 %
Refrigerator	40 %
Upright freezer	38 %
Answering machine	52 %
Cassette / CD Player	79 %
Clock	73 %
Cordless telephone	93 %
Hi-Fi system	69 %
Iron	72 %
Vacuum	97 %
Fax	19 %
Personal computer	82 %
Printer	77 %
TV 1	96 %
TV 2	41 %
TV 3	9 %
VCR / DVD	71 %
TV Receiver box	48 %
Hob	46 %
Oven	62 %
Microwave	72 %
Kettle	85 %
Small cooking (group)	100 %
Dish washer	67 %
Tumble dryer	36 %
Washing machine	91 %
Washer dryer	4 %
Electric instantaneous water heater	20 %
Electric shower	0 %
Storage heaters	0 %
Other electric space heating	7 %
Lighting	100%

Appendix A.2. Assumptions of the electricity system optimization model

Appendix A.2.1. CO_2 reduction and renewable energy targets

All modeled market regions (Germany and its neighboring countries) are assumed to achieve their national renewable energy targets stated in the National Renewable Energy Action Plans (NREAP's) by 2020 (A.17) and the joint CO_2 reduction targets depicted in Table A.18.

Table A.17: National renewable energy targets in MW

	Onshore wind		Offshore wind		PV		Biomass	
	2015	2020	2015	2020	2015	2020	2015	2020
Austria	2.0	2.6	0.0	0.0	0.2	0.3	1.3	1.3
Belgium, Netherlands, Luxemburg	6.0	8.7	1.7	6.9	1.2	2.2	5.4	5.4
Czech Republic	0.5	0.7	0.0	0.0	2.0	1.7	0.3	0.4
Denmark	2.9	2.9	1.3	1.3	0.0	0.0	2.8	2.8
France	10.8	19.0	2.7	6.0	2.2	4.9	3.0	3.0
Germany	33.6	35.8	3.0	10.0	34.3	51.8	8.8	8.8
Poland	3.4	5.6	0.0	0.5	0.0	0.0	2.5	2.5
Switzerland	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Table A.18: CO_2 reduction targets (in comparison to 1990 levels)

2020	2025	2030	2035	2040	2045	2050
30 %	45 %	60 %	68 %	75%	83 %	90 %

Appendix A.2.2. Electricity demand and potential for cogeneration

The assumed electricity demand is based on the reference scenario of the EU member states NREAP's (ECN (2011)) and is shown in Table A.19. The assumed maximum potential for heat produced in co-generation within each market region is depicted in Table A.20.

Table A.19: Gross electricity demand in TWh

	2015	2020	2025	2030	2035	2040	2045	2050
Germany	611	612	621	631	631	631	631	631
Austria	71	78	78	78	80	82	85	87
Belgium, Netherlands, Luxemburg	247	259	259	259	267	275	283	290
Czech Republic	80	88	93	99	105	111	117	124
Denmark	40	41	41	41	43	44	45	46
France	575	599	621	643	662	682	701	721
Poland	178	202	202	202	214	227	240	253
Switzerland	61	65	65	65	67	69	71	73

Appendix A.2.3. Investment costs and techno-economic parameters of conventional, renewable and storage technologies

Table A.20: Maximum potential for heat generated in CHP plants in TWh

	2015	2020	2025	2030	2035	2040	2045	2050
Germany	191.7	192.4	192.7	192.9	192.9	192.9	192.9	192.9
Austria	41.0	41.2	41.4	41.5	41.7	41.8	41.9	42.0
Belgium, Netherlands, Luxemburg	129.0	129.9	130.3	130.8	131.2	131.5	131.9	132.3
Czech Republic	54.5	55.1	55.4	55.7	56.0	56.4	56.7	57.0
Denmark	54.4	54.7	54.9	55.1	55.3	55.4	55.6	55.7
France	31.4	31.6	31.7	31.8	31.9	32.0	32.1	32.2
Poland	92.4	93.3	93.9	94.4	95.0	95.5	96.0	96.6
Switzerland	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7

Table A.21: Overnight investment costs of conventional, renewable and storage technologies per power output [€$_{2011}$/kW$_{el}$] based on Jägemann et al. (2013), Fürsch et al. (2013) and IEA (2011) and PROGNOS/EWI/GWS (2010)

Technologies	2015	2020	2025	2030	2035	2040	2045	2050
CCGT	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250
CCGT - CCS	-	-	-	1,550	1,525	1,500	1,475	1,450
CCGT - CHP	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500
CCGT - CHP and CCS	-	-	-	1,700	1,675	1,650	1,625	1,600
Hard Coal	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500
Hard Coal - innovative		2,250	2,000	1,875	1,800	1,750	1,700	1,650
Hard Coal - innovative CHP	2,650	2,650	2,400	2,275	2,200	2,150	2,100	2,050
Hard Coal - innovative CHP and CCS	-	-	-	2,875	2,800	2,700	2,650	2,600
Lignite	1,850	1,850	1,850	1,850	1,850	1,850	1,850	1,850
Lignite - innovative	1,950	1,950	1,950	1,950	1,950	1,950	1,950	1,950
Lignite - CCS	-	-	-	2,550	2,525	2,500	2,475	2,450
Nuclear	3,157	3,157	3,157	3,157	3,157	3,157	3,157	3,157
OCGT	700	700	700	700	700	700	700	700
CAES	850	850	850	850	850	850	850	850
Biomass gas	2,399	2,398	2,396	2,395	2,394	2,393	2,392	2,390
Biomass gas - CHP	2,599	2,597	2,596	2,595	2,594	2,592	2,591	2,590
Biomass solid	3,298	3,297	3,295	3,293	3,292	3,290	3,288	3,287
Biomass solid - CHP	3,498	3,497	3,495	3,493	3,491	3,490	3,488	3,486
CSP	4,494	3,989	3,709	3,429	3,266	3,102	2953	2805
Geothermal (hot dry rock)	12,752	10,504	10,002	9,500	9,268	9,035	9031	9026
Geothermal (high enthalpy)	1,275	1,050	1,000	950	927	904	903	903
Onshore wind	1,225	1,200	1,175	1,150	1,125	1,100	1,075	1,050
Offshore wind	2,650	2,200	2,050	1,900	1825	1,750	1,725	1,700
PV ground	1,260	1,100	900	810	765	720	675	630
PV roof	1,400	1,200	1,000	900	850	800	750	700

Table A.22: Techno-economic parameters for conventional and storage technologies based on Jägemann et al. (2013), Fürsch et al. (2013), IEA (2011) and PROGNOS/EWI/GWS (2010)

	η [%]	β [%]	ef [t CO_2 /MWh_{th}]	av [%]	FOM-costs [€ $_{2011}/kW$]	Lifetime [a]
CCGT	60.0	-	0.201	84.50	28.2	30
CCGT - CCS	53.0	-	0.020	84.50	40.0	30
CCGT - CHP	36.0	-	0.201	84.50	88.2	30
CCGT - CHP and CCS	36.0	-	0.030	84.50	100.0	30
Hard Coal	46.0	-	0.335	83.75	36.1	45
Hard Coal - innovative	50.0	-	0.335	83.75	36.1	45
Hard Coal - innovative CHP	22.5	-	0.335	83.75	55.1	45
Hard Coal - innovative CHP and CCS	18.5	-	0.050	83.75	110.0	45
Lignite	43.0	-	0.406	86.25	43.1	45
Lignite - innovative	46.5	-	0.406	86.25	43.1	45
Lignite - CCS	43.0	-	0.041	86.25	103.0	45
Nuclear	33.0	-	0.000	84.50	96.6	60
OCGT	40.0	-	0.201	84.50	17.0	25
CAES	86.0	82.0	0.0	95.00	9.2	40
Pump storage	87.0	83.0	0.0	95.00	11.5	100
Hydro storage	87.0	-	0.0	95.00	11.5	100

Table A.23: Techno-economic parameters for RES-E technologies based on EWI (2010), Fürsch et al. (2013), Jägemann et al. (2013), IEA (2010a) and IEA (2010b)

	η [%]	av [%]	Secured capacity [%]	Fixed O&M costs [€ $_{2011}/kW$]	Lifetime [a]
Biomass gas	40.0	85	85	120	30
Biomass gas - CHP	30.0	85	85	130	30
Biomass solid	30.0	85	85	165	30
Biomass solid - CHP	22.5	85	85	175	30
Concentrating solar power	-	-	40	100	25
Geothermal (hot dry rock)	22.5	85	85	300	30
Geothermal (high enthalpy)	22.5	85	85	30	30
Offshore wind	-	-	5	93	25
Onshore wind	-	-	5	13	25
PV ground	-	-	0	12	30
PV roof	-	-	0	12	30
Run-off-river hydropower	-	-	50	11.5	100

Appendix A.2.4. Extension of grid infrastructure

The interconnector capacities between Germany and its neighboring countries are assumed to be expanded according to projects planned according to the ENTSO-E's 10-Year Network Development Plan 2012 ENSTO-E (2012). The assumptions regarding the interconnection expansions between the modeled market regions are shown in Table A.24.

Table A.24: Interconnection expansions between the modeled market regions in GW

Import country	Export country	2015	2020	2025	2030
Austria	Germany		3.7		
Belgium, Netherlands, Luxemburg	Germany	1.9	1.0		
Czech Republic	Germany				1.9
Denmark	Germany				0.6
France	Switzerland				1.0
Germany	Austria		3.7		
Germany	Poland		1.9		1.7
Germany	Czech Republic				1.9
Germany	Belgium, Netherlands, Luxemburg	1.9	1.0		
Germany	Denmark		1.0		0.6
Poland	Germany		3.7		
Switzerland	France				1.0

Appendix A.2.5. Fuel prices

The assumptions regarding the future development of fuel prices are based on IEA (2011) and PROGNOS/EWI/GWS (2010) and are shown in Table A.25.

Table A.25: Fuel prices

	2015	2020	2025	2030	2035	2040	2045	2050
Coal	12.3	12.5	12.7	12.8	12.9	13.0	13.0	13.1
Gas	23.3	25.2	26.9	28.3	29.1	29.8	30.5	31.3
Lignite	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Nuclear	3.6	3.7	3.7	3.7	3.8	3.8	3.9	3.9
Oil	90.4	99.0	105.0	110.0	113.0	114.0	115.0	116.0

Appendix A.3. Iterative approach

From a total system perspective, an increased share of in-house PV electricity consumption causes changes in the residual load (both in volume and structure), which in turn affects both the wholesale electricity price (via a change in the provision and operation of power plants) and the residential electricity tariff (via changes in the wholesale electricity price and the renewable energy surcharge). The latter effect occurs due to the fact that under the current feed-in tariff system in Germany, the costs associated with the promotion of renewable energies are passed on to electricity consumers via the so-called 'renewable energy surcharge' as part of the residential electricity tariff (Figure 1).[32] As such, the level of the renewable energy surcharge increases if (ceteris paribus) the annual amount of electricity purchased from the grid by (non-privileged) electricity consumers decreases.

However, changes in the wholesale electricity price and the residential electricity tariff, in turn, influence the cost-optimal dimensioning of the PV and battery storage capacities from the single household's perspective. In particular, households are assumed to avoid the residential electricity tariff for the amount of self-produced PV electricity consumed in-house and receive the wholesale electricity price for the amount of surplus (not self-consumed) PV electricity that is fed into the grid. Hence, the amount of surplus PV electricity generation fed in to the grid is asssumed to be remunerated with its actual market value at a specific hour.

To capture this immanent interdependency, the results of the household optimization model are iterated with the results of an electricity system optimization model, which determines (among others) the hourly wholesale electricity prices and the residential electricity tariff per year for Germany until convergence of results is achieved (see below). Figure A.10 shows a schematic representation of the iterative process to quantify the consequences of both exempting in-house PV electricity consumption from taxes, levies and surcharges and allocating network cost to electricity customers via energy-related instead of capacity-related (cost-reflective) network tariffs. Overall, the iterative process can be divided into two seperate steps:

Step 1: Based on the single household's demand profiles (8760 h), solar radiation profiles (8760 h), the PV and battery storage system investment costs, the residential electricity tariff and the hourly wholesale electricity prices (8760 h), the household optimization model determines the cost-optimal PV and storage capacities from the single household's perspective (depending on the number of residents living in the house and the location of the house). Hourly system performance statistics, including the single household's PV electricity in-house consumption and grid feed-in profiles for 8760 h of the year, are also determined. The initial values for the wholesale electricity price, the renewable energy surcharge and the residential electricity tariff for the first iteration are shown in Table A.26.

Step 2: The results of the household optimization model (i.e., the cost-optimal PV and battery storage capacities as well as the PV electricity in-house consumption and grid feed-in profiles for 8760 h) serve as

[32] Specifically, the revenue from the renewable electricity sold on the power exchange is deducted from the cost associated with the payment of renewable energy feed-in tariffs. The remainder is passed on to (non-privileged) electricity consumers as the renewable energy surcharge. Hence, the renewable energy surcharge [in €$_{2011}$/kWh] corresponds to the difference between the annual sum of feed-in tariffs paid for the renewable energy supply and the annual revenues earned by selling the renewable energy supply at the wholesale electricity market [€$_{2011}$] divided by the annual amount of electricity purchased from the grid by (non-privileged) electricity consumers [kWh].

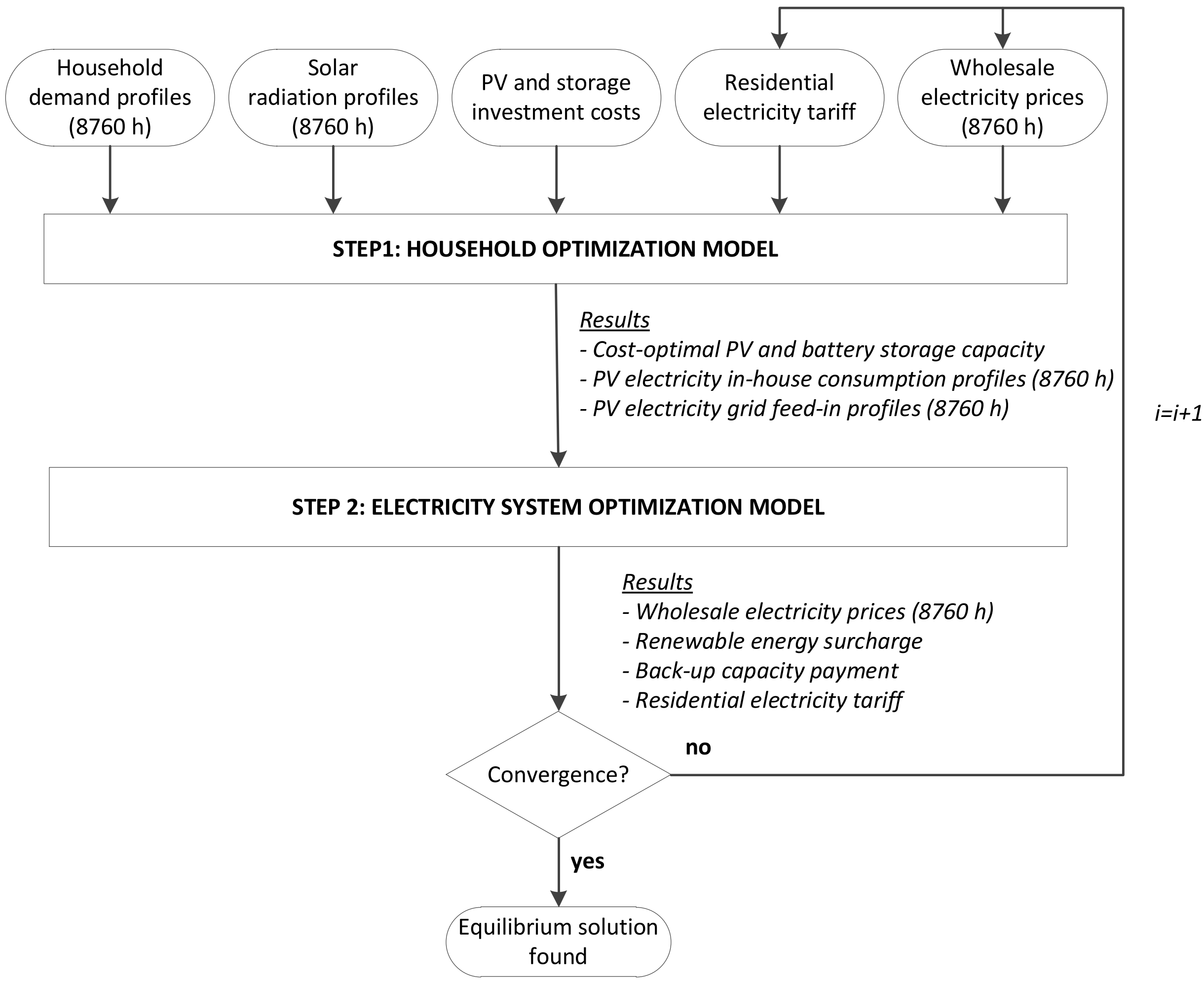

Figure A.10: Schematic representation of the iterative process

Table A.26: Initial assumptions for iteration step 1

	2020	2025	2030	2035	2040	2045	2050
Renewable energy surcharge [ct/kWh]	6.0	5.0	3.0	2.0	1.0	-	
Back-up capacity payment [ct/kWh]				1.5			
Average wholesale electricity price [ct/kWh]				5			

input parameters for the electricity system optimization model.

Based on these input parameters, the electricity system optimization model determines (among others) the hourly wholesale prices, the renewable energy surcharge, the back-up capacity payment and the retail electricity tariff per year.

Subsequently, the wholesale electricity prices and the retail electricity tariff are again taken as input parameters for the household optimization model. Based on the new hourly wholesale electricity prices and the new retail electricity tariff, the household optimization model again determines the cost-optimal PV and storage capacities from the single household's perspective and the corresponding PV electricity in-house consumption and grid feed-in profiles for 8760 h of the year (Step 1).

This iterative process (Steps 1 - 2) is continued until convergence of results is achieved. Formally, the iterative process is stopped after the change in the cost-optimal PV and battery storage capacities from iteration i to iteration i+1 is smaller than 2 %.

Appendix A.4. Change in the optimal (scaled-up) capacities of PV and storage systems during the iterative process

Figure A.11 shows the development of the optimal (scaled-up) PV and storage capacities during the iterative process. Convergence of results is achieved after nine iteration steps. Both (scaled-up) PV capacities and storage capacities change by less than 2 % from iteration step 8 to iteration step 9.

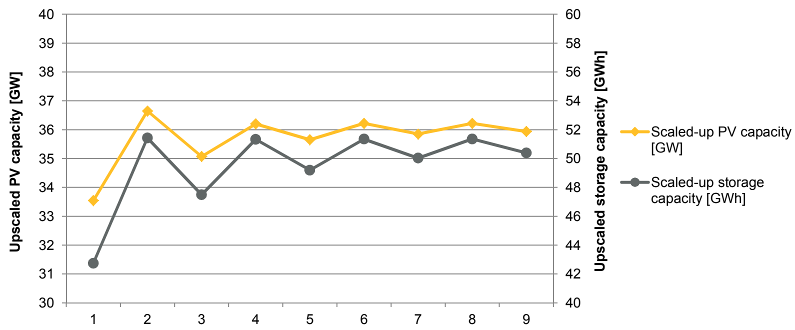

Figure A.11: Change in the optimal (scaled-up) PV and storage capacities during the iterative process

Appendix A.5. Sensitivity analysis and robustness of results

To demonstrate the robustness of results we repeat the iteration for two alternative starting values. In Sensitivity (i), we assume an initial average wholesale electricity price of 3 ct/kWh instead of 5 ct/kWh (see Table A.26), whereas in Sensitivity (ii), we assume an initial back-up capacity payment of 2.5 ct/kWh instead of 1.5 ct/kWh. The development of the optimal (scaled-up) PV and storage capacities during the iterative process for an initial average wholesale electricity price of 3 ct/kWh and an initial back-up capacity payment of 2.5 ct/kWh is shown in Figures A.12 and A.12. As can be seen, both the (scaled-up) PV and storage capacities converge to the same optimal capacities despite different initial values.

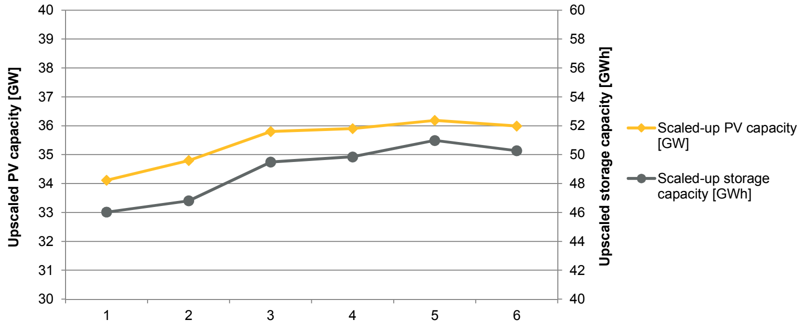

Figure A.12: Sensitivity (i) – Change in the optimal (scaled-up) PV and storage capacities during the iterative process

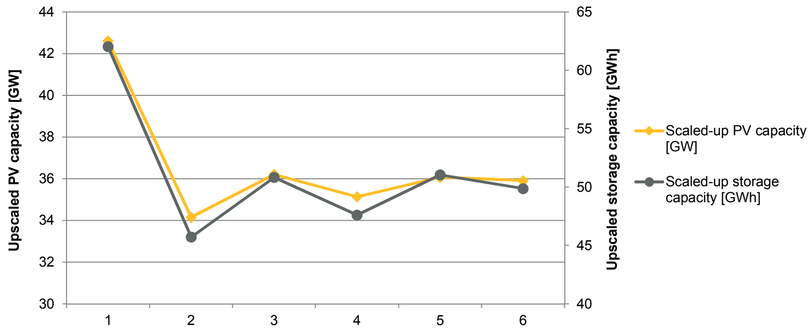

Figure A.13: Sensitivity (ii) – Change in the optimal (scaled-up) PV and storage capacities during the iterative process