Hamburg Institute of International Economics

Photovoltaic self-consumption after the support period: Will it pay off in a cross-sector perspective?

Jonas Klamka, André Wolf, Lars G. Ehrlich

HWWI Research

Paper 182

Hamburg Institute of International Economics (HWWI) | 2018
ISSN 1861-504X

Corresponding author:
Jonas Klamka
jonas.klamka@uni-siegen.de

HWWI Research Paper
Hamburg Institute of International Economics (HWWI)
Oberhafenstr. 1 | 20097 Hamburg, Germany
Telephone: +49 (0)40 34 05 76 - 0 | Fax: +49 (0)40 34 05 76 - 150
info@hwwi.org | www.hwwi.org
ISSN 1861-504X

„Photovoltaic self-consumption after the support period: Will it pay off in a cross-sector perspective?”

Jonas Klamka[a]*, André Wolf[b], Lars G. Ehrlich[b]

a: Universität Siegen – Lehrstuhl für Europäische Wirtschaftspolitik, Unteres Schloss 3, 57076 Siegen, Germany
b: Hamburgisches WeltWirtschaftsInstitut (HWWI), Oberhafenstraße 1, 20097 Hamburg, Germany
**: Corresponding author, jonas.klamka@uni-siegen.de*

We quantify the cost savings potential of photovoltaic self-consumption by single-family houses with small-scale roof-top photovoltaic (PV) systems in Germany against the background of recent storage applications after the end of the legal support period. We analyze different systems where an already installed PV system is combined with battery storage and/or a power-to-heat solution (heating rod plus thermal storage). A comparison is made in terms of a household’s electricity and heating costs under cost-minimizing operation of each system. For this purpose, we carry out comprehensive simulations of site-specific PV production and determine the optimal self-consumption as well as the optimal charging of the hot water thermal storage and the battery system. We use 25 representative electricity load profiles, which differ only in the temporal distribution of consumption, to obtain a broader picture of the cost savings potential. Results suggest that the major share of the savings potential is due to direct PV self-consumption and thus concerns the electricity costs. A profitability analysis reveals that the inclusion of a hot water thermal storage and/or a battery storage system does not pay off when juxtaposing cost savings and investment expenses, at least at current prices.

Keywords: Residential photovoltaic; self-sufficiency; battery system; power-to-heat

1. Introduction
1.1. Motivation

After years of remarkable growth of photovoltaic (PV) systems in Germany, the expansion slows noticeably due roof-top systems (up to 10 kWp) located on roughly 1.5 million single- and two family houses all over Germany (to the latest adjustments of the support scheme, the renewable energy act (EEG) (BMWi, 2015)). However, a considerable quantity of photovoltaic (PV) capacity - 40 GW at the end of 2016 - has been built up in recent years fueled by generous financial support instruments of the past. Of this capacity approximately 5.4 GW are small-scale (Table 1; BNetzA, 2017).

Type	**Up to 10 kW** in Megawatt	Share	**> 10 kW** in Megawatt	Share	**Total** in Megawatt
Roof-top	5360.2	18.0 %	24450.2	82.0 %	29810.4
Ground mounted	13.9	0.1 %	10320.3	99.9 %	10334.2
Total	**5374.1**		**34770.5**		**40144.6**

Source: BNetzA (2017), photovoltaic capacity in Germany as of 31.12.2016.

Table 1: Photovoltaic capacity in Germany by size groups

The subsidy for feeding into the grid ends after a period of 20 years. However, most manufacturers of solar modules provide a technical guarantee of 25 years or even longer (Fraunhofer ISE, 2015). Studies on life time expectancy of PV panels even suggest the potential of a 30-year average lifetime for PV modules (Fthenakis et al., 2016). Therefore, PV systems can be expected to operate considerably longer than the remuneration period. In 2021, the first feed-in remuneration contracts will run out and several years later a large amount from the PV installation boom (2009-13) will follow.[1]

At the end of 2017 there was no clear regulation how to deal with such PV systems after the support period. Only priority feed-in will remain. Therefore, it is likely that the owners have to negotiate and conclude contracts about the remuneration for feeding into the grid with local utilities and/or direct marketers on their own, with only modest expectation of sufficiently high feed-in tariffs.[2] Hence, with the end of this support period, the business model for owners of a PV system will change (e.g. Williams et al., 2012; Luthander et al., 2015). This applies in particular to the first generation of PV owners who benefitted from feed-in tariffs substantially higher than the costs of purchasing electricity from suppliers. While the goal was previously to maximize feed-in, the best way to approach this new situation has yet to be identified. This leads to the question: What should an owner of a small-scale PV system do after the end of the remuneration period?

Under the assumption that the PV system is operable for several additional years, the owner could choose between four possible options (Figure 1): 1) she could maximize the benefit of self-consumption, 2) she could keep producing electricity and sell it directly, 3) she could dismantle or decommission the system, or 4) she could renew the system. Option 4) will only be chosen if a new system is favorable for the owner in terms of remuneration or expected lifetime, option 3) will be chosen if the expected revenues of option 1) and 2) are negative or smaller than the scrap value minus the expenses for dismantling the PV system and the system owner has no incentives to invest in a new system. In the following, options 2) – 4) will not further be discussed. Option 2) is – at least in our opinion – very interesting regarding alternative business models for the marketing of electricity. However, as outlined above, this option appears not to be attractive for owners of small scale PV systems. The experience in Germany shows that the major part of direct marketers require a minimum size of 100 kWp for their portfolio (Kelm et al., 2014). Moreover, rational households will weigh this option against the cost savings from self-consumption, which will continue to be sizeable as long as electricity consumer prices in Germany do not plummet dramatically. For this reason, and also because of the uncertainty related to the

[1] In the years 2009 to 2013, nearly three-quarters of the total installed capacity in 2016 where built up.
[2] E.g. Kelm et al. (2014) point out that the share of PV systems below 100kw participating in direct marketing is negligible due to the disproportionate cost of marketing those systems.

negotiation outcomes, we will not further analyze the economic rationale behind this option. The research focus of this paper is therefore on option 1): the analysis of the potential benefits from self-consumption.

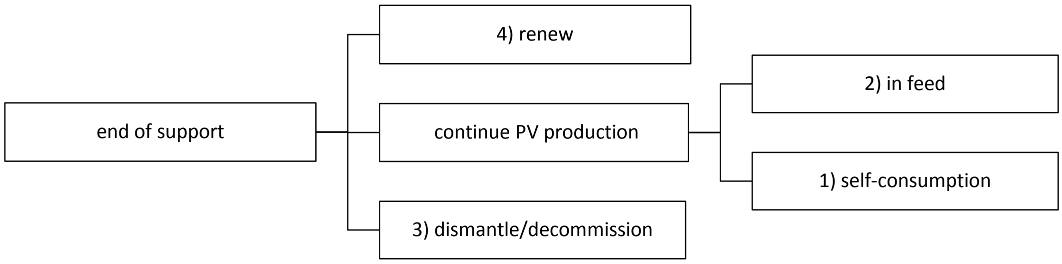

Figure 1: Options after the end of support

However, due to the different patterns of PV production and household consumption, a large part of the electricity produced should be stored intraday. Therefore, to fully exploit the potential of self-consumption, an investment into storage systems is required. At the moment, there are two main storage options for private households: battery systems and hot water thermal storages.

The latter storage option involves the conversion of electricity into thermal energy. As a consequence, from a societal point of view, this option is of special interest in the context of Germany's current attempts to decarbonize its private heating market and support renewable energy in residential heating (e.g. Renewable Energy Heat Act). In 2016, the share of the residential sector of total greenhouse gas (GHG) emissions in Germany accounted for 10 % (UBA, 2018). Since space heating and hot water account for 82 % of the final energy consumption in private households, a significant amount of these GHG emissions is caused by heat generation. With 26 % (oil) and 50 % (gas) of the energy consumption for heating purposes, private heat generation in Germany is still heavily dominated by fossil fuels (Destatis, 2017c). In addition, due to the currently moderate oil prices, this pattern is not likely to change dramatically in the near future. In this regard, using energy from the PV system to produce heat could reduce the use of heating oil and natural gas in the private heating sector and therefore contribute to the decarbonization of this sector.

Against this background, we quantify the wider economic potential of PV self-consumption by single-family houses with small-scale roof-top photovoltaic systems against the background of two recent storage applications (power-to-heat-modules[3] and battery systems) in Germany. We focus on single-family houses because the majority of the small scale roof-top systems are installed on these types of buildings (BMWi, 2015). Profitability of the systems is evaluated by means of a discounted cash flows analysis of each of the three system setups (Table 2). The reference system consists of a small scale PV system and a conventional gas-fired condensing boiler without any storage options.[4] The second system adds battery storage for storing self-produced electricity to the reference case. The third system includes instead of battery storage a simple Power-to-Heat-module (PtH-module). This PtH-module consists of two elements: an electric heating application and a hot water thermal storage tank (herein after: thermal storage). The electric heating application is integrated in the thermal storage as a second heat source in addition to the condensing gas boiler. Finally, the fourth system comprises both battery storage and the thermal storage including the PtH-module. Comparing Net Present Values of these systems provides a comprehensive picture of the microeconomic benefits of PV generation at household level in post-support periods. For this purpose, we carry out comprehensive simulations of site-specific PV production and determine the optimal PV self-consumption as well as the optimal charging of the thermal storage and the battery system in quarter-hourly resolution.

[3] In this paper, we use the term power-to-heat-module (PtH-module) to describe the technical solution for storing electricity as heat in the hot-water system.
[4] In the remainder of this paper, we focus on gas condensing boiler systems, because they represent the most common heating source in Germany.

Components	Reference	System 2	System 3	System 4
PV system	+	+	+	+
Gas-fired condensing boiler	+	+	+	+
Battery storage		+		+
PtH-module			+	+

Table 2: Technical system setups

1.2. Related literature and research context

In recent years, a growing research interest concerning the economic potential of PV self-consumption has arisen. This is on the one hand driven by the substantial cost reductions of PV modules and the attainment of grid parity for PV in many countries, which make PV self-consumption more attractive.[5] On the other hand it is due to the declining remunerations of the national support schemes and obligatory self-consumption shares, which reduces attractiveness of in-feed and increases attractiveness of on-site consumption.

Luthander et al. (2015) provide a comprehensive literature review of PV self-consumption in buildings. Most of the contributions investigate the use of residential battery systems for an optimized PV self-consumption or the potential of demand side management; only three are concerned with thermal storage applications (Williams et al., 2012; Vrettos et al., 2013; Thygesen and Karlsson, 2014). All of them consider heat pumps as heating source in combination with hot water thermal tanks. The most recent contribution of Lang et al. (2016) also focuses solely on electric heating applications. Balcombe et al. (2015) investigate a system setup with a Stirling engine for combined heat and power production with a battery system and a solar PV module in the UK.

Bloess et al. (2018) present an extensive literature review of model-based analyses concerning PtH technologies (excluding combined generation of heat and power) for renewable energy integration. They point out that across the considered studies PtH can in general effectively contribute to the integration of renewable energy by the substitution of costly fossil fuels. However, they remark that many studies focus on future scenarios with high shares of intermittent renewable energy, instead of investigating the potential impact of those technologies on the status quo energy system.

We add to the debate this – to our knowledge – less considered issue. We consider already existing PV systems and fossil energy as a heating source – more precisely gas condensing boiler systems. Our point of departure is thus deliberately the status quo of the legacy system and not a rather artificial first-best technology scenario.

1.3. Outline of the paper

The remainder of this paper is structured as follows. In section 2 we present our simulation approach and the data used. First (2.1), the heat load profile is generated based on the reference load profile method of the German technical guideline VDI 4655. Second (2.2), the PV output of the roof-top system is simulated on a quarter-hourly basis for an average year in Southern Germany. Third (2.3), the selection and standardization of the electricity load profiles is explained. In section 2.4, all three time series are used to calculate the cost savings of the different systems as well as the corresponding net present values of the investments of the considered system setups. The results are presented in section 3 and a sensitivity analysis regarding battery size is conducted. Section 4 concludes with a discussion.

[5] Grid parity is understood as the situation in which the levelized cost of electricity (and thus in the medium-run also the feed-in tariff of a newly installed renewable energy source (e.g. PV roof-top system)) is less or equal to the domestic electricity price.

2. Data and methodology

In this study three types of energy profiles are used to determine the optimal path for PV self-consumption in a cross-sector perspective: consumption profiles for heat and electricity as well as PV production profiles. Since load profiles are subject to seasonal, daily and intra-daily fluctuations, we use 15-min frequency to capture long-term as well as short-term dependencies. Quarter-hourly heat load profiles are derived by using the synthetic reference profiles by the VDI Guideline 4655. In addition, the PV production profiles are obtained based on recent literature. Furthermore, measured electricity profiles from the HTW Berlin (2015) are applied to provide representative electricity load profiles. Figure 2 depicts the samples of these load profiles on a winter and on a summer day.

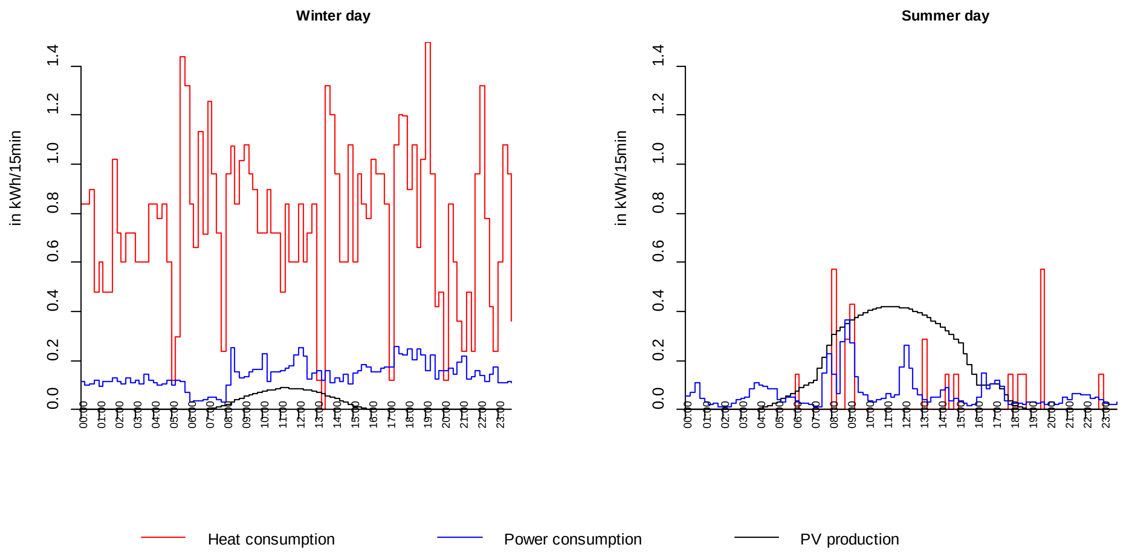

Figure 2: Sample of daily load and production profiles on a winter and summer day

2.1. Simulation of the heat load profiles

The energy demand for heating purposes that could potentially be covered by the photovoltaic system is investigated by calculating representative heat load profiles for sample households. To this end, the reference load profile method of the German technical guideline VDI 4655 is used to generate the energy demand for space heating and domestic hot water for typical single- and two-family houses (SFH) over the course of a year on quarter-hourly basis.

There exist various approaches to determine the energy demand for space heating and domestic hot water, in particular since one of the striking characteristics of the heating market is its diversity and complexity. The number of possible combinations of heating systems and the configuration of the building stock is enormous and many variables need to be taken into consideration. The key non-behavioral factors affecting the energy demand for space heating and domestic hot water are the equipment of the building (size, thermal insulation status and the heating system) as well as external factors like the outside temperature, regional climatic parameters (e.g. wind conditions) and further regional particularities as building and population structure. Hence, diverse approaches exist to fit different purposes with respective advantages and shortcomings. One can distinguish between standard load profile methods, statistical load profile methods, physical models and reference load profile methods (Fischer et al., 2016).

In this study, the reference profile method from the guideline 4655 of the VDI (Association of German Engineers) is the model of choice for generating heat demand curves of considered buildings. It is a commonly chosen option in the literature for calculating detailed heat load profiles for buildings (e.g. Pohl et al., 2014; Siemer et al., 2016; McKenna et al., 2017; Haupt and Müller, 2017). The guidelines' inherent purpose is to generate reference profiles as a tool for simulating system efficiencies of combined heat and power units alongside corresponding economic efficiencies for residential buildings. On the basis of measured values, the guideline determines ten typical day-categories depending on season, outside temperature, days of the week and weather conditions. The underlying procedure to determine the reference profiles is described in detail in guideline 4655 of the VDI. By means of these reference profiles one is able to derive individual heat profiles for a distinct set of variables and hence simulate daily demand curves for a specific sample building. The following specifications are needed for the determination: i) the building type ii) the number of residents, iii) the living space of the building, iv) the total annual heat demand and v) the respective climate zone where the building is located.

For our analysis the following assumptions are made regarding the reference building: i) We focus on single-family houses and did not consider multi-family houses in our analysis, due to the fact that SFH make up about 83.1 % of the national housing stock (Destatis, 2017a) and the majority of the small scale photovoltaic roof-top systems are installed on this building type (BMWi, 2015). ii) Moreover, we assumed the sample SFH to have three residents. iii) Furthermore, the living space of the sample SFH in our analysis is assumed to match the national average of SFH with 128 m^2 (Destatis, 2017a). iv) The specific heat demand is considered to be 110 kWh/m^{2}a.[6] In 2016 the overall average specific heat demand in Germany was 127.7 kWh/m^{2}a (Destatis, 2017b). In addition, following the guideline, the annual energy demand for domestic hot water is included with a lump sum of 500 kWh/resident. In combination with iii) this leads to a total energy consumption for heating purposes of 15,127 kWh/a for the investigated sample building. v) Concerning the location of the building the TRY-region 13 of the German Meteorological Service (DWD) is used. The TRYs represent the characteristic weather and temperature conditions for different regions in Germany over the course of a year. They are developed from long-run measurements of weather conditions and represent the values and variability of the long-term means of the corresponding meteorological regions. Their original purpose is the simulation concerning heating and room air equipment and the thermal performance of buildings (DWD, 2017). In this regard, we used climatic TRY-regions 13, which suitably cover the largest part of Southern Germany's land area.

2.2. Simulation of residential photovoltaic production

The output of a solar module is mainly determined by three parameters: the solar irradiance on the tilted surface, the ambient temperature and technical characteristics of the used solar panel (Hellman et al., 2014). We model the equation for hourly PV production in line with established methods (e.g. Lang et al., 2016; Duffie and Beckman, 2013; Hellman et al., 2014). The output P_t^{PV} of the PV system at hour t is computed as:

$$P_t^{PV} = G_t(\beta, \phi, \delta_t, \gamma, \omega_n) \times A \times \eta_t(\eta_r, \kappa_{TC}, G_t) \times PR \quad (1)$$

The function G_t represents solar irradiation on the PV module, A is the parameter for the area-size of the modules, the function η_t represents the relative efficiency and PR denotes the performance ratio of the system. Parameters of the functions G_t and η_t are explained in formal detail in Appendix A. However, the basic mechanisms and parameters used in the simulation are explained shortly in a less formal manner in the following paragraph.

The solar irradiation on the tilted surface depends on location, azimuth and declination of the modules. Due to the feed-in tariffs in Germany, most systems have a production-maximizing southern orientation and a declination between 30° – 40° (Zipp, 2015; Fraunhofer ISE, 2015). Since we consider already installed systems, we assume a southern orientation (azimuth = 0) and an average declination of 35°. For solar irradiance and ambient temperature, we again make use of the time series from the TRY database. The horizontal and diffuse

[6] Due to the downsizing effect of regulations like the EnEV (Energy Saving Ordinance) on heat demand, the respective energy demand for recent SFH is substantially lower than the national average. Since we do not consider a specific insulation standard (e.g. low or zero energy houses) we choose 110 kWh/m^2 as a reasonable parameter for our simulation.

irradiation data is calculated by the DWD, the ambient temperatures are measured at the corresponding weather station (Muehldorf). For the technical specifications (e.g. temperature coefficient) of the solar panel, we use average values for a crystalline PV modules from recent literature on PV modelling (e.g. Hellman et al., 2014; Lorenz et al., 2011; Skoplaki and Palyvos, 2009; Mattei et al., 2006). We assume a nominal module efficiency of 15.3 %, which is corrected for temperature effects (Eq. A.7/A.8 in Appendix A). Typical values for the performance ratio (PR) lie between 0.8 - 0.9. Since we do not consider newly installed PV modules, we use a conservative PR of 0.7, taking degradation effects into account. We investigate a PV system with about 5 kWp, which corresponds to an area-size of about 35 m^2. In sum, 4521 kWh (904.2 kWh/kWp) are generated over the course of a year.

2.3. Electricity load profile

To simulate a household's consumption pattern of electricity, researchers can draw on artificial load profiles. In practice, such load profiles are used by network operators for predicting the load caused by small customers without registered measurement devices. These kind of profiles are usually significantly smoother than actual measured data. In sum, these profiles match the aggregated demand for a greater number of households well, but they do not depict the volatile temporal consumption pattern of single households due to socioeconomic factors (e.g. employment status, leisure activities). To account for these circumstances we choose a synthesized dataset of actual measured load profiles provided by HTW Berlin (2015) for our analysis. The data set consists of 74 profiles of German single family houses with a temporal resolution of 1 minute. Furthermore we selected the 25 profiles which have a total consumption between 4000 and 5000 kWh/a. To ensure comparability, all profiles are scaled to a total consumption of 4521 kWh/a. Therefore, the profiles only differ in terms of the individual temporal distribution of consumption. By considering a set of different temporal consumption patterns, we try to obtain a broader picture regarding the drivers of the profitability of the system setups. Therefore, we calculate for each profile the share of consumption that arises between 6 p.m. and 8 a.m. (hereinafter referred to as night share), to classify households regarding their daily consumption pattern. The night shares of the profiles range between 0.39 and 0.65.

2.4. Cost simulation and DCF analysis

Our first aim is to analyze the cost savings from electricity self-consumption under each of the three systems described. This is done by simulating electricity and heating expenses at a quarter-hourly level for each of the systems. In doing so, we assume a cost-minimizing operation of each system, as should be realistic for economically rational households. As a consequence, optimal system operation will strongly hinge on the evolution of consumer prices of electricity and fossil heating sources. Current market conditions in Germany reveal a significant discrepancy. In 2016, the annual average consumer price of electricity amounted to about 29.7 Ct/kWh (Destatis, 2018) and thus remained close to an all-time high. During the same time period, effective gas prices per kWh were observed to lie at an average of 6.8 Ct/kWh (Destatis, 2018) and declined afterwards. Even with recovering fossil fuel prices in the future, it is highly unlikely that the price gap between the two energy forms will narrow considerably. Hence, imposing a strict priority of direct self-consumption of electricity compared to an indirect self-use for heating purposes via the PtH-module is no controversial assumption: total cost savings will simply be higher.

Further design options concern the technical side. Adding batteries (e.g. lithium ions batteries) to the PV module can be expected to raise electricity cost savings: by creating storage opportunities, the adverse impact of the limited conformity of generation and consumption patterns over time can partly be neutralized. The degree of this effect is crucially determined by storage capacity as well as discharge efficiency of the battery system. In principle, by combining several battery cells to one system, storage capacities of considerable magnitude could be created. However, costs of larger systems are still prohibitively high from the perspective of single households (McKenna et al. 2013). In this study, we therefore only consider battery storages up to 6 kWh. As a base case value, we choose 4 kWh, which was found to be in the cost-efficient range by Balcombe et al. (2015). Moreover, Weniger et al. (2014) show that a battery size of about 1 kWh/kWp is sufficiently dimensioned for achieving high degrees of self-sufficiency. In reality, discharge efficiency is a time-variant measure, changing slightly with ambient temperature, operating voltage and state-of-charge. Trying to reproduce these complex details in our simulation would add little to our understanding of the economic implications. Instead, we follow parts of the literature by treating discharge efficiency as a fixed parameter defined as the ratio of usable electricity output to electricity input (Castillo-Cagigal et al., 2011; Chen et al., 2012; Purvins et al., 2013). As a parameter value for our base case simulations, we impose an efficiency level of 80 % as proposed by Balcombe et al. (2015).

Capacity considerations are also relevant for the PtH-module. The amount of electricity-generated heat available to the household over time both depends on the performance capacity of the heating rod and the storage capacity of the thermal storage. For the former, a value of 6 kW is implemented, which is within the typical range of sizes currently sold on the market. For the latter, a volume of 500 l is chosen, which is sufficiently large for single-family houses. A further technical restriction is a constraint to the quantity of heat stored at each instant, which is defined by the upper and the lower temperature limits of the thermal storage. For these limits, experience-based values of 35 °C and 85 °C are chosen. Furthermore, the hourly level of standing losses of heat energy stored within the thermal storage is accounted for by applying the approximation proposed by the norm DIN EN 304. Finally, the efficiency of energy conversion through PtH has to be specified. As the heating rod is simply plugged into the thermal storage, efficiency can be assumed to approach 100 %. In our simulations, we specify a value of 99 %. Having defined the economic and technical settings, we can formulate the cost equations resulting from the premise of cost-minimizing operation. As explained above, this premise will imply a usage priority of self-generated PV electricity for the purpose of direct consumption. Under *Reference* (no storage opportunities), equations for annual electricity (C^E) and heating (C^H) costs summed up over the quarter hours u over a simulation year y are simply defined as:

$$C_{1,y}^{E} = p_{y}^{E} \sum_{u=1}^{35040} max.\{Q_{u,y}^{E} - P_{u,y}^{PV}; 0\} \tag{2}$$

$$C_{1,y}^{H} = p_{y}^{H} \sum_{u=1}^{35040} Q_{u,y}^{H} \tag{3}$$

where Q^E (Q^H) marks the exogenous consumption quantities of electricity (heat) and p^E (p^H) denotes the corresponding consumer price on the market.[7] With this system, savings potentials compared to the reference of fully external provision are thus restricted by the amount of PV electricity that can be instantly consumed. Under *System 2*, the existence of battery storage enhances savings opportunities, but only with respect to electricity costs:

$$C_{2,y}^{E} = p_{y}^{E} \sum_{u=1}^{35040} max.\{Q_{u,y}^{E} - P_{u,y}^{PV} - v \cdot B_{u-1,y}^{PV}; 0\} \tag{4}$$

$$C_{2,y}^{H} = C_{1,y}^{H} \tag{5}$$

[7] For the sake of notational clarity, we do not use an additional index for the respective household in the following equations. Nevertheless, the simulations are carried out for each of the 25 different electricity load profiles.

where B_{u-1}^{PV} denotes the battery's state-of-charge (in kWh) at the end of the preceding quarter hour and υ denotes the discharge efficiency. Under *System 3*, opportunities to save heating costs are created by the PtH-module, where the accumulated amount of heat in the thermal storage represents a constraint:

$$C_{3,y}^{E} = C_{1,y}^{E} \tag{6}$$

$$C_{3,y}^{H} = p_y^H \sum_{u=1}^{35040} max.\left\{Q_{u,y}^{H} - \widetilde{Q_{3,u,y}^{H}}; 0\right\} \tag{7}$$

where $\widetilde{Q_{3,u,y}^{H}}$ stands for the maximum amount of heat that can be drawn from the thermal storage in quarter hour u under *System 3* (i.e. the amount causing the storage temperature to drop to its minimal level of 35 °C). A precise formula for $\widetilde{Q_{3,u,y}^{H}}$ is derived in Appendix B. Most importantly, it positively depends on recent levels of electricity generation and negatively on recent levels of electricity consumption. Under the full *System 4*, the household is in the position to make use of two kinds of energy storages for cutting its energy expenses. Given the priority of electricity consumption, only the amount of generated PV electricity that exceeds the capacity of battery storage will be directed to the PtH-module. Hence, electricity expenses will be the same as under *System 2*. In general:

$$C_{4,y}^{E} = C_{2,y}^{E} \tag{8}$$

$$C_{4,y}^{H} = p_y^H \sum_{u=1}^{35040} max.\left\{Q_{u,y}^{H} - \widetilde{Q_{4,,u,y}^{H}}; 0\right\} \tag{9}$$

where $\widetilde{Q_{4,u,y}^{H}}$, the maximum amount of heat extractable from the thermal storage, will tend to be lower than under *System 3*. Finally, for each system, model dynamics are described by the evolution of two state variables over time: state-of-charge of the PV battery and temperature within the thermal storage. The corresponding dynamic equations are given in Appendix B.

In order to assess the different systems in terms of their profitability, pure cost comparisons are however insufficient. Energy cost savings resulting from switching to a technologically more advanced system need to be weighed against the required investment expenses. Therefore, as a next step, the cost estimates enter a cost-benefit-analysis. Precisely, we undertake Net Present Value (NPV) calculations for the investments involved in switching from *Reference* to *System 2, 3* and *4*. Hence, investment scenarios correspond to the acquisition of a PV battery storage (*System 2*), a thermal storage plus heating rod (*System 3*) or both (*System 4*), in each case from the perspective of owners of an (already installed) PV system and a gas-fired condensing boiler. We consider a project period of 10 years, which seems reasonable given the limited planning horizon of a typical middle-class household. Net Present Values of the investments into system $s = \{2,3,4\}$ are calculated as follows:

$$NPV_s = -INV_{s,0} + \sum_{y=0}^{x} \frac{\left(C_{1,y}^{E} - C_{s,y}^{E}\right) + \left(C_{1,y}^{H} - C_{s,y}^{H}\right)}{(1+r)^y} \tag{10}$$

with $INV_{s,0}$ denoting the initial investment expenses and r denoting the annual discount rate. To determine the investment expenses, some market research concerning current prices of battery and thermal storage was carried out. Based on research of current prices paid in online stores, we choose the following representative prices for the base case scenario: 6000 Euro (1500 Euro/kWh) for the turn key battery storage[8] and 2500 Euro for the thermal storage. As the annual discount rate, we choose a value of 2 %, reflecting the currently low level of interest rates in the Euro area. Concerning the patterns of energy use, we make the assumption that current patterns will persist in the nearer future, leading to constant annual savings.

3. Results

3.1. Cost savings

We perform simulations for each of the 25 electricity profiles based on the set of parameter values mentioned above. To start with, Table 3 lists the average annual electricity and heating costs over all profiles. The first comparison that can be made is between *Reference* and *System 2* (PV module with and without storage facilities). As heat provision is not affected, savings are limited to expenses for electricity. The ability to store limited amounts of self-generated electricity during the day allows for a better exploitation of PV electricity for the purpose of self-consumption. Under the given setup and current consumer prices, annual savings would amount to about 320 Euros on average. Of course, these cost savings need to be weighed against the one-time investment costs of battery storage, as is done in the following section 3.2.

System	Annual electricity costs in Euro/year	Annual heating costs in Euro/year	Annual total costs in Euro/year
Reference	885.10	1016.32	1901.42
System 2 (PV + Bat.)	565.24	1016.32	1581.56
System 3 (PV + Therm.)	885.10	886.45	1771.55
System 4 (PV + Bat. + Therm.)	565.24	942.23	1507.47

Table 3: Simulated average energy expenses under the different systems

The additional potential of electricity usage for heating purposes is revealed by the simulations for *Systems 3* and *4*. In absence of battery storage (*System 3*), average annual savings in heating costs through the PtH-module are estimated to be about 130 Euro. Again, these values have to be seen in relation to expected investment needs. For households already possessing a thermal storage as part of their heating system, investments will confine to the acquisition of an electric heater. For households without thermal storage capacities, the need to buy a storage tank will raise investment costs even more. Finally, a comparison to the most comprehensive *System 4* with its twofold storage options reveals the trade-off in cost efficiency between electricity and heating. While the addition of battery storage reduces electricity costs compared to *System 3*, heating costs are slightly higher: less PV electricity is available for heating purposes, as more of it can be used to meet the electricity demand. Nevertheless, total costs are the lowest under this setup. Compared to the operation of a PV module alone (*Reference*), average savings in energy costs add up to more than 393 Euros per annum. Again, this sum needs to be confronted with the investment expenses associated with the creation of storage capacities.

Table 4 provides metrics for the self-sufficiency rate (SSR) of the different system setups. Self-sufficiency indicates the share of residential electicity/heat demand, which can be met by PV production over the course of the year. It therefore includes also stored PV generation. The SSR of electricity only varies with the availability of a battery system. On average, 34 % of the electricity demand could be met directly (*Reference and System 3*). Our results underpin the results of Quoilin et al. (2016), who show that the average SSR of a European household without any storage application varies between 30 % and 37 %. By adding the battery system, the SSR could be raised by 24 percentage points in our simulation. Regarding the SSR of heat, a maximum is reached in *System 3*.

[8] As pointed out by ISEA (2017) we assume an end user price for the battery storage of 1500 €/kWh; this was the 2016 average price of lithium ions battery systems in Germany.

More than 13 % of the annual heat demand could be met on average by the PV system and the PtH-module. The lower share for *System 4* (7 %) is due to the priority use of PV generation for charging the battery.

In order to illustrate the dependence on the households' electricity load profiles, Figure 3 depict annual savings in total energy costs in comparison to Reference for each of the 25 profiles under Systems 2, 3 and 4, respectively.[9] The profiles are distinguished by the night share of electricity consumption. In line with intuition, cost savings tend to be higher for profiles with a higher night share, as this allows for a better exploitation of storage opportunities. Respectively, vice versa there are fewer incentives to invest in storage applications if the household's consumption pattern is better in line with the PV production.

Self-sufficiency rate (SSR)	Reference	2.	3.	4.
Electricity	0.24 – 0.41	0.50 – 0.64	0.24 – 0.41	0.50 – 0.64
	Ø 0.34	Ø 0.58	Ø 0.34	Ø 0.58
Heat	-	-	0.11 – 0.15	0.06 – 0.09
	-	-	Ø 0.13	Ø 0.07

Source: own calculations

Table 4: Range and average of self-sufficiency rates (SSR)

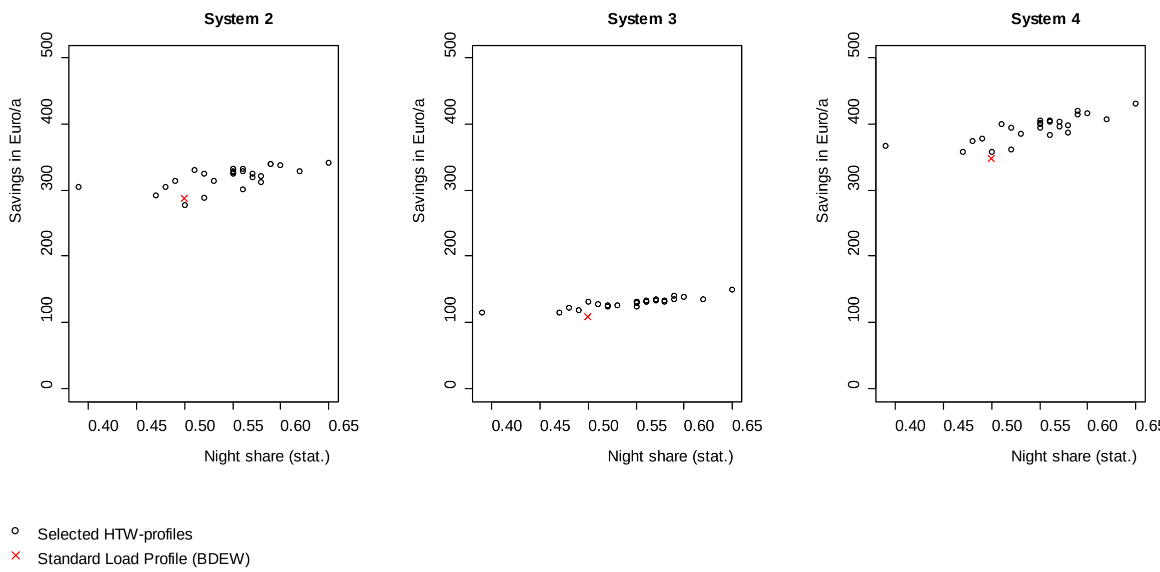

Figure 3: Comparison of annually cost savings of System 2, 3 and 4 against Reference

3.2. Returns to investment

For an evaluation of the returns to investing into battery and/or thermal storage, a NPV analysis is carried out. Again, the perspective of an owner of an already installed PV system outside the remuneration period, i.e. *Reference*, is taken. Before addressing results for specific electricity profiles, we have a look at the average returns. Under the parameter set mentioned above, we obtain the results listed in Table 5.

[9] For the sake of comparability, we additionally depict the results for the Standard Load Profile (BDEW), since it is frequently used by other studies as stated in Hayn et al. (2014). It shows that using the Standard Load Profile underestimates the cost savings potential of SFH in Germany, at least in our simulations.

System	Total investment costs in Euro	Annual cost savings in Euro	Net Present Value in Euro	Discounted total savings in Euro
System 2 (PV + Bat.)	6000	320	-3394	2060
System 3 (PV + Therm.)	2500	130	-1383	1190
System 4 (PV + Bat. + Therm.)	8500	393	-4892	3610

Source: own calculations

Table 5: Investment costs, average annual cost savings, average NPV and average discounted total savings for implementing Systems 2, 3 and 4

Under the assumption that the investment cost for the turn key battery system is 1500 Euro/kWh, the acquisition of a battery system with 4 kWh leads for all profiles to negative NPVs, on average -3394 Euro for *System 2*. For *System 3* the average NPV amounts to -1383 Euro, assuming investment cost of 2500 Euro for a hot water thermal tank, a PtH-module, hydraulic components and installation. *System 4's* average NPV, combining battery storage and PtH-module, amounts to -4892 Euro. From an economic perspective, there is no incentive for a rational household to invest in storage, at least with the investment costs assumed in our simulation. The discounted total savings (Tab. 5) indicate to what extent the investment costs of the different systems has to fall to become economic reasonable. In consideration of the mature heating technology, it is unlikely that the investment costs drop dramatically for System 3 in the near future, while the battery costs decreased rapidly in the last years.[10]

Nevertheless, this result should be qualified with respect to electricity profiles. Given the discrepancy in cost savings among the electricity profiles, calculated NPVs are likewise dependent on the patterns of use. This is illustrated in Figure 4, again with profiles distinguished by the night share of electricity consumption. While outcomes are slightly better for profiles with higher night shares, the NPV remains in every case far below zero. Hence, with current energy prices, investments do not pay off regardless of the household type analyzed.

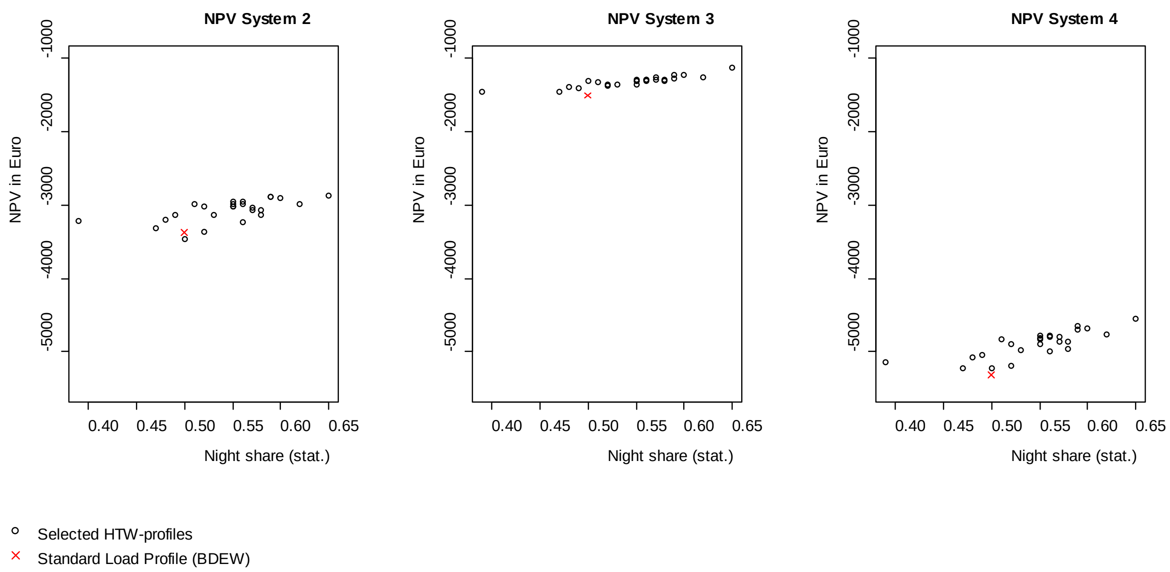

Figure 4: Net present values of each system

[10] We assume that the household has to invest in a new hot water thermal storage with a unit for domestic hot water. If we assume that a retrofit of the existing system is sufficient, this implies substantially lower investment costs. Under that assumption, the average NPV of System 3 could already be positive.

3.3. Sensitivity analysis

Given the high level of technical and economic detail involved in our model specification, a sensitivity analysis is essential for understanding the dependence of simulation results on the scenario design. In principle, such an analysis could address any technical feature of the household's system of energy provision. However, as our focus is on cost savings in the context of storage options, we focus on three crucial parameters: electricity prices, gas prices and battery capacity. Concerning the energy prices, we introduce variation by considering trend projections instead of current prices used before. Trend projections of electricity and gas prices have been undertaken based on a linear regression. As these projections yield a moderate positive trend for the prices of both energy carriers, predictions of cost savings and thus also of investment returns become slightly more optimistic, as Figure 5 reveal. Nevertheless, NPV estimates persistently remain in a negative range, implicating that even with a return to long-term price trends in energy markets the examined investment options will not pay off.

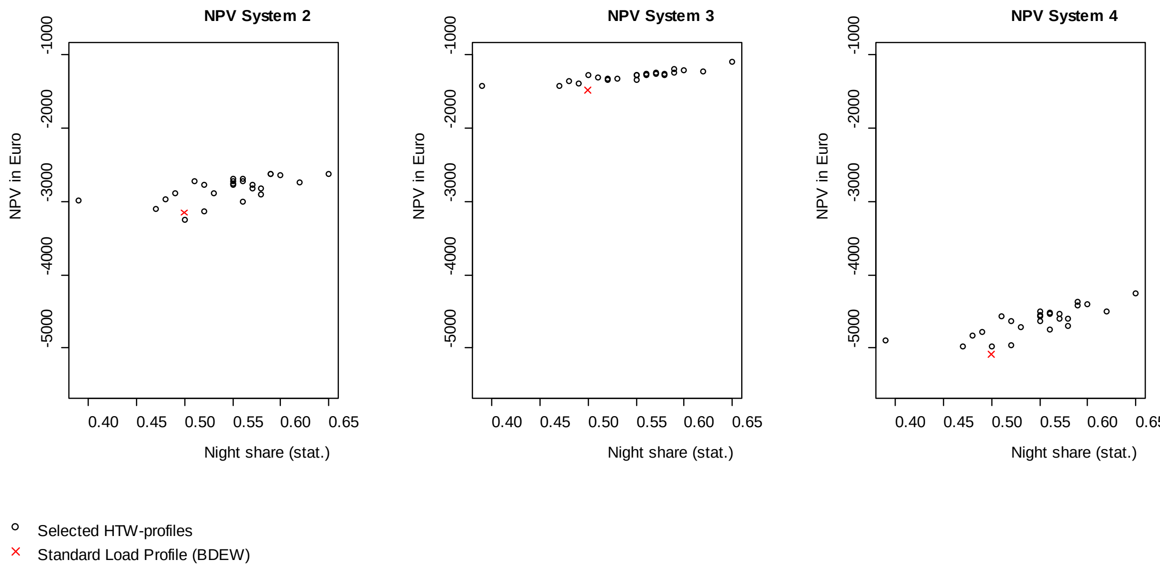

Figure 5: Net present value of each system under price trend projections

Concerning a variation in battery storage, a higher capacity allows for more significant reductions of electricity expenses, as consumption becomes less reliant on current weather conditions. However, as mentioned above, large battery capacities are currently assessed to be prohibitively expensive right now and likely also in the nearer future from the viewpoint of an average household. We therefore restrict the parameter variation to a reasonable range of up to 6 kWh. The results of the sensitivity analysis concerning the battery capacity are shown in Figure 6 as box plots. None of the considered battery capacities has a positive NPV.

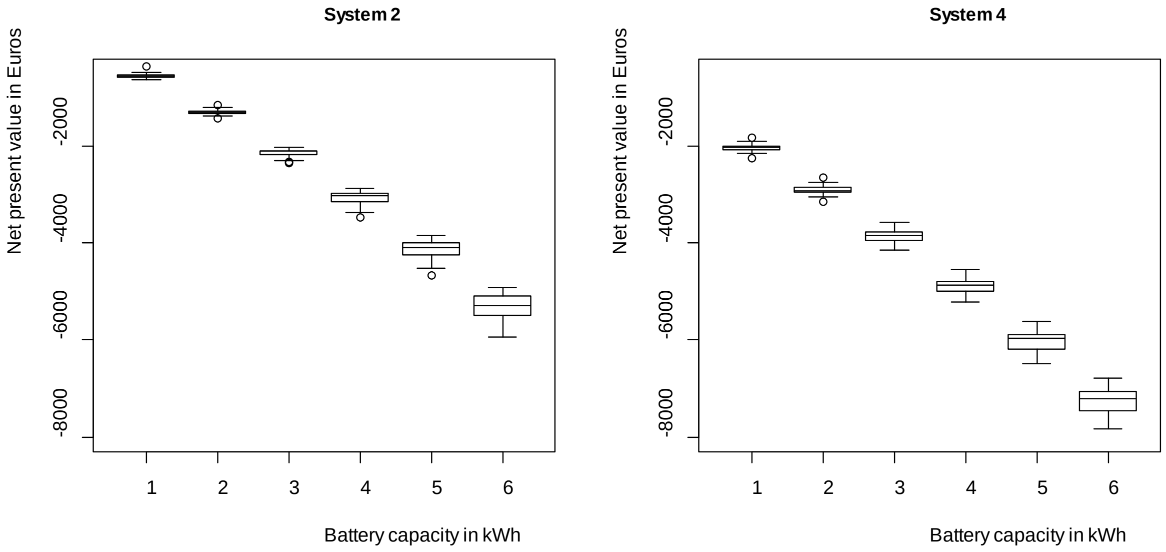

Figure 6: Net present values of System 2 and 4 for different battery capacities

4. Conclusion

The purpose of this paper is to assess the cost savings potential of PV self-consumption of single- family houses after the support period in Germany. We focus on a cross-sector perspective and therefore took heat demand (SH and DHW) into account. In the *Reference case*, the heat demand is satisfied by the gas condensing boiler and electricity consumption by the grid as well as direct utilization of the PV system. In this case, the annual costs amounted to 1901 Euros on average. The comparison of the four system setups indicates that the biggest (gross) cost savings potential is achieved with a battery system and a thermal storage (*System 4*): about 393 Euro/year. The difference between the implementation of a battery system (about 320 Euro annual savings on average) and the PtH-module (about 130 Euro annual savings on average) is of moderate importance in terms of cost savings, but significant in terms of the NPV of the investments needed. Against the backdrop of relatively high battery prices per kWh, it seems more reasonable to choose the PtH-option rather than the battery for raising the SSR for an individual household. Nevertheless, under the current price assumptions neither storage option yields positive NPV. Hence, cross-sector PV self-consumption does not pay off, at least at the current prices assumed in our simulations. But, regarding the fast declining battery prices and the relatively long time until the majority of PV system will run out of support, it is very likely that the incentives for investing in storage application will rather grow than decline. The policy makers should carefully monitor this development and timely create a reliable legal framework if they want to safeguard the continued operation of former supported PV systems without creating new redistributive effects.

Further, our findings support the intuitive assumption that the higher the household's night share of consumption, the greater the benefit of a storage application. We find a positive relationship between the NPV of investing in a storage application and the night share of consumption. Furthermore, the range of our results is only driven by the different temporal distributions of consumption, not by the magnitude. As an additional side finding we can show that the use of the standard load profiles (BDEW) rather underestimates the cost savings potential of SFH in our simulations. These results underpin the necessity to consider different consumption patterns when evaluating the benefits of self-consumption.

References

Balcombe, Paul; Rigby, Dan; Azapagic, Adisa (2015): Energy self-sufficiency, grid demand variability and consumer costs. Integrating solar PV, Stirling engine CHP and battery storage. In *Applied Energy* 155, pp. 393–408. DOI: 10.1016/j.apenergy.2015.06.017.

Bloess, Andreas; Schill, Wolf-Peter; Zerrahn, Alexander (2018): Power-to-heat for renewable energy integration. A review of technologies, modeling approaches, and flexibility potentials. In *Applied Energy* 212, pp. 1611–1626. DOI: 10.1016/j.apenergy.2017.12.073.

BMWi (2015): Marktanalyse Photovoltaik-Aufdachanlagen. Edited by Bundesministerium für Wirtschaft und Energie (BMWi). Available online at http://www.bmwi.de/BMWi/Redaktion/PDF/M-O/marktanalyse-photovoltaik-dachanlagen,property=pdf,bereich=bmwi2012,sprache=de,rwb=true.pdf.

BNetzA (2017): Das EEG in Zahlen 2016. Erneuerbare Energieträger: Installierte Leistung nach Größenklassen (in MW). Edited by Bundesnetzagentur (BNetzA). Available online at https://www.bundesnetzagentur.de/SharedDocs/Downloads/DE/Sachgebiete/Energie/Unternehmen_Institutionen/ErneuerbareEnergien/ZahlenDatenInformationen/EEGinZahlen_2016.xlsx?__blob=publicationFile&v=3.

Castillo-Cagigal, M.; Caamaño-Martín, E.; Matallanas, E.; Masa-Bote, D.; Gutiérrez, A.; Monasterio-Huelin, F.; Jiménez-Leube, J. (2011): PV self-consumption optimization with storage and Active DSM for the residential sector. In *Solar Energy* 85 (9), pp. 2338–2348. DOI: 10.1016/j.solener.2011.06.028.

Chen, X. P.; Wang, Y. D.; Yu, H. D.; Wu, D. W.; Li, Yapeng; Roskilly, A. P. (2012): A domestic CHP system with hybrid electrical energy storage. In *Energy and Buildings* 55, pp. 361–368. DOI: 10.1016/j.enbuild.2012.08.019.

Destatis (2017a): Bestand an Wohnungen. Fachserie 5 Reihe 3. Edited by Statistisches Bundesamt (Destatis). Available online at https://www.destatis.de/DE/Publikationen/Thematisch/Bauen/Wohnsituation/BestandWohnungen2050300167004.pdf?__blob=publicationFile, checked on 3/20/2018.

Destatis (2017b): Energieverbrauch. Energie für Raumwärme nach Haushaltsgrößenklassen. Edited by Statistisches Bundesamt (Destatis). Available online at https://www.destatis.de/DE/ZahlenFakten/GesamtwirtschaftUmwelt/Umwelt/UmweltoekonomischeGesamtrechnungen/MaterialEnergiefluesse/Tabellen/EnergieRaumwaerme.html.

Destatis (2017c): Umweltnutzung und Wirtschaft. Tabellen zu den Umweltökonomischen Gesamtrechnungen Teil 2: Energie. Energie für Raumwärme nach Gebäudetypen und Energieträgern. Edited by Statistisches Bundesamt (Destatis).

Destatis (2018): Data on energy price trends. Long-time series from January 2000 to January 2018. Edited by Statistisches Bundesamt (Destatis). Available online at https://www.destatis.de/DE/Publikationen/Thematisch/Preise/Energiepreise/EnergyPriceTrendsPDF_5619002.pdf?__blob=publicationFile, checked on 3/20/2018.

Duffie, John A.; Beckman, William A. (2013): Solar engineering of thermal processes. 4. ed. Hoboken NJ: Wiley.

DWD (2017): Ortsgenaue Testreferenzjahre von Deutschland für mittlere, extreme und zukünftige Witterungsverhältnisse. Edited by Deutscher Wetterdienst (DWD) und Bundesamt für Bauwesen und Raumordnung (BBR). Available online at http://www.bbsr.bund.de/BBSR/DE/FP/ZB/Auftragsforschung/5EnergieKlimaBauen/2013/testreferenzjahre/try-handbuch.pdf?__blob=publicationFile&v=6, checked on 3/20/2018.

Fischer, David; Wolf, Tobias; Scherer, Johannes; Wille-Haussmann, Bernhard (2016): A stochastic bottom-up model for space heating and domestic hot water load profiles for German households. In *Energy and Buildings* 124, pp. 120–128. DOI: 10.1016/j.enbuild.2016.04.069.

Fraunhofer ISE (2015): Recent Facts about Photovoltaics in Germany. With assistance of Harry Wirth. Edited by Fraunhofer Institut für Solare Energiesysteme (ISE).

Fthenakis, Vasilis; Frischknecht, Rolf; Raugei, Marco; Kim, H. Chul; Alsema, Erik; Held, Michael; Wild-Scholten, Mariska de (2011): Methodology guidelines on life cycle assessment of photovoltaic electricity. 2nd edition, IEA PVPS Task 12, International Energy Agency Photovoltaic Power systems Programme.

Haupt, Axel; Müller, Karsten (2017): Integration of a LOHC storage into a heat-controlled CHP system. In *Energy* 118, pp. 1123–1130. DOI: 10.1016/j.energy.2016.10.129.

Hayn, Marian; Bertsch, Valentin; Fichtner, Wolf (2014): Electricity load profiles in Europe. The importance of household segmentation. In *Energy Research & Social Science* 3, pp. 30–45. DOI: 10.1016/j.erss.2014.07.002.

Hellman, Hannu-Pekka; Koivisto, Matti; Lehtonen, Matti (2014): Photovoltaic power generation hourly modelling. 15th International Scientific Conference on Electric Power Engineering (EPE).

HTW Berlin (2015): Representative electrical load profiles of residential buildings in Germany with a temporal resolution of one second. dataset. Edited by HTW Berlin - University of Applied Science.

ISEA (2017): Wissenschaftliches Mess- und Evaluierungsprogramm Solarspeicher 2.0. Jahres Bericht 2017. With assistance of Jan Figgener, David Haberschusz, Kai-Philipp Kairies, Oliver Wessels, Benedikt Tepe, Markus Ebbert et al. Edited by Institut für Stromrichtertechnik und Elektrische Antriebe (ISEA).

Kelm, Tobias; Schmidt, Maike; Taumann, Michael; Püttner, Andreas; Jachmann, Henning; Capota, Michael et al. (2014): Vorhaben IIc Solare Strahlungsenergie. Vorbereitung und Begleitung der Erstellung des Erfahrungsberichts 2014 gemäß § 65 EEG. With assistance of Zentrum für Sonnenenergie- und Wasserstoff-Forschung Baden-Württemberg (ZSW), Fraunhofer-Institut für Windenergie und Energiesystemtechnik (IWES), Bosch & Partner GmbH, GfK SE. Edited by Bundesministerium für Wirtschaft und Energie (BMWi).

Lang, Tillmann; Ammann, David; Girod, Bastien (2016): Profitability in absence of subsidies. A techno-economic analysis of rooftop photovoltaic self-consumption in residential and commercial buildings. In *Renewable Energy* 87, pp. 77–87. DOI: 10.1016/j.renene.2015.09.059.

Lorenz, Elke; Scheidsteger, Thomas; Hurka, Johannes; Heinemann, Detlev; Kurz, Christian (2011): Regional PV power prediction for improved grid integration. In *Prog. Photovolt: Res. Appl.* 19 (7), pp. 757–771. DOI: 10.1002/pip.1033.

Luthander, Rasmus; Widén, Joakim; Nilsson, Daniel; Palm, Jenny (2015): Photovoltaic self-consumption in buildings. A review. In *Applied Energy* 142, pp. 80–94. DOI: 10.1016/j.apenergy.2014.12.028.

Mattei, M.; Notton, G.; Cristofari, C.; Muselli, M.; Poggi, P. (2006): Calculation of the polycrystalline PV module temperature using a simple method of energy balance. In *Renewable Energy* 31 (4), pp. 553–567. DOI: 10.1016/j.renene.2005.03.010.

McKenna, Eoghan; McManus, Marcelle; Cooper, Sam; Thomson, Murray (2013): Economic and environmental impact of lead-acid batteries in grid-connected domestic PV systems. In *Applied Energy* 104, pp. 239–249. DOI: 10.1016/j.apenergy.2012.11.016.

McKenna, Russell; Merkel, Erik; Fichtner, Wolf (2017): Energy autonomy in residential buildings. A techno-economic model-based analysis of the scale effects. In *Applied Energy* 189, pp. 800–815. DOI: 10.1016/j.apenergy.2016.03.062.

Pohl, Elmar; Diarra, David (2014): Assessment of primary energy savings by means of CHP systems in domestic energy supply. In *Applied Thermal Engineering* 71 (2), pp. 830–837. DOI: 10.1016/j.applthermaleng.2013.12.021.

Purvins, Arturs; Papaioannou, Ioulia T.; Debarberis, Luigi (2013): Application of battery-based storage systems in household-demand smoothening in electricity-distribution grids. In *Energy Conversion and Management* 65, pp. 272–284. DOI: 10.1016/j.enconman.2012.07.018.

Quoilin, Sylvain; Kavvadias, Konstantinos; Mercier, Arnaud; Pappone, Irene; Zucker, Andreas (2016): Quantifying self-consumption linked to solar home battery systems. Statistical analysis and economic assessment. In *Applied Energy* 182, pp. 58–67. DOI: 10.1016/j.apenergy.2016.08.077.

Siemer, Lars; Schöpfer, Frank; Kleinhans, David (2016): Cost-optimal operation of energy storage units. Benefits of a problem-specific approach. In *Journal of Energy Storage* 6, pp. 11–21. DOI: 10.1016/j.est.2016.01.005.

Skoplaki, E.; Palyvos, J. A. (2009): On the temperature dependence of photovoltaic module electrical performance. A review of efficiency/power correlations. In *Solar Energy* 83 (5), pp. 614–624. DOI: 10.1016/j.solener.2008.10.008.

Thygesen, Richard; Karlsson, Björn (2014): Simulation and analysis of a solar assisted heat pump system with two different storage types for high levels of PV electricity self-consumption. In *Solar Energy* 103, pp. 19–27. DOI: 10.1016/j.solener.2014.02.013.

UBA (2018): National Trend Tables for the German Atmospheric Emission Reporting 1990 - 2016. Edited by Umweltbundesamt (UBA). Available online at https://www.umweltbundesamt.de/sites/default/files/medien/361/dokumente/2017_12_18_em_entwicklung_in_d_trendtabelle_thg_v1.0.xlsx.

Vrettos, Evangelos; Witzig, Andreas; Kurmann, Roland; Koch, Stephan; Andersson, Göran (2013): Maximizing local PV utilization using small-scale batteries and flexible thermal loads. In *EU PVSEC*.

Weniger, Johannes; Tjaden, Tjarko; Quaschning, Volker (2014): Sizing of Residential PV Battery Systems. In *Energy Procedia* 46, pp. 78–87. DOI: 10.1016/j.egypro.2014.01.160.

Williams, C.J.C.; Binder, J. O.; Kelm, T. (2012): Demand side management through heat pumps, thermal storage and battery storage to increase local self-consumption and grid compatibility of PV systems. In *3rd IEEE PES Innovative Smart Grid Technologies Europe (ISGT Europe), October 14-17, 2012. Piscataway*.

Zipp, Alexander (2015): Revenue prospects of photovoltaic in Germany—Influence opportunities by variation of the plant orientation. In *Energy Policy* 81, pp. 86–97. DOI: 10.1016/j.enpol.2015.02.017.

Appendices

Appendix A: Simulation of PV generation

Index:

$t = 1, \dots, T$	Hours of the year 2020 ($T = 8760$)
$n = 1, \dots, N$	Day of the year ($N = 365$)

Parameters:

ϕ	Latitude of the weather station / PV system (48.17° North)
γ	Azimuth of the PV system (0; south orientated)
β	Slope of the panel area (35°)
ρ	Ground albedo (0.2)
A	Total panel area (35 m^2)
PR	Performance ratio (0.7)
κ_{TC}	Temperature coefficient of the solar module (- 0.4 %/°C)
T_{NOCT}	Nominal operating cell temperature (25 °C)
T_{STC}	Standard test condition temperature of the solar module (46 °C)
η_r	Reference solar module efficiency (15.3 %)

Exogenous variables:

ω_n	Hour angle on solar noon[11] at day n
G_t^g	Total radiation on horizontal surface at time t
G_t^b	Beam radiation on horizontal surface at time t
G_t^d	Diffuse radiation on horizontal surface at time t
T_t^a	Ambient temperature at time t

Endogenous variables:

P_t^{PV}	PV generation at time t
G_t	Total radiation on tilted surface at time t
R_n^b	Geometric factor at day n
ψ_n	Angle of incidence at day n
ψ_n^Z	Zenith angle at day n
δ_n	Declination at day n
η_t	Solar module efficiency at time t
T_t^c	Cell temperature at time t

Equations:

$$G_t = R_n^b \times G_t^b + (0.5 \times (1 + \cos\beta) \times G_t^d + \rho \times G_t^g) \quad \text{(A.1)}$$

$$G_t^g = G_t^b + G_t^d \quad \text{(A.2)}$$

[11] We choose a constant hour angle (at solar noon) for every day of the year for the sake of simplification and the avoidance of failures due to sunrise/sunset.

$$R_n^b = \frac{\cos \psi_n}{\cos \psi_n^Z} \tag{A.3}$$

$$\cos \psi_n = \sin \delta_n \times (\sin \phi \times \cos \beta - \cos \phi \times \sin \beta \times \cos \gamma) + \cos \omega_n \times \cos \delta_n \times (\cos \phi \times \cos \beta + \sin \phi \times \sin \beta \times \cos \gamma) + \cos \delta_n \times \sin \beta \times \sin \gamma \times \sin \omega_n \tag{A.4}$$

$$\cos \psi_n^Z = \cos \phi \times \cos \delta_n \times \cos \omega_n + \sin \phi \times \sin \delta_n \tag{A.5}$$

$$\delta_n = -23.45 \times \cos(2 \times \frac{\pi}{365.25} \times (n + 10)) \tag{A.6}$$

$$\eta_t = \eta_r \times (1 + \kappa_{TC} \times (T_t^c - T_{STC}) \tag{A.7}$$

$$T_t^c = T_t^a + (T_{NOCT} - 20\ ℃) \times \frac{G_t}{800\ W/m^2} \tag{A.8}$$

Appendix B: Cost simulation

Index:	
$t = 1, \ldots., T$	Hours of the year 2020 ($T = 8760$)
Natural constant:	
c	Specific heat capacity of water (4182$\frac{J}{kg \cdot ℃}$)
Parameters:	
C	Capacity of the battery storage (kW)
η	Efficiency of heating rod
m	Capacity of thermal storage [kg]
TS^{min}	Minimum temperature within the thermal storage [°C]
TS^{max}	Maximum temperature within the thermal storage [°C]
p^g	Consumer price of gas [€/kWh]
p^e	Consumer price of electricity [€/kWh]
Exogenous variables:	
P_t^{PV}	Generated electricity by the PV module in t [kWh]
Q_t^E	Electricity consumption in t [kWh]
Q_t^H	Heat consumption in t [kWh]
Endogenous variables:	
B_t	State-of-charge of the battery at the end of t [kW]
TS_t	Temperature within the thermal storage at the end of t [°C]
PtH_t	Heat energy [kWh] generated through PtH in t
E_t	Standing losses of heat energy [kWh] stored within the thermal storage during t

Equations of motion

$$B_t = B_{t-1} + P_t^{PV} - Q_t^E \tag{B.1}$$

$$TS_t = TS_{t-1} + \Delta TS_{t-1,t} \tag{B.2}$$

$$\Delta TS_{t-1,t} = \frac{3{,}600{,}000 \frac{J}{kWh}}{c \times m} \times (PtH_t - Q_t^H - E_t) \tag{B.3}$$

$$E_t = \frac{0.08532 \frac{kWh}{°\mathrm{C}} \times TS_{t-1} - 2.11937\ kWh}{24} \tag{B.4}$$

$$PtH_t = max.\{\eta \times (B_{t-1} + P_t^{PV} - Q_t^E - C); 0\} \tag{B.5}$$

Side conditions:

$$0 \leq B_t \leq C, TS^{min} \leq TS_t \leq TS^{max}, PtH_t \leq \eta \times \bar{S}$$

The **Hamburg Institute of International Economics (HWWI)** is an independent economic research institute that carries out basic and applied research and provides impulses for business, politics and society. The Hamburg Chamber of Commerce is shareholder in the Institute whereas the Helmut Schmidt University / University of the Federal Armed Forces Hamburg is its scientific partner. The Institute also cooperates closely with the HSBA Hamburg School of Business Administration.

The HWWI's main goals are to:
• Promote economic sciences in research and teaching;
• Conduct high-quality economic research;
• Transfer and disseminate economic knowledge to policy makers, stakeholders and the general public.

The HWWI carries out interdisciplinary research activities in the context of the following research areas:
• Digital Economics
• Labour, Education & Demography
• International Economics and Trade
• Energy & Environmental Economics
• Urban and Regional Economics

Hamburg Institute of International Economics (HWWI)

Oberhafenstr. 1 | 20097 Hamburg | Germany
Telephone: +49 (0)40 34 05 76 - 0 | Fax: +49 (0)40 34 05 76 - 150
info@hwwi.org | www.hwwi.org