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Incentives for flexible consumption and production on end-user level

- Evidence from a German case study and outlook for 2030 -

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Abstract

The flexibilization of electricity demand and production becomes increasingly important in energy systems with rising shares of fluctuating renewable electricity production. Power-to-heat and cogeneration units, combined with thermal storages, are considered as promising technologies for the provision of flexibility since they allow for a decoupling of thermal loads, electricity consumption and production. Based on a real-world case study, this paper explores the economic potentials of flexible, spot market-oriented operation for small residential heat pumps, electric storage heaters and medium-sized cogeneration systems from an end-users´ view in Germany. Using numerous models for the determination of heat demands, future spot market prices and unit dispatch, financial incentives in terms of expected cost savings (consumption) and profit increases (production) are derived for the years 2015-2017 as well as for three scenarios in 2030. Results suggest that only those consumers with high electricity demand and sufficient thermal storage capacities may substantially benefit from load shifting. Furthermore, existing remuneration schemes for feed-in and high retail prices for electricity consumption hamper a market-oriented production; maximization of electricity self-consumption is the most profitable operation strategy instead. To unlock flexibility potentials on end-user level, increased market price volatility is needed and policy makers should work towards a design of regulated price components that induces less dilution of market price signals.

Keywords : power system flexibilization; demand side management; virtual power plant; CHP, heat pump

JEL-Classification : P48, Q42, Q48

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Content

1 Introduction

1.1 Motivation and research context

Rising shares of renewable electricity production from fluctuating energy sources like wind and solar pose new challenges to power systems in many countries. As one key challenge, a constant balance between intermittent electricity generation and demand has to be guaranteed and therefore technologies that provide flexibility gain in importance. Supplementary to conventional flexibility options like pumped hydro storage or gas turbines, alternative solutions may be increasingly needed; out of those some have already been established in the markets, for example flexible industrial loads.

Within the discussion about the future demand for flexibility and about the most suitable technology mix on both the supply and the demand side, also small and decentral flexibility options receive growing attention. Here, special focus is often laid on electric heating systems and small/medium-sized motor based combined heat and power (CHP) systems in the commercial as well as in the residential sectors. The main reasons why those heating systems are considered as promising flexibility options are as follows: From a technical point of view, it is argued that thermal storage capacity is an inherent feature of electric storage heaters, of most heat pumps and of CHP systems which, to a certain degree, may be used to decouple heat demands from electricity consumption or production (Lund et al 2015, Cruz et al. 2018, Bloess et al. 2018). If accurate forecasts for volatile spot or reserve power market prices and for heat demands are at hand and if storage filling levels can be determined in a reliable way, unit operation may be adjusted from the conventional heat-oriented operation mode to a more market oriented one without compromising end users' comfort. From an economical perspective, it is stated that those thermal storage capacities can provide flexibility in a very cost-efficient way because investments in corresponding heating systems are incurred anyway.

The German power system can be regarded as a telling example for this. In 2021, electricity production from renewable sources accounted for about 42% of electricity demand. According to official targets, this share should rise up to 80% in 2030 whereas major contributions are expected to come from wind and solar capacities (BMWK 2022a, BMWK 2022b). Also, in Germany, large numbers of heat pumps, electric storage heaters and CHP systems already exist and, in theory, their flexibility potentials just have to be tapped as a valuable by-product. The prevailing opinion is that this goes hand in hand with financial benefits for the owners of the heating systems: Cost for electricity consumption of electric storage systems and heat pumps may be reduced if operating times are matched with low market prices and, vice versa, CHP systems might become more profitable if their electricity production primarily takes places in periods with high market prices.

However, to frame the decision problem from an end user´s perspective correctly, it is important to note that retail electricity prices include a variety of regulated components such as taxes, grid charges and levies. This is especially true for the German case where wholesale market procurement cost and sales margins only account for about 23% of a typical household´s gross electricity price (BDEW 2020). A discussion about financial benefits from a flexible operation of electric heating systems therefore should not only take into account possible savings that might be generated from exploiting low market prices. Rather, the specific design of regulated components also must be reflected because it may have a determining influence on the end user´s incentives whether the pricing of those components depends on the consumption patterns. For so-called prosumers which not only consume but also produce electricity (here: owners of CHP systems), a realistic economic assessment of production flexibility likewise has to account for regulated price components. First, the end users' value of produced electricity exceeds market prices if self-consumption can avoid payments for taxes, grid charges and/or levies. Second, for electricity feed-in regulated price components in the form of remuneration schemes may be relevant. Both aspects potentially decouple production schedules from market price signals.

The paper at hand addresses the above-mentioned issues and aims to answers the following research questions:

- What are the economic benefits of a spot market oriented flexibilization of small heat pumps, electric storage heaters and medium sized CHP systems from an end-user´s perspective?

- How do the specific regulatory framework, the individual heating system configuration and the structure of spot market prices influence these benefits?

- How might incentives for flexibilization develop under different market scenarios for the year 2030?

1.2 Related literature

Since electricity production from fluctuating renewable energies becomes more and more popular in many countries all over the world, an extensive body of literature dealing with questions around the utilization of flexibility options has emerged. In view of the research questions of this paper, three relevant literature strands have been identified.

First of all, various contributions analyse how electric load shifting measures, also known as demand side management (DSM) or demand response (DR), can contribute to improve the overall efficiency of the energy system[1]. For example, Strbac (2008) discusses the major benefits and challenges of DSM in the context of the UK electricity system. Bergaentzlé et al. (2014) present a quantitative study that examines the energy and environmental benefits of DSM employed for an isolated country as well as for five interconnected European countries. With reference to research projects and real industrial case studies, Siano (2014) introduces a survey of DR potentials and benefits in smart grids. Here, it is also described which enabling technologies such as communication systems, smart meters and energy controllers are needed to facilitate the coordination of DR in a smart grid environment. A more comprehensive review of literature in the field of DR and DSM can be found in Gelazanskas & Gamage (2014) as well as in O´Connell et al. (2014). As a recent publication, Arias et al. (2018) provide a review and analysis of trends related to DR, based on about 170 other papers.

The second relevant literature strand examines the potentials of DSM for the specific cases of residential or commercial power-to-heat applications. These are mostly heat pump systems. Many publications assess the effects of an increased market penetration on the overall power system or, like Salpakari et al. (2016), on other aggregated energy systems like cities. With focus on both the system benefits and the impacts for the individual participants, for example, Felten et al. (2018) use an agent-based simulation framework to examine the interplay of a local pricing mechanism, local photovoltaic generation and flexible heat pump systems within a structurally congested distribution grid. For this field, a systematic literature review regarding the different power to heat technologies, their flexibility potentials and relevant modelling approaches can be found in Bloes et al. (2018).

Besides this, a considerable number of studies address the behaviour of heat pumps under flexible operation at the level of single buildings in detail. The most prominent research topics here are technical aspects and designs of heat pump systems in order to increase flexibility, fields of application and control approaches. Also, many publications present elaborate modelling techniques to achieve a realistic depiction of the complex technical interactions between heat pumps, the associated heating and building equipment (e.g., thermal storage, pipework, radiators, floor heating) and building dynamics which include an accurate determination of heating demands in high temporal resolution. According to the literature excerpt as shown in Felten & Weber (2018), the majority of recent literature also addresses the question of economic benefits from an end-user´s perspective and under different pricing regimes.

A third stream of research investigates the flexibility potentials that may be provided by prosumers, i.e., those end-users who both produce and consume electricity. Regarding the flexibilization of their production capabilities, there has been a growing discussion about how photovoltaic-battery storage

[1] Palensky & Dietrich (2011) provide an overview about the taxonomy for DSM/DR and their various types.

systems (PV-BSS) may allow prosumers to be more flexible in regard to when to feed electricity into the grid and several works have also addressed the impacts of end-user tariffs on the production or feed-in schedules. Considering market as well as grid integration, Thomsen & Weber (2021) assess how the design of retail prices, network charges and levies affect the operation of small-scale PV-BSS in Germany. A combined use of batteries and heat storages in a hybrid PV-micro-CHP system is examined in Kneiske & Braun (2017). Both studies also analyse the effects of electricity self-consumption, variable electricity rates and variable PV feed-in tariffs and the authors emphasize the significance of tariff design for incentivizing flexibility provision from households with PV-BSS.

With focus on owners of CHP systems, several analyses have been conducted to assess the economic benefits of a flexible operation strategy that follows the prosumer´s electric load profile compared to the standard operation mode which is heat oriented[2]. Examples are given in Mago et al. (2009), Lozano et al. (2009), Ren & Gao (2010) and Löbberding & Madlener (2019). Most of these techno-economic studies aim at a cost optimal sizing and operation of the CHP system, accordingly, they also account for the cost of electricity grid supply (retail tariffs) and CHP support schemes. However, the utilization of production flexibility for market purposes is not examined here.

This aspect is dealt with in the broad range of literature on virtual power plants (VPP) which aggregate distributed electricity generation facilities, energy storage units and controllable loads into centrally managed clusters[3]. In an earlier work, Wille-Hausmann et al. (2009) introduce a modelling approach for an optimized management of clustered CHP systems with thermal storages, selling electricity in the German hourly day-ahead market. This paper already raises the issue of an adequate configuration of the CHP remuneration scheme applicable at this time and it has been pointed out that reforms of the feed-in tariffs are needed to make a shift from a heat oriented towards a more flexible market-oriented operation mode profitable for the CHP owner. With a view to more recent publications, a considerable number of studies have put the focus on the market-oriented valorisation of CHP flexibility within VPP portfolios from the perspective of so-called aggregators. This includes the development of optimal bidding and scheduling strategies in power and ancillary service markets or the use for reducing the imbalance error of renewable generation along with the development of corresponding optimization approaches and control techniques. For small and medium-sized CHP-units, which are likely to be

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[2] Across literature, different terminology is used for the operation modes. In this paper, a unit dispatch that follows the electric load profile is referred to as “self-consumption oriented”.

[3] Initially, the concept of “virtual utilities” has been developed for the cost-efficient integration of distributed generation in decentralized electrical power markets (Coll-Mayor et al. 2004). Today, for VPPs a more holistic definition is in use which, for example, includes DSM/DR. Ghavidel et al. (2016) present a brief review on VPP components and operation systems from this newer perspective.

owned by prosumers in residential or commercial applications, examples covering the aforementioned research topics include Zapata et al. (2014), Ghahgharaee Zamani et al. (2016), Dietrich et al. (2020) and Bolzoni et al. (2020). However, on site generated electricity can be used either to be sold in the markets or it may be used to meet the prosumer´s electric demand, and therefore create value for the prosumer via savings from avoided grid supply. Accordingly, the degree of flexibility provided by prosumers for VPP applications depends not only on market price signals. Existing remuneration schemes for feed-in may also affect the CHP owner´s operating decision. To the best of the author´s knowledge, the only study that considers the impacts of prosumers´ electricity self-consumption on the CHP flexibility potentials can be found in Zapata et al. (2014).

The paper at hand contributes to the existing literature by a research approach with the following main distinctive features: Based on a comparatively simple modelling approach with regard to the heating systems, it examines the main drivers for the profitability of a flexible, spot market-oriented operation. Special emphasis is put on the three core aspects (I) market price volatility, (II) influence of individual system configuration and heating demand structure on the availability of flexibility potentials and (III), as an important part of the end-user's electricity bill, regulated price components for electricity consumption. Moreover, for CHP systems, the presented case study explicitly considers the impacts of prosumers´ electricity self-consumption and of feed-in tariffs on the utilization of production flexibility for market purposes. Furthermore, an extended assessment period of three historical years has been chosen and to give an outlook on the possible financial incentives for flexibilization in the future, a validated market model has been applied to simulate different spot price scenarios for the year 2030.

1.3 Structure of this work

The remainder of this paper is organized as follows: Section 2 describes the methodology applied and explains the key regulatory aspects relevant for the analysis. Section 3 defines the characteristics of the case study. In Section 4, results are presented and discussed. Finally, conclusions and policy implications are stated in Section 5.

2 Methodology

This section outlines the modelling framework which is depicted in Figure 1. The analysis is built on models of medium complexity and the methodology´s description focuses on a clarification of the modelling approach, its general assumptions and the key regulatory aspects that have been considered. Regarding the optimization models that determine unit commitment for consumers and prosumers under different operation modes, Appendix A. gives insight into the essential mathematical expressions. Further details are published in Dietrich et al. (2018) and Kippelt et al. (2016).

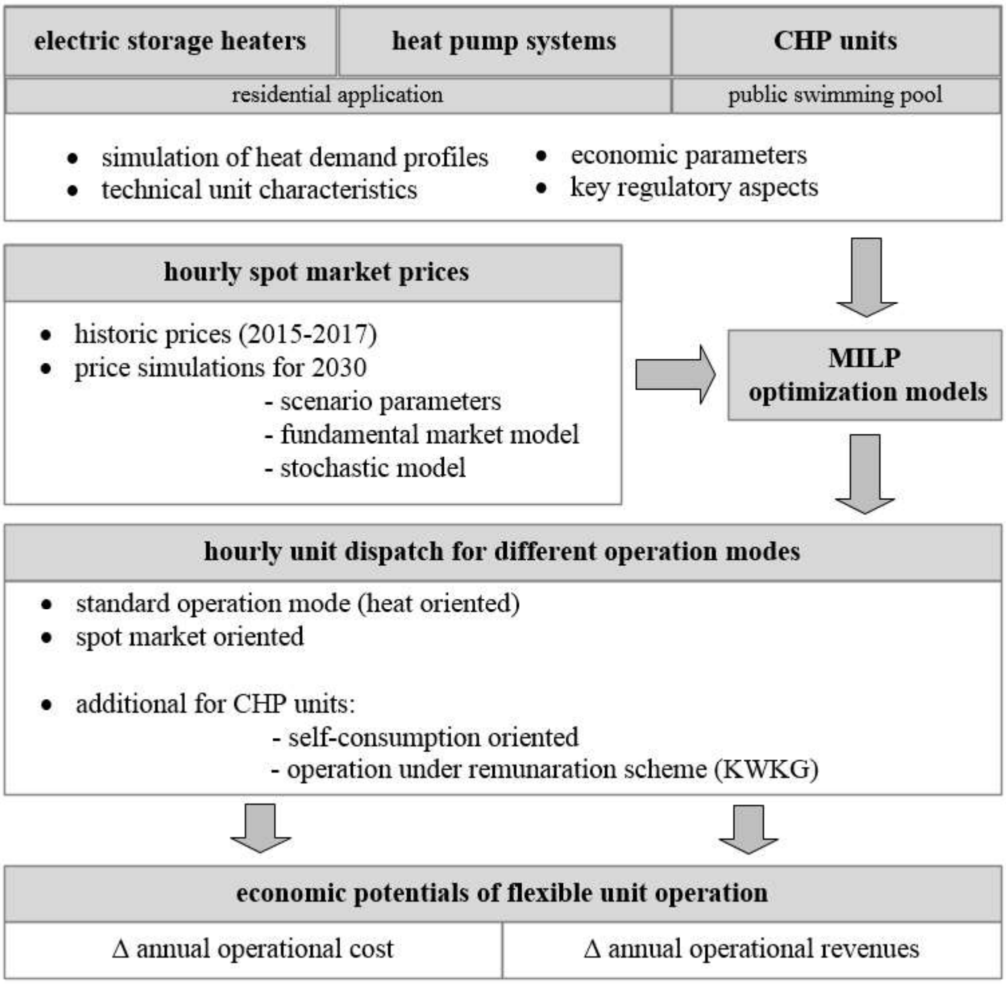

Figure 1: Schematic overview of the modelling framework

2.1 General assumptions and modelling approach

The aim of the analysis is to assess the economic incentives for end-users and prosumers to provide flexibility in consumption or/and production by a market-oriented operation of their heating system under different regulatory settings. Therefore, consumption and production schedules are derived using optimization models (cf. Section 2.3). Therefrom, impacts on annual operational cost and revenues are calculated for the different alternative regulations (cf. Section.2.4) and then compared to the status quo, i.e., the conventional heat-oriented operation mode.

For a market-oriented utilisation of flexibility, several wholesale market segments may be considered. However, this paper focusses on the hourly day-ahead spot market because economic incentives are evaluated for the recent German situation (historical market prices from 2015 to 2017), as well as for the year 2030. Here, calculations are based on price simulations that are limited to the hourly spot market due to methodological constraints (cf. Section 2.6)[4]. Accordingly, possible benefits from further market segments e.g., the provision of ancillary services or intertemporal arbitrage on intraday markets are left out of consideration. Given the small size of the heating systems under study it is also assumed that consumers and prosumers act as price takers.

Within this context, it is important to mention that small end-users cannot directly participate on wholesale markets in Germany until now, mainly due to existing minimum bid sizes. Suppliers or so-called aggregators have to sign contracts with end-users and act as enablers who valorise the flexibility potentials on the markets. These agents also have to satisfy institutional requirements for a successful management of flexibility including the provision of trading, forecasting and billing systems; furthermore, they have to tackle uncertainty in market prices and heat demands (Dietrich & Weber 2017). This goes hand in hand with the "split incentives problem" because benefits and cost from the market-oriented operation need to be shared between enabling agents and end-users, establishing a sustainable business case for both (Eid et al. 2016). Throughout this paper, these agency problems are neglected, assuming that all financial benefits are directly accruing to the end-users whereas cost for flexibilization, market participation and related trading activities are not considered.

The underlying optimization models are formulated as deterministic mixed integer linear programs with constraints such as unit-specific technical restrictions and energy balance equations that ensure a continuous coverage of the end-users´ electricity and heat demand as well as a physical balance between production, (self-)consumption, grid supply and grid infeed (cf. Appendix). Depending on the cases under study, different objective functions for consumers or prosumers are applied to determine specific operation modes (cf. Section 2.3)[5]. Because deterministic modelling techniques ignore uncertainties regarding future market prices and heat or power demands, the market value of flexibility options may be overestimated if applied over a longer period (Dietrich et al. 2020). Therefore, a rolling-horizon approach is implemented. Optimization is executed at 0:00 at each day of the year and the respective period of perfect foresight is bound to 36 hours.

[4] To the author´s best knowledge, modelling of long-term price forecasts for other market segments such as the intraday or the ancillary services markets is far from being trivial and corresponding modelling approaches are still at the development stage. An example for upcoming concepts is given in Pape (2018).

[5] For certain CHP operation modes, the electricity balance is not a binding constraint within the optimization model due to the objective function, but determined in subsequent calculations, see section 2.3 and 2.4.

2.2 Key regulatory aspects

The following subsections briefly describe regulatory aspects that are relevant for the analysis within the specific German context. Focus lies on the current design of end-users´ electricity prices, on the remuneration schemes for electricity production from medium-sized CHP units and on the treatment of self-consumption.

2.2.1 End users´ electricity prices

Most commonly, electricity tariffs for German households consist of a monthly basic charge, which incorporates cost e.g., for metering and billing services and a volumetric price for electricity consumption in ct/kWh. In 2019, the average gross electricity price for households with an annual consumption between 2,500 and 5,000 kWh was close to 30 ct/kWh, whereby price components under governmental control account for about 75% of the price (BNetzA 2019). Hereby, the main components are grid charges (average of 6.9 ct/kWh) and the Renewable Energies Act levy (6.4 ct/kWh), coming along with several taxes, the concession fee and various other surcharges.

However, with a typical price around 22 ct/kWh in 2019, supply tariffs for electric heating systems usually are significantly lower than standard supply rates (BNetzA 2019). This is mainly due to reduced grid charges and concession fees, applied for installations that may be disconnected via the ripple-control system by the local network operator during peak demand periods. For a control scheme operated by an aggregator or supplier, it is foreseen that reduced grid charges are continued to be granted, yet details are still not defined (EnWG 2005, § 14a). More importantly, this rule aims at control schemes that provide flexibility on low-voltage network level to manage temporal local grid congestions. Therefore, it is unclear how a market-oriented operation mode may affect existing or future privileges in terms of reduced grid charges and if differences in grid charges between market-oriented and conventional operation modes could over-compensate potential cost savings from short-term procurement of electricity. Application of regular concession fees under the market-oriented operation mode may further amplify this effect. So far, it is not explicitly stated whether an innovative pricing structure proposed by an aggregator could qualify as so-called “Schwachlasttarif” (off-peak tariff), which is the legal basis for reduced concession fees until today (KAV 1992, § 2).

Given the aforementioned open questions, electricity price components under governmental control are not considered within the optimization models for heat pumps and electric storage heaters. Instead, the determination of market-oriented consumption schedules as well as the calculations of the consumers´ economic benefits are solely based on hourly spot market prices. However, within the analysis for the case of prosumers, end user electricity prices are used (cf. Section 2.4 and Appendix 3). Here, prices reflect individual rates for the specific prosumer under study, e.g., a large public swimming bath. For such consumers, net rates range around 20 ct/kWh and thus are far below typical household electricity prices. This is due to the following reasons: First, for end users with high annual electricity consumption, suppliers provide individual contracts, based on volume-discounted rates. Second, value added tax is not included, as it is a transitory item from a business perspective. Furthermore, the concession fee for larger consumers is smaller, if existing at all. Notably public swimming baths are often classified as a municipal undertaking. Finally, for large consumers with an annual demand above 100 MWh, grid charges include an energy (ct/kWh) and a capacity (€/kW) part.[6] Correspondingly, the energy-based grid charges are lower compared to small household consumers.

2.2.2 CHP remuneration schemes and treatment of self-consumption

For the promotion of cogeneration technologies, German policy introduced a variety of support schemes whereof the CHP Act (KWKG) serves as a main instrument. Due to regular amendments, different versions coexist and the specific rules that apply for an individual CHP system depend on the year of its commissioning. The fundamental concept behind the KWKG is, until now, a support mechanism based on remunerations for electricity feed-in paid on a time-invariant per unit basis granted until total electricity production equals 30,000 full load hours. Additional revenues either come from a bonus on top of the remuneration that is determined as an average of all hourly wholesale market prices of the previous quarter ("reference price") or from so-called direct marketing. Here, the CHP owner enters a contract with an aggregator or electricity trader and current spot prices determine the additional revenues. In this case, revenues from feed in can exceed the standard remuneration if operation focuses on hours with prices above the average. Such direct marketing is mandatory for CHP units with a nameplate capacity exceeding 100 kW put into operation from January 2016, whereas owners of older installations can choose for the conventional bonus system or for the direct marketing scheme (KWKG 2015, § 4) The concept of mandatory direct marketing also aims at a more market-oriented operation because remuneration payments are suspended during hours with zero or negative day-ahead spot market prices. Accordingly, the paper at hand considers the above-mentioned version of the 2016 CHP support scheme even though the specific CHP unit under study has been put into operation in 2012[7].

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[6] The level of energy and capacity associated grid charges depends on the individual relation between annual consumption and annual peak demand, metered in quarter hourly intervals (annual utilization time). Within the context of prosumers, it is noteworthy to mention that the decisive load profile is derived from annual grid supply. Therefore, changes in self-consumption patterns may not only affect supply tariffs in terms of diminished volume discounts or adjusted risk mark-ups. Rather they are also likely to influence the level of capacity and energy-based grid charges. Both aspects are not considered within this study´s modelling approach.

[7] For reasons of simplicity, it is assumed in the case study that the rules of the 2016 remuneration scheme have been in place during the first year of the modelling and assessment horizon (2015-2017) already.

Furthermore, feed-in from decentral CHP generation benefits from a supplementary remuneration for avoided grid cost, paid by the local grid operator on a per unit basis. The idea is that electricity production is consumed locally within the regional distribution grid and therefore cost for operating and extending upstream network levels are avoided[8].

Regarding the treatment of self-consumption, the following rules apply: In general, price components under governmental control (cf. Section 2.2.1) are not charged for self-consumed electricity, with the exception of a certain share of the Renewable Energies Act levy. Here, shares of 30% in 2015, 35% in 2016 and 40% from 2017 on have to be paid per kilowatt-hour. In certain cases, the CHP law also grants remunerations for self-consumed amounts of electricity that is not fed into the public grid. However, the specific prosumer under study doesn´t meet the relevant requirements.

2.3 Determination of consumption and production schedules

Hourly consumption and production schedules provide the basis for the calculation of energy-related annual cost and revenue streams, used within the economic potential analysis (cf. Section 2.4). Hence, the specific unit commitment has to be determined for the standard operation modes, assumed as heat oriented, and for the market-oriented operation modes. Additionally, in order to analyse the effects of the CHP remuneration scheme and to assess the economic implications of self-consumption, several alternative operation modes are considered for the case of the prosumer.

To determine heat-oriented consumption schedules for the heat pumps under study, the simulation model developed in Kippelt et al. (2016) is used. It calculates operating times by means of a storage level hysteresis algorithm and under consideration of an outdoor temperature-dependent coefficient of performance. As a result, power consumption patterns are characterised by sets of consecutive operating hours during which the thermal storage´s temperature level is raised from its minimum to its maximum set point. For an approximation of the electric storage heaters´ conventional operation mode, the optimization model presented in this paper is adopted in the following way: Charging processes are bound to the enabling intervals of the traditional German ripple control scheme (10:00 p.m. to 6:00 a.m.) by including a multiplicative binary parameter in the constraints for maximum and minimum power consumption, cf. Equation 9 and 10 in Appendix A.4. Furthermore, spot market prices are replaced by monotonously decreasing dummy prices with identical values for each day´s enabling interval. Along with the cost-minimizing objective function (cf. Equation 1), this leads to a unit

[8] With increasing amounts of decentral electricity generation, mainly from wind and solar power plants, periods with reverse power flows from distribution to transmission grid level and local grid congestions can be observed more and more frequently in Germany. Hence, expenses for congestion management and grid expansion occur instead of savings from avoided grid cost. Against this backdrop, policymakers decided to phase out the remuneration for avoided grid cost. New installations with volatile renewable generation are affected since 2018, new CHP units from 2023 on (EEG 2014, §120).

scheduling similar to the common reverse charge control scheme where the storage´s charging process is initiated in a way that the required storage filling level is reached towards the end of the enabling interval. For the prosumer´s CHP units, the optimization model explained in Appendix A also determines the standard operation mode. Here, an objective function that minimizes heat supply from the district heating grid is applied (cf. Equation 2). Correspondingly, the highest possible heat demand driven utilization rate of the CHP units is achieved, which has been the typical aim of system dimensioning and operating in practice until now.

The market-oriented operation modes are based on a mark-to-market approach where consumed (heat pumps and electric storage heaters) and produced (CHP units) electricity amounts are valued at hourly spot market prices, neglecting regulated electricity price components and CHP support schemes. Consumption and production schedules are the outcome of the optimization models as described in the Appendix, applying objective functions (1) and (3). As a result, the market-oriented operation mode ensures that thermal flexibility potentials are utilised to minimize the cost for heat provision. This is of special importance for the case of the CHP units because from the prosumer´s perspective, additional costs arise from electricity demand that has to be covered by public grid. These costs are not considered within the market-oriented optimization of the CHP units. Yet, for the economic analysis, end users´ electricity supply cost are derived from subsequent calculations that specify the schedules of hourly physical balances between CHP electricity production (optimization result), electricity demand, self-consumption, feed-in and grid supply according to Equations 11 and 12. This procedure is also applied for the heat-oriented operation mode and for the direct marketing mechanism (objective function (2) and (4)); cf. Table 1 in Section 2.4).

The determination of the CHP unit´s alternative operation modes breaks down as follows: Objective function (4) reproduces a cost minimal unit dispatch that considers revenues from the remuneration scheme under the direct marketing mechanism according to the CHP law KWKG 2016. Additionally, in (5) costs for electricity supply based on end users' electricity prices are considered. Within the analysis for the scenarios in 2030, where it is assumed that support schemes are phased out, objective function (3) is applied for the market-oriented operation mode again. To evaluate the future impacts of self-consumption on unit dispatch and on the prosumers' cost situation, objective function (6) finally accounts for revenues from produced electricity that is sold on the spot market as well as for cost for electricity supply.

2.4 Determination of economic potentials

For consumers with heat pumps and electric storage heaters, the determination of economic potentials is straightforward. Based on consumption schedules and hourly spot market prices, annual wholesale market procurement cost are calculated for market-oriented and conventional operation modes. It is assumed that suppliers´ cost savings from a flexible unit commitment are passed on to the end-users´ electricity bill and that retail margins, taxes and other additional price components under governmental control remain unchanged under the market-oriented operation.

To assess the economic potentials from the prosumers’ point of view, the financial impacts of the different operation modes are compared to a cost situation where the heat and electricity demand are covered without a CHP system. More precisely, a simplified profitability analysis approximates the economic efficiency of the CHP system in terms of an average annual surplus value that accounts for revenues from electricity sales as well as for fuel expenses and costs for alternative supply of the prosumers´ heat and electricity demand[9]. Here, the cost for electricity supply are calculated on the basis of end-users´ retail prices, not on market prices. Furthermore, depending on the operation mode under consideration, the above-mentioned CHP remuneration and self-consumption rules may be applied. For a better understanding of how the specific economic parameters are derived from the respective CHP dispatch schedules (optimization model´s outcome), Table 1 provides a summary.

Table 1: Determination of cost and revenues for the economic assessment of the CHP units

	CHP operation mode					
	Heat oriented KWKG	Heat oriented	Market-oriented	Direct marketing KWKG	Self-consumption oriented KWKG	Self-consumption oriented
Objective function No.	(2)	(2)	(3)	(4)	(5)	(6)
Period under study	2015-2017	2030	2015-2017 2030	2015-2017	2015-2017	2030
			Cost			
District heating*	○	○	■	■	■	■
Gas consumption*	○	○	■	■	■	■
Electricity supply*	○	○	○	○	■	■
EEG levy for self-consumption	○	-	-	■	■	-
			Revenues			
Feed-in remuneration	○	-	-	■	■	-
Avoided grid use remuneration	○	-	-	■	■	-
Spot market prices for feed-in	○	○	■	■	■	■

* Net retail prices ■ According to optimization model´s outcome ○ According to subsequent calculations - Not relevant

[9] Additional revenues from heat sales may become relevant if the prosumers´ building is connected to a local heat or district heating network, which is given for the public swimming pool considered in the case study. However, thermal infeed into the network is not possible here due to the specific buildings´ heating system design (pipe connection, heat exchangers, temperature levels).

2.5 Simulation of heat demand

Based on measurements of annual heating consumption from 2015 to 2017 and on local hourly ambient temperature profiles, two different approaches are adopted to simulate individual thermal load profiles. For the residential use cases of electric storage heaters and heat pumps, the stochastic model presented in Kippelt et al. (2016) is applied. The basic parametrisation of this model rests on a detailed analysis of the quarter hourly thermal power consumption of 13 German households, measured between 03/2012 and 08/2013. Here, by use of random sigmoidal functions and random samples of daily activity periods, annual heating demands are broken down to quarter hourly daily profiles, altered through stochastic influences by means of the Ornstein-Uhlenbeck process. To determine the thermal load profiles for the use cases of the two CHP-units installed in a public swimming pool, specific data available in the case study are used (cf. Section 3.1).

2.6 Simulation of spot market prices for 2030

To estimate possible future benefits of a flexible operation mode, hourly spot market prices are simulated for three scenarios in 2030. For this, a fundamental electricity market model (as described in Kallabis et al. (2016), Pape et al. (2016) and Beran et al. (2018)). calculates the cost minimal generation dispatch of the German power plant fleet, required to cover German residual load. Conventional power plants are modelled in the form of five technology classes for lignite, coal, combined cycle gas turbines, open gas turbines and oil power plants, assuming a uniform distribution of the units' fuel efficiency in each class within a range between a minimum and a maximum value and considering hourly availabilities, approximated by historical data. Besides production from renewable energy sources, residual load incorporates conventional CHP must-run generation and, estimated by means of regression analysis, pumped-storage power plants´ operation as well as hourly foreign trade balances. Because spot market prices are also influenced by non-fundamental factors which the model cannot reproduce, a subsequent stochastic model is applied to mimic the characteristics of observed prices. Kallabis et al. (2016), Pape et al. (2016) and Beran et al. (2019) describe further details of both modelling approaches and their validation in different applications.

3 Characteristics of the case study

The technical specification of the flexibility options under consideration in the case study are based on the experience of the research project “Die Stadt als Speicher” carried out in Germany (Dietrich et al. 2018). Amongst others, the below-mentioned flexibility options have been aggregated into a virtual power plant, proving their ability for market-oriented operation within a one-year field test. Furthermore, this section gives insight into to the characteristics of the historical hourly spot market prices and into specific economic parameters, relevant for the optimization models as well as for the economic assessment from an end-users´ view.

3.1 Technical unit characteristics

On the consumers´ side, the analysis in this paper draws on three exemplary households, located in the Ruhr region, a major German metropolitan area. Two are equipped with small heat pumps, which also cover demand for domestic hot water, and with water-based thermal storage units. Their thermal storage capacity is determined by the storage volume of 300 litres each and by the difference between the individual maximum and minimum setpoints of the storages´ temperature levels. Because heat pump No. 1 is a ground-source system, the coefficient of performance is less sensitive to changes in ambient temperature (Staffell et al. 2012) and on average significantly better compared to heat pump No.2 (air-source system). The other household uses conventional electric storage heaters with solid-state magnesite storages. Here, it is assumed that the thermal storage capacity is designed for an eight-hour charging process during the traditional night-time enabling interval of the German ripple control system. Table 2 depicts the key technical specifications of the consumers´ heating systems considered within the case study.

Table 2: Key technical specifications of the consumers´ heating systems

Heating system	Max. power consumption [kW_{el}]	Thermal storage capacity [kWh_{th}]	Ø COP 2015-2017	Ø annual heating demand, 2015-2017 [illegible]
Heat pump No. 1	3.3	7.7	4.6	35.5
Heat pump No. 2	5.0	5.2	3.0	14.4
Electric storage heater*	36.0	288.0	1	23.7

* Values correspond to the sum of ten heating units placed in several rooms.

The case of a prosumer is represented by a large public swimming pool. Here, two gas-fired motor-based CHP units with an overall fuel efficiency of 86.8% and a maximum/minimum power output of 540/290 kW_{th} and 420/210 kW_{el} each are installed. Alternative heat supply is available from a district heating network and annual heating demands for the years 2015-2017 are between 8 and 10 GWh_{th} whereas electricity consumption is around 3.5 GWh_{el} p.a. As an approximated value for thermal storage capacity, 4.9 MWh_{th} has been derived from the pool volume, the specific heat capacity of water and a maximum permitted water temperature variation of ± 0.5 °K. Furthermore, it is assumed that thermal storage losses contribute to the overall heating of the swimming pool and therefore, effective storage losses are zero. To derive hourly heat demand profiles, a simplified procedure has been applied as followed: For the specific public swimming pool under consideration, hourly historical data of ambient temperature levels, CHP heat production and supply from district heating network are available. Those measurements indicate that a variation in ambient temperature comes along with a change in heat demand of around 15 kW_{th} per degree Celsius. Hence, hourly thermal load profiles are approximated by using a linear fitting algorithm that matches hourly heating demands with the corresponding outdoor temperatures and the total amounts of annual thermal heat production/supply. Regarding electric load profiles, real measurements of hourly electricity consumption for the years 2015-2017 are used.

3.2 Economic parameters for 2015-2017

The hourly day-ahead spot market prices applied for the case study correspond to official market data from the European power exchange EPEX Spot. Table 3 depicts statistical key indicators, which give insight into the structure of German day-ahead market prices for the period 2015-2017.

Table 3: Statistical key indicators of hourly day-ahead spot prices for 2015-2017. Source: EPEX Spot, own calculations.

Year	Maximum [ct/kWh]	Minimum [ct/kWh]	Average [ct/kWh]	Standard deviation [ct/kWh]	Average intra-day standard deviation [ct/kWh]	Negative prices [#]
2015	9.98	-7.99	3.16	1.27	1.16	128
2016	10.50	-13.01	2.90	1.24	0.71	96
2017	16.35	-8.31	3.42	1.76	0.92	145

Further economic parameters related to the prosumer case are specified in Table 4**.** Retail prices for electricity, gas and district heating origin from the public swimming pool´s individual purchasing contracts and are stated as net prices because the value added tax has to be treated as a cost-neutral transitory item within business operation.

Table 4: Economic parameters, related to the case of the prosumer [ct/kWh], net values.

Year	Retail price electricity	Retail price gas	Retail price district heating	Prorated Renewable Energies Act levy *
2015	19.70	3.14	3.79	1.85
2016	19.70	3.16	3.79	2.22
2017	20.41	3.16	4.41	2.75

* Cf. Section 2.2, charged for self-consumption of produced electricity

Besides these costs and depending on the CHP units’ operation mode under consideration, revenues from remuneration according to the KWKG 2016 may become relevant. The feed-in tariff corresponding to the nameplate-capacities of 420 kW_{el} each amounts to 5.23 ct/kWh[10]. Based on data from the local grid operator, valid for generators connected to the medium voltage level, values between 0.15 and 0.16 ct/kWh are used to depict avoided grid charges.

For the case of consumers, retail electricity prices for heat pumps and electric storage heaters are not explicitly quantified here. As explained in Section 2.2, retail margins, taxes and other additional price elements under governmental control are not relevant for the cost effects of different operation modes because those components are assumed to stay unchanged.

3.3 Market scenarios for 2030

The parameterization of the spot price simulation model (cf. Section 2.6) requires numerous assumptions regarding future developments of interdependent fundamental factors that determine electricity market conditions in 2030. A particular challenge is to combine the expected individual factor levels to consistent and plausible scenarios. However, against the background of this papers´ scope, a simplified approach is followed: The case study's assumptions closely refer to the scenario parameters as stated within the official German electricity network development plan, published by the German transmission grid operators (Deutsche Übertragungsnetzbetreiber 2017). One the one hand, based on legal obligations, these scenarios have to represent possible developments in electricity generation and consumption structures that account for the targets of the German energy policy, such as the share of renewable production in 2030. On the other hand, the assumptions can be regarded as mostly consistent since they form the basis for a European market simulation as described in Pöyry (2015) which also provide the data for subsequent official network analyses.

To examine a range of possible future developments, three scenarios are chosen for the case study. In a nutshell, those can be described as followed: Scenario A2030 assumes a moderate transformation towards an electricity system based on renewable energies whereas Scenario B2030 and C2030 are characterized by a faster and more innovative path of development. The latter two also imply a considerable expansion of conventional flexibility options in the form of gas fired power plants. Also, compared to Scenario A2030, this technology is favoured by relatively low gas prices and higher prices for CO_2-emission certificates. Table 5 depicts the main scenario parameters as used within the spot price simulation model.

[10] The KWKG 2016 defines decremented remunerations rates for specific ranges of power output. The mentioned value reflects a capacity-weighted average rate.

Table 5: Scenario overview, derived from Deutsche Übertragungsnetzbetreiber (2017)

	Reference 2015	Scenario A2030	Scenario B2030	Scenario C2030
Gross electricity demand* [TWh]	550.9	539.8	571.1	603.5
Thereof renewable production** [%]	28.0	52.0	53.0	54.0
Peak demand* [GW]	88.3	86.1	86.1	86.1
Conventional generation capacities [GW]	98.2	67.4	65.7	61.2
Thereof gas fired power plants [GW]	30.3	30.5	37.8	37.8
Pump storage capacities [GW]	9.4	11.9	11.9	11.9
Renewable generation capacities [GW]	104.7	135.7	149.4	164.5
Thereof wind and solar [GW]	83.9	127.2	139.8	153.9
Import*** [TWh]	1.3	1.0	17.8	34.5
Export*** [TWh]	46.5	47.0	15.4	8.1
Price of CO_2 emission certificates [€/t]	7.7	23.0	28.0	28.0
Price Lignite [€/MWh_{th}]	4.3	3.1	3.1	3.1
Price of hard coal [€/MWh_{th}]	7.3	10.6	9.5	9.5
Price of natural gas [€/MWh_{th}]	22.2	32.0	29.0	29.0

* Adjusted, without power plant self-consumption, including grid losses

** Adjusted, including power plant self-consumption and grid losses

*** Adjusted to the German trade balance according to Übertragungsnetzbetreiber (2017)

Regarding time series for load, renewable production and availabilities/outages of conventional power plants, hourly data from the ENTSO-E (European Network of Transmission System Operators for Electricity) are used, 2015 serves as the reference year. Further assumptions are necessary concerning the future development of end users´ prices. For natural gas and district heating, it is expected that rates increase according to the growth of the wholesale gas prices in the scenarios (+0.98 ct/kWh and +0.68 ct/kWh). Changes in electricity tariffs are based on the absolute differences between the annual average spot market prices in 2015, (real prices) and in 2030 (simulation results).

4 Case study results and discussion

In Section 4.1, the results of the price simulation for 2030 are presented. Then, Sections 4.2 and 4.3 provide insight into the main findings of the economic potential analysis for flexible consumers and prosumers under today's situation (2015-2017) as well as for the future scenarios.

4.1 Simulation results for spot market prices in 2030

Table 6 (statistical key indicators), Figure 2 (distribution of prices) and Figure 3 (price duration curves) summarize the outcome from the spot price simulation model. The following points are noteworthy:

- Compared to the years 2015-2017, average price levels in 2030 roughly double. These results are within the range of other publications, expecting average spot market prices between 4.7 and 8.0 ct/kWh (ewi, gws, prognos 2014, insight e 2015, Statnett 2016, energybrainpool 2017).
- A considerable increase of hours with very high and with negative prices occurs. However, absolute values decrease for the latter.
- Overall price volatility, measured by standard deviation, increases significantly.
- As Scenario A2030 is characterised by a relatively low renewable generation, it exhibits the highest scarcity prices and more pronounced intra-day volatility.
- Modelling results for scenarios B2030 and C2030 are very similar, main differences appear within low/negative prices.

For this, two main reasons can be identified: First, spreads between variable generation cost of conventional generation technologies serve as key drivers for price-volatility because they determine the slope of the hourly supply stack. In scenario A2030, those spreads turn out to be the highest. Furthermore, specific fuel and CO_2 prices in B2030 and C2030 are identical. Second, for these scenarios it is assumed that about 10 GW of additional conventional flexibilities in the form of gas fired power plants and pumped storage will be installed in Germany. Consequently, this is reflected in a less volatile price structure. The smoothing effect of flexibility on the simulated spot prices becomes even more prevalent in scenario C2030 since conventional CHP must-run generation is expected to become considerably more flexible here.

Table 6: Statistical key indicators of spot price simulations for 2030. Source: own calculations.

Scenario	Maximum [ct/kWh]	Minimum [ct/kWh]	Average [ct/kWh]	Standard deviation [ct/kWh]	Average intra-day standard deviation [ct/kWh]	Negative prices [#]
A2030	38.62	-2.68	6.67	3.67	1.57	397
B2030	22.63	-2.76	6.42	2.44	1.12	417
C2030	23.41	-2.44	6.40	2.52	1.11	486

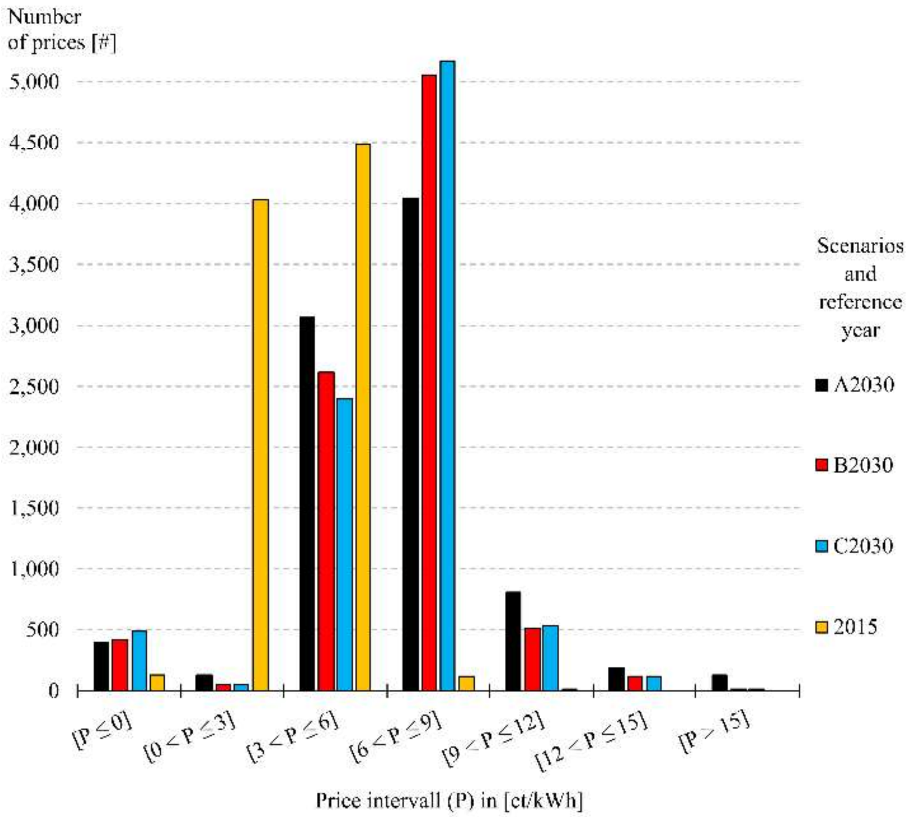

Figure 2: Distribution of simulated spot prices, compared to historical prices of the reference year 2015.

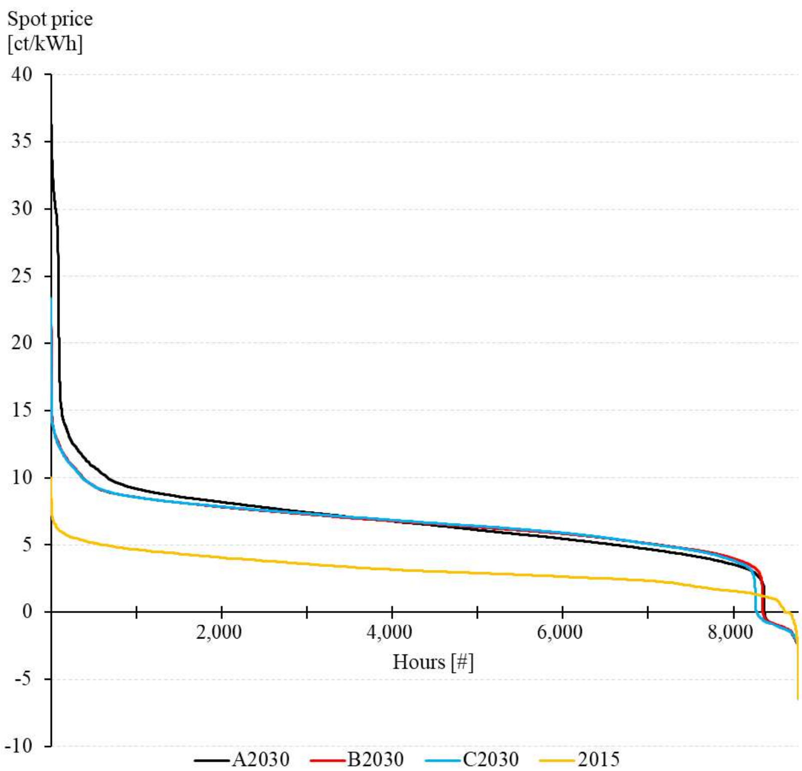

Figure 3: Annual price duration curve of simulated spot prices, compared to historical prices of the reference year 2015.

4.2 Economic potentials for the flexible consumers

4.2.1 Electric storage heaters

Modelling results reveal that owners of electric storage heaters can gain a significant economic benefit from the market-oriented operation mode. Figure 4 depicts the main findings in terms of annual wholesale market procurement cost for electricity, based on hourly spot market prices. Compared to the standard operation mode, where the storage charging process has to be undertaken between 10:00 p.m. and 6:00 a.m. (cf. Section 2.3), annual savings from a flexible and cost-optimized storage operation are in the range of 125 € for 2015 and 2017. However, for 2016, the potential of a market-oriented storage operation is limited due to very low spot price volatility and decreased price levels during night times. In the future scenarios, procurement cost more than double if the storage heater dispatch is carried out as usual. Here, a flexible operation strategy that considers fluctuations in short-term market prices can become an important risk management tool to mitigate the increase of the household´s electricity bill. The corresponding cost savings from the market-oriented operation mode in 2030 are between 320 and 360 €/a.

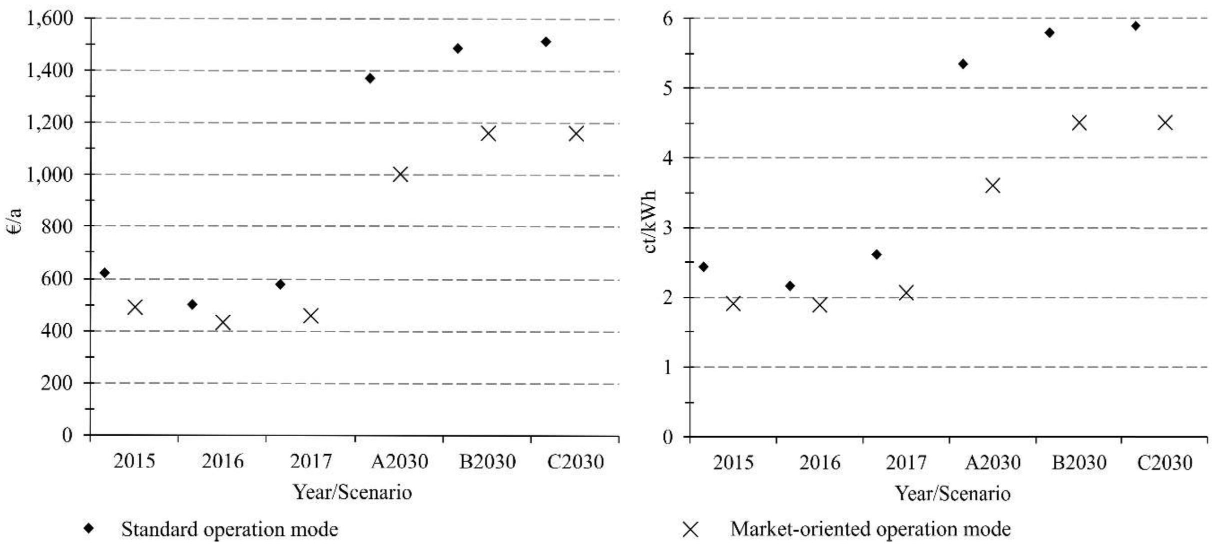

Figure 4: Wholesale market electricity procurement cost for different operation modes of the electric storage heating system, annual cost (left) and annual average cost per kWh (right).

Those findings can be explained from several perspectives. First, the nigh storage heaters under study feature a considerable flexibility potential due to their large thermal storage capacity. This allows for a cost optimal dispatch during hours with low market prices even in times of high heating demand. Second, the level of possible cost savings from flexible operation strongly correlates with intra-day price variability which is lowest in 2016 and highest in scenario A2030. Finally, due to a high overall electricity consumption (around 23.7 MWh p.a.) even small savings per kWh accumulate to significant total amounts.

Expressed in relative values, annual savings in wholesale market procurement cost are between 12 and 21% for the period 2015-2017 and between 22 and 27% within the future scenarios. However, it can be expected that the absolute savings are more decisive for end consumers' choices. Furthermore, these relative numbers are not valid for the retail prices and household bills, because taxes, levies and grid charges, which constitute the majority of the final electricity bill, are assumed to remain unchanged. Also, as explained in Section 2.2.1, in Germany, night storage heaters benefit from electricity tariffs with reduced grid charges and concession fees and as of today it is unclear whether these benefits would also be granted in case of a market-oriented operation. Under the existing regulatory framework, reduced grid charges and concession fees lead to financial advantages of about 3.7 ct/kWh compared to a standard supply tariff for the specific household examined here. Obviously, the above shown possible savings on the wholesale/procurement side would be ripped off if the reductions in grid charges and concession fees were not granted under a market-oriented operation.

4.2.2 Heat pumps

For the heat pumps considered in this case study, economic benefits of a market-oriented operation turn out to be modest. As shown in Figure 5, annual cost saving potentials vary between 15 and 25 € for recent years. In 2030, maximum values of 32 € (heat pump 1) and 38 € (heat pump 2) can be achieved in scenario A2030. Expressed in percentage values, relative savings between 5 to 13% are significant, however, it can be expected that the level of absolute savings will hardly provide sufficient incentives for the households to opt out of the standard operation mode. This becomes even more obvious if cost for flexibilization, market participation and related management/trading activities are factored in.

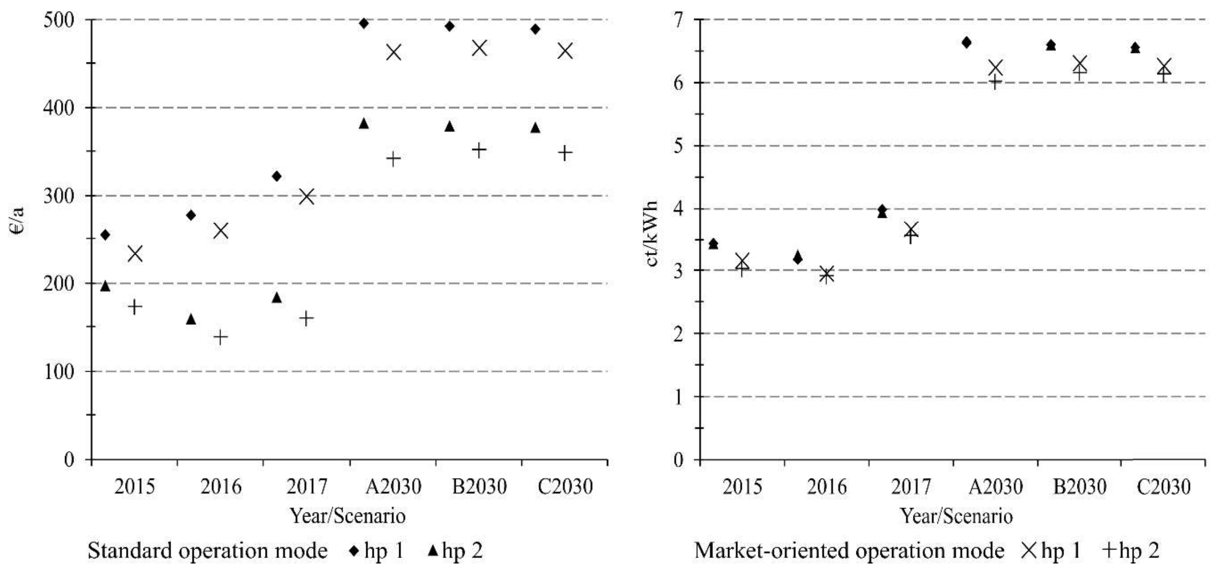

Figure 5: Wholesale market electricity procurement cost for different operation modes of the heat pumps (hp), annual cost (left) and annual average cost per kWh (right).

The main reasons for the small cost savings are low electricity demands (around 7.5 MWh for hp1 and 5.7 MWh for hp2), combined with limited flexibility potentials. As a key driver for the latter, the specific system design of heat pumps can be identified: Small storage volumes and small differences between supply and return flow temperature lead to very low thermal storage capacities, cf. Section 3.1 Table 2. Consequently, the decoupling of heat demand and electricity supply can be achieved for a few hours only. This also implies that such heat pump storage systems can hardly make a significant contribution to the stabilisation of the overall power system in situations of prolonged shortages (high market prices) during periods of high heating demand, since there is an obligation to consume electricity. Likewise, their capabilities for compensating electricity generation surpluses (low market prices) for several hours are very limited especially beyond the main heating period. The degree of load shifting potential from residential heat pumps, which is postulated to be significant for the integration of fluctuating renewable production in most previous publications, accordingly is rather small for the specific system configuration under study here.

Against this background, it is of special interest to what extent different system configurations with larger storage volume and/or increased maximum power consumption of the heat pump enhance flexibility potentials and therefore improve financial benefits of a market-oriented operation. Figure 6 presents the outcome of a sensitivity analysis in terms of *additionally* created value, carried out for heat pump 2 under the most profitable scenario A2030.

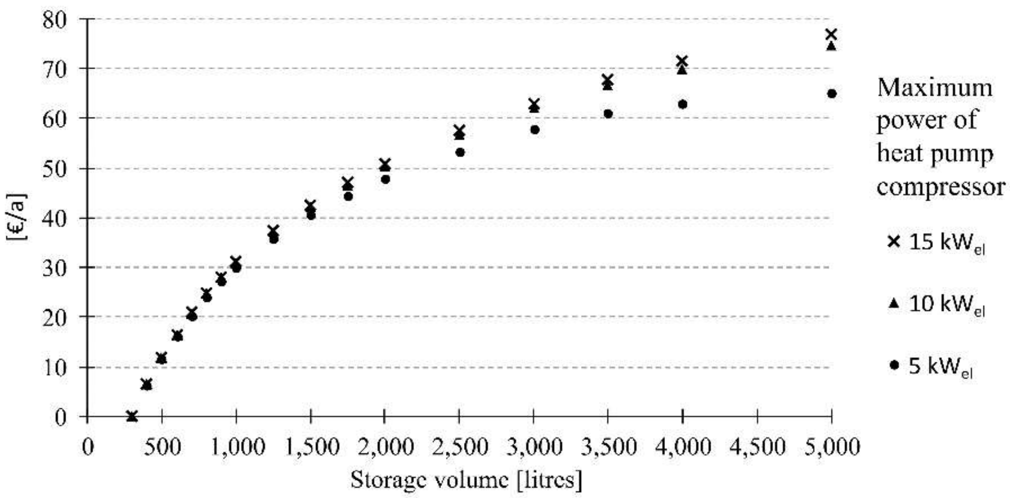

Figure 6: Additional electricity cost savings from modified system design in scenario A2030 (Heat pump 2, compared to the basic configuration with 5 kWel and 300 litres storage volume).

Here, coming from 38 € in the basic configuration, notable improvements can only be achieved with very large storage volumes of more than 1,000 litres, whereas positive effects of an increased power consumption only become relevant if storage volume exceeds 2,500 litres. However, it is questionable if these added values are sufficient to cover additional investments cost for enhanced system flexibility within a reasonable time[11]. Besides, it is likely that available space will limit storage sizes in most residential applications.

4.3 Economic potentials for the flexible prosumer

4.3.1 Today's situation

For the years 2015-2017, Figure 7 provides a summary of the modelling results in terms of average annual cost and revenues related to the different operation modes of the CHP units. The average surplus values (black bars) provide an indication of the overall financial advantages that come from CHP operation compared to a situation where total heat demand is covered by district heating and all electricity is bought from the grid (left bar, number [1]). Table 7 presents the corresponding average annual energy amounts as well as the average full-load hours of the CHP units.

Results clearly show that the market-oriented operation mode [5] comes along with considerable financial drawbacks compared to the other operation modes under the KWKG support scheme ([2], [3] and [4]). Average surplus values decrease by around 60 %, full-load hours, corresponding electricity and heat production as well as self-consumption and feed-in amounts almost halve. The remaining surplus value of nearly 300,000 € p.a. is still rather high at first sight, however, investment cost and expenses for maintenance of the CHP units are not factored in here. Therefore, a profitable CHP operation is far from certain in this case.

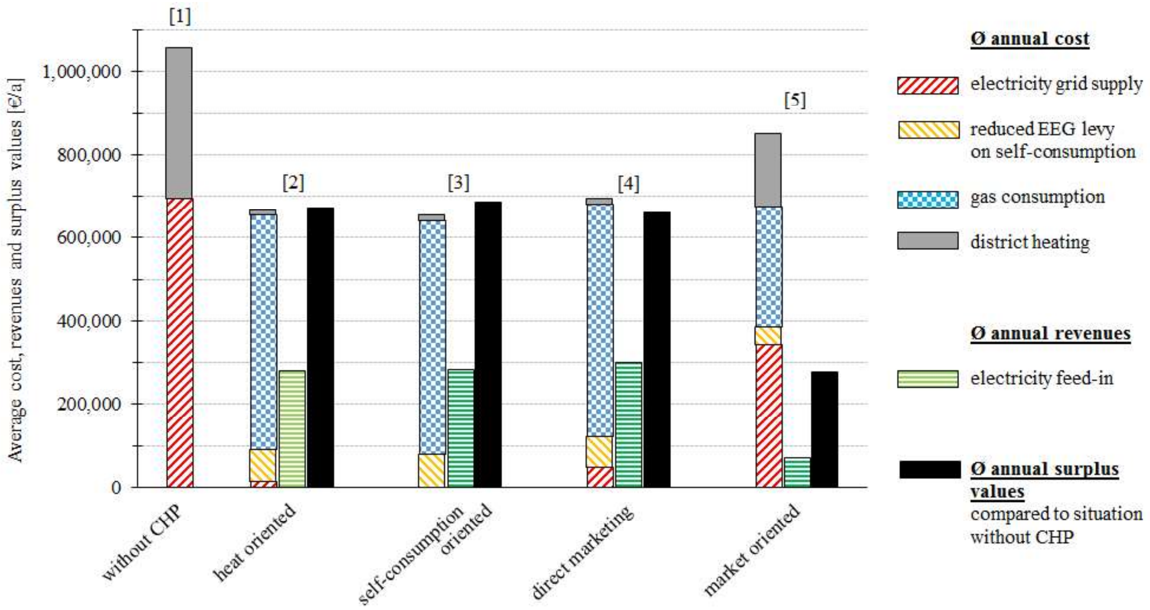

Figure 7: Average annual cost, revenues, and surplus values for alternative CHP operation modes under the KWKG support scheme, years 2015-2017.

11 Based on investment cost assumptions derived from Felten & Weber (2018). Regarding flexibility values, it is noteworthy to mention that these authors find almost similar results for comparable system configurations and equal spot price scenarios, even though their modelling approach for the building heating demand and heat pump systems is much more sophisticated.

Table 7: Average annual energy amounts, revenues from feed-in and full-load hours for alternative CHP operation modes, years 2015-2017.

Operation model	district heating [MWh]	electricity grid supply [MWh]	electricity self-consumption [MWh]	electricity feed-in [MWh]	revenues from feed-in [ct/kWh]	full-load hours [#]
[1] without CHP	9,049	3,498	-	-	-	-
[2] heat oriented	87	73	3,425	3,358	8.40	8,075
[3] self-consumption oriented	350	3	3,495	3,258	8.71	8,038
[4] direct marketing	399	243	3,255	3,472	8,66	8,007
[5] market oriented	4,561	1,736	1,762	1,721	4.17	4,146

The outcomes for the market-oriented operation mode [5] can be explained by the optimization model´s decisions for unit dispatch aiming towards a minimization of cost for heat supply. As explained in Section 2.3, the dispatch in case of the market-oriented operation does neither account for retail tariff components for procured electricity nor for additional remunerations granted for feed-in. Accordingly, combined heat and power production is favourable against the alternative heat supply only above a certain spot market price level. This threshold depends on the prices for district heating and gas consumption as well as on the CHP unit´s efficiency and its power-to-heat ratio. E.g., spot market prices in 2015 have to exceed 3.38 ct/kWh which was the case in 3,440 hours. The flexibility of the CHP system therefore is used to match electricity production with high market prices and thus will provide electricity for the power system especially during times with tight supply.

It is important to mention that self-consumption of CHP electricity is determined separately here; based on the optimization model´s production schedule and the load profile (cf. Section 2.4) [12]. As depicted in Table 7, about 50% of heat and electricity demand will be covered by CHP production in the market-oriented operation mode. When comparing the costs to the situation without CHP [1], it becomes obvious that the cost savings from reduced electricity supply from the grid, including avoided taxes, levies and grid charges are the main driver for the surplus value and the corresponding profitability of the CHP units. In contrast, spot market revenues from feed-in play a minor role.

Among the operation modes [2], [3] and [4], there are only slight differences in results. High utilization rates come along with large amounts of produced heat and power; supply from the district heating network and from the electricity grid are almost entirely avoided. With average annual surplus values around 660,000 to 690,000 €, the CHP units are likely to be very profitable for the owner and, as already stated above, avoided electricity cost make a substantial contribution to the surplus values. It

[12] The self-consumption-oriented operation mode in the market scenarios for 2030 considers both; spot market prices for electricity feed-in and the cost of electricity supply.

is also noticeable that the amounts of electricity feed-in roughly double compared to the market-oriented operation mode, whereas the corresponding revenues quadruple.

This clearly illustrates how the support mechanism of the KWKG with its time-invariant remuneration scheme on a per unit basis (here: 5.23 ct/kWh) incentivizes unit dispatch decisions towards an inflexible “produce and forget” approach, decoupled from market price signals. The so-called direct marketing mechanism, which is explicitly implemented in the modelling approach [3] and [4], accounts for revenues from hourly spot market prices. However, these come on top of the fixed remuneration and therefore revenues from feed-in are above the mentioned threshold (3.38 ct/kWh in 2015) as soon as market prices are positive. Due to the high heating demand of the swimming pool, this leads to a more or less full utilisation of the CHP units. Furthermore, the dimensioning of the CHP units allows for high utilisation rates which has been a common aim in practice until now. For the specific case under consideration here, also a high electricity demand exists and self-consumption becomes a valuable co-benefit due to high retail prices for electricity (cf. Section 2.2.1). If this value is addressed explicitly (self-consumption-oriented mode [3]) and minimization of cost includes heat as well as power consumption, the flexibility of the CHP system is primarily used to match electricity production with the electricity load profile. Here, the decoupling of unit dispatch from market prices is not only induced by the CHP remuneration scheme but further intensified by the price gap between resale and wholesale electricity prices which is the driving force for self-consumption.

4.3.2 Market scenarios for 2030

As illustrated in Figure 8 and Table 8, annual cost for the provision of heat and electricity rise at around 10% in the scenario without CHP production even though heat demand in 2030 (derived from the base year 2015) is around 14% below the above shown average demand for the period 2015-2017. This cost increase is mainly driven by the development of retail prices for electricity grid supply from an average rate of 19.9 ct/kWh for 2015-2017 up to 23.2 ct/kWh in scenario A2030 and 22.9 ct/kWh in scenario C2030[13].

Regarding the annual surplus values (black bars), it is apparent that the economic benefits from CHP operation in scenario C2030 are significantly higher than those in scenario A2030. These results can be explained by a lower ratio between gas and district heating prices in scenario C2030 (3.82 to 4.47 ct/kWh vs. 4.12 to 4.77 ct/kWh in A2030, cf. Section 3.3.3) which leads to higher utilization rates and higher annual revenues from electricity feed-in within the self-consumption and the market-oriented operation modes. The corresponding threshold spot market prices that make heat production from

[13] Modelling results for the scenario B2030 and C2030 only slightly deviate. Therefore, the result description is limited to the comparison between scenario A2030 and C2030 here.

CHP advantageous compared to district heating are 4.71 ct/kWh in A2030 and 4.31 ct/kWh in C2030 and simulated prices exceed these thresholds in 6,975 respectively 7,750 hours.

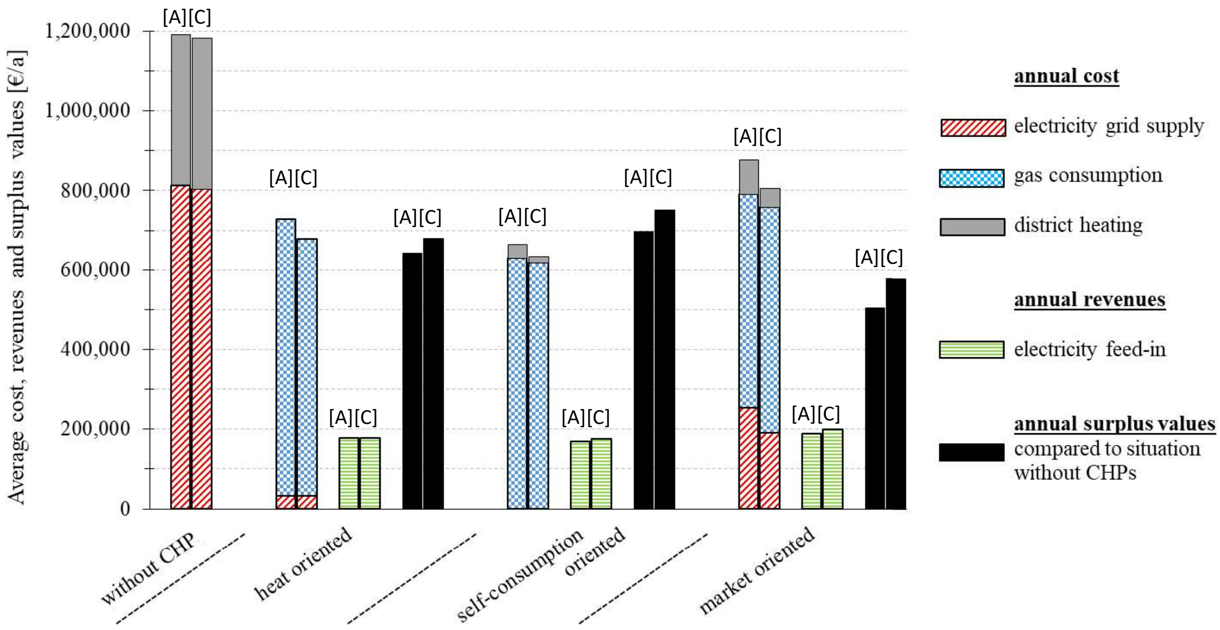

Figure 8: Average annual cost, revenues, and surplus values for alternative CHP operation modes, scenario A2030 ([A]) and C2030 ([C]).

Considering the assumption of a phased-out CHP promotion scheme in 2030, it is furthermore noticeable that annual surplus values increase compared to 2015-2017, except within the heat-oriented scenario for A2030. The loss of remuneration payments for feed-in is compensated by a growth in cost savings from electricity self-consumption and by increased market values for feed-in. Because spot market prices in 2030 reach significantly higher levels, also the market-oriented operation modes become much more profitable. Annual surplus values here nearly double and average revenues from feed-in almost equal the corresponding revenues under today's CHP promotion scheme. In this context, as indicated in Table 8, it is surprising at first sight that average revenues (ct/kWh) from feed-in are higher in the self-consumption-oriented operation mode than in the market-oriented operation mode in both scenarios. The explanation is that feed-in takes basically place during the same hours and therefore at the same market prices; however, feed-in amounts within the self-consumption-oriented operation are smaller and more focused on the hours with very high spot prices. Results also clearly show that in the self-consumption-oriented scheme electricity feed-in decreases by around 34% (A2030) and 28% (C2030) in contrast to 2015-2017 which indicates that, without remuneration payments, the unit dispatch under the self-consumption-oriented operation is at least partly matched to market price signals[14]. However, the degree of this market-oriented feed-in strongly

[14] To some extent, lower heat demand in 2030 and therefore less CHP full load hours also contribute to this decline. However, within the heat-oriented operation feed-in amounts only drop at around 17%.

depends on the specific heat and electricity load profiles, the minimum/maximum power production restrictions and on the thermal storage capacity because these factors determine how much flexibility can be utilized for the most cost effective and therefore prevailing purpose which is the maximization of electricity self-consumption.

Table 8: Average annual energy amounts, revenues from feed-in and full-load hours for alternative CHP operation modes, scenario A2030 and C2030.

		district heating [MWh]	electricity grid supply [MWh]	electricity self-consumption [MWh]	electricity feed-in [MWh]	Ø revenues from feed-in [ct/kWh]	full-load hours [#]
without CHPs	A	7,937	3,502	-	-	-	-
	C	7,937	3,502	-	-	-	-
heat oriented	A	0	146	3,356	2,778	6.42	7,302
	C	0	146	3,356	2,778	6.39	7,302
self-consumption oriented	A	716	0.1	3,502	2,053	8.28	6,613
	C	360	0.3	3,502	2,361	7.47	6.980
market oriented	A	1,820	1,097	2,406	2,347	8,08	5,658
	C	1,049	835	2,668	2,738	7.33	6,435

5 Conclusions and policy implications

This paper has investigated the economic incentives for a flexible, spot-market-oriented operation mode of small heat pumps, night storage heaters and CHP systems from an end-user perspective. The analysis has been conducted for the German market situation from 2015 to 2017 and its specific regulatory framework regarding electricity price components under governmental control and CHP support schemes. Furthermore, possible future developments have been considered based on simulated spot market prices for 2030.

Firstly, results show that volatile market prices are a fundamental precondition for financial benefits from load or production shifting activities, offering additional flexibility to the power system. Even though high shares of fluctuating renewable generation are commonly linked to high price volatility, the recent experience for the German spot market reveals that price differentials are limited if large amounts of conventional flexibility options are still available. Under the scenario settings for 2030, overall price volatility is likely to stay relatively low for the same reason: Gas fired power plants and pump storages still provide sufficient flexibility to balance supply and demand of electricity, also, prices for CO_2 emission certificates are rather low. Accordingly, decentral flexibility options have to compete against conventional technologies and other players who have entered the markets already, for example suppliers of industrial demand side management. This may result in low (expected) financial benefits and therefore limited incentives for the market-oriented operation of smaller flexibility options.

However, this paper analyses only one particular business case, which is the participation in the hourly day ahead spot market. Commercialization of end user flexibility may become more attractive if other short-term market segments are also considered, e.g., the intraday or ancillary service markets. Moreover, in the future, end-users may play a key role in solving local problems on distribution grid level where flexibility can become a valuable asset to increase the share of power generation from fluctuating renewables in spatial proximity on the one hand and to manage power consumption from electric vehicle charging on the other. Hence, future research should investigate which value could be created by a multi-purpose application in existing and upcoming multiple market segments.

Secondly, for the specific system configurations under study here, the analysis reveals that heat-related flexibility potentials on end-user level might create only limited economic benefits due to technical restrictions and individual system characteristics. Especially for small heat pumps, combined with small thermal storages, absolute cost savings from a market-oriented operation turn out to be minor, which is also a result of low overall electricity consumption and strong seasonal heat demand patterns in Germany. Therefore, it is questionable if the operation of such heating systems will be fully integrated into the short-term electricity markets. However, consumers with high annual electricity consumption and large storage capacities may substantially benefit from a flexible unit-operation that responds to fluctuations in market prices. Regarding CHP systems, it has to be considered that most existing units installed with end users are designed to cover thermal base loads and motor-based CHP units usually feature an almost constant output-ratio of electricity and heat production. Consequently, opportunity cost of alternative heat supply is of crucial relevance within a flexible operation mode. Therefore, from the owners' perspective, an inflexible operation of the CHP unit might be economically favourable even at very low spot market prices.

Finally, the findings of this paper´s case study reveal that the current German regulation hampers flexible consumption and production on end-user level. For electric heating systems, it is unclear if today´s conditional privileges that are granted on certain regulated electricity price components will also be applied under a market-oriented operation scheme. This is putting a risk on potential monetary benefits from load shifting because cost savings from exploiting hours with low market prices may be compensated by increased rates for grid charges and concession fees. Therefore, policy makers should put special emphasis on a design of regulated electricity price components that is non-discriminatory with regard to consumption patterns that follow short term market price signals.

As a main obstacle for flexible production, incentives to maximize self-consumption are identified. Volumetric billing of grid charges, the renewable energy act levy, the electricity tax and various other regulated price components creates a large gap between electricity retail prices per kWh and market prices, which in turn increases the value of self-consumption far above the market value. Consequently, end-users who operate CHP systems will use the flexibility of their systems primarily to match electricity production with load profiles instead with market prices. Depending on system configuration and load profile, residual flexibility may be used for a market-oriented feed-in of electricity. However, the German CHP remuneration scheme is also based on a time-invariant volumetric feed-in tariff that again decouples unit commitment from market price signals. To activate flexibility from prosumers and to incentivise a more market-oriented production, policy has to work towards a regulation that allows for a less biased (if not unbiased) transfer of market price signals to end users.

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Appendix: Optimization models to determine unit commitment

Appendix 1 Nomenclature

Index

T=1, … ,T: Quarter-hours of the year

Technical parameters

$\mathrm{P}^{\mathrm{Cons}_{\mathrm{max}}}$: Maximum electric power consumption of heat pump and night storage heater [kW]

$\mathrm{P}^{\mathrm{Cons}_{\mathrm{min}}}$: Minimum electric power consumption of heat pump and night storage heater [kW]

$\mathrm{P}^{\mathrm{Prod}_{\mathrm{max}}}$: Maximum electric power production of CHP units [kW]

$\mathrm{P}^{\mathrm{Prod}_{\mathrm{min}}}$: Minimum electric power production of CHP unit [kW]

$\mathrm{Q}^{\mathrm{Sto}_{\mathrm{max}}}$: Capacity of thermal storage [kWh]

$\dot{\mathrm{Q}}^{\mathrm{StoIn}_{\mathrm{max}}}$: Maximum heat flux into thermal storage [kW]

$\dot{\mathrm{Q}}^{\mathrm{StoOut}_{\mathrm{max}}}$: Maximum heat flux out of thermal storage [kW]

$\dot{\mathrm{Q}}^{\mathrm{DH}_{\mathrm{max}}}$: Maximum heat flux out of district heating network [kW]

$\dot{\mathrm{Q}}^{StoLoss}$: Constant loss of thermal storage [kW]

η^{StoVar}: State of charge-dependent loss factor [0-1]

η^{CHP}: Overall efficiency of the CHP unit

a: Slope of linear equation for CHP coefficient [-]

b: Section of linear equation for CHP coefficient [-]

OT: Off-times indicator for standard operation mode of night storage heater [0;1]

COP: Coefficient of performance [-]

D^{H}: Heat demand (load profile) [kW]

D^{El}: Electric demand of the prosumer (load profile) [kW]

Δt: Length of time interval [1/4 h]

Economic parameters

$\mathrm{p}^{\mathrm{Spot}}$: Spot market electricity price [€/kWh]

p^{El}: End consumer electricity price (net value) [€/kWh]

p^{Gas}: End consumer gas price (net value) [€/kWh]

p^{DH}: End consumer district heating price (net value) [€/kWh]

$\mathrm{p}^{\mathrm{FIT}}$: Feed-in tariff according to CHP law [€/kWh]

$\mathrm{p}^{\mathrm{AGU}}$: Remuneration for avoided grid use according to CHP law [€/kWh]

p^{EEG}: Prorated EEG levy charged for self-consumption [€/kWh]

Variables

P^{Cons}: Power consumption of heat pump and night storage heater [kW]

P^{Prod}: Power production of CHP unit [kW]

P^{SC}: Self-consumption of the prosumer [kW]

P^{GI}: Grid infeed of the CHP unit [kW]

P^{Pur}: Electricity purchase of the prosumer [kW]

G: Gas consumption of CHP unit [kW]

$\dot{Q}^{Prod}$: Thermal production [kW]

$\dot{Q}^{DH}$: Thermal power supply from district heating system [kW]

$\dot{Q}^{StoIn}$: Heat flux into thermal storage [kW]

$\dot{Q}^{StoOut}$: Heat flux out of thermal storage [kW]

Q^{Sto}: State of charge of thermal storage [kWh]

ON: Binary variable for state of unit operation [1;0]

Appendix 2 Objective functions for heat pump and night storage heater

Market-oriented operation:

$$Min!\,Obj = \sum_{t=1}^{T} \left(P_t^{Cons} \cdot \mathrm{Pr}_{\mathrm{t}}^{Spot}\right) \cdot \Delta \mathrm{t} \tag{1}$$

Appendix 3 Objective functions for different operation modes of CHP-units

Heat oriented operation:

$$Min!\,Obj = \sum_{t=1}^{T} \dot{Q}_t^{DH} \cdot \Delta \mathrm{t} \tag{2}$$

Market-oriented operation, no support scheme:

$$Min!\,Obj = \sum_{t=1}^{T} \left(G_t \cdot \mathrm{p}^{Gas} + \dot{Q}_t^{DH} \cdot \mathrm{p}^{DH} - P_t^{Prod} \cdot \mathrm{p}_\mathrm{t}^{Spot}\right) \cdot \Delta\mathrm{t} \tag{3}$$

Direct marketing:

Based on provisions of the German CHP law of 2016

$$Min!\,Obj = \sum_{t=1}^{T} \left(G_t \cdot \mathrm{p}^{Gas} + \dot{Q}_t^{DH} \cdot \mathrm{p}^{DH} - P_t^{Prod} \cdot \left(\mathrm{p}_\mathrm{t}^{Spot} + \mathrm{p}_\mathrm{t}^{\mathrm{FIT}} + \mathrm{p}^{\mathrm{AGU}}\right)\right) \cdot \Delta\mathrm{t} \tag{4}$$

Consideration of the cost of grid supply, rules for self-consumption and direct marketing

Based on provisions of the German CHP law of 2016

$$\begin{aligned} Min!\,Obj = \sum_{t=1}^{T} \Big(& P_t^{Pur} \cdot \mathrm{p}^{El} + P_t^{SC} \cdot \mathrm{p}^{\mathrm{EEG}} + G_t \cdot \mathrm{p}^{Gas} + \dot{Q}_t^{DH} \cdot \mathrm{p}^{DH} - P_t^{GI} \\ & \cdot \left(\mathrm{p}_\mathrm{t}^{Spot} + \mathrm{p}_\mathrm{t}^{\mathrm{FIT}} + \mathrm{p}^{\mathrm{AGU}}\right)\Big) \cdot \Delta\mathrm{t} \end{aligned} \tag{5}$$

Consideration of the cost of grid supply, no support scheme, no rules for self-consumption:

$$Min!\,Obj = \sum_{t=1}^{T} \left(P_t^{Pur} \cdot \mathrm{p}^{El} + G_t \cdot \mathrm{p}^{Gas} + \dot{Q}_t^{DH} \cdot \mathrm{p}^{DH} - P_t^{GI} \cdot \mathrm{p}_\mathrm{t}^{Spot}\right) \cdot \Delta\mathrm{t} \tag{6}$$

Appendix 4 Modelling of heat production from electric storage heater and heat pump

Power-to-heat constraint electric storage heater:

$$P_t^{Cons} = \dot{Q}_t^{StoIn} \tag{7}$$

Power-to-heat constraint heat pump:

$$P_t^{Cons} \cdot \mathrm{COP}_\mathrm{t} = \dot{Q}_t^{StoIn} \tag{8}$$

Restrictions for maximum and minimum electricity consumption:

$$P_t^{Cons} \leq \mathrm{P}^{\mathrm{Cons_{max}}} \cdot ON \tag{9}$$

$$P_t^{Cons} \geq \mathrm{P}^{\mathrm{Cons_{min}}} \cdot ON \tag{10}$$

For the simulation of night storage heaters' standard operation, the off-times indicator "OT" is inserted as a multiplier with values of 1 between 10:00 p.m. and 6:00 a.m. and 0 for remaining hours.

Appendix 5 Modelling of prosumer with CHP unit

Coverage of electricity demand:

$$P_t^{Pur} + P_t^{SC} = \mathrm{D}_\mathrm{t}^{El} \tag{11}$$

Physical balance between electricity production, grid infeed and self-consumption:

$$P_t^{Prod} = P_t^{GI} + P_t^{SC} \tag{12}$$

Dependency between electricity production and heat production:

$$\dot{Q}_t^{Prod} = a \cdot P_t^{Prod} + b \cdot ON \tag{13}$$

Restrictions for maximum and minimum electricity production:

$$P_t^{Prod} \leq \mathrm{P^{Prod}}_{\max} \cdot ON \tag{14}$$

$$P_t^{Prod} \geq \mathrm{P^{Prod}}_{\min} \cdot ON \tag{15}$$

Constrain for gas consumption:

$$G_t = (P_t^{Prod} + \dot{Q}_t^{Prod})/\eta^{\mathrm{CHP}} \tag{16}$$

Restrictions for maximum thermal supply from backup heating system:

$$\dot{Q}_t^{DH} \leq \dot{\mathrm{Q}}^{\mathrm{DH}}{}_{\max} \tag{17}$$

Appendix 6 Modelling of heat supply with thermal storage

Coverage of heat demand:

$$\dot{Q}_t^{StoOut} = \mathrm{D}_\mathrm{t}^{H} \tag{18}$$

Storage balance between two time steps:

$$Q_{t+1}^{Sto} = Q_t^{Sto} \cdot \eta^{\mathrm{StoVar}} - \left(\dot{\mathrm{Q}}^{\mathrm{StoLoss}} + \dot{Q}_t^{StoOut} - \dot{Q}_t^{StoIn}\right) \cdot \Delta\mathrm{t} \tag{19}$$

For electric storage heaters and public swimming pool, losses are neglected because they contribute to the coverage of the overall buildings thermal demand. For the swimming pool, alternative heat supply from the district heating network is considered by adding $-\dot{Q}_t^{DH}$ in the term in brackets.

Restriction for storage capacity:

$$Q_t^{Sto} \leq \mathrm{Q^{Sto}}_{\max} \tag{20}$$

Limitation of heat flux into and out of thermal storage:

$$\dot{Q}_t^{StoIn} \leq \dot{\mathrm{Q}}^{\mathrm{StoIn}}{}_{\max} \tag{21}$$

$$\dot{Q}_t^{StoOut} \leq \dot{\mathrm{Q}}^{\mathrm{StoOut}}{}_{\max} \tag{22}$$

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