# Optimal system design for energy communities in multi-family buildings: the case of the German Tenant Electricity Law

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**Abstract**

Involving residential actors in the energy transition is crucial for its success. Local energy generation, consumption and trading are identified as desirable forms of involvement, especially in energy communities. The potentials for energy communities in the residential building stock are high but are largely untapped in multi-family buildings. In many countries, rapidly evolving legal frameworks aim at overcoming related barriers, e.g. ownership structures, principal-agent problems and system complexity. But academic literature is scarce regarding the techno-economic and environmental implications of such complex frameworks. This paper develops a mixed-integer linear program (MILP) optimisation model for assessing the implementation of multi-energy systems in an energy community in multi-family buildings with a special distinction between investor and user; the model is applied to the German Tenant Electricity Law. Based on hourly demands from appliances, heating and electric vehicles, the optimal energy system layout and dispatch are determined. The results contain a rich set of performance indicators that demonstrate how the legal framework affects the technologies' interdependencies and economic viability of multi-energy system energy communities. Certain economic technology combinations may fail to support national emissions mitigation goals and lead to lock-ins in Europe's largest residential building stock. The subsidies do not lead to the utilisation of a battery storage. Despite this, self-sufficiency ratios of more than 90% are observable for systems with combined heat and power plants and heat pumps. Public $CO_2$ mitigation costs range between 147.5–272.8 €$/t_{CO2}$. Finally, the results show the strong influence of the heat demand on the system layout.

*Keywords:* Tenant Electricity Law, self-consumption, optimization, energy communities, multi-energy system, multi family housing, photovoltaic (PV), combined heat and power (CHP)

**Highlights**

- System optimisation of distinct operators and consumers in multi-family buildings
- Inclusion of Tenant Electricity Law leads to complex investment and dispatch decisions
- Highest profitability combining photovoltaic, combined heat and power and heat pump
- Combined heat and power is favoured, but profits depend on buildings' heating demand
- Legislation incentivises energy communities but may offset national CO2 mitigation

**Nomenclature**

| ***Parameters and Symbols*** | | ***Index*** | |
|---|---|---|---|
| *clt* | Calendar life time | *inv* | Investment |
| *i* | Discount rate | *inv*, *fix* | Fixed investment |
| $clt_{rem}$ | Remaining calendar life time | *inv*, *var* | Variable investment |
| *c* | Cost | *rem* | Residual value |
| *VAT* | Value added taxes | *O&M* | Operation & maintenance |
| *EF* | $CO_2$ emission factor | *grid* | Electricity from the grid |
| $A_{roof}$ | Area of roof | *ll* | Landlord |
| $\Delta C_{el}$ | Energy cost savings | *te* | Tenant |
| *SCR* | Self-consumption rate | *th* | Thermal |
| *DSS* | Degree of self-sufficiency | *el* | Electric |
| *DA* | Degree of electrical autonomy | *fees* | Fees |
| *BigM* | Big number | *pv* | Photovoltaic |
| $r_{chp,min}$ | Minimum load factor of CHP | *self* | Self-consumed not by tenant |
| $h_{chp,fullload}$ | Subsidized CHP full load hours | *chp* | Combined heat and power |
| $cap_{REL,lim}$ | Capacity limit for levy exemption | *feedin* | Feed-in tariff |
| $E_{REL,lim}$ | Energy limit for levy exemption | *boiler* | Gas boiler |
| *COP* | Coefficient of performance | *gas* | Natural gas |
| *D* | Demand | *levy* | REL levy |
| *cac* | $CO_2$ abatement cost | *M&I* | Metering & invoicing |
| *CF* | Cash flow | *wo* | Without subsidies |
| $r_{el}$ | Yearly electricity price change rate | *SCP* | Self-consumption premium |
| $r_{EF}$ | Yearly emission factor change rate | *tot* | Total amount per year |
| *R* | Revenue | *ref* | Reference case |
| ***Sets*** | | *opt* | Optimised case |
| *l* | technology | *EF* | $CO_2$ emission factor |
| *a* | year | *subs* | Subsidies |
| *t* | hours | *export* | Export into grid |
| *rs* | remuneration scheme | | |

## 1. Introduction

On-site renewable energy generation and utilisation in buildings has been a popular topic for decades [1] and remains an important element for future sustainable urban energy systems. Especially for photovoltaic (PV) installations in urban areas, large amounts of potential remain untapped. This potential is an essential part of the bottom-up approach to energy system transition, which the European Commission [2] and the European Parliament and the Council of the EU [3] introduced in the form of energy communities. On the European level, policymakers drafted various laws to incentivise building owners to install on-site energy generators such as PV or Combined Heat and Power (CHP) [4]. The legislation allows for a diverse variety of business models [5] with the overall goal of lowering electricity prices and expanding the share of renewable energy sources (RES). Additionally, the policies incentivise both self-generation and self-consumption to make the energy system transition more affordable for households while reducing stress on electricity grids [6].

On the national level, the building stock is responsible for a significant amount of green-

**Nomenclature continued**

| *Variables* | | *Acronyms* | |
|---|---|---|---|
| *acf* | Annual cash flow | HH | Household |
| $C_{inv}$ | Discounted investment/cost | PV | Photovoltaic |
| *NPV* | Net present value | CHP | Combined heat and power |
| *cap* | Capacity | HP | Heat pump |
| *E* | Energy | HS | Heat storage |
| *P* | Power | boiler | Gas boiler |
| *D* | Demand | cap | Capacity |
| $CO_2$ | Mass/amount of $CO_2$ emissions | el | Electric |
| $\Delta CO_2$ | Abated amount of $CO_2$ emissions | th | Thermal |
| *Q* | Heat | RES | Renewable energy sources |
| *bin* | Binary decision variable | POV | Point of view |
| | | KPI | Key performance indicator |

house gas emissions[1] and thus plays a key role in reducing the building stock's energy consumption[2]. While the installation of renewable energy systems in single-family buildings (SFBs) is an established practice, there is still potential in multi-family buildings (MFBs). This relatively high reduction potential remains barely utilized because of diverse ownership structures and the principal-agent dilemma. Therefore, energy communities need to consider concepts beyond the conventional self-consumption-based approach. Internal revenue streams need to provide value for both the principal and the agent, i.e. the landlord and the tenant respectively. Reviewing existing policies in different European countries, multiple cash flows, energy flows, and data flows connecting various market participants lead to rather complex legal frameworks [9]. Examples of such policies are the Private Wire Network policy in the UK, the Collective Auto Consumption policy in Spain, the Post Code Rose policy in the Netherlands and the Mieterstrom policy in Germany. Finally, the multi-energy system nature of energy communities offers higher efficiencies, higher reliability, and the integration of a larger share of RES [10]. Nevertheless, identifying the optimal size and dispatch for a system that considers multiple energy forms and their interactions requires large amounts of computational resources. Additionally, the temporal resolution influences the precision of the results, but a high resolution is computationally expensive [11].

As outlined in the literature review in Section 2, energy communities at the building and district scale are active research areas. Despite many contributions towards optimising multi-energy systems at these scales in recent years, most studies investigate energy communities' self-consumption in a traditional sense. They do not consider the different economic situations of investor and user, and studies about novel business models are scarce [5]. This paper, therefore, aims to fill this research gap with a fundamental techno-economic analysis of optimal energy system configurations for multiple MFBs in the context of energy communities by taking the legal framework into account.

The key contribution and novelty of this paper is the optimisation of the design and operation of an energy community considering:

- multi-energy forms, electricity, heat and electric mobility, and
- internal revenue streams, where investor and user are non-identical, and

[1] In Germany, the building sector makes up more than 25% of greenhouse gas emissions [7].
[2] In Germany, its number of apartments makes up 53% of the building stock [8].

- the complexity of energy communities' legal framework, and
- a high temporal resolution of one year in hourly time steps, and
- degression effects for the remuneration of self-generated electricity.

We apply the model to four MFBs in Germany and implement the German Tenant Electricity Law (TEL)[3]. Similar to other European energy community policies, the TEL supports operators (landlords) to install PV on and CHP in MFBs and profit from the on-site consumption of the electricity by their tenants instead of relying solely on feed-in tariffs. Additionally, tenants can profit from reduced energy expenditures and higher shares of renewable electricity supply. The optimization model, solved on a high-performance computing system, allows us to identify non-intuitive coherence among different technologies. Additionally, the model results present challenges for the optimal system design process that arise from complex internal energy and cash flows in combination with technical constraints. Subsequently, we derive policy and business implications on avoiding pitfalls in investment and operational decisions.

The analysis is threefold: we study the combination of different technology components (component-wise analysis), the influence of different building types (building-wise analysis) and the sensitivity to policy changes (comparison of the amendment from TEL 2020 to 2021). The key performance indicators (KPI) are the Net Present Value (NPV), the technical capacities to describe the design of the energy system, measures to describe the self-consumption behaviour and grid interaction, as well as the $CO_2$ emissions and abatement.

This paper is structured as follows. In Section 2, we summarise the existing international academic literature on energy communities and different legal frameworks concerning TEL. As a conclusion of the literature review, we identify the scientific gap addressed by the paper. Section 3 gives a detailed description of the current TEL, the economic conditions, and remuneration and subsidies schemes. Furthermore, Section 3.2 lists the most relevant model equations, and Section 3.3 presents this study's KPIs. Section 4 elaborates on the design of the three main analyses, which are evaluated in Section 5. The results are further discussed in Section 6 together with policy implications, methodological shortcomings and an outlook for future studies. Section 7 ends the paper with concluding remarks.

## 2. Literature review

Different publications deal with the benefits of decentralised multi-energy systems in multi-apartment buildings. Lindberg et al. [12] used a mixed-integer model to investigate solutions for zero energy MFBs with 10 apartments in Germany. While a combination of CHP-system with a PV-system has been identified as a robust cost-optimal investment, the system causes large impacts on the grid in peak hours. A techno-economic analysis of energy-related active retrofitting of MFBs is presented by Fina et al. [13] without considering any legal constraints. A further assessment of the tenant model in an Austrian MFB showed that the economic viability of PV-systems strongly depends on the retail electricity prices [14]. Fina et al. [14] conclude that the case should be a win-win situation for both landlords and tenants in Germany due to the higher retail prices, but the Austrian TEL is also less restrictive. This also applies to the model of [15], which optimised the energy system design of a six-floor MFB in Northern Italy. A similar study

[3]This study considers the law in force up to the 1st. of January 2021.

of a multi-apartment building with a stronger focus on energy autonomy and hybrid systems has been conducted by Comodi et al. [16]. While the authors conclude that a battery would increase independence from the grid, the costs are very high. Palomba et al. [17] optimised the supply systems of two main MFB typologies in three climate regions in Europe. The results showed the possibility of achieving high solar shares for domestic hot water even in northern climates. By taking the main German levies and taxes for self-generation and -consumption into account, the optimization results of McKenna et al. [18] indicate a shift in the economically optimal level of electrical self-sufficiency with scale. The effect of the then current legal regime on the optimal design of a CHP is also highlighted by Merkel et al. [19].

Research with a sharper focus on the national TEL is mostly presented in non peer-reviewed (grey) literature and/or written in German. Three simple exemplary TEL business-case evaluations in terms of a 20 party MFB are presented in the German study of Harder and Durmaz [20]. While the installation of a CHP-system leads to an economic advantage of around 600 € per annum, the PV-system on the other hand only yields around 40 € per annum. A combination of the two systems with simultaneous consideration of e-mobility loads demonstrates an economic advantage of around 50 € per annum. The implementation of the additional battery system leads to higher security but also a lower economic advantage [20]. Additionally, the non peer-reviewed article by [21] applies a techno-environmental analysis of MFBs with PV-systems and electric vehicle charging stations under the TEL. It is shown that 2-4 tCO2e/a emissions can be saved, depending on the building size. The economic advantages of the TEL for the tenant and the operator is also supported by the results of Scheller et al. [22] and the conference proceeding of Seim et al. [23]. Furthermore, the practical tool of Knoop et al. [24] represent a simple assessment tool for the TEL in Germany. An overview of existing policies in the EU that foster the potential of collective renewable energy prosumers in energy communities is given by Inês et al. [4]. Detailed examples of practical implementations of different forms of the TEL in the UK (Private Wire Networks policy), Spain (Collective Auto Consumption policy), Netherlands (Post Code Rose policy) and Germany (Mieterstrom policy) are presented by Stephen Hall et al. [9].

While the number of publications indicates an increasing interest in energy communities or neighbourhoods, the legal frameworks in action are considered to be at an early stage [25]. The energy hub approach has been taken into account by various publications to determine the optimal energy system design of neighbourhoods. An overview is given in the review article by Mohammadi et al. [26], who lists 129 scientific papers using the approach; most of them without considering the legal framework apart from the feed-in tariffs. Thereby, Ghorab [27] implement a multi-objective optimization model to minimize the overall cost and emissions of different building archetypes in Canada forming an energy hub. A similar approach has been used by [28] to evaluate and size neighbourhood energy systems according to their energy-autonomy, economic and ecological performance. A multi-objective optimization model for the investment planning of distributed heat and electricity supply systems has been applied by [29] to a district with various apartment buildings in Germany. Batić et al. [30] present a linear programming approach to optimize the daily schedule of a multi-energy system on a research campus in Belgrade. The focus is on demand-side management applications considering a dynamic electricity tariff. Ma et al. [31] simulate the operation of an energy district with 1000 buildings in China to increase self-consumption. Jing et al. [32] present a general market concept for local energy hubs in China connecting residential and commercial prosumers. For the optimization of a multi-energy system in a building in Tehran, Eshraghi et al. [33] formulate an optimisation model considering a flexible electricity tariff. Scheller et al. [34, 35, 36] assess community business models in Germany with and without legal aspects. They propose an optimisation model to determine the optimal investment and operation of a community electricity storage system.

The foregoing discussion highlights previous attempts to optimise multi-energy system designs. While individual publications take different legal conditions of decentralised technologies into account, none of the techno-economic studies properly consider energy communities, where the operator and the consumer are not the same entity as is the case in many MFBs. In such a case, there is a variety of legal requirements regarding the market remunerations and premiums as well as the statutory fees, levies and taxes [37, 20]. While F.G. Reis et al. [5] elaborated an overview of archetypes covering the wide range of conceptual possible business models in energy community settings, the analysis revealed that traditional self-consumption place-based communities are still dominating the research landscape. Business models involving differentiated services and non-identical investor and users are still scarce. Furthermore, as our analysis showed, hardly any techno-economic study has investigated the complexity of the legal setting in general and the German TEL in MFBs in particular. To fill this gap, the economic and environmental implications need to be assessed by addressing the uncertainties. The current contribution, an extension of Braeuer et al. [38], develops and applies a techno-economic optimisation model for MFBs with a special focus on the TEL in Germany. In addition to the legislative texts [39, 40], the legal opinions of Herz and Henning [41] and the practical descriptions of Behr and Großklos [42] serve as a basis for the implementation. The results provide a more detailed view on single archetypes of emerging energy community arrangements as conceptually analyzed by [5] to identify an optimal solution for arrangements with non-identical operator and end-consumer. In this context, this study can be seen as an in-depth analysis of different European energy community archetypes.

## 3. Methodology

For this study, we apply a mixed-integer linear optimisation model (MILP) that incorporates the legal frameworks of the TEL 2021. First, the regulatory framework and the monetary flows of the legal frameworks relevant for energy system modelling are presented in Section 3.1. The implementation of the regulatory frameworks in the MILP model is explained in Section 3.2. Finally, the KPIs required for evaluating the model results are shown in Section 3.3.

### *3.1. Implementation of the regulatory framework*

The Tenant Electricity Model (TEM) is an established concept that enables self-consumption of self-generated electricity in an MFB. The Renewable Energies Law (REL) in 2014 [39] together with the Combined Heat and Power Law (CHPL) [43] initialised the Tenant Electricity Law (TEL), and the most recent changes in the REL 2021 [40] and CHPL 2020 [44] introduce substantial modifications to the levels of the subsidies. The TEL aims to incentivise the installation of renewable energy systems and self-consumption in MFBs. The law establishes the legal framework for the landlord, leaseholder, or contractor to act as the tenant's electrical contractor. The electricity tariff must be at least 10% less than the local basic electricity provider's tariff. The contract must be renewed every year, and it must not have any influence on the rent agreement. Behr and Großklos [42] provide a handbook on the initial TEL.

The legal framework incentivises a high amount of self-generated and self-consumed electricity by guaranteeing different subsidy payments per kilowatt hour, levy and fee exceptions. To better illustrate the remunerations for different energy flows, Figure 1 presents a TEM in an MFB, its optional technological components and the possible energy flows as arrows. The symbols in the arrows indicate the specific payment linked to each energy flow and are further explained in Section 3.2.

Herz and Henning [41] summarise the remuneration concept of PV-electricity in a TEM according to the REL 2017. Even though the REL 2021 changes the amount of compensation, the underlying scheme remains the same. In the REL of 2021, for all PV systems smaller than 100 $kW_p$, self-consumed PV electricity sold to the tenants is exempted from all fees except the REL levy, value-added taxes, and costs for metering & invoicing. Additionally, a Tenant Electricity Premium or a so-called Self-Consumption Premium (SCP) is remunerated. Surplus PV electricity can be fed into the grid under a feed-in tariff. Self-consumed PV electricity directed to a heat pump (HP) or battery does not receive an SCP but is only charged with a REL levy for systems larger than 30 $kW_p$ and 30 $MWh/a$. Notably, the amount of feed-in tariff and SCP depends on the installed PV capacity, see supplementary information (SI) Section SI D. The PV subsidy scheme is fixed for 20 years.

A similar concept with varying premiums and tariffs holds for self-generated electricity from a CHP unit. For an up-to-date summary of the most recent CHPL 2020 implications, see Briem et al. [45]. In the CHPL 2020, a de-minimis limit exempts CHP-units with a size smaller than 10 $kW_{el}$ and a self-consumption of less than 10 $MWh/a$ from the REL levy. Larger units have to pay 40% of the levy on self-consumed electricity. In contrast to the PV remuneration, feed-in tariff and SCP are fixed independent of size. Additionally, the SCP is paid for CHP electricity sold to tenants and self-consumed in an HP or battery. The described subsidy scheme is limited to units smaller than 50 $kW_{el}$ and 30,000 full load hours.

How to consider the cost for heat generation from a heat pump in a TEM and pass it on to the tenants is an open question. A consultation of the authors with a German law firm specializing in energy law revealed no precedents for such a model. For this study, the authors consider a heat pump as a self-consuming unit. Thus, self-generated CHP electricity drawn by the heat pump is remunerated with a SCP. Nonetheless, the overall assumption is that the switch to a TEM does not inflict additional costs for heating on the tenants. It is priced in the same way as in the reference system. Here the operational cost is the gas expenditure for a gas boiler.

### *3.2. Optimisation model*

The model used to determine the energy system of the MFB is based on [46]. The MILP model defines the optimal system set up and operation from a landlord's point of view (POV). The model determines the optimal energy flows on an hourly basis for one representative year matching the households' electricity and heating demand. Electricity tariffs and surcharges change with a yearly rate ($r_{el}$). The objective function is the maximisation of the Net Present Value (NPV). The decision variables are binary variables for different technology options. Furthermore, positive continuous variables describe the technology dimensions, namely installed capacity and the energy flow between them. One notable exception is the CHP capacity; it is given as an exogenous model parameter further explained in Section 4.2. The model is implemented in Matlab and solved with the CPLEX solver. Figure 1 gives an overview of the considered system components, the energy and cash flows.

The objective function in Equation 1 describes the $NPV$ as the the difference between the discounted investment ($C^l_{inv}$), which considers future re-investment and residual value, and the discounted annual cash flow ($acf$). The discounted investment is shown in Equation 2 and considers the initial investment in the year $a = 0$ for each technology $l$. The initial investment consists of a fixed component ($c^{l,a=0}_{inv,fix}$) for every technology option ($bin^l_{fix}$) and a variable component

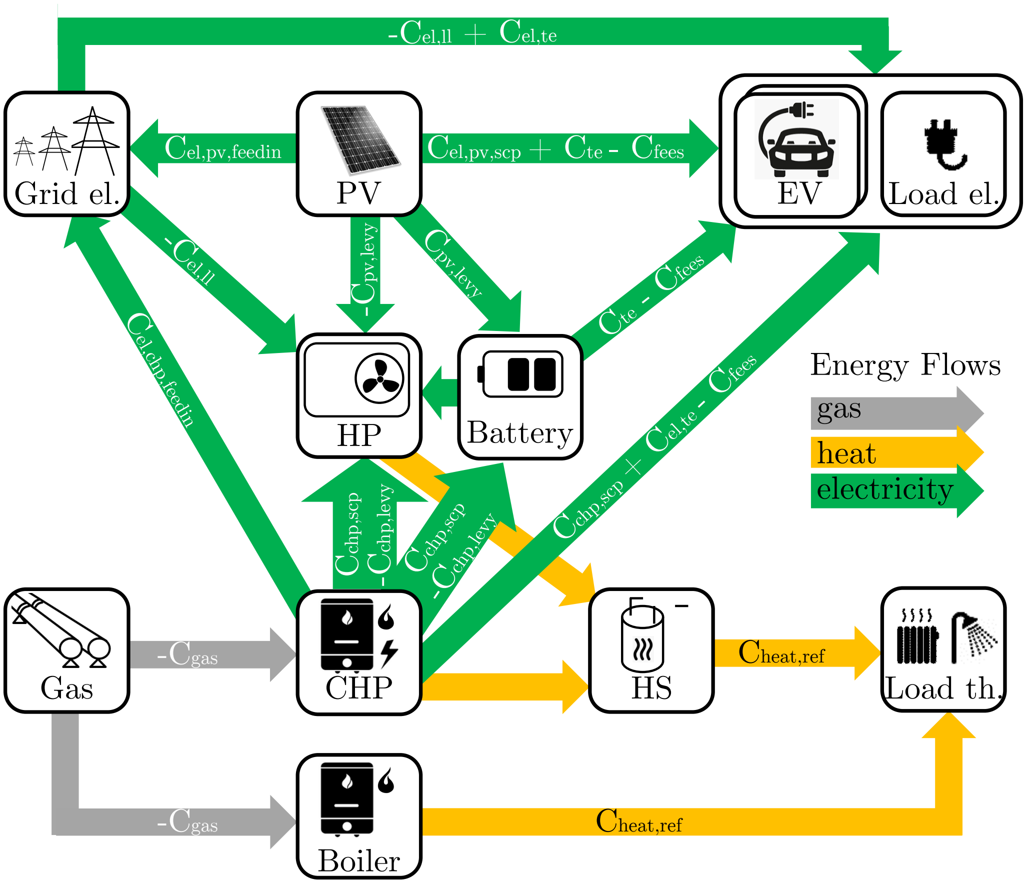


Figure 1: Illustration of the Tenant Electricity Model (TEM) and the optional technological components. The possible energy flows are illustrated by arrows and the symbols represent the remuneration for the respective energy flow from the landlord's point of view.

($c^{l,a=0}_{inv,var}$) that depends on the installed capacity ($cap^l$). Additionally, Equation 2 includes a discounted reinvestment after the calendar lifetime ($clt$) of technology $l$ is reached and a discounted residual value after the considered investment period $A$. This allows the different lifetimes of the technology options to be taken into account.

Equation 3 represents the annual cash flow illustrated in Figure 1, consisting of five parts. The first part considers a term for operation and maintenance, which is a percentage of the installed capacity ($cap^l$) for each technology $l$. The second part defines the revenue from the self-generated electricity ($P$) the landlord ($ll$) sells to the tenants ($te$). The third part determines the revenue and expenditure on electricity drawn from the grid. The fourth and fifth parts define the additional revenue from PV and CHP generated electricity respectively. The last part considers the revenue from providing heat to the tenants.

In more detail, the landlord sells the self-generated electricity to the tenants ($P^t_{ll,te}$) for every hour $t$ for the tenant electricity price ($c^a_{el,te}$) avoiding various fees ($c^a_{fees}$). The avoided fees are

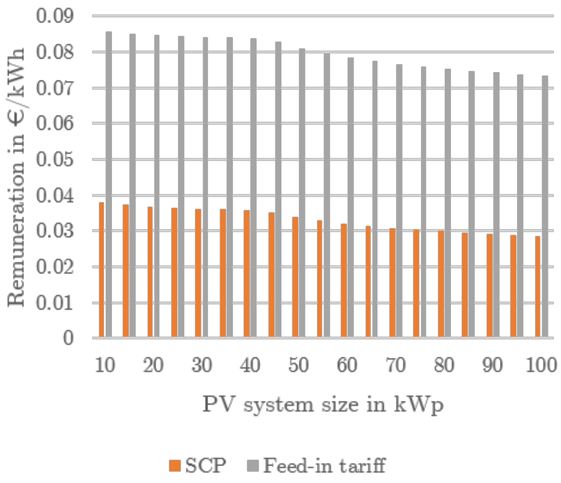


Figure 2: Feed-in tariff and self-consumption premium depending on remuneration scheme of discrete PV system sizes in January 2021.

shown in Equation 4. Concerning grid electricity ($P^t_{grid,ll}$), the landlord pays the price $c^a_{grid,ll}$. Grid electricity that is directly forwarded to the tenants ($P^t_{grid,te}$) is charged with the tenant electricity price and not exempted from any fees.

Next to selling self-generated electricity for the tenant electricity price, additional revenue from PV electricity is either generated by feeding electricity into the grid ($P^{t,rs}_{pv,grid}$) with a fixed feed-in tariff ($c_{pv,feedin}$) or by the SCP ($c_{pv,scp}$) paid on tenant electricity from PV ($P^{t,rs}_{pv,te}$). PV electricity that is not self-consumed by the tenants but within the building ($P^{t,rs}_{PV,self}$), for example in a central heat pump or battery storage system, is charged with additional surcharges or levies ($c^a_{levy}$).

The German legislation makes the remuneration value dependent upon the installed PV capacity. To consider this dependency, we introduce remuneration schemes that result in discrete remuneration steps for PV electricity, further explained in Section D.1. For this study, the spectrum of possible remuneration schemes ($rs$) is divided into 19 sectors as illustrated in Figure 2. Every remuneration scheme coincides with a respective value of the feed-in tariff, the tenant electricity premium and the self-consumption levies. With Equations 5, 6, and 7 the model selects the relevant remuneration scheme. The binary variable $bin^{rs}_{pv}$ indicates the selected revenue scheme and Equation 5 states that the model can only choose one $rs$. Considering $bin^{rs}_{pv}$, Equation 6 defines the variable for the PV capacity ($cap_{pv}$) to be less or equal to upper level in the selected remuneration scheme ($cap^{rs}_{pv}$). The PV electricity flow ($P^{t,rs}_{pv,cf}$) is defined for the full set of remuneration schemes. Nonetheless, Equation 7 allows only $P^{t,rs}_{pv,cf}$ from the selected remuneration scheme to be greater than zero[4]. Equation 7 is defined for the respective cash flows ($cf$) tenant electricity ($te$), feed-in ($feedin$) or REL levy ($self$).

In analogy to PV electricity, the fifth part of the annual cash flow in Equation 3 describes the additional revenue for CHP electricity. Electricity generated by the CHP unit can either be fed into the grid ($P_{chp,grid}$), remunerated by the feed-in tariff, sold as tenant electricity ($P_{chp,te}$) or self-consumed in a heat pump or battery storage system ($P_{chp,self}$). The latter two options

[4] *BigM* describes a significantly large number according to the Big M Method in operations research.

profit from the SCP ($c_{chp,scp}$). Electricity that is self-consumed but not by the tenants ($P_{chp,self}$ and $P_{chp,self,wo}$) is charged with a levy ($c_{levy}$). Additionally, Equation 3 considers the expenditure for gas consumption of the CHP unit as the quotient of the generated electricity ($P^t_{el,chp}$) and the electric efficiency ($\eta_{el,chp}$) times the gas price ($c^a_{gas}$). Equation 8 states that the CHP generated electricity can either be remunerated by the subsidy scheme or it is distributed without any additional payments (marked by the index *wo*) except the tenant electricity price. Equation 9, Equation 10 and Equation 11 constrain the CHP operation. The former two define the electrical output of the CHP unit ($P^t_{el,chp}$) as a semi-continuous variable to be either zero or greater than a minimal output ($P_{chp,min}$), which is set as a factor ($r_{chp,min}$) of the installed capacity, Equation 10. The latter Equation 11 restricts the the operational full load hours per year ($\frac{\sum_t^T P^t_{el,chp}}{cap_{chp}}$) to remain below a fixed limit ($h_{chp,fullload}$).

The German legislation states that the levy on self-consumed CHP electricity is only paid once the installed capacity or the produced energy amount exceeds a trivial limit ($cap_{chp,lim}$ or $P_{chp,lim}$ respectively). Equation 12 introduces the binary variable $bin_{chp,lim}$ that equals one once the model chooses to exceed the specified capacity limit. Equation 13 defines the self-consumed electricity amount that is charged with the additional levy once either limit is exceeded.

The final part of Equation 3 describes the revenue from satisfying the heat demand of the tenants. Heat is sold to the tenants for a price that equals the operational costs of the gas boiler. Heat is provided either through the CHP, the boiler, the heat pump or a combination of all three. Equation 14 states that the heat pump converts electricity coming either from the PV system, the CHP or from the grid with a time- and temperature-dependent COP into heat. The self-generated electricity is considered as part of the self-consumption electricity flow $P^t_{chp,self}$ and $P^t_{pv,self}$ in Equation 3. Further explanations of the model can be found in the Appendix.

$$\max NPV, NPV = -\sum_{l\in L} C^l_{inv} + \sum_{a=0}^{A} \frac{acf^a}{(1+i)^a} \tag{1}$$

$$C^l_{inv} = c^{l,a=0}_{inv,fix} \cdot bin^l_{fix} + c^{l,a=0}_{inv,var} \cdot cap^l + \frac{c^{l,a=clt^l}_{inv,var} \cdot cap^l}{(1+i)^{clt^l}} - \frac{clt^l_{rem}}{clt^l} \cdot \frac{c^{l,a=A}_{inv,var} \cdot cap^l}{(1+i)^A} \tag{2}$$

$$\begin{aligned} acf^a = &\sum_{l=1}^{L} -c^l_{O\&M} \cdot cap^l + \\ &\sum_{t=1}^{8760} \Bigg( P^t_{ll,te} \cdot (c^a_{el,te} - c^a_{fees}) + \Big[ -P^t_{grid,ll} \cdot c^a_{el,ll} + P^t_{grid,te} \cdot c^a_{el,te} \Big] + \\ &\Big[ \sum_{rs}^{19} \Big( P^{t,rs}_{pv,grid} \cdot c^{rs}_{pv,feedin} + P^{t,rs}_{pv,te} \cdot c^{rs}_{pv,scp} - P^{t,rs}_{pv,self} \cdot c^{a,rs}_{pv,levy} \Big) \Big] + \\ &\Big[ P^t_{chp,grid} \cdot c_{chp,feedin} + (P^t_{chp,te} + P^t_{chp,self}) \cdot c_{chp,scp} - \\ &(P^t_{chp,self} + P^t_{chp,self,wo}) \cdot c^a_{levy} - P^t_{chp,el} \cdot \frac{c^a_{gas}}{\eta_{chp,el}} \Big] + \\ &(Q^t_{te} - Q^t_{boiler}) \cdot \frac{c^a_{gas}}{\eta_{boiler}} \Bigg) \; \forall\, a \in A \end{aligned} \tag{3}$$

$$c_{fees} = c^a_{levy} + VAT + c^a_{M\&I} \tag{4}$$

$$\sum_{rs}^{19} bin^{rs}_{pv} = 1 \tag{5}$$

$$cap_{pv} \leq \sum_{rs}^{19} bin^{rs}_{pv} \cdot cap^{rs}_{pv} \tag{6}$$

$$P^{t,rs}_{pv,cf} \leq bin^{rs}_{pv} \cdot bigM \quad \forall\, rs, cf \in \{feedin, scp, levy\} \tag{7}$$

$$P^t_{el,chp} = P_{chp,grid} + P_{chp,te} + P_{chp,self} + P_{chp,grid,wo} + P_{chp,te,wo} + P_{chp,self,wo} \tag{8}$$

$$bin^t_{chp} \cdot P_{chp,min} \leq P^t_{el,chp} \quad \forall\, t \in T \tag{9}$$

$$P_{chp,min} = r_{chp,min} \cdot cap_{chp} \tag{10}$$

$$\frac{\sum_t^T (P^t_{chp,grid} + P^t_{chp,te} + P^t_{chp,self})}{cap_{chp}} \leq h_{chp,fullload} \tag{11}$$

$$cap_{chp} \leq cap_{lim,REL} + bin_{chp,levy} \cdot BigM \tag{12}$$

$$\sum_t^T \left(P^t_{chp,self,hp} + P^t_{chp,self,bat} - P^t_{chp,self} - P^t_{chp,self,wo}\right) \leq E_{chp,lim,levy} \cdot (1 - bin_{chp,levy}) \tag{13}$$

$$Q^t_{hp} = [P^t_{pv,self,hp} + P^t_{chp,self,hp} + P^t_{grid,hp}] \cdot COP^t \quad \forall\, t \in T \tag{14}$$

### 3.3. Key performance indicators

To evaluate the economic performance of the system layout, the NPV over a period of 20 years is used. To assess the self-generated energy usage the electrical self-consumption rate ($SCR_{el}$), the degree of electrical self-sufficiency ($DSS_{el}$) as well as the degree of electrical autonomy ($DA_{el}$) are employed [18], see Equation 15, 16 and 17. Additionally, the Grid Interaction Index 18 and the normalized Grid Interaction Index 19 are calculated according to [18].

$$SCR_{el} = \frac{\sum_t^T (P^t_{pv,self} + P^t_{pc,te} + P^t_{chp,self} + P^t_{chp,te})}{\sum_t^T (P^t_{pv,gen} + P^t_{chp,gen})} \tag{15}$$

$$DSS_{el} = \frac{\sum_t^T (P^t_{pv,self} + P^t_{pv,te} + P^t_{chp,self} + P^t_{chp,self})}{\sum_t^T (D^t_{el,te} + D^t_{el,hp} + D^t_{el,ev})} \tag{16}$$

$$DA_{el} = \frac{DSS_{el}}{SCR_{el}} = \frac{\sum_t^T (P^t_{pv,gen} + P^t_{chp,gen})}{\sum_t^T (D^t_{el,te} + D^t_{el,hp} + D^t_{el,ev})} \tag{17}$$

$$GII = \sqrt{\frac{1}{T-1}\sum_{t}^{T}\left(\frac{P^t_{intogrid}}{max|P^t_{intogrid}|} - \frac{1}{T} * \sum_{t=T}^{N}\frac{P^t_{intogrid}}{max|P^t_{intogrid}|}\right)^2} \tag{18}$$

$$GII_{norm} = \frac{GII}{\sqrt{\frac{1}{T-1}\sum_{t}^{T}\left(\frac{D^t_{el}}{max|D^t_{el}|} - \frac{1}{T} * \sum_{t}^{T}\frac{D^t_{el}}{max|D^t_{el}|}\right)^2}} \tag{19}$$

For the assessment of Greenhouse Gas (GHG) emissions, only $CO_2$ is considered and allocated according to the 'polluter pays principle' as described in [47]. Namely, this includes emissions from grid electricity and natural gas consumption but no emissions from PV electricity. The MFB represents the system boundaries.

Equation 20 defines the amount of $CO_2$-emissions ($CO_{2,i}$) for both cases $i$. It is the sum of the $CO_2$ emissions from electricity of the grid and $CO_2$ emissions from natural gas consumption over the respective investment period $T$. $CO_2$ emissions from the grid are the product of the total energy demand from the grid for case $i$ for one year ($D^i_{grid,tot}$) multiplied by the $CO_2$ emission factor of the grid ($EF_{grid}$). The increasing share of RES in the national electricity mix will further diminish $EF_{grid}$ in the future. To depict this development, $EF_{grid}$ is reduced every year by the $CO_2$ reduction factor ($r_{EF,grid}$). The $CO_2$ emissions from gas consumption are comprised of the yearly gas demand ($D^i_{gas,tot}$) for case $i$ multiplied by the $CO_2$ emission factor of gas ($EF_{gas}$), which is assumed not to change over the respective investment period.

Equation 21 defines the $CO_2$ abatement ($\Delta CO_2$). $\Delta CO_2$ is the difference between the emitted amount of $CO_2$ in a reference case (*ref*) and the optimized tenant electricity case (*opt*).

Finally to account for emissions from exported energy two values are calculated. $CO_{2,export}$ provides the total quantity of exported emissions and $\Delta CO_{2,export}$ describes the added or reduced quantity of exported emission in comparison to the respective grid emissions. Equation 22 determines $CO_{2,export}$ as the sum of the electricity fed into the grid by the respective energy generator multiplied by the respective emission factor[5], $EF_{pv}$ or $EF_{chp,el}$.

Equation 23 calculates $\Delta CO_{2,export}$ as the difference between the exported emissions and the replaced emissions caused by the energy mix in the grid determined by the grid emission factor. A negative value for $\Delta CO_{2,export}$ illustrates that the feed-in electricity reduces the grid emissions and vice-versa. Furthermore, Equation 24 assesses the $CO_2$ abatement cost from the government's point of view ($cac_{subs}$) considering the paid subsidies. Equation 24 relates the cash flow of these public subsidies ($CF_{sub}$), namely the SCP and feed-in tariff, to the abated $CO_2$ emissions.

$$\begin{aligned} CO_{2,i} = \sum_{a}^{A}\Big(& D^a_{grid,tot}\cdot\left(EF_{grid} * (1 - r_{EF,grid})^a\right) + \\ & D^a_{gas,tot}\cdot EF_{gas}\Big)\ \forall i \in \{ref, opt\} \end{aligned} \tag{20}$$

$$\Delta CO_2 = CO_{2,ref} - CO_{2,opt} \tag{21}$$

[5]For further explanation of $EF_{chp,el}$ as the emission factor of a co-generation process, see [48] and Section SI A.

$$CO_{2,export} = \sum_{t}^{T} \left( P^{t}_{pv,grid} \cdot EF_{pv} + \left( P^{t}_{chp,grid} + P^{t}_{chp,grid,wo} \right) \cdot EF_{chp,el} \right) \cdot A \tag{22}$$

$$\begin{aligned} \Delta CO_{2,export} = CO_{2,export} - \sum_{a}^{A} \sum_{t}^{T} \Big( & P^{t}_{pv,grid} \cdot EF_{grid} \cdot (1 - r_{EF,grid})^{a} \\ & + \left( P^{t}_{chp,grid} + P^{t}_{chp,grid,wo} \right) \cdot EF_{grid} \cdot (1 - r_{EF,grid})^{a} \Big) \end{aligned} \tag{23}$$

$$cac_{subs} = \frac{\sum_{t}^{T} CF^{t}_{subs}}{\Delta CO_2 - \Delta CO_{2,export}} \tag{24}$$

## 4. Study design

In this section, we describe the various configurations that the model is applied to. First, we briefly summarise the input data and assumptions, Section 4.1. Secondly, we differentiate between a component-wise and building-wise analysis and elaborate on the computational framework conditions, Section 4.2.

### 4.1. Input data and assumptions

The baseline date for remuneration and consumer prices in our study is the 1st of January 2021. This includes the most recent changes in the REL 2021 and CHPL 2020. The assumed technology prices are based on the year 2018 and adapted by a technology-specific growth factor. The input parameters are shown in the Appendix Table A.5, Table A.6, and Table A.8. Table A.7 shows the consumer prices for the electricity for tenant and landlord as well as the gas price. Prices are based on statistical values for Germany in 2020 [49]. They consider a growth rate of 2% as well as an additional $CO_2$-price according to [50], also shown in Table A.7. The feed-in tariff and self-consumption premium for PV is shown in Figure 2 and Table A.8.

The building is assumed to be in Karlsruhe, Germany, TRY-region 12 (test reference weather year of the DWD). We compare four building types. The respective heating and electricity demand profiles are derived from the Synpro tool [51], which considers an individual profile for each apartment within the MFB. The building details are shown in Table 1. To consider electric vehicles (EV), we incorporate a variety of driving profiles derived from [52] based on data of the German Mobility Panel (MOP). This dataset gathers a variety of driving patterns observable for German personal motorized vehicles. With the assumption of EV characteristics for a sample of car models of different manufacturers, [52] translates these driving patterns into EV charging profiles. The EV-profiles are for one typical week; we assume the behaviour is repetitive for the whole year.

### 4.2. Component-wise and building-wise analyses

The main analyses are divided into two sections. First, we study the different technological system components by themselves and in combination with each other for building 1. This so-called component-wise analysis allows us to identify the key economic drivers for a successful

| | Unit | Bldg1 | Bldg2 | Bldg3 | Bldg4 |
|---|---|---|---|---|---|
| Demand,el | MWh/a | 29.8 | 31.5 | 31.5 | 30.0 |
| Demand,th | MWh/a | 113.0 | 100.9 | 58.0 | 40.4 |
| Occupants | # | 24 | 29 | 26 | 26 |
| BldgAge | | < 1978 | 1979-2001 | > 2001 | > 2001 |
| Insulation | | standard | standard | standard | passive |
| $A_{roof}$ | $m^2$ | 176.0 | 166.8 | 125.6 | 125.6 |
| $A_{living}$ | $m^2$ | 376.5 | 446.8 | 431.3 | 431.3 |

Table 1: Input data of the four analyzed building types

| | Components | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Name | Boi | HS | PV | Bat | HP | CHP | EV | EVopt |
| REF | x | x | | | | | | |
| PV | x | x | x | | | | | |
| PV_BAT | x | x | x | x | | | | |
| PV_HP | x | x | x | | x | | | |
| CHP | x | x | | | | x | | |
| CHP_BAT | x | x | | x | | x | | |
| CHP_HP | x | x | | | x | x | | |
| PV_CHP | x | x | x | | | x | | |
| PV_CHP_BAT | x | x | x | x | | x | | |
| COMBI | x | x | x | x | x | x | | |
| COMBI_EV | x | x | x | x | x | x | x | |
| COMBI_EVopt | x | x | x | x | x | x | | x |
| Boi: Gas boiler, HS: Heat storage, PV: Photovoltaic, Bat: Battery | | | | | | | | |
| HP: Heat pump, CHP: Combined heat and power | | | | | | | | |
| EV: 6 electric vehicles, EVopt: 6 Evs & Optimized charging | | | | | | | | |

Table 2: System names of component wise analysis; *x* marks which component option is included in the model run.

TEM. Table 2 presents the technological combinations and their abbreviations for this publication.

Secondly, the building-wise analysis studies the system *COMBI* where the model can invest in all system components without considering EV. This analysis compares the heating and electricity profiles of four different building types, see Table 1. The first two building types represent the overwhelming majority of the MFH building stock. According to [53], in terms of living area, this building type covers around 34% and 26% of the German building stock for MFHs, respectively. The last two building types represent a modern MFH with different insulation levels. Thus, the four buildings are presented in decreasing order of their heating demand.

In both analyses, we apply a green-field approach, where the heating system in terms of generator and storage needs replacement, and no on-sight electricity generation exists. The reference case (*REF*) for the economic performance of the TEM is the case where only a conventional gas boiler to cover the heating demand is installed, and electricity is drawn from the grid. The reference case is not participating in the TEL scheme. Fuel costs for the boiler are forwarded directly to the tenants, and the electricity is purchased by the tenants individually. For all other cases, we assume that all tenants participate in the TEM as the tenant electricity price is 10% below the basic provider's tariff for an electricity demand between 2500 $kWh$ and 5000 $kWh$ per year [49, p. 282].

For this study, we alter $cap_{chp}$ in incremental steps of 10 $kW_{el}$ up to 50 $kW_{el}$. A model formulation with a continuous variable for the CHP capacity results in very long run times, which conflicts with the study's goal to compare the TEM configurations. Thus, for every system of the component-wise analysis with a CHP unit as a technology option and every building in the building-wise analysis, we perform 6 model runs for $cap_{chp}$ between 0 $kW_{el}$ and 50 $kW_{el}$. For the study's results, we use the model run and respective $cap_{chp}$ with the highest $NPV$, which represents the objective value.

To solve the problem, we used the CPLEX solver and a maximum run time of 48 hours. The model is optimised on a Linux-based High-Performance Cluster with up to 150 GB RAM and 8 cores at 2.1 GHz in one single node. Up to 50 nodes in parallel carried out the various model runs.

## 5. Results

This section divides the results into three parts. In the first Section 5.1, we evaluate the systems design of the component-wise analysis and the influence of the design on the KPIs. After that, in Section 5.2, we present the outcome for the building-wise analysis. Finally, we compare the influence of the most recent amendment of the TEL for January 2021 and the previous TEL in July 2020 on the NPV and the energy system layout in Section 5.3.

Figure 3 summarises main results of Section 5.1 and Section 5.2. It shows the $\Delta NPV$ and the $CO_2$ abatement of the different system designs. While the PV systems (*PV* and *PV_HP*) have the lowest $\Delta NPV$, the implementation of a CHP more than doubles the NPV. Moreover, this first glimpse indicates that technology diversity further increases the achievable NPV. A more detailed look reveals a complementary effect of the different technologies on the system's operation to utilise guaranteed subsidies more efficiently. Despite this complementarity, introducing a battery storage system was not found to increase the NPV[6]. That is why all the system results with a battery as an optional component are omitted in the following sections. For the building-wise analysis, Figure 3 [right-hand sight of the delimiter] indicates a decrease of $\Delta NPV$ along with a reduction of the building's heating demand. Concerning the $CO_2$ abatement, Figure 3 shows mostly positive $CO_2$ abatement that correlates positively with $\Delta NPV$. However, the CHP systems without an HP (*CHP* and *PV_CHP*) as well as the *COMBI* system for Bldg 4 with the highest degree of insulation have negative $CO_2$ abatement. According to the polluter-pays principle, these systems emit more $CO_2$ than the reference case. However, these systems feed a large share of their self-generated electricity into the grid, which leads to relatively large quantities of $CO_2$ export compared to the other systems.

### 5.1. Component-wise analysis

Table 3 summarises the most relevant KPIs, the installed technologies, and capacities. The column *REF* describes the reference case—the negative NPV results from accounting for the boiler's initial investment and its operational costs. The table depicts the unique systems designs

[6] As part of a sensitivity analysis, we altered the variable part of the battery price in steps of 50 €/$kWh$. The model only chose to install a battery for a variable price of 100 €/$kWh$ or less.

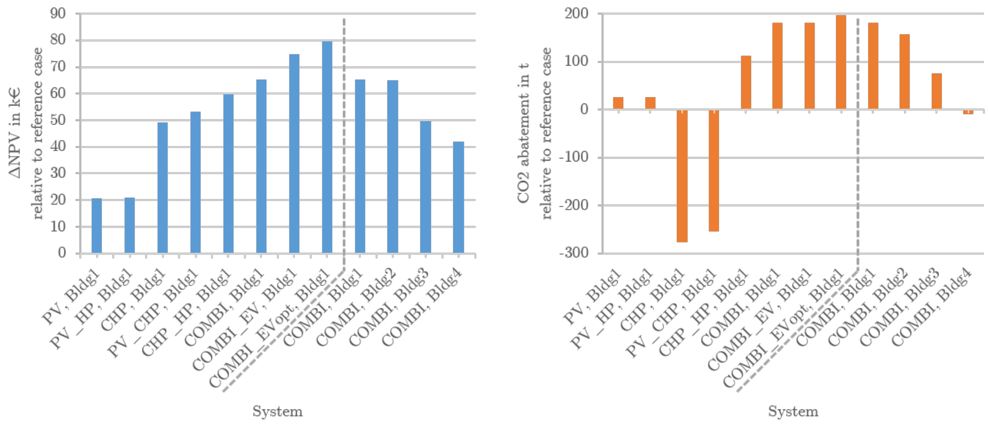


Figure 3: Summary of $\Delta NPV$ and $CO_2$ abatement of the component and building-wise analysis. The line delimiter divides the two analyses.

found by the optimisation in increasing order of $\Delta NPV$[7]. For system *PV_HP*, the PV system size of 10 $kW_p$ complies with the first remuneration step of the TEL. Without any additional flexible electricity consumers such as an HP in the system, the self-consumption rate is 66.5%, and the remaining PV-electricity is fed into the grid. A conventional gas boiler covers the heat demand. Regarding the total $CO_2$ emissions, the abated amount of $CO_2$ emissions are relatively low with 13% of the highest $CO_2$ abatement in system *COMBI_EVopt*. $\Delta CO_{2,export}$ with a value of $-11.3$ $t_{\text{CO2}}$ indicates a negative amount of $CO_2$ emissions fed into the grid.

Comparing the *PV_HP* system and the *CHP* system, $\Delta NPV$ more than doubles to a total of 49.0 $k€$. The *CHP* system, as well as the *PV_CHP* system, fully exploits the capacity limit of the CHP unit of 50 $kW_{el}$ set by the TEL to reach the maximum NPV. Considering the full load hours, the CHP unit hardly operates outside of the subsidy scheme, while the model strictly restricts the *PV_CHP* system to the 30,000 subsidised full load hours. Notably, in both systems, the CHP unit's peak power output is around 40 $kW_{el}$ and thus less than the installed capacity. In both systems, the CHP unit covers most of the heat demand. The values of $SCR_{el}$ and $DA_{el}$ indicate that almost 80% of the self-generated electricity is fed into the grid and the amount of self-generated electricity is more than 2.5 times as high as the electricity demand in the building. This leads to relatively high $CO_2$ emissions and consequently high negative values for $CO_2$ abatement according to the polluter pays principle. Large amounts of $CO_2$ emissions are exported, 380.2 $t_{\text{CO2}}$ and 381.4 $t_{\text{CO2}}$ respectively, which are greater than the negative value of the $CO_2$ abatement. However, the values of $\Delta CO_{2,export}$ with 125.8 $t_{\text{CO2}}$ and 120.4 $t_{\text{CO2}}$ respectively indicate that the feed-in increases the emission factor of grid electricity.

Compared to the CHP only system, installing an HP (*CHP_HP*) increases $\Delta NPV$ by more than 20% to around 60 $k€$. The model chooses an HP with 12.7 $kW_{th}$. The HP introduces a flexible electricity demand to the system of roughly 60%. This demand is flexible in the sense that the HPs dispatch is an endogenous decision variable of the optimisation model. Along with a

[7] The result of the *PV_HP* system represents the *PV* system's result as well. Both systems have the same design because in *PV_HP* no HP is chosen

relatively small CHP unit with 10 $kW_{el}$, the system achieves an $SCR_{el}$ of almost 100%, covering 89.4% ($DSS_{el}$) of the electricity demand by self-generated electricity. Together with a $DA_{el}$ of 89.6%, around 10% of the electricity comes from the grid. This leads to abated $CO_2$ emissions of 111.4 $t_{CO2}$. The full load hours of the CHP exceed the full load hour limit of the subsidies scheme by a factor of three. Hence, only one-third of the CHP hours are subsidized with the premium. This reduces the profit from electricity consumed by the tenants. Additionally, around 40% of the CHP electricity is directed to the HP.

In the case of total technological freedom (*COMBI*), the model chooses to install PV, HP and CHP. Compared to the PV only system (*PV*) and the CHP only system (*CHP*), $\Delta NPV$ increases by more than 200% and 33% respectively. The PV system is sized greater than the 10 $kW_p$ threshold of the first PV-remuneration step. Thus, this optimal system design can increase profits even though it has to compensate for a lower feed-in tariff and a lower SCP for PV electricity compared to the *PV* system. This compensation is achieved by a higher self-consumption (*SCR* = 89.2%) as PV electricity is fed to the HP. 28% of the PV electricity is directed to the HP and around 10% to the grid.

| KPI | Unit | REF | PV_HP | CHP | PV_CHP | CHP_HP | COMBI | COMBI_EV | COMBI_EVopt |
|---|---|---|---|---|---|---|---|---|---|
| $NPV$ | $k€$ | -13.4 | 7.4 | 35.6 | 39.7 | 46.2 | 52.0 | 61.4 | 66.3 |
| $\Delta NPV$ | $k€$ | - | 20.8 | 49.0 | 53.1 | 59.7 | 65.4 | 74.8 | 79.8 |
| $D_{el,te}$ | MWh/a | 29.8 | 29.8 | 29.8 | 29.8 | 29.8 | 29.8 | 36.8 | 36.9 |
| $D_{el,hp}$ | MWh/a | - | - | - | - | 18.4 | 23.2 | 21.9 | 22.2 |
| $D_{el,tot}$ | MWh/a | 29.8 | 29.8 | 29.8 | 29.8 | 48.2 | 53.0 | 58.7 | 59.1 |
| $cap_{PV}$ | kW | - | 10.0 | - | 7.6 | - | 12.6 | 15.0 | 15.0 |
| $cap_{CHP}$ | kWel | - | - | 50.0 | 50.0 | 10.0 | 20.0 | 20.0 | 20.0 |
| $cap_{HP}$ | kWth | - | - | - | - | 12.7 | 14.4 | 14.0 | 13.9 |
| $cap_{HS}$ | kWh | - | - | 81.4 | 77.9 | 76.1 | 66.8 | 68.7 | 59.4 |
| $cap_{boil}$ | kWh | 60.3 | 60.3 | - | 1.0 | 12.4 | - | - | - |
| $P_{chp,max}$ | kWel | - | - | 40.1 | 39.4 | 10.0 | 20.0 | 20.0 | 20.0 |
| $h_{chp,full}$ | hours | - | - | 30524 | 30000 | 86366 | 38745 | 41006 | 40239 |
| $SCR_{el}$ | % | - | 70.0 | 20.5 | 23.9 | 99.8 | 90.2 | 91.4 | 96.9 |
| $DSS_{el}$ | % | - | 21.0 | 52.4 | 65.7 | 89.4 | 85.2 | 84.8 | 88.2 |
| $DA_{el}$ | % | - | 30.0 | 256.0 | 274.5 | 89.6 | 94.4 | 92.8 | 91.0 |
| $GII$ | % | - | 17.6 | 22.2 | 22.7 | 4.1 | 10.2 | 9.7 | 9.0 |
| $GII_{norm}$ | % | - | 113.7 | 143.2 | 146.5 | 20.3 | 53.0 | 58.9 | 59.7 |
| $CO_{2,ref}$ | t | 659.3 | 659.3 | 659.3 | 659.3 | 659.3 | 659.3 | 688.9 | 688.9 |
| $CO_{2,opt}$ | t | 659.3 | 633.1 | 935.9 | 913.4 | 548.0 | 477.9 | 508.5 | 491.4 |
| $\Delta CO_2$ | t | - | 26.2 | -276.6 | -254.1 | 111.4 | 181.4 | 180.4 | 197.5 |
| $CO_{2,export}$ | t | - | - | 380.2 | 381.4 | 0.5 | 23.2 | 20.8 | 10.3 |
| $\Delta CO_{2,export}$ | t | - | -11.3 | 125.8 | 120.4 | 0.2 | 2.7 | 1.0 | 3.4 |
| $CF_{subs}$ | $k€$ | - | 6.3 | 147.5 | 152.1 | 16.4 | 41.5 | 42.2 | 39.9 |
| $cac_{subs}$ | $€/t_{CO2}$ | - | 169.3 | - | - | 147.5 | 232.0 | 235.4 | 205.4 |

Table 3: Selected results for the component-wise analysis sorted by $\Delta NPV$ for an investment period of 20 years. Results for systems with a battery option are omitted, as no battery is installed.

Introducing the additional electricity demand of six EVs increases $\Delta NPV$ and the PV to 15 $kW_p$[8] while simultaneously increasing the $SCR_{el}$ to 90.2%. Adding the option of optimised

[8]It should be noted that the PV threshold of 15 $kW_p$ is a result of internal PV remuneration steps of the optimisation

charging of these EVs, $\Delta NPV$ increases even further as the $SCR_{el}$ rises to 95.7%. The $DA_{el}$ decreases as the CHP generation is reduced, leading to the overall highest amount of $CO_2$ abatement. This high value for $CO_2$ abatement compared to the system *COMBI* and *COMBI_EV* also leads to the lowest $CO_2$ abatement cost considering paid subsidies $cac_{subs}$. Nonetheless, the lowest $cac_{subs}$ overall are attributed to the *CHP_HP* system which is followed by the *PV_HP* system. The high $SCR_{el}$ reveals that the system utilises the high SCP for PV and CHP electricity. Additionally, as almost no CHP electricity is fed into the grid, almost all energy forms that account for $CO_2$ emissions are consumed within the MFB.

Regarding the grid interaction, GII and $\mathrm{GII_{norm}}$ enable a comparative analysis (Table 3). High SCR, DSS and DA in combination with low GII values relate to systems that are favourable and highly beneficial from a grid system serving point of view. The systems with a high share of electricity fed into the grid (systems *PV_HP*, *CHP*, and *PV_CHP*) demonstrate relatively high values for GII and $\mathrm{GII_{norm}}$. This indicates high variations of electricity feed-in, which can be explained by the mismatch of the PV or CHP generation profile with the electricity demand profile. For the PV, these variations can be explained through the mismatch of irradiation and electricity demand profile (especially during summer), and for the CHP during the winter season with a mismatch between the electricity and heat demand profile and over-sizing of the CHP. The systems with an additional and flexible energy demand such as HP or load such as EVs present a lower profile variation or allow for higher capacities at similar levels of variations (e.g. PV capacity in COMBI vs. $\mathrm{COMBI_{EV}}$).

Figure 4 presents the waterfall diagram of discounted cash flows and the resulting *NPV* for 20 years of operation, for system *COMBI* for building 1. The largest investment of about 36 $k€$ is spent on the CHP unit. Operational costs for fuel to run the CHP unit and consumption fees make up the largest fraction of the negative cash flows. Despite a premium on electricity consumption, generation and feed-in, the returns from selling heat are a major component of compensating the initial and operational expenditures. This includes heat generated by the CHP as well as the HP. Concerning the other cash flows for self-generated electricity, the smallest part comes from feed-in tariffs followed by the revenue through the self-consumption premium. Selling self-generated electricity to the tenants is the second most substantial contribution that drives the NPV above zero. One peculiarity concerns the electricity drawn from the grid, whereby the landlord generates positive earnings. Due to the landlord's ability to bundle the electricity demand in one single contract, service providers offer lower prices to the landlord than the tenants for electricity from the grid. Therefore, slight earnings from grid consumption can be made. The large portion of cash flows accounting for self-consumed heat emphasizes that directing CHP electricity to the HP is a profitable option to increase the revenue from CHP electricity.

Figure 5 presents the sorted duration curve for the first year of operation for the earnings from directing self-generated electricity to the grid, the tenants, or converting it to heat via the HP and then selling it to the tenants. It illustrates the influence of COP on the earnings from HP self-consumption. Indeed for half the year, it is most profitable to directly self-consume PV- and CHP-generated electricity with the HP[9]. However, taking advantage of this is limited by the heat demand and respective storage capacities. Hence, the most profitable combination of PV-based HP heat supply is on the one hand limited by the size of the heat storage and the heat demand,

model, see Figure 2.

[9]In our study, the COP ranges from 1.6 in winter to almost 5 in summer. As long as the HP is operated with a COP above roughly 2.5 or 3, the earnings from converting the PV electricity or CHP electricity to heat surpass the earnings from selling the electricity directly to the tenants or feeding it into the grid.

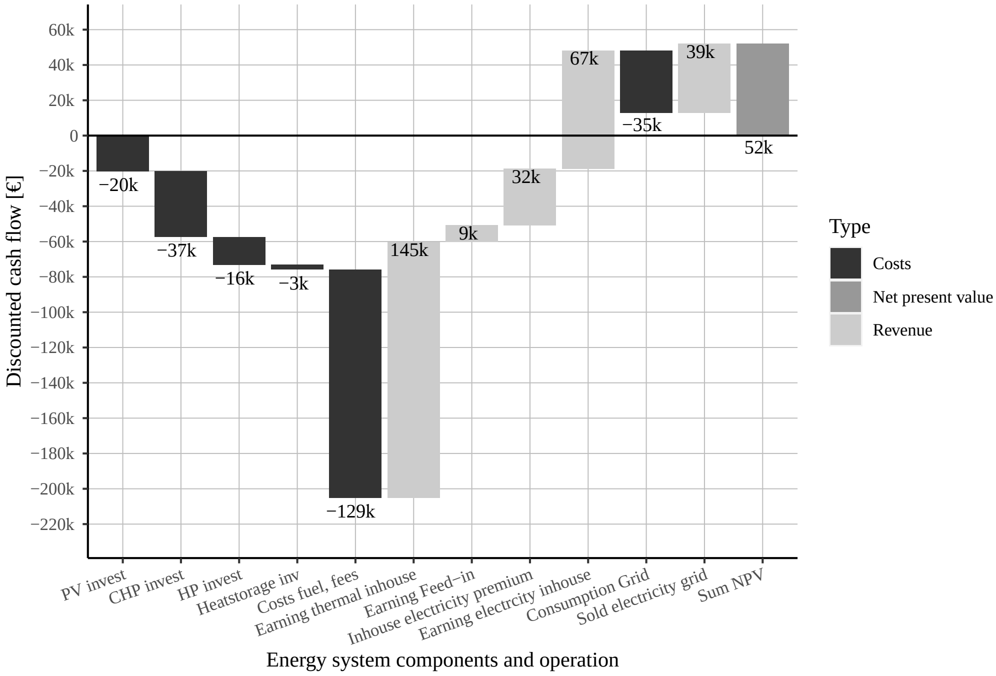


Figure 4: Discounted cash flows and *NPV* sorted by system components and operations of COMBI system in building 1.

whereby the latter is typically low when COP is highest. On the other hand, it is limited by the CHP operation, as heat is a by-product of the CHP operation and can only be consumed within the building. The cash flows and energy flows are further explained and illustrated in Figure SI B.

### 5.2. *Results for different buildings types*

Besides the analysis of technology combinations, the input parameters are varied in this section. We consider four different building types for the building-wise analysis, where the most characteristic features are the different total heat demands and demand profiles[10]. Table 4 presents the building-wise analysis results in descending order of total annual heat demand. As to be expected, the model invests in smaller CHP units for the newer buildings, indicating that the heating demand bounds the size of the CHP. For building 1, 2, and 3, the model invests in an HP. Together with the HS, the HP provides a flexible energy demand. This allows for self-consumption rates of values greater than 88%. Considering the $DSS_{el}$ the self-generated electricity satisfies between roughly 83% and around 85% of the electricity demand for all buildings.

Additionally, the results indicate that the heat demand restricts the size of the CHP unit and the HP as well. For building 3, the unit size of the HP is reduced compared to building 1 and

[10] A sensitivity analysis for different interest rates for building 1 is presented in Appendix A.2

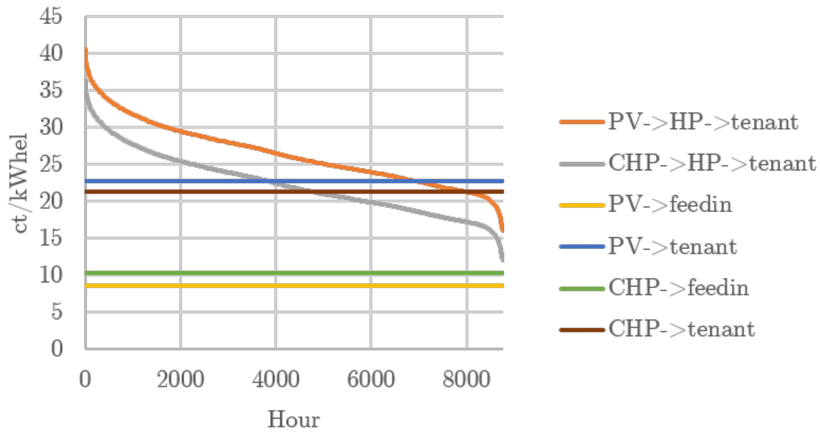


Figure 5: Earnings from PV and CHP generated electricity as a sorted annual duration curve for the first year of operation; the earnings result from electricity direct self-consumption, feed-in or self-consumption in the HP which has an environmental-temperature-dependent COP.

2. However, in building 4, the model does not invest in an HP at all. With no HP, the system does not install any profitable solution to offer a flexible electricity demand. Consequently, the $SCR_{el}$ of 78% is relatively low. Greater electricity feed-in leads to a $DA_{el}$ above 100%, which results in negative $CO_2$ abatement. For building 2 and 3 $cac_{subs}$ are nearly identical and 17% higher than for building 1. Regarding the grid interaction, multi-technology systems (PV, CHP, HP) seem to be NPV optimal with a feed-in variation corresponding to a GII of about 10%. This is especially noteworthy as demand profiles vary between the buildings. Notably, compared to the other buildings, the level of $CO_2$ emissions in the reference case for building 4 is relatively low, which makes $CO_2$ abatement more challenging — building 1 with the highest reference $CO_2$ emissions indicates the highest $CO_2$ abatement as well as the lowest $cac_{subs}$.

In Conclusion, a lower heat demand has a strong influence on the overall system design and performance. It reduces the capacity of the heat generators, like CHP and HP but of the PV system as well. Furthermore, this reduction influences the self-consumption potential and subsequently the profitability, as the NPV is lowest for building 4, $CO_2$ abatement and grid interaction.

### *5.3. Comparison of the amendment from TEL 2020 to 2021*

The TEL's most recent changes occurred in the REL between 2020 and 2021 and the CHPL between 2018 and 2020. Table A.9 gives an overview of these changes. Noticeable changes are the increase in the SCP for PV and CHP electricity and the increase of the feed-in tariff for CHP electricity. While the SCP for the CHP almost doubled, the feed-in tariff increased by around 37%. Simultaneously, the amendment reduces the maximum number of full load hours eligible for subsidies by one third.

The model results for the implementation of the 2020 legislation are shown in Table A.10. Figure 6 illustrates the effect the legislative changes have on the model outcome, system setup and KPIs. The amendment of the law increases the installed PV capacity as well as the CHP capacity. In 2020, the model does not install a CHP unit larger than 10 $kW_{el}$. In 2021, the CHP

| | Unit | Bldg1 < 1978 | Bldg2 1979-2001 | Bldg3 > 2001 | Bldg4 > 2001passiv |
|---|---|---|---|---|---|
| $NPV$ | $k€$ | 52.0 | 50.4 | 38.2 | 33.0 |
| $\Delta NPV$ | $k€$ | 65.4 | 64.9 | 49.6 | 41.9 |
| $Q_{te}$ | MWh/a | 113.0 | 100.9 | 58.0 | 40.4 |
| $D_{el,te}$ | MWh/a | 29.8 | 31.5 | 31.5 | 30.0 |
| $D_{el,hp}$ | MWh/a | 23.2 | 19.6 | 7.8 | - |
| $D_{el,tot}$ | MWh/a | 53.0 | 51.1 | 39.3 | 30.0 |
| $cap_{PV}$ | kW | 12.6 | 12.9 | 9.6 | 7.7 |
| $cap_{CHP}$ | kWel | 20.0 | 20.0 | 10.0 | 10.0 |
| $cap_{HP}$ | kWth | 14.4 | 12.8 | 6.2 | - |
| $cap_{HS}$ | kWh | 66.8 | 71.9 | 78.4 | 53.3 |
| $cap_{boil}$ | kWh | - | - | 2.9 | 3.4 |
| $P_{chp,max}$ | kWel | 20.0 | 20.0 | 10.0 | 10.0 |
| $h_{chp,full}$ | hours | 38745 | 36513 | 52473 | 49671 |
| $SCR_{el}$ | % | 90.2 | 89.6 | 95.4 | 78.9 |
| $DSS_{el}$ | % | 85.2 | 84.3 | 84.5 | 83.4 |
| $DA_{el}$ | % | 94.4 | 94.1 | 88.6 | 105.8 |
| $GII$ | % | 10.2 | 10.5 | 9.1 | 12.7 |
| $GII_{norm}$ | % | 53.0 | 57.3 | 56.7 | 89.4 |
| $CO_{2,ref}$ | t | 659.3 | 609.0 | 406.6 | 316.7 |
| $CO_{2,opt}$ | t | 477.9 | 452.9 | 331.8 | 325.9 |
| $\Delta CO_2$ | t | 181.4 | 156.1 | 74.8 | -9.2 |
| $CO_{2,export}$ | t | 23.2 | 23.6 | 3.2 | 33.1 |
| $\Delta CO_{2,export}$ | t | 2.7 | 2.7 | -3.6 | 5.0 |
| $CF_{subs}$ | $k€$ | 41.5 | 41.7 | 21.4 | 26.5 |
| $cac_{subs}$ | $€/t_{CO2}$ | 232.0 | 272.2 | 272.8 | - |

Table 4: Results for the 4 building types for system *COMBI*

capacities range between 10 $kW_{el}$ and 50 $kW_{el}$. This can be interpreted as a result of the rise in CHP remuneration in combination with a reduction of the maximum full load hours. Generating electricity in the CHP unit yields higher profits than in 2020. Additionally, full load hours are defined as the ratio between total electricity output and installed capacity. Thus increasing the capacity allows the model to generate more electricity that falls under the TEL subsidy scheme. Eventually, the model exploits the provided limiting full load hour constraint. A comparison of the results for system *PV_CHP* in 2020 and 2021 illustrates this effect. In 2020 the model invests in a 10 $kW_{el}$ CHP unit and no PV. Considering the full load hours, almost 40% of the CHP electricity does not receive subsidies and 80% of the generated electricity is self-consumed. In 2021, the model installs the maximum CHP capacity of 50 $kW_{el}$ and a PV system. The maximum full load hours are not exceeded and only 20% of the electricity is self-consumed.

Overall, the systems in 2020 reach higher SCR values. At the same time, the $CO_2$ abatement and NPV in 2021 are more elevated. Nonetheless, along with the subsidies' increase from 2020 to 2021, the $CO_2$ abatement rise by a maximum factor of almost three. As a final notable observation, the results for system *CHP_HP* are relatively similar in both years. In this system, the HP offers high electric flexibility for the CHP dispatch. Both laws stimulate the system to reach a

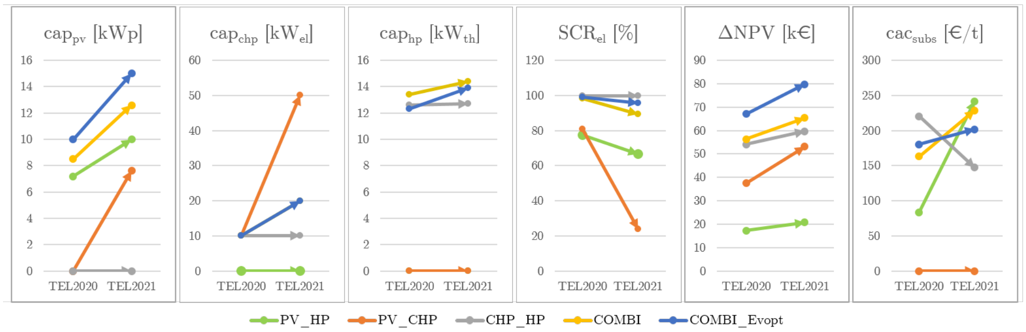


Figure 6: Comparing the results of the tenant electricity model for the TEL in July 2020 and the TEL in January 2021 in building 1

high SCR above 99.8%, and the same system setup achieves this.

## 6. Discussion

In this section, we present our key findings and conclude policy implications. This is followed by a discussion about the uncertainties of the presented optimisation model and the resulting considerations for a real-life business application. Finally, we elaborate on future research topics that build upon this study.

### *6.1. Key findings and policy implications*

The component-wise analysis suggests that the introduction of additional and flexible electricity demand to the system increases the NPV of the tenant electricity model. This flexibility is the result of the additional shiftable electricity demand of an HP or a fleet of EVs. According to the TEM, self-consumption of electricity is always more profitable than feed-in. Therefore, an optimised HP dispatch or EV charging schedule increases the self-consumption rate and maximises the NPV compared to a situation without them. Considering self-consumed PV electricity, flexibility through optimised EV-charging has a higher value than the HP dispatch due to the higher availability of EV-charging in summer and despite the favourable COP of the HP in summer.

Overall, the CHP operation can profit the most from the legal and subsidy framework, which renders the CHP unit a favourable technology for a profitable TEM. Furthermore, the results indicate that the heat demand has a strong influence on the investment and dispatch decisions for CHP and HP. From the building-wise analysis it is clear that larger building heat demands increase the NPV. More precisely, a greater heat demand allows for a larger CHP unit, the integration of an HP, and thus a high self-consumption rate. In the passive house with the lowest heat demand, investing in an HP is not profitable, which results in a low SCR, a relatively low NPV, and subsequently negative $CO_2$ abatement. In the latter case, additional electric flexibility like EV charging that is independent of the heating demand should be considered to increase the economic and ecological performance of the building.

This study shows that the TEM has the potential to reduce $CO_2$ emissions for most of the buildings analysed here. In fact for building 1, the system with the highest $CO_2$ abatement also presents the highest NPV for an investor. The amendment of the TEL in 2021 incentivises increased PV investment and yields higher $CO_2$ abatement than the previous law in 2020. However, as the amendment in 2021 increases the amount of remuneration, the $CO_2$ abatement cost also increases.

Nonetheless, the TEL is drafted strongly in favour of CHP-investment, which may be seen as a conflict with long-term $CO_2$ emission goals. In some cases, the reduction of the subsidised full load hours by the legislative changes leads to an over-sizing of the CHP-unit, which results in a large amount of grid feed-in and $CO_2$ emissions. The over-sizing could also impose additional stress on the grid as indicated by the GII. Furthermore, high insulation standards in buildings offer lower profitability for investors as the CHP's profitability increases with increasing heating demand. As building insulation standards continue to improve in future years, the economic case for such CHP systems will continue to diminish.

On a national level, the household sectors account for 25% of the national electricity consumption [54] and of this sector 53% are apartments [8]. Thus a widespread diffusion of the TEM could potentially affect the national electricity mix as the TEM incentivises on-site electricity generation and a high self-consumption rate. Nonetheless, the demonstrated lock-ins might counteract mitigation achievements in other sectors. The results have shown that the TEM favours gas-driven CHP technologies to an extent that the future $CO_2$ emission factor of the building's electricity might surpass the national grid emission factor. Additionally, the German government calculates that energy savings of at least 36% in the building sector [55] are needed to achieve the 2050 mitigation goals. Still, investment in energy conservation such as insulation diminishes the profitability of the TEM.

Whilst PV operation by itself is profitable, more importantly, the TEL allows the investor to exploit the potential of combining different technology options. Investing in a PV system by itself yields rather low profits, and integrating an HP into such a system is economically not feasible. However, while combining a CHP unit with an HP is already profitable, including a PV system yields even more benefits. It increases the NPV, and the HP allows for a larger PV system's profitable operation than in the PV only case resulting in greater $CO_2$ abatement. The PV system is even larger when considering optimised EV charging. This same system that combines all technologies yields the highest profit and $CO_2$ abatement. Thus, the technology combination options achieve larger PV instalments, which is the TEL's ultimate goal.

In conclusion and under the assumption of continuous decarbonisation of the power sector, the TEL can counteract $CO_2$ mitigation and energy conservation actions in a large share of buildings. Although CHPs are being considered as a bridging technology, in a 20 year time frame from now they may become a burden. Firstly, the grid decarbonisation can erode current fossil-based CHP benefits in efficiency and carbon emissions, and vice versa. Secondly, as heat demand strongly correlates with NPV, the incentives and arguments for energy conservation in old buildings fall out and a lock-in is generated. Investors would have to give up profits to save energy. Thirdly, less complex combinations e.g. CHP only or CHP-HP are more profitable than PV only or PV-CHP but do not contribute any additional renewable energies. Hence, profit-maximising adoption with system layouts of low complexity can lead to lock-ins in Europe's largest residential building stock, which might slow down investments in renewable energies and heat demand reduction (energy conservation).

### *6.2. Methodology and future research*

For this study, we assume a control and metering concept that allows for the proposed TEM and is already implemented in the buildings - other metering concepts, such as a totaliser considering the whole building and not the individual apartments, yield different results. On the tenants' side, we assume no changes in the number of tenants and their behaviour. Furthermore, we assume a 100% participation in the TEM of all tenants over 20 years. On the landlord's side, we do not consider any additional financial burden, e.g. administrative measures, income or trade taxation considerations. Particularly the latter is a current hurdle for the adoption of tenant electricity. Depending on the landlord's taxation situation, implementing a TEM can lead to income taxes or being taxed as a commercial entity. Moreover, inconclusive information on exemptions regarding trade taxes hinders the full consideration of all possible combinations[11]. These assumptions and simplifications need to be carefully considered, as they influence economic decisions.

In addition, one needs to consider the uncertainties as a result of the model formulation and uncertainties through input parameters. The developed model operates with perfect foresight, which is a strong simplification for a real-life operation with many unknowns, e.g. for the energy storage system's optimal dispatch. Furthermore, we assume one representative year for the energy demand, driving, solar irradiation, and ambient temperature profiles over the investment period of 20 years. This assumption introduces input uncertainties. For example, considering a representative yet repetitive tenants' behaviour over the investment period of 20 years might not hold up to reality, even more so when considering disruptive events such as the COVID-19 pandemic. The pandemic changed the occupancy duration of households, which has a positive correlation with the energy consumption in the building, especially during off-peak hours. Additionally, this kind of event influences all sectors altering the national load and generation profiles as well as energy market behaviour [57]. Detailed empirical evidence is expected to be published in the near future. Nonetheless, for Germany, the first glimpse in a small study (N 200 households) shows a total increase of 1.8% in electricity consumption and differing intra-week temporal shifts of electricity consumption (for 44% of the sample, no shift was observed). Nevertheless, it is unclear whether observed changes will prevail in the long term [58]. Our model results show that an increasing energy demand potentially increases self-consumption and thus affects profitability positively. Simultaneously, additional grid electricity imports represent a negligible financial risk.

Additional input uncertainties arise from the regional focus. The case study region is Karlsruhe in the upper Rhine region and represents a best-case scenario regarding solar irradiation and warmer climate conditions in Germany. Considering other climate regions would affect the heat demand in the building, COP of the heat pump, and the PV potential. The electricity load profile is likely to be independent of the location, as it depends on the household structure and the social and demographic background of the occupants. Less sunny and colder regions in Germany would coincide with higher heat demand. The results of the comparison of the four different buildings in Section 5.2 allow for the deduction of the following outcomes. Increasing heat demand is likely to positively influence profitability as the CHP operation increases and thus the share of CHP electricity and the self-consumption rate. The decline of the COP of the heat pump would further increase the electricity demand, which would positively affect the self-consumption rate. These effects, in turn, could potentially compensate for the lower irradiation and PV output. Furthermore, as lower irradiation diminishes PV output, the self-consumption rate for PV electricity would remain high due to the time overlap of PV generation and electricity consumption. Nonetheless, colder climate regions in Germany would most likely increase the natural gas consumption and lower the emission performance. Finally, other regions offer differ-

[11]The exemption from trade taxes was announced together with the current REL amendment. Nonetheless, up until the 10th of February 2021 [56], we could not identify any legal changes.

ent electricity tariffs. A reduction of the tenant electricity price due to the tenants' willingness to pay or legal regulations might put the profitably of TEM under stress.

Other simplifications and assumptions concern the heat supply and exogenous conditions. It is modelled without detailed consideration of heat inertia or return flow temperature. Additionally and to allow for an adequate solving time, we selected discrete CHP capacities, see Section 4. Concerning the exogenous conditions, some of the analysed combinations achieve high degrees of electrical autonomy, which reduces the demand for grid electricity. This reduction would impact the contract between the landlord and grid service provider, likely resulting in an increasing electricity tariff. As well as influencing the tariff of a specific building, this newly-created energy community may also have wider impacts on the whole energy system. If a critical number of these communities become established, they may create a positive feedback loop [59], whereby increasing network fees distributed across fewer and fewer customers provide additional incentive for higher electrical autonomy [6]. We do not address this issue directly, as it is out of scope and requires a coupled and iterative approach with multiple system models. Nonetheless, Figure 4 indicates this contractual uncertainty as a small risk.

All of the mentioned limitations should be considered for the interpretation of the results. Further analyses of these limitations are presented in the supplementary information. Nevertheless, whilst the absolute results are sensitive to variations, the overall trends in the results seem to be more robust.

The issue with over-sizing of CHP systems for MFBs may also suggest advantages in further aggregation. As well as economies of scale through larger plant sizes, aggregating to a district or neighbourhood level has the advantage of smoothing-out fluctuations in demand and supply [18]. By also including some additional diversity of customers, optimising an highly-renewable energy system at the district level can be economically and environmentally advantageous [28]. For example, it may ameliorate the encountered problem with large feed-ins of relatively high-$CO_2$-intensity electricity. Appropriately dimensioned plants at the district level would have higher self-sufficiency rates and therefore a lower overall environmental impact. But the challenge of achieving high utilization rates of coupled heat production in summer still remains. In some contexts, the application of Seasonal Thermal Energy Storage (STES) systems may be appropriate, which would enable summer heat to be used in the winter months, but obviously has a significant influence on the costs [60].

Overall, our results show the complexity of the TEL and the possible adverse adoption based on incomplete or imperfect information. On the one hand, several simplifications and uncertainties indicate the limitations of the presented results. On the other hand, they emphasize the complexity for practitioners to implement a TEM in a real-life setting and give valuable insights into the different technologies' operational dependencies. It is therefore important to highlight the importance of the relationship between electricity and heating demand. Thus, future research should focus on renewables policy design to avoid adverse adoption and/or undesirable side-effects of subsidy schemes. In the present case, this means limiting the potential to oversize CHP units and feed large amounts of excess (CHP) electricity into the grid. Furthermore, policy should adopt to an evolving energy system by closely considering and varying the EV driving profiles, charging infrastructure and other system-wide developments. Such analyses could be implemented through the application of model couplings between the sort of micro-level building model employed here and a whole energy system model at the national scale. Additionally, altering the tenants' structure via the number of tenants or the composition of age and social background affects the electricity and heating demand simultaneously [61]. So this aspect should also be explored with linked models of socioeconomic technology adoption combined with spatially-disaggregated data on German households. Including insulation measures in the model would also be another step to depicting a more futuristic energy system, as only then could the competition effects between decentralised demand and supply sides be analysed. Furthermore, comparing different CHP modelling techniques or adding stochastic scenarios would help to better grasp the investment decision's complexity. In order to include some or all of the mentioned options while keeping the model solvable, the model complexity must be reduced. For example, an aggregated representation of the time series structure may be an option to achieve this complexity reduction. Finally, the results reveal non-intuitive coherence among the various energy and cash flows. Thus, investigating the implications of business models and legal frameworks in other countries could be of high interest for future work.

## 7. Conclusion

In this paper, we formulate a MILP optimisation model to investigate the energy system design and operation of an MFB considering multiple technologies to match different electricity and heating demands. In contrast to other publications, this model includes multiple technological options such as PV, CHP, HP, and EV charging. The novelty is the application to the German case of the Tenant Electricity Law (TEL), a framework for local energy communities. We determine the optimal system design for different technology combinations and building types. Additionally, we compare the effect of the TEL amendment from 2020 to the current version in 2021. We analyse the economic and ecological performance as well as the interaction with the national grid.

This comprehensive model and the study of the legal framework, technological variety and the principle agent distinction discloses the merits and pitfalls of energy communities. The key findings show that the latest amendment of the TEL in Germany increases the profitability of a TEM in MFBs. Hence, the amendment possibly increases the attractiveness of its adoption and accelerates its diffusion in MFHs, but the current framework favours the CHP technology over other options. Nonetheless, the law fosters the various technologies' dependencies as the highest profitability is achieved when combining PV, CHP, HP and EV. However, the current TEL may fail to support national $CO_2$ mitigation goals. First, this is because the TEM's profitability depends on the heat demand and a reduction of the heat demand, through insulation measures, might coincide with a profitability reduction. Secondly, it needs to be discussed if subsidising CHP operation as a bridging technology achieves the desired levels of $CO_2$ abatement.

Tapping renewable energy sources and increasing energy conservation in the built environment through energy communities seems to be a model of choice in many countries to reach climate mitigation goals. Hence this study contributes additional insights to the international scientific and policy discussion around energy communities. The implementation of energy communities differs greatly by country, with forms of the TEL in the UK (Private Wire Networks policy), Spain (Collective Auto Consumption policy), Netherlands (Post Code Rose policy). By adding another case study application to this research, this paper has further extended the the existing knowledge about cost- and environmentally-effective applications to also include the current German situation. Furthermore, the gain of insight through the developed detailed approach provides a persuasive precedent for international practitioners, policymakers and investigating other energy community frameworks in detail.

## Appendix A. Additional tables

### *Appendix A.1. Consumer prices*

Table A.7 describes the consumer prices for electricity in absolute terms without inflation. Prices are based on statistical values for Germany in 2020 [49]. Equation A.1 shows that the base price from the year 2020 ($c^{t_0}_{el,landlord}$) is adapted by the the yearly growth rate $r_{el}$. $c^{t_0}_{el,landlord}$ refers to statistical mean value of German electricity tariffs by a third-party provider for a yearly electricity demand above 15 $MWh$ in [49]. Equation A.2 shows that the tenant electricity price is based on the basic provider tariff from the year 2020 ($c^{t_0}_{el,basic}$). We assume that the landlord asks for 90% of this tariff to fulfil the TEL requirements. This tariff is adapted by the yearly growth rate $r_{el}$. $c^{t_0}_{el,basic}$ refers to statistical mean value of German electricity tariffs by the basic procider for a yearly electricity demand between 2.5 $MWh$ and 5.0 $MWh$ in [49]. Accordingly, the gas price is derived from the gas price in the base year ($c^{t_0}_{gas,pure}$) and a yearly growth rate ($r_{gas}$). $c^{t_0}_{gas,pure}$ refers to statistical mean value of German electricity tariffs without $CO_2$ charges yearly gas demand below 55.556 $MWh$ and above 55.556 $MWh$ in [49]. Additionally, we include $CO_2$ emission charges ($c_{CO2}$) corresponding with a $CO_2$ emission factor for natural gas ($EF_{gas,2019}$) [62]. The $CO_2$ emission charges are based on the German law [50].

$$c^{t}_{el,landlord} = c^{t_0}_{el,landlord} \cdot (1 + r_{el})^{t-t_0} \tag{A.1}$$

$$c^{t}_{el,tenant} = 0.9 * c^{t_0}_{el,basic} \cdot (1 + r_{el})^{t-t_0} \tag{A.2}$$

$$c^{t}_{gas} = c^{t_0}_{gas,pure} \cdot (1 + r_{gas})^{t-t_0} + c^{t}_{CO2} \cdot EF_{gs,2019}/1000/1000 \tag{A.3}$$

### *Appendix A.2. Sensitivity analysis for different interest rates*

Figure A.7 shows the results of the sensitivity analysis for different interest rates. The analysis is applied to building 1 system COMBI. The studied interest rates are altered between 1% and 8% in steps of 1%. Results indicate the highest $\Delta NPV$ for an interest rate of 1% and a declining trend for increasing interest rates. Nonetheless, in all cases, the TEM is profitable. Considering Equation 1, increasing interest rates affect the annual cash flow negatively, thus stressing the profitability of the investment. Similarly, increasing interest rates seem to negatively impact the installed capacities of PV, HP, and CHP in Figure A.7. At interest rate greater than 5% gas heating boilers are installed. Low interest rates coincide with large PV and CHP capacities and a relatively low self-consumption rate. While the interest rate of 8% results in the lowest values of installed capacities but a high self-consumption rate. These results indicate that feeding electricity into the grid is profitable if the value of the annual cash flow is relatively high. Vice versa, in the case of low valued annual cash flow, almost no electricity is fed into the grid but self-consumed within the building at the heat pump or in households. The low profitability of grid feed-in results in smaller CHP units and the additional installation of a boiler to cover the heat demand.

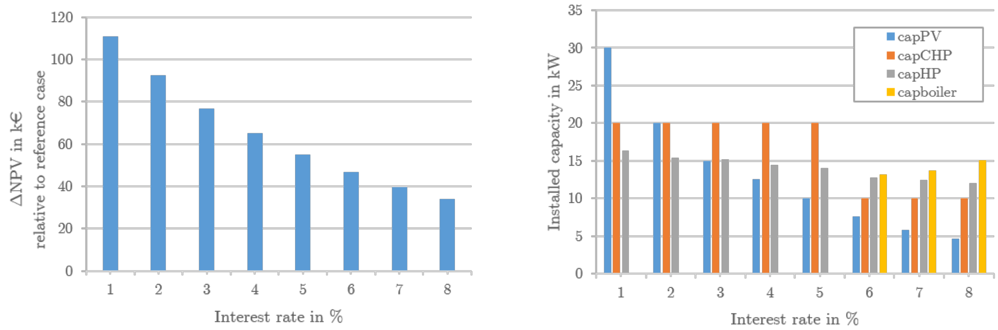


Figure A.7: Results of sensitivity analysis for different interest rates for the COMBI system in building 1 showing $\Delta NPV$ and installed capacities for PV, HP, CHP, and gas heating boilers.

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| Parameter | Description | Unit | Value |
|---|---|---|---|
| $c_{REL}$ | REL levy | $€/kWh$ | 0.0650 |
| VAT | Value added taxes | % | 19 |
| $c_{M\&I}$ | Cost metering & invoicing | $€/kWh$ | 0.0061 |
| $c_{chp,te}$ [1] | CHP self-consumption premium | $€/kWh$ | 0.0800 |
| $c_{chp,feedin}$ [1] | CHP feed-in | $€/kWh$ | 0.1600 |
| $c_{inv,fix}^{PV,a=0}$ | PV, fix cost | € | 0 |
| $c_{inv,var}^{PV,a=0}$ | PV, variable cost | $€/kWp$ | 1194.39 |
| $c_{inv,fix}^{chp,a=0}$ | CHP, fix cost | € | 15000 |
| $c_{inv,var}^{chp,a=0}$ | CHP, variable cost | $€/kW_{el}$ | 970.30 |
| $c_{inv,fix}^{bat,a=0}$ | Battery, fix cost | € | 2000 |
| $c_{inv,var}^{bat,a=0}$ | Battery, variable cost | $€/kWh$ | 530.84 |
| $c_{inv,fix}^{inv,a=0}$ | Inverter, fix cost | € | 0 |
| $c_{inv,var}^{inv,a=0}$ | Inverter, variable cost | $€/kW_{el}$ | 250 |
| $c_{inv,fix}^{hp,a=0}$ | Heat pump, fix cost | € | 5000 |
| $c_{inv,var}^{hp,a=0}$ | Heat Pump, variable cost | $€/kW_{th}$ | 582 |
| $c_{inv,fix}^{boiler}$ | Boiler, fix cost | € | 0 |
| $c_{inv,var}^{boiler}$ | Boiler, variable cost | $€/kW_{th}$ | 175 |

[1] $cap^{CHP} < 50kWel$

Table A.5: Input data 1

| Parameter | Unit | Value | parameter | Unit | Value |
|---|---|---|---|---|---|
| $A$ | *Years* | 20 | $\eta_{chp,el}$ | - | 0.35 |
| $T$ | *Hours* | 8760 | $\eta_{chp,th}$ | - | 0.58 |
| $i$ | % | 4 | $\sigma_{chp}$ | - | 0.60 |
| $r_{el}$ | % | 2 | $r_{chp,min}$ | % | 40 |
| $EF_{el,grid,2019}$ | $g_{CO2}/kWh_{el}$ | 401 | $cap_{lim,REL}$ | $kW_{el}$ | 10 |
| $r_{EFgrid}$ | % | -6 | $E_{chp,lim,REL}$ | $MWh$ | 10 |
| $EF_{gas,2019}$ | $g_{CO2}/kWh$ | 201 | $EF_{chp,el}$ | $g_{CO2}/kWh_{el}$ | 313 |
| $r_{EFgas}$ | % | 0 | $\eta_{el,altl}$ | - | 0.40 |
| $EF_{el,PV,2019}$ | $g_{CO2}/kWh_{el}$ | 0 | $\eta_{th,alt}$ | - | 0.90 |
| $r_{EF,PV}$ | % | -6 | | | |

Table A.6: Input data 2

| Year | $c_{el,landlord}$ | $c_{el,tenant}$ | $c_{gas}$ | $c_{CO2}$ |
|---|---|---|---|---|
| | €$/kWh$ | €$/kWh$ | €$/kWh$ | €$/t_{CO2}$ |
| 2021 | 0.2802 | 0.3103 | 0.0633 | 25 |
| 2022 | 0.2858 | 0.3165 | 0.0654 | 30 |
| 2023 | 0.2915 | 0.3228 | 0.0676 | 35 |
| 2024 | 0.2973 | 0.3293 | 0.0709 | 45 |
| 2025 | 0.3033 | 0.3359 | 0.0741 | 55 |
| 2026 | 0.3094 | 0.3426 | 0.0754 | 55 |
| 2027 | 0.3155 | 0.3494 | 0.0766 | 55 |
| 2028 | 0.3219 | 0.3564 | 0.0780 | 55 |
| 2029 | 0.3283 | 0.3635 | 0.0793 | 55 |
| 2030 | 0.3349 | 0.3708 | 0.0827 | 65 |
| 2031 | 0.3416 | 0.3782 | 0.0841 | 65 |
| 2032 | 0.3484 | 0.3858 | 0.0855 | 65 |
| 2033 | 0.3554 | 0.3935 | 0.0869 | 65 |
| 2034 | 0.3625 | 0.4014 | 0.0884 | 65 |
| 2035 | 0.3697 | 0.4094 | 0.0919 | 75 |
| 2036 | 0.3771 | 0.4176 | 0.0935 | 75 |
| 2037 | 0.3846 | 0.4260 | 0.0950 | 75 |
| 2038 | 0.3923 | 0.4345 | 0.0966 | 75 |
| 2039 | 0.4002 | 0.4432 | 0.0983 | 75 |
| 2040 | 0.4082 | 0.4520 | 0.0999 | 75 |

Table A.7: Consumer prices for landlord and tenants as absolute prices

| $rs$ Remuneration scheme | $cap_{pv}^{rs}$ Upper limit | $c_{pv,scp}$ €$/kWh$ | $c_{pv,feedin}$ €$/kWh$ | $c_{pv,levy}$ €$/kWh$ |
|---|---|---|---|---|
| 1 | 10 | 0.0379 | 0.0856 | - |
| 2 | 15 | 0.0374 | 0.0851 | - |
| 3 | 20 | 0.0367 | 0.0846 | - |
| 4 | 25 | 0.0364 | 0.0843 | - |
| 5 | 30 | 0.0362 | 0.0841 | - |
| 6 | 35 | 0.0360 | 0.0840 | 0.4351 |
| 7 | 40 | 0.0359 | 0.0839 | 0.4351 |
| 8 | 45 | 0.0352 | 0.0828 | 0.4351 |
| 9 | 50 | 0.0340 | 0.0811 | 0.4351 |
| 10 | 55 | 0.0330 | 0.0797 | 0.4351 |
| 11 | 60 | 0.0322 | 0.0785 | 0.4351 |
| 12 | 65 | 0.0315 | 0.0775 | 0.4351 |
| 13 | 70 | 0.0309 | 0.0767 | 0.4351 |
| 14 | 75 | 0.0304 | 0.0760 | 0.4351 |
| 15 | 80 | 0.0300 | 0.0753 | 0.4351 |
| 16 | 85 | 0.0296 | 0.0748 | 0.4351 |
| 17 | 90 | 0.0293 | 0.0743 | 0.4351 |
| 18 | 95 | 0.0290 | 0.0738 | 0.4351 |
| 19 | 100 | 0.0287 | 0.0735 | 0.4351 |

Table A.8: Tenant self-consumption premium, feed-in tariff and self-consumption levy for PV-electricity depending on the remuneration scheme and installed PV capacity respectively.

| Parameter | Capacity limit | Unit | 01.07.2020 | 01.01.2021 |
|---|---|---|---|---|
| $SCP_{pv}$ | $cap_{pv} <= 10kWp$ | $ct/kWh$ | 0.53 | 3.79 |
| | $cap_{pv} <= 40kWp$ | $ct/kWh$ | 0.28 | 3.52 |
| | $cap_{pv} <= 750kWp$ | $ct/kWh$ | -1.11 | 2.37 |
| $feed-in_{pv}$ | $cap_{pv} <= 10kWp$ | $ct/kWh$ | 9.03 | 8.56 |
| | $cap_{pv} <= 40kWp$ | $ct/kWh$ | 8.78 | 8.33 |
| | $cap_{pv} <= 750kWp$ | $ct/kWh$ | 6.89 | 6.62 |
| $SCP_{chp}$ | | $ct/kWh$ | 4.10 | 8.00 |
| $feed-in_{chp}$ | | $ct/kWh$ | 11.66 | 16.00 |
| $h_{chp,fullload}$ | | hours | 45000 | 30000 |

Table A.9: Most important changes between legislation on 01.07.2020 and 01.01.2021.

| KPI | Unit | REF | PV_ HP | PV_ CHP | CHP | CHP_ HP | COMBI | COMBI_ EV | COMBI_ EVopt |
|---|---|---|---|---|---|---|---|---|---|
| $NPV$ | $k€$ | -13.4 | 3.9 | 24.0 | 24.0 | 40.7 | 43.0 | 50.0 | 53.7 |
| $\Delta NPV$ | $k€$ | - | 17.3 | 37.4 | 37.5 | 54.1 | 56.4 | 63.5 | 67.1 |
| $D_{el,te}$ | MWh/a | 29.8 | 29.8 | 29.8 | 29.8 | 29.8 | 29.8 | 36.8 | 36.9 |
| $D_{el,hp}$ | MWh/a | - | - | - | - | 18.4 | 20.6 | 18.7 | 18.3 |
| $D_{el,tot}$ | MWh/a | 29.8 | 29.8 | 29.8 | 29.8 | 48.2 | 50.4 | 55.6 | 55.1 |
| $cap_{PV}$ | kW | - | 7.2 | - | - | - | 8.5 | 10.0 | 10.0 |
| $cap_{CHP}$ | kWel | - | - | 10.0 | 10.0 | 10.0 | 10.0 | 10.0 | 10.0 |
| $cap_{HP}$ | kWth | - | - | - | - | 12.6 | 13.4 | 13.1 | 12.3 |
| $cap_{HS}$ | kWh | - | - | 63.8 | 63.9 | 76.6 | 75.9 | 76.2 | 73.9 |
| $cap_{boil}$ | kWh | 60.3 | 60.3 | 25.7 | 25.7 | 12.4 | 11.8 | 12.0 | 13.1 |
| $P_{chp,max}$ | kWel | - | - | 10.0 | 10.0 | 10.0 | 10.0 | 10.0 | 10.0 |
| $h_{chp,full}$ | hours | - | - | 62436 | 62582 | 86214 | 78101 | 82484 | 87342 |
| $SCR_{el}$ | % | - | 81.5 | 80.7 | 80.6 | 99.9 | 99.0 | 98.8 | 100.0 |
| $DSS_{el}$ | % | - | 17.8 | 84.5 | 84.6 | 89.3 | 91.8 | 89.4 | 95.7 |
| $DA_{el}$ | % | - | 21.8 | 104.7 | 105.0 | 89.4 | 92.7 | 90.5 | 95.7 |
| $GII$ | % | - | 14.1 | 13.2 | 13.2 | 3.3 | 5.4 | 5.8 | 2.2 |
| $GII_{norm}$ | % | - | 91.1 | 85.0 | 85.1 | 16.1 | 27.1 | 46.8 | 12.2 |
| $CO_{2,ref}$ | t | 667.3 | 667.3 | 667.3 | 667.3 | 667.3 | 667.3 | 698.7 | 698.7 |
| $CO_{2,opt}$ | t | 667.3 | 643.7 | 695.4 | 695.6 | 549.3 | 496.6 | 535.6 | 538.2 |
| $\Delta CO_2$ | t | - | 23.6 | -28.1 | -28.3 | 118.0 | 170.8 | 163.1 | 160.6 |
| $CO_{2,export}$ | t | - | - | 37.8 | 38.0 | 0.4 | 1.3 | 1.4 | - |
| $\Delta CO_{2,export}$ | t | - | -5.4 | 10.9 | 10.9 | 0.1 | -0.8 | -1.3 | - |
| $CF_{subs}$ | $k€$ | - | 1.9 | 18.7 | 18.8 | 12.6 | 13.3 | 13.6 | 12.9 |
| $cac_{subs}$ | $€/t_{CO2}$ | - | 64.0 | - | - | 106.8 | 77.5 | 82.6 | 80.6 |

Table A.10: Results for component wise analysis sorted by $\Delta NPV$ for comparison of the TEL in July 2020 and the TEL in January 2021

**Supplementary Information**
for

**Optimal system design for energy communities in multi-family buildings: the case of the German Tenant Electricity Law**

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## SI A. Emissions for electricity fed into the grid

Regarding the allocation of fuel and emissions respectively from co-generation processes in the CHP-unit the alternative generation method is used A.1. This method is utilised for the national and official energy accounting in Germany [48]. Furthermore, it is in line with the methodology for determining the efficiency of the co-generation process in [2] and [3]. According to the national Working Group on Energy Balances (AGEB) [48] parameters for the alternative efficiencies are $\eta_{th,alt} = 0.80$ and $\eta_{el,alt} = 0.40$[12].

$$EF_{chp,el} = (1 - PES) * \frac{\eta_{chp,el}}{\eta_{el,alt}} \cdot \frac{EF_{gas}}{\eta_{chp,el}} \quad with \quad PES = 1 - \frac{1}{\frac{\eta_{chp,th}}{\eta_{th,alt}} + \frac{\eta_{chp,el}}{\eta_{el,alt}}} \tag{A.1}$$

## SI B. In-house cash-flow and energy flow

Equations B.1, B.2 and B.3 further explain the calculation of earnings from CHP operation. In Equation B.1 the CHP unit generates heat and feeds the electricity into the grid, thus only payment for heat and through the feed-in tarif can be charged. Equation B.2 displays the operational mode where the electricity of the CHP unit is sold to the tenants and the SCP and the tenant electricity price is charged. Finally, Equation B.3 represents the case, where the electricity is converted in the HP to heat. This increases the amount of heat sold to tenants and charges only the SCP for electricity self-consumption.

[12] Based on [3] the parameters would be $\eta_{th,alt} = 0.92$ and $\eta_{el,alt} = 0.455$ which would alter the specific emissions coefficients by +/- 1g each

$$
\begin{aligned}
R_{chp,feedin} &= \frac{1}{\sigma_{chp}} \cdot \frac{c_{gas}}{\eta_{boiler}} + c_{chp,feedin} - \frac{c_{gas}}{\eta_{el,chp}} \\
&= \Big[\frac{1}{0.6} \cdot \frac{6.33}{0.85} + 16.00 - \frac{6.33}{0.35}\Big]\ ct/kWh_{el} \\
&= 10.33\ ct/kWh_{el}
\end{aligned}
\tag{B.1}
$$

$$
\begin{aligned}
R_{chp,te} &= \frac{1}{\sigma_{chp}} \cdot \frac{c_{gas}}{\eta_{boiler}} + (c_{el,te} + c_{chp,te} - c_{fees}) - \frac{c_{gas}}{\eta_{el,chp}} \\
&= \Big[\frac{1}{0.6} \cdot \frac{6.33}{0.85} + (31.03 + 8.00 - 12.08) - \frac{6.33}{0.35}\Big]\ ct/kWh_{el} \\
&= 21.28\ ct/kWh_{el}
\end{aligned}
\tag{B.2}
$$

$$
\begin{aligned}
R_{chp,te} &= (\frac{1}{\sigma_{chp}} + COP_{hp}) \cdot \frac{c_{gas}}{\eta_{boiler}} + (c_{chp,te} - 0.4 * c_{chp,self}) - \frac{c_{gas}}{\eta_{el,chp}} \\
&= \Big[(\frac{1}{0.6} + 3.5) \cdot \frac{6.33}{0.85} + (8.00 - 0.4 \cdot 6.5) - \frac{6.33}{0.35}\Big]\ ct/kWh_{el} \\
&= 25.79\ ct/kWh_{el}
\end{aligned}
\tag{B.3}
$$

*Energy flow illustration.* Figure B.8 and Figure B.9 show the energy flows for two days in summer. It shows the system COMBI for building 1 where the CHP unit is 20 $kW_{el}$ large. The model has chosen not to install a boiler, which results in the CHP and the HP as the only heat source in the building. Figure B.8 illustrates that most of the PV electricity is self-consumed within the building. In this case the minimum load of the CHP is 8 $kW_{el}$. Thus, the electricity load during the day is too low to be covered by the CHP. One part of the PV electricity is directed to the HP to generate heat and fill the heat storage. The potential of heat generation of the HP is limited by the size of the heat storage and the operation of the CHP unit in the evening. In the evening there is a peak demand for electricity, which allows the CHP to operate. In order to do so, the heat as a bi-product of the electricity generation needs to be either stored or directly consumed; storage capacity and heat demand are limiting factors. This illustration helps to grasp the complexity of identifying the optimal dispatch. It also shows the effect of perfect foresight on the dispatch decision.

Figure B.9 shows another exemplary summer day. Here, the storage level is fairly high, which is a result of a dispatch decision in the following day. The figure illustrates the operational challenges of the CHP unit. It only operates during one hour in the evening to cover the peak demand. The electricity demand of the households during this hour is still below the minimum load of the CHP. Thus, the model chooses to generate additional electricity that is directed to the HP in order to surpass the minimum load restriction. Notably, the heat storage with around 66 $kWh$ is not fully utilized. This indicates that the dispatch of CHP and HP is additionally constrained by the heat demand of the building, which is relatively low during the summer season.

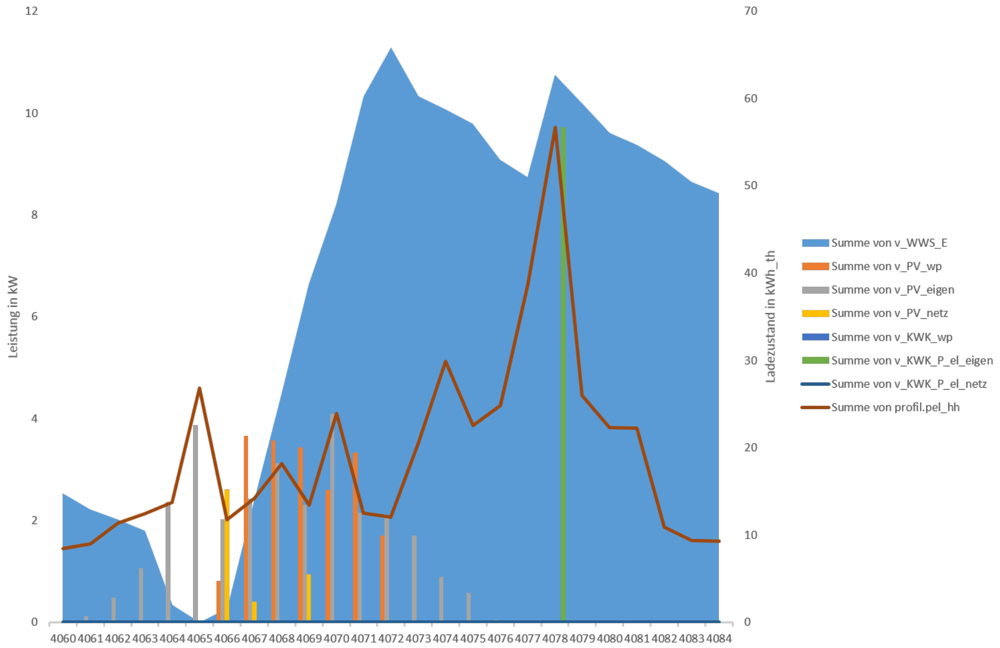


Figure B.8: Exemplary energy flow for day 1 in summer for Building 1, system COMBI and a CHP unit of 20 $kW_{el}$.

## SI C. Cascading mode for the CHP unit

From the results of the main analysis, we understand that the minimum load criteria of the CHP operation ($P_{chp,min}$) influences the system's dimensions as well as the dispatch decisions. To calculate the optimal dispatch of the CHP unit presents substantial complexities. To reduce the complexity of the problem, it is possible to aggregate the time steps or introduce other simplifications or assumptions. One simplification, which offers additional economic implications, is the assumption of a cascading mode in the CHP installation. The cascading mode describes the possibility to install multiple smaller CHP-units instead of one large unit. Thus, the system can operate continuously between a relatively small minimum load and its maximum load. For example, considering a minimum load of 4 $kW_{el}$, one would install a first CHP unit with 10 $kW_{el}$. In a cascading mode to guarantee a continuous operation, the second CHP unit would need to provide a minimum load of 6 $kW_{el}$ with a capacity of 15 $kW_{el}$. The next step is to invest in a 22.5 $kW_{el}$ CHP unit, thus achieving a full capacity of 47.5 $kW_{el}$ with a minimum load of 4 $kW_{el}$.

$$cap_{chp,1} = 4\,kW_{el} + P_{chp,min,2} = 10\,kW_{el} \tag{C.1}$$

$$\begin{aligned} cap_{chp,1} + cap_{chp,2} &= cap_{chp,min,1} + P_{chp,2} + P_{chp,min,3} \\ 25\,kW_{el} &= 10\,kW_{el} + 6\,kW_{el} + P_{chp,min,3} \end{aligned} \tag{C.2}$$

To implement the cascading mode into the model, we doubled the fix cost for the CHP system or tripled it for a cascading mode of two units or three units respectively. This price variation can

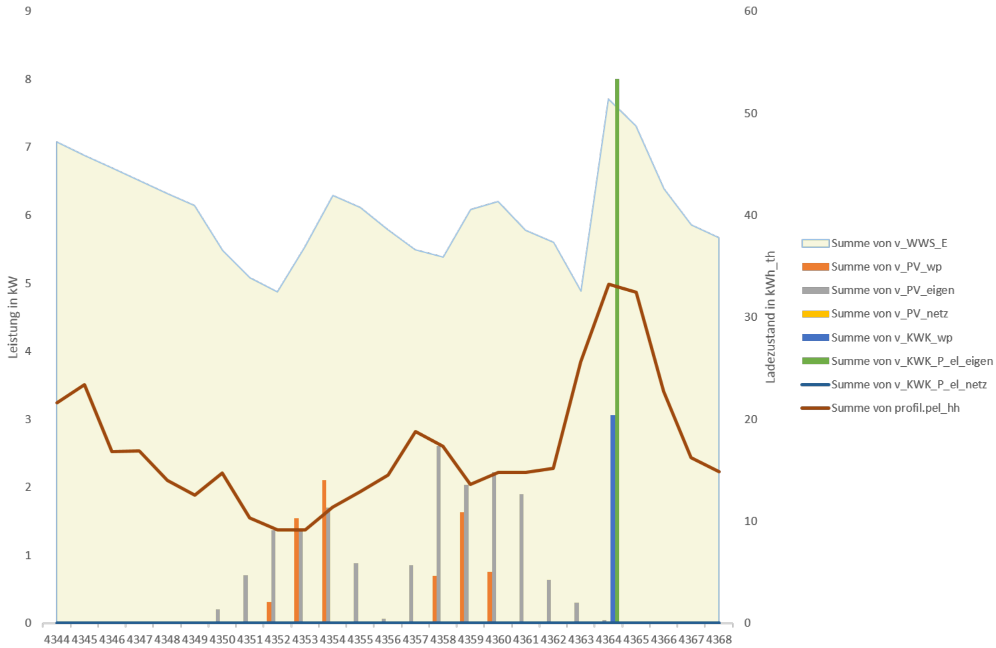


Figure B.9: Exemplary energy flow for day 1 in summer for Building 1, system COMBI and a CHP unit of 20 $kW_{el}$.

also be interpreted as investment in other CHP technologies that are more expensive. Nonetheless, for the analysis of the cascading mode, the minimum load was set to 4 $kW_{el}$ and the CHP capacity is implemented as a continuous variable of the optimisation model. All the other CHP parameters are not changed. Table C.11 and Table C.12 present the results of the cascading mode analysis where the fixed price for a CHP unit is either doubled or tripled respectively. The results reveal that the price variation does not have an impact on the system design but on the NPV as the CHP investment increases. Compared to the main results in Table 3, the model chooses to expand the CHP unit where possible. The CHP unit mostly operates within the subsidised 30,000 full load hours. As the CHP capacity is enlarged, the PV dimensions are smaller, $CO_2$ abatement is and the *SCR* reduces as more electricity is fed into the grid.

The results are of economic relevance for a real life application. There exist technologies like natural gas driven fuel cells, that offer a lower minimum load than conventional CHPs. Nonetheless, the investment is much higher. The results in Table C.11 and C.12 indicate that the investment in a CHP unit with double or triple the fixed costs still yields a positive NPV and is favorable compared to a system without a CHP. As the optimal dispatch for a large CHP unit as seen in the main results is rather complex, it might be economically advantageous to pay the higher investment for a system with a low minimum load. This allows for a more flexible operation and avoids uncertainty risks.

| KPI | Unit | REF | CHP | PV_ CHP | CHP_ HP | COMBI | COMBI_ EV | COMBI_ EVopt |
|---|---|---|---|---|---|---|---|---|
| $NPV$ | $k€$ | -13.4 | 37.3 | 39.3 | 41.9 | 45.0 | 55.0 | 59.4 |
| $\Delta NPV$ | $k€$ | - | 50.7 | 52.7 | 55.3 | 58.4 | 68.5 | 72.8 |
| $D_{el,te}$ | MWh/a | 29.8 | 29.8 | 29.8 | 29.8 | 29.8 | 36.8 | 36.9 |
| $D_{el,hp}$ | MWh/a | - | - | - | 17.2 | 18.8 | 17.6 | 18.6 |
| $D_{el,tot}$ | MWh/a | 29.8 | 29.8 | 29.8 | 47.0 | 48.7 | 54.5 | 55.4 |
| $cap_{PV}$ | kW | - | - | 5.8 | - | 8.1 | 12.0 | 12.7 |
| $cap_{CHP}$ | kWel | - | 50.0 | 50.0 | 32.8 | 30.8 | 32.3 | 31.1 |
| $cap_{HP}$ | kWth | - | - | - | 11.0 | 11.7 | 11.3 | 11.7 |
| $cap_{HS}$ | kWh | - | 40.0 | 40.6 | 47.4 | 50.8 | 50.1 | 41.4 |
| $cap_{boil}$ | kWh | 60.3 | - | - | - | - | - | - |
| $P_{chp,max}$ | kW | - | 40.1 | 40.1 | 32.8 | 30.8 | 32.3 | 31.1 |
| $h_{chp,full}$ | hours | - | 30184 | 30189 | 30000 | 30000 | 30000 | 30000 |
| $SCR_{el}$ | % | - | 32.6 | 33.2 | 85.0 | 85.1 | 85.4 | 91.2 |
| $DSS_{el}$ | % | - | 82.5 | 89.9 | 88.9 | 93.7 | 92.8 | 95.5 |
| $DA_{el}$ | % | - | 253.2 | 270.8 | 104.6 | 110.1 | 108.7 | 104.8 |
| $GII$ | % | - | 19.5 | 19.6 | 10.6 | 11.2 | 10.9 | 9.9 |
| $GII_{norm}$ | % | - | 125.5 | 126.5 | 57.4 | 60.3 | 80.0 | 94.0 |
| $CO_{2,ref}$ | t | 659.3 | 659.3 | 659.3 | 659.3 | 659.3 | 688.9 | 688.9 |
| $CO_{2,opt}$ | t | 659.3 | 888.6 | 879.5 | 586.8 | 544.0 | 572.1 | 545.6 |
| $\Delta CO_2$ | t | - | -229.3 | -220.1 | 72.6 | 115.3 | 116.7 | 143.3 |
| $CO_{2,export}$ | t | - | 318.7 | 334.1 | 46.3 | 44.8 | 43.0 | 32.0 |
| $\Delta CO_{2,export}$ | t | - | 105.4 | 108.0 | 15.3 | 11.4 | 6.8 | 10.6 |
| $CF_{subs}$ | $k€$ | - | 136.9 | 142.6 | 61.5 | 61.9 | 66.1 | 61.6 |
| $cac_{subs}$ | $€/t_{CO2}$ | - | - | - | 847.7 | 536.8 | 566.5 | 430.1 |

Table C.11: Results for component wise analysis sorted by $\Delta NPV$, cascading mode with double the fix price for CHP representing a system with two CHP-units

## SI D. PV remuneration

To determine the amount of remuneration for PV electricity, the REL 2021 introduces three pricing levels that result in the following subsidies for the 1st of January 2021:

- Up to a PV capacity of $cap_{pv} <= 10\,kW_p$ the feed-in tariff is $8.56\,ct/kWh$ and the SCP is $3.79\,ct/kWh$
- For a PV capacity of $10\,kW_p < cap_{pv} <= 40\,kW_p$ the feed-in tariff is $8.33\,ct/kWh$ and the SCP is $3.52\,ct/kWh$
- For a PV capacity of $40\,kW_p < cap_{pv} <= 750\,kW_p$ the feed-in tariff is $6.62\,ct/kWh$ and the SCP is $2.37\,ct/kWh$

The prices for the different levels are taken into account proportionally. As an example,

| KPI | Unit | REF | CHP | PV_CHP | CHP_HP | COMBI | COMBI_EV | COMBI_EVopt |
|---|---|---|---|---|---|---|---|---|
| $NPV$ | $k€$ | -13.4 | 22.3 | 24.4 | 26.9 | 30.3 | 40.0 | 44.3 |
| $\Delta NPV$ | $k€$ | - | 35.7 | 37.8 | 40.3 | 43.7 | 53.4 | 57.7 |
| $D_{el,te}$ | MWh/a | 29.8 | 29.8 | 29.8 | 29.8 | 29.8 | 36.8 | 36.9 |
| $D_{el,hp}$ | MWh/a | - | - | - | 17.2 | 18.8 | 17.2 | 18.6 |
| $D_{el,tot}$ | MWh/a | 29.8 | 29.8 | 29.8 | 47.0 | 48.6 | 54.1 | 55.4 |
| $cap_{PV}$ | kW | - | - | 5.8 | - | 8.2 | 10.0 | 12.8 |
| $cap_{CHP}$ | kWel | - | 50.0 | 50.0 | 32.8 | 30.8 | 32.7 | 31.1 |
| $cap_{HP}$ | kWth | - | - | - | 11.0 | 11.7 | 11.1 | 11.7 |
| $cap_{HS}$ | kWh | - | 42.5 | 40.5 | 46.3 | 44.4 | 50.0 | 41.7 |
| $cap_{boil}$ | kWh | 60.3 | - | - | - | - | - | - |
| $P_{chp,max}$ | kW | - | 40.1 | 40.1 | 32.8 | 30.8 | 32.7 | 31.1 |
| $h_{chp,full}$ | hours | - | 30188 | 30191 | 30000 | 30000 | 30000 | 30000 |
| $SCR_{el}$ | % | - | 32.7 | 33.3 | 84.8 | 85.0 | 85.9 | 91.0 |
| $DSS_{el}$ | % | - | 82.7 | 90.1 | 88.9 | 93.4 | 92.3 | 95.4 |
| $DA_{el}$ | % | - | 253.2 | 270.7 | 104.9 | 109.9 | 107.4 | 104.9 |
| $GII$ | % | - | 19.5 | 19.6 | 10.6 | 11.4 | 10.5 | 10.0 |
| $GII_{norm}$ | % | - | 125.5 | 126.6 | 57.6 | 62.2 | 77.7 | 90.5 |
| $CO_{2,ref}$ | t | 659.3 | 659.3 | 659.3 | 659.3 | 659.3 | 688.9 | 688.9 |
| $CO_{2,opt}$ | t | 659.3 | 888.4 | 879.3 | 587.5 | 543.5 | 581.0 | 545.8 |
| $\Delta CO_2$ | t | - | -229.1 | -219.9 | 71.8 | 115.8 | 107.8 | 143.1 |
| $CO_{2,export}$ | t | - | 318.3 | 333.5 | 47.0 | 45.6 | 44.2 | 32.8 |
| $\Delta CO_{2,export}$ | t | - | 105.3 | 107.9 | 15.5 | 12.0 | 9.9 | 10.8 |
| $CF_{subs}$ | $k€$ | - | 136.8 | 142.5 | 61.7 | 61.9 | 66.0 | 61.7 |
| $cac_{subs}$ | $€/t_{CO2}$ | - | - | - | 859.3 | 534.1 | 611.7 | 431.4 |

Table C.12: Results for component wise analysis sorted by $\Delta NPV$, cascading mode with **triple** the fix price for CHP representing a system with three CHP-units

Equation D.1 illustrates the resulting feed-in tariff for a PV system of 50 $kW_p$.

$$\begin{aligned} c_{pv,feedin} &= \left[\frac{10}{50} \cdot 8.56 + \frac{40-10}{50} \cdot 8.33 + \frac{50-40}{50} \cdot 6.62\right] ct/kWh \\ &= 8.03\ ct/kWh \end{aligned} \tag{D.1}$$

For this study to depict that proportional pricing system, we divided the range of possible PV capacities between 0 $kW_p$ and 100 $kW_p$ into 19 remuneration schemes. This is further mentioned in Section 3.2 in Equation 5 and Equation 6, and shown in Table A.8. For calculating the remuneration scheme, we used the mean capacity of the lower and upper limit of the respective remuneration scheme. For example, for remuneration scheme 10, we calculated the price level for a mean PV capacity of 52.5 $kW_p$.

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