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Impact of energy communities on the European electricity and heating system decarbonization pathway: Comparing local and global flexibility responses

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ABSTRACT

This paper investigates how the European electricity and heating system is impacted when medium-scale energy communities (ECs) are developed widely across Europe. We study the response on the capacity expansion of the cross-border transmission and national generation and storage within the European electricity and heating system with and without ECs in selected European countries. The representation of ECs has a special focus on flexibility, and we analyze the difference between flexibility responses by ECs towards local versus global cost minimization. Results show that EC development decreases total electricity and heating system costs on the transition towards a decarbonized European system in line with the 1.5 °C target, and less generation and storage capacity expansion is needed on a national scale to achieve climate targets. We also identify a conflict of interest between optimizing EC flexibility towards local cost minimization versus European cost minimization.

1. Introduction

In addition to measures substantially decreasing energy demand, cost-effective decarbonization of the European electricity system requires high shares of variable renewable energy sources (VRES) and increased electricity market trading between European countries [1]. Simultaneously, energy communities (ECs) are developing as part of the large-scale energy transition [2]. We define ECs as a group of buildings with low-carbon technologies to supply, store, and internally share/trade electricity and heating. Distributed resources in ECs have increasingly favorable economics [3], and novel proposals for community-based markets are emerging [4].

As buildings make up about 40% of final energy consumption in the European Union (EU) [5], successful building renovation and decarbonization of heating systems will significantly impact the central European electricity system. EU climate goals demand the reduction of current fossil fuel use in European buildings implying an increased use of alternative energy carriers [6], including electricity [7]. More electricity use within buildings, combined with the increased potential for demand side management (DSM) [8], enables the building sector to become so-called energy hubs [9]. Energy services within buildings with certain flexibility can be smartly dispatched towards optimizing economic and environmental parameters [10], including maximizing self-consumption of local energy production [11] and minimizing peak load [12]. In this paper, we define the decisions on how to operate some distributed energy resources within the ECs as the community's *flexibility responses*, i.e., the net operational plan for energy resources in response to an economic and/or environmental objective.

It is still unclear how the development and operation of ECs will impact the central electricity system [13], and most previous research on future large-scale electricity system development do not consider operational details from the building sector. This paper therefore addresses the response on the capacity expansion of the cross-border transmission and national generation and storage within the European electricity and heating system with and without a wide development of ECs across the EU.

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Abbreviations

ASHP	Air-sourced heat pump
CE	Capacity expansion
CHP	Combined heat and power
DER	Distributed energy resources
DSM	Demand-side management
EC	Energy community
EOP	Electricity only plant
EU	European Union
HOP	Heat only plant
IntFlex	Case study instance with integrated flexibility from energy communities on a European level
MEC	Model energy communities
OSM	Open-source model
PV	Photovoltaic
SiteFlex	Case study instance with on-site flexibility responses from energy communities on a local level
VRES	Variable renewable energy sources

The regulatory framework in ECs will impact the optimization of the community's flexibility responses as defined above. In particular, regulations regarding the grid tariff design [14] and the presence of energy systems aggregators [15] will have large implications on the flexibility responses of ECs. Ferro et al. [16] develop a framework where an aggregator can coordinate and incentivize flexibility responses from multiple microgrids and buildings towards participation in a balancing market. To our knowledge, no existing research has studied the difference between optimized flexibility responses from ECs deciding their own operations versus optimized flexibility responses from a collection of ECs deciding its operations via an aggregator. Thus, this paper addresses the difference in capacity expansion of the cross-border transmission and national generation and storage within the European electricity and heating system with and without the presence of national aggregators for ECs across the EU.

We use the capacity expansion model EMPIRE [17] to analyze the baseline transition pathway for the European electricity and heating system towards 2060 in line with the Paris agreement [18]. The main benefit of the EMPIRE model is the consolidation of (1) long-term investments, (2) short-term operations, (3) short term uncertainty, and (4) coupling between electricity and heating [17]. Consolidating these four aspects enables us to represent key energy carriers in ECs (electricity and heat) with an hourly resolution. The baseline produced by EMPIRE assumes growing electricity demand resulting from a wide electrification of society, and the results include technology mix on a national level.

Based on the resulting mean of future electricity prices and CO2 intensities from the EMPIRE baseline, we use the open-source GUSTO model [19] to analyze cost optimal electricity and heating system designs for future ECs on the neighborhood level in different European countries, including Norway, Austria, Spain, Portugal, France, and Poland. Particularly, we used four different model ECs (formed by 10–12 individual buildings) in order to adequately represent the existing building stock in the countries. The main benefit of the GUSTO model in this analysis is that the model allows to investigate the energy technology investment decision and energy dispatch at the local level. In addition to local electricity and heating system design, GUSTO also produces hourly profiles on net grid interactions between the ECs and the connected electricity and heating system.

Based on the GUSTO results, we analyze how European capacity expansion in EMPIRE is impacted when national load profiles are modified according to a wide national EC development in selected European countries. We further study how local electricity storage within the ECs are operated towards cost minimization on the European level with an aggregator versus cost minimization on the neighborhood level without a national aggregator to compare the flexibility responses towards two different objectives.

We address the following research questions:

1. How does a large scale roll-out of ECs across Europe affect centralized investments in the European electricity system, as well as within national heating systems?
2. How does a large scale aggregation and utilization of EC flexibility on the European level impact investments in the European electricity system and national heating systems?

For the first question, we compare two cases of EMPIRE: One case representing no development of ECs and another case in which ECs are developed. For the two cases, we present the differences in investments in generation and storage of electricity on a European level and heat on a national level. We also present differences in European cross-border transmission investments. For the second question, we also compare investments in two cases of EMPIRE, and we assume EC development in both cases. In one case, we assume local electricity storage in ECs are operated to minimize costs within each EC, while in the other case, EC storage are aggregated within each country and operated to minimize costs on the European level.

The remainder of the paper is organized as follows: Section 2 presents background for our study and links it to relevant literature. Section 3 presents the structure of the mathematical programs, the input data, and the assumptions of our study. Section 4 presents and discusses the results, before Section 5 concludes the paper.

2. Background

This section gives a comprehensive overview of the most relevant aspects for ECs and their role in future energy systems. As a starting point, Section 2.1 describes ECs in general, places them in a historical context, and elaborates on their theoretical potentials and development pathways. The literature shows that a large-scale growth of ECs across Europe will provide opportunities and benefits but requires adaptions in the energy systems. However, Allan et al. [3] highlight that there is a lack of existing literature that specifically addresses the impact of local energy supply on higher-level centralized investment decisions. Section 2.2 addresses a core benefit of ECs, namely, the provision and utilization of flexibility options. In particular, Section 2.2 presents work that addresses both the differences in local versus centralized utilization of local small-scale flexibility options and methods that enable the aggregation of these onto higher levels. Finally, Section 2.3 presents relevant work analyzing the future large-scale electricity and heating systems, and how they can sufficiently represent techno-economic future scenarios that cost-efficiently respect climate policy.

2.1. Energy communities in a sustainable energy transition

Since the European Commission published the legislative package entitled 'Clean Energy for All Europeans' in 2016, many research projects have been focusing on its impact on the future European energy system [20,21]. The package has a special focus on renewable energy, energy efficiency, and empowering consumers, which has led to an increased interest in energy communities (EC) [2]. ECs in this work are defined as multi-carrier energy systems connecting several residential buildings focusing on meeting their electricity and heat demand cost-effectively [22]. Literature, however, shows various EC definitions related to its building stock composition. Exemplarily the work by Fina et al. [23] includes also small commercial buildings. In any case, ECs aim for both high shares of on-site renewable generation (e.g., rooftop and building-integrated PV systems [24]) and increased energy efficiency (e.g., by building stock renovation [25]). Soeiro and Dias [26] find that the main motivations to establish renewable ECs around Europe are related to environmental and climate impacts. Inês et al. [27] find that changing regulations are providing increasing opportunities for ECs in several European countries. Based on this, we anticipate that many ECs will develop in Europe in the next decades (see for example in [28,29]).

In general, ECs are a relatively novel form of participation in the energy system, but they have recently become important in the sustainable energy transition [30]. Different techno-economic, socio-economic, and policy-related achievements made this pivotal role possible [31]. Numerous scientific literature investigate a broad range of implications in the context of ECs [32], including their profitability [23,33], their potential to integrate distributed renewable sources into energy systems [2], and their potential to reduce local greenhouse gas emissions [34,35].

Historically, microgrids have been an integral part of ECs. However, the common understanding of ECs now goes beyond microgrids [36]. The work by Zwickl-Bernhard and Auer [19] comprehensively addresses the similarities and differences between microgrids and ECs. Note that the ECs within this work are defined considering a physical grid connection and hence coincide with microgrids.

In general, an EC is formed by aggregating individual prosumers [37]. Considering demand load profile, renewable generation potentials, and building stock characteristics, the EC enables taking advantage of local synergies [11], while applying a holistic approach [38]. Thus, besides efficiency-enhancing effects, high shares of local renewable generation technologies and the optimal utilization of flexibility options such as small-scale battery storage [39] and sector coupling are provided [40].

Given the different characteristics of prosumers, it is also crucial to note that individual incentives to participate in the EC can vary widely [41]. Zwickl-Bernhard and Auer [42] identify profit maximization, boosting local self-reliance, and enhancing system stability to be relevant incentives, and describe these incentives in detail, including their historical context.

As the preceding discussion shows, a key benefit of ECs is their ability to exploit local synergies due to participant diversity. Simultaneously, the optimal supply of local energy services varies depending on the perspective taken [12]. It is still unclear whether the optimal energy services supply from a higher-level perspective (e.g., aggregator/system or national level) will differ significantly from the local perspective. We hypothesize that there is a difference in the optimal energy technology investment decisions with global, national, regional, or local perspectives. A comprehensive understanding of these differences and related trade-offs among local energy service provision and supply from outside the area (e.g., district heating and cooling) are crucial for a coordinated sustainable energy transition.

There is a lack of research that sufficiently examines all of these aspects. Bringing the different perspectives together, namely, the system/aggregator, national, and (local) neighborhood level, enables both a sustainable and self-reliant energy provision (see for example [43] or [44]). The latter demonstrates a trend-setting regional attempt to create energy cooperation related to national (higher-level) resource dependencies. In light of the identified lack of scientific literature on the wide implementation of ECs and their impact on the higher-level energy system, this work may be considered a pioneering attempt.

2.2. Aggregation and flexibility responses with different objectives

Flexibility options for energy systems are manifold. Lund et al. [8] list grid reinforcement and expansion, flexible dispatchable power plants, energy storage, sector coupling, energy markets and DSM. Demand and supply side flexibility, sector coupling through power-to-gas or power-to-heat, and energy storage can be provided centrally with large-scale technologies or by distributed small-scale applications. Large scale flexibility options are already included in EMPIRE [17,45] and similar tools to investigate the future development of energy systems with a high penetration of VRES. Although the potential for distributed flexibility is significant, it is yet unclear for what purpose the flexibility should be utilized and how flexibility responses differ with different objectives. In this work, we study the impact of further expansion and system integration of decentralized flexibilities in general and ECs in particular.

In a perfectly competitive electricity market, profit maximizing decisions in smaller firms will also maximize social welfare given complete and correct price signals [46]. This is also true in electricity systems with VRES and electricity storage [47]. In reality, the challenge is to ensure that flexibility providers are faced with a complete and correct price signals, including production prices, grid prices, and pollution prices. Eid et al. [48] review different applications, incentives, and market designs for flexibility management of DER. Schwabeneder et al. [49] provide a classification for demand response and investigate the impact of different general flexibility characteristics on the profitability of load shifting. They highlight that market-driven flexibility optimization does not necessarily yield a reduction in carbon emissions of the electricity system. Nolting and Praktiknjo [50] conduct a techno-economic analysis of flexible heat pump controls and find that economic and environmental efficiency are in conflict. This is supported by Fleischhacker et al. [34] who optimize the portfolios of ECs with different objectives. They conclude that solutions for minimum cost and minimum carbon emissions are contrary to each other. Schwabeneder et al. [51] investigate business cases for aggregators of residential customers with flexible technologies in different European electricity markets. They show that neglecting household specific cost in the optimization of an aggregators portfolio can yield sub-optimal results.

These findings suggest that individual objectives from a private perspective and the objectives from a system perspective may not always coincide without complete and correct prices. This poses a challenge for the integration of distributed flexibilities in a system analysis framework. The computational complexity of a capacity expansion planning model for multiple European countries that considers a high number of distributed small-scale flexibility options represents another challenge. It can be tackled by aggregating all flexibilities at a country or node level and simplifying their representation in the optimization model. Müller et al. [52] provide a generic approach for this purpose using zonotopic sets: The feasible region of a flexibility option in a linear optimization problem describes a convex polytope. In their approach, they inner-approximate this region by a subclass of polytopes, known as zonotopes, and they show how zonotopes can be aggregated and disaggregated efficiently. The impact of the information loss caused by modified or incomplete objectives for ECs and simplified aggregated flexibility representation in flexibility dispatch models is discussed in Section 3.3.3.

As we have not identified previous research analyzing how distributed flexibility responses from ECs differ when utilized with a European perspective versus an EC perspective, our case study explores this topic. In this paper, we compare: (a) the case where flexibility is optimized by ECs locally according to their own techno-economic target and (b) the case where flexibility is optimized by an aggregator who coordinates the response of all ECs on a national level. We assume that the latter case is feasible in reality by assuming that the techno-economic target in ECs can be modified via an aggregator that links the ECs to the national market, see [16]. Studying the details of the business model connecting ECs to the aggregator is beyond the scope of this paper; we study the impact on investments in the European market given the feasibility of such aggregation.

2.3. Large-scale electricity and heating system decarbonization

There are many modeling tools that analyze the future development of electricity and heating systems in light of strong climate policy. Several tools address large-scale electricity systems, including Europe as a whole. Collins et al. [53] and Ringkjøb et al. [54] review modeling tools that analyze electricity systems with high shares of VRES, and they highlight the challenge to represent short-term variability in long-term models. One promising approach is using representative time periods and stochastic programming, see for example [55,56]. In addition to sufficient temporal details, the consideration of options to balance VRES variability and uncertainty are crucial in long-term models. Brown et al. [57] investigate synergies between transmission expansion and sector coupling, and they find that increased sector coupling can decrease the need for transmission reinforcement. Lund et al. [58] focus on sector coupling between electricity and heat sectors in the Nordic-Baltic region, and further propose regulatory measures that can unlock beneficial sector coupling. Ashfaq et al. [59] analyze integration of the heat sector in a highly renewable European electricity system, and they find that heat pumps are particularly relevant in a pan-European electricity system. Chen et al. [60] investigate the impact of decarbonized building heating in Northern Europe, and they find that increased use of heat pumps for building heating significantly increase wind power development.

Although large-scale models have been adapted to increasingly deal with challenges and opportunities in future electricity systems [54], few large-scale models focus on explicit representation of ECs within large-scale electricity systems. However, some literature explore ECs, or specific assets within ECs, in large-scale models. Seljom et al. [61] analyze the impact of Zero Energy Buildings on the Scandinavian electricity and heating system using a stochastic version of TIMES [62,63], but do not consider potential storage and flexibility by buildings. Backe et al. [17,43] consider the impact of ECs in the European electricity system, but do not consider building heat in [43] and the case study in [17] is limited to considering ECs in Norway. Although there exists several models that are able to represent ECs in a large-scale model, we choose EMPIRE for this paper as an extension of the work in [17, 43] because EMPIRE consolidates long-term investments, short-term operations, operational uncertainty, and power-to-heat linking.

2.4. Progress beyond state of the art

To contribute to the literature above, this paper uses a large-scale model for the future development of the European electricity and heating system in line with the Paris Agreement, and we analyze the impact on investments on the European level by exogenously representing the development of ECs in different countries and climates across Europe. Consequently, this work's progress beyond the state of the art can be summarized as follows:

- First, the development of an integrated electricity and heating system modeling framework by coupling input and output from EMPIRE and GUSTO enables a systematic investigation of a large-scale roll-out of decentralized ECs across Europe in the light of achieving aspired climate goals and carbon neutrality. This approach can be seen as a pioneering attempt to deepen the understanding of centralized and decentralized energy planning decisions. Note that the main novelty of our modeling framework is the context and the linkage between the models; the two models themselves are already existing tools.
- Second, this modeling framework sets out to enhance decentralized (local) energy infrastructure decisions, such as ECs, in a global energy system planning context and make related benefits and trade-offs more apparent. Thereby, the trade-offs are closely linked to interest conflicts by different energy system perspectives (i.e., local and global) on utilization of energy technology/infrastructure. In particular, small-scale flexibility options and its optimal dispatch from the different perspectives are comprehensively analyzed.
- Third, the effects of simplifying the model representation of distributed flexibility options provided by ECs in optimization models are investigated. The implications of aggregating multiple components and disregarding distributed local objectives are analyzed and compared quantitatively. This provides a better understanding of the loss of information due to these simplifications and its effect on model results.

3. Method

This section outlines the methodology, assumptions, and data applied in this paper. We choose to use EMPIRE and GUSTO because of the benefits raised in Section 1, however, Pisciella et al. [64] provide a comprehensive overview of several openly available models that could be adopted in the context of our analysis.

We use EMPIRE [17] as a tool to generate a baseline for the development of the European electricity and heating system. Further, EMPIRE produces input to GUSTO [19] regarding average values on future electricity and CO2 prices that impact EC design. GUSTO is used to produce cost-efficient EC designs for different neighborhood types, countries, and future periods. The results from GUSTO are used to modify EMPIRE input to reflect our assumption about a wide EC development across Europe. Note that the EC development is an exogenous assumption, not an endogenous decision in EMPIRE.

Both EMPIRE and GUSTO consider optimization of flexibility responses as described in Section 2.2. In both models, both capacity expansion and hourly operations are considered as endogenous decisions for different energy resources that could adapt their production or consumption of electricity or heat with some flexibility.

An overview of the overall modeling approach is given in Fig. 1 indicating the spatial resolution of the models as well as the linkage between them. We compare the following three numerical instances in EMPIRE:

- Baseline: EMPIRE without ECs.
- On-site flexibility (SiteFlex): EMPIRE with ECs and EC flexibility optimization in GUSTO.
- Integrated flexibility (IntFlex): EMPIRE with ECs and EC flexibility optimization in EMPIRE.

Section 3.1 introduces the EMPIRE model. Section 3.2 presents the open-source GUSTO model, whereby Section 3.3 shows a detailed description of the linkage between both models.

3.1. The EMPIRE model

EMPIRE [12] is a linear stochastic capacity expansion model supporting long-term investments in the European electricity system on the transition towards decarbonization. An open version of EMPIRE can be downloaded from [65]. In existing literature, the EMPIRE model is used to analyze the development on the European electricity system with large shares of VRES [56,66], the impact of demand response on the future European electricity system [45], and the short-term interactions between the future electricity system, building heating, and electric vehicle charging [17].

EMPIRE models the electricity and heating system as a network, where nodes represent national electricity and heat markets and arcs represent international electricity transmission. Investments are modeled in multiple investment periods in 5-year steps, and there are eight five-year investment periods from 2020–2060. Within each investment period, EMPIRE considers representative operational time periods on an hourly resolution. The operational time periods are split into four

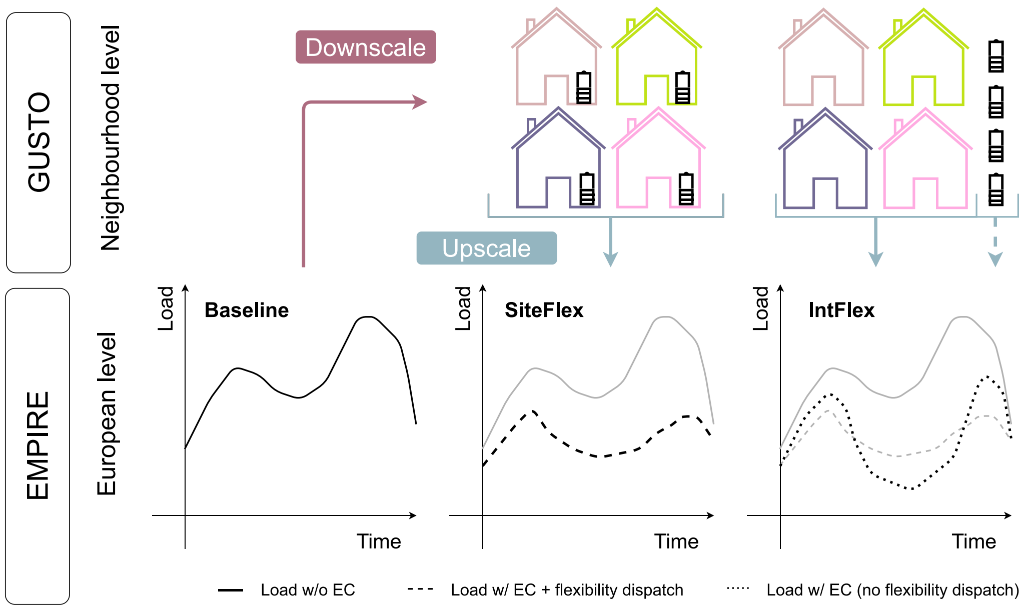


Fig. 1. Overall modeling approach and linkage between the EMPIRE and GUSTO model.

independent regular seasons of 168 representative hours and two independent peak seasons of 24 h. EMPIRE represents uncertainty by having different realizations of short-term demand and renewable energy potential in 10 different operational scenarios for every season and investment period. The consideration of different operational scenarios makes EMPIRE a two-stage stochastic program, where the first stage decisions represent investments and the second stage decisions represent operations. Because EMPIRE includes several investment periods in the same instance, it has a multi-horizon structure as introduced in [67]. A more detailed description of EMPIRE as used in this paper is presented in [17].

The input to EMPIRE defines technical and economic parameters of the European electricity and heating system, including existing asset capacity [68], maximum asset capacity, asset lifetime, operational and investment costs [69], and short-term demand [70]. The objective function of EMPIRE quantifies total electricity and heating system costs, and the objective is minimized with respect to short-term market clearing in every node, up-ramping constraints of thermal plants, short-term availability of VRES, energy balance of storage, and EU wide GHG emission caps. The main output from EMPIRE is total system costs along with the investment decisions in generation, transmission, and storage assets aggregated by node and arc for each investment period. EMPIRE also outputs hourly operational decisions for all representative hours.

We represent the European electricity and heating system with 35 market zones[1] and 85 existing and potential international transmission connections. We consider an annual discount rate of 5% following [66]. The CO2eq. cap is assumed to follow [71][2] from 1 110 to 22 Mton CO2eq. per year from 2020–2060.[3] Note that the CO2eq. cap is defined for each investment period separately, not as a budget for the whole planning horizon. Defining a CO2eq. cap per investment period allows us to extract a shadow value on the carbon cap policy constraint (the carbon price) for each investment period as endogenous output from EMPIRE. Operational emission intensity by technology are according to [73], and we assume no emissions related to renewables, including biomass. In this paper, we do not consider the option of carbon capture and storage technologies nor the production/use of hydrogen.

Short-term availability of VRES is from renewables.ninja [74,75], and short-term load profiles and hydro power availability is based on historical profiles from ENTSO-E [70]. ECs are represented through an exogenous net modification of short-term electricity and heat demand within selected countries. Thus, the energy demand of ECs is assumed to be part of the baseline energy demand in each country in EMPIRE. Building heat profiles in EMPIRE are simulated through [76] based on historical temperature profiles from [77]. Data for VRES, hydro power, and short-term electricity- and heat demand are sampled to produce 10 unique realizations per season and investment period while preserving cross-correlation for the years 2015–2019. All electricity load profiles are scaled to correspond to annual future electricity demand according to results from GENeSYS-MOD [78] and the 'societal commitment' narrative. As a baseline, nationally aggregated final heat demand per country remains at historical levels following [79] assuming decreased building heat demand from renovation cancels out with a net growth in the building stock. Lacking reductions of final building heat demand is assuming business as usual for European building renovation towards 2060: 85–95% of today's buildings will be standing in 2050, and renovation of buildings is currently around 1% [80]. Norwegian building heat demand is scaled following [81]. Electric heat in European countries according to [82] is further subtracted from electricity loads to avoid double counting of heat demand. EMPIRE does not consider cooling loads. The load shedding cost is assumed to be EUR 22 000/MWh for both electricity and heat following [83].

The EMPIRE model is implemented in Python 3.8.6 and uses Pyomo 6.0.1. In this paper, the model is solved with Gurobi 9.1.1 using interior point method (barrier algorithm) without crossover. The operational decisions are resolved in representative weeks and representative peak days with hourly resolution. With four representative seasonal weeks, two peak days, ten stochastic scenarios, and eight investment periods, each node and edge in EMPIRE represent 57 600 hours. The complete numerical instances for EMPIRE contain 95 061 585 continuous variables and 145 138 185 constraints for Baseline and SiteFlex. For IntFlex, the instance size increases to 96 789 905 continuous variables and 147 447 465 constraints because of additional decision variables for EC flexibility responses. All three instances are solved on a computer cluster with 2x 3.5 GHz Intel Xeon Gold 6144 CPU (8 core) and 384 Gb RAM. The solution times are 36 536 s for Baseline, 51 431 s for SiteFlex, and 42 141 s for IntFlex.

[1] EMPIRE represents one market zone per country in the EU-27 minus Cyprus and Montenegro plus Bosnia Herzegovina, Great Britain, North Macedonia, Serbia, Switzerland, and five Norwegian zones representing Nord Pool bidding zones.

[2] See Figure 6 presented by the European Commission [71].

[3] Recent developments [72] suggest that the European Commission will increase its ambition from [71], which should be considered in future work.

3.2. The GUSTO model

The GUSTO model [19] is an open-source model (OSM) that optimizes both the energy technology investment decision (portfolio optimization) and the energy technology dispatch on a local level. It is an extension of the existing OSM *urbs* by [84]. The expansion of the model's framework includes additional features and functionalities for analyzing local energy systems such as ECs. See the authors' previous publication in [19] for a detailed description of the model's extension. The most relevant aspects are briefly discussed in the following.

The extended model is a mixed integer linear program and gives the following objective functions for the neighborhood's perspective: (i) minimizing total (annual) costs of supply, (ii) minimizing total GHG emissions, (iii) maximizing local self-consumption, and (iv) scheduled generation compliance within the neighborhood. Concerning the literature already referred to, the following is more detailed about the latter two objective functions. Maximizing local self-consumption is an essential operational strategy for ECs. Thereby, the optimal utilization of the local flexibility options (e.g., small-scale battery storage) and energy technologies minimize the interaction with the public grid. Note that this corresponds to the dual problem of maximizing local self-consumption. Finally, the objective function (iv) considers scheduled generation compliance of local renewable resources into the public grid. By 'generation compliance' we mean that the EC dispatches local technologies to ensure compliance with declared renewable generation (i.e., due to the participation of the EC on the day-ahead spot market). However, this functionality lies outside of the scope of this paper. The major inputs mainly relate to the description of the ECs in technical and economic terms. These include, among others, local specific heating costs and available technology capacities (e.g., potential availability of a district heating network connection for the EC). Furthermore, the model takes into account the hourly electricity and heat demand profile, available rooftop area, and hourly efficiency profiles (e.g., heat pump coefficient of performance). The main outputs pertain to the local technology investment decision and technology dispatch.

The model includes the provision of multiple local energy services (e.g., electricity, heat, cooling) and the use of commodities. The most important constraint in the model framework is the load satisfaction constraint that ensures that the local energy demand is supplied. The model framework also incorporates temporal and spatial clustering algorithms. The latter is of particular importance in this work, as it enables the upscaling of the local results (energy technology portfolio and dispatch) to the province or the national level (see the detailed description of the upscaling process in Section 3.3.2).

The specific data set for the GUSTO model takes into account the local characteristics of the neighborhoods in each country considered, including electricity and heating demand profile on the building level, the solar radiation, and the electricity/heating prices. The electricity and heating demand profiles on the building level are standard load profiles from [85–87]. Note that the ECs comprise different building efficiency standards represented by a variation of the load profiles in each settlement pattern. The solar radiation is provided by [88,89]. Electricity prices are derived using historical electricity price profiles from [88]. Greenhouse gas emission prices are taken as the endogenous modeling result of the EMPIRE model.

The GUSTO model is implemented in Python 3.6.10 and uses Pyomo 5.6.7. The model is solved with the solver Gurobi 9.0.3. The optimization problem of a single model run (e.g., Norwegian rural EC in the investment period 2025–30) contains 788 500 continuous and 10 binary decision variables. The optimal energy technology investment decision and energy dispatch at the EC level are resolved in an hourly resolution for a single year. The solution time varies between the different model runs but is less than 30 min.

3.3. Linking EMPIRE and GUSTO

The main difference between EMPIRE and GUSTO is related to two dimensions: geographical coverage and time structure. Also note that GUSTO considers cooling demand, which is not considered in EMPIRE. Cooling loads are therefore not part of the linking between EMPIRE and GUSTO.

In terms of geographical coverage, EMPIRE covers most countries in Europe (see Section 3.1), and compared to GUSTO, it includes a simplified representation of all ECs as aggregated assets within single countries. GUSTO captures more details on the EC perspective, and includes less details on the surrounding electricity and heating system compared to EMPIRE. GUSTO also considers details on grid interactions, including price signals produced by grid tariffs. EMPIRE consider cross-border net transfer capacities between European countries, but grid infrastructure within countries is neglected by EMPIRE.

In terms of time structure, EMPIRE considers operations within several representative weeks. EMPIRE further considers long-term investment periods towards 2060, and several representative weeks are allocated to each investment period. GUSTO considers operations within a single representative year, and it does not consider several investment periods. Both models consider hourly operations.

The modeling linking is illustrated in Fig. 2 and explained in the following.

3.3.1. Downscale

As mentioned before, the implementation of ECs in this work leads to a variation of the initial electricity and heat demand in EMPIRE. Thereby, the initial demand profiles are historical data input to EMPIRE. Based on these, the annual demand for the residential sector is obtained. Note that the data set in EMPIRE contains both residential and non-residential heat demand. The latter part cannot be modified by ECs as considered in this paper and thus remains unchanged. The electricity and heating demand profiles on the building level are calculated on the basis of standard load profiles (see also Section 3.2 for a comprehensive description of the input data in the GUSTO model).

The Baseline (Fig. 1) in EMPIRE is solved with the input data as presented in Section 3.1. EMPIRE results from Baseline regarding future average prices is used to solve GUSTO when reflecting future periods. For the electricity prices, hourly profiles for the respective country from the year 2019 from the ENTSO-E Transparency Platform [70] are used. They are scaled to match the mean value of electricity prices from EMPIRE results for the considered investment period.

3.3.2. Upscale

Upscaling enables modeling results at the neighborhood level to be transferred to the national level. Thereby, the modus operandi in this work is in line with [23,33]. In particular, the total existing building stock is represented by so-called model energy communities (MECs). The main steps are as follows. First, the building stock on different spatially resolved levels (e.g., province-level) is analyzed and split into characteristic settlement patterns, namely, single-family households, small multi-apartment buildings, and large multi-apartment buildings. Various sets of these form the above mentioned MECs in a second step (see Table 1). The MECs are *City ECs*, *Town ECs*, *Mixed ECs*, and *Rural ECs*, specifically accounting for different population densities and building stock characteristics (e.g., available rooftop area for PV capacities). Note that we used the definition of the MECs (in terms of its size and number of buildings, energy demand, available energy technologies, etc.) from Fina et al. in [23,33]. Third, after determining the optimal local supply by the optimization model, the neighborhood-level results are multiplied by the corresponding number of implemented ECs and scaled up (see Fig. 3). Further information about the upscale can be found in Appendix A.

Table 1
Set of four model energy communities and their formation by different settlement patterns based on Fina et al. [23].

	Large multi-apartment building	Small multi-apartment building	Single-family household
Number of units per building	10 or more units	3-6 units	1 unit
Population density	high	mid	low
City EC	10	–	–
Town EC	–	10	–
Mixed EC	2	–	10
Rural EC	–	–	10

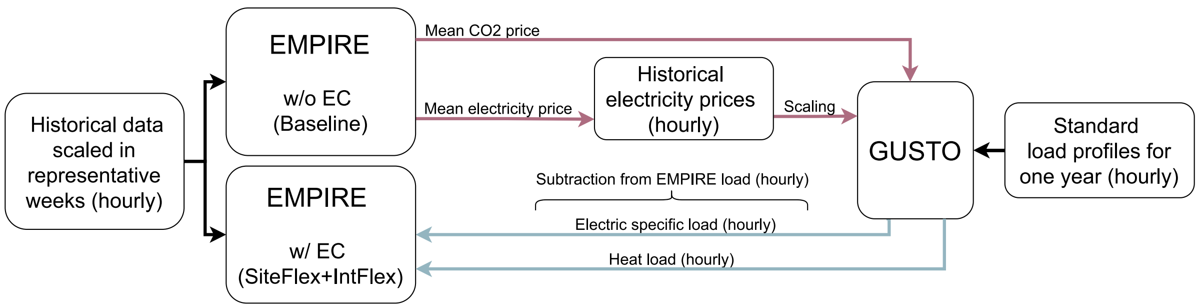


Fig. 2. Illustration of linking between the EMPIRE and GUSTO model for every investment period and country considered.

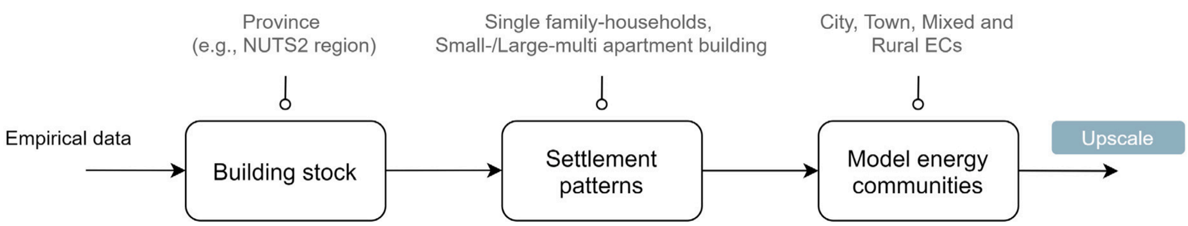


Fig. 3. Procedure for upscaling considering the exisiting building stock, settlement patterns and model energy communities.

3.3.3. Flexibility aggregation

Distributed flexible technologies cannot be considered individually in large-scale capacity expansion models. Thus, distributed storages within ECs are aggregated and represented as large-scale technologies on the country level in EMPIRE.

However, the aggregation yields loss of information, such that EMPIRE may result in aggregated schedules that are different from GUSTO with a more disaggregated and detailed representation of flexible technologies. Furthermore, ECs in the GUSTO model do not only consider market prices in the objective function, but also grid tariffs, fees, and surcharges. Hence, operational decisions in GUSTO might differ from EMPIRE either because: (a) EMPIRE does not consider EC loads in a disaggregated way or (b) EMPIRE does not consider EC grid costs and surcharges.

Fig. 4(a) illustrates the effects of simplified flexibility representations in optimization models along two axes: the level of aggregation of individual components and the incentives considered in the objective function. Fig. 4(b) illustrates how identical or different individual components results in different aggregated representations.

To compare the impact of modifications in the objective function with the impact of simplifications introduced by technology aggregation, we perform a numerical experiment. For further details on the methods and results in this numerical experiment, please refer to Appendix B. In summary, we find that the impact of modifications in the objective function is significantly higher than the effects of the simplifications introduced by technology aggregation. Hence, for the analysis in IntFlex that investigates the operation of EC storage that are endogenously dispatched in EMPIRE, a further refinement of aggregation approaches for different technologies is not considered necessary.

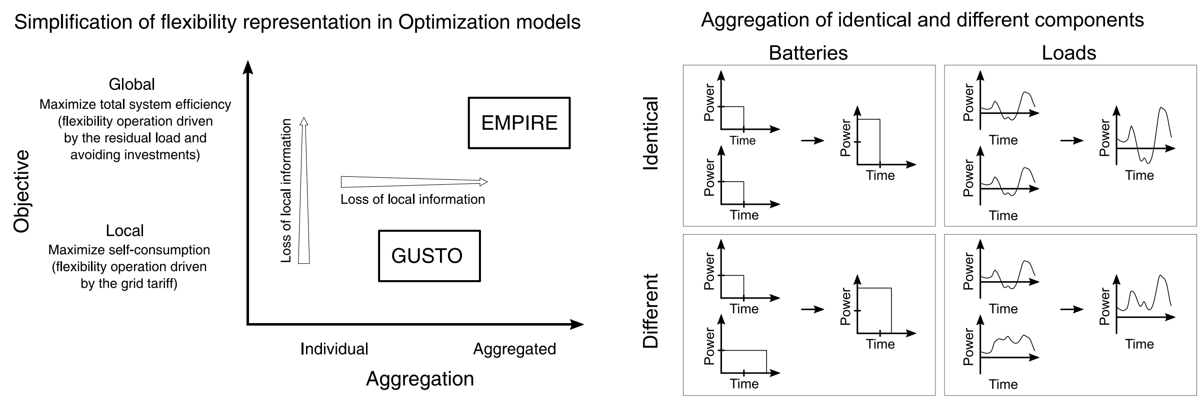
4. Results and discussion

This section presents and discusses the results from the Baseline, SiteFlex, and IntFlex. The main results are presented first, and the following sections elaborate and discuss further results.

The objective function values from EMPIRE represent total system costs from the three cases. The Baseline results in total system costs of EUR 5 776 billon, SiteFlex in EUR 5 745 billion, and IntFlex in EUR 5 742 billion (see Table 2). Thus, the development of ECs makes it more cost-efficient to develop the European electricity and heating system towards 2060. Note that this claim is not including the cost of developing ECs, i.e., the upscaled costs from the GUSTO model (see Section 4.4). Although there are most cost savings from making EC storage dispatch endogenous in EMPIRE (IntFlex), the cost savings from Baseline to SiteFlex (−0.5%) are larger than cost savings from SiteFlex to IntFlex (−0.1%).

4.1. EMPIRE baseline

Fig. 5(a) presents results from EMPIRE on the development of the European electricity system for the Baseline in terms of expected output by source. Recall the assumption that Europe meets its climate targets by 2050 [71] and that annual electricity use grows in line with GENeSYS-MOD results [78] and the 'societal commitment' narrative. EMPIRE results in a massive capacity expansion of solar PV, onshore wind, and offshore wind towards 2040, and more than 50% of electricity is produced by wind and solar after 2030. This requires massive investments: wind and solar produced 14% of European electricity in 2018 [68]. After 2040, 80–85% of European electricity production is wind or solar, while the rest is produced primarily with biomass and hydro power. Electricity produced by fossil fuels are largely phased



(a) Loss of information when aggregating flexibility. (b) Aggregation of batteries and loads.

Fig. 4. Illustration of the concepts investigated for aggregating the EC flexibility.

Table 2
Objective function values and total capacity expansion (CE) from 2020–2060 in EMPIRE by case.

Case	Objective [EUR]	CE generation [GW]	CE storage [GW]	CE transmission [GW]
Baseline	5.776e+12 (0.0%)	7 881 (0.0%)	2 062 (0.0%)	118 (0.0%)
SiteFlex	5.745e+12 (−0.5%)	7 828 (−0.7%)	2 053 (−0.4%)	118 (0.0%)
IntFlex	5.742e+12 (−0.6%)	7 819 (−0.8%)	2 019 (−2.1%)	118 (0.0%)

out by 2045 due to ambitious climate targets, and nuclear is gradually phased out due to large investment costs compared to VRES. Note that the phase-out of nuclear is an endogenous decision, not a constraint in the model. By 2060, 1 162 TWh of annual VRES electricity production is curtailed, which is 16% of total annual electricity production. Note that EMPIRE does not consider alternative use of surplus electricity production, e.g., hydrogen production.

Fig. 5(b) presents expected building heat production by source in the Baseline. Already from 2025, electricity-based heating dominates the market, with air-sourced heat pumps (ASHP) supplying more than 50% of heating demand. This implies a massive capacity expansion of heat pumps as electricity-based heating met about 12% of heating demand in EU28 in 2010 [90]. Note that Fig. 5(b) presents final heat supply; primary heat supply is significantly reduced with heat pumps. The large share of electricity-based heating is mainly driven by binding emission constraints in EMPIRE limiting the opportunity to use fossil fuels for heating. By 2040, building heat is primarily provided via electricity, waste, and biomass, and bio-based heating replaces waste-based heating by 2050 due to emission constraints. If waste-based heating can be combined with carbon capture and storage at similar costs as bio-based heating, it would be an equivalent option to bio-based heating in EMPIRE.

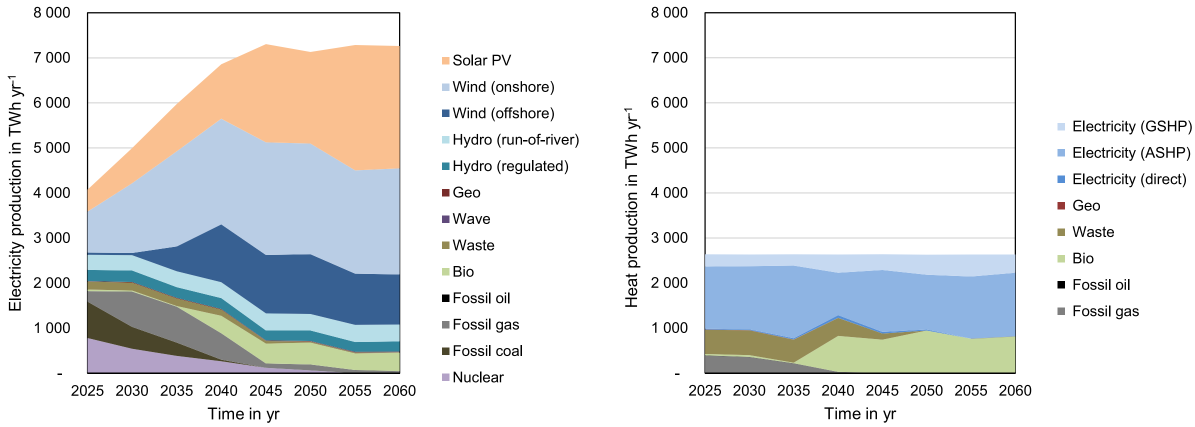
Fig. 6 presents total European storage capacity installed in future time periods in the Baseline. The bars in Fig. 6 represent energy storage capacity and the crosses represent charge/discharge capacity. There is no capacity expansion of pumped hydro storage towards 2060, while there is major capacity expansion of hot water storage and lithium-ion batteries. As the cheaper option, hot water storage expands to dominate total storage capacity by 2040 and plays an important balancing role in the electricity system through flexible use of heat pumps. From 2040, lithium-ion batteries expand greatly. While hot water storage continues to dominate European storage capacity, lithium-ion batteries dominate European charge/discharge capacity from 2040. By 2060, total electricity and heat storage capacity represents 0.3% of European electricity demand. Note that EMPIRE does not consider seasonal storage.

Fig. 7 presents net transfer capacity expansion between all nodes for future time periods in the Baseline. All transmission capacity expansion happens before 2045, after which European electricity demand stabilizes (see Fig. 5(a)). EMPIRE defines a maximum allowed expansion of cross-border transmission, which is fully developed. By 2045, the total European cross-border expansion is 118 GW, where the largest expansion is between Germany and France (14 GW), Great Britain and France (8 GW), and Sweden and NO1 (7 GW). EMPIRE results for the Baseline are closely aligned with system needs presented by ENTSO-E in 2020 [91]: ENTSO-E presents 35 GW new capacity by 2025, 50 GW additional capacity between 2025 and 2030, and 43 GW between 2030 and 2040. Note that results represent cross-border transmission capacity expansion, and required grid investments within European countries are neglected in EMPIRE.

4.2. Energy community design in GUSTO

Fig. 8 shows the highlights of the EC results. In detail, Fig. 8(a) presents the local self-reliance for the different MECs in the three relevant investment periods. Note that these are balance sheet results. Comparing the three different investment periods, it is evident that the local self-reliance increases for each MEC. The main reason is the profitability of a heating system replacement. In the first investment period, the main driver is on-site PV generation. The existing heating system supplies a large part of the heat demand. In the latter two investment periods, the ECs also invest in a heating system (mainly heat pump). Hence, the share of local self-reliance increases significantly. Fig. 8(b) shows the annual duration line for the residential heat demand in Austria. Note that a share of 50 % implemented ECs is reached in the last investment period. The implementation of ECs significantly reduces the peak heat load and total heat demand. In addition, Fig. 8(c) shows the electricity and heat electricity demand modification by 50 % implemented ECs in Austria. The electrification of the heat demand supply within the ECs leads to a significant increase of the electricity demand.

Fig. 9 presents the implemented storage capacities in the ECs. Note that the composition/diversity of the prosumers within the ECs can be seen as a short-term flexibility option (energy sharing within the local area). Therefore, no short-term, small-scale batteries are installed. However, the ECs invest in hydrogen storage. This flexibility option is used as seasonal storage in the highly electrified neighborhoods. Fig. 9(a) shows the development of hydrogen storage in the different investment periods and countries. France and Spain have the highest share of hydrogen storage installed. Fig. 9(b) presents in detail the storage capacity distribution in the different MECs for the last investment period.



(a) Electricity (b) Heat

Fig. 5. Development of expected annual electricity and heat generation by source for all nodes in EMPIRE in the Baseline.

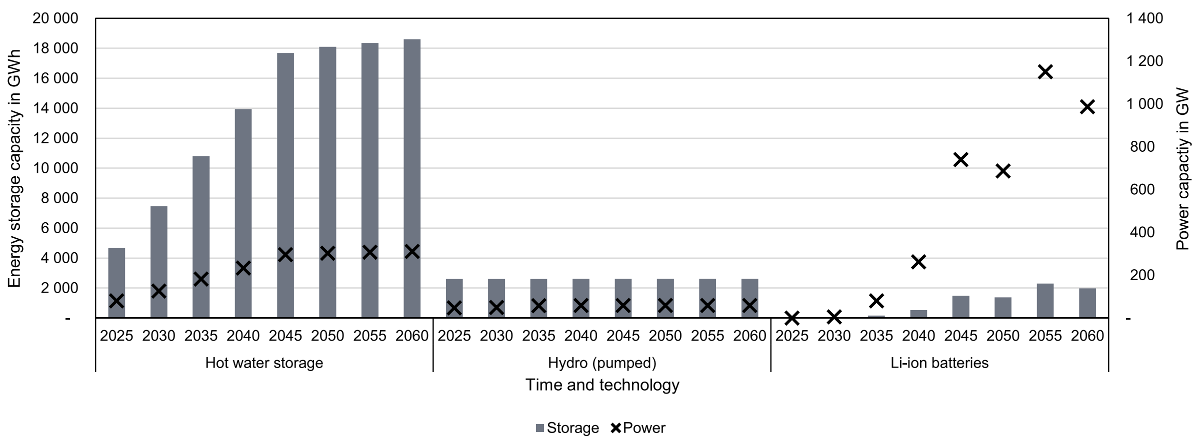
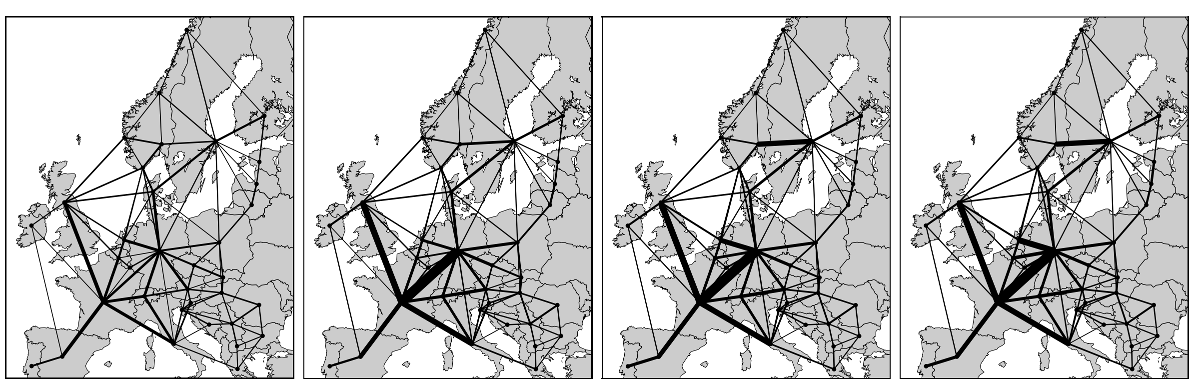


Fig. 6. Development of net storage capacity by technology for all nodes in EMPIRE in the Baseline.



(a) 2020-2025 (b) 2025-2030 (c) 2030-2035 (d) 2035-2040

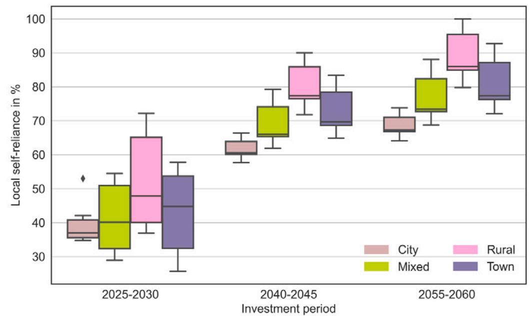
Fig. 7. Illustration of net transfer capacity between nodes in EMPIRE from 2020–2040 in the Baseline.

4.3. Energy community impact in EMPIRE (SiteFlex and IntFlex)

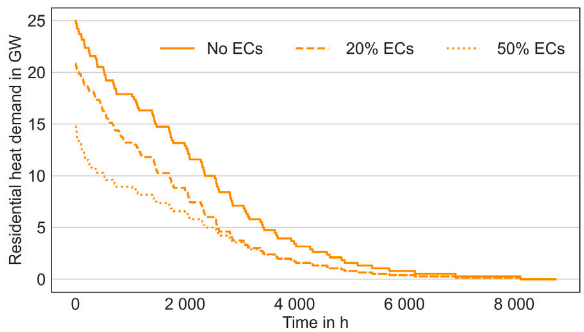
This section focuses on presenting the difference in SiteFlex and IntFlex in EMPIRE compared to the Baseline (see Section 4.1).

In SiteFlex and IntFlex (Fig. 1), we modify EMPIRE load profiles with upscaled results from GUSTO for each five-year investment period in EMPIRE after 2025. The load profile modification is assumed in three steps: 2% of residential buildings are ECs in 2025–2040, 20% in 2040–2055, and 50% in 2055–2060. The load profile modification is similar to the approach of Seljom et al. [61] who run a stochastic capacity expansion model with modified input profiles to represent the introduction of Zero Energy Buildings in Scandinavia.

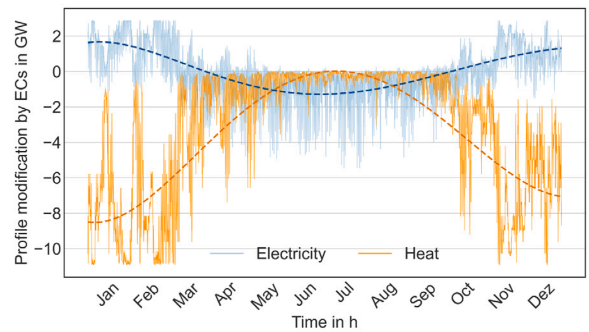
In IntFlex, we additionally assume free flexibility capacity from ECs in EMPIRE. IntFlex also includes modifying electricity and heat load profiles like SiteFlex, but the profile modifications do not include storage operations as optimized by GUSTO. Note that we still assume



(a) Local self-reliance of the MECs in three investment periods

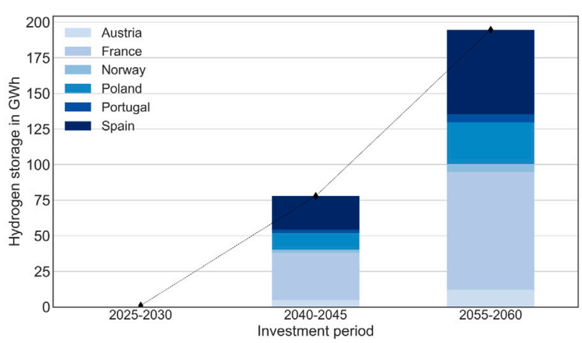


(b) Residential heat demand including EC development



(c) Profile modification by 50 % ECs

Fig. 8. MECs local self-reliance in 8(a), heat demand reduction in Austria by different shares of ECs in 8(b), and demand profile modification in Austria in 8(c).



(a) Hydrogen storage capacities

(b) Distribution among MECs in 2055-2060

Fig. 9. Implemented hydrogen storage capacities in the different investment periods in 9(a) and hydrogen storage capacity distribution among the MECs for the last investment period.

that storage is part of the ECs in EMPIRE according to upscaled GUSTO results; the difference from SiteFlex is that the aggregated storage capacity from ECs is endogenously dispatched in EMPIRE with a European perspective, reflecting the assumption that flexibility response is provided by ECs via a national aggregator.

For cross-border transmission in EMPIRE, there is no difference in capacity expansion between the three cases (Table 2). The maximum allowed transmission capacity expansion in EMPIRE is maximized by 2045 in all cases (Fig. 7), while most ECs are developed after 2045. It is therefore unclear whether ECs would impact transmission expansion if we would assume more EC development before 2045.

For generation and storage assets, the development of ECs has a significant impact on capacity expansion in EMPIRE. SiteFlex and IntFlex result in 50 and 60 GW net reduction of generation capacity expansion outside ECs compared to the Baseline, respectively (Table 2). Fig. 10 presents the difference in generation capacity expansion from the Baseline by case and technology, not including capacity within ECs.

Not surprisingly, there is reduced capacity expansion of solar PV and heat pumps in EMPIRE in SiteFlex and IntFlex compared to the Baseline (Fig. 10) as these technologies are part of the ECs and largely shape the EC modification in EMPIRE (Fig. 8(c)).

In SiteFlex and IntFlex, the ECs shift investments from onshore wind towards offshore wind compared to the Baseline (Fig. 10). The shift happens mainly from south to north: Spain develops 8 GW less onshore wind in SiteFlex compared to the Baseline and 11 GW less in IntFlex compared to the Baseline. Less onshore wind capacity is compensated by the same capacity built offshore in France and Great Britain in both SiteFlex and IntFlex. Recall that ECs are assumed to develop in Spain and France, but not in Great Britain, which indicates spill-over effects in European countries that do not develop ECs. IntFlex causes more generation capacity expansion of offshore wind compared to SiteFlex as the ECs use their flexibility to absorb more offshore wind, and less generation capacity expansion of solar PV and onshore wind is developed in IntFlex compared to SiteFlex. The difference between

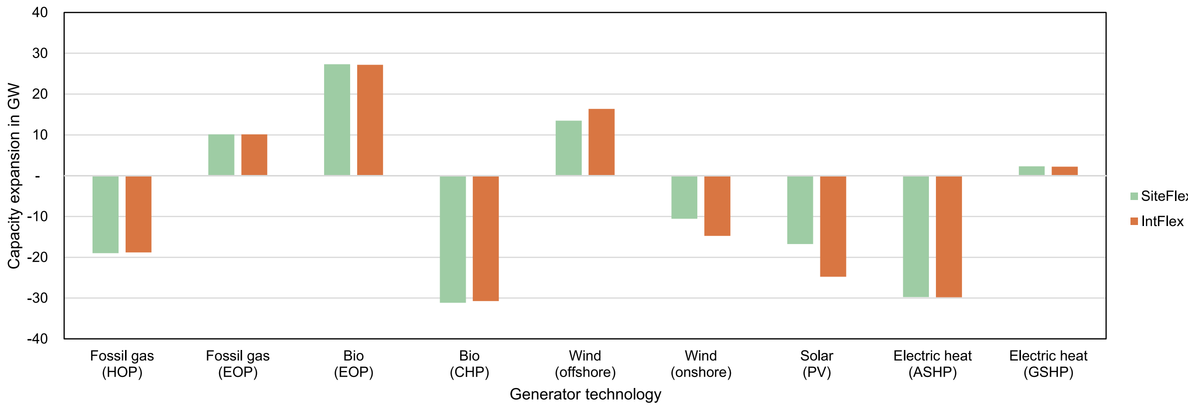


Fig. 10. Difference in generation capacity expansion for all nodes and periods in SiteFlex and IntFlex compared to the Baseline by technology. EOP = electricity-only plant, HOP = heat-only plant, CHP = combined heat and power plant.

onshore and offshore wind in EMPIRE is the investment cost and the hourly availability profiles. Since offshore wind has higher investment costs, the growth in offshore wind in SiteFlex and IntFlex compared to the Baseline is triggered by an overall better fit between offshore production profiles and load profiles with ECs across Europe. This is related to ECs raising electricity demand during winter (Fig. 8(c)), and offshore wind has better capacity factor than onshore wind, especially during winter. Note that in all cases, investment costs for both onshore and offshore wind decreases in line with [69].

The introduction of ECs decreases both total electricity and heat production in EMPIRE. The ECs cause less expansion of heat production capacity in EMPIRE, however, they cause more expansion of electricity production capacity to meet increased electricity demand during winter (Fig. 8(c)). Thus, ECs cause a 3% increase in total VRES curtailment in SiteFlex from the Baseline and a 2% increase in IntFlex from the Baseline. By effectively causing more VRES curtailment, the ECs increase the opportunity for alternative use of surplus electricity, e.g., hydrogen production.

Although the ECs contribute to reduced total demand in EMPIRE, the ECs make it more expensive to meet climate targets in EMPIRE. The expected carbon price in EMPIRE increases in SiteFlex and IntFlex compared to the Baseline, and the increase is largest with 50% ECs in the last investment period, where the expected carbon price increases to more than EUR 560/tonCO_2eq. in SiteFlex and IntFlex, which is 18% higher than the Baseline. The increased carbon price with ECs is related to increased electricity demand during winter (Fig. 8(c)). Even though the ECs significantly reduces heat demand in the winter (Fig. 8(c)), producing more electricity in EMPIRE in the winter, without increasing GHG emissions beyond a very low emission cap, is more expensive than cost- and emission savings from reducing winter heat demand. Recall that the total costs are decreased in SiteFlex and IntFlex compared to the Baseline (Table 2) because the ECs trigger compensating cost savings for the increased carbon price, e.g., energy efficient building heating, reduced electricity and heat demand in the summer, and less total capacity expansion in EMPIRE.

ECs further cause a net reduction in expansion of fossil gas capacity (Fig. 10), but the reduction in fossil gas heating capacity is partly compensated by more open cycle gas turbine capacity. The open cycle gas turbines have an average capacity factor of 0.03, which indicates that ECs trigger an increased need for peak load capacity. Again, this is related to ECs raising electricity demand during winter (Fig. 8(c)) which is when European load is likely to peak. Less bio-based combined heat and power (CHP) capacity is developed in EMPIRE in SiteFlex and IntFlex compared to the Baseline, which is partly compensated by more bio-based electricity-only capacity (Fig. 10).

For storage, SiteFlex and IntFlex both result in net reduction of storage capacity expansion in EMPIRE compared to the Baseline (Table 2). Fig. 11 illustrates that SiteFlex causes 184 GWh less energy storage

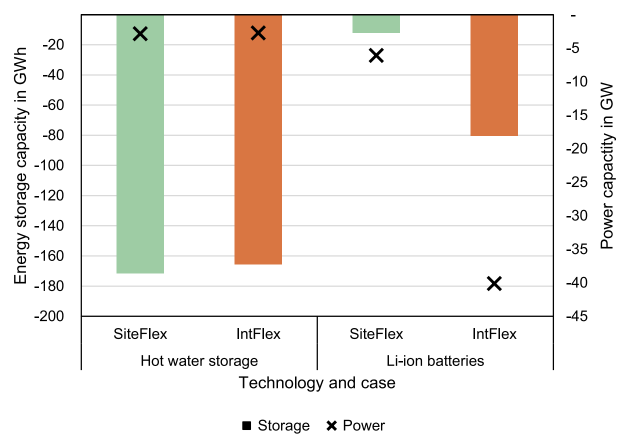


Fig. 11. Difference in storage capacity expansion for all nodes and periods compared to the Baseline by technology and case.

capacity and 9 GW less power capacity compared to the Baseline, while IntFlex causes 246 GWh less energy storage capacity and 43 GW less power capacity compared to the Baseline. For hot water storage, there is little difference between SiteFlex and IntFlex. For li-ion batteries, the reduced capacity expansion from the Baseline is almost 7 times larger for IntFlex compared to SiteFlex.

Recall that the difference between SiteFlex and IntFlex is how aggregated EC electricity storage is *operated* in EMPIRE, and the results show several billion EUR in cost savings (Table 2) and a significant effect on investments in EMPIRE (Figs. 10 and 11). In 2040–2045, around 70% of electricity in France is produced by wind, while around 30% of electricity in Spain is produced by solar PV. Fig. 12 illustrates the mean storage dispatch with 95% confidence intervals for all representative winter weeks in Spain and France in 2040–2045 by case. In SiteFlex, the EC storage operation is cost optimal from the EC perspective, and the trend is to balance solar PV by charging during the day and discharging during the evening. In IntFlex, the EC storage operation is cost optimal from the European perspective. For France in IntFlex (Fig. 12), the EC storage operation is more directed towards balancing wind, which is sometimes in conflict with operation in SiteFlex. For Spain, the EC storage operation is directed more towards balancing solar in IntFlex, which is more coordinated with SiteFlex (Fig. 12).

4.4. Discussion and model limitations

Both EMPIRE and GUSTO are linear models with simplified representations of technical, economical, regulatory, policy-related, and

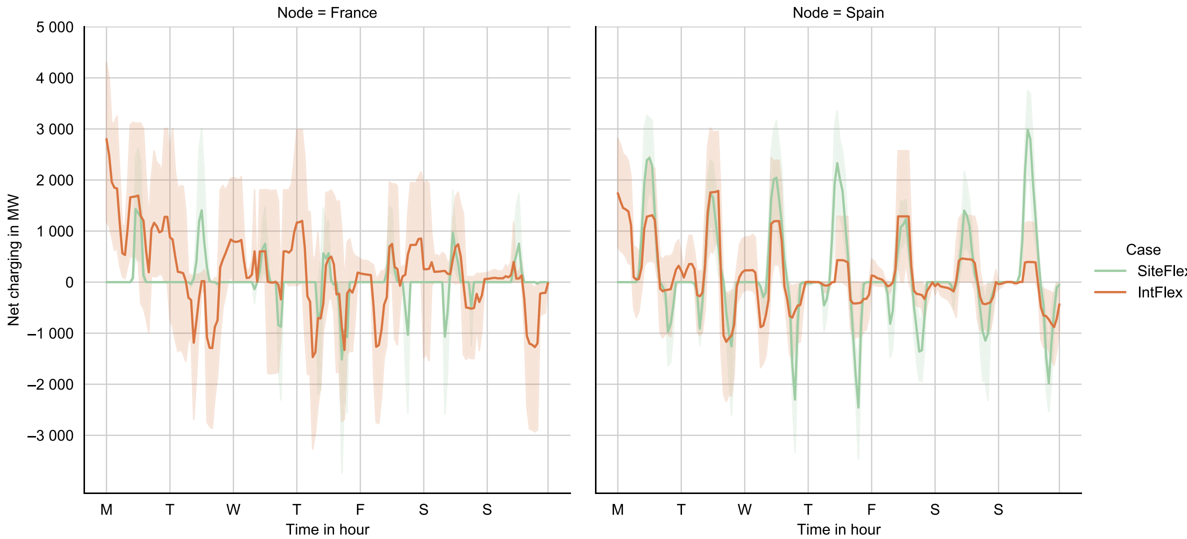


Fig. 12. Net charging profile (mean and 95% confidence interval) of EC electricity storage in EMPIRE in 2040–2045 for winter weeks in France and Spain by case.

ultimately political conditions. Both models optimize costs, and thereby assume ideal market behavior within each modeled system. The two models are linked to preserve details on the neighborhood perspective and the European perspective. Because we consider future developments in the energy system, it is hard to validate the results of our analysis. However, we focus on comparing results from several instances of the same models. Further, the results in EMPIRE and GUSTO are aligned with similar research regarding the growth of VRES and the importance of heat pumps, see e.g., [57,60,79].

Our modeling linking could continue beyond the iterations presented in this paper. The results from SiteFlex and IntFlex could be provided as updated input back to GUSTO, and ideally, we would continue to iterate between the two models until the instances converge to an equilibrium, i.e., until one full iteration does not significantly alter objectives and decisions in neither EMPIRE nor GUSTO. We do not iterate between the two models more than once because of long computational times. Further work could improve this by using less computationally demanding models and/or developing a single integrated bilevel optimization model.

Not integrating the two models into a single bilevel model is less computationally challenging, however, it creates challenges in coordinating assumptions and data when linking the models. A particular challenge in our case is that GUSTO models a single representative year per instance, whereas EMPIRE models several representative weeks and days per instance. Linking hourly electricity and heat load profiles and price profiles between GUSTO and EMPIRE is therefore hard to coordinate, although it is key when modeling short-term interactions between ECs and the surrounding electricity and heating system. Nevertheless, this paper focuses on long-term investment results in EMPIRE, and we believe the results highlighted in this paper present robust long-term effects even though short-term data linking can be improved.

The differences in flexibility dispatch between SiteFlex and IntFlex are a result of the objective functions for each model covering the neighborhood perspective in GUSTO and the European perspective in EMPIRE. More specifically, GUSTO lacks a price signal from a national aggregator for VRES utilization external to the EC, whereas EMPIRE lacks a price signal for grid utilization within countries. The difference between SiteFlex and IntFlex is therefore partly explained by how the two models simplify hourly prices. In reality, price signals can also be simplified for practical and/or political reasons, including grid tariffs that are not cost reflective [92]. Designing a market that provides complete and correct prices for flexibility providers, such that best priority of different objectives can be dynamically signaled, is increasingly important with more electrification, more VRES, and more ECs. We see the need for studying the details of how complete and correct prices can be integrated into the techno-economic target of ECs (via aggregators), however, it is beyond the scope of this paper.

Recall that we assume no reduction in net final heat demand in buildings by 2060 in EMPIRE in the Baseline (Fig. 5(b)), which is somehow pessimistic compared to related studies, e.g., [78]. Thus, the future need for building heat supply in EMPIRE is potentially exaggerated in our case study. However, this paper focuses on the differences between three cases with the same underlying assumptions, and we focus on the impact of ECs on one potential future.

In our study, we consider ECs in a few selected countries across Europe, for a few selected settlement patterns, and within a few selected future investment periods. Further, in IntFlex in EMPIRE, we consider a single aggregated EC flexibility technology, namely hydrogen storage, although the ECs could offer more flexibility, e.g., flexible heating and use of appliances. It is still unclear how expanding our case study along these dimensions affect our findings, but we anticipate an amplification of the observed results because we consider a wide climatic, geographic, and demographic European scope.

In EMPIRE, total system costs are decreased with the introduction of ECs (Table 2). However, the upscaled costs of developing ECs in GUSTO most probably compensates and exceeds the decreased system costs in EMPIRE. This implies that cost savings on a European level do not necessarily balance the aggregated costs of developing ECs. However, EMPIRE simplifies and neglects many aspects of electricity and heating system costs where ECs have further economic value, e.g., more cost-efficient grid infrastructure within neighborhoods and countries. EC development is also often motivated by environmental and climate impacts over costs [26].

Although the input to EMPIRE is the maximum allowed emission reductions for Europe as a whole following the European Commission [71], these constraints are binding for all instances in all investment periods, meaning that we have a non-zero shadow price on these constraints representing European wide carbon prices. EMPIRE results in high carbon prices ranging between EUR 400–600/tonCO_2eq. after 2040 for all cases, which is in line with similar research [78]. Emission policy in EMPIRE represents strong political power by assuming all operational GHG emission policies are regulated, including emissions currently not regulated by the EU emission trading system, e.g., individual gas heating. Future carbon prices are complicated to forecast, and our results indicate an endogenous cost of achieving climate targets, i.e., what pricing is necessary to follow the assumed emission reduction pathway [71]. The market, as opposed to policy makers, is expected to increasingly influence the development of the European carbon cap [93], but political strengthening of the emission cap will still be important [94].

5. Conclusion

This paper analyzes how the European electricity and heating system is impacted by a wide development of ECs across Europe, and how ECs can contribute flexibility towards making European decarbonization more cost efficient. We analyze capacity expansion in Europe towards 2060 in line with climate targets considering short-term variability and uncertainty. We then use the results in a separate capacity expansion model to cost optimize EC technology investments considering one year of hourly operations in France, Spain, Portugal, Norway, Austria, and Poland. The resulting grid interaction by the ECs represent a modification of national load profiles, and we then analyze European capacity expansion with an exogenous load profile modification reflecting the EC development in the respective countries.

Results show that the development of ECs causes less capacity expansion across Europe. On the European level, storage capacity expansion is decreased, while generation capacity expansion shifts from building heating capacity towards electricity production capacity. The shift towards more electricity production capacity happens because the ECs increase electricity demand during winter due to electrification of building heating, which also increase the attractiveness of offshore wind producing most electricity in the winter. In total, ECs reduce the total costs of transitioning towards a European electricity and heating system in line with the assumed emission reduction pathway [71], however, increased electricity demand during winter causes higher carbon prices and more VRES curtailment.

Results further indicate a conflict of interest between cost optimizing EC flexibility towards self-consumption and grid tariffs versus utilizing EC flexibility in a larger European context. This is supported both by results on European capacity expansion and by identifying a high impact of price signals faced by ECs on flexibility dispatch. If the EC flexibility dispatch is to coordinate with the European cost optimal storage operation, there must be price signals and incentives locally that reflect the flexibility needs on a European level. Ideally, the magnitude of the incentives should also reflect whether a local or a European objective should be prioritized in any given hour. Further research is needed on EC market design that ensures the balance between local and global objectives.

Further work should consider options in EMPIRE to handle surplus electricity production, i.e. VRES curtailment, including hydrogen production and use. This would increase the value of electricity production not fed into the grid, but note that utilizing VRES curtailment for power-to-X is not alone self-sustaining. EMPIRE should also include the representation of seasonal storage following e.g. [95]. The consideration of cooling loads, as well as more ambitious retrofitting of European buildings, could further improve the EMPIRE model. More detailed modeling of ECs in GUSTO can also improve our results, including the consideration of more countries, climatic years, and EC typologies. The linking between EMPIRE and GUSTO can be further improved with more similar short-term temporal consideration and more coordination of correlations between the two models related to price signals, climatic conditions, and load profiles.

Further work should also pursue a systematic development of key performance indicators and metrics, with both quantitative and qualitative parameters for ECs. Quantitative parameters could better represent climate diversity across Europe, spillover effects across countries, etc., while qualitative parameters could indicate the drivers and barriers for a coordinated development of ECs on the local and the European level.

CRediT authorship contribution statement

Stian Backe: Conceptualization, Methodology, Software, Validation, Formal analysis, Writing – original draft, Writing – review & editing, Visualization, Project administration. **Sebastian Zwickl-Bernhard:** Conceptualization, Methodology, Software, Validation, Formal analysis, Writing – original draft, Writing – review & editing, Visualization. **Daniel Schwabeneder:** Conceptualization, Methodology, Software, Validation, Formal analysis, Writing – original draft, Writing – review & editing, Visualization. **Hans Auer:** Conceptualization, Funding acquisition, Supervision, Writing – review & editing. **Magnus Korpås:** Conceptualization, Funding acquisition, Supervision, Writing – review & editing. **Asgeir Tomasgard:** Conceptualization, Funding acquisition, Supervision, Writing – review & editing.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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Appendix A. Upscale of the energy demand profile modification

In the following, we elaborate on how the EC electricity and heat profiles from the GUSTO model are processed and represented in the EMPIRE model. In this work, the implementation of ECs results in an energy demand profile modification on local and national levels. The modification results from the difference between the initial demand profile (for electricity and heat) and the one after the implementation of the ECs. Note that the initial demand profiles in the GUSTO model are calculated based on a bottom-up approach using standard load profiles. This is already outlined in Section 3.3. However, the EMPIRE model uses different historical data for the electricity and heat demand. Therefore, when adding the modification to the EMPIRE model, the following is taken into account.

In the case of a negative total heat demand (historical data plus modification) at a given time step t, the modification by the ECs is limited so that it is not negative. The curtailment is subsequently added as a negative offset to the entire annual demand profile. Note that the total heat demand profile consists of both the residential and non-residential. Furthermore, it is pointed out that this procedure is only necessary for a few hours per year and also only in the last investment period of the ECs. The authors are aware that, in principle, a modification calculation for each historical year could prevent this. However, this option disproportionately increases the calculation complexity.

Appendix B. Significance of techno-economic components in flexibility aggregation

In the following, we investigate the significance of the distortions introduced by aggregating different flexibility options and modifying the objective of the illustrative example. We consider 30 households with PV systems and batteries. Further, 30 different load profiles with a quarter-hourly resolution is generated using the `LoadProfileGenerator` developed by Pflugradt and Muntwyler [96]. Different installed PV capacities ranging from 1 kW to 5 kW are assumed and PV production profiles for the nine Austrian NUTS-2 regions are obtained from renewables.ninja [74,75]. All batteries have a storage capacity of 3 kWh, and, to avoid aggregating identical technologies, the installed charging and discharging capacities range from 1 kW to 5 kW.

For the optimization, electricity spot market prices in Austria for the year 2019 are obtained from ENTSO-E [70], as well as the grid tariff, fees, and surcharges for network level 7 are considered in the objective function [97–102]. The models are formulated as linear optimization problems minimizing the total cost for electricity procurement of all considered households using the simulation framework and generic storage interface presented in [51]. To avoid over-stressing of batteries, levelized cost of storage of 50 EUR/MWh are assumed.

The optimal operation of the considered households is determined using various model setups which differ along the following dimensions:

- *Aggregation*: Households can be considered individually, adding variables and constraints for each component, or they can be aggregated to a single large-scale household.
  - *Individual*: All flexible components and households are modeled individually.
  - *Aggregated*: Load and PV profiles are summed to single quarter-hourly profiles and batteries are aggregated by adding up the charging and storage capacity values.
- *Integration*: Distributed flexibilities can be integrated in EMPIRE either statically, by optimizing their operation beforehand and modifying the residual loads included in EMPIRE accordingly. Alternatively, they can be implemented as flexibility options and their residual load is determined dynamically by EMPIRE. In this case the shadow prices in EMPIRE determine their operation. Drawing an analogy to this analysis and considering the market prices as the shadow prices in EMPIRE, the following options are considered:
  - *Static*: A constant energy supply tariff is considered. In some sense this corresponds to SiteFlex, although SiteFlex considers dynamic market prices. However, the important point here is that the prices considered in the objective are not exactly the EMPIRE shadow prices.
  - *Dynamic*: Market prices are considered in the objective of the models. Assuming that these prices correspond to EMPIRE's shadow prices and that distributed flexibilities are price-takers this corresponds to a dynamic model integration.
- *Cost*: Typically, unit commitment models at a system level do not consider cost components like the grid tariff, fees and surcharges. However, these are key cost components incentivizing local self-consumption and determining the operation of distributed flexibilities. The effects of disregarding cost components in the objective is investigated by considering the following options in the objective in addition to the market prices or the supply tariff:
  - *None*: No additional cost are considered.
  - *Technology*: Only technology-specific cost, in this case the batteries' operational cost are considered.
  - *Tariff*: Only the grid tariff, fees and surcharges are considered.
  - *All*: Both of the above are considered.

Fig. 13 shows residual production profiles for all households resulting from different model setups. The *Optimal* setup considers dynamic market prices and all cost components. Furthermore, all technologies are modeled individually. This configuration represents the benchmark that other aggregated setups aim to approximate. The *Inflexible* setup corresponds to a status quo scenario without any flexibility activation, considering only the load and PV production profiles of all households. Compared to the *Optimal* setup it results in higher consumption and feed-in. In the *Aggregated Static* configuration a single aggregated household is considered without dynamic market prices. However, local cost components like the grid tariff, fees, surcharges and battery operation cost are considered. This results in higher self-consumption shares than the *Optimal* setup. This suggests that the local objective is depicted correctly, but the available flexibility is overestimated through the aggregation. Finally, the *Aggregated Dynamic* setup considers a single aggregated household with dynamic market prices, but neglects local cost components. This significantly impacts the incentives for flexibility activation in the objective function, disregarding the benefits of local self-consumption. Hence, the residual production profile results in higher peaks for both consumption and production during hours of lowest and highest prices.

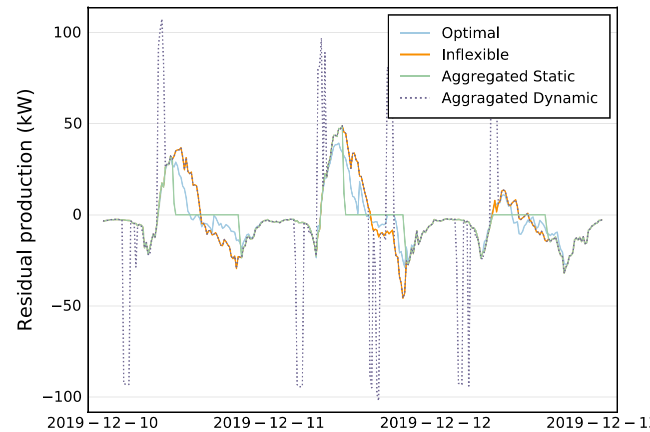


Fig. 13. Residual production profiles with different model setups for three days.

Table 3
Correlation and root mean square error of the annual residual profiles compared to the optimal profile.

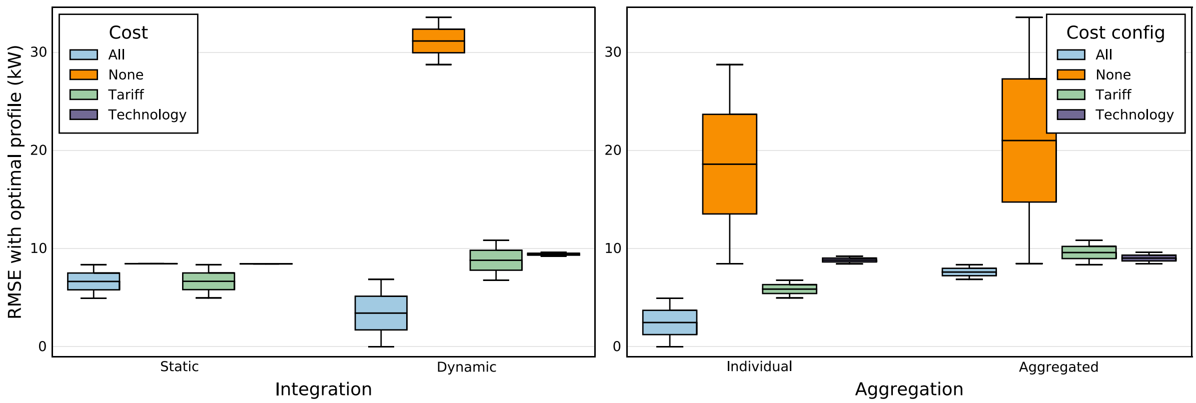
	Correlation	RMSE
Inflexible	0.93	8.42 kW
Aggregated Static	0.90	8.36 kW
Aggregated Dynamic	0.61	33.56 kW

Consider the annual aggregated residual production profiles of all households.

Table 3 shows the correlation and root mean square error (RMSE) of the profile in the *Optimal* setup compared to other configurations. The *Inflexible* and the *Aggregated Static* setups achieve quite similar results with a slightly higher correlation for the *Inflexible* and a slightly lower RMSE for the *Aggregated Static* configuration. The *Aggregated Dynamic* setup results in significantly higher deviations in the residual load profile.

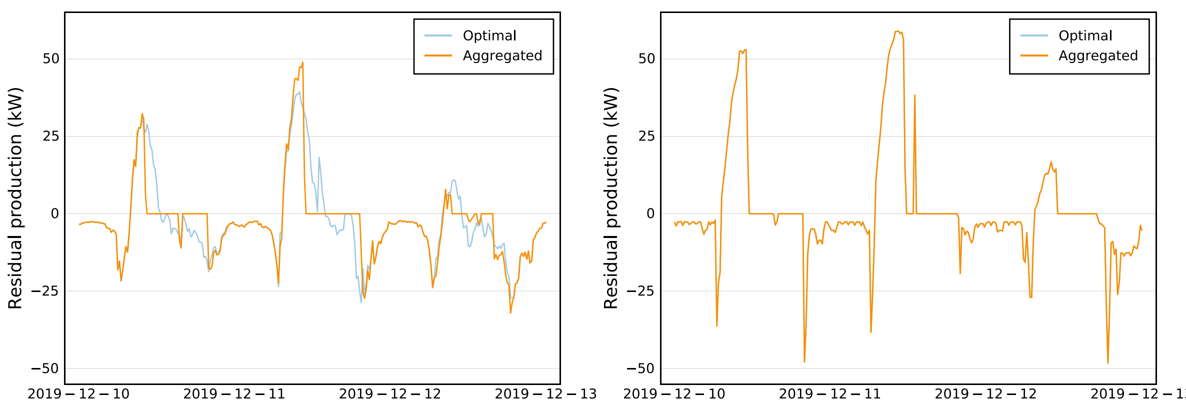
Fig. 14 shows the RMSE with the optimal residual profile for all different model setups grouped by cost configurations. Fig. 14(a) suggests that not considering any local costs with a *Dynamic* model integration yields significantly higher deviations from the optimal profile than other setups. For a *Static* model integration the impact of the cost configuration is significantly smaller. Fig. 14(b) compares the *Individual* technology consideration with the *Aggregated* case. Even though an individual consideration yields smaller RMSE values, the impact of the cost configuration is more significant.

These results suggest that for a *Dynamic* model integration the modification of objectives by neglecting local cost has a greater affect on the changes in flexibility activation than the information loss due to aggregation of components. However, considering either the grid tariff or technology-specific cost already significantly improves the results. To isolate the effects of aggregation, fix the *Integration* setup to *Dynamic* and the *Cost* setup to *All*. Fig. 15(a) shows the impact of aggregation



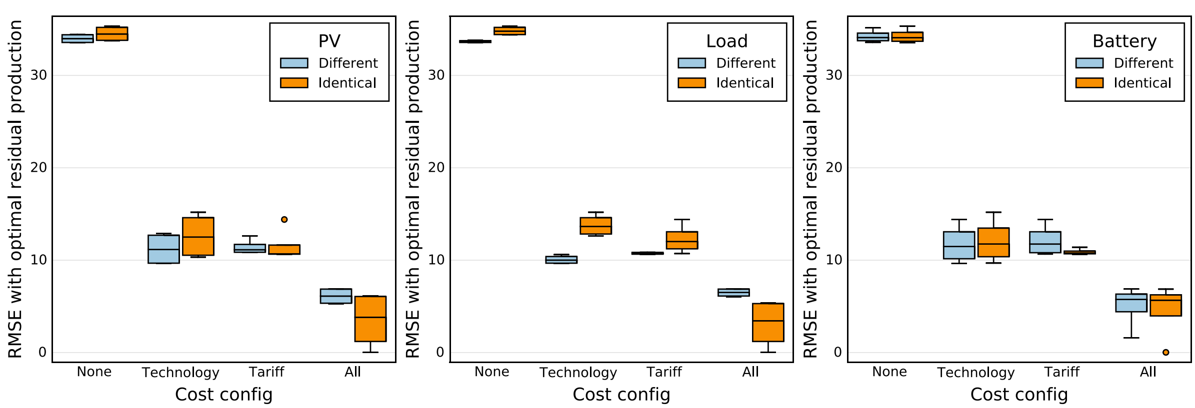
(a) Comparing different *Integration* configurations (b) Comparing different *Aggregation* configurations

Fig. 14. Root mean square error of all model setups with the *Optimal* residual production profile grouped by *Cost* setup.



(a) Different households (b) Identical households

Fig. 15. Residual production profiles with all local cost considered and *Dynamic* integration for three days.



(a) PV configuration (b) Load configuration (c) Battery configuration

Fig. 16. Root mean square error of all model setups with the *Optimal* residual production profile versus *Cost* configuration.

on the residual production profiles for three days. In the aggregated case the residual production is closer to zero. Hence, it provides higher self-consumption share than the individual consideration of each component. This suggests that the available flexibility is overestimated by aggregated components.

If instead a community with identical households with the same PV and load profiles and the same battery are considered, the aggregated results match the individual results, as illustrated in Fig. 15(b). To further investigate the effects of the technology composition on the quality of aggregation, eight community setups are considered. They differ by considering either identical or different specifications for batteries, PV profiles and load profiles. Fig. 16 shows the resulting RMSEs of the residual production profiles with the *Optimal* load profiles for different *Cost* configurations, grouped by technology specification for PV profiles, load profiles and batteries. When considering all local cost components, community configurations with identical technology specifications provide better results than general configurations with different technologies. However, for the other *Cost* configurations this statement is not true.

Fig. 16 emphasizes again that the impact of modifications in the objective function is significantly higher than the effects of the simplifications introduced by technology aggregation. Hence, for the analysis in IntFlex, which investigates the operation of ECs controlled by a central planner in an optimal way for the entire energy system, a further refinement of aggregation approaches for different technologies is not considered necessary.

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