BUSINESS MODELS FOR ENERGY COMMUNITIES

A Comparative Simulation of Energy Sharing, Pricing and Value Distribution

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ABSTRACT

Energy communities (ECs) can increase the local use of renewable energy sources locally. Local Energy Markets (LEMs) could be used to share energy among members in the EC. Currently, it is unclear how different pricing mechanisms affect costs, revenues and value distribution among members. Furthermore, it is also unclear when EV integration through C2V2C will become profitable. The purpose of this work is to evaluate the economic outcomes for ECs where energy from solar PV is shared (physically or virtually) between households and an EV. This work combines a literature study of energy communities, pricing mechanisms and relevant policy documents. Then a MATLAB simulation of one EC is conducted to compare different pricing mechanisms. A second simulation of two ECs with an EV is conducted to evaluate C2V2C and EV profitability. Two types of sharing are compared physical and virtual sharing along with different pricing mechanisms such as fixed price, and an auction-based pricing mechanism. The effects of network tariffs and electricity taxes are also considered in some cases to evaluate the impact of them in terms savings. A summer week is simulated using hourly load profiles, electricity price, and PV profile. The EV profitability depends on technical and behavioral parameter such as delivered energy, charging and discharging power and delay. Because the simulation is conducted during summer week it represents conditions with relatively high PV generation. Generally, cases that used physical sharing resulted in the lowest total net bills, mainly because internally shared electricity was exempt from network tariffs and electricity taxes in the simulated cases.

Keywords: Energy community, Energy sharing, Pricing mechanism, Peer-to-peer trading, Electric Vehicle, Photovoltaic

PREFACE

This work was carried out during the spring of 2026 at Mälardalen University, within the Master of Science programme in Industrial Engineering and Management. This work was initiated with an interest in energy communities and EV integration and business models and having the opportunity to contact Pei Huang who proposed this work. I want to thank Pei work guiding me through this degree project.

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Adrian Estelli

SUMMARY

Due to the rapid global growth of renewable energy sources (RES), particularly solar photovoltaic (PV) systems, integrating small-scale PV producers into the electricity grid has become increasingly challenging. Energy communities (ECs) offer a potential solution by enabling more efficient local use of PV generation. At the same time, the rapid growth of electric vehicles (EVs) creates opportunities for new services related to ancillary markets and electricity storage.

Local energy markets (LEMs) enable local electricity trading and can be combined with ECs to support trade between prosumers and consumers. Several pricing mechanisms can be applied in LEMs. However, it remains unclear which mechanisms provide the best economic outcomes. It is also unclear how costs and revenues are distributed among stakeholders, including prosumers, consumers, market agents, and EV owners. Regulation plays an important role, as the economic outcome of an EC is strongly affected by whether internal electricity sharing is subject to network tariffs and electricity taxes.

The aim of this work is to compare and evaluate the economic outcomes of ECs under different regulatory settings and pricing mechanisms. An EV is integrated into two ECs to assess the profitability of EV participation. The distribution of costs and revenues among different stakeholders is also analysed.

This work combines a literature review with MATLAB simulations. The literature review covers regulations, pricing mechanisms, and real-world examples of ECs. The MATLAB model uses hourly load, PV generation, and electricity price data. It determines internal electricity prices based on the selected pricing mechanism and distributes traded electricity among consumers. Two types of energy sharing are considered: physical sharing (PS) and virtual sharing (VS). These are subject to different network tariffs and electricity taxes.

Overall, physical sharing resulted in lower total costs because it was exempt from network tariffs and electricity taxes. Dynamic pricing mechanisms, such as supply-and-demand ratio (SDR) pricing, generated the largest savings for the EC. In the VS-NetFeeRed case, prosumers benefited the most, while consumers did not benefit compared with other cases. This highlights the importance of fairness in EC design, as the distribution of benefits may affect stakeholders' willingness to participate in the long term.

The EV was profitable only in the PS-SDR case. In all other cases, EV integration was not profitable. Changes in charging and discharging capacity, delivered energy, or delayed charging and discharging did not change any unprofitable case into a profitable one. The results show that pricing mechanisms, regulatory conditions, and the distribution of benefits are crucial for making ECs economically attractive. However, the potential for profitable EV integration appears limited, as the EV generated a profit in only one case.

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NOMENCLATURE

Symbol	Description	Unit
S_t	Total PV surplus in the EC	kWh
$surplus_{i,t}$	Surplus of household *i* at time *t*	kW
$deficit_{i,t}$	Energy deficit of household *i* at time *t*	kW
SDR_t	Supply and Demand ratio	-
$P_{sell,t}$	Internal selling price at time *t*	EUR
$P_{buy,t}$	Internal buying price at time *t*	EUR
λ_{sell}	Feed-in tariff	EUR
λ_{buy}	Grid price (spot price + network tariff + electricity tax)	EUR
μ	Agent markup	EUR
w_2	Weighting for Dynamic pricing mechanism	-
b_i	Household *i* buy/sell bid	EUR
P_t^{clear}	Clearing price at time *t*	EUR
a^*	Last accepted ask	EUR
b^*	Last accepted bid	EUR
$\lambda_{energy,t}$	Spot price at time *t*	EUR
$\lambda_{redtariff,t}$	Reduced network tariff	EUR
E_t^{p2p}	Energy available for internal trading at time *t*	kWh
$p2p_{sell_{i,t}}$	Amount of energy sold internally by household *i* at time *t*	kWh
$p2p_{buy_{i,t}}$	Amount of energy bought internally by household *i* at time *t*	kWh
$E_{Export_{i,t}}$	Amount of energy exported to the grid from household *i* at time *t*	kWh

Symbol	Description	Unit
$E_{Import_{i,t}}$	Amount of energy imported from the grid to household i at time t	kWh

ABBREVIATIONS

Abbreviation	Description
C2V2C	Community-to-Vehicle-to-Community
CEC	Citizen Energy Community
DSO	Distribution System Operator
EC	Energy Community
EV	Electric Vehicle
LEM	Local Energy Market
P2P	Peer-to-Peer
PS	Physical Sharing
PV	Photovoltaic
REC	Renewable Energy Community
SDR	Supply-Demand Ratio
VS	Virtual Sharing

1 INTRODUCTION

Globally, renewable energy capacity is expected to double by 2030, corresponding to an increase of 4,600 GW. Solar PV is expected to account for the largest share of this capacity

expansion, representing approximately 80% of the total increase. This is mainly driven by lower costs and growing social acceptance. Distributed solar PV is also expected to expand, indicating that a larger share of renewable electricity generation is shifting towards end users. One of the main challenges associated with the expansion of renewable electricity generation is grid integration (International Energy Agency, 2025a).

The EU's Clean Energy Package aims at creating an electricity market that is more centered around the customer. To enable this, electricity markets have been adapted to allow consumers to trade flexibility and their self-generated electricity. However, the electricity market remains centralized and is largely built around large-scale electricity producers rather than smaller producers. Some of the barriers for smaller producers are that bid sizes in centralized electricity markets are large and transaction costs are high, making it difficult for them to participate. Local energy markets (LEMs) can be seen as an approach that enables smaller producers to trade electricity within a geographically limited area. Within an energy community, LEMs can function as a platform to strengthen self-sufficiency and improve electricity availability (Chen & Vandendriessche, 2025).

In 2024 over 17 million EVs were sold which accounts for about 20% new cars sold globally. China maintains the lead in number of EVs sold with sale exceeding 11 million in 2024. Globally EVs accounted for 180 TWh of electricity consumed in 2024 which was an increase of about 60% compared to the previous year. In 2030 EVs could account for more than 4% of the electricity demand in Europe. EVs could also provide demand-side flexibility with smart charging which could help alleviate stress on the grid during, for example during periods of high demand. To incentivize flexibility in charging different tariffs could be used, for example time-of-use and critical peak pricing (International Energy Agency, 2025b).

1.1 Background

Chen and Vandendriessche (2025) highlight the potential role of local energy markets (LEMs) as an organisational mechanism for electricity exchange within energy communities, adding to the development of 'community-based LEMs'. As they note (p.341), "LEMs can serve as a way of arranging within CECs and RECs the sharing of electricity from both community members' privately owned assets and community-owned production units." At the same time, the regulatory framework established by the recast IEMD and RED II grants energy communities the right to share electricity, particularly when it is generated by community-owned production units. However, the practical scope of such arrangements ultimately depends on how Member States interpret and implement these provisions in national legislation (transposing EU law) (eg., Chen et al., 2025). As Chen and Vandendriessche (2025, p. 343) caution, "If Member States adopt a strict interpretation of relevant provisions, in terms of enabling electricity sharing within CECs and RECs, the role of LEMs is limited to trading electricity derived from community-owned production units with their members rather than trading between community members."

Adding to the legal complexity the authors further note that EU legislation also introduces the notion of "energy transfers" (IEMD art 16(3)(e), REDII art 22 (4)(c)), which requires distribution system operators (DSOs) to cooperate with energy communities in facilitating exchanges of energy within CECs and RECs. Although the concept is not precisely defined in EU law, it may encompass different forms of internal exchange, including both energy sharing and transactions between individual members. Recent amendments to the Electricity Directive

(art 15a) (amending directive2024/1711) also strengthen the legal basis for such arrangements by confirming that active customers retain the right to share and trade self-produced electricity from renewable sources, regardless of whether participating in an energy community.

Taken together, these developments suggest that local energy markets could evolve into mechanisms that support not only the coordination of community-owned generation but potentially also internal peer-to-peer (P2P) trading between community members within energy communities. In the existing literature on LEMs, both bilateral contracts and exchange-based markets at the local level, despite exhibiting different degrees of organisation, are commonly grouped under the broader concept of local markets (Chen & Vandendriessche, 2025). In particular, bilateral trading arrangements are often characterised as a more decentralised market model and are frequently associated with P2P electricity trading between individual participants.

Recent regulatory developments within the EU electricity market framework further clarify how such exchanges may be organised in practice (e.g., amending directive 2024/1711). The 2024 revision of the Market Directive introduces the role of an "organizer of energy sharing," an entity responsible for coordinating electricity sharing arrangements among participants. This role may be fulfilled by different actors, including renewable energy communities (RECs), aggregators, suppliers, or digital platforms. The organizer is typically responsible for managing participating members, defining allocation rules for shared electricity, and communicating settlement data to the distribution system operator (DSO).

New models for EVs are emerging with the rapid increase of EVs. They can be used by aggregators to provide flexibility services, or they can be charge by locally produced electricity. Combined with local PV production EV owners can charge their EVs and improve their use of the PV system (Brown et al., 2019). In community-to-vehicle-to-community (C2V2C) the EV delivers electricity between two energy communities, utilizing surplus PV power in one community to charge and discharge in the second community when there is a demand (Board et al., 2024). They highlight some potential benefits of C2V2C such as reduced grid congestion and better utilization of local renewable energy. Currently it is unclear how different pricing mechanisms affect different stakeholders in ECs. Further, the economic viability of EV integration for C2V2C is uncertain. This report aims to bring further insight into how different pricing mechanism affect stakeholders and the economic viability of C2V2C.

1.2 Aim

This work aims to analyze different economic outcomes for energy communities where buildings and EVs cooperate through physical or virtual energy sharing. Through a literature review and MATLAB-based simulation the impact of different pricing mechanisms on different stakeholders in one EC is evaluated in the first part. In the second part, the economic viability of C2V2C is evaluated. The work aims to provide relevant knowledge for investors, end customers, decision-makers and to provide how future business models can be adapted to accommodate EU policy and regulatory requirements.

- Review existing real-life cases of energy communities and different pricing/allocation mechanisms from the cases and literature.
- Evaluate different pricing/allocation mechanisms affect different actors' revenues and costs.

- Evaluate the profitability of integrating an EV into two ECs.
- From the comparison of different pricing and allocation mechanisms and EV integration, provide suggestions of how to choose pricing and allocation mechanisms and how to integrate an EV.

1.3 Research Questions

1. What are the different pricing mechanisms available for ECs?
2. How do different pricing and allocation mechanisms affect value creation, revenue distribution, and risk allocation among actors in energy communities?
3. How are costs and revenues distributed among different actors (e.g., households, prosumers, and EV owners) under varying regulatory conditions, particularly with respect to network tariffs and electricity taxes?
4. Under what conditions is the integration of electric vehicles (EVs) for electricity delivery between multiple energy communities profitable, and how is this influenced by user behavior and technical parameters?

1.4 Delimitation

This study does not include multi-market optimization. Revenues from ancillary services, such as frequency regulation and local flexibility markets, are therefore excluded. This delimitation is motivated by the fact that these markets are still under development. For example, the forthcoming Network Code on Demand Response (NC DR) is expected to support the development of local flexibility markets. At the same time, the integration of European balancing markets is ongoing through platforms such as MARI and PICASSO, which support balancing and frequency control services.

These markets currently differ in terms of design, standardization, and implementation across power systems. This makes it difficult to develop simulation assumptions that are generally applicable. In addition, the limited scope and time frame of this degree project make it impractical to include these complex market structures.

2 METHOD

2.1 Overview of the Study Methodology

The simulation analysis is complemented by a literature review. The purpose of the review is to place the simulation results in the context of previous research on energy communities, energy sharing, and pricing mechanisms. In addition to academic literature, policy documents and regulatory reports are reviewed to clarify the institutional and regulatory context for energy communities in the European Union. The reviewed material includes documents from the European Commission, national regulatory authorities, and national energy agencies. These sources provide information on EU energy policy, including provisions related to energy communities, energy sharing, and electricity market participation.

The literature review also examines real-world examples of energy community projects in Europe. These cases are used to identify pricing mechanisms and electricity-sharing arrangements that have been applied in practice. Particular attention is given to how electricity is shared, priced, and allocated among participants.

Together, the simulation model and the literature review provide both a quantitative and contextual basis for analysing residential energy communities under different technical and regulatory conditions. Figure 1 provides an overview of the methodology.

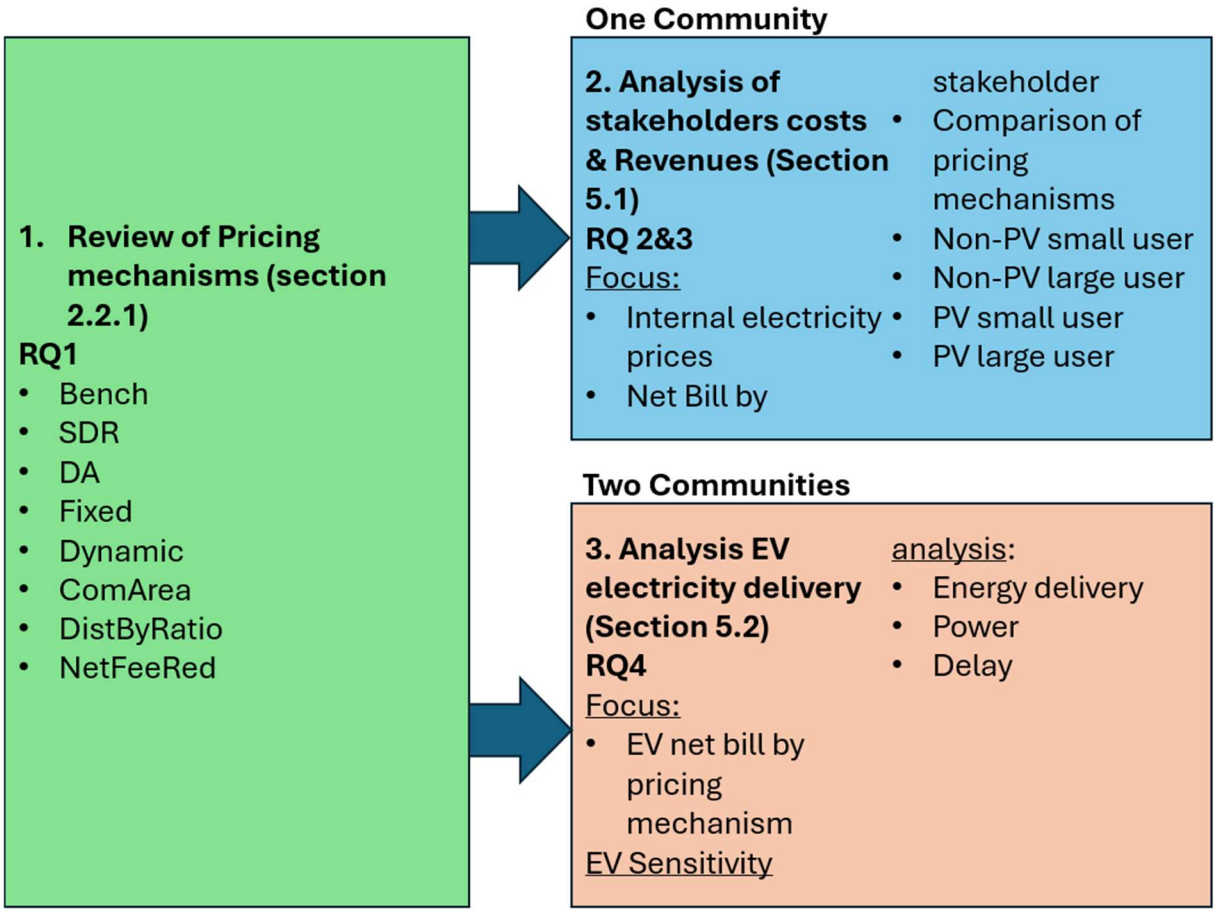

Figure 1. Overview of the methodology.

2.2 Pricing mechanisms and Energy Sharing

In this section all pricing mechanisms considered are described by how the internal buying and selling price are calculated. In (almost) all cases there will be an agent profit that results from the difference between the internal buying and selling price. The agent in this case refers to an entity that facilitates the internal electricity trading within the EC. Depending on the structure of the EC, the agent could, for example, be an aggregator, a property owner or an energy community operator. The agent profit can be used to cover administrative costs; operational costs associated with operating the internal trading. In some EC structures, this profit may also be redistributed among EC members. Table 1 summarizes the different pricing mechanisms and scenarios considered for the ECs.

2.2.1 Pricing Mechanisms

In all models' self-consumption is prioritized, which means the surplus of each household with PV-system is traded after their own demand is satisfied. This means that in the case of SDR model the total *surplus* within the community is considered instead of the total *supply*. This is due to this rule that each household with a PV-system use it to satisfy their own demand. If it was the case that there was no such rule all electricity from PV would first be allocated by the different pricing mechanisms internally. Then if there still was some surplus electricity from the PV-systems – it would be exported to the grid.

Supply-demand ratio (SDR)

Common to these models is that the buying and selling prices are based either on the grid electricity price, excluding electricity tax and network tariffs, or on the relationship between the internal surplus and deficit of electricity. For example, the model based on the supply-demand ratio (SDR) uses the total surplus and deficit in the community according to:

$$S_t = \sum_{i=1}^{N} surplus_{i,t} \tag{1}$$

$$D_t = \sum_{i=1}^{N} deficit_{i,t} \tag{2}$$

$$SDR_t = \frac{S_t}{D_t} \tag{3}$$

Where S_t [kWh] is the total surplus, D_t [kWh] is the total demand at time *t*.

If $SDR_t > 1$, the surplus is greater than the deficit in the energy community, and the internal selling price $P_{sell,t}$ [EUR/kWh] is set according to:

$$P_{sell,t} = \lambda_{sell} \tag{4}$$

Where λ_{sell} [EUR/kWh] is the feed-in tariff. The internal buying price $P_{buy,t}$ [EUR/kWh] is then calculated by:

$$P_{buy,t} = P_{sell,t} + \mu \tag{5}$$

Where μ [EUR/kWh] is the markup used to ensure that there is a profit for the agent.

In the case where $0 \leq SDR_t \leq 1$, the internal selling price and buying price are set according to the following principle:

$$P_{sell,t} = \frac{\lambda_{sell}\lambda_{buy,t}}{(\lambda_{buy,t} - \lambda_{sell})SDR_t + \lambda_{sell}} \tag{6}$$

$$P_{buy,t} = P_{sell,t} + \mu \tag{7}$$

Where $\lambda_{buy,t}$ [EUR/kWh] is the spot price including network transfer fee and electricity tax. Based on this formula, the buying price decreases as the electricity surplus within the community increases. The goal is to set a buy and sell price that benefits both the seller and buyer. The seller benefits from being able to sell at a higher price than it would sell the electricity to grid, and the buyer benefits from the buying price being lower than the grid price. However, sometimes the buy price will be the same as the grid price and the sell price the same as the feed-in tariff. In that case it is equally profitable to buy and sell internally as it is to the grid.

Weighted Dynamic Pricing

The second dynamic pricing model is weighted, and the prices are calculated as follows:

$$P_{sell,t} = w_2 \lambda_{buy,t} + (1 - w_2)\lambda_{sell,t} \tag{8}$$

where w_2 [-] is a weight selected within the interval:

$$0 \leq w_2 \leq 1 \tag{9}$$

To avoid selling prices lower than λ_{sell}, the highest value of λ_{sell} and the calculated price is always selected:

$$P_{sell,t} = \max(\lambda_{sell}, P_{sell,t}) \tag{10}$$

To ensure that the internal buying price never exceeds the grid price, the lowest value of the internal calculated buying price and $\lambda_{buy,t}$ is selected:

$$P_{buy,t} = \min(\lambda_{buy,t}, P_{sell,t} + \mu) \tag{11}$$

This means that the markup may be lower in some cases when the selling price is high and the markup would otherwise make the internal buying price higher than the grid price.

Double Auction

In the double auction model only actors with surplus PV can act as sellers and only actors with a deficit can act as a buyer for a given time step. The buying and selling bids are randomly generated within the interval of the feed-in tariff and the grid price which consists of the spot price, electricity tax and network tariff:

$$b_i \in [\lambda_{sell}, \lambda_{buy}] \tag{12}$$

Where b_i is the bid of actor *i*. For reproducibility of the rng(42) is used in the MATLAB simulation to handle the randomness. The same seed is used in both double auction cases which result in the same bids and asks. This means that the bidding process does not affect the outcome of those cases. The bids are then sorted, with sellers sorted in ascending order and buyers in descending order for each time step. Bids are accepted according to the following criterion:

$$b_{buy,j,t} \geq b_{sell,j,t} \tag{13}$$

The price is set based on the last accepted pair of buying and selling bids, i.e. b^* and a^*. The clearing price is then set as:

$$P_t^{clear} = \frac{a^* + b^*}{2} \tag{14}$$

Based on this clearing price, the final buying and selling prices are set according to:

$$P_t^{sell} = P_{clear,t} - \frac{1}{2} G_t \tag{15}$$

$$P_t^{buy} = P_{clear,t} + \frac{1}{2} G_t \tag{16}$$

Where G_t [EUR/kWh] is the auction gap, which is the difference between the b^* bid and a^*. By setting the prices in this way, a difference arises between the buying and selling price, which becomes the agent's profit.

Reduced Network Tariff

In this pricing model, the buying price is based on the grid electricity price, excluding network tariff and tax, minus the network tariff, and then a reduced network tariff is added:

$$P_{buy,t} = \lambda_{energy,t} + \lambda_{redtariff,t} + \mu \tag{17}$$

With this pricing model, the buying price is always lower than the grid price. However, there is a risk that the calculated selling price becomes lower than $\lambda_{sell,t}$. To prevent this, the highest value of λ_{sell} and the calculated price is always selected:

$$P_{sell,t} = \max\left(P_{buy,t} - \mu, \lambda_{sell}\right) \tag{18}$$

Fixed price

These models are very similar. A fixed selling price is set above $\lambda_{sell,t}$ to make it beneficial for sellers to sell their surplus electricity internally first. A buying price is then set slightly above the selling price to ensure that there is a profit for the agent. One risk with this model is that, during some periods, it may be cheaper to buy electricity from the grid than to buy it internally.

Post-auditing

In this model, the surplus is bought and sold within the community at the same prices as those applied by the grid. The difference is that the margin is distributed between producers, consumers, and an agent. In this case, producers receive 50%, consumers receive 40%, and the agent receives 10%.

Property Operator and Owner

In this case, all surplus electricity is shared free of charge with the common areas of the property. If any surplus remains after the common areas have had their demand met, this electricity is sold to the grid. This means that the property does not need to buy as much electricity from the grid, thereby reducing its electricity cost. This benefit can be transferred to the residents of the property through lower fees or rents.

2.2.2 Energy sharing

Energy sharing is how the electricity is traded within an energy community is distributed to consumers and how much each producer sells. In total two different energy sharing mechanisms are considered. It is important to note that energy sharing doesn't *necessarily* involve market-based mechanisms of distributing electricity.

Proportional sharing

The allocation of traded electricity is proportional to a producer's supply or a consumer's demand. First, the amount of energy E_t^{p2p} [kWh] that can be traded internally is determined by:

$$E_t^{p2p} = \min(S_t, D_t) \tag{17}$$

where S_t is the total electricity surplus in the community and D_t is the total electricity deficit in the community. Each producer sells a share of the internally traded electricity depending on its share of the total surplus. The sellers share $p2p_{sell_{i,t}}$ [kWh] is calculated by:

$$p2p_{sell_{i,t}} = E_t^{p2p} \cdot \frac{Surplus_{i,t}}{S_t} \tag{18}$$

This means that sellers with a larger surplus are allocated a larger number of internal sales. The allocation among buyers works in a similar way, where buyers with a larger deficit are allocated a larger share of the internally traded electricity. The buyers share $p2p_{bu\ _{i,t}}$ [kWh] is calculated by:

$$p2p_{bu\ _{i,t}} = E_t^{p2p} \cdot \frac{Deficit_{j,t}}{D_t} \tag{19}$$

The amount of electricity bought from or sold to the grid after internal trading is determined as follows:

$$E_{Export_{i,t}} = S_{i,t} - p2p_{sell_{i,t}} \tag{20}$$

$$E_{Import_{i,t}} = D_{i,t} - p2p_{buy_{i,t}} \tag{21}$$

This means that surplus electricity is exported to the grid $E_{Export_{i,t}}$ [kWh] after it has been sold internally, while the deficit that is not covered by internal trading is covered by purchasing electricity from the grid $E_{Import_{i,t}}$ [kWh]. This method for allocating shared electricity within the energy community is applied to all pricing models, except for special cases where electricity is explicitly allocated in another way. The double auction model is also applied with another type of energy sharing: sequential sharing.

Sequential energy sharing

This type of energy sharing distribution is applied with the double auction mechanisms. This means that the seller first in the list after the bids are sorted is allowed to sell its electricity first and the buyer willing to pay the most gets its electricity first. The amount of energy that can be traded internally is determined by the same equation as the proportional sharing. For each time step the amount of energy that transferred from seller *a* to buyer *b* $q_{a,b,t}$ is determined by:

$$q_{a,b,t} = \min\left(E_{a,rem}^S, E_{b,rem}^B, E_t^{p2p} - E_t^{traded}\right) \tag{22}$$

Where $E_{a,rem,t}^S$ [kWh] is the remaining surplus electricity of seller *a* at time *t* and $E_{b,rem}^B$ [kWh] is the demand of buyer *b* at time *t.* E_t^{traded} [kWh] is the amount of electricity that has been distributed.

Then the amount of electricity sold by seller *i* at time *t* and the amount bought by buyer *j* at time *t* is updated as follows:

$$p2p_{sell_{i,t}} = p2p_{sell_{i,t}} + q_{a,b,t} \tag{23}$$

$$p2p_{bu\ _{j,t}} = p2ps_{buy_{j,t}} + q_{a,b,t} \tag{24}$$

After each matching of buyer and seller, the sellers remaining surplus and the buyer's deficit is calculated:

$$E^{S}_{a,rem,t} = E^{S}_{a,rem,t} - q_{a,b,t} \tag{25}$$

$$E^{B}_{b,rem,t} = E^{B}_{b,rem,t} - q_{a,b,t} \tag{26}$$

If a seller doesn't have any more electricity to sell, the algorithm moves on to the next seller. In the same way, when a buyer has satisfied its demand, the algorithm moves on to the next buyer in the list. This process continues until either there are no more accepted sellers and buyers or all the electricity for internal trading has been distributed between buyers and sellers.

Table 1. Scenario Overview.

Scenario ID	Pricing	P2P Buy	P2P Sell	Taxes	MG	Sharing Principle	Network charges	Comments	Reference(s)
VS-Bench	Dynamic price (Feed-in + network fee)	p_buy = min(p_sell + network + tax + markup, p_grid)	p_sell = min(w2 * p_grid + (1-w2) * feed-in, feed-in)	Yes	No	Proportional	Yes	0<w2<1	
PS-SDR	SDR	p_buy =min(p_sell + markup, p_grid)	p_sell = max(p_grid * feed-in)/((p_grid - feed-in) * SDR +feed-in)	No	Yes	Proportional	No	feed-in<p_buy,p_sell< p_grid	(Deng et al., 2023; Liu et al., 2017; Long et al., 2018)
PS-DouAucPro	DA	p_buy = clearing price + 0.5 * gap	p_sell = clearing price - 0.5 * gap	No	Yes	Proportional	No	feed-in<p_buy,p_sell< p_grid	(Baez-Gonzalez et al., 2018)
PS-DouAucSeq	DA	p_buy = clearing price + 0.5 * gap	p_sell = clearing price - 0.5 * gap	No	Yes	Sequential	No	feed-in<p_buy,p_sell< p_grid	(Baez-Gonzalez et al., 2018)
PS-Fixed	Fixed price	p_buy = p_sell + markup	p_sell = 0.07 EUR/kWh	No	Yes	Proportional	No	Simple, but risk of p_buy > p_grid	(Henni et al., 2021)
PS-Dynam	Dynamic price (Feed-in + network fee)	p_buy = min(p_sell + markup, p_grid)	p_sell = max(w2 * p_grid + (1-w2) * feed-in, feed-in)	No	Yes	Proportional	No	feed-in<p_buy,p_sell< p_grid	
PS-ComArea	Market to grid (no internal trading)	-	-	No	Yes	Common areas	No	No, internal surplus PV is used for common areas.	

VS-DisByRatio	x*(p_grid-feed-in) allocated proportionally among actors	p_grid	feed-in	Yes	No	Proportional	Yes	50% of p_grid - feed-in to producer, 40% to consumer, 10% to agent. x in the pricing column is the actor's share of the benefit	(Danielsson et al., 2024)
VS-NetFeeRed	Dynamic price (Feed-in + network fee)	p_buy = max(p_grid - network + reduced_network, feed-in)	p_sell = max(p_buy - markup, feed-in)	No	No	Proportional	Yes	feed-in<p_buy,p_sell< p_grid Reduced network tariff	(Zepter et al., 2019)

2.3 System Modeling

The model uses real data for load profiles and the PV data used as input is from PVGIS. Real data is used for electricity price, and the resolution of the load profile, PV and electricity data is hourly. The time period which is simulated is one summer week. It provides information on energy sharing during periods of high solar PV which can be shared within an EC. A one-week period also captures daily variation in solar PV and load, but also differences in EV usage patterns. However, it does not capture the seasonal variations and therefore is not representative for more than the week simulated. It can provide insights into what to expect during periods of higher solar PV.

2.3.1 Electricity Demand Data and PV Supply

The electricity demand data is based on real load profile which has been used in a previous study by Board et al., (2024) and it is reused in this report. It provides data for a residential building and data from a university. However, the university load data is for a single building, which have then been divided into three load profiles representing three buildings instead of a single building. The reason for this is to construct a second energy community in which electricity can be shared between the three buildings and the EV.

The PV supply profile is generated from PVGIS which provides hourly PV production estimates based on inputs such as slope of the panels, azimuth and nominal power (European Commission, Joint Research Centre, 2025). The reason for using PVGIS is that it is simple to generate PV profile with hourly resolution and it accounts for solar radiation data which makes it more realistic. In Section 4 the input parameters that were used to obtain the PV profile can be found.

2.3.2 EV Modeling in the C2V2C Service

The EV is modeled by considering the following parameters deliverable energy (E_delivery), delay and charging and discharge rate (kW). Battery degradation and charging and discharge losses are not considered. In C2V2C an EV is integrated into two different ECs and acts as portable battery. When modeling the EV, it is treated as an extra load or supply depending on which EC it is currently in. In this report, the charging needs required for the commute between the two ECs is not considered, only the amount of electricity delivered between the ECs. The location of the EV is determined by the schedule that is based on a predefined schedule. More details on the schedule can be found in Section 4.3 where the EV setup will be described in detail with all the parameters considered with values.

First the net load $Net_{c,t}$ [kW] in each energy community (EC1 and EC2) is calculated by:

$$Net_{c.t} = L_{c,t} - PV_{c,t} \tag{27}$$

Where c is the EC (either 1 or 2) and $L_{c,t}$ [kW] and $PV_{c,t}$ [kW] is the total load and total PV generation of EC c at time t. When $Net_{c.t} > 0$ there is a deficit and when $Net_{c.t} < 0$ there is a surplus of solar PV. The total energy available is defined by:

$$E_{max} = E_{min} + E_{delivery} \tag{28}$$

Where E_{max} [kWh] is the maximum EV energy level, E_{min} [kWh] minimum energy level and $E_{delivery}$ [kWh] is energy available for energy sharing.

The EV charges in EC2 when there is a surplus there. The amount of energy charged when there is a surplus is calculated by:

$$P_{charg\ ,t} = \min\left(P_{char\quad ,max}, \frac{E_{max} - E_{current,t}}{\Delta t}, -Net_{2,t}\right) if\ Net_{2,t} < 0 \tag{29}$$

Where $P_{charg\ ,t}$ [kW] is the charging power, $P_{charge,max}$ [kW] is the maximum charging power. $E_{current,t}$ is the current energy state of the EV and Δt is the time step.

$$P_{charge,t} = \min\left(P_{charg\ ,max}, \frac{E_{max} - E_{current,t}}{\Delta t}\right) if\ Net_{2,t} > 0 \tag{30}$$

The EV discharge in EC1 when it has a demand. If there is no demand in EC1, the EV will not export electricity to the grid. The EV discharges in EC1 according to:

$$P_{dis,t} = \min\left(P_{dis,max}, \frac{E_{max} - E_{current,t}}{\Delta t}, Net_{1,t}\right) if\ Net_{1,t} > 0 \tag{31}$$

Where $P_{dis,t}$ [kW] is the discharging power of the EV. Then if $Net_{1,t} \leq 0$ the EV discharging power is set according to:

$$P_{dis,t} = 0 \tag{32}$$

The energy state of the EV is then updated by:

$$E_{current,t+1} = E_{current,t} + P_{charge,t}\Delta t \tag{33}$$

When charging and when discharging it is updated by:

$$E_{current,t+1} = E_{current,t} - P_{dis,t}\Delta t \tag{34}$$

Charging and discharging of the EV are constrained by:

$$E_{min} \leq E_{current,t} \leq E_{max} \tag{35}$$

2.4 System Model

Figure 2 shows an overview of the MATLAB model used to evaluate how different pricing mechanisms and energy sharing affect the electricity costs and revenues for different actors, grid import and export. The model compares each actor's load and PV generation and then

calculates if the actors have a surplus or deficit of electricity for each hour. Then it allocates the amount of electricity that is possible to share. The remaining amount energy to be exchanged with the grid is calculated, and then the costs and revenues are evaluated.

First all the input data is prepared, and load and PV profiles are prepared in the main code. There are two main codes one for the first scenario with one EC and a second for the second scenario with EV integration into two ECs. They work similarly but the second main code prepares the EV inputs and the second EC2 PV and load profiles as well. Other than that, they are similar. Then the main codes run a for loop through all pricing mechanisms. Each pricing mechanism has its own function, and they are similar in their structure apart from how the internal buying and selling prices are determined. The allocation of the traded electricity is the same for all cases except when stated otherwise in their description. The second main code for EV integration also uses a for loop to run all the scenarios for the sensitivity analysis. Lastly, the results are calculated such as net bill (cost minus revenues) for the simulated week along with agent profit and the net bill divided by type of stakeholder. The results are saved into an Excel spreadsheet which is then used to plot the results.

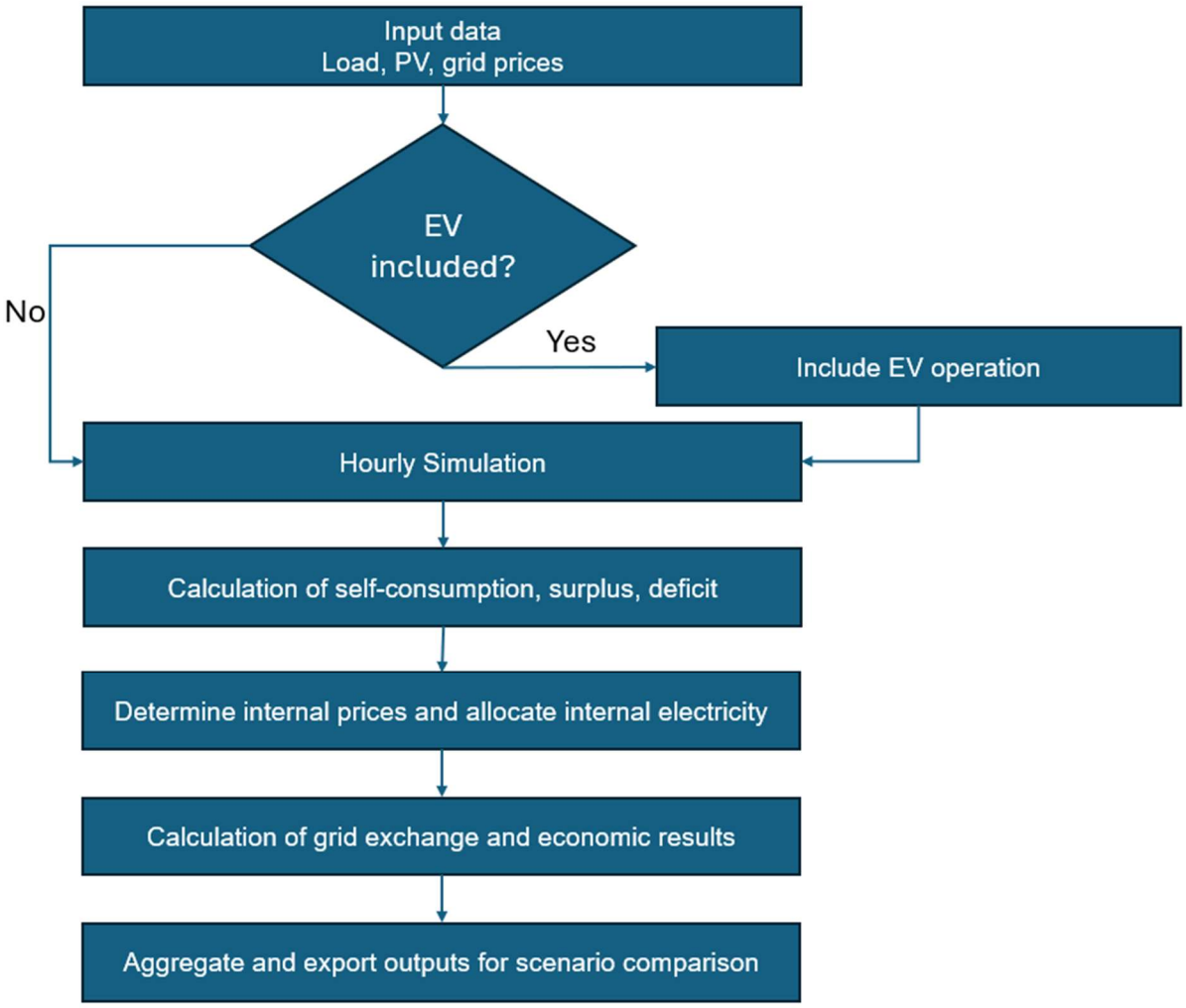

Figure 2. Matlab Model Overview.

3 LITERATURE STUDY

3.1 Regulatory Frameworks for Energy Communities

3.1.1 Energy Communities in EU Law and Policy

The concept of community energy predates the formal EU legal definition of energy communities. It broadly refers to collective energy initiatives that involve citizen participation in the energy system. Caramizaru and Uihlein (2020) describe community energy as a "wide range of collective energy actions that involve citizens' participation in the energy system". Historically, community energy has often been linked to grassroots environmental movements, particularly those shaped by anti-nuclear activism and the oil crises of the 1960s and 1970s.

Energy communities can be understood as a formalised version of community energy. They represent "new types of non-commercial entities" (Caramizaru & Uihlein, 2020, p. 4) with diverse legal and organizational forms. Their purpose is to enable citizens, local authorities, and small and medium-sized enterprises (SMEs) to jointly produce, consume, share, and manage energy. Unlike conventional market actors, ECs are primarily intended to generate environmental, economic, or social benefits for their members or local communities, rather than financial profit.

In the European Union, ECs were formally introduced through the Clean Energy for All Europeans Package (CEP) in 2017. The CEP recognizes the growing role of prosumers and collective forms of energy participation in the future energy system. In EU legislation, energy communities include two main legal concepts: Renewable Energy Communities (RECs), introduced in the Renewable Energy Directive (EU) 2018/2001, commonly referred to as RED II, and Citizen Energy Communities (CECs), introduced in the recast Internal Electricity Market Directive (EU) 2019/944 (IEMD).

RECs focus on energy from renewable sources and are subject to geographical proximity requirements. Their activities may include the production, consumption, sharing, and distribution of renewable energy, as well as district heating, biogas, energy efficiency measures, and energy services such as electric vehicle (EV) charging. CECs, by contrast, are limited to electricity-related activities but are technology-neutral. This means that they may involve electricity from both renewable and non-renewable sources. As noted by Khorrami, Falvo, and Pompili (2025), "While RECs and CECs have distinct legal origins and scopes, together they constitute the complete concept of ECs." Both legal frameworks also allow flexibility in organizational structure, enabling ECs to be established as, for example, associations or cooperatives. Table 2 summarizes the main differences between RECs and CECs under EU law.

According to EU law, ECs must be based on open and voluntary participation. Effective control must be exercised by members or shareholders who are located in proximity to the energy projects, particularly in the case of RECs. The CEP frames ECs as an important instrument for accelerating the energy transition while also supporting broader societal objectives. These include energy justice, local economic development, citizen engagement, energy democracy, reduced energy poverty, and increased social acceptance of renewable energy technologies. In

this sense, Caramizaru and Uihlein (2020) describe energy communities as part of both the energy transition and social innovation.

Caramizaru and Uihlein (2020) also identify investment in local energy infrastructure as a key motivation for establishing ECs. Examples include distributed energy resources, district heating, energy efficiency measures, and EV charging infrastructure. Although financial incentives, such as ownership shares or lower electricity prices, are important, they are often combined with social and environmental motivations. Commercial activities beyond the membership base are relatively uncommon, as community-oriented objectives usually take priority over profit maximization. Even when ECs perform utility-like activities, such as electricity sales or energy efficiency services, cooperative-based models differ from traditional utilities. Profits are typically reinvested in the community or redistributed to members under limited-return arrangements. Interest in ECs is increasing across Europe, particularly because of their potential contribution to local energy transitions and new business models. However, their development remains uneven across Member States.

Table 2. Comparison of REC & CEC.

Renewable Energy Community (REC)	**Citizen Energy Community (CEC)**
A legal entity (Article 2(16), Renewable Energy Directive): (a) which, in accordance with the applicable national law, is based on open and voluntary participation, is autonomous, and is effectively controlled by shareholders or members that are located in the proximity of the renewable energy projects that are owned and developed by that legal entity; (b) the shareholders or members of which are natural persons, SMEs or local authorities, including municipalities; (c) the primary purpose of which is to provide environmental, economic or social community benefits for its shareholders or members or for the local areas where it operates, rather than financial profits.	A legal entity that (Article 2(11), Electricity Market Directive): (a) is based on voluntary and open participation and is effectively controlled by members or shareholders that are natural persons, local authorities, including municipalities, or small enterprises; (b) has for its primary purpose to provide environmental, economic or social community benefits to its members or shareholders or to the local areas where it operates rather than to generate financial profits; and (c) may engage in generation, including from renewable sources, distribution, supply, consumption, aggregation, energy storage, energy efficiency services or charging services for electric vehicles or provide other energy services to its members or shareholders;

3.1.2 Energy Sharing in EU Law and Policy

Despite the obligation to transpose RED II by 30 June 2021 and the Internal Electricity Market Directive (IEMD) by 31 December 2020, Sweden still lacks a formal legal definition and dedicated regulatory framework ECs. REScoop.eu (2024) describes Sweden as the last EU Member State without such a framework.

In its report on the implementation of the EU Clean Energy Package, the Swedish Energy Markets Inspectorate (Ei) proposed a legal framework for ECs as part of its transposition proposal (Ei R2020:02). Ei recommended that ECs should be regulated under the Economic Associations Act. The proposal introduced the Swedish terms *medborgarenergigemenskap* for Citizen Energy Communities (CECs) and *gemenskap för förnybar energi* for Renewable Energy Communities (RECs). However, several consultation bodies considered these translations linguistically awkward and conceptually unclear. Some stakeholders argued that the established term "cooperative" would have been more appropriate (Palm, 2021).

The consultation bodies also criticized the proposed framework for being legally and institutionally vague. They raised concerns about accountability, liability, and the suitability of economic associations as an organizational form for ECs. The Swedish Energy Agency and several municipalities also highlighted uncertainties regarding the purpose and legal scope of ECs. In addition, the Swedish Tax Agency stated that ECs should charge market-based prices to their members. This implies that below-market pricing would not be permitted unless explicitly clarified in legislation (Palm, 2021).

Several consultation bodies also called for further investigation of non-concession grids (*icke-koncessionspliktiga nät*, IKNs). They argued that restrictions on grid ownership by ECs should be reconsidered. Regional Energy Agencies Sweden noted that prohibiting ECs from owning grids would expose members to both network charges and energy taxes. This would reduce the benefits compared with internal electricity sharing through IKNs. Regional Energy Agencies Sweden and Property Owners Sweden also referred to a Swedish government report that proposed expanded opportunities for grid ownership and electricity trading. They argued that such reforms would be important for making ECs practically viable in Sweden (Palm, 2021).

According to Palm (2021), the absence of an enabling legal and fiscal framework is a major barrier to the development of ECs in Sweden. This includes the lack of simplified regulatory procedures and targeted economic incentives. Palm further notes that Ei expressed limited expectations regarding the future role of ECs. The report also lacked a clear vision of how ECs could contribute to the Swedish energy system. Several stakeholders criticized this position and argued that the regulator should actively support the emergence of ECs, rather than only assess their limited market impact.

The proposal was not adopted by the previous government (Regeringen, 2022, Prop. 2021/22:153, p. 112). As a result, Swedish law still does not contain a statutory definition of ECs or a dedicated enabling framework (REScoop.eu, 2024). Instead, relevant provisions are fragmented across the Electricity Act (1997:857), the IKN Ordinance (2007:215, as amended), and the Energy Tax Act (1994:1776), also referred to as *lagen om skatt på energi* (LSE). These legal instruments only allow limited forms of behind-the-meter electricity sharing through internal networks. They also provide tax exemptions for self-consumed electricity only under specific conditions. This fragmented regulatory environment constrains the formation and scaling of ECs in Sweden. It has also raised concerns regarding Sweden's compliance with EU transposition obligations, particularly Article 22(4) of RED II.

3.1.3 Energy Community and Sharing in Swedish Law and Policy

Recent revisions of EU electricity and renewable energy legislation have introduced the concept of energy sharing alongside the existing framework for energy communities (ECs). Under Directive (EU) 2024/1711, energy sharing refers to the sharing of electricity from renewable sources within a geographically limited area defined by Member States. Unlike behind-the-meter self-consumption, this form of energy sharing explicitly relies on the public electricity network. It complements existing rules on individual and collective self-consumption and aims to broaden participation in local renewable energy systems.

EU policymakers identify several potential benefits of energy sharing. It can reduce consumers' exposure to volatile wholesale electricity prices and enable participation by consumers who cannot install their own generation assets due to spatial or financial constraints. It can also mobilize private investment in renewable energy. In addition, energy sharing may increase flexibility among smaller consumers when combined with dynamic pricing signals and storage technologies. In this way, it can contribute to system efficiency and decarbonization. Member States must transpose the provisions on energy sharing into national law by 17 July 2026.

Energy sharing is broader than the concept of ECs. It also applies to active customers, who may share surplus renewable electricity either free of charge or in return for remuneration. This can be done directly between participants or through a third-party organizer. EU law also recognizes peer-to-peer (P2P) trading of renewable energy. In the Renewable Energy Directive (RED), P2P trading is defined as the sale of renewable electricity between market participants through contracts with predetermined automated settlement conditions. These transactions may take place directly or through certified intermediaries, such as aggregators.

It is therefore important to distinguish between the organizational and contractual dimensions of these arrangements. Participation in energy sharing or P2P trading does not require membership in an EC. However, ECs may act as legal entities that organize or facilitate such arrangements. P2P trading should therefore be understood as a complementary market mechanism, rather than as a defining feature of ECs.

This regulatory development highlights the potential role of energy sharing in local renewable energy systems. It also provides the basis for the simulated scenarios in this study, where P2P trading is used as a mechanism for sharing electricity within the EC.

3.2 Organizational Structures and Governance

3.2.1 Governance and Structure of Energy Communities

The simplest form of an energy community (EC) consists only of consumers. In this model, members do not jointly own energy assets. Instead, the main purpose is to obtain collective discounts or to aggregate demand response capacity. Consumers may also form coalitions with prosumers to purchase surplus electricity, for example through peer-to-peer (P2P) trading (Gjorgievski et al., 2021).

Another common type of EC is based on collective investment in large-scale energy production. These communities have often been organized as energy cooperatives, limited partnerships, or non-profit consumer-owned companies (Gjorgievski et al., 2021).

3.2.2 Business Models for Energy Communities

Barabino et al. (2023) identify six categories of business models for energy communities (ECs): prosumer-based models, collective generation, aggregation, third-party sponsorship, local energy markets (LEMs), and cooperatives. Reis et al. (2021) identify eight business model types: energy cooperatives, community prosumerism, LEMs, community collective generation, third-party sponsored communities, community flexibility aggregation, community energy service companies (ESCOs), and e-mobility. Reis et al. (2021) also note that this classification is not exhaustive, as several hybrid business models may emerge in practice.

The two classifications overlap substantially. The main difference is that Reis et al. (2021) include community ESCOs and e-mobility as separate business model categories. Table 3 summarises the business models identified by Barabino et al. (2023) and Reis et al. (2021).

Table 3. Overview of EC business models described in literature.

Business model	**Description**	**Reference(s)**
Prosumer	The members are prosumers who can produce electricity and share it to other members.	(Barabino et al., 2023)
Collective generation/Community Collective Generation	Energy storage and generation is shared among the members, and the benefits and investment are also shared among the members.	(Barabino et al., 2023; Reis et al., 2021)
Aggregator/Flexibility aggregation	An aggregator can access flexibility markets or negotiate better conditions.	(Barabino et al., 2023; Reis et al., 2021)
3rd part sponsored	A third party owns the assets and may gain some financial compensation for it. Member can get benefits in the form of lower energy prices and renewable energy.	(Barabino et al., 2023; Reis et al., 2021)
Local Energy Market	Members can trade their energy within the community through P2P platforms.	(Barabino et al., 2023; Reis et al., 2021)
Energy Cooperatives	Members manage the community and reinvest in it, and the rest is distributed among the members	(Barabino et al., 2023; Reis et al., 2021)
E-mobility cooperatives	Cooperative with EVs can use their batteries as storage and exploit vehicle-to-grid and smart charging to reduce energy bill.	(Reis et al., 2021)

The literature shows that energy communities (ECs) can be based on a wide range of business models. The scenarios simulated in this study combine elements of local energy markets

(LEMs), prosumer-based models, and e-mobility models. This is because the scenarios include local electricity trading and prosumers. In the second part of the study, an electric vehicle (EV) is integrated into the model, which adds an e-mobility component to the business model.

3.2.3 Revenue and Cost Allocation Mechanisms

Several studies emphasize that prices in peer-to-peer (P2P) electricity markets should be higher than the feed-in tariff but lower than the conventional retail electricity price (Deng et al., 2023; Henni et al., 2021; Liu et al., 2017; Long et al., 2018; Paudel et al., 2019; Zepter et al., 2019). This price range is important because it creates benefits for both sellers and buyers. Prosumers receive a higher price than they would obtain from selling surplus electricity to the grid, while consumers can purchase electricity at a lower price than from the conventional electricity market.

Several studies use the supply–demand ratio (SDR) as a dynamic pricing mechanism for P2P trading (Deng et al., 2023; Liu et al., 2017; Long et al., 2018). In these models, the feed-in tariff defines the lower price bound, while the conventional retail electricity price defines the upper bound. When the SDR is between zero and one, the internal P2P price is calculated dynamically within this range. When the SDR is greater than one, the price is set equal to the feed-in tariff. When the SDR is zero, no internal electricity is available, and all electricity is purchased from the grid at the retail electricity price.

Henni et al. (2021) propose a fixed pricing model for P2P electricity trading. In their model, the feed-in tariff is used as the lower price bound, while the average electricity market price is used as the upper bound. Based on these limits, they develop four pricing scenarios to analyze how different price levels affect consumers and prosumers. The prosumer group includes households with photovoltaic (PV) systems only and households with both PV systems and battery energy storage systems (BESSs).

Zepter et al. (2019) propose a pricing model in which the P2P price is based on the retail electricity price minus network fees. This creates an internal price that is lower than the conventional electricity price, which encourages consumers to buy electricity within the community or local energy market. As in other pricing models, the feed-in tariff is used as a price floor. This approach is dynamic, transparent, and relatively simple to calculate.

Baez-Gonzalez et al. (2018) propose a continuous double auction (CDA) for P2P energy trading. In this model, prosumers can act either as buyers or sellers, but not both at the same time. Compared with a discrete-time double auction (DDA), a CDA may enable more electricity to be traded because participants do not need to wait for the next market session.

Overall, the literature shows that P2P electricity prices should generally be set between the feed-in tariff and the conventional retail electricity price. This principle is important for the scenario design in this study, as the aim is to develop pricing mechanisms that are beneficial for both prosumers and consumers. The pricing mechanisms identified in the literature are therefore used in the simulated scenarios to compare their economic performance.

3.3 Empirical Examples in the Swedish and European Context

In this section some real-world cases of energy communities will be presented as they are used to design the scenarios simulated in this work.

3.3.1 Tamarinden (Sweden)

The energy community project in Tamarinden, Örebro, is a collaboration between Örebro Municipality and five construction companies. Each construction company has one voting right, while the municipality does not have voting rights under normal conditions. If one of the construction companies withdraws, the municipality may temporarily assume voting rights until a new actor is found. The legal entity used for the Tamarinden energy community is a joint property association (*samfällighetsförening*). This association will own and operate the community's local distribution grid. However, the current organisational form does not fulfil the requirements for a Renewable Energy Community (REC) or a Citizen Energy Community (CEC) as defined in EU legislation. This is because membership is linked to property ownership and does not allow open entry and exit in the same way as required under the EU framework (Lönntoft & Hasselqvist, 2024).

The local direct-current (DC) grid enables electricity sharing both within and between properties in Tamarinden. The Swedish Energy Markets Inspectorate has decided that each property only needs one connection to the external grid, rather than separate grid connections for each apartment. In addition, the Supreme Administrative Court has ruled that electricity shared within Tamarinden is exempt from energy tax. According to Lönntoft and Hasselqvist (2024), the economic viability of the project depends strongly on whether internal electricity sharing can remain exempt from taxation.

3.3.2 Hammarby Sjöstad (Sweden)

The legal entity for the energy community in Hammarby Sjöstad is an economic association consisting of the housing associations that participate in the community. This organizational form is similar to a cooperative, as it enables members to collaborate democratically on issues related to sustainable energy supply. In this case, the members do not jointly own energy infrastructure. If joint ownership of infrastructure had been required, a joint property association (*samfällighetsförening*) would have been a more suitable organizational form (Danielsson et al., 2024).

The energy community has adopted statutes that guide decision-making among its members. Its board consists of six members and meets monthly to follow up on ongoing work, allocate resources, and guide the continued development of the energy community (Danielsson et al., 2024).

The purpose of virtual electricity sharing is to reduce electricity costs for participating members. For the model to be viable, all involved actors must receive part of the economic benefit. In Hammarby Sjöstad, a housing association that shares surplus electricity with another member must receive higher compensation than it would have received by selling the electricity to the grid. At the same time, the housing association that receives the shared electricity benefits from reduced energy tax and network tariffs. Actors that enable the sharing arrangement, such as the

electricity retailer and the distribution system operator (DSO), must also be compensated for their role.

Danielsson et al. (2024) propose the following distribution of the economic benefit: 50% to the producer of surplus electricity, 29% to the member receiving the shared electricity, 20% to the energy community, and 1% to the electricity retailer and the DSO. The shares allocated to the energy community, the retailer, and the DSO are intended to cover the administrative costs associated with managing the energy community and facilitating electricity sharing. The viability of virtual electricity sharing therefore depends strongly on reduced network tariffs and reduced energy taxes.

3.3.3 GridFlex Heeten (Netherlands)

GridFlex Heeten is a Citizen Energy Community (CEC) project located in Heeten, the Netherlands. The project involves several actors, including Enexis B.V., Endona U.A., Enpuls B.V., DrTen B.V., ICT Group N.V., and the University of Twente. The community consists of 47 households connected downstream of a single transformer. These households cooperate to reduce stress on the local distribution network. Some households have rooftop photovoltaic (PV) systems, while others have a 5 kWh battery installed behind the meter. Data from smart meters and PV production are available within the project. In addition, households use an app to gain insight into their energy consumption. For the purpose of the project, all participating households are treated as one aggregated entity behind the transformer (Reijnders et al., 2020).

The households still pay the distribution system operator (DSO) for their individual grid connections. However, the community as a whole is treated as having one shared connection for energy transport purposes. Electricity exchanged within the community is therefore not subject to DSO transport charges. Instead, the transport cost is calculated for the entire community and is based on the community's demand, measured in kilowatts (kW), during 15-minute intervals. Three demand levels are used, and the transport cost increases quadratically between these levels. This tariff structure is intended to encourage self-consumption and reduce peak demand. The project has been granted an exemption from Dutch law to test alternative electricity tariffs and validate different pricing mechanisms (Reijnders et al., 2020).

3.3.4 Allensbach (Germany)

The community consists of 12 semi-detached houses and two apartment buildings, all of which are privately owned. It is organized as an owner community established by the property owners. The community has a total photovoltaic (PV) capacity of 88 kWp. It also includes heat pumps and a combined heat and power (CHP) plant provided by Energiedienst AG. Flexible household appliances are used as virtual batteries to support load shifting. The community has a private electricity grid operated by Energiedienst AG, whose responsibilities include metering and electricity supply (Werner, 2024).

Electricity generated by the community's PV systems and CHP plant is primarily consumed within the community. However, this electricity is not provided free of charge. Instead, the internal price is based on a price signal called the balance indicator (BI), which ranges from -1 to 1 and indicates either energy surplus or scarcity. Cost savings are mainly achieved through

increased self-consumption, which reduces the community's dependence on the external electricity grid (Werner, 2024).

3.4 Synthesis and Research Gaps

The literature and empirical cases show that regulation has a significant impact on the viability of different types of energy communities (ECs) and on the forms of energy sharing that are permitted.

The literature also shows that ECs can be organized in several ways. This is partly because business models often overlap. These business models differ in terms of ownership structure, governance, participating actors, and electricity allocation mechanisms. However, many internal pricing mechanisms for local electricity are based on similar principles. The feed-in tariff often defines the lower price bound, while the retail electricity price defines the upper price bound. Real-world cases further show that regulation strongly influences which business models are feasible in practice.

In many studies, peer-to-peer (P2P) pricing models are simplified. They are often analyzed without considering tariff structures, tax regimes, or detailed regulatory conditions. In addition, electric vehicles (EVs) are commonly treated as flexibility assets, rather than as active participants that can share energy between communities. As a result, the economic effects of EV-based energy sharing on EC profitability remain insufficiently explored.

Based on these gaps, this study combines a literature review with simulations of electricity sharing within ECs. The simulations compare different pricing mechanisms, tariff structures, and regulatory conditions. The study also examines how EV behavior affects profitability and how costs and revenues are distributed among members of the energy community.

4 CONFIGURATION OF CASE STUDIES

In this section the configuration of the case studies is described. The PV system and load configuration used in both parts are described. The settings of the EV in C2V2C are described with the different EV configurations considered in the economic evaluation of C2V2C. In Table 4, the inputs for the PV-model are summarized.

Table 4. Summary of technical input parameters for the PV profile.

Parameter	Value
Year	2023
Solar radiation database	PVGIS-SARAH3
Mounting type	Fixed
Latitude	59.623
Longitude	16.548
Elevation [m]	32
Azimuth [°]	180
Tilt [°]	35

PV technology	Crystalline Silicone
Nominal Power [kW]	10
System losses [%]	14

4.1 Building Community Power demand and Supply profiles

The input data consist partly of real-world data, including electricity load profiles, network tariffs, and taxes. One load profile represents 74 households, while the other represents the electricity demand of a university building. The university load profile is divided into three separate load profiles to represent three buildings on a university campus. The largest building accounts for 50% of the total load, the second for 30%, and the third for 20%. This setup enables the analysis of energy sharing between buildings within an energy community (EC) under different pricing mechanisms.

The first EC consists of 74 households. Of these, 40 households have photovoltaic (PV) systems, while the remaining 34 households do not. Figure 3 shows the load profiles and PV production for EC1 This ensures that there are both prosumers and consumers in the community. It also makes it possible to compare how these two groups are affected by the different pricing mechanisms included in the simulation.

The second EC consists of three university buildings, all equipped with PV systems. This community is intended to represent a workplace or campus environment with several buildings. The PV system size is scaled according to each building's electricity demand. The building with the highest demand therefore has the largest PV system. The PV profile is scaled by a factor of 30 for the largest building, 25 for the second-largest building, and 15 for the smallest building. The aggregated PV production from all three buildings is shown in Figure 4.

The PV profile is generated for a full year with hourly resolution. The PV systems are assumed to be located in Västerås, with a panel tilt angle of 35° and a south-facing orientation. The 40 households with PV systems use the same PV production profile. In the simulation code, the household PV profile is scaled by a factor of 0.35 to obtain a suitable system size. During the simulated week, the load in EC1 peaks at approximately 70 kW. There are also short periods

when PV production exceeds the total demand in the community. The PV production peaks at approximately 40 kW.

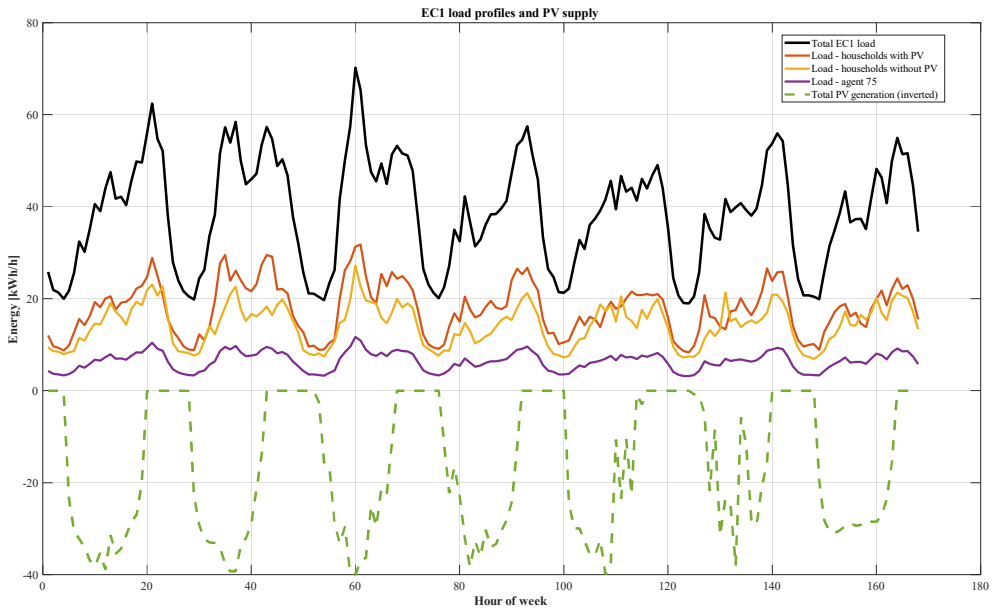

Figure 3. EC1 load and PV-supply profile.

In the second case, two energy communities (ECs) are modelled. All three buildings in the second EC are equipped with photovoltaic (PV) systems. Each building has a separate PV profile with an individual scaling factor to ensure that the PV capacity is appropriately dimensioned in relation to the building's electricity demand.

Figure 4 shows the load profile and PV production profile for EC2. The peak electricity demand in EC2 is approximately 160 kW during the simulated week. The PV system is relatively large and is able to cover the community's demand during several periods of high electricity use.

Total PV production peaks at approximately 200 kW, compared with a peak demand of approximately 160 kW.

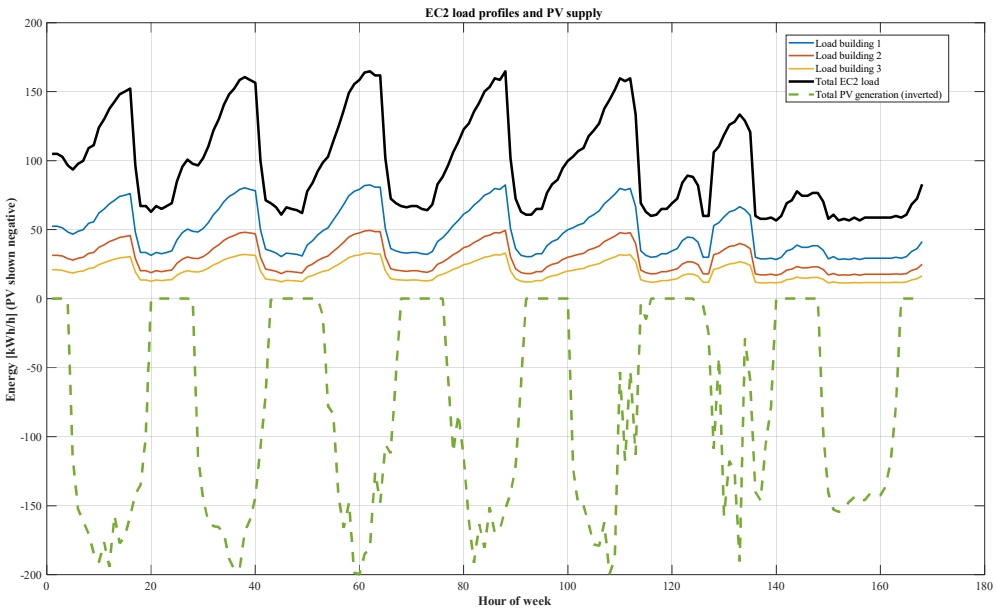

Figure 4. EC2 load and PV-supply profile.

4.2 EV Modeling

The EV is created with an initial state of charge of 15 kWh which is also the minimum charge of the EV. It can charge up to 30 kWh in the base scenario which means it has 15 kWh electricity available to charge and discharge. In the base scenario the EV's charging and discharging capacity is 2 kW. The EV charging and discharging capacity determines how quickly the EV's battery charges – in other words how many hours it takes to charge and discharge it fully. This will affect the EV's profitability due to changes in electricity price. A delay is also considered (1 hour delay in the base scenario) which shifts the charging and discharging away from the arrival time in either of the ECs. Depending on the electricity price when the EV starts to charge or discharge will affect the profitability of the EV.

The EV behavior is defined as such that the EV is located at EC2 from Monday to Friday between 08:00 and 16:00, where it can be charged. Then, between 17:00 and 07:00 (when including the minimum delay of 1h) from Monday to Friday, as well as during Saturday and Sunday, the EV is located at EC1, where it is discharged to supply that energy community with electricity if there is a demand. In the modeling the EV is considered as an extra load in the load profile or as an extra supplier in the PV profile. This is determined by the schedule described above. The delay parameter determines when the EV either starts charging or discharging. This will affect the cost and revenue of the EV as the electricity price changes by the hour.

A sensitivity analysis is then performed where the charging and discharging capacity is varied between 1–4 kW, the amount of delivered energy between 10–20 kWh, and the delay between 1–3 hours. These parameters are adjusted one at a time. In the base scenario, the delivered energy is 15 kWh, the charging/discharging capacity is 2 kW, and the charging/discharging

delay is 1 hour. In total, eight different scenarios are simulated. The reason for not simulating and evaluating all possible combinations of these parameters is that this would result in too many scenarios and would not be manageable within the scope of this work. Each scenario is simulated using all pricing models, except for free internal sharing.

Scenario ID	E_delivery (kWh)	E_charge (kW)	Delay (h)
1	10	2	1
2	20	2	1
3	15	2	1
4	15	1	1
5	15	2	2
6	15	3	1
7	15	4	1
8	15	2	2

Table 5. EV scenario overview

4.3 Electricity Price Data

Electricity tax is included in the simulation based on the tax level applicable in Sweden. Electricity prices are based on NordPool day-ahead hourly data for Sweden's bidding zone SE3 in 2025. The network transfer tariff is set to 21.50 öre/kWh, based on tariff information from Mälarenergi (Mälarenergi, n.d.). A feed-in price of SEK 0.50/kWh is assumed, based on a forecast from the Swedish Energy Agency (Energimyndigheten, 2025). In addition, grid-benefit compensation is assumed to be 5 öre/kWh. This compensation is paid by the distribution system operator (DSO) to producers because local electricity generation can provide benefits to the distribution grid. The level of grid-benefit compensation varies between DSOs.

All prices expressed in SEK are converted to EUR in MATLAB after the input values have been defined. An exchange rate of 10.74 SEK/EUR is used. This value is chosen because the exchange rate has generally been within the range of approximately 10.50–11.30 SEK/EUR during the relevant period. Sweden does not currently have a general feed-in tariff. However, until 1 January 2026, small-scale producers received tax compensation of SEK 0.60/kWh for electricity exported to the grid.

The electricity price data are used in the pricing models that calculate internal buying and selling prices for electricity. When the grid price is used in these models, electricity tax and network tariffs are included. This reflects the actual cost of purchasing electricity from the grid. Excluding taxes and network tariffs would make the internal buying price unrealistically low in some cases, and it could even fall below the feed-in price. The objective is therefore to set the internal buying price below the grid purchase price, while keeping the internal selling price above the feed-in price. If this condition is met, internal electricity trading becomes economically beneficial for both consumers and producers compared with buying electricity from, or selling electricity to, the grid.

Pricing Parameters	Value	Reference
Electricity price	Sweden, SE3, 2025	NordPool
Network tariff	21.50 öre/kWh	(Mälarenergi, n.d.)
Tax	36 öre/kWh	(Skatteverket, 2025)
Feed-in Tariff	50 öre/kWh	(Energimyndigheten, 2025)

Grid Benefit Compensation	5 öre/kWh	Assumed
Exchange Rate (SEK/EUR)	10.74	Assumed

Table 6. Economic inputs.

4.4 Scenario Simulation Settings

The different scenarios are constructed from different pricing mechanisms described earlier and with different tax and network fee conditions based on cases from different EU countries. The scenarios are summarized in Table 1. The aim is to compare the different pricing mechanisms under different regulatory conditions and sharing principles. Both physical (microgrid) and virtual sharing (VS) are considered as these types of sharing mechanisms are usually considered different under regulations and policy. Physical sharing is not (usually) subject taxes and network fees as this happens "behind the meter", which makes possible savings of physical sharing greater than virtual sharing that often are subject to taxes and network tariff as it utilizes the public grid. When evaluating physical sharing investments into microgrids are not considered or the cost of operating the microgrid. This work only evaluates the amount of savings between virtual sharing and physical sharing. Therefore, this work cannot be used to determine if a microgrid is a worthwhile investment.

The VS-Bench scenario represents virtual sharing. Electricity traded within the energy community (EC) is therefore still subject to electricity tax and network charges. The main difference from conventional grid trading is that internal buying and selling prices are calculated within the EC. The purpose of this scenario is to make internal electricity sharing more attractive for both prosumers and consumers, while still including the same taxes and network charges as conventional grid electricity.

The PS-Dynam scenario is similar to VS-Bench, but it is based on physical sharing. This means that internally shared electricity is exempt from electricity tax and network charges. Together, VS-Bench and PS-Dynam make it possible to evaluate how taxes and network charges affect the net bills of consumers, prosumers, and the EC as a whole. These two scenarios therefore represent two different forms of energy sharing: virtual sharing and physical sharing.

Two scenarios use a double auction mechanism combined with physical sharing: PS-DouAucPro and PS-DouAucSeq. In both scenarios, the internal buying and selling prices are determined by bids from buyers and sellers. The difference between the two scenarios lies in how the traded electricity is allocated between participants. PS-DouAucPro uses proportional allocation, while PS-DouAucSeq uses sequential allocation. These allocation principles are described in more detail in Section 2.2.2. The purpose of these scenarios is to evaluate how different allocation rules affect the economic outcomes of stakeholders.

The PS-SDR scenario differs from the other scenarios because the internal price is mainly determined by the local photovoltaic (PV) surplus and the supply–demand ratio (SDR). The grid price and the feed-in price are used as the upper and lower price bounds, respectively.

In the PS-ComArea scenario, surplus PV electricity from households is shared with the common areas of the building. This can increase the building's self-consumption and reduce electricity costs for shared facilities. In practice, these savings could potentially be transferred to residents through, for example, lower rents or fees.

The PS-Fixed scenario uses physical sharing with fixed internal buying and selling prices. This represents a simple pricing mechanism that is easy to implement, but it may be less responsive to changes in electricity prices, demand, and PV generation.

The VS-DisByRatio scenario uses virtual sharing, and both electricity tax and network tariffs are included. In this scenario, the economic benefit is calculated as the difference between the spot price and the feed-in price. This benefit is then distributed among the prosumer, the consumer, and the agent. The scenario is inspired by the Hammarby Sjöstad energy community described in Section 3.3.2. The distribution of benefits between stakeholders is described in Section 2.2.1. This scenario illustrates an alternative way of allocating economic benefits within an EC.

The VS-NetFeeRed scenario also uses virtual sharing. However, electricity tax is excluded, and a reduced network tariff is applied. This scenario is inspired by regulatory conditions in Austria and is used to analyse how reduced network charges can affect the economic performance of virtual energy sharing.

Model Abbreviation	**Description**
PS-SDR	Physical sharing with SDR pricing mechanism
PS-Dynam	Physical sharing with Dynamic pricing mechanism
PS-Fixed	Physical sharing with Fixed pricing mechanism
VS-NetFeeRed	Virtual sharing with Reduced Network Tariff
PS-DouAucSeq	Physical sharing with Double auction and Sequential sharing
PS-DouAucProp	Physical sharing with Double auction and Proportional sharing
PS-ComArea	Physical sharing, Property Operator and Owner
VS-DisByRatio	Virtual sharing, Post Auditing
VS-Bench	Virtual sharing with Dynamic pricing mechanism

Table 7. Overview of simulated models. See Section 2.2.1 and 2.2.2 for more information about each pricing mechanism and energy sharing allocation method.

5 RESULTS

This chapter presents the simulation results. Section 5.1 first presents the results for the different pricing mechanisms in a single energy community (EC). The pricing mechanisms are evaluated using three main indicators: the total net bill for the EC, the net bill divided by stakeholder group, and the agent profit.

Section 5.2 presents the results for electric vehicle (EV) integration in two ECs. This part evaluates the net bill for different stakeholders, EV profit, and agent profit. All results are based on simulations of one summer week. This period was selected because photovoltaic (PV) generation is relatively high in Sweden during summer, which increases the likelihood of surplus PV electricity that can be shared within the EC.

5.1 Evaluation of different pricing mechanisms

5.1.1 Comparison of Different Pricing Mechanisms

Figure 5 compares the internal prices for the different pricing mechanisms during the simulated week with the grid price and the feed-in price. Most pricing mechanisms follow the fluctuations in the grid price, as they are calculated partly or fully based on it. However, some scenarios deviate more clearly, particularly PS-SDR and the two double auction scenarios.

The PS-SDR scenario differs because the internal buying and selling prices are determined by the local supply–demand ratio (SDR). When the community has a large surplus of photovoltaic (PV) electricity, the internal prices decrease. This means that internal prices may be low even when the grid buying price is high. As a result, PS-SDR can diverge substantially from the grid price.

The two double auction scenarios, PS-DouAucPro and PS-DouAucSeq, also show price deviations from the grid price. This is because buying and selling bids are randomly generated within the interval between the feed-in price and the grid buying price. The resulting clearing price can therefore differ from the grid price, depending on the accepted bids.

In the PS-Dynam and VS-Bench scenarios, the internal price depends on the weighting factor (w_2) in Equation (8). Changing this parameter increases or decreases the internal price and therefore affects which stakeholder group benefits the most. A higher internal selling price benefits prosumers, while a lower internal buying price benefits consumers.

The PS-Fixed scenario provides stable and predictable internal prices. This makes it simple to implement, but less responsive to changes in grid prices, demand, and PV generation. In the VS-DisByRatio scenario, the internal buying price is equal to the grid price, while the internal selling price is equal to the feed-in price. This makes the compensation predictable for prosumers. However, the benefit for consumers depends on the distribution of the economic surplus and is therefore less directly reflected in the internal buying price.

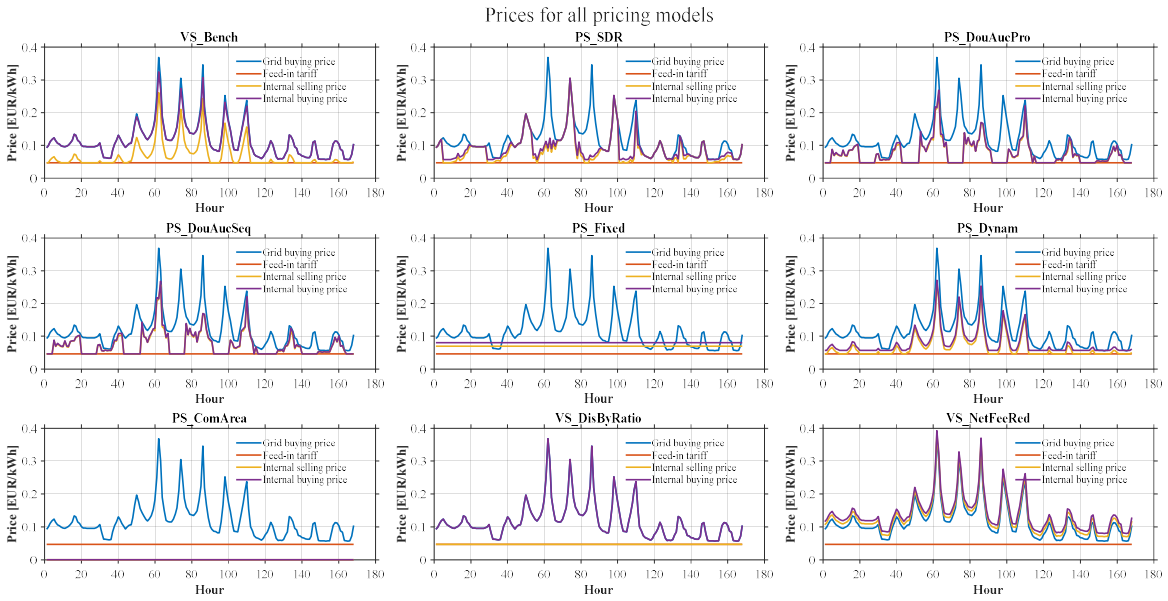

Figure 5. Internal pricing compared to feed-in tariff and grid price (including tax and network tariff).

5.1.2 Agent Profit

The agent generates a profit in all scenarios except PS-ComArea, as this scenario does not include internal electricity trading. In the other scenarios, the internal buying price is generally higher than the internal selling price. The difference between these prices creates a profit for the agent. However, in some hours the buying and selling prices may be equal. In those cases, the agent does not earn a profit from the internal trade.

Figure 6 shows that the agent profit follows a similar pattern in most scenarios. The main difference between these scenarios is the amount of electricity traded internally. VS-DisByRatio differs from the other scenarios because the agent receives a fixed share, 10%, of the economic benefit created by the difference between the grid price and the feed-in price. This leads to more variable profits over the simulated week. The agent profit is higher during periods with large photovoltaic (PV) surplus and lower when the available surplus is limited.

Three pricing mechanisms result in the same total agent profit of EUR 12.5. These scenarios also show a relatively stable profit pattern over the week, as shown in Figure 6. The two double auction scenarios generate the same total agent profit of EUR 1.5, since the internal prices are calculated using the same pricing rule. VS-Bench and VS-DisByRatio generate similar total profits over the week, but the timing of the profit differs. VS-DisByRatio is more volatile and has a few distinct profit peaks, while the profit in VS-Bench is more evenly distributed.

Table 7 summarises the agent profit for all pricing mechanisms. The similar profit levels in several scenarios are mainly explained by the use of the same markup between the internal selling and buying prices. As a result, the agent profit depends primarily on the amount of electricity traded within the energy community.

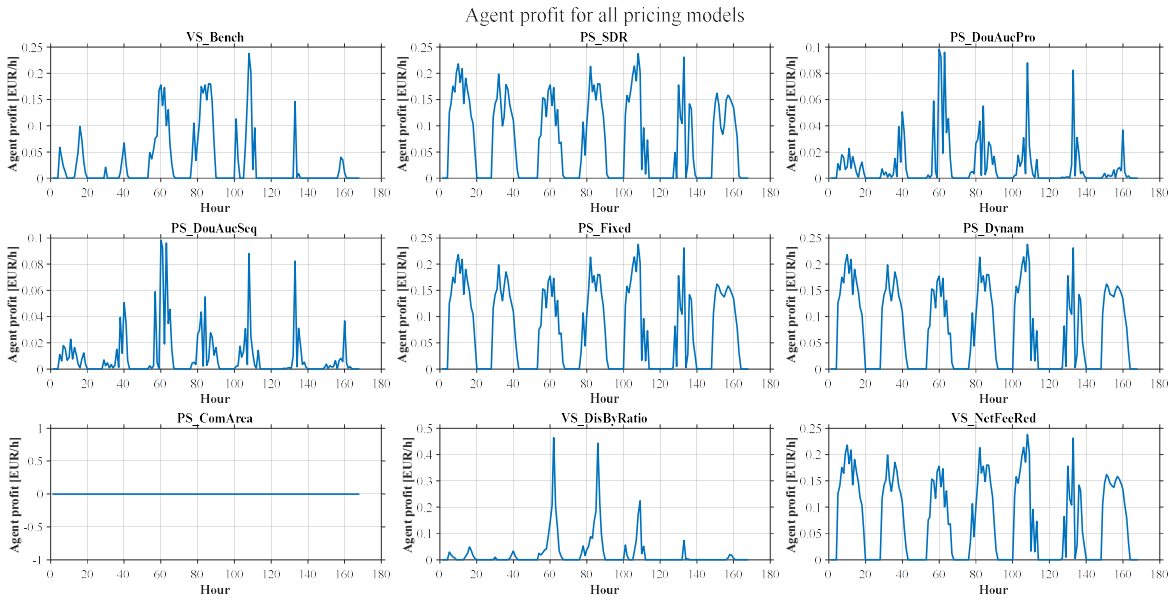

Figure 6. Agent profit distribution.

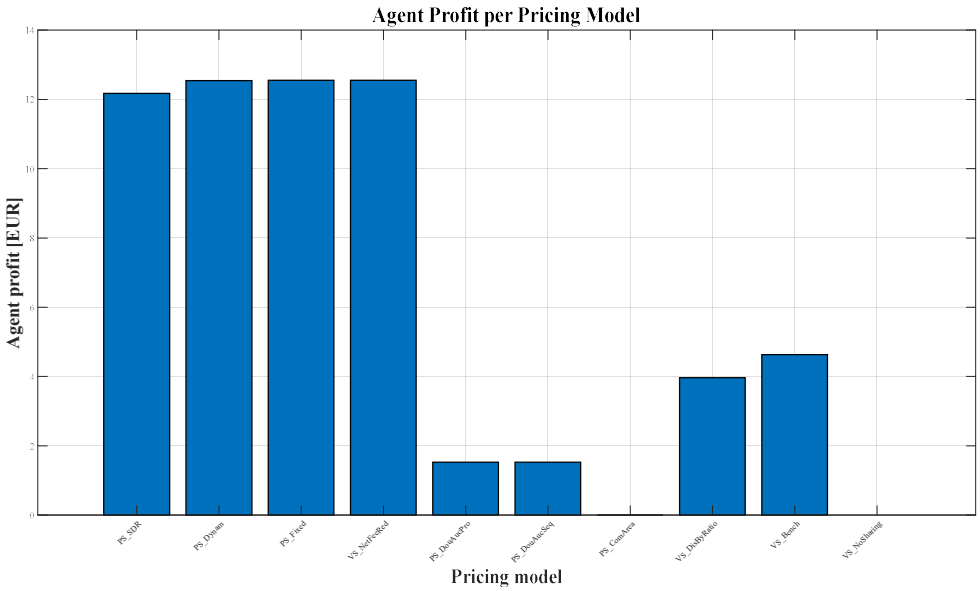

Figure 7. Total agent profit for each pricing mechanism.

Model	Agent Profit [EUR]
PS-SDR	12.2
PS-Dynam	12.5
PS-Fixed	12.5
VS-NetFeeRed	12.5
PS-DouAucSeq	1.5

PS-DouAucProp	1.5
PS-ComArea	0
VS-DisByRatio	4.0
VS-Bench	4.6
VS-NoSharing	0

Table 8. Agent profit by pricing mechanism.

Figure 8 shows that the allocation of internally traded electricity follows a similar pattern in most scenarios, except for PS-DouAucSeq and PS-ComArea. In the scenarios with similar patterns, larger households receive more electricity because internal electricity is allocated proportionally based on demand. This means that households with higher unmet demand receive a larger share of the electricity traded within the energy community.

PS-DouAucSeq and PS-ComArea differ because they use different allocation principles. In PS-ComArea, only one actor receives electricity. This actor represents the common areas of an apartment building, and the electricity is supplied free of charge from surplus photovoltaic (PV) production. In PS-DouAucSeq, electricity is allocated sequentially. As a result, some households may not receive any surplus electricity even if they still have unmet demand.

In PS-DouAucPro, the amount of electricity traded internally is lower than in most other scenarios, as shown in Figure 6. This can be explained by the fact that not all bids are accepted in the double auction. Consequently, some surplus electricity is sold to the grid even though some households still have remaining demand. These households must therefore cover part of their demand by purchasing electricity from the grid. The same mechanism also applies in PS-DouAucSeq.

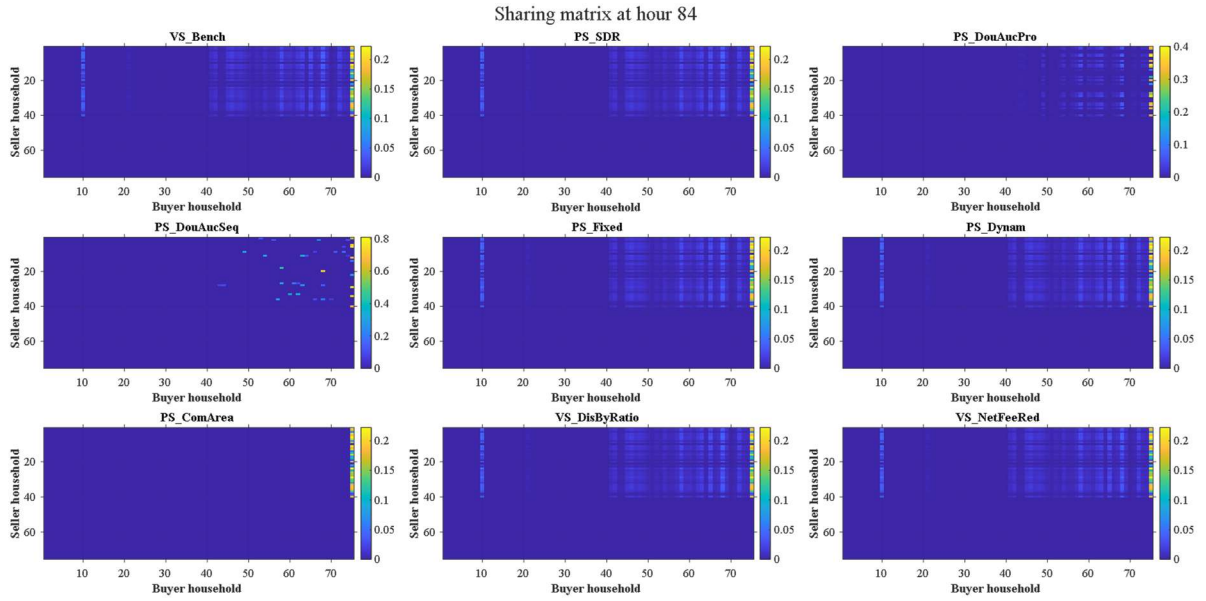

Figure 8. Energy sharing for each pricing mechanism.

5.1.3 Total Net Bill by Pricing Mechanism

Figure 9 shows the total net bill for the energy community under each pricing mechanism. In the VS-NoSharing case, no electricity is traded internally. All surplus photovoltaic (PV) electricity is therefore sold to the grid at the feed-in price, while consumers purchase their

electricity from the grid. As shown in Table 8, this results in the highest total net bill, EUR 506.1.

Several pricing mechanisms result in similar total net bills. VS-DisByRatio and VS-Bench have among the highest net bills, EUR 470.4 and EUR 471.1, respectively. However, both are still lower than the VS-NoSharing case. This is expected because these scenarios are based on virtual sharing, where electricity tax and network tariffs are still included. VS-NetFeeRed differs from the other virtual sharing scenarios because electricity tax is excluded and a reduced network tariff is applied. As a result, its total net bill is similar to those of PS-SDR and PS-Dynam.

For the energy community as a whole, the differences between most pricing mechanisms are relatively small. The two double auction scenarios both result in a total net bill of EUR 450.8, which is higher than in several other physical sharing scenarios. This is because not all available surplus electricity is traded internally. Some bids are not accepted in the auction, which means that part of the surplus electricity is sold to the grid and part of the demand is covered by grid purchases. This increases costs for consumers and reduces revenues for producers.

The PS-ComArea scenario also results in a relatively high total net bill compared with most other physical sharing scenarios. This is because only a limited share of the surplus electricity can be used internally by the common areas. Consequently, more electricity is exchanged with the grid. Table 10 summarizes the total net bill for each pricing mechanism and compares the results with the VS-NoSharing and VS-Bench cases.

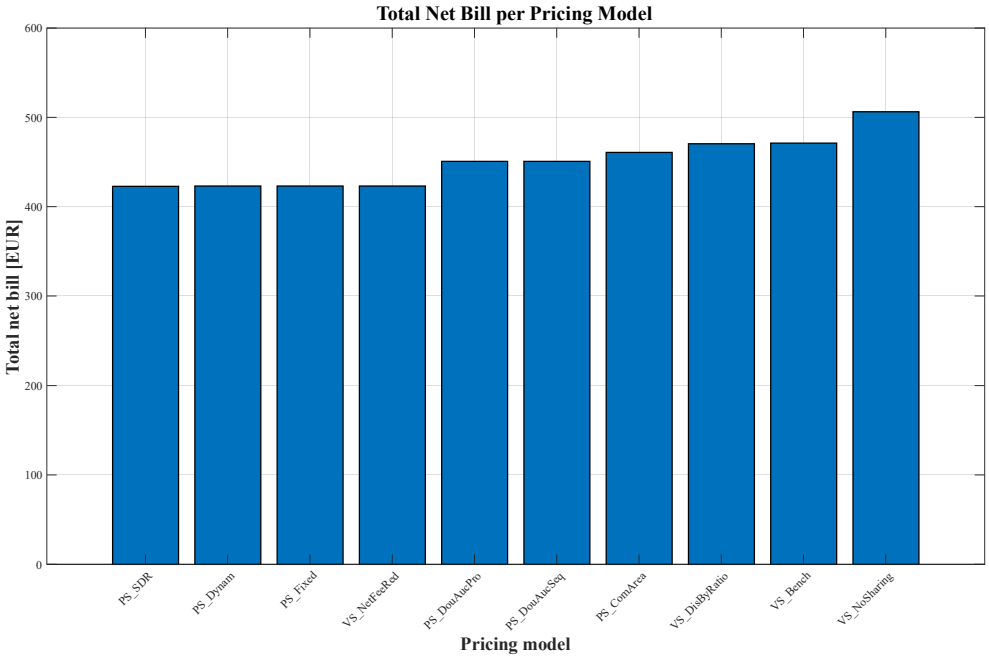

Figure 9. Total net bill for each pricing mechanism.

Model	Total Net Bill [EUR]	% Difference from VS-NoSharing	% Difference from VS-Bench
PS-SDR	422.9	-16.4%	-10.2%
PS-Dynam	423.3	-16.4%	-10.2%
PS-Fixed	423.3	-16.4%	-10.2%
VS-NetFeeRed	423.3	-16.4%	-10.2%

PS-DouAucSeq	450.8	-10.9%	-4.3%
PS-DouAucProp	450.8	-10.9%	-4.3%
PS-ComArea	460.8	-9.0%	-2.2%
VS-DisByRatio	470.4	-7.0%	-0.1%
VS-Bench	471.1	-6.9%	-
VS-NoSharing	506.1	-	7.4%

Table 9. Comparison of total net bill.

5.1.4 Distribution of Total Net Bill Between Stakeholders

Figure 10 shows how the total net bill is distributed between prosumers, consumers, and the property owner. The distribution is similar across most pricing mechanisms, although some scenarios differ more clearly.

In the PS-ComArea scenario, the share of the total net bill allocated to the common areas is lower than in the other scenarios. This is because the common areas are the only actor receiving surplus photovoltaic (PV) electricity in this case, and this electricity is supplied free of charge. In the PS-SDR scenario, the prosumers' share of the total net bill is higher than under most other pricing mechanisms. This indicates that prosumers benefit less from this mechanism. The reason is that a large PV surplus reduces the internal electricity price, which benefits consumers more than prosumers.

Table 10 presents the total net bill and the net bill for each stakeholder group. In PS-ComArea, the net bill for the common areas is EUR 51.3, which is considerably lower than in the other scenarios. This result is expected, as the common areas receive all internally allocated surplus electricity free of charge.

Another scenario that differs from the others is VS-NetFeeRed. In this case, the prosumers' total net bill is negative, meaning that prosumers make a net profit. At the same time, consumers have the highest net bill among all scenarios. This indicates that the pricing mechanism benefits prosumers more than consumers. The main explanation is that VS-NetFeeRed has significantly higher internal buying and selling prices than the other pricing mechanisms.

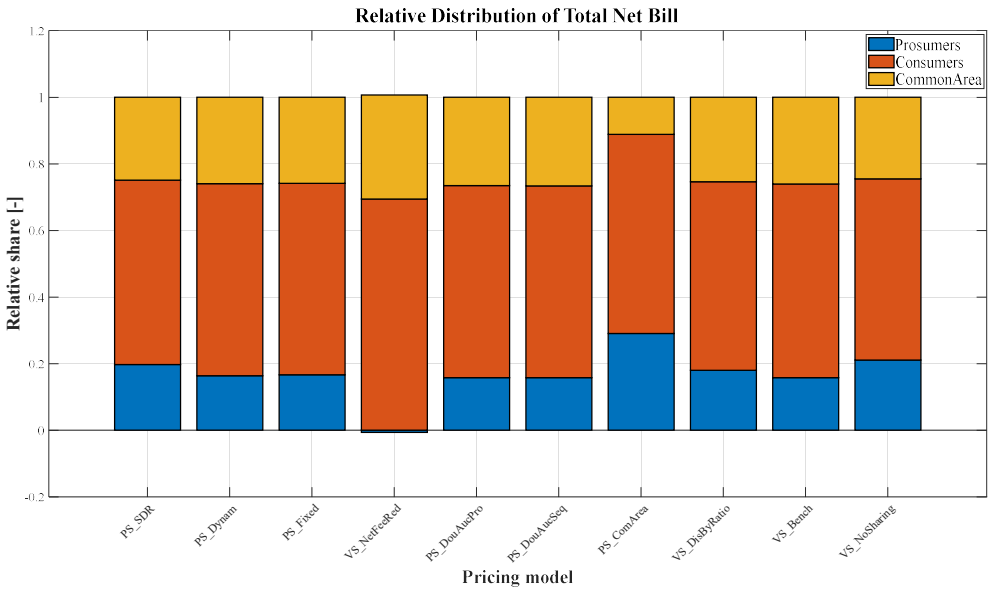

Figure 10. Distribution of total net bill between consumers, prosumers and common area.

Model	Total Net Bill [EUR]	Prosumer [EUR]	Consumer [EUR]	Common Area [EUR]
PS-SDR	422.9	83.6	234.2	105.1
PS-Dynam	423.3	69.5	244.1	109.7
PS-Fixed	423.3	70.7	243.4	109.2
VS-NetFeeRed	423.3	-2.7	294.0	132.0
PS-DouAucSeq	450.8	71.2	259.6	120.0
PS-DouAucProp	450.8	71.3	260.2	119.4
PS-ComArea	460.8	133.9	275.6	51.3
VS-DisByRatio	470.4	84.8	266.1	119.5
VS-Bench	471.1	74.5	273.7	122.9
VS-NoSharing	506.1	106.7	275.6	123.8

Table 10. Net bill by stakeholder category and pricing mechanism

5.1.5 Comparison of Small and Large Users with and without PV

Figure 11 compares the net bill for small and large households with and without photovoltaic (PV) systems during the simulated week. Large users are defined as households with a load above the 75th percentile. In general, non-PV users have higher net bills than PV users of the same size. Smaller users also tend to have lower net bills than larger users, regardless of whether they have PV systems.

When the results are compared with the VS-Bench scenario, PV users have higher costs in several pricing mechanisms. This is particularly clear in the two double auction scenarios and in VS-DisByRatio. In these cases, many PV users are worse off than in the benchmark scenario. By contrast, PV users benefit substantially in the VS-NetFeeRed scenario, where they have lower costs than in the benchmark case. However, non-PV users have higher costs in this scenario, indicating that the benefits are distributed more favorably towards prosumers.

The PS-ComArea scenario differs from the other cases. In this scenario, both PV and non-PV users are generally worse off compared with the benchmark. PV users only receive revenue from electricity exported to the grid, while non-PV users must purchase all their electricity from the grid. The only actor that benefits is the common area agent, which receives surplus PV electricity free of charge. This reduces the amount of electricity that must be purchased from the grid for common-area demand.

The results for PS-Dynam are expected, as this scenario uses the same basic price calculation as VS-Bench but excludes electricity tax and network tariffs. As a result, all stakeholder groups have lower costs in PS-Dynam than in the benchmark scenario.

Several small PV users have a negative net bill in many scenarios, meaning that their revenues exceed their electricity costs. This can be explained by the fact that the PV system size is not adjusted to each household individually, but rather to the energy community as a whole. Households with low electricity demand can therefore sell a larger share of their PV production while purchasing less electricity from the grid or from the community. Larger PV users still benefit from self-consumption, but their higher electricity demand means that they must purchase more electricity overall.

The difference between small and large users without PV is relatively limited. However, large non-PV users are more sensitive to higher internal buying prices because they purchase more electricity. The pricing mechanisms with the lowest internal buying prices are therefore most beneficial for these users. For large non-PV users, the least favourable outcomes occur in the double auction scenarios and in the scenarios based on virtual sharing.

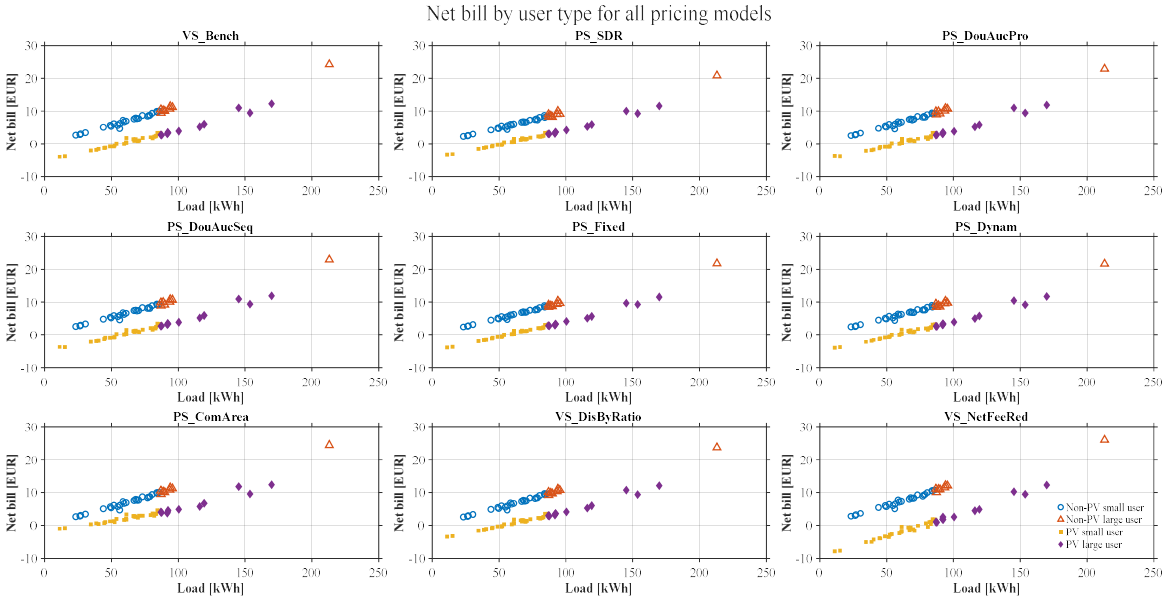

Figure 11. Comparison of small and large users with and without PV for each pricing mechanism

5.2 Evaluation of EV Agent Integration in two ECs

5.2.1 EV Net Bill for each Pricing Mechanism

Figure 12 shows the electric vehicle (EV) net bill for each pricing mechanism. The PS-SDR scenario is the only case in which the EV net bill is negative. This means that the EV generates a profit by transporting electricity from one energy community (EC) to another. In this scenario, the EV profit is approximately EUR 0.28 (Table 11) during the simulated week.

The EV net bill varies between the pricing mechanisms. The three virtual sharing scenarios result in the highest EV net bills. VS-Bench and VS-DisByRatio include electricity tax and network tariffs, while VS-NetFeeRed excludes electricity tax but includes a reduced network tariff. The remaining scenarios are based on physical sharing, where internally shared electricity is exempt from electricity tax and network charges. These scenarios generally result in lower internal prices, which reduces the EV net bill.

The cost and revenue components of the EV net bill are also shown in Figure 12. The cost represents the electricity purchased by the EV in EC2, where it charges. The revenue represents the electricity sold by the EV in EC1, where it discharges. In most scenarios, the charging cost is higher than the revenue from selling electricity. As a result, the EV does not generate a profit in these cases. The only exception is PS-SDR, where the price difference between charging and discharging is sufficient to make the EV profitable.

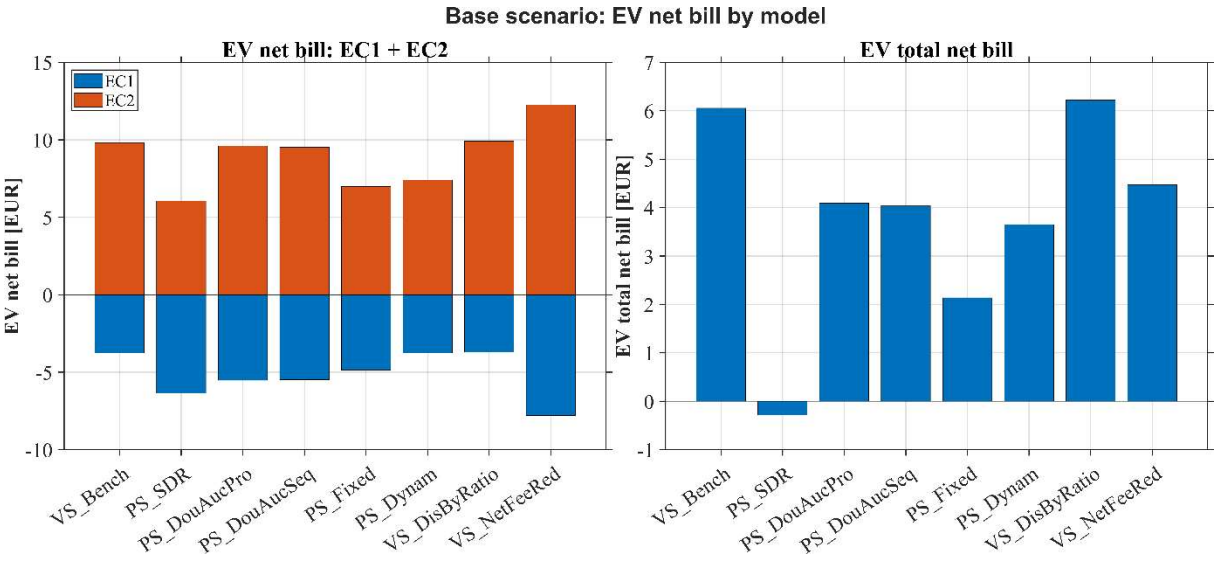

Figure 12. EV net bill by model.

Scenario	EV net bill [EUR]	% Difference from VS-Bench
VS-Bench	6.05	-
PS-SDR	-0.28	-104.7%
PS-DouAucPro	4.09	-32.4%
PS-DouAucSeq	4.04	-33,3%
PS-Fixed	2.14	-64.7%
PS-Dynam	3.65	-39.7%
VS-DisByRatio	6.22	2.7%
VS-NetFeeRed	4.47	-26.2%

Table 11. Comparison of EV net bill in the base EV scenario: E_delivery = 15 kWh, P_max = 2 kW, Delay = 1 h.

Figure 13 shows that, for most pricing mechanisms, the electric vehicle (EV) charges during periods with high electricity prices. This helps explain why the EV does not generate a profit in most scenarios. Since the EV charging schedule is predetermined, charging often coincides with price peaks.

The PS-SDR scenario differs from the other scenarios. In this case, the EV usually charges when the internal price is low and discharges when the price is higher. This is because the internal price is strongly influenced by the local photovoltaic (PV) surplus. During daytime hours, when PV production is high, the EV can charge at a lower internal price. It can then discharge later when the internal price is higher.

In the two double auction scenarios, PS-DouAucPro and PS-DouAucSeq, there are periods when the EV buys electricity below the selling price. However, the EV also charges during price peaks, when the buying price is higher than the selling price. This reduces the overall profitability of the EV in the double auction scenarios.

Among the scenarios where the EV does not generate a profit, PS-Fixed gives the lowest total net bill. With fixed pricing, the EV is not exposed to temporary price peaks. However, the fixed price difference is not large enough to make the EV profitable during the simulated week. As a result, PS-Fixed leads to a lower EV net bill than all pricing mechanisms except PS-SDR.

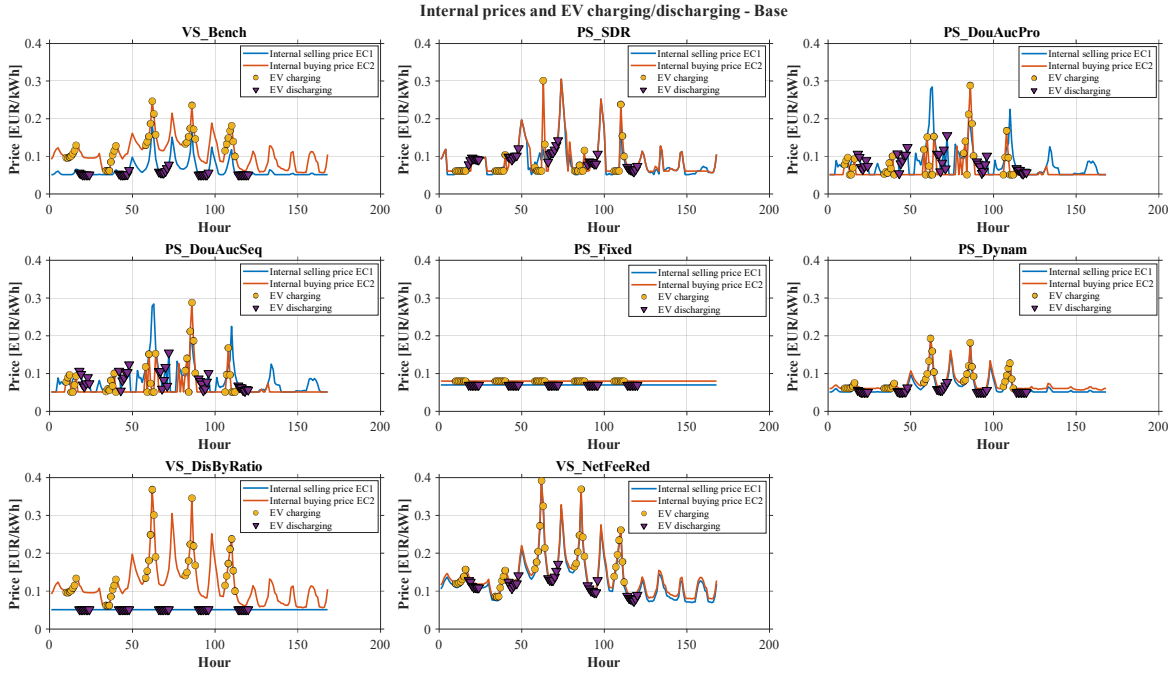

Figure 13. Internal prices and EV charging/discharging base EV scenario settings

5.2.2 Sensitivity Analysis of EV Net Bill

In all scenarios except PS-SDR, the electric vehicle (EV) net bill increases when the amount of delivered electricity increases. A possible explanation is that higher electricity delivery requires the EV to purchase more electricity during periods with high internal buying prices. Although the EV can also sell more electricity, the selling price is generally lower than the buying price. This increases the total net bill for the EV.

Changes in charging capacity produce three main patterns, as shown in Figure 14. In some scenarios, the EV net bill increases when the charging capacity rises from 1 kW to 2 kW and from 2 kW to 3 kW. However, the net bill decreases when the charging capacity is increased to 4 kW. In other scenarios, the net bill increases at 2 kW but then decreases when the charging capacity is increased to 3 kW and 4 kW. The PS-SDR scenario follows a different pattern. In this case, the net bill decreases slightly at 2 kW and continues to decrease as charging capacity increases.

The increase in the EV net bill at 2 kW or 3 kW may be explained by longer exposure to high buying prices or by discharging during periods with lower selling prices. PS-SDR differs because it is the only scenario in which a higher charging capacity consistently reduces the EV net bill. This is because the EV more often charges at low internal prices and sells electricity at higher internal prices in the PS-SDR scenario.

Increasing the delay generally lowers the EV net bill or leaves it relatively unchanged. The main exception is PS-SDR, where the net bill increases as the delay becomes longer. A delay can shift EV charging away from price peaks or shift discharging to periods with higher selling prices. However, in PS-SDR, the delay may reduce the alignment between low-price charging periods and high-price discharging periods.

VS-Bench and VS-DisByRatio result in the highest EV net bills across the sensitivity analysis. This is expected because these scenarios include both network tariffs and electricity tax. VS-NetFeeRed performs better than the other virtual sharing scenarios because it excludes electricity tax and applies a reduced network tariff.

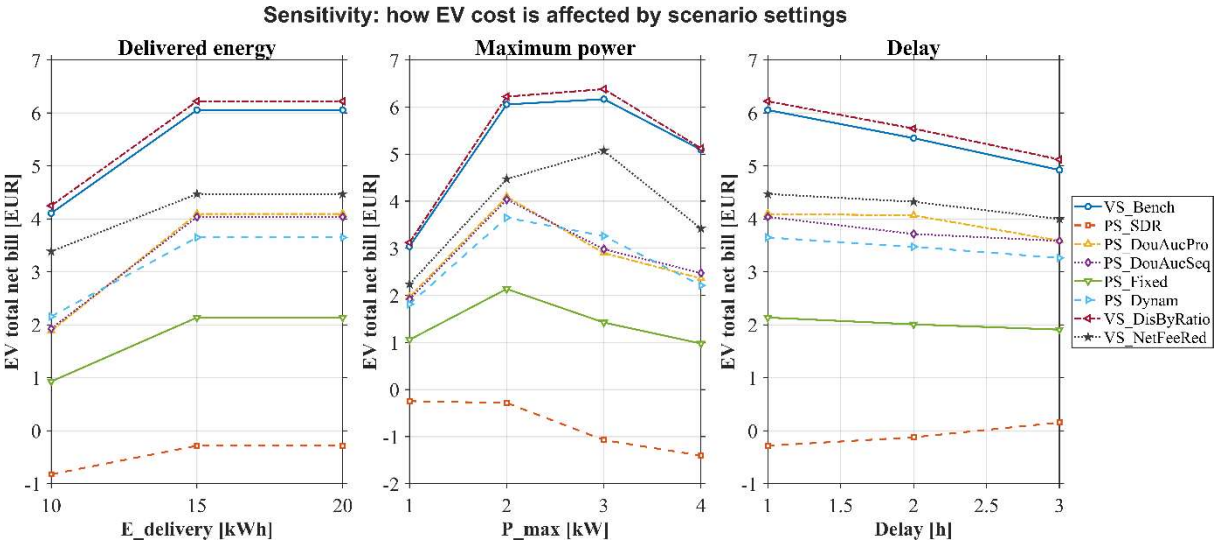

Figure 14. EV net bill sensitivity analysis

6 DISCUSSION

6.1 Effects of Pricing Mechanisms

The results in Section 5.1 show that members of an energy community (EC) can reduce their net bills through a local energy market (LEM) based on peer-to-peer (P2P) electricity trading. Several pricing mechanisms can be used in such a market. However, the results also show that different mechanisms benefit different stakeholder groups and affect the total net bill of the community in different ways. This section is therefore mainly related to RQ1 and RQ2, as it evaluates available pricing mechanisms for ECs and analyses how they affect value creation and value distribution among stakeholders.

Four pricing mechanisms stand out in terms of the total net bill: PS-SDR, PS-Dynam, VS-NetFeeRed, and PS-Fixed. These scenarios result in substantially lower total net bills than the other pricing mechanisms. For three of these four mechanisms, the distribution of the total net bill is relatively similar. PS-SDR differs because the internal electricity price depends on the local photovoltaic (PV) surplus. This allows the internal price to decrease when local surplus is high, even if the grid price remains high.

In all scenarios except the double auction scenarios, all available surplus electricity is used within the EC before any electricity is exported to the grid. This explains why these pricing mechanisms generally create larger savings for the community. This result is consistent with Deng et al. (2023), who show that bidding strategies may reduce the amount of electricity traded internally and lead to higher internal prices compared with SDR-based pricing.

VS-NetFeeRed differs from the other high-performing scenarios because it benefits prosumers more strongly than consumers. This is mainly explained by the internal selling price, which is generally higher than in the other pricing mechanisms. As a result, prosumers receive higher revenues and lower net bills. PS-ComArea also produces a distinct outcome for prosumers, but in the opposite direction. In this scenario, prosumers receive no revenue for the surplus electricity shared with the common areas. Although they can still sell some electricity to the grid, their total revenue is lower than in the other scenarios. This finding is directly related to RQ2, as it shows that the distribution of benefits between prosumers and consumers is as important as the total savings created by the EC.

The distribution of benefits is important because it may affect the willingness of different stakeholder groups to participate in an EC. For example, VS-NetFeeRed provides relatively large benefits to prosumers, while consumers receive smaller benefits. Such an uneven distribution could reduce consumer acceptance of the pricing mechanism.

Most pricing mechanisms are exposed to price volatility because they are partly based on the current grid price. As a result, EC members remain exposed to electricity price fluctuations in many scenarios. PS-Fixed is an exception, as both the internal buying and selling prices are fixed. This makes the pricing mechanism predictable for both prosumers and consumers. Prosumers are guaranteed a selling price above the feed-in price, which ensures that they benefit from internal trading. For consumers, however, there is a risk that the fixed internal buying price may be higher than the grid price in some periods. This is a key drawback of the fixed pricing model and means that the fixed price level must be chosen carefully. Depending on the

feed-in price, the fixed internal price may need to be set lower to ensure that it remains below the grid price during most periods.

PS-SDR also differs from the other mechanisms because it is not directly linked to the grid price. Instead, it is based on the total electricity surplus in the community. This allows internal prices to deviate substantially from grid prices. During periods with high local PV surplus, consumers can therefore access electricity at prices that are much lower than the grid price. Overall, value is created in the EC mainly by reducing members' net bills. At the same time, internal electricity trading increases the use of local PV generation and reduces dependence on the external grid.

6.2 Distribution of Costs and Revenues under Different Regulatory conditions

The results show that scenarios based on virtual sharing generally have higher net bills than scenarios based on physical sharing. This is because virtual sharing usually remains subject to network tariffs and electricity taxes. Physical sharing, as illustrated by the Tamarinden case, can be exempt from these charges, which significantly reduces electricity costs (Hasselqvist & Warneryd, 2024). This effect is most clearly shown by the comparison between PS-Dynam and VS-Bench. The two scenarios use a similar pricing logic, but VS-Bench includes network tariffs and electricity tax in the internal buying price because it is based on virtual sharing. This finding addresses RQ3 by showing how network tariffs and electricity taxes affect the economic outcomes of physical and virtual energy sharing.

VS-NetFeeRed represents a virtual sharing scenario inspired by Austrian regulation, where the network tariff is reduced by 57%. The results show that virtual sharing can become economically viable when supported by regulatory incentives. Reduced network tariffs can therefore increase the savings from virtual sharing. However, Chen et al. (2025) raise concerns about the fairness of reduced grid tariffs for Renewable Energy Communities (RECs). They argue that such reductions may shift costs to other distribution system operator (DSO) customers. They also note that the positive impact of ECs on the electricity network has not yet been fully demonstrated. This suggests that the long-term feasibility of reduced network tariffs for virtual sharing may be limited. From a cost-saving perspective, physical sharing is more attractive, but it requires investment in a local grid, which may reduce its feasibility in many cases. This also supports RQ3, as it shows that regulatory conditions strongly influence the economic attractiveness of virtual sharing.

Economic performance is not the only relevant criterion. The distribution of benefits between stakeholders is also important. Henni et al. (2021) propose three fairness conditions: larger investments should be rewarded, consumption of locally produced electricity should be encouraged, and no household should be disadvantaged by participating. Based on these principles, the internal price should not be set too high, as this benefits prosumers at the expense of consumers. It should also not be set too low, as this has the opposite effect. In this study, VS-NetFeeRed appears to benefit prosumers more than consumers compared with the other pricing mechanisms. By contrast, PS-ComArea disadvantages prosumers because they receive limited compensation for the electricity shared with the common areas.

6.3 EV Profitability

In the PS-SDR scenario, the electric vehicle (EV) is profitable because the internal buying price can be substantially lower than the grid price. This is possible because the internal price is determined by the local electricity surplus in the energy community (EC), rather than directly by the grid price. High local photovoltaic (PV) production can therefore result in low internal prices, even when the grid price is high. Grid prices may be high for several reasons, such as low wind power production or high electricity demand. This finding is directly related to RQ4, as it shows that community-to-vehicle-to-community (C2V2C) integration is economically viable only under specific pricing conditions. In this study, PS-SDR is the only pricing mechanism that enables the EV to charge during low-price periods and discharge during higher-price periods.

The profitability of the EV in PS-SDR is also explained by the price difference between the two ECs at different times of the day. When the EV is located at the workplace community, PV production is high and there is a large electricity surplus. This lowers the internal price and allows the EV to charge at a relatively low cost. When the EV returns to the residential community, PV production is much lower and electricity demand is higher. The EV can therefore discharge and sell electricity at a higher internal price than the price paid during charging.

The EV is not profitable under any of the other pricing mechanisms. This indicates that the potential for using an EV as a portable battery between ECs is limited under the assumptions used in this study. However, smart charging and discharging could improve the economic viability of C2V2C by avoiding charging during price peaks and prioritising discharge during high-price periods (Tirunagari et al., 2022). At present, reserve markets may offer higher revenues for EV owners than C2V2C, which can make these markets more attractive (Signer et al., 2023). Board et al. (2024) also show that C2V2C can create value beyond direct EV profitability, for example by increasing the self-consumption rate within the community. In relation to RQ4, the results suggest that C2V2C is unlikely to be attractive for EV owners unless the pricing mechanism and the charging and discharging schedule create favourable price differences.

6.4 Implications for Energy Communities

The results show that virtual energy sharing leads to lower savings for energy community (EC) members when network tariffs and electricity taxes are included. This indicates that tax exemptions, reduced network tariffs, or other regulatory incentives may be needed to make virtual sharing economically viable. Physical sharing creates larger savings under the assumptions used in this study, mainly because internally shared electricity is exempt from network tariffs and electricity tax. However, physical sharing also requires investment in a local grid or microgrid, which increases implementation costs and may reduce feasibility. This finding relates to RQ3, as it shows that the feasibility of virtual sharing depends strongly on the treatment of network tariffs and electricity tax.

When selecting a pricing mechanism, several criteria should be considered. Three central criteria are simplicity, fairness, and savings. Simplicity refers to how easy the mechanism is to implement and understand. A fixed price is an example of a simple mechanism. It is predictable

for both producers and consumers and does not require hourly price calculations. However, it also involves a trade-off. If the grid buying price falls below the fixed internal buying price, consumers may pay more than they would have paid by purchasing electricity directly from the grid.

Fairness is also important because different pricing mechanisms affect stakeholder groups differently. For example, VS-NetFeeRed provides relatively large benefits to prosumers compared with consumers. An EC pricing mechanism should therefore be designed so that it creates benefits for all participating members. Even if a mechanism reduces the total net bill of the EC, it may not be accepted if the distribution of benefits is perceived as unfair. This could reduce the willingness of some stakeholders to participate and, in turn, affect the performance of the EC. What is considered fair may also differ between ECs, as each community has its own ownership structure, member composition, technical conditions, and objectives.

These findings are consistent with the cases of Tamarinden and Hammarby Sjöstad. Tamarinden achieves larger savings through physical sharing, while virtual sharing in Hammarby Sjöstad depends more strongly on reduced network tariffs and tax-related incentives (Hasselqvist & Warneryd, 2024). Reduced grid tariffs can improve the economic performance of virtual sharing. However, Chen et al. (2025) raise concerns that reduced grid tariffs for Renewable Energy Communities (RECs) may shift costs to other distribution system operator (DSO) customers. They also note that the positive network impacts of ECs have not yet been fully demonstrated. This suggests that reduced grid tariffs may improve the viability of virtual sharing, but their long-term regulatory justification may be limited.

Overall, physical sharing appears more attractive from a cost-saving perspective, but it requires additional infrastructure investment. Virtual sharing is easier to implement in existing grid structures, but its economic viability depends more strongly on regulatory support. This is also relevant to RQ2, because the results show that total savings alone are not sufficient. The distribution of costs and benefits between members is equally important for the acceptance and long-term viability of an EC.

6.5 Limitations of the Methodology

One limitation of the method is the simplified photovoltaic (PV) system setup. The PV profiles are not based on measured production data, which may affect the internal prices generated by the pricing mechanisms and the estimated profitability of the electric vehicle (EV). This is particularly relevant in the PS-SDR scenario, where the internal price is strongly influenced by the amount of local PV surplus. However, this simplification was necessary due to time constraints. The main purpose of the study was not to optimize PV system design, but to compare pricing mechanisms and energy-sharing arrangements. Another limitation is that the simulation assumes full knowledge of electricity demand and electricity prices, as historical data are used. In a real implementation, such information would not be fully known in advance.

A further limitation is the predetermined EV schedule. This does not fully represent real-world EV use, where travel patterns are more variable and may include additional trips. Different EV behavior could affect profitability, especially if several EVs were integrated into the energy community (EC). The EV model also excludes charging and discharging losses, battery degradation, and maintenance-related costs. These assumptions make the simulation less

realistic and may overestimate the economic viability of community-to-vehicle-to-community (C2V2C) operation. In addition, the model does not include smart charging or smart discharging. As a result, the EV may charge or discharge during non-optimal price periods, which can reduce its profitability.

The one-week simulation period is also a limitation. It does not capture seasonal variation in PV production or longer-term variation in electricity demand. This limits the extent to which the results can be used to assess the long-term viability of a specific EC configuration. The results should therefore be interpreted as indicative rather than as a basis for investment decisions.

7 CONCLUSIONS

In this report there are different pricing mechanisms from literature and real-world cases for energy sharing in ECs with PV production. Different types of sharing were considered where in some cases network tariffs and taxes were included in internal trading. The total net bill for the EC was compared for all pricing mechanisms. Then an analysis of which type of stakeholders benefited the most from each pricing mechanism to evaluate the fairness.

In the second part a second EC was added and an EV where the EV delivers electricity between the communities. The economic performance of the EV under the different pricing mechanisms was evaluated and compared. Lastly, a sensitivity analysis was conducted where the amount of electricity delivered, charging capacity and delay was adjusted individually to see how it impacts the economic performance of the EV.

7.1 RQ1: Pricing mechanisms available for ECs

This work identified several pricing mechanisms that could be used in energy communities (ECs). These range from simple mechanisms, such as fixed pricing, to more complex mechanisms, such as supply–demand ratio (SDR)-based pricing. The mechanisms differ in terms of simplicity, predictability, fairness, and economic performance.

Fixed pricing provides a simple and predictable mechanism for internal electricity trading. However, it also involves a risk that the grid price may fall below the internal buying price, which would make internal trading less attractive for consumers. More complex mechanisms, such as PS-SDR, set the internal buying and selling prices based on the local surplus of photovoltaic (PV) electricity. This allows the internal price to respond to local supply conditions.

Other pricing mechanisms are based on the grid price. These are more dynamic than fixed pricing and can still provide lower internal buying prices than the conventional grid price. However, they do not directly account for the amount of surplus PV electricity available within the EC. Overall, the results show that the design of an internal pricing mechanism involves a trade-off between simplicity, predictability, fairness, and economic performance.

7.2 RQ2: Value creation, revenue distribution and risk allocation

The pricing mechanism that provided the greatest benefit for the energy community (EC) as a whole was PS-SDR, which resulted in the lowest total net bill of EUR 422.9, as shown in Table 8. Three other scenarios produced similar results: PS-Dynam, PS-Fixed, and VS-NetFeeRed, each with a total net bill of EUR 423.3. By contrast, VS-Bench had the highest total net bill among the energy sharing scenarios, at EUR 471.1. This is EUR 48.2 higher than the total net bill in PS-SDR.

Although the total net bill was similar for several pricing mechanisms, the distribution of costs and benefits differed between stakeholder groups. In VS-NetFeeRed, prosumers achieved a net profit of EUR 2.7, while consumers had a net bill of EUR 294.0, as shown in Table 9. This indicates that this pricing mechanism benefits prosumers more strongly than consumers.

The results also show that risk is allocated differently depending on the pricing mechanism. PS-Fixed provides predictable prices for both buyers and sellers. However, buyers face the risk that the fixed internal buying price may be higher than the grid price in some periods. Other dynamic pricing mechanisms, such as PS-Dynam, reduce this risk because the internal price is linked to the grid price. PS-SDR also limits this risk, as the internal price is mainly determined by the local photovoltaic (PV) surplus and is constrained so that it cannot exceed the grid price.

7.3 RQ3: Regulatory conditions, network tariffs and electricity taxes

The results indicate that regulatory conditions have a significant impact on total savings within the energy community (EC). Physical sharing generally results in the largest savings because internally shared electricity is not subject to network tariffs or electricity tax. In contrast, virtual sharing results in lower savings because both network tariffs and electricity tax are included. This effect is most clearly shown by the comparison between VS-Bench and PS-Dynam, where the only difference is the type of energy sharing. The total net bill is EUR 471.1 in VS-Bench and EUR 423.3 in PS-Dynam, corresponding to a difference of EUR 47.8.

The VS-NetFeeRed scenario shows that virtual sharing can become economically competitive when network tariffs are reduced and electricity tax is exempted. In this scenario, the total net bill is EUR 423.3, which is the same as in PS-Dynam. This demonstrates that the pricing mechanism is not the only factor affecting economic performance. Regulatory conditions also have a major influence on the feasibility of EC business models. Tax exemptions, reduced network tariffs, or other regulatory incentives may therefore be necessary for virtual sharing to become economically competitive with physical sharing.

7.4 RQ4: EV integration and profitability

Electric vehicle (EV) integration was profitable only in the PS-SDR scenario, where the EV generated a profit of EUR 0.28. This can be explained by the structure of the supply–demand ratio (SDR) pricing mechanism. In this scenario, internal prices depend on the local surplus of photovoltaic (PV) electricity rather than directly on the grid price. The EV schedule is also

important. In the simulation, the EV charges during the day, which coincides with periods of high PV production and lower internal prices under the SDR mechanism.

In the other scenarios, the price difference between charging and discharging was not large enough for the EV to generate a profit. This shows that EV profitability is highly sensitive to both the pricing mechanism and the EV schedule. The main conclusion is therefore that EV integration is unlikely to be profitable unless the pricing mechanism and the charging and discharging schedule create a sufficiently large price difference between the two energy communities (ECs).

For EC business models that include EVs, smart charging and smart discharging could improve economic viability. Since this study does not optimize the EV charging and discharging strategy, the EV may charge or discharge during unfavorable price periods. However, community-to-vehicle-to-community (C2V2C) operation may still provide non-monetary or system-level benefits, such as increased self-consumption of locally produced electricity.

8 SUGGESTIONS FOR FURTHER WORK

A limitation in this report is the setup of the PV-system, an improvement in this work could be to use a more realistic PV-system. Since the EV had a predetermined schedule, future work could investigate how smart charging affects EV profitability. Future work could include investments costs related to microgrid to evaluate the return on investment of a microgrid. This would give more information to whether using physical sharing or virtual sharing is more viable economically. Lastly, simulating for a year to capture the seasonal variation in PV production and electricity demand to better understand the economic viability of pricing mechanisms and EV integration.

9 DECLARATION ABOUT GENERATIVE AI AND AI-SUPPORTED TECHNOLOGY

The AI-based tool ChatGPT has been used during the process of this work. It has mainly been used for developing ideas and to improve the language in the report by correcting grammatical error to improve the clarity of the text. The author takes full responsibility for the results and analysis presented in this work.

Model name: ChatGPT

Version: GPT-5.5

Developer: OpenAI

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