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Who Pays for Community Energy? Peer-to-Peer Trading, Distribution Grid Headroom and the Supplier's Dilemma

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Abstract

Renewable Energy Communities (RECs) with peer-to-peer (P2P) trading can lower bills and unlock flexibility, but they also reshape supplier revenue and distribution-network headroom. We couple an agent-based REC market model to a Transformer Headroom Index (THI) to evaluate welfare and grid outcomes across seasons. A 20-household feeder in South-East England with PVs, EVs, and heat pumps is simulated with and without P2P under four retail tariffs: Flat, Economy-7, Agile, and a wholesale-linked Dynamic tariff. Metrics include community net bills, supplier profit, and import/export headroom for 50 and 100 kVA transformers.

Results reveal a persistent distributional trade-off: tariffs that minimise community bills compress supplier margins. P2P accentuates this by reducing grid purchases in PV-rich periods. P2P improves import headroom via EV load shifting; however, in PV-rich summer it can synchronise prosumer behaviour around price spikes, concentrating exports into short windows that erode export headroom. Nonetheless, across seasons, P2P is consistently part of the Pareto-optimal solution set, though the preferred supporting tariff varies by season.

Policy implications derived from these trade-offs include: the need to re-base residual cost recovery onto fixed or capacity charges, the adoption of facilitation fees and THI-based flexibility contracts for value-sharing, the addition of Dynamic Operating Envelopes (DOEs) as guardrails for real-time

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tariffs, and the regulatory enablement of EVs as flexibility assets.

Terminology and Nomenclature

Table 1: Table of acronyms and their meanings.

Acronym	Meaning
ABM	Agent-Based Model
ASHP	Air-source Heat Pump
CDA	Continuous Double Auction
DER	Distributed Energy Resource
DOE	Dynamic Operating Envelope
DSO	Distribution System Operator
EU	European Union
EV	Electric Vehicle
LEM	Local Energy Market
LV	Low Voltage
PF	Power Factor
PV	Photovoltaics
P2P	Peer-to-peer
REC	Renewable Energy Community
SoC	State of Charge
THI	Transformer Headroom Index
TOU	Time-of-Use
V2G	Vehicle-to-Grid
V2H	Vehicle-to-Home

Table 2: Symbols used with their meanings and units when applicable.

Symbol	Meaning	Units
$\text{Bill}_{\text{comm}}$	Aggregated community bill	GBP/week
Bill_i	Bill of household i	GBP/week
L_t	Net community load at time t (imports-exports)	kW
$p_{i,t}^{\text{ASHP}}$	Air source heat pump power consumption for household i at time t	kW
$p_{i,t}^{\text{EV,ch}}$	EV charging power for household i at time t	kW
$p_{i,t}^{\text{EV,dis}}$	EV discharging (V2H) power for household i at time t	kW
$p_{i,t}^{\text{exp}}$	Power exported by household i at time t	kWh (per interval)
$p_{i,t}^{\text{imp}}$	Power imported by household i at time t	kWh (per interval)
$p_{i,t}^{\text{load}}$	Native household demand (excl. flexible devices)	kWh/h
$p_{i,t}^{\text{p2p,exp}}$	Power exported with P2P trading from household i at time t	kW
$p_{i,t}^{\text{p2p,imp}}$	Power imported from P2P trading by household i at time t	kW
$p_{i,t}^{\text{PV}}$	PV generation of household i at time t	kW
P2PCashflows_i	Net peer-to-peer market cashflows of household i	GBP/week
S	Transformer apparent power rating	kVA
$\text{SoC}_{i,t}$	State of charge of EV/home battery for household i at time t	kWh
T	Total number of auction intervals (market-clearing periods) in the simulation horizon	
THI^{+}	Transformer Headroom Index for Imports	Dimensionless
THI^{-}	Transformer Headroom Index for Exports	Dimensionless
α	Supplier margin (markup parameter)	Dimensionless
Δt	Time step length	h
η_{ch}	Charging efficiency of EV battery	Dimensionless
η_{dis}	Discharging efficiency of EV battery	Dimensionless
π_t^{exp}	Export tariff (price for prosumers to sell to the supplier at time t)	GBP/kWh
π_t^{imp}	Import tariff (price for prosumers to buy from supplier at time t)	GBP/kWh
Π^{sup}	Supplier profit	GBP/week
π_t^{wh}	Wholesale electricity price at time t	GBP/kWh
ϕ	Transformer power factor	Dimensionless

1. Introduction

As policy-makers seek new roles for citizens in the energy transition, energy communities and P2P electricity trading have moved from concept to formal policy priority in Europe and beyond. The European Commission frames energy communities as citizen-driven initiatives that support the clean-energy transition and improve local efficiency [?]. EU legislation now explicitly recognises them through RECs (Directive (EU) 2018/2001) and Citizen Energy Communities (Directive (EU) 2019/944). These frameworks aim to enable participation, self-consumption, and collective energy actions at the local level [? ? ?].

Such communities promise to lower bills, unlock demand-side flexibility, and accelerate DER uptake. Yet they also raise a fundamental policy challenge: how do we enable local trading that benefits both communities and the grid without undermining supplier revenues or creating new network stresses? Early empirical work suggests that retailers may lose revenue under P2P schemes, especially when value is shifted outside traditional contracts or when network tariffs do not capture load impacts [? ?]. At the same time, regulation and tariff design in many jurisdictions have not kept pace, as existing frameworks were not built for prosumers trading among themselves. Evidence also remains limited on how such markets redistribute value or affect real distribution infrastructure [? ? ?].

A growing literature highlights the organisational forms and roles within energy communities. These initiatives build on the broader rise of prosumerism, where end-users shift from passive consumption to actively producing and managing electricity [? ?]. Collective action at community level has been shown to amplify both climate and consumer benefits, giving rise to diverse organisational models. Communities vary in their location and purpose [?], governance structures [?], energy activities [?], and legal forms and grid connection types [?]. Their success depends on aligning the goals of internal members with those of external stakeholders such as suppliers and DSOs [?]. Within these systems, actors may take on roles as consumers/prosumers, energy service providers, or community managers [?], and these functions often overlap. For example, electricity suppliers may also act as community managers to capture regulatory benefits, cost savings, or new revenue streams.

While this organisational literature is well developed, two gaps remain salient for policy. First, most studies address device scheduling, bidding/clearing, or settlement in isolation, rather than connecting household flexibility to LEM clearing and cash-flow settlement in a single framework [? ? ?]. Second, network physics is often simplified, so few works quantify grid impacts with planner-facing metrics that speak to DSOs and regulators [? ?]. Recent contributions also show that misaligned tariffs and settlement rules can distort outcomes and create inequities among stakeholders [? ? ? ? ?]. Together, these studies underscore the need for holistic analyses that bridge technical, market, and regulatory layers.

Methodologically, the literature tends to divide along two tracks:

1. Auction-based ABMs
2. Optimisation and game-theoretic approaches

ABMs capture price formation and behavioural richness in continuous double-auction (CDA) settings [? ? ?], but often simplify settlement rules and grid representation. Optimisation and game-theoretic approaches capture feasibility and equilibrium properties [? ? ?], but typically abstract from real-world tariffs, seasonal variation, and explicit cashflows. Reviews stress the role of flexibility within energy communities, whether from storage, demand response, or EVs, but also note that the value of this flexibility is highly dependent on tariff structures and market design [? ?]. As a result, regulators still lack seasonal, tariff-aware evidence that links P2P trading and EV-enabled flexibility through V2H to simple indicators of network headroom that map onto transformer rating decisions and reinforcement needs [? ?].

This work's contributions are the following:

1. A holistic design and analysis of a REC accounting for stakeholder interests and grid infrastructure constraints through the combination of a Local Energy Market's ABM model with a Transformer Headroom Index (THI).
2. Demonstrated through a Pareto trade-off analysis of said REC's behaviour across different seasons that the introduction of P2P trading has a robust advantage over grid-only operation.
3. Showcased that in PV-rich summer regimes P2P and real-time export pricing can synchronise peer/prosumer behaviour, tightening export headroom, limiting the network's ability to absorb PV power, despite EV-driven import headroom relief.
4. Translated the findings of this study into practical policy recommendations.

The rest of this paper is structured as follows: Section ?? presents the methodology, including an overview of the REC model, the experimental configuration, the data, and the analysis methods. Section ?? reports the results. In section ?? we discuss the policy implications of the findings and Section ?? provides the conclusions. Finally, Appendix A contains the characteristics of the 20 households considered in this study, Appendix B provides the pseudocode of the CDA market clearing and finally, in Appendix C the Pareto filtering and Knee-Point selection methodology is demonstrated.

2. Methodology

2.1. REC Model and Experimental Configuration

We build on the ABM market of Hutty and Brown [?], where households trade with the grid and, when enabled, among themselves via P2P. This results in two transaction modes examined, denoted "Grid only" and "Grid-P2P". The community comprises $N = 20$ households; 10 own 3 kW PVs (varied orientation), 15 own EVs with V2H capacity, and all use ASHPs for heating (see Appendix A for household characteristics).

We opted for a 20-household, single-feeder community to keep the links between market behaviour, cash-flow settlement, and transformer headroom transparent. This scale is consistent with early P2P energy-community trials, which typically involve a few dozen households (e.g., 37 in the Quartierstrom pilot in Walenstadt; 18 in the Fremantle trial by Power Ledger; and 10 in Origin Energy's Busselton trial).

Furthermore, the whole community adheres to the same retail tariff for both imports and exports of electricity from and to the grid. This tariff is, however, adjustable. The types of retail tariffs explored are the flat, a TOU tariff, specifically, the Economy 7 UK tariff, an agile and finally, a dynamic tariff which follows the trend of the wholesale price but scaled accordingly so that the yearly average price matches the flat tariff. The dynamic tariff is included to probe behaviour under high price flexibility since in 2022, agile prices were frequently capped due to extreme wholesale conditions.

We examine eight scenarios combining the two transaction modes with the four retail tariffs as presented in Table ??.

Each scenario is run as a separate experiment under three seasonal weeks:

- **Winter**: 7–13 January 2022,
- **Spring (Shoulder)**: 10–16 April 2022,

- **Summer**: 7–13 August 2022.

These weeks were selected as season-representative based on weather and wholesale conditions; autumn 2022 resembled spring, so we report a single shoulder season.

Table 3: Simulation scenarios.

#	**Transaction mode**	**Retail tariff**
1	Grid only	Flat
2	Grid - P2P	Flat
3	Grid only	Agile
4	Grid - P2P	Agile
5	Grid only	TOU
6	Grid - P2P	TOU
7	Grid only	Dynamic
8	Grid - P2P	Dynamic

EV (V2H) dynamics (flexibility resource). EVs provide the principal shiftable resource. SoC evolves as:

$$\mathrm{SoC}_{i,t+1} = \mathrm{SoC}_{i,t} + \eta_{\mathrm{ch}}\, p_{i,t}^{\mathrm{EV,ch}} \Delta t - \frac{1}{\eta_{\mathrm{dis}}}\, p_{i,t}^{\mathrm{EV,dis}} \Delta t \tag{1}$$

with availability windows encoding driving; V2H enables discharge to the home/community. SoC is bounded between minimum and maximum capacities; charging/discharging are rate-limited and not allowed simultaneously.

ASHP and PV (non-shiftable and stochastic supply).. ASHP electric draw $p_{i,t}^{\mathrm{HP}}$ is obtained from thermal load and coefficient of performance assumptions; PV output $p_{i,t}^{\mathrm{PV}}$ follows irradiance, orientation, and size (inverter-limited).

2.1.1. LEM Operation and P2P Transactions

Time is discretised into steps $t \in \{1, \ldots, T\}$ (60 min settlement periods, $\Delta t = 1\,\mathrm{h}$). We define $p_{i,t}^{\mathrm{load}}$ as the household's native (inflexible) electrical demand (e.g., lighting/appliances), excluding EV charging/discharging, PV, and ASHP consumption. The nodal power balance for household i at time t is:

$$p_{i,t}^{\mathrm{imp}} + p_{i,t}^{\mathrm{p2p,imp}} + p_{i,t}^{\mathrm{PV}} + p_{i,t}^{\mathrm{EV,dis}} = p_{i,t}^{\mathrm{load}} + p_{i,t}^{\mathrm{ASHP}} + p_{i,t}^{\mathrm{EV,ch}} + p_{i,t}^{\mathrm{p2p,exp}} + p_{i,t}^{\mathrm{exp}} \tag{2}$$

All power variables are non-negative (kW) and bounded by device ratings; energy per period is $p\,\Delta t$. We enforce mutual exclusivity for import/export and EV charge/discharge within a period, and respect device/SoC constraints.

When P2P is enabled, the local market operates as an hourly CDA where buyers and sellers submit quantities and reservation prices derived from marginal valuations relative to grid import/export prices and device/SoC constraints. The CDA clears at the midpoint between the highest bid and lowest ask; any residual net demand or surplus settles with the grid at $(\pi_t^{\mathrm{imp}}, \pi_t^{\mathrm{exp}})$. Full LEM–CDA pseudocode is provided in Appendix B.

2.2. Data and Parameterisation

In order for the experiments to be carried out effectively certain data needs to be incorporated in the ABM of an energy community and other data is important for further analysis. An overview of the datasets utilised, their particular use in the study and their sources are presented in Table **??**.

Table 4: Datasets used and their sources.

Dataset / Description	Source
Hourly climate (temperature, irradiance) for South East England, 2022	NASA POWER [a]
Smart-meter consumption (100 UK households, 2022); appliance-only loads (no EVs)	EDF Energy R&D UK Centre (anonymised cohort)
Agile import/export price series (half-hourly, SE England, 2022)	Octopus Agile tariffs [b]
UK wholesale electricity price series, 2022	Nord Pool (via EDF Energy R&D UK Centre) [c]

[a] NASA POWER Project, "Power Data Access Viewer," NASA LaRC. Accessed 2024-09-18. `https://power.larc.nasa.gov/data-access-viewer/`

[b] Octopus Energy Developer API (primary source); retrieved via Energy Stats UK CSV export: `Csv_agile_j_south_eastern_england.csv` (import) and `Csv_agileoutgoing_j_south_eastern_england.csv` (export). Accessed 2024-09-20. `https://files.energy-stats.uk/csv_output/`

[c] Nord Pool GB day-ahead auction (half-hour) price series, price area GB; Accessed 2024-10-15.

Moreover, the selected import flat tariff price is £0.28 [?] and the import TOU Economy 7 prices opted for are £0.1078 from midnight until 7.00 am (GMT) or from 1.00 am until 8.00 am (BST) and £0.2892 for the remaining hours, which are a characteristic example of Economy 7 standard rate tariffs in 2022 in the UK [?]. As for the export tariff, namely the price for which prosumers can sell power back to the grid, it is set at £0.084 for both the flat and TOU tariffs. This is the average of the bundled export tariffs offered in the UK in 2022 [?]. Overall, the wholesale and import and export tariffs applied in each experiment is presented in Figure ?? below.

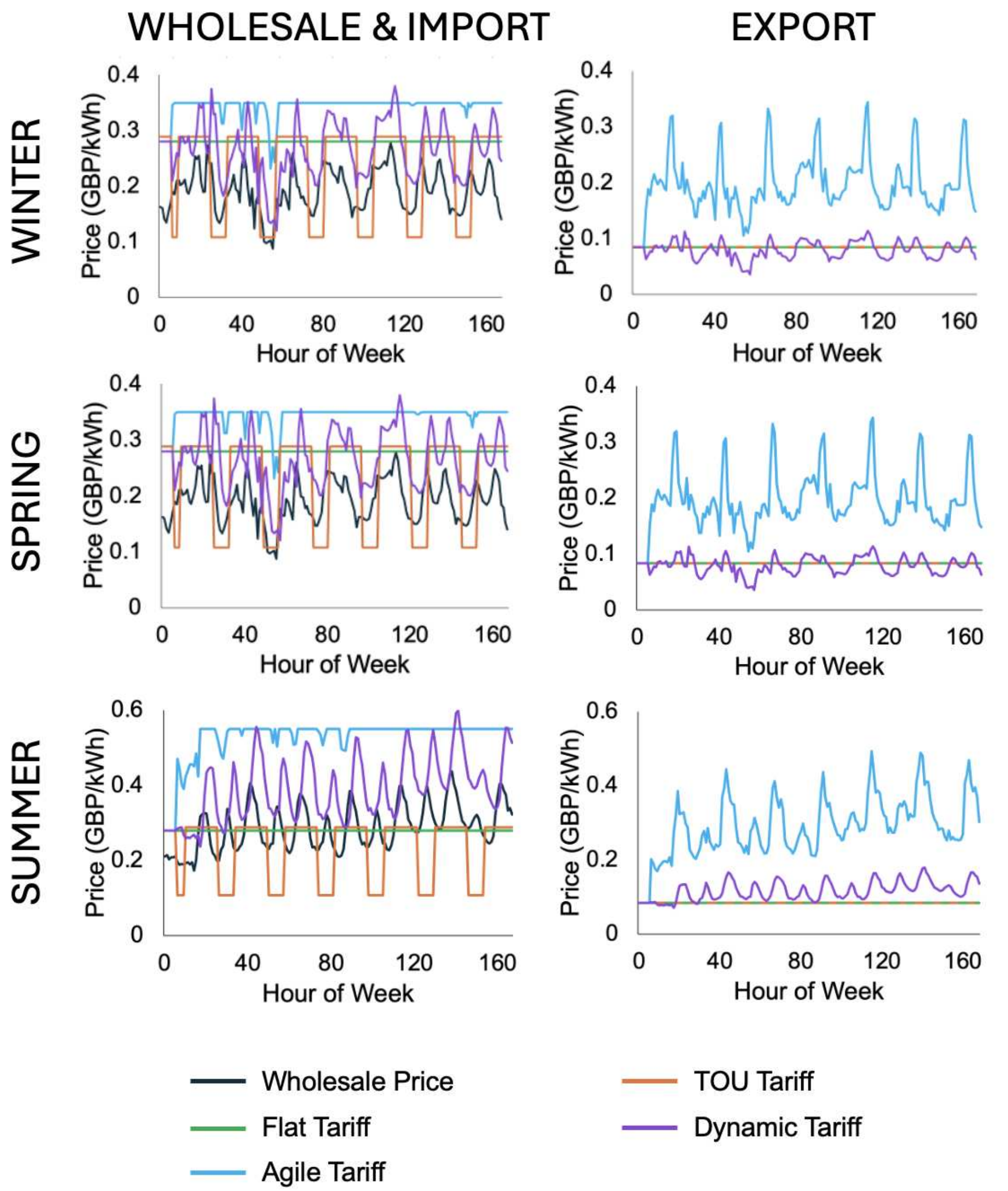

Figure 1: Wholesale prices and import and export tariffs per hour of the week for each experiment (Winter, Spring and Summer).

Furthermore, Figure ?? summarises the daily exogenous weather drivers across the study weeks: (a) average air temperature and (b) global horizontal irradiance (GHI) as a proxy for PV yield.

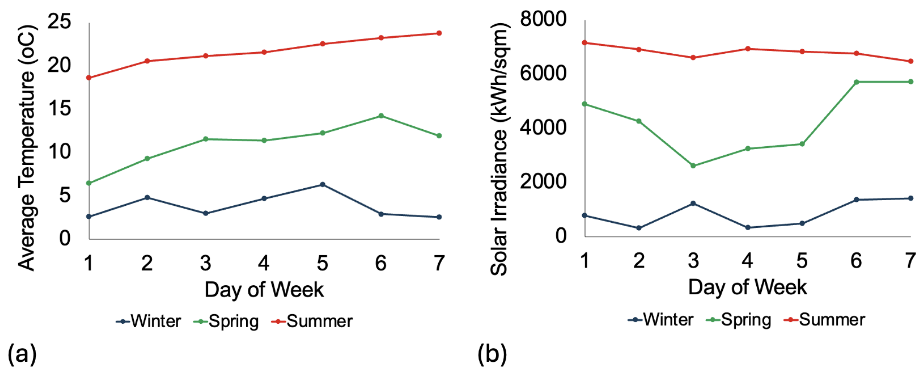

Figure 2: (a) Daily average temperatures for each experiment. (b) Daily solar irradiance for each experiment.

2.3. Analysis

2.3.1. Welfare Metrics for Stakeholders

Let $\pi_t^{\text{imp}}, \pi_t^{\text{exp}}$ denote grid import and export prices, and π_t^{wh} the wholesale price in GBP/kWh. The bill of household i is given by

$$\text{Bill}_i = \sum_t \left(\pi_t^{\text{imp}}\, p_{i,t}^{\text{imp}} - \pi_t^{\text{exp}}\, p_{i,t}^{\text{exp}}\right) \Delta t \;\pm\; \text{P2PCashflows}_i \tag{3}$$

At the community level, the metric of interest is the aggregated bill of all households, namely, the community bill:

$$\text{Bill}_{\text{comm}} = \sum_i \text{Bill}_i \tag{4}$$

Another key metric documented is the supplier profit over the community:

$$\Pi_{\text{sup}} = \sum_t \left[\left(\pi_t^{\text{imp}} - \pi_t^{\text{wh}}\right) \sum_i p_{i,t}^{\text{imp}} \;+\; \left(\pi_t^{\text{wh}} - \pi_t^{\text{exp}}\right) \sum_i p_{i,t}^{\text{exp}} \right] \Delta t \tag{5}$$

In Eq. (**??**), π_t^{wh} is the wholesale price used both to procure imports and to monetise exports for the supplier. All flows are non-negative and we disallow simultaneous import and export within a period. Finally, P2P trades do not appear directly in Π_{sup}, they only affect it via changes in $\sum_i p_{i,t}^{\text{imp}}$ and $\sum_i p_{i,t}^{\text{exp}}$.

Tariff construction. Flat and TOU import and export prices are constants (Section **??**). By contrast, the agile and the dynamic tariffs are hourly. Agile follows half-hourly prices (see Table **??**). The dynamic import tariff is wholesale-linked and scaled by a constant factor, α, chosen so that its annual average unit price equals the flat tariff. Concretely, α is set to the ratio of the flat unit rate to the calendar-year (2022) average wholesale price. Multiplying each half-hourly wholesale price by α preserves the time profile while aligning the annual mean with flat. Exports use the same construction so that the dynamic export tariff has the same annual mean as its flat counterpart. Figure **??** shows the time series used for each seasonal week.

2.3.2. Grid Metrics

The outcomes of the three seasonal experiments should also be interpreted in light of distribution grid constraints, as these may render certain tariff/transaction scenarios less viable than apparent from welfare metrics alone.

The central grid-facing variable is the community net load, defined as:

$$L_t = \sum_i p_{i,t}^{\text{imp}} - \sum_i p_{i,t}^{\text{exp}} \tag{6}$$

L_t captures the aggregate import and export profile imposed on the LV network, indicating when the community contributes to import peaks or export surpluses.

In LV networks, a frequent bottleneck is the distribution transformer that transfers power from the primary (typically 11 kV) network to LV circuits (about 230–250 V) [**? ?**]. Its rating is specified in kVA (apparent power), while usable active power depends on the PF, i.e., the ratio of active to apparent power. Domestic PF commonly lies between 0.92 and 0.99 [**? ?**]; we therefore adopt a community-average PF: ϕ=0.95.

The study region is South East England. The local District Network Operator, UK Power Networks, reported in 2019 a fleet of over 118,000 distribution transformers spanning small single-phase pole-mounted units up to 1 MVA three-phase ground-mounted units [**?**]. Consistent with that portfolio and the community size we model, we evaluate two plausible ratings $S \in \{50, 100\}$ kVA (at ϕ=0.95) as representative supply options for the case study [**?**].

To link the community net load L_t (defined in (**??**)) to planning relevance, we introduce the Transformer Headroom Index (THI):

$$\mathrm{THI}^{+} \;=\; 1-\frac{\max\bigl(0,\ \max_t L_t\bigr)}{S\,\phi}, \qquad \mathrm{THI}^{-} \;=\; 1-\frac{\max\bigl(0,\ \max_t(-L_t)\bigr)}{S\,\phi} \quad (7)$$

Here, THI^{+} tracks proximity to import capacity and THI^{-} to export capacity. Values closer to 1 indicate greater headroom; negative values indicate exceedance. We report THI for both S=50 and 100 kVA and compare grid only against grid-P2P configurations to quantify headroom changes attributable to market design and flexibility.

2.3.3. Multi-Objective Selection of Tariff–Transaction Configurations: Pareto Filtering and Knee–Point Selection

For each season (Winter, Spring, Summer) we compare tariff - transaction mode combinations across multiple welfare and grid metrics. To ensure comparability, all metrics are oriented so that higher values represent better outcomes and then rescaled to a common range.

We then identify the Pareto-efficient set for each season. These are the options where no metric can be improved without worsening at least one other. This step removes dominated tariff-transaction mode combinations and leaves only the genuine trade-offs.

From this Pareto-efficient set we highlight one or more knee point, combinations that represent the most balanced compromises. At a knee, improving one metric would require a disproportionately large sacrifice on others. To avoid bias toward any single metric or arbitrary weighting, we apply two complementary selectors that are assumption-light, threshold-free and based on the priciple of minimising normalised distance to the ideal point: the Chebyshev minimax shortfall rule [**?**], and the TOPSIS closeness-to-utopia approach [**?**].

In the results we present the surviving Pareto-efficient configurations and visually emphasise the knees in parallel-coordinate plots. Because all metrics are normalised to the same scale, these trade-offs are transparent and directly comparable across metrics within each season. This pipeline therefore provides a clear and preference-light way to identify which tariff - transaction mode combinations offer the most persuasive balance of community, supplier, and grid outcomes. Formal definitions of the normalisation, Pareto dominance, and knee selectors are provided in Appendix C.

3. Results

Results are presented by scenario (tariff–transaction mode configuration) and by seasonal experiment (winter, spring, summer experiment for each scenario). We organise results in two primary frames:

- grid metrics for planning relevance.
- welfare metrics for stakeholders (prosumers, supplier),

3.1. Welfare of Stakeholders

The key stakeholders in this REC are the electricity supplier and the community of prosumers. Hence, it is critical to analyse which scenarios per experiment are more favourable for each.

Figure **??** shows the supplier's weekly profit per scenario per experiment, Π^{sup}. The agile import tariff closely mirrors the behaviour of a much higher flat tariff, effectively plateauing at its highest rate across experiments (see Figure **??**). This substantially boosts supplier profit in winter, when community imports are high due to limited DER output. The flat and dynamic tariffs in winter lead to lower supplier profit, while TOU is costing the supplier. Enabling P2P in winter trims profit only slightly (or not at all) across tariffs, with a maximum reduction of 3.6% under the flat tariff, because PV generation is minimal and the community relies on grid imports. In spring, profits compress but stay positive, with TOU tariff being the least profitable. Under this PV-richer season, adding P2P consistently reduces supplier profit across tariffs by 20% to 67%. In summer, community exports charged to the supplier are highest. The impact varies by tariff: the agile tariff notably leads to supplier loss, while the others remain profitable, and TOU becomes relatively profitable despite its weaker performance in other seasons. P2P also has tariff-specific effects: with flat and dynamic tariffs, profits fall by 4% and 24%, respectively; under agile, the supplier's loss doubles. In contrast, introducing P2P with TOU raises profits by 6% by converting midday exports into local trades and reducing export payouts. Overall, supplier outcomes are driven jointly by tariff design and the seasonal net position. P2P primarily reduces supplier profits when it replaces retail imports, but it can increase profits when it absorbs local surpluses that would otherwise be exported and paid at the export price.

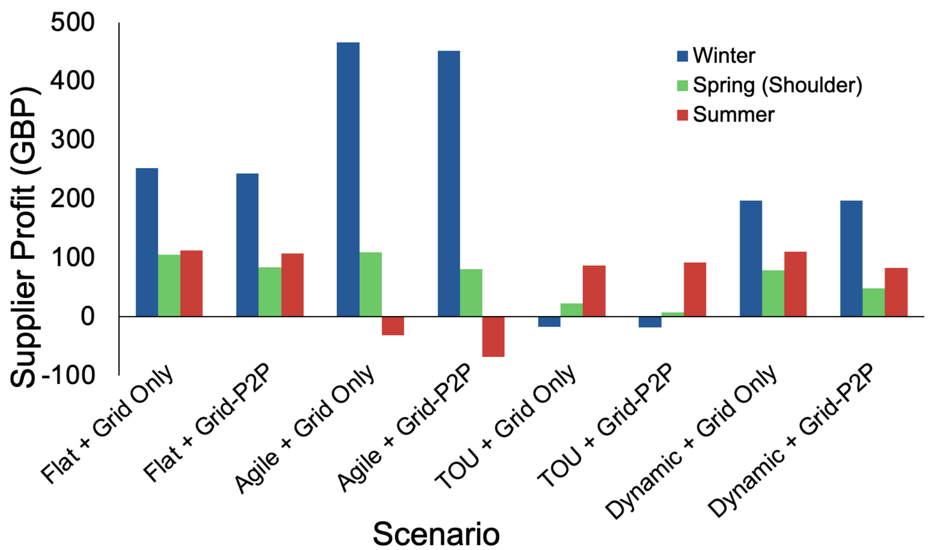

Figure 3: Supplier's weekly profit in GBP per scenario per experiment.

Meanwhile, Figure **??** shows the community's weekly aggregated bill, $\text{Bill}_{\text{comm}}$, for each scenario and season. In winter, when PV generation is minimal and P2P trading remains limited even when enabled, the retail tariff is the dominant driver; here, the TOU tariff yields the lowest community bills. TOU also minimises bills in spring, largely because its off-peak night import rate is considerably lower than the other tariffs (see Figure **??**). By contrast, in summer the agile tariff clearly outperforms all others, pushing community net bills below zero turning the bill into net credit. These negative values indicate that, on balance, the community becomes a net exporter and earns revenues under agile export pricing. While the effect of P2P trading is marginal in winter (maximum net bill reduction with P2P is 2.2%), in spring and summer the combination of abundant PV generation and P2P exchanges consistently reduces bills relative to grid-only scenarios. Specifically, in spring there is a percentage decrease of approximately 25% across all tariffs while in the summer, the decrease can be so effective that the net bill becomes community credit or increases the credit further. Hence, tariff design and seasonal PV availability jointly determine the financial position of the community.

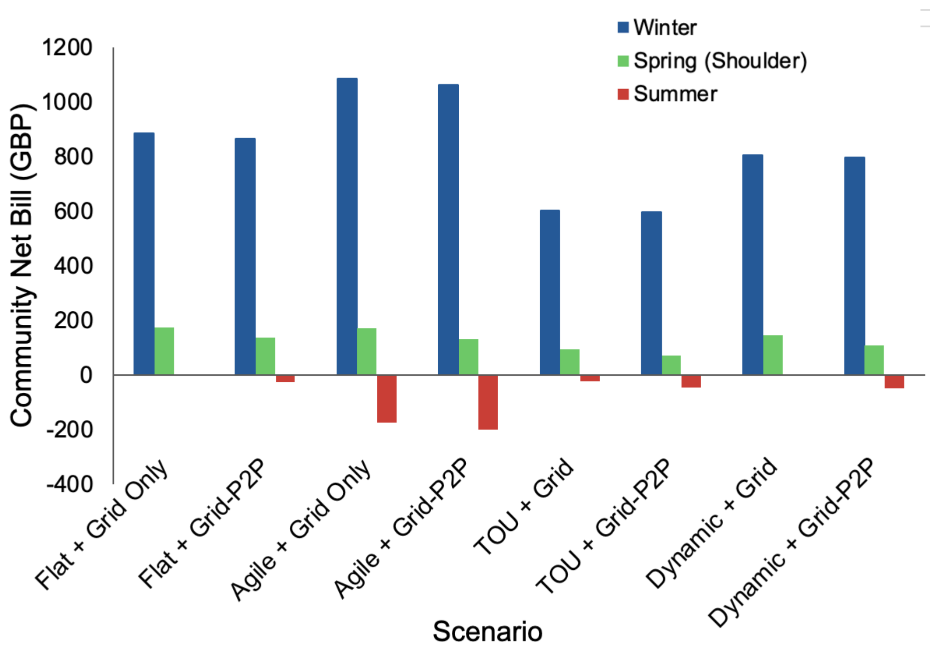

Figure 4: Community's weekly aggregated bill in GBP per scenario per experiment.

Figures **??** and **??** together highlight the fundamental trade-off between supplier and community welfare. Tariffs that minimise the community bill such as TOU in winter and spring, and agile in summer, tend to weaken supplier margins. Conversely, tariffs that bolster supplier profit, particularly the agile and flat in winter and spring, and flat and dynamic in summer, impose higher costs on the community. P2P generally lowers the community bill (especially in PV-rich spring/summer) and reduces supplier profit with the exception of TOU in the summer where P2P is a win-win for community and supplier. These results underline the tension between stakeholder interests and the need for mechanisms that balance financial outcomes while respecting grid constraints.

3.2. Impacts on the Grid

While financial gain is a key motivator for stakeholder participation in LEMs, the primary system-level objective is to facilitate seamless DER integration. The impact of P2P trading can therefore be evaluated by examining both the community's net load patterns and their implications for transformer capacity.

The strain imposed on the grid is captured by the community's net load, defined as the difference between imports and exports. Figure **??** presents the hourly net load, L_t distribution across one representative week for all tariff–transaction scenarios. In winter, net load is high due to extensive imports required to power heat pumps under limited PV generation. Under these conditions, the 50 kVA transformer limit is occasionally exceeded, particularly for agile, TOU, and dynamic tariffs without P2P. Introducing P2P trading reduces these peaks and smooths load profiles, in some cases (e.g. TOU in winter and spring) lowering the transformer requirement from 100 kVA to 50 kVA. In summer, P2P trading instead mitigates large negative peaks, which correspond to high PV exports that may strain the local grid's ability to absorb generation with the only exception being the summer experiment with agile tariff which is investigated further later. In all other cases, P2P improves load distribution by dampening extreme positive and negative excursions.

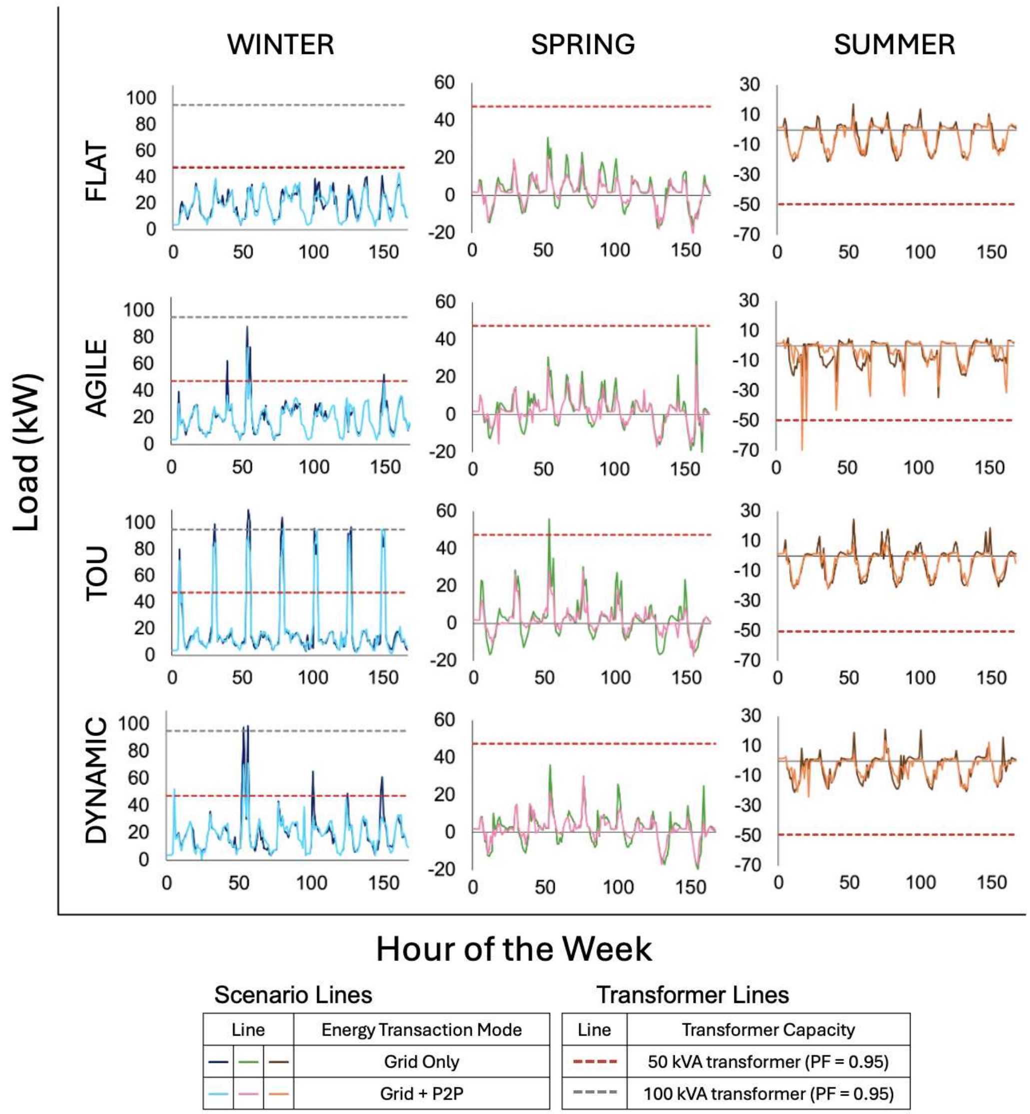

Figure 5: Total community load in kWh across 168 hours (one week) with grid connection alone or grid connection and P2P trading. Each subplot presents that information of the simulations for a different experiment and retail tariff. Where possible, transformer lines for a transformer of 50kVA and 100kVA are presented as well.

To translate these effects into planning terms, Figure **??** presents the THI for each scenario and season. THI values closer to 1 indicate comfortable headroom, while negative values mark capacity exceedance. The heatmaps confirm that winter is the most challenging season for import headroom (THI^{+}), with several tariff–transaction configurations exceeding the 50 kVA limit. In most cases, the introduction of P2P trading alleviates these constraints, smoothing peaks and distributing flows more evenly. Summer stress is concentrated on the export side (THI^{-}), where the agile tariff approaches or exceeds limits. While the effect of P2P is generally beneficial, there are a few cases where its impact is slightly negative (e.g. flat import in winter or export in spring, TOU export in spring, dynamic export in summer). Although deviations are generally small, the agile tariff in the summer case is a clear exception where P2P exacerbates export stress and lowers THI^{-}. Wholesale-linked export signals coincide with abundant PV, aligning prosumer behaviour so that EV discharges cluster at export price spikes as shown in Figure **??**. Meanwhile, P2P raises EV charging despite nearly flat, though elevated, import prices, concentrating surplus into short windows; the residual is exported at the agile rate, deepening negative net-load excursions (Figure **??**) and further reducing THI^{-} (Figure **??**). In short, under agile in summer, P2P amplifies export peaks rather than mitigating them.

Finally, across all seasons the 100 kVA transformer consistently provides adequate headroom, albeit at the cost of more expensive infrastructure, while mirroring the patterns of the 50kVA case in terms of transaction mode impact, as expected.

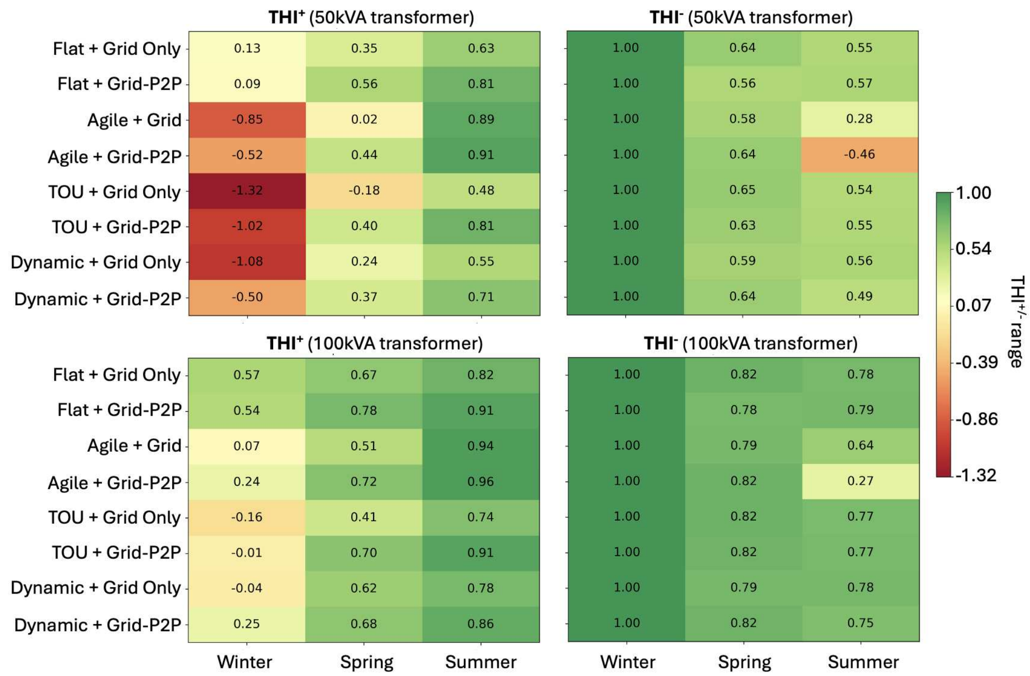

Figure 6: Seasonal THI for tariff–transaction scenarios. Import (THI^+) and export (THI^-) headroom are shown for 50 kVA and 100 kVA transformers (PF = 0.95) across all seasonal experiments (winter, spring, summer). Values closer to 1 indicate greater headroom; negative THI values (THI^+ or THI^-) denote exceedance of transformer import or export capacity, respectively.

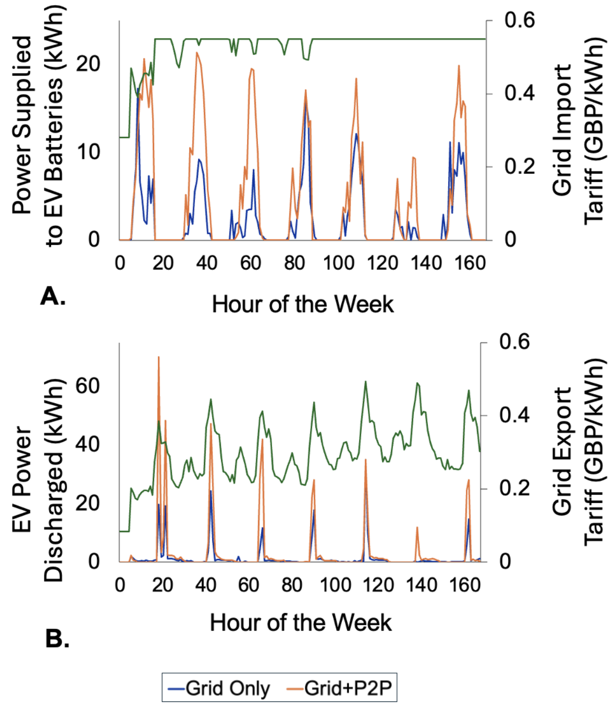

Figure 7: Aggregated EV battery behaviour and agile retail tariffs for the community during the summer experiment week. A: Power supplied to EV batteries (kWh) and the grid import tariff (GBP/kWh) as functions of the hour of the week. B: Power discharged from EVs (kWh) and the grid export tariff (GBP/kWh) across the same timeframe.

Overall, Figures ?? and ?? confirm that P2P trading is an effective mechanism for easing grid strain, but its benefits can be reversed under certain tariff structures, underscoring the importance of coordinated market and network design.

3.2.1. Role of EV Batteries in P2P load balancing

To understand how P2P trading achieves load balancing and consequently eases grid strain, we examined whether the effect could be attributed to household ASHPs or EV batteries. In winter and spring experiments, where peak reduction was observed, the aggregated ASHP demand profiles were almost identical with or without P2P, indicating that heat pumps do not contribute to this effect. Instead, the flexibility must come from EV batteries.

To investigate this, Figure ?? shows the hourly aggregated power supplied to EVs under scenarios with high positive peaks driven by ASHP demand as shown in Figure ??. Without P2P trading, EV charging coincides with net community load peaks. With P2P trading, these peaks are substantially reduced, as EV charging is rescheduled to exploit P2P exchanges rather than relying solely on grid imports. This adjustment arises from the interaction between P2P trading and the potential for V2H, enabling EV owners to shift charging times and store energy for later resale within the community. In this way, EV-enabled flexibility under P2P trading reduces net load peaks and alleviates strain on the grid.

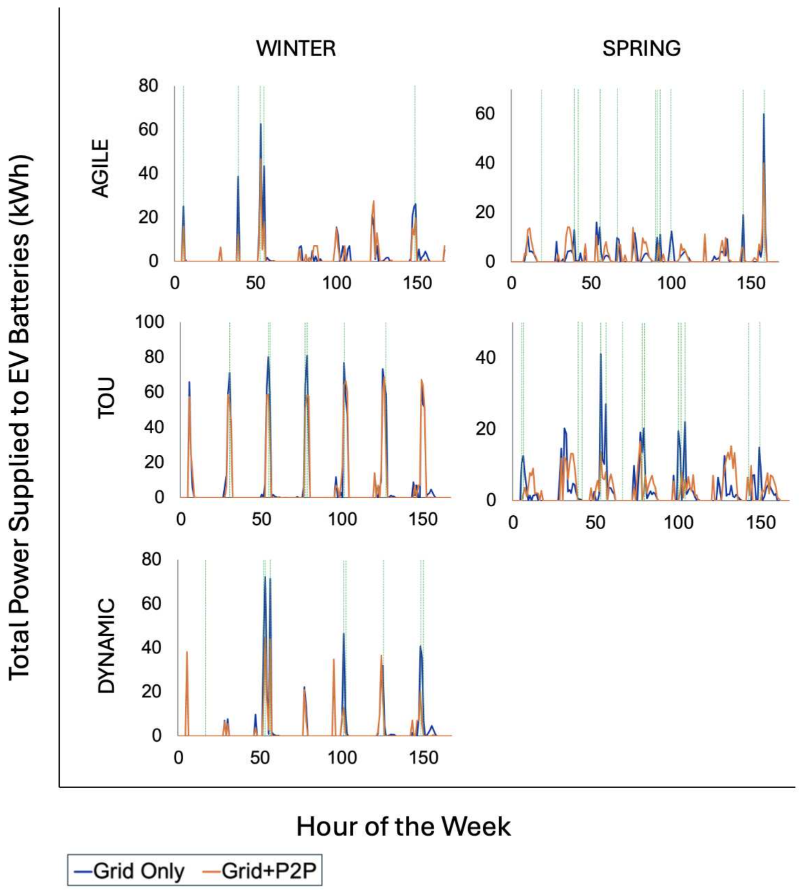

Figure 8: Total hourly energy supplied to EV batteries across 168 hours (one week) under grid only and grid-P2P conditions. Each subplot corresponds to a seasonal experiment (winter, spring) and retail tariff. Vertical green dashed lines indicate the hours of peak community load identified in Figure ??. The comparison highlights how P2P trading shifts and reduces EV charging peaks relative to net community demand.

3.3. Multi-Objective Assessment

Planning and tariff design face simultaneous goals: lower community bills, maintain supplier margins, and protect transformer headroom. Optimising any single metric in isolation can backfire on the others. A multi-objective view is therefore essential: it reveals the feasible co-improvements and the irreducible trade-offs, and prevents overweighting any one stakeholder or the grid.

In the preceding sections, stakeholder welfare and grid impacts were analysed separately. To capture trade-offs across both frames, Figure **??** applies Pareto filtering and knee-point identification to the combined metric space. The left-hand panels show all tariff–transaction mode scenarios for each season, with higher values in all parallel axes indicating better performance across the four oriented and normalised metrics: community net bill, supplier profit, and transformer headroom indices (THI^{+}, THI^{-}). The right-hand panels highlight the non-dominated Pareto set, within which knee points are identified using two assumption-light selectors: Chebyshev and TOPSIS.

From the left-hand panel of Figure **??**, a clear trade-off emerges: within each season, configurations that lower the community's net bill typically reduce the supplier's profit, and vice versa. P2P generally shifts outcomes toward lower bills and lower supplier margins in winter and spring, which is consistent with those seasons being import dominated. In summer, when PV surplus drives exports, P2P still reduces the bill and, under TOU, it also raises supplier profit by soaking up exports that would otherwise earn export credits. Seasonality is pronounced: winter shows higher community bills and higher supplier profit, spring compresses both money metrics, and summer shifts to low or negative community bills with supplier profit highly tariff dependent, with agile tariff being the weakest. Across seasons, $\mathrm{THI}^{\pm}$ shows modest dispersion relative to the money metrics, and P2P does not materially degrade headroom. Specifically, THI^{+} generally improves while THI^{-} changes are small, so network conditions remain broadly stable. Overall, configurations that perform strongly in one season often underperform in another, indicating a tension between robustness and single-season performance.

The results in the right-hand panel of Figure **??** confirm that no single tariff–transaction combination dominates across all metrics. In each season exactly one configuration is dominated, with all others lying on the Pareto front: Dynamic+Grid Only is dominated in winter and spring, while TOU+Grid Only is dominated in summer. In winter, both selectors (Chebyshev and

TOPSIS) choose the same knee, Flat+Grid-P2P. In spring there is again a single knee, now Agile+Grid-P2P. In summer the selectors diverge, reflecting export-driven asymmetries in summer that weight the bill–profit trade-off differently across selectors. Specifically, Chebyshev selects Dynamic+Grid-P2P, whereas TOPSIS selects TOU+Grid-P2P. Overall, knees vary by season, and, in summer, by selector, underscoring that they are signposts of balanced trade-offs rather than definitive prescriptions.

Each knee identified on the Pareto front corresponds to a different tariff; however, all knees are Grid+P2P configurations, reflecting a balanced reduction in the community bill with no significant deterioration in supplier profit and no evident harm to THI. Method agreement is present in winter and spring, whereas in summer the selectors diverge, mirroring the mixed incentives under high exports. Across seasons, knees avoid extremes in all metrics and instead settle on options that keep supplier profit acceptable, deliver clear bill reductions, and hold THI roughly steady. THI thus acts more as a guardrail than a driver; the bill–profit trade-off is the main determinant of the selected compromises. In conclusion, although the tariff that underlies the knee varies by season, P2P is favoured in every case because it converts local surpluses into local consumption and trims imports, improving bills while leaving headroom largely unchanged.

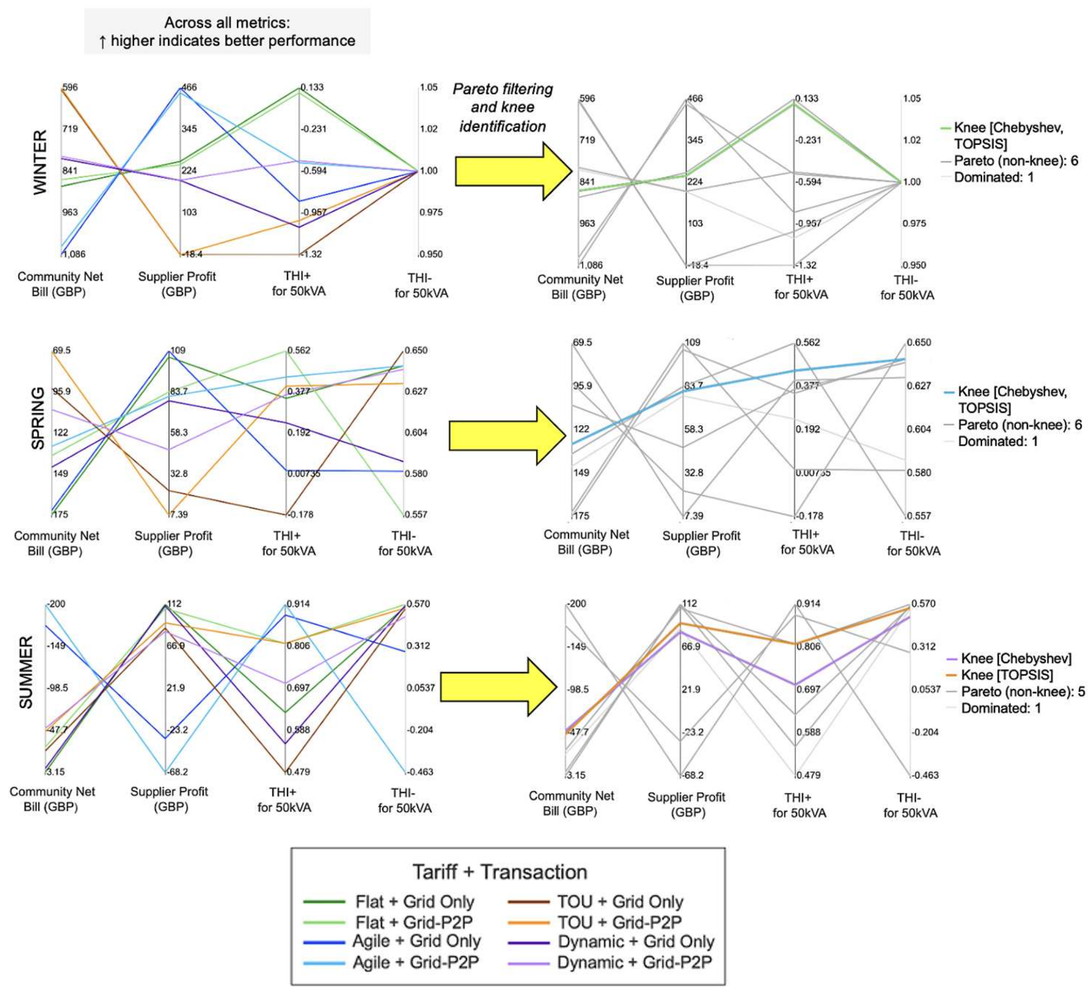

Figure 9: Seasonal Pareto filtering and knee-point identification across welfare and grid metrics. Left panels show all tariff–transaction scenarios (coloured lines) for winter, spring, and summer experiments. Right panels display the filtered Pareto set, distinguishing non-knee Pareto solutions (dark grey), dominated alternatives (light grey) and knee points (coloured to match the respective scenario in the left panels) as identified by two distinct selectors (Chebyshev, TOPSIS). Counts of non-knee Pareto and dominated alternatives are indicated next to each filtered plot. Metrics include community net bill, supplier profit, and transformer headroom indices (THI$^+$, THI$^-$) for a 50 kVA with PF=0.95.

4. Discussion and Policy Implications

The results of this study suggest three quantitative patterns that are directly relevant for policy. First, across seasons and tariffs there is a persistent distributional tension between community bills and supplier margins. Tariffs that minimise the community's net bill, such as TOU with P2P in winter and spring or agile with P2P in summer, systematically compress supplier profit (Figures ??–??). Conversely, tariff–transaction combinations that protect supplier profit, such as flat or dynamic without P2P in winter and spring, impose higher costs on the community. P2P consistently shifts outcomes towards lower bills and lower supplier profit, with one notable exception: under TOU in summer, P2P simultaneously reduces the community bill and increases supplier profit by converting midday exports into local trades.

Second, P2P trading usually improves or leaves unchanged import headroom, THI^{+}, by shifting EV charging away from import peaks (Figures ??, ??). Across tariffs, the overall level of THI^{+} is driven mainly by seasonal load and the choice of tariff; P2P has a modest but generally beneficial effect on import headroom, rather than reversing the impact of tariff design. In several winter and spring cases, this relief would allow a 50 kVA transformer to operate within limits, where a 100 kVA unit would otherwise be prudent (Figure ??). Export headroom, THI^{-}, is more sensitive to tariff design. Under flat, TOU and dynamic tariffs, P2P only marginally affects THI^{-}, but in summer under agile pricing, P2P plus real-time export signals tighten export headroom and drive THI^{-} towards or below zero as prosumers synchronise exports into price spikes (Figures ??–??).

Third, the multi-objective analysis confirms that no single tariff dominates across community net bill, supplier profit and transformer headroom. In each season, almost all tariff–transaction combinations lie on the seasonal Pareto frontier once metrics are normalised, yet the identified knee-points, the most balanced compromises, always involve Grid+P2P rather than Grid-only operation (Figure ??). In winter the knee is Flat+Grid-P2P; in spring it is Agile+Grid-P2P; in summer the Chebyshev and TOPSIS selectors choose Dynamic+Grid-P2P and TOU+Grid-P2P respectively. This indicates that P2P trading is consistently part of the "least-regret" set once all stakeholders and grid metrics are considered, but that the preferred supporting tariff is context-dependent.

These findings suggest that policy debates should move beyond whether to allow P2P trading, as our results show it forms part of all balanced solutions. Instead, the focus should shift to designing tariffs, settlement rules, and network constraints around P2P. Specifically:

- Current volumetric cost recovery is incompatible with P2P scaling. The observed erosion of supplier profits implies that residual cost recovery must be decoupled from behavioural price signals.

- THI provides a simple, planner-facing headroom index in our case study. Here it is used as an ex post indicator of how tariff–transaction combinations affect import and export capacity margins, illustrating how similar indices could help DSOs link REC operation to network planning and flexibility valuation.

- Real-time export tariffs require physical guardrails. Given the risk of synchronised exporting we observed under agile pricing, such tariffs must be accompanied by network-aware limits to prevent aggregate exports from violating local headroom constraints.

We discuss these implications under four policy priorities which are introduced in Figure **??**. These implications are directed at multiple governance levels and market actors. Depending on the recommendation, implementation may involve national governments, energy regulators, DSOs, electricity suppliers, aggregators, and community energy organisations. Where appropriate, the responsible actors are identified within the discussion of each policy priority.

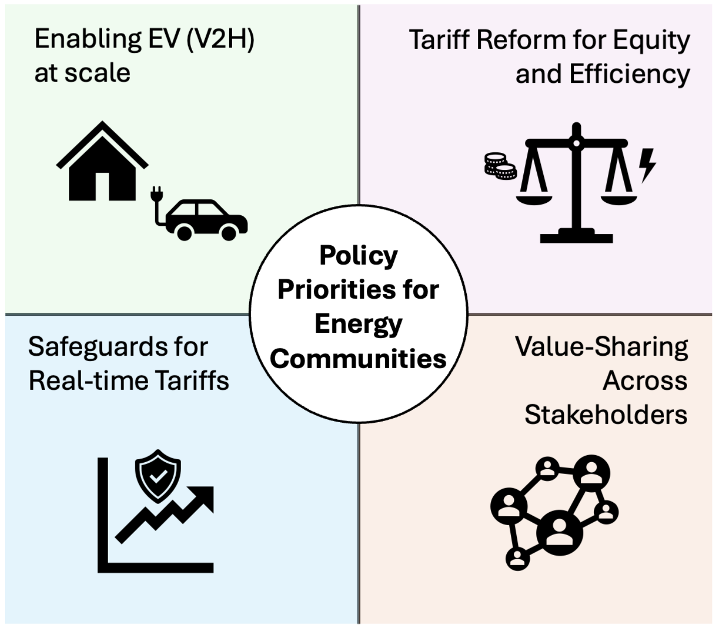

Figure 10: Policy priorities for energy communities

Finally, while the policy priorities identified here have broader relevance, their implementation readiness varies across jurisdictions. Recent literature highlights substantial differences across the EU in how Member States have transposed and operationalised energy community provisions, resulting in varying levels of institutional support, incentive structures, and market participation opportunities for RECs [?]. Consequently, the feasibility and pace of implementing the recommendations proposed here may vary across jurisdictions, with some recommendations being more readily adopted in countries with well-established enabling frameworks than in those where enabling legislation, market arrangements, or institutional support structures are still emerging [?].

4.1. Tariff Reform for Equity and Efficiency

The seasonal patterns in Figures **??**–**??** highlight that current volumetric tariffs conflate two functions: residual cost recovery and forward-looking behavioural signals. In our study, TOU imports minimise community bills in winter and spring, and agile export prices in summer turn the community into a net exporter with net credit under P2P. However, these same tariffs compress supplier profit, especially when P2P reduces grid imports in PV-rich seasons. This is also visible in the Pareto plots of Figure **??**, where movements towards lower community net bills are typically accompanied by declines in supplier profit.

This trade-off between community bills and supplier profit implies that recovering sunk network and supplier costs through per-kWh import charges will become increasingly unstable as communities self-consume or trade locally. If tariffs are not reformed, this means that an increasing share of fixed system costs would need to be recovered from customers who are not part of an energy community.

In this study, equity refers specifically to the distributional equity, defined as the sharing of REC benefits and associated tariff costs among stakeholders. Our results therefore support a shift towards decoupling equity from efficiency in retail tariffs. Residual costs should be recovered in ways that do not distort local trading, while time-varying, forward-looking elements such as TOU, agile and dynamic tariffs should only be used where they genuinely relieve grid stress. At the same time, all households, including those who cannot or choose not to participate, must be protected. Our results highlight, in particular, the need for equitable charges so that non-participants do not shoulder a growing share of residual cost recovery as P2P expands. In practice, this also requires transparency about bill impacts and appropriate data safeguards in the operation of RECs, although these aspects lie beyond the scope of our model.

We propose three measures as critical:

1. Recover sunk network costs through fixed or capacity-based charges, as recognised in Ofgem's Targeted Charging Review and the EU Electricity Directive [**? ? ?**].
2. Reserve TOU or time-/location-varying tariffs for situations where they effectively smooth demand, relieve local constraints (where administratively feasible), and avoid export prices that trigger synchronised behaviour, as seen in our agile–summer case.
3. Guarantee opt-in/opt-out rights, bill comparators, transparent data-use rules, and mandatory reporting from community pilots on both distributional outcomes (e.g., community bills, supplier profits) and grid outcomes (e.g., $\mathrm{THI}^{+/-}$, hours-at-risk) [**? ?**].

These measures can facilitate the scaling of RECs with LEMs without regressive effects or loss of public legitimacy. As for the implementation of these reforms, it would primarily fall within the remit of national governments and energy regulators responsible for tariff design and cost recovery mechanisms.

However, such systemic changes may face both regulatory and political challenges. Existing tariff structures and cost recovery arrangements are often embedded within established regulatory frameworks, making reform inherently challenging and often gradual. In addition, fixed or capacity-based charges may encounter stakeholder resistance where they are perceived to increase costs for low-consumption households, reduce the financial benefits currently associated with self-consumption, or redistribute costs between REC participants and non-participating consumers. Consequently, executing these transitions smoothly is likely to require careful regulatory design, transparent communication of bill impacts, and appropriate protections for vulnerable consumers [**?** **?**]. Effective governance arrangements, including ongoing monitoring of cost and benefit allocation and clear reporting requirements, will also be important to ensure that equity objectives are maintained as participation in RECs expands [**?**]. Finally, achieving these reforms in practice may require phased implementation and extensive stakeholder consultation to balance economic efficiency objectives with public and political acceptability.

4.2. Value-sharing across stakeholders

In our simulations, P2P trading consistently reduces grid imports in PV-rich periods and shifts value from suppliers to the community, while often improving transformer headroom. For instance, in spring P2P reduced supplier profit by 20–67% across tariffs while cutting the community's net bill by around 25%, and in several winter and spring cases THI^{+} improves sufficiently for a 50 kVA transformer to operate within limits instead of a 100 kVA unit (Figures **??**–**??**, **??**). Yet these grid benefits are not monetised for DSOs, and suppliers only see reduced margins.

From a policy perspective, these patterns point to a misalignment: communities and the grid gain, suppliers lose, and DSOs lack a mechanism to recognise or reward community contributions. If unresolved, this creates strong incentives for incumbent opposition or for suppliers to recoup losses by raising tariffs elsewhere.

Our results therefore justify two complementary value-sharing mechanisms that can transform P2P from a distributive conflict into an incentive-compatible system. Specifically, we propose:

1. **Supplier value-sharing.** P2P trading fundamentally relies on supplier-facing market and retail services, including licensing, balancing responsibility, and data/settlement infrastructure. However, our results show that it systematically compresses the margins required to maintain these services (Figure **??**). To resolve this tension, we recommend a facilitation fee per kWh of P2P throughput that explicitly covers these fixed costs [**?**]. As a consequence, the fixed costs of balancing and settlement services, which are still required by P2P participants, are not unfairly shifted to non-participating customers. To ensure community incentives are preserved, this fee could be bounded by a fraction of the bill reduction observed in balanced scenarios, using the Pareto knee-points (Figure **??**) as a benchmark for sustainable compensation. Furthermore, where REC operation demonstrably reduces network costs (for example by lowering hours-at-risk or peak kW at the transformer), a "beneficiary-pays" credit could allocate a portion of those monetised grid savings to the actors that enabled them. In practice, this would mean the DSO directly remitting a portion of its avoided reinforcement or flexibility savings back to the community. Where the retail supplier is instrumental in facilitating this coordination, a share of this credit would be allocated to them as well [**?**]. Critically, such credits should be tied to measured outcomes to avoid overcompensation.
2. **DSO procurement of flexibility.** In our analysis, the THI metric provides a simple ex post quantification of local capacity margins, explicitly measuring import and export headroom (Figure **??**). While we do not model THI-driven control signals, the behaviour of THI across scenarios illustrates how DSOs could use similar headroom indices to identify when P2P-coordinated EV flexibility is a cost-effective non-wires alternative and to specify where and when flexibility is most valuable [**?**]. To align incentives, DSO–community flexibility arrangements could take the form of performance-based contracts: payments would trigger only when the community improves $\text{THI}^{+}/\text{THI}^{-}$ scores, for instance by reducing the duration or severity of capacity threshold breaches. A portion of the resulting avoided costs can then be shared with both the community and the enabling suppliers as a beneficiary-pays credit. Existing frameworks, such as the standardised local products and pay-for-performance contracts already tested in UK flexibility tenders [**?**], provide a ready-made pathway to operationalise this integration.

Implementing these mechanisms would require coordination between regulators, suppliers, DSOs, and community energy organisations. In practice, implementation would require transparent methodologies for measuring and verifying the network and market benefits generated by RECs, particularly where these benefits form the basis of supplier facilitation payments or THI-linked flexibility rewards. Governance arrangements would therefore need to clearly define responsibilities for data provision, performance verification, payment allocation, and oversight across suppliers, DSOs, aggregators, and community operators. Implementing these may also introduce additional administrative and transaction costs associated with measurement, verification, settlement, and reporting processes, which should be weighed against the system and market benefits they are intended to deliver. Without such institutional arrangements, disputes over value attribution and benefit sharing may undermine stakeholder confidence and limit deployment at scale [**?**].

4.3. Safeguards for Real-Time Tariffs

The summer-agile case reveals that highly granular export prices can synchronise prosumer behaviour, and that this synchronisation is further reinforced when P2P trading is enabled. In that case, EV discharging and P2P trades cluster around export price spikes, producing deeper negative net-load peaks (Figure **??**) and a reduction in THI^{-} relative to other tariffs (Figure **??**). This is confirmed by the EV behaviour in Figure **??**, where discharging aligns closely with agile export price peaks. In contrast, TOU and flat tariffs show no comparable deterioration of THI^{-}, and TOU+P2P in summer even yields a rare win-win for both community and supplier.

These results indicate that real-time export tariffs pose a particular risk of export congestion when combined with P2P trading in PV-rich regimes, whereas TOU-style structures appear safer from a network perspective in our study. We therefore suggest that export-oriented DOEs and similar guardrails should be treated as integral design elements, rather than optional add-ons, when deploying real-time export tariffs at scale in PV-rich LV networks.

Our findings support two types of guardrails:

1. **DOEs informed by THI.** A practical approach is to implement DOEs that adjust import and export caps in near real-time based on feeder capacity [**?**]. DOEs are already being deployed in jurisdictions such

as Australia, where they are used to manage DER exports while maintaining network security [?]. DSOs could use THI^{-} trajectories to set these limits. For example, a planning rule might require that THI^{-} remains above a minimum acceptable threshold; DOEs would then be calculated such that, even when agile export prices induce synchronised behaviour, aggregate net exports do not push THI^{-} below this threshold. Embedding these envelopes directly into P2P clearing, so bids and asks are constrained by the current export envelope, would ensure that collective responses remain within the physical hosting capacity of the grid.

2. **Anti-herding rules in tariff design.** The agile-summer results suggest that abrupt export spikes create the largest headroom stress. It could therefore be required that suppliers smooth extreme export price spikes, for example by applying ramp-rate constraints or limiting the amplitude of very short-lived peaks, especially on sunny days with forecast PV surplus. In parallel, LEM rules could allow P2P trades to clear in staggered batches or with randomised activation windows, so that flexible devices do not all respond at the same instant. Comparable principles already operate in the UK via DSO-led active network management and flexible connection schemes, where export or import capacity is dynamically constrained according to local network conditions to prevent congestion and maintain network security [?]. These schemes, therefore, provide a practical precedent for the network-aware safeguards proposed here.

DSOs would be the primary actors responsible for monitoring network conditions and implementing these operational safeguards. Effective implementation would also require timely access to network and market data, together with governance arrangements that clearly define data-sharing responsibilities, accountability, and oversight across DSOs, suppliers, aggregators, and community operators. Regulatory frameworks may therefore need to evolve to support the exchange of operational information necessary for network-aware market coordination while maintaining appropriate consumer and data protections.

Ultimately, pairing real-time tariffs with network-aware coordination allows RECs to capture the benefits of price responsiveness while preventing coincident surpluses. Critically, the THI metric enables DSOs to move from static worst-case assumptions to risk-based planning, quantifying exactly how much headroom exists for these market operations across different seasons. This turns real-time pricing into a contributor to grid stability rather than a source of outlier stresses like those observed in our summer-agile scenario.

4.4. Enabling EV (V2H) at scale

Section **??** showed that the primary driver of import-side headroom improvements under P2P is EV flexibility rather than ASHP demand. When P2P is enabled, EV charging shifts away from hours of peak community net load (Figure **??**), reducing import peaks and improving THI^+, particularly in winter and spring (Figures **??**–**??**). V2H discharging in summer further helps absorb PV surplus or shift exports in time. These behaviours underpin the improved grid outcomes for Grid+P2P scenarios and are present in all seasonal Pareto knees involving P2P (Figure **??**).

From a policy perspective, this suggests that EVs are the main operational lever by which RECs with P2P can deliver system-friendly behaviour. To harness this at scale, regulators should ensure EVs are treated as trusted flexibility assets. This requires three enablers that connect our modelled benefits to current regulatory frameworks:

1. **Interoperability and communication standards.** The EV scheduling that improves THI^+ in our simulations presupposes reliable communication and control across vehicles, chargers, and the community market platform. Adoption of open standards such as ISO 15118 and the Open Charge Point Protocol [**?**] provide this foundation; their adoption is a prerequisite for replicating the EV-mediated headroom gains observed in our case study.
2. **Settlement rules for bi-directional flows.** Our community bill and supplier profit metrics assume clear attribution of imports and exports between the EV, the household, and the supplier. Real-world implementation requires regulatory clarity on allocation of settlement responsibility: specifically, defining which licensed entity is legally responsible for metering and settling V2H and V2G energy volumes to prevent double-charging or dispute [**?**]. Without this, the EV flexibility that improves THI^+ and reduces community bills in our results may remain untapped.
3. **Battery welfare safeguards.** Households will only consent to flexible EV use if compensated for battery degradation [**?**]. Although

our model does not explicitly calculate these costs, the community savings generated by P2P trading can be substantial, particularly during PV-rich periods (see Figure **??**). This confirms that there is ample financial margin to pay households for battery wear, internalising the cost without eroding the overall incentive to participate.

In light of the critical role EV flexibility plays in our THI and Pareto outcomes, treating EVs as regulated flexibility assets, rather than mere loads, appears essential for realising the system benefits of RECs. Achieving this will require coordinated action from regulators, suppliers, aggregators, chargepoint operators, vehicle manufacturers, and community energy organisations to ensure that interoperability, settlement, and consumer protection frameworks evolve alongside technical capabilities. Successful deployment will also depend on maintaining consumer trust through transparent participation arrangements, clear compensation mechanisms, and confidence that flexibility services will not adversely affect vehicle usability or battery health. Behavioural uptake is also unlikely to depend solely on financial incentives, with consumer perceptions, trust, awareness, and prior experience all influencing participation decisions in EV flexibility schemes [**?**].

4.5. Towards a Policy Roadmap

Collectively, the four policy priorities developed above form a coherent roadmap for scaling community energy. Although our simulation parameters are specific to the UK, the broader mechanisms identified in this study are relevant to jurisdictions with unbundled power sectors and high penetrations of variable renewable generation. Specifically, these priorities rely on three fundamental mechanisms identified by our analysis: the trade-offs between community bills and supplier profit, the impact of tariffs on transformer headroom (THI), and the vital role of EV flexibility.

While the findings presented here are derived from a representative 20-household UK case study, their interpretation requires consideration of several modelling simplifications. First, network performance is evaluated using the THI, a planning-oriented indicator of import and export capacity margins, rather than a full representation of voltage and thermal constraints. Consequently, the analysis does not capture all operational realities faced by DSOs, including local voltage deviations, phase imbalance, and feeder-specific thermal constraints. Therefore, the THI should be viewed as an exploratory policy-analysis tool designed to illustrate how tariff design and local trading arrangements influence network headroom, rather than as a validated metric for real-time network management. Second, the study considers a single feeder and community configuration; larger communities, alternative network topologies, and different demand or generation compositions may produce different quantitative outcomes.

These limitations imply that the numerical results reported here should not be interpreted as directly transferable to all jurisdictions or network contexts. Rather, the policy implications are intended to arise from the broader mechanisms observed in the analysis. In particular, the distributional trade-offs between community savings and supplier revenues, the importance of EV flexibility in shaping network outcomes, and the need for network-aware safeguards under highly dynamic pricing structures are likely to remain relevant across a wide range of REC implementations, even where the magnitude of the effects differs.

The mechanisms proposed here should be viewed as complementary to, rather than substitutes for, existing flexibility market arrangements. For example, THI-linked incentives share similarities with emerging DSO flexibility markets in that both seek to reward actions that improve local network performance and reduce the need for conventional network reinforcement [**?**]. However, whereas DSO flexibility markets typically procure specific flexibility services from individual assets or aggregators to address identified network constraints [**?**], the mechanisms proposed here focus on allocating and sharing the broader network and market value generated collectively through REC participation and local trading. Beyond local network services, the flexibility enabled through REC participation may also create value through participation in wholesale, balancing, or capacity markets [**?**]. Future policy development should therefore consider how local value-sharing arrangements can be coordinated with wider flexibility market structures to capture both local network and system-wide benefits. This highlights the need for future regulatory frameworks to coordinate value streams across retail, local flexibility, and wholesale market layers to avoid conflicting incentives, support effective revenue stacking, and ensure efficient deployment of distributed flexibility.

With these mechanisms and limitations in mind, we propose four mutually reinforcing steps to operationalise the roadmap:

1. Residual cost recovery re-basing on fixed or capacity-based charges.
2. Embedding of outcome-based value-sharing between communities, sup-

pliers, and DSOs.
3. Making real-time export tariffs explicitly network-aware.
4. Treating EVs as regulated flexibility assets rather than passive loads.

By aligning price signals, revenue flows and technical safeguards with the quantitative trade-offs revealed in our case study, this roadmap moves RECs with P2P trading beyond isolated pilots. The result is a scalable, regulation-compatible practice that supports both decarbonisation and equity, aligning the interests of households, suppliers and DSOs.

5. Conclusions

In this work we linked an ABM of a REC market with a planning metric, THI, to evaluate how tariff design and P2P trading shape community bills, supplier profit, and distribution headroom across seasons. Across winter, spring, and summer weeks in 2022, we found a persistent distributional tension: configurations that lower community bills, especially TOU in winter/spring and agile pricing in summer, systematically erode supplier profits, while options that bolster supplier profit raise costs for households. P2P trading accentuates this divergence by reducing grid purchases in PV-rich periods. These patterns clarify that current tariff and settlement arrangements are not neutral to community trading and require reform if RECs are to scale without backlash.

Grid outcomes depend on both season and tariff structure. P2P generally improves import headroom (THI^{+}) by shifting EV charging away from peak hours, occasionally enabling a 50 kVA transformer where 100 kVA would otherwise be prudent. However, in high-PV summer conditions, P2P with agile export signals can synchronise prosumer behaviour and reduce THI^{-}, a reminder that sharper real-time prices are not inherently "grid-friendly" without coordination. EV flexibility, rather than ASHP demand, was the principal mediator of these headroom effects.

A multi-objective assessment confirmed that no single tariff design dominated across community cost, supplier profit, and import/export headroom in all seasons. However, all Pareto knee-points selected included P2P trading. This is a very promising outcome for community energy with P2P; yet, the deviation in optimal tariffs highlighted the need for context-aware policy rather than one-size-fits-all rules.

Translating findings into action, four policy levers emerge, moving from abstract goals to specific regulatory instruments:

1. Tariff Reform: Re-basing residual cost recovery onto fixed or capacity-based charges to decouple equity from the efficiency signals of P2P.
2. Value-Sharing: Introducing supplier facilitation fees and THI-based flexibility payments to monetise the benefits provided to the grid and retail infrastructure.
3. Safeguards: Pairing real-time export tariffs with DOEs to prevent synchronised export congestion.
4. EV(V2H) Enablement: Standardising interoperability and bi-directional settlement to treat EVs as regulated flexibility assets.

This study is deliberately transparent yet stylised: it considers a single-feeder, 20-household REC, hourly CDA clearing, a simplified LV representation via THIs and tariffs calibrated to 2022 conditions. Future work should:

- test robustness across heterogeneous feeders and community sizes,
- adopt finer temporal resolution,
- incorporate stochastic participation,
- explore alternative settlement rules,
- model voltage and thermal constraints explicitly, and
- validate behaviours in field pilots.

Extending the analysis to distributional equity impacts on vulnerable and non-participating households, supplier portfolio effects, and interactions with DSO flexibility markets will further support evidence-based regulation.

Overall, RECs with P2P trading can reduce household bills and enhance transformer headroom, primarily by coordinating EV flexibility. Without policy reform, however, these gains tend to reallocate value away from suppliers and can occasionally intensify export constraints under dynamic pricing. With targeted tariff design, bounded value-sharing, and network-aware coordination, community energy can function as a cooperative asset for households, suppliers, and DSOs alike.

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