



Impacts of Local Energy Communities on Low Voltage Distribution Networks

Downloaded from: <https://research.chalmers.se>, 2026-10-13 03:28 UTC

Citation for the original published paper (version of record):

Bhamidipati, V., Steen, D., Le, A. (2026). Impacts of Local Energy Communities on Low Voltage Distribution Networks. 25th Wind and Solar Integration Workshop

N.B. When citing this work, cite the original published paper.

Impacts of Local Energy Communities on Low Voltage Distribution Networks

B V Suryakiran^{1}, David Steen¹, Le Anh Tuan¹*

¹*Electric Power Engineering, Chalmers University of Technology, Gothenburg, Sweden*

^{*}*vensur@chalmers.se*

Keywords: Local Energy Community, Distribution System Operator, Self-consumption, Scenario Analysis, Prosumers

Abstract

This paper presents a scenario-analysis framework for evaluating the impacts of local energy communities on distribution network performance and associated economic implications. A distribution network comprising residential, commercial, and industrial prosumers, defined as per their demand profiles, is considered. Scenarios are constructed based on all possible community compositions and benchmarked against a reference case in which prosumers purchase electricity under a self-consumption strategy. Each scenario is implemented in two stages. First, operating schedules are optimized to minimize total energy procurement cost. Second, optimized schedules are evaluated using linearized distribution power flow equations to assess network performance. Each scenario is evaluated using network KPIs, including maximum feeder loading and minimum nodal voltage, and economic KPIs, including energy cost, peak cost, and overall cost. The results suggest that local energy communities primarily achieve overall cost minimization through reductions in peak-related costs. Across all local energy community configurations, 13% cases exhibit a higher maximum line loading than in the reference case, with these instances predominantly associated with homogeneous prosumer compositions. This effect arises from the mismatch between local community demand patterns and aggregate feeder demand. While batteries reduce the peak of a homogeneous community, their charging during community low-demand hours can coincide with the feeder peak, leading to higher maximum line loading at the network level.

1 Introduction

End-consumers in modern distribution systems are increasingly equipped with flexible resources such as rooftop PV, electric vehicles, heat pumps, and home batteries through both private investment and public support schemes. These distributed resources alter power flows and may increase grid-side variability, creating new requirements and opportunities for flexibility provision and local energy management. In this context, Local Energy Communities (LECs) have emerged as a community-based framework for the collective management and operation of prosumer energy resources.

The deployment of such community-based approaches has been enabled by recent European Union (EU) regulatory reforms. The Clean Energy Package provides the overarching framework by recognizing energy communities and facilitating their participation in energy markets [1]. Directive (EU) 2019/944 defines Citizen Energy Communities [2], while Directive (EU) 2018/2001 (RED II) establishes Renewable Energy Communities [3], together supporting collective renewable generation, self-consumption, and enhanced consumer participation. Moreover, Regulation (EU) 2019/943 strengthens market design provisions for the non-discriminatory participation of flexibility resources, including storage and demand-side solutions [4].

In response to these regulatory developments, LECs have attracted increasing research attention in Europe. A Norwegian low-voltage case study on a real neighborhood feeder with

52 households shows that uncoordinated battery and EV arbitrage can increase peaks, losses, and voltage fluctuations [5]. Using demand data from Madrid, Spain, similar adverse network effects under uncoordinated battery and EV arbitrage are reported [6]. An Italian case study similarly emphasizes the need for grid-aware incentives and control, noting that individual customer objectives can conflict with Distribution System Operator (DSO) flexibility requirements while can also lead to increased losses and line loading [7]. Medium-voltage impacts are further shown to be topology-dependent [8]. By contrast, a German low-voltage case study demonstrates that monitoring and active network management can mitigate violations under local energy exchange [9]. Collectively, these studies show that LEC performance is shaped by control strategy and network topology, as well as by participant composition and available assets. However, most studies consider only a narrow set of community compositions and do not systematically explore variations in prosumer demand types, technology configurations, and community sizes.

This paper performs a scenario analysis on the impacts of LECs across communities comprising different prosumer composition and community sizes. The main contributions are as follows:

- A scenario-analysis framework is developed to assess the impacts of LECs on distribution network performance and the economic outcomes for prosumers, considering an exhaustive set of community compositions and sizes relative to self-consumption (SC) scenarios.

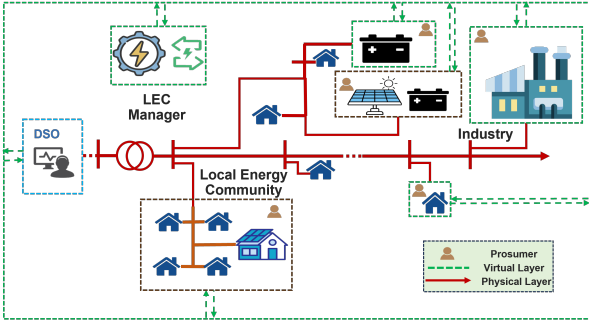


Fig. 1. Schematic representation of a LV network.

- Identification of the key performance indices across LEC scenarios for DSOs, LEC managers and prosumers for understanding the scope of LECs in terms of benefits for the prosumers and LEC managers and network impacts for the DSO.

The remainder of the paper is organized as follows: Section 2 presents the study framework, supported by mathematical modelling in Section 3. Section 4 reports the test system and results, and Section 5 concludes the paper.

2 Scenario Analysis Framework and Methodology

Figure 1 shows the schematic of the LV distribution system, in which the DSO supplies electricity to consumers and the LEC manager functions as an aggregator coordinating prosumers within a community framework. Under the SC scheme, prosumers optimize their assets independently to reduce their electricity bills, whereas under the LEC scheme, selected prosumers are coordinated and optimized jointly while non-participating prosumers continue to operate under SC, thereby enabling a consistent baseline comparison under identical temporal and market conditions. The physical layer represents the flow of electricity, while the virtual layer represents the corresponding economic interactions within the network. Figure

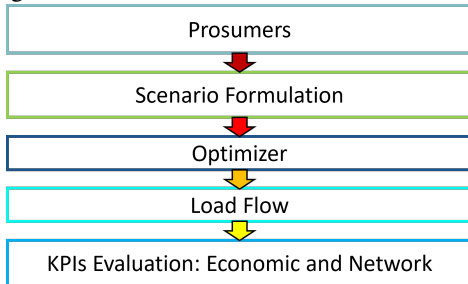


Fig. 2. Flow of the presented work.

2 illustrates the scenario analysis workflow. A mixed-demand feeder with twelve prosumers are considered such that the overall feeder demand is almost equally distributed among industrial, commercial and residential prosumers. These prosumers are also equipped with either PV or BESS or both PV and BESS. Considering these prosumers, all feasible LEC compositions are generated, ranging from two-prosumer communities to a single community comprising all prosumers, with

each of them self scheduling independently in the reference case. For each case, operating schedules are first optimized for minimum daily costs and then assessed through load-flow analysis incorporating network characteristics and prosumer location. The tariff structure is adopted from Goteborg Energi, Sweden [10]. The prosumer tariff comprises of a subscription fee, energy tariff and a monthly power tariff, detailed in the next section. The resulting outputs are used to derive network KPIs, including maximum changes in line loading and voltage deviations in LEC relative to SC, as well as economic KPIs, including energy cost, peak cost, and total cost, as described in the following section.

3 Mathematical Modelling

This section presents the optimization model used for the analysis. The formulation is based on Mixed Integer Linear Programming (MILP). The modelling is partly adopted from [11].

3.1 Objective Function

The objective is to minimize each prosumer's daily electricity cost according to equation (1), comprising a subscription fee, an energy tariff, and a power tariff. For the i^{th} prosumer, the subscription fee C_i^{sub} is a fixed monthly charge. Here, C_i^{energy} denotes the hourly energy cost for the i^{th} prosumer for imports P_t^{imp} and exports P_t^{exp} . The energy cost is given by equation (2), where $\sigma_t^{DA_spot}$ is the day-ahead spot price, σ^{Trans} the transmission fee, σ^{Tax} the tax component, and σ^{Comp} the network loss compensation.

$$\min Z = \sum_i (C_i^{sub} + C_i^{energy} + C_i^{power}) \quad (1)$$

$$C_i^{energy} = \sum_t \left[(\sigma_t^{DA_spot} + \sigma^{Trans} + \sigma^{Tax}) P_t^{imp} - (\sigma_t^{DA_spot} + \sigma^{Comp} + \sigma^{Tax}) P_t^{exp} \right] \Delta t \quad \forall i \quad (2)$$

$$C_i^{peak} = \sigma_{peak_effect_fee} \cdot P_{peak} \quad \forall i \quad (3)$$

3.2 Constraints

3.2.1 Load balance constraint: Equation (4) defines the power balance between imports, exports, demand, and asset schedules. Here, P_t^{imp} and P_t^{exp} denote imported and exported power, respectively; P_t^D denotes the demand of prosumer i at time t ; $P_{i,t}^{b,ch}$ and $P_{i,t}^{b,dis}$ represent BESS charging and discharging power, respectively; and $P_{i,t}^{PV}$ denotes PV generation. The constraints in (5) employ a big- M formulation to prevent P_t^{imp} and P_t^{exp} from being positive simultaneously.

$$P_t^{imp} - P_t^{exp} = \sum_i (P_{i,t}^D + P_{i,t}^{b,ch}) - \sum_i (P_{i,t}^{PV} + P_{i,t}^{b,dis}) \quad (4)$$

$$0 \leq P_t^{imp} \leq M \cdot u_t, 0 \leq P_t^{exp} \leq M \cdot (1 - u_t), u_t \in \{0, 1\} \quad (5)$$

3.2.2 Battery Energy Storage System: A simplistic model of BESS is used, wherein charging and discharging powers are bounded by P_{rated}^b as described in equations (6)-(7). $w_{i,t}$ is a binary variable that prevents simultaneous charging and discharging. The relation between the battery State of Charge (SoC) and the charging/discharging powers is described in equation (8). η_c and η_d are the charging and discharging efficiencies. E_r^b is the rated BESS capacity. The SoC is constrained by $SoC_{\min}$ and $SoC_{\max}$ denoting its lower and upper bounds in equation (9). A cyclic boundary condition enforces equality between initial and final SoC to avoid end-of-horizon effects as describe in equation (10).

$$0 \leq P_{i,t}^{b,dis} \leq P_{\text{rated}}^b(1 - w_{i,t}) \quad \forall t, \forall i \quad (6)$$

$$0 \leq P_{i,t}^{b,ch} \leq P_{\text{rated}}^b w_{i,t}, w_{i,t} \in \{0, 1\} \quad \forall t, \forall i \quad (7)$$

$$SoC_{i,t}^b = SoC_{i,t-1}^b + \frac{P_{i,t}^{b,ch} \eta_c}{E_r^b} \Delta t - \frac{P_{i,t}^{b,dis}}{E_r^b \eta_d} \Delta t \quad \forall t, \forall i \quad (8)$$

$$SoC_{\min} \leq SoC_{i,t}^b \leq SoC_{\max} \quad \forall t, \forall i \quad (9)$$

$$SoC_{i,1}^b = SoC_{i,T}^b \quad \forall i \quad (10)$$

3.3 Linearized Distribution Power Flow

The second-stage load-flow (LF) analysis uses linearized distribution flow equations[12] to estimate line flows and nodal voltages. This also reduces computational burden relative to AC-LF. Equations (11) and (12) relate nodal power demand to line power flows while neglecting line losses, where Φ denotes the Bus Injection to Branch Current (BIBC) matrix representing network topology. Equation (13) then relates nodal voltages to line flows.

$$P_{l,t}^f = \Phi \cdot P_{n,t}^L \quad (11)$$

$$Q_{l,t}^f = \Phi \cdot Q_{n,t}^L \quad (12)$$

$$V_{n+1,t} = V_{n,t} - (r_l P_{l,t}^f + x_l Q_{l,t}^f) \quad (13)$$

4 Results and Discussions

4.1 Description of Test System

The single line diagram of feeder used in the simulations is shown in Fig. 3. The feeder model is derived from the corresponding CIGRE LV [13] residential feeder data, and the assumed prosumer configurations are listed in Table 1. The prosumers are considered such that the feeder demand is almost distributed equally among industrial, commercial and residential. Load power factors are assumed to be 0.9 lagging for all loads. Line current limits are set to 0.8 kA. The hourly data used in simulation for prosumer demand, spot prices [14], and PV generation [15] are presented in Fig. 4. The data is considered for two months, viz., winter peak and summer peak in area SE3 in Sweden.

4.2 Results and Discussions

This section presents network and economic performance across 4083 LEC combinations, ranging from communities

Table 1 Prosumer configurations, connected demand and rated capacity of DERs

Prosumer	Category	Connected Demand (kW)	PV (kWp)	BESS (kW/kWh)
P1	Industrial	172	50	50/150
P2	Commercial	55	25	25/75
P3	Commercial	55	–	25/75
P4	Commercial	55	25	–
P5	Residential	20	10	10/30
P6	Residential	20	–	10/30
P7	Residential	20	10	–
P8	Residential	20	10	10/30
P9	Residential	20	–	10/30
P10	Residential	20	10	–
P11	Residential	20	10	10/30
P12	Residential	20	–	10/30

with two prosumers to those comprising all twelve prosumers, and compares each case against the SC baseline, as explained in Section 2.

4.2.1 Network KPIs: Fig. 5 illustrates the case-wise change in maximum feeder line loading under LEC operation relative to SC. The maximum line loading observed in SC case is 82.3%. The line loading observed in LECs varied within the range of (–5.5% to 2.6%), approximately. The number of cases, wherein line loading observed in LEC cases is greater than SC case are 527 (13 %). Around 1% cases observed no change in line loading, and around 86 % cases saw a reduced line loading levels in LEC when compared with SC. This suggests that LECs generally contribute to reducing maximum feeder line loading. However, in certain cases, they may also lead to an increase in feeder maximum line loading.

Figure 6 further categorizes all cases according to different prosumer-type combinations to examine the maximum line loading results. It is observed that residential-only and commercial-only case more frequently observe a higher maximum line loading compared to SC case, which indicates that LECs composed of homogeneous prosumer types are more likely to exhibit higher maximum line loading compared to SC case. Further, with the inclusion of industrial prosumers,

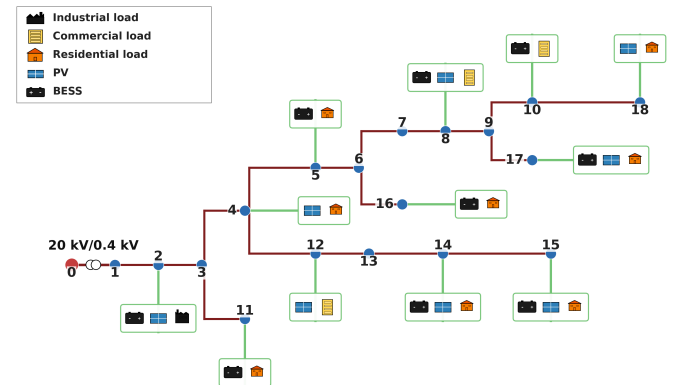


Fig. 3. Single line diagram of simulated network

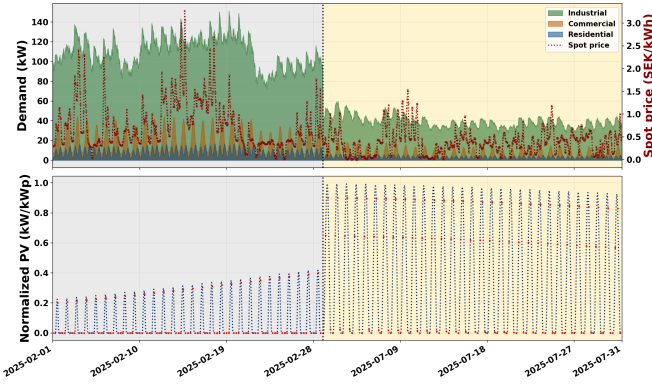


Fig. 4 Hourly prosumer demand, spot prices, and normalized PV generation for February (Winter) and July (Summer).

approximately half of the cases exhibit lower maximum line loading in LECs than in SC. The most favorable outcomes are observed for prosumer combinations with complementary demand profiles, specifically residential and commercial prosumers, where LECs observe more frequently a reduction in maximum line loading relative to SC. Overall, these results suggest that prosumer homogeneity increases the likelihood of higher line loading in LEC configurations, whereas greater heterogeneity, particularly through complementary demand patterns, enhances the probability of achieving lower line loading compared with SC.

Figure 7 shows the effect of LEC size on the instances where LECs observe a higher maximum line loading compared to SC. It is observed that the effect of LEC size on maximum line loading depends strongly on the underlying prosumer composition. For homogeneous configurations, viz., residential only and commercial only, an increase in LEC size is associated with a higher probability of LECs exhibiting greater maximum line loading than the corresponding SC case. In contrast, for mixed configurations with complementary demand profiles, especially the residential–commercial combination, the likelihood of higher line loading in LECs decreases with increasing LEC size. This suggests that scaling up LECs composed of complementary prosumer types can improve load diversity and reduce maximum line loading relative to SC, whereas increasing the size of more homogeneous LECs may amplify coincident demand and thereby increase the probability of higher line loading.

Fig. 8 compares the monthly minimum nodal voltage under LEC and SC operation using parity plots, where the dotted line separates cases with improved minimum voltage under LEC from those with reduced minimum voltage relative to SC. Overall, the observed variation is very less across cases and is well within the limits, with no consistent monotonic trend.

4.2.2 Economic KPIs: Fig. 9 compares the monthly aggregated peak, energy, and total costs under LEC relative to SC using parity plots, where points below the parity line indicate cost reductions under LEC. Overall, LECs yields consistent reductions in total cost, driven primarily by reductions in peak costs, as evidenced by the systematic shift below parity line in the peak-cost plots. By contrast, energy-cost changes are small

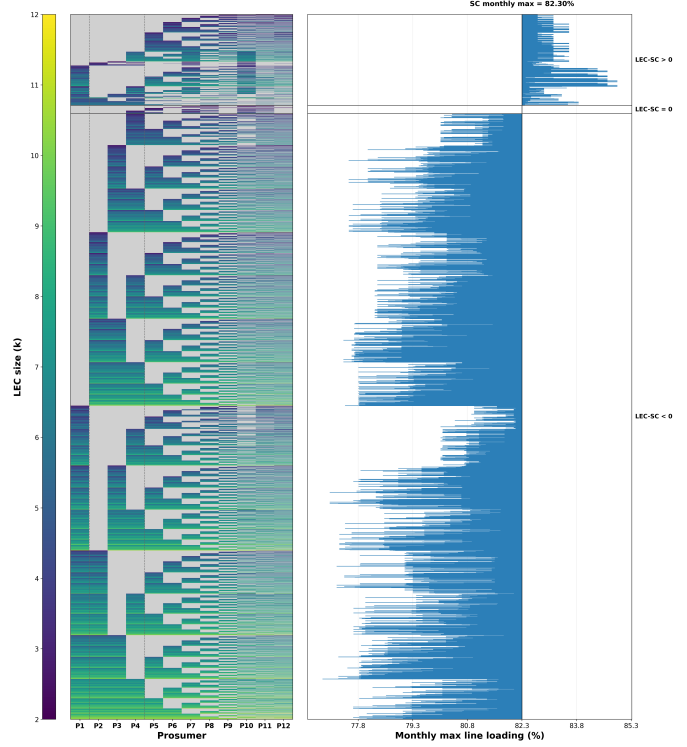


Fig. 5 Change in maximum line loading of feeder under LEC relative to SC

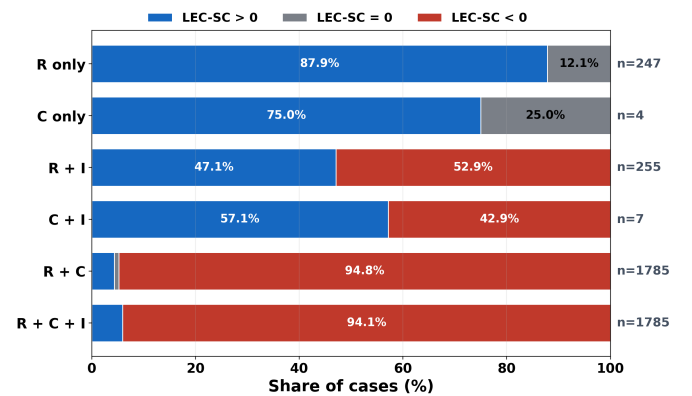


Fig. 6 Share of cases classified as per the maximum line loading levels

and remain close to parity line, indicating almost no to limited contribution from energy arbitrage relative to peak shaving.

4.2.3 Discussions on Overall Network Impact: Fig.10 illustrates the trade-off between community-level peak reduction and local network impacts for a LEC case. By coordinating operation, the LEC reduces the community-level peak load relative to the SC case during 08:00 and 18:00 hrs. However, this peak reduction is achieved through a shift in the operating profile of the LEC members, which increases its own peak consumption during 12:00 hrs which coincides with the non-LEC members' peak demand. As a consequence, the loading of line 1-2 increases under LEC operation and the minimum voltage at bus 2 is reduced compared with the SC baseline, highlighting

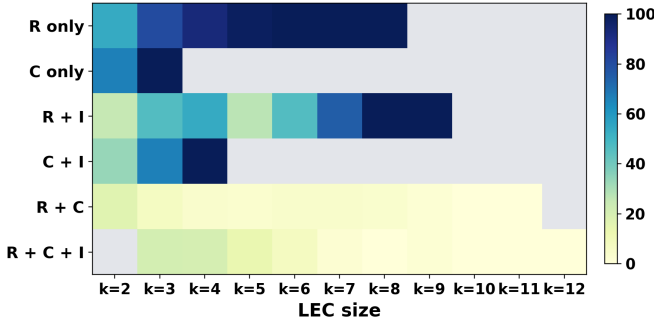


Fig. 7 Distribution of cases where line loading in LEC is higher than SC as per the LEC size

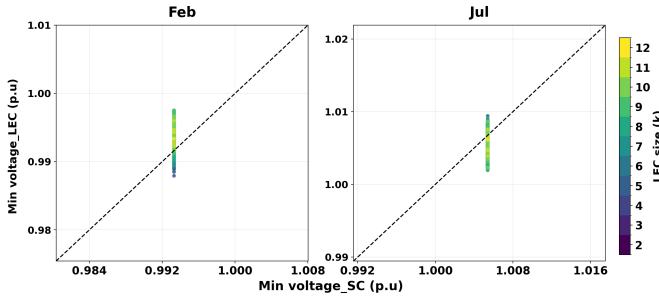


Fig. 8 Minimum nodal voltage in LEC Compared with SC (Residential)

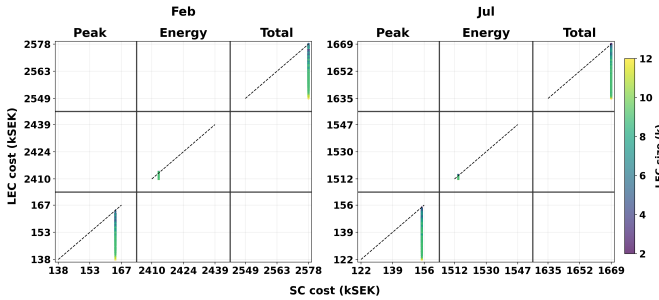


Fig. 9 Comparison of peak, energy, and total costs under LEC versus SC across feeder types.

that community-level objectives can induce localized congestion and voltage degradation when the coordination strategy is not explicitly constrained by network limits. The scenario analysis framework presented considers all probabilistic combinations of the prosumers assumed in the system. Hence, the problem size grows combinatorially and amounts to $2^n - 1$ cases, including the SC reference cases, for n prosumers. Parallel computing is used for solving the framework. The results also suggest that many of the possible LEC cases are unlikely to worsen network performance and may therefore be excluded. A case pruning strategy is within the scope of future work to reduce the number of scenarios and thus the computational burden.

5 Conclusion

This paper evaluates an exhaustive set of LEC configurations across industrial, commercial, and residential feeders to benchmark LEC operation against a SC baseline using network and

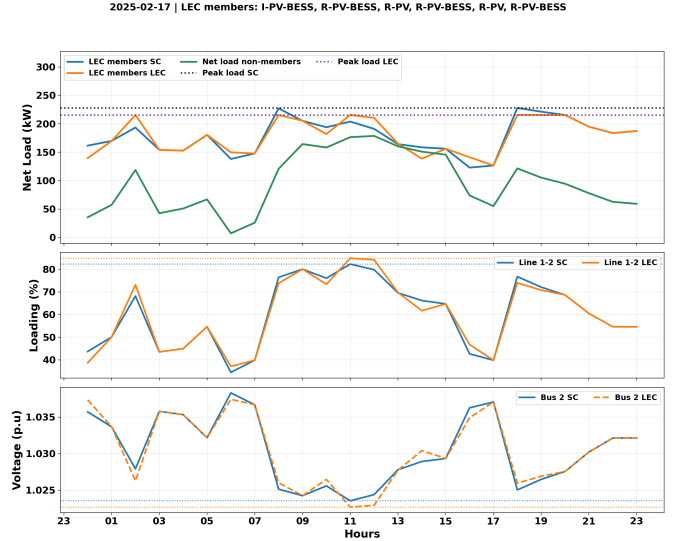


Fig. 10 Case where higher feeder line loading is observed in LEC compared to SC

economic KPIs. Around 13% cases observe a higher maximum line loading in LEC compared to the reference SC case. The maximum line loading in LECs varied in the range of (-5.5% to 2.6%) relative to the SC. Results show that monotonous compositions of LECs lead to higher maximum feeder line loading while communities with heterogeneous composition of prosumers are more likely to reduce the maximum feeder line loading. Economically, LEC operation consistently reduces total cost across all feeders, driven predominantly by peak-charge reductions, with energy-cost changes remaining small. Overall, cost-optimal coordination primarily acts through peak shaving, which can induce localized line overloading and voltage deviation impacts unless explicit grid constraints are incorporated, motivating planning-oriented screening of community designs.

6 Acknowledgements

The authors would like to acknowledge the contributions and supports from the project partners: Svenska kraftnät, E.ON Energy Distribution, Volvo Cars, and Chalmers Industriteknik for their valuable inputs and discussions.

The presented work is part of the project “Building to Building to Grid (B2B2G) Services” and is financed through the Swedish Electricity Storage and Balancing Centre (SESBC).

7 References

- [1] Lazaroïu, A.C., Roscia, M., Lazaroïu, G.C., et al.: ‘Review of energy communities: definitions, regulations, topologies, and technologies’, *Smart Cities*, 2025, 8, (1), pp. 8
- [2] Steen, D., Lamm, J., Hartvigsson, E.: ‘Implementation of distribution network development plans according to EU Directive 2019/944: possibilities for automation’. *Proc. CIRED 2024 Vienna Workshop*, 2024, pp. 913–916

- [3] Mugnier, A., Sueur, M., Gardin, M.: ‘France’s Risk Analysis Related to Sustainability Criteria of the European Directive (UE) 2018/2001-RED II’ (Comite Interprofessionnel du Bois Energie-CIBE, Paris, France, 2022), No. INIS-FR-23-1202
- [4] Gkoktsis, G., Kreutzer, M., Scheel, K., et al.: ‘Opinion on Supplementing Regulation (EU) 2019/943’, 2023
- [5] Dyngé, M.F., del Granado, P.C., Hashemipour, N., et al.: ‘Impact of local electricity markets and peer-to-peer trading on low-voltage grid operations’, *Applied Energy*, 2021, 301, pp. 117404
- [6] Nour, M., Chaves-Ávila, J.P., Troncia, M., et al.: ‘Impacts of community energy trading on low voltage distribution networks’, *IEEE Access*, 2023, 11, pp. 50412–50430
- [7] Dimovski, A., Moncecchi, M., Merlo, M.: ‘Impact of energy communities on the distribution network: An Italian case study’, *Sustainable Energy, Grids and Networks*, 2023, 35, pp. 101148
- [8] Barbagelata, L.: ‘Energy communities’ impact on medium voltage distribution networks’. Master’s thesis, Politecnico di Milano, 2024
- [9] Wege, F., Gümrükcü, E., Wortberg, T., et al.: ‘Impacts of local energy exchange in low voltage communities: A German case study’, *IEEE Access*, 2023, 11, pp. 95768–95781
- [10] Göteborg Energi: ‘Elnätsavgiften (electricity network tariffs)’, <https://www.goteborgenergi.se/foretag/elnat/elratsavgiften>, accessed 17 July 2026.
- [11] Mazidi, M., Sridhar, A., Steen, D., et al.: ‘Evaluating the Potential for Developing Local Energy Communities in Sweden: Case Studies at Jättsten and Chalmers Campus’. *Proc. Nordic Energy Informatics Academy Conference*, 2025, pp. 173–186
- [12] Baran, M.E., Wu, F.F.: ‘Network reconfiguration in distribution systems for loss reduction and load balancing’, *IEEE Transactions on Power Delivery*, 1989, 4, (2), pp. 1401–1407
- [13] CIGRE Task Force C6.04.02: ‘Benchmark Systems for Network Integration of Renewable Energy Resources’, 2011, Version 7
- [14] ENTSO-E: ‘ENTSO-E Transparency Platform’, <https://transparency.entsoe.eu/>, accessed 6 March 2026
- [15] Zippenfenig, P.: ‘Open-Meteo.com Weather API’, Zenodo, 2024, doi:10.5281/ZENODO.7970649