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On the operation and implications of grid-interactive renewable energy communities

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ABSTRACT

The increasing installations of photovoltaic systems, electric vehicle chargers, heat pumps, and battery storage systems challenge distribution system operators to prevent critical grid operations. Nonetheless, flexibility potential from customer-owned assets remains untapped due to lacking federated coordination and incentives. In Europe, emerging renewable energy communities can address this challenge by facilitating collective optimal operation of flexible assets and providing grid services. This paper presents an approach for renewable energy communities to offer participants' flexibility through grid-interactive operations. Distribution system operators then based on optimal power flow calculations request flexibility use to prevent voltage violations, transformer overloads, and line overloads. A case study with simulations for a future rural low-voltage grid is conducted. The results show that, compared to business-as-usual operations or renewable energy communities with fixed import and export limits, the grid-interactive approach ensures non-critical grid operations cost-efficiently and reduces curtailment by 60% to 90%, down to 1.1% of total generation. By providing both upward and downward flexibility and aligning with distribution system operators' requirements, grid-interactive renewable energy communities can be key in enhancing the efficient use and stability of distribution grids.

1. Introduction

Energy policies, aligned with the United Nations Sustainable Development Goals 7 and 11, aim to create sustainable cities and communities [1]. This entails affordable energy for consumers, security of supply, and the use of renewable energy to achieve net zero goals. At the same time, the increasing installation of renewable energies and the shift towards electrification of transportation and heating have transformed the energy landscape, impacting distribution grids. In particular, low-voltage (LV) distribution grids are reaching their hosting capacity, due to the rapid deployment of solar photovoltaics (PV), heat pumps (HP) and electric vehicles (EV), leading to substantial grid reinforcement expenditures, notably in rural areas [2]. With PV, EV and HP, building load profiles change. Demand and feed-in power peaks can lead to voltage violations and overloads of lines and transformer stations, challenging distribution system operators (DSO) with their objective to provide a secure and reliable supply [3–5]. In this context, a flexible use of these assets, including battery storage systems, can help to reduce or defer grid reinforcements [6].

New approaches are needed to address the emerging challenge of harnessing the flexibility of assets at multiple sites in the distribution grid for this purpose. In Europe, the concept of Renewable Energy Communities (REC) was introduced as part of the recast of the Renewable Energy Directive [7]. The REC is defined as a legal entity based on open and voluntary participation of residents, small- and medium sized enterprises (SMEs), or local authorities in geographical proximity. Participants are entitled to produce, consume, store and sell renewable energy, as well as to share, within the REC, renewable energy that is generated by the generation units owned by the REC. The primary purpose of RECs is to provide environmental, economic or social community benefits for its participants or for the local areas where they operate [7]. The Renewable Energy Directive does not apply directly in all EU Member States, but must be transposed into national law. In Austria, the Renewable Energy Expansion Act (*Erneuerbaren-Ausbau-Gesetz*, EAG) providing the legal framework for RECs was adopted in July 2021 [8]. According to this law, in a REC, the participants' consumption and generation assets must be connected through the distribution grid. Common regulatory aspects for RECs exist in Austria, Finland, France, Italy, the Netherlands, and Portugal. These regulations permit third parties to perform operational tasks as a service and enable the provision of energy services [9]. Thus, RECs enable the collective and optimized operation of flexible, participant-owned assets. They have the potential to minimize electricity costs and can have a role in

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supporting the operation of distribution grids facing the energy system transformation.

1.1. Literature review

There are several approaches to optimize the operation of RECs. Based on the operational complexity, these are categorized into optimization based on internal objectives, operation considering grid constraints, or grid-interactive operation in a REC-DSO cooperation.

Studies that focus on optimizing REC operation based on internal objectives highlight the advantage of collective operational optimization. Cosic et al. [10] develop a mixed-integer linear programming framework for optimizing operational dispatch, allowing for renewable energy sharing among participants within the REC. They show a reduction in total annual energy costs of 15% and CO_2 emissions of 34% through collective REC operation. Mustika et al. [11] aim to maximize collective self-consumption and self-sufficiency ratios and introduce allocation sharing rules among members. Results from a real-world case study in France indicate a 11.7% reduction in total electricity costs when using an optimization-based REC operation approach compared to a rule-based operation scenario where members are not organized as a REC. The results are both based on case studies involving small energy communities with less than ten participants. The impact of REC operation on the distribution grid is not assessed.

Other studies examine REC operation under grid constraints or demonstrate the impacts of operation on the distribution grid. Norbu et al. [12] design a heuristic-based community battery control algorithm that considers local LV network operation constraints to keep the bus voltage within permissible limits. However, REC operation is not optimized. Weckesser et al. [13] analyse the potential impact of REC operation on the distribution grid using power flow analysis and consider different operating strategies and battery storage placements. They show that transitioning from a strategy that maximizes the economic benefit to a peak shaving strategy reduces the maximum LV line loading by up to 58.5%, while costs only increase by 0.3%. Flexible loads, such as EV charging stations or HPs, were not taken into account. They calculate the impact of REC operation on the distribution grid, but lack active control of REC operation to minimize grid impact. The maximum LV line loading is not specified as a grid constraint for REC operation. Mehta and Tiefenbeck [14] perform a case study on different REC designs and show the impact on the electricity grid. The authors simulate a heuristic-based operation where prosumers self-consume PV generation and contribute excess to a REC electricity pool. A REC operator then distributes surplus electricity to households with residual demand, however, not complying with grid constraints, e.g., the transformer capacity, by using flexibility.

Regarding cooperations of RECs and DSOs, Berg et al. [15] study how a shared battery in a REC can provide services to the distribution grid. They develop a linear optimization model for battery operation, subject to voltage limits and a degradation constraints. In a case study, they investigate how battery operation differs when RECs cooperate with DSOs to share the battery use. The remuneration for avoiding voltage violation is very low and amounts to 0.12% of the total electricity cost. The practical agreement between DSO and REC has not been addressed. It remains unclear whether the battery is controlled by the REC operator or the DSO and how the cooperation is organized for data exchange. Kainz et al. [16] apply the concept of operating envelopes as dynamic active power limits for residual demand and feed-in of RECs. These are calculated and provided by DSOs. A REC operator considers the operating envelope as constraint in a linear optimization framework for the REC operation. The work focuses on reducing transformer overloads by grid-friendly REC operation and compares the results with cost-optimal REC and non-REC business-as-usual cases. Voltage violations and line overloads are not addressed.

A further overview on research related to methods and modelling approaches of RECs as well as quantifying the operational impacts, categorized by economic, environmental and technical impacts, is provided by Gjorgievski et al. [17].

Further literature addresses operation with consideration of grid constraints for individual sites. In their work, Petrou et al. [18] develop a framework for DSOs to ensure the integrity of distribution grids. This is achieved by using an optimal power flow analysis to determine dynamic operation limits. The study includes a comparison of dynamic and fixed export limits for prosumers within a real Australian LV network. Heidari Yazdi et al. [19] propose a coordinated operation of PV inverters and load shifting for over-voltage regulation. They apply both active power curtailment and reactive power compensation. Hatta et al. [20] emphasize the need for interoperation between smart consumer groups and the power system to avoid a deterioration in power quality. Alnaser et al. [21] analyses the provision of short term operating reserve services from batteries. In the work, the authors determine the maximum committed reserve power with minimal impact on energy sufficiency and considering distribution grid constraints. Paladin et al. [22] propose a micro-energy and micro-balancing market for smart domestic energy trading in LV grids. They demonstrate to keep voltage profiles within set limits in case of contingency. These studies do not take into account implications of collective energy sharing.

1.2. Scope and contributions

The existing literature on RECs focuses primarily on economic operations and energy management strategies aimed at optimizing energy sharing between REC participants [23]. While many studies address the use of decentralized flexibility within the distribution grid, taking into account voltage or line constraints, they mainly focus on individual sites. In this regard, there are few studies on the potential of RECs, which offer the advantage of local aggregation of flexibility and existing interfaces with DSOs. There is a research gap concerning the extent to which DSOs can utilize customer-owned flexible assets in RECs to avoid critical states in distribution grids.

The objective of this paper is to present an approach for grid-interactive REC operation that aligns REC objectives with DSO grid concerns in an affordable, sustainable, and reliable manner. The methodology involves a REC optimization model for cost-optimal scheduling of flexible assets. Both participants' upward and downward flexibility along with associated prices are calculated. The REC communicates a preferred operation and offers upward and downward flexibility. The DSO uses an optimal AC power flow to decide whether to accept the preferred operation or request flexibility use to avoid voltage violations and line or transformer overloads. A case study for a future rural LV grid is conducted to compare a 'business-as-usual' operation, a REC with fixed import and export limits, and the grid-interactive REC operation approach. The analysis shows which operation ensures non-critical grid operations and evaluates the impact on PV curtailment, energy sharing within the REC, and financial benefits. In summary, the contributions of this paper include:

- A grid-interactive REC operation approach that includes cost-optimal scheduling of participants' assets and flexibility offers to DSOs, enabling them to request the flexibility use based on an optimal AC power flow calculation to ensure non-critical grid operation.
- A case study for grid-interactive REC operation and comparison scenarios that demonstrates the viability and advantages of the proposed approach.

The following sections of this paper structure as follows: Section 2 presents the methodology for grid-interactive REC operation and introduces REC and DSO frameworks. Section 3 describes the considered grid topology and REC setup, the comparison operating strategies, and evaluation metrics for the case study. Section 4 presents the results of the simulation of different operation scenarios, providing insights into the benefits of grid-interactive RECs. Section 5 discusses the main findings and concludes the paper.

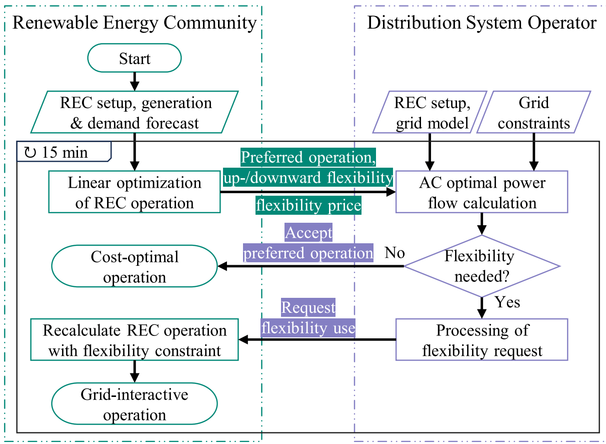

Fig. 1. Concept for cooperation between Renewable Energy Community and Distribution System Operator for calculation of Grid-Interactive Operation.

2. Method

2.1. Overview of grid-interactive REC operation concept

Fig. 1 provides an overview of the novel grid-interactive REC operation concept. Initially, the REC computes a preferred cost-optimal operation based on the REC setup, including participant information, asset specifications, and forecasts for uncontrollable generation and demand. Additionally, the available upward and downward flexibility reserve and corresponding flexibility prices are calculated. This involves solving the linear optimization problem described below.

For the DSO to be able to assess the impact on the LV grid, the REC has to provide the optimization results. Using this time series data of the REC operation and flexibility, the REC setup, the participant locations in the grid, and an overall grid model, the DSO performs an AC optimal power flow (OPF) analysis to detect possible violations of grid constraints and assess the demand for flexibility use to prevent such issues. This calculation considers both voltage violations and potential overloads in lines and transformer stations.

If voltages and power flows resulting from the preferred operation adhere to grid constraints, the DSO will approve the operation. However, in the event of grid constraint violations, the DSO will request the flexibility use of certain individual participants, a group of participants or the entire REC. This is done to prevent issues related to overvoltages or overloads in the grid infrastructure. Then, the REC recalculates the operation, taking the flexibility request into account as constraints in its optimization model.

2.2. Optimization of renewable energy community operation

The operation of the REC is computed in a framework that draws on previous work in [24]. It considers a REC of participants all connected to the public electricity distribution grid that allows for both purchase and feed-in of electricity and energy sharing among participants. Fig. 2 shows the model of the simplified distribution grid, the REC with its virtual bus, and exemplary participants with a grid connection via smart meter (SM) and assets connected to two participant buses. Each participant has a base load and can operate additional PV systems, battery storage systems, EV chargers and heat pumps.

A linear optimization of the REC operation is formulated based on the general model with the open-source optimization modelling language *Pyomo* [25] in *Python* and solved with the commercial solver *Gurobi 8.0.1* [26]. It considers variable power flows across the participant boundaries for both *external grid exchange* with the public

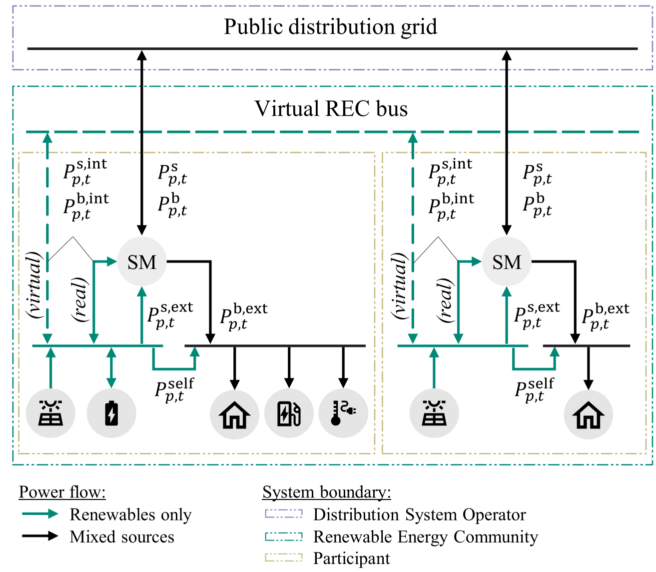

Fig. 2. General model of Renewable Energy Community, Participants and their connection to the public distribution grid by Smart Meters (SM).

distribution grid ($P^{\mathrm{b,ext}}_{p,t}$, $P^{\mathrm{s,ext}}_{p,t}$) and *internal REC exchange* via the virtual REC bus ($P^{\mathrm{b,int}}_{p,t}$, $P^{\mathrm{s,int}}_{p,t}$). Additionally, power flows of participants' assets and self-consumption ($P^{\mathrm{self}}_{p,t}$) within the participant boundaries are taken into account. All variable values are defined for the set of non-negative real numbers.

The objective is to minimize the operation costs for every participant (p) in the set of all participants ($\mathcal{P}$) and each time step (t) in the considered time horizon ($\mathcal{T}$). The costs result from associated buying and selling prices for the internal exchange among REC participants ($c^{\mathrm{b,int}}_t$, $c^{\mathrm{s,int}}_t$) and for the external exchange outside the REC ($c^{\mathrm{b,ext}}_t$, $c^{\mathrm{s,ext}}_t$). The optimization problem is subject to constraints on REC level, participant level, and asset level.

$$\begin{aligned}\text{minimize}\quad & \sum_{p\in\mathcal{P}}\sum_{t\in\mathcal{T}}\Big(\underbrace{P^{\mathrm{b,int}}_{p,t}c^{\mathrm{b,int}}_t - P^{\mathrm{s,int}}_{p,t}c^{\mathrm{s,int}}_t}_{\text{internal REC exchange}} \\ & \qquad + \underbrace{P^{\mathrm{b,ext}}_{p,t}c^{\mathrm{b,ext}}_t - P^{\mathrm{s,ext}}_{p,t}c^{\mathrm{s,ext}}_t}_{\text{external grid exchange}}\Big) \qquad (1)\end{aligned}$$

subject to (2)–(8)

At the REC level, the internal exchange of all participants has to be in balance for each time step (t):

$$\sum_{p\in\mathcal{P}}(P^{\mathrm{b,int}}_{p,t} - P^{\mathrm{s,int}}_{p,t}) = 0, \quad \forall\, t\in\mathcal{T} \qquad (2)$$

For each participant, two types of buses are distinguished. Each of these bus types is subject to balance constraints at every time step. The first balance constraint applies to a bus with electricity from renewable sources only, referred to as 'renewable electricity bus' (green). The second balance constraint is defined for a bus with electricity from all sources, referred to as 'electricity bus' (black). All loads are connected to the electricity bus and can always be supplied either via the external grid purchase or via the renewable electricity bus. This enables individual or collective self-consumption. However, as legal regulations stipulate that only renewable energy may be shared within the REC, a reverse power flow from the electricity bus to the renewable electricity bus is not possible. This ensures that the separation of renewable electricity and electricity from mixed sources is maintained.

The balance constraints encompass all power flows across the participant system boundary ($P^{\mathrm{b,ext}}_t$, $P^{\mathrm{b,int}}_t$, $P^{\mathrm{s,ext}}_t$, $P^{\mathrm{s,int}}_t$). Moreover, the inputs and outputs of all assets are considered. These are categorized based on their type, including the power generated ($P^{\text{out}}_{g,t}$) by all generation units ($\mathcal{G}$), the power charged and discharged ($P^{\text{ch}}_{st,t}$, $P^{\text{dch}}_{st,t}$) by all storage units ($\mathcal{ST}$), and the power consumed ($P^{\text{in}}_{ul,t}$, $P^{\text{in}}_{cl,t}$) by all uncontrollable loads ($\mathcal{UL}$) and controllable loads ($\mathcal{CL}$). Thereby, the set of controllable loads includes the electric loads of EV chargers and heat pumps.

The electricity bus balance constraint (3) encompasses all loads and the external residual demand ($P^{\text{b,ext}}_t$). The renewable electricity bus balance constraint (4) includes all generation and storage units, internal energy sharing ($P^{\text{b,int}}_t$, $P^{\text{s,int}}_t$), and the external surplus feed-in ($P^{\text{s,int}}_t$). The internal power flow between the two buses for individual and collective self-consumption (P^{self}_t) is included in both balance constraints (3) and (4).

$$\sum_{ul\in\mathcal{UL}} P^{\text{in}}_{ul,t} + \sum_{cl\in\mathcal{CL}} P^{\text{in}}_{cl,t} - P^{\text{self}}_t = P^{\text{b,ext}}_t, \quad \forall\, t\in\mathcal{T} \tag{3}$$

$$\sum_{g\in\mathcal{G}} P^{\text{out}}_{g,t} + \sum_{st\in\mathcal{ST}} (P^{\text{dch}}_{st,t} - P^{\text{ch}}_{st,t}) - P^{\text{self}}_t = P^{\text{s,ext}}_t + P^{\text{s,int}}_t - P^{\text{b,int}}_t, \quad \forall\, t\in\mathcal{T} \tag{4}$$

At asset level, the generated power ($P^{\text{out}}_{g,t}$) is derived from the relative power generation forecast ($\rho_{g,t}$) and the rated power of the system (P^{R}_g), minus the curtailment ($P^{\text{curt}}_{g,t}$).

$$P^{\text{out}}_{g,t} = \rho_{g,t} P^{\text{R}}_g - P^{\text{curt}}_{g,t}, \quad \forall\, t\in\mathcal{T} \tag{5}$$

$$P^{\text{out}}_{g,t}, P^{\text{curt}}_{g,t} \in \left[0, P^{\text{R}}_g\right] \tag{6}$$

$$\rho_{g,t} \in [0,1] \tag{7}$$

Battery storage systems are modelled by constraints for the current state of charge ($SoC_{st,t}$), describing the stored energy compared to the rated capacity (e^{R}_{st}). This equals the state of charge from the previous time step adjusted by the energy charged and discharged, considering the respective efficiencies ($\eta^{ch}_{st}, \eta^{dch}_{st}$).

$$SoC_{st,t} - SoC_{st,t-1} = \frac{\Delta\tau}{e^{\text{R}}_{st}} \left(\eta^{\text{ch}}_{st} P^{\text{ch}}_{st,t} - \frac{P^{\text{dch}}_{st,t}}{\eta^{\text{dch}}_{st}} \right), \quad \forall\, t\in\mathcal{T}\backslash\{t_0\} \tag{8}$$

$$SoC_{st,t} - \text{SoC}^{\text{init}}_{\text{st}} = \frac{\Delta\tau}{e^{\text{R}}_{st}} \left(\eta^{\text{ch}}_{st} P^{\text{ch}}_{st,t} - \frac{P^{\text{dch}}_{st,t}}{\eta^{\text{dch}}_{st}} \right), \qquad t = t_0 \tag{9}$$

For each time step, the state of charge is constrained by lower and upper limits ($\underline{\text{SoC}_{\text{st}}}, \overline{\text{SoC}_{\text{st}}}$). The charging and discharging power is limited by the storage system's rated power (P^{R}_{st}).

$$SoC_{st,t} \in \left[\underline{\text{SoC}_{st}}, \overline{\text{SoC}_{st}}\right] \tag{10}$$

$$P^{\text{ch}}_{st,t}, P^{\text{dch}}_{st,t} \in \left[0, P^{\text{R}}_{st}\right] \tag{11}$$

Flexible loads of EV charging and heat pumps are considered as a combination of assets. Flexible loads are modelled as a conversion unit (EV charger, heat pump), with a downstream energy storage (EV battery, thermal storage) and a downstream load (EV demand, heat demand). Downstream assets in this combination are not included in Eqs. (3) and (4).

The EV energy demand ($P^{\text{in}}_{ev,t}$) is modelled by discharging the EV battery ($P^{\text{dch}}_{ev,t}$). The charging power ($P^{\text{ch}}_{ev,t}$) is calculated from the EV charger power input ($P^{\text{in}}_{cl,t}$) and the associated efficiency (η_{cl}). Furthermore, the availability ($a_{ev,t}$) of the EV as time-dependent parameter is taken into account.

$$a_{ev,t} P^{\text{ch}}_{ev,t} = \eta_{cl} P^{\text{in}}_{cl,t}, \quad \forall\, t\in\mathcal{T} \tag{12}$$

$$P^{\text{in}}_{ev,t} = P^{\text{dch}}_{ev,t}, \quad \forall\, t\in\mathcal{T} \tag{13}$$

$$P^{\text{in}}_{cl,t} \in \left[0, P^{\text{R}}_{cl}\right], \eta_{cl} \in [0,1], a_{ev,t} \in \{0,1\} \tag{14}$$

Analogously, the participant's thermal demand ($P^{\text{in}}_{th,t}$) is covered by the thermal storage ($P^{\text{dch}}_{th,t}$). The charging power ($P^{\text{ch}}_{th,t}$) equals the power input of the heat pump ($P^{\text{in}}_{cl,t}$) and the coefficient of performance at that time step ($COP_{cl,t}$).

$$P^{\text{ch}}_{th,t} = COP_{cl,t} P^{\text{in}}_{cl,t}, \quad \forall\, t\in\mathcal{T} \tag{15}$$

$$P^{\text{in}}_{th,t} = P^{\text{dch}}_{th,t}, \quad \forall\, t\in\mathcal{T} \tag{16}$$

$$P^{\text{in}}_{cl,t} \in \left[0, P^{\text{R}}_{cl}\right], COP_{cl,t} \in \mathbb{R}^+ \tag{17}$$

For the EV battery and thermal storage, Eqs. (8) to (11) apply analogously.

The optimization of REC operation is simulated using a rolling horizon approach with intervals of 3 h, a forecast horizon of 24 h, and a resolution of 15 min. The simulation assumes perfect foresight of relative power generation forecasts ($\rho_{g,t}$), uncontrollable loads ($P^{\text{in}}_{ul,t}$), and EV and thermal demands ($P^{\text{in}}_{ev,t}$, $P^{\text{in}}_{th,t}$) for the next 24 h. The initial state of charge of energy storage systems ($\text{SoC}^{\text{init}}_{\text{st}}$) at the beginning of each iteration ($t = t_0$) is transferred from the resulting state of charge of the previous iteration at that time ($SoC_{st,t}$). At the beginning of the simulation, $\text{SoC}^{\text{init}}_{\text{st}}$ is set to zero.

2.3. Flexibility assessment and pricing

According to classifications and characterizations of power system flexibility resources by Degefa et al. [27], different flexibility resources within RECs are identified. Flexibility options are possible changes in the use of demand-side resources, EV chargers and heat pumps, from their preferred operation in response to an external DSO signal. Other options include charging or discharging battery storage systems in a way that deviates from their cost-optimal operation, or the curtailment of PV systems. Reducing consumption or increasing production is referred to as *upward flexibility* (F^+), whereas an increase in consumption or a reduction in production as *downward flexibility* (F^-). The flexibility of different asset types is quantified by the following approaches:

PV systems: The output power (P^{out}_t) of the preferred operation is considered as curtailable and offered as downward flexibility ($F^-_{g,t}$).

Battery storage systems: The difference between either the rated power (P^{R}_{st}) or the maximum charging power to reach to upper SoC limit ($P^{\text{ch,max}}_{st,t}$) and the current charging or discharging power ($P^{\text{ch}}_{st,t}$, $P^{\text{dch}}_{st,t}$) is assumed to be the downward flexibility ($F^-_{st,t}$) of a battery storage with the rated capacity (e^{R}_{st}). Analogously, the upward flexibility ($F^+_{st,t}$) is calculated.

$$P^{\text{ch,max}}_{st,t} = \frac{e^{\text{R}}_{st}}{\eta^{\text{ch}}_{st}\Delta t}\left(\overline{\text{SoC}_{\text{st}}} - SoC_{st,t-1}\right) \tag{18}$$

$$P^{\text{dch,max}}_{st,t} = \frac{\eta^{\text{dch}}_{st} e^{\text{R}}_{st}}{\Delta t}\left(SoC_{st,t-1} - \underline{\text{SoC}_{\text{st}}}\right) \tag{19}$$

$$F^-_{st,t} = \min(\text{P}^{\text{R}}_{\text{st}}, P^{\text{ch,max}}_{st,t}) - P^{\text{ch}}_{st,t} + P^{\text{dch}}_{st,t} \tag{20}$$

$$F^+_{st,t} = \min(\text{P}^{\text{R}}_{\text{st}}, P^{\text{dch,max}}_{st,t}) - P^{\text{dch}}_{st,t} + P^{\text{ch}}_{st,t} \tag{21}$$

EV chargers: If the EV is plugged in and not fully charged, the difference between the current and the maximum charging power can be offered as downward flexibility ($F^-_{cl,t}$). Whenever the EV is charging, even though charging can be postponed to another time before the next departure, or the current state of charge is already sufficient for the entire next journey, the current charging power is counted as upward flexibility ($F^+_{cl,t}$).

Heat pumps: Similar applies to heat pumps. The difference between the current and maximum input power can be offered as downward flexibility ($F^-_{cl,t}$) in case the downstream thermal storage does not reach the upper temperature. Furthermore, the current output is also an upward flexibility ($F^+_{cl,t}$) as long as the lower temperature of the thermal storage is not reached if the flexibility is requested.

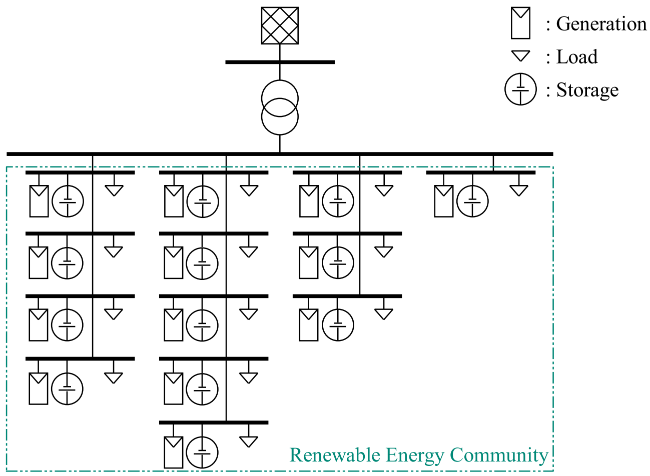

Fig. 3. Illustrative model of low-voltage grid with uncontrollable generation and load as well as battery storage systems providing upward and downward flexibility at each node.

The overall flexibility reserve of a participant (p) is calculated by summing the flexibility reserves for all sets of its generation units ($\mathcal{G}_p$), storage units ($\mathcal{ST}_p$) and controllable loads ($\mathcal{CL}_p$).

$$F^{-}_{p,t} = \sum_{g\in\mathcal{G}_p} F^{-}_{g,t} + \sum_{st\in\mathcal{ST}_p} F^{-}_{st,t} + \sum_{cl\in\mathcal{CL}_p} F^{-}_{cl,t} \tag{22}$$

$$F^{+}_{p,t} = \sum_{st\in\mathcal{ST}_p} F^{+}_{st,t} + \sum_{cl\in\mathcal{CL}_p} F^{+}_{cl,t} \tag{23}$$

The *flexibility price* (λ^{F}_t) for providing upward or downward flexibility is calculated based on the dual variables of the balance constraints (3) and (4) at the participant buses. These dual variables represent the marginal price needed to influence the bus balance by a marginal increase or decrease in surplus feed-in or residual demand through changes in the use of flexible assets. The price corresponds to the additional costs incurred when activating flexibility, deviating from the cost-optimal REC operation. It is assumed that the flexibility price is constant regardless of the amount of flexibility each participant offers at a time step t.

The preferred operation from the cost-optimization, the flexibility reserve of all participants and the corresponding flexibility prices for its deployment are provided to the DSO.

2.4. Distribution system operator framework

The DSO receives the information on participants' operation, flexibility reserve and prices. This information is mapped to the given grid topology shown in Fig. 3. At each node, one generator and one load are modelled to represent the preferred operation, and one storage to represent the flexibility. In case of a residual demand for one participant, this value is transferred to the load element at the grid node and, in case of a surplus feed-in, to the generation element. Both generation and load elements are considered as uncontrollable. Upward and downward flexibility are represented by the limits for the maximal charge and discharge power of the storage element. The storage element is considered as controllable to activate the flexibility. The initial value for the storage element is set to zero in each simulation step, which represents that the flexibility is not activated. All values are updated for each time step. The overall simulation is carried out with a rolling horizon of 15 min.

To calculate the flexibility need for compliance with grid constraints, an OPF is performed using *pandapower* [28] that implements the interior point solver provided by *PYPOWER* [29]. The objective is to minimize the cost of upward and downward flexibility use required at a considered time step (t) using a piecewise linear cost function. This takes into account active power flexibility, without provision of reactive power.

$$\begin{aligned} &\text{minimize} \quad \sum_{p\in\mathcal{P}} |\lambda^{\mathrm{F}}_t F_{p,t}| \\ &\text{subject to} \quad (26)\text{–}(29) \end{aligned} \tag{24}$$

A detailed overview on power flow constraints is provided by [29]. This section shows specific constraints and adaptions. The active power at a node ($P_{n,t}$) is given by the preferred operation of a participant at this node, i.e., the internal and external exchange from the cost-optimized REC operation, and the flexibility deployment ($F_{p,t}$). The flexibility deployment is limited by the available reserve that has been communicated between REC operator and DSO for each participant node and can take any real numbers within these limits.

$$P_{n,t} = P^{\mathrm{b,int}}_{p,t} - P^{\mathrm{s,int}}_{p,t} + P^{\mathrm{b,ext}}_{p,t} - P^{\mathrm{s,ext}}_{p,t} + F_{p,t} \tag{25}$$

$$F^{-}_{p,t} \le F_{p,t} \le F^{+}_{p,t}, \quad \forall p \in \mathcal{P} \tag{26}$$

The flexibility use serves to ensure grid integrity. Therefore, three different constraints are considered. The voltage magnitude (V) at each node (n) is limited by lower and upper bounds ($\underline{\mathrm{V}}, \overline{\mathrm{V}}$) to 0.95 p.u. and 1.05 p.u., respectively. Further constraints are given for the transformer (T) and each line (l) in the set of lines ($\mathcal{L}$) to limit the upper loading ($\overline{\mathrm{L}^{\mathrm{T}}}$, $\overline{\mathrm{L}^{\mathrm{l}}}$) to 100%.

$$\underline{\mathrm{V}} \le V_{n,t} \le \overline{\mathrm{V}}, \quad \forall n \in \mathcal{N} \tag{27}$$

$$L_{l,t} \le \overline{\mathrm{L}^{\mathrm{l}}}, \quad \forall l \in \mathcal{L} \tag{28}$$

$$L^{\mathrm{T}}_t \le \overline{\mathrm{L}^{\mathrm{T}}} \tag{29}$$

Two scenarios are examined. In the first, no flexibility deployment is necessary to ensure grid integrity. The DSO accepts the cost-optimal operation of the REC. In the second, the DSO sends a request to the REC, specifying the flexibility to be provided by individual or all participants. The REC operator fulfils the request by recalculating the optimization of REC operation with consideration of these additional constraints.

3. Simulation cases

3.1. Distribution grid and renewable energy community

For the simulation of REC and grid operations, the SimBench data set is used [30]. The publicly available data set serves as a benchmark for solutions in grid analysis, grid planning, and grid operations. It is also suitable for the simulation of RECs, as it provides data for the

Table 1
Specifications of Illustrative Renewable Energy Community [30].

Parameter	Type	Value	Unit
Participants	Count	13	–
PV systems	Count	13	–
	Total rated power	400	kWp
Battery storage systems	Count	5	–
	Total rated power	206	kW
	Total capacity	412	kWh
EV chargers	Count	7	–
	Total rated power	77.1	kW
Heat pumps	Count	8	–
	Total rated power	25.8	kW

definition of the LV grid, REC, participants and assets. In addition, the data set provides generation and load time series with a resolution of 15 min, that are adopted as a perfect foresight.

SimBench provides typical German LV grid models for different degrees of urbanization and development scenarios. The simulations are carried out for a rural LV grid with future deployment of flexible assets shown in Table 1. The number and design parameters of PV systems, batteries, EV chargers and heat pumps are based on projections of asset installations in 2034 [31]. This specific grid is selected because unrestricted business-as-usual operation without grid reinforcements would lead to overloads and voltage violations. It is a case where the described future challenges in the distribution grids will occur.

The calculations are conducted for operations in May, when critical grid states occur most frequently in the data set.

3.2. Electricity tariff

Simulations use July 2022 consumer electricity prices in Germany from [32]. The external feed-in tariff is calculated based on [33,34], and the remuneration for internal REC feed-in is set to the cost for energy procurement and sales. Energy sharing incentives include reduced grid fees, taxes, and levies based on current legislation in Austria [8, 35].

3.3. Alternative operating strategies

For comparison with the **Grid-Interactive REC** strategy presented in Section 2, alternative operating strategies are introduced, which are categorized into two business-as-usual and three REC operating strategies below. These alternative strategies serve as a benchmark to assess the effectiveness in avoiding critical grid operations, minimizing curtailment, and evaluating economic viability.

(1) **Business-as-usual (BAU)**: Individuals are considered to not form a REC. The operation of flexibilities is performed by a rule-based approach deviating from the optimization described in Section 2.2. Battery storage systems are immediately charged with the surplus of the participants' renewable electricity generation and discharged with the residual demand, subject to the above stated battery constraints. A possible load shift, e.g., from EV charging or heat pumps, is not utilized. EV batteries are charged directly after plug-in. Thermal storages are charged as soon as a threshold state of charge value of 30% is reached. Two different BAU cases are distinguished. In the *Unrestricted BAU* case, there is no upper power limit for surplus feed-in to the electricity grid. In the *Restricted BAU* case, however, the surplus feed-in is limited to 50% of the PV system's rated power, resulting in a curtailment of exceeding surplus generation. The maximum residual demand is not limited.

(2) **Renewable Energy Community (REC)**: Individuals are considered to form a centrally coordinated REC that applies the linear optimization described in Section 2.2. Unlike the grid-interactive REC strategy, it is assumed that flexibility is not offered and the DSO is not able to intervene. Three different REC cases are distinguished. In the *Unrestricted REC* case, there is no limit for surplus feed-in to the electricity grid. Additionally, two variations *Restricted RECs* are examined. In the first restricted REC case, an additional constraint is introduced, limiting the overall external import or export of the REC to 100% of the transformer's rated power. This constraint aims to prevent transformer overloads, without considering voltage violations or line overloads. In the second restricted REC case, the external import or export limit of the REC is reduced to 75% of the transformer's rated power to mitigate the risk of voltage violations or line overloads.

3.4. Evaluation metrics

To evaluate the effectiveness of the presented approach, metrics are defined based on the goals of affordability, security of supply, and sustainability. To assess critical grid operations, first, the *maximum transformer loading* quantifies the highest power transmitted by the transformer compared to its rated capacity. Similarly, the *maximum line loading* metric captures the highest current flow through a line relative to its rated capacity. *Voltage violations* are investigated by tracking the events where the node voltage falls below 0.95 p.u. or exceeds 1.05 p.u. at least once a day. For transformers, an additional metric, the *Overload Energy Transfer* (OET), is introduced. This metric, measured in kWh, is defined as the amount of energy transferred when the rated power ($\overline{P^{\mathrm{T}}}$) is exceeded:

$$OET = \overline{\mathrm{P}^{\mathrm{T}}}\Delta \mathrm{t} \sum_{t \in \mathcal{T}} (\max(L_t^{\mathrm{T}} - \overline{\mathrm{L}^{\mathrm{T}}}, 0)) \tag{30}$$

Addressing sustainability concerns, the evaluation includes metrics for the amount and percentage of *curtailment* and the internal use of renewable energy. The internal use includes the *collective self-consumption ratio* (C-SCR), indicating the share of the total local generation (E^{gen}), before curtailment, used internally and not fed into the external grid, and the *collective self-sufficiency ratio* (C-SSR), indicating the share of total demand (E^{dem}) covered internally and not from sources outside the REC.

$$C\text{-}SCR = 1 - \frac{\Delta\tau}{E^{\mathrm{gen}}} \sum_{p \in \mathcal{P}, t \in \mathcal{T}} P_{p,t}^{\mathrm{s,ext}} \tag{31}$$

$$C\text{-}SSR = 1 - \frac{\Delta\tau}{E^{\mathrm{dem}}} \sum_{p \in \mathcal{P}, t \in \mathcal{T}} P_{p,t}^{\mathrm{b,ext}} \tag{32}$$

Financial aspects are considered through the *operational profit* metric, which corresponds to the value of the optimization objective function.

All grid metrics are provided by the DSO framework. Costs, energy use and curtailment are results of the REC framework.

4. Results

This section presents the results and evaluation of the proposed strategy for a grid-interactive REC operation compared to alternative strategies shown in Section 3.3. Simulations are conducted for a one-month period in which the LV grid is at its highest load due to feed-in from local PV generation. Individual effects are discussed based on daily profiles, and the comparison is concluded using evaluation metrics defined in Section 3.4 over the entire simulation period. The results are categorized, starting with the impact regarding critical grid operation and curtailment, and concluding with the impact regarding energy sharing and financial benefits.

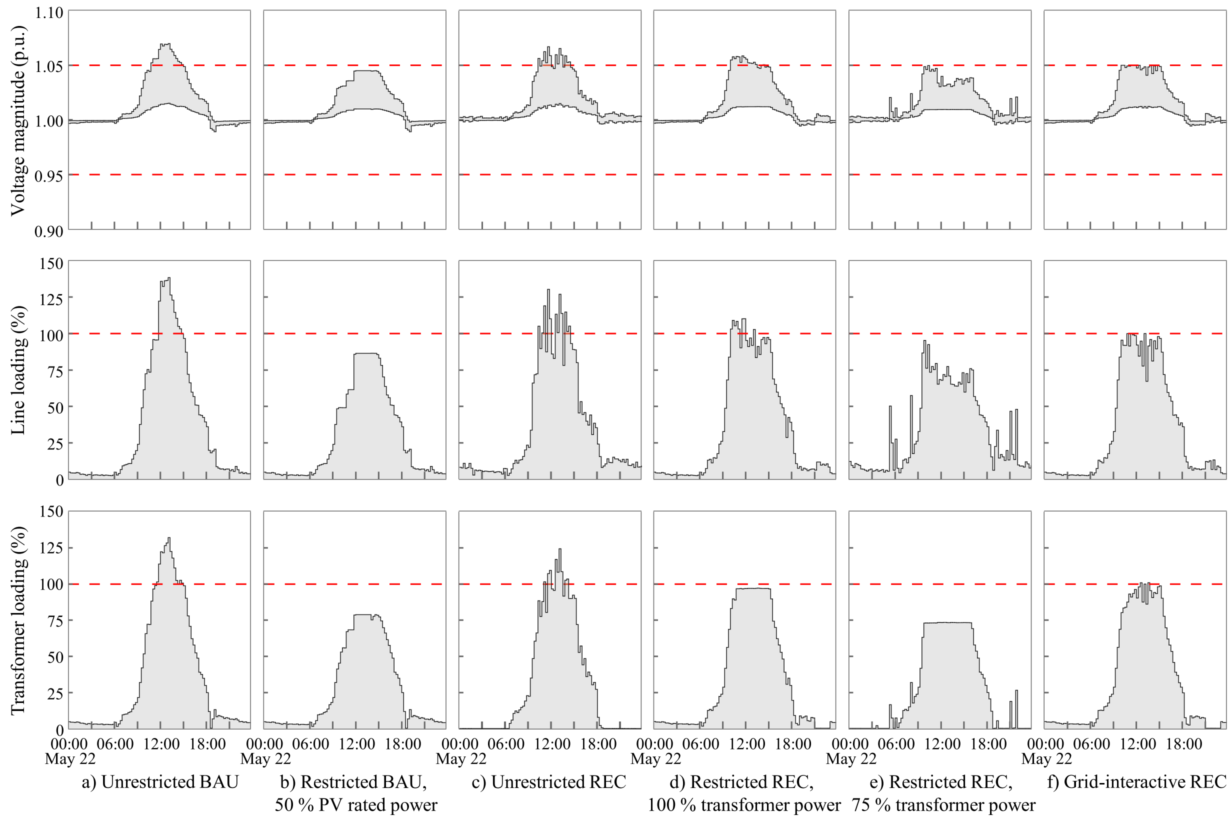

Fig. 4. Comparison of grid operation profiles for the operating strategies considered on a day characterized by high PV feed-in, showing the highest and lowest voltage magnitudes (top), maximum line loading (centre) and transformer loading (bottom).

Table 2
Comparison of evaluation metrics for a one-month simulation period in May.

Scenario	Max. transformer loading (%)	Max. line loading (%)	Voltage violation (days)	Overload energy transfer (kWh)	Curtailment (kWh/%)	Non-critical grid state
Unrestricted BAU	136.2	147.5	18	2250	–	✗
Restricted BAU, 50% PV rated power	78.8	86.6	0	–	8105 / 14.4	✓
Unrestricted REC	132.5	143.9	18	725	–	✗
Restricted REC, 100% transformer power	97.2	129.6	17	–	–	✗
Restricted REC, 75% transformer power	73.5	96.7	0	–	1695 / 3.0	✓
Grid-interactive REC	100.0	100.0	0	–	630 / 1.1	✓

4.1. Critical grid operation and curtailment

Fig. 4 depicts a comparison of the operating strategies on May 22nd, when the load on the electrical grid is at its highest. Three events that can trigger a critical grid operation are shown. One is the voltage magnitude at the participant nodes that is illustrated as the range between the highest and lowest voltage at a given time. If this range exceeds the specified limits (dashed red lines), it is considered as a violation. The same applies to the loading of lines and transformers. A violation occurs when the limit of 100% is exceeded.

Starting with the unrestricted BAU case, it is noticeable that there are three different violations or overloads. The highest voltage magnitude is approximately 0.02 p.u. above the limit of 1.05 p.u., the highest load on a line reaches 138%, and the transformer is loaded at 132%. Critical grid operation persists for about three hours continuously, with multiple violations of limits occurring simultaneously. In the restricted BAU case, however, there are no critical grid operations. In this case, 462 kWh of renewable energy is curtailed, which is slightly more than 10% of the possible generation at that day.

The REC cases aim for cost optimization and enable energy sharing. In the unrestricted REC scenario, similar to the unrestricted BAU scenario, voltage violations and overloads are observed. The highest voltage magnitude exceeds the limit by about 0.02 p.u. as well. However, the highest line loading is slightly lower at 130%, as well as the transformer loading at 124%. The overload lasts for only one hour without interruption. Nevertheless, transitioning to a REC does not ensure non-critical grid operation without additional measures. In the restricted REC cases, transformer overloads do not occur due to a fixed limit on the surplus feed-in for the entire REC as a collective. In the first restricted REC case, the transformer loading is below the critical threshold at 97%. Due to line losses, there is a slight deviation from the 100% limit. However, it also becomes evident that this limit does not prevent critical grid operation, as the highest load on a line still reaches 110%, and a voltage violation with 1.06 p.u. occurs at least at one node. In the second restricted REC case with stronger limitation of the surplus feed-in to 75% of the transformer's rated power, the maximum line loading falls below the critical limit to 95% and the highest voltage magnitude is 1.05 p.u. without exceeding the limit. The line loading is increased in the morning and evening and there are occasional peaks. This is due to the fact that battery storage systems are discharged to supply the demand of other participants by internal energy sharing. There is also targeted discharging into the external grid to be able to store more PV generation at midday. The coordinated optimal REC operation reduces the curtailment to 64 kWh, about 85% less than in the restricted BAU case. In the case of grid-interactive REC operation, none of the three situations of critical grid operation occur. By adhering to the flexibility request of the DSO, the REC operator reaches, but does not exceed, the limits. It is still necessary to curtail PV generation for this purpose. However, the grid-interactive REC also utilizes the storage capacity of batteries and load shifting, requiring a much lower curtailment of renewable energy, specifically 40 kWh. This corresponds to less than 1% of total PV generation.

Fig. 5 provides a detailed overview of the aggregated operation of customer-owned assets within the REC. The focus is on the comparison of the three operation scenarios that do not lead to critical grid operations. In the Figure, individual asset operation is categorized, with the demand of all HPs and EVs constituting the flexible load and all other consumers the uncontrollable load. Additional categories are the charging and discharging of customer-owned batteries, as well as the generation and curtailment of PV systems. The uncontrollable load thereby remains unchanged in all scenarios.

Differences are found in the operation of batteries, which are installed only at 5 of the 13 nodes. In BAU operation, these batteries discharge at night for self-consumption and charge surplus energy during the day up to their maximum state of charge. The batteries are not fully discharged so that they are already charged by noon. This differs in the restricted REC case due to two factors. Firstly, energy sharing is incentivized, meaning that not only the individual self-consumption is supplied at night, but also consumption of participants who do not own a battery storage. This is highlighted by the internal exchange. Secondly, the optimization is based on a forecast for 24 hours, allowing targeted discharging into the external grid to maximize storage of own PV generation during the day. In the grid-interactive REC, there is no feed-in limit for the REC, eliminating the need to discharge into the external grid. Intermittently, internal energy sharing occurs, and batteries are charged during peak generation times. In the restricted REC cases, flexible loads are shifted to times of surplus generation, subject to the asset constraints. In the grid-interactive REC case, load shifting occurs between 11 a.m. and 3 p.m. when the DSO requests downward flexibility, aiming to avoid exceeding the grid metrics threshold. Moreover, EV batteries and thermal storages charge more than in the BAU case. This occurs because it is a more cost-effective alternative to curtailing PV generation. In the BAU case, PV generation is significantly curtailed at each node due to the fixed feed-in limit, defined for the most critical day of the year. This curtailment occurs even when the grid metrics do not reach the threshold, e.g., before 11 a.m. and after 3 p.m. In the restricted REC case, curtailment is also needed for peak shaving, but to a much lesser extent. In contrast, in the grid-interactive REC case, occasional curtailment is necessary at a some nodes to prevent local voltage violations or line overloads only when no alternative flexibility is available.

Table 2 provides a comprehensive overview on grid metrics and curtailment over the one-month simulation period. In the unrestricted BAU scenario, high transformer and line loading, coupled with frequent voltage violations, show potential grid issues. Restricting PV power to 50% in the BAU scenario leads to improved grid metrics and achieves a non-critical grid state, although with the highest PV curtailment of 8105 kWh. Since the overload energy transfer in 'Unrestricted BAU' is about 75% lower, this indicates a predominantly unnecessary curtailment. Both restricted REC scenarios show the impact of REC feed-in limitations based on the transformer power on the grid metrics, with a 75% transformer power scenario achieving a non-critical grid state. With the coordinated and collective REC operation, curtailment is reduced by 80% compared to BAU.

The grid-interactive REC scenario is most effectively preventing critical grid operations. It optimally utilizes both transformers and lines, operating at their full capacity of 100% without leading to voltage violations. Additionally, it achieves a minimal curtailment of 630 kWh, which is about 60% less than in the restricted REC case and 90% less compared to BAU. By cost-optimal scheduling of participants' flexible assets and adapting to DSO flexibility requests, the grid-interactive REC maximizes the use of renewable energy.

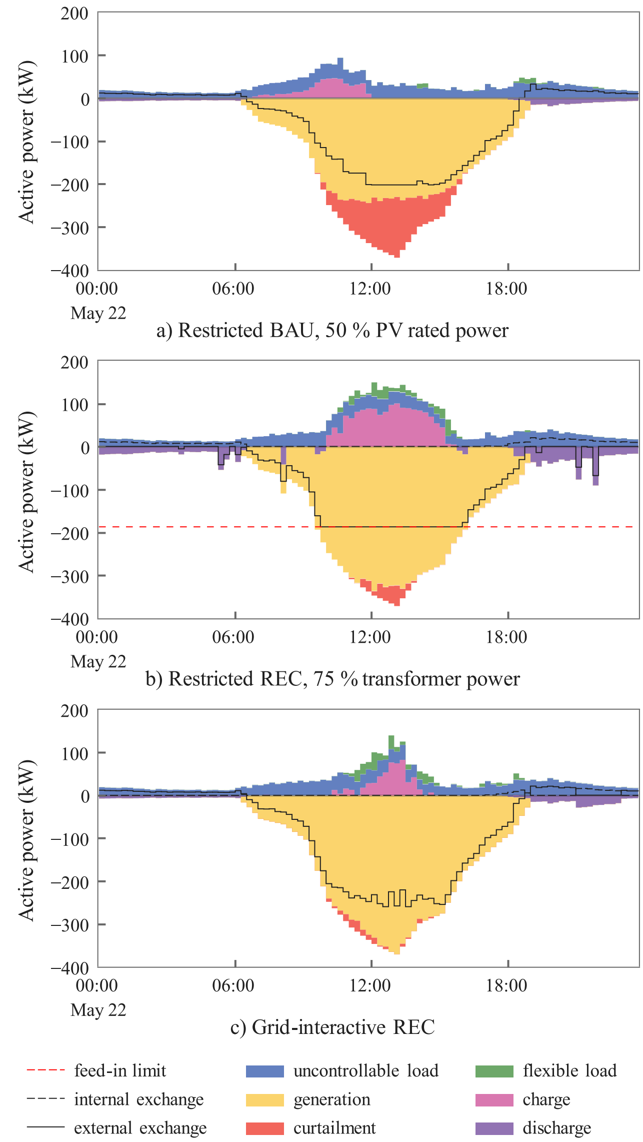

Fig. 5. Comparison of customer asset operation and the aggregated internal and external power exchange of non-critical grid operation cases.

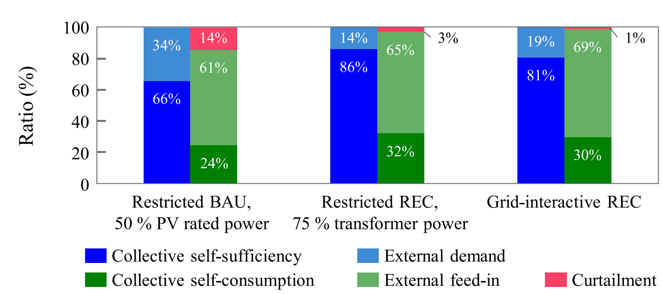

Fig. 6. Implications on energy import and export, self-consumption and self-sufficiency metrics for non-critical grid operation cases.

4.2. Energy sharing and financial benefits

The implications on self-sufficiency, self-consumption, and financial profit for the REC and its participants are illustrated in Figs. 6 and 7. Again, only cases that lead to non-critical grid operations are taken into consideration.

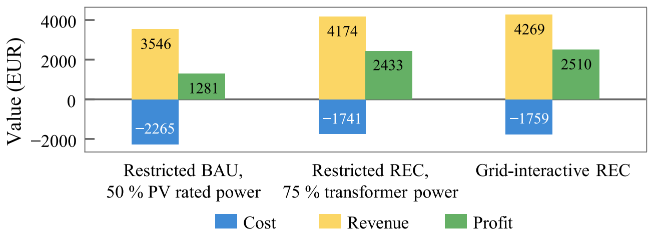

Fig. 7. Financial implications of non-critical grid operation cases.

The energy metrics show that in REC cases, intentional energy sharing contributes to enhanced collective self-sufficiency compared to the unintentional energy sharing in the BAU case. The need for external energy imports decreases from 34% of the overall demand to 14% and 19%, respectively. This results in about 50% less energy supplied through the transformer. On the generation side, in the BAU scenario, about 25% less local PV energy is utilized at the 13 nodes compared to the REC cases. This is due to the absence of collective optimization among flexible loads and storage systems. Despite lower collective self-consumption, less energy is fed in externally due to grid limitations. When comparing the two REC cases, the energy sharing ratio is higher in the restricted REC scenario, as fixed export limits require higher storage utilization.

Regarding financial profit, the data show different results for the non-critical grid operation cases, considering the costs for residual electricity purchase and revenues from surplus electricity sales. To objectively quantify benefits, all figures are stated without compensation payments for curtailment or flexibility services. In the BAU case, missing incentives for energy sharing and strong curtailment lead to comparatively high costs and low revenues. Of the two REC cases, the grid-interactive one is advantageous. The profit is 3% higher compared to the REC scenario with fixed export limits and 95% higher than the BAU case without REC formation. This shows that, compared to a case with feed-in limitation, the REC may have a financial interest in offering flexibility and using it according to the specifications of the DSO if, in return, the limitation is waived at times when it is not required by the grid conditions.

5. Discussion and conclusion

In this study, a comprehensive framework is introduced for the operation of Renewable Energy Communities (RECs), focusing on the grid-interactive use of participants' flexibility to support distribution system operators (DSOs). The approach enables RECs to offer accessible flexibility to DSOs through a simple interface. By using optimal power flow calculations, DSOs identify grid nodes where the flexibility can be utilized most cost-effectively. They can then request RECs to adjust their operation, preventing critical grid states.

The simulation results for a typical German rural LV grid with future deployment of flexible assets show that, compared to business-as-usual operations and RECs with fixed import and export limits, critical grid operations are prevented with minimal cost and curtailment. Alternative strategies require larger safety margins, leading to increased and often unwarranted renewable energy curtailment, and less financial profit. The grid-interactive REC approach with communication of preferred operation and flexibility requests enables intraday adaptations, reducing the impact of forecast uncertainty that is not explicitly considered in this study. DSOs benefit from a simplified coordination process, managing a single interface to the REC rather than multiple interfaces with individual customers. The approach enables well-documented and equitable decision-making regarding interventions and deviations from optimal operations at specific grid nodes. However, compared to fixed limits for the operation of PV systems or RECs, the approach requires additional computational effort for DSOs. There may also be cases where REC flexibility is not sufficient to solve a critical grid situation, especially in a scenario with demand-side congestion, e.g. from charging electric vehicles and heat pumps. In such scenarios, preventive measures such as grid expansion or reinforcement or curative interventions by DSO are required. The grid-interactive operation approach should not be treated as an obligation for RECs, but as an opportunity to use the existing flexibility to overcome fixed limitations for operation and to prevent unforeseen emergency interventions by the DSO.

While the simulations focus on a REC spanning an entire low-voltage grid, future research should address the implications of lower participation rates in specific grid segments and the potential contribution of providing reactive power, e.g., from PV inverters, which was disregarded in this study. In real-world applications, forecast errors occur unavoidably, and finding solutions to accommodate them is a priority for future research. One option to provide secured flexibility is to incorporate additional information, e.g., for EV charging, such as the earliest required end of charging and the minimum state of charge for the next trip. For battery storage systems, reducing the range between the lower and upper state of charge limits for the optimization of REC operation can ensure the availability of upward and downward flexibility. Furthermore, it must be analysed which type of remuneration is most appropriate to fulfil DSO flexibility requests, considering that the preferred operation and declared flexibility costs are truthfully communicated. Thereby, it is necessary to prevent a remuneration that is designed in a way which incentivizes a REC operation consciously forcing the activation of flexibility. Policymakers should also consider regulatory frameworks that link incentives for energy sharing within a REC to the requirement of providing flexibility for the distribution grid.

Grid-interactive RECs can prove crucial as DSOs face the challenge of preventing critical grid operations due to the ongoing expansion of PV systems, EV chargers, heat pumps, and batteries. They can address the multitude of objectives, both ensuring security of supply, providing affordable energy to consumers, and promoting the use of renewable energy.

CRediT authorship contribution statement

Robin Sudhoff: Writing – original draft, Visualization, Software, Resources, Project administration, Conceptualization, Data curation, Formal analysis, Investigation, Methodology. **Robin Derzbach:** Writing – review & editing, Investigation, Data curation. **Sebastian Schreck:** Writing – review & editing, Validation, Supervision, Resources, Conceptualization. **Sebastian Thiem:** Writing – review & editing, Validation, Funding acquisition. **Stefan Niessen:** Writing – review & editing, Validation, Supervision, Funding acquisition.

Declaration of competing interest

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

Data availability

The authors do not have permission to share data.

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