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Low-Voltage Renewable Energy Communities' Impact on the Distribution Networks

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Abstract: Renewable energy communities (RECs) are widely regarded as a transformative opportunity to enhance the management of electricity distribution networks, benefiting the system as a whole and its participants through local energy production, increased self-consumption, and empowering citizens. However, their proliferation introduces significant challenges for distribution system management, particularly at the low-voltage (LV) level, where participants are primarily located. Despite its critical role, the LV network is often overlooked in favor of studies focusing on the system-level impacts. This paper addresses this gap by evaluating the impact of RECs on LV networks and the broader distribution system. The study analyzes various LV networks representative of the Italian context, encompassing both rural and urban areas. By leveraging the software tool OpenDSS and Monte Carlo simulations over an entire year, the analysis captures the inherent variability of load demand and photovoltaic generation, as well as the resulting network imbalances under diverse policy scenarios. The findings reveal that the increasing level of self-consumption could significantly challenge distribution network operation, limiting also the sourcing of flexibility. These results underscore the necessity for advanced management strategies and targeted investments in grid flexibility to ensure the reliability and efficiency of distribution networks integrating RECs.

Keywords: renewable energy communities; distribution networks; flexibility; network operation

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1. Introduction

The directives within the EU Clean Energy Package [1] emphasize energy and efficiency, aiming to reshape the economy and society under a new model of sustainability. In the envisioned future, consumers will participate in energy markets, enabling greater empowerment and encouraging active responsibility for their energy usage. To achieve this, consumers need secure options for directly managing their available energy.

Even more challenging objectives, prioritizing advancing environmental sustainability, are the subject of the European Green Deal (EGD) [2], which revisits and expands the sustainability priorities initially set out in the Clean Energy Package. In the EGD, some themes are treated with more emphasis, such as consumer empowerment and protection, open access to the integrated market, third-party access to transmission and distribution infrastructure, unbundling requirements for operators and distribution systems, and rules on the independence of regulatory authorities in the member states.

Renewable energy sources (RESs), particularly solar photovoltaics, are becoming increasingly common in different applications, serving as a crucial means of reducing the environmental impact of energy production. However, the inherent non-programmability of renewable sources necessitates efforts to optimize their management efficiency. This can be accomplished through the establishment of energy communities, allowing members to exchange energy generated from RES among themselves.

In this context, renewable energy communities (RECs) are emerging as a pivotal element in the European Union's energy transition strategy. Their growth introduces both promising advancements and complex challenges for the effective management of electrical distribution networks [3,4]. RECs encourage private sector investment and enhance public acceptance of energy initiatives, facilitating the long-term utilization of renewable resources. Moreover, the advantages for community members extend beyond lowering electricity costs, addressing broader goals such as pollution reduction and local economic revitalization through job creation. This approach empowers citizens to participate actively and assume greater responsibility for achieving the energy transition.

Thus, energy communities offer innovative potential, but their full impact on the EU energy transition is still unclear. Further research is needed to quantify their local, regional, and national contributions, assess their economic, environmental, and social effects, and identify barriers to broader community participation in energy projects.

Moreover, the increased network connection of RES and recent advancements in information and communication technologies (ICT) have prompted regulators and distribution system operators (DSOs) to explore flexibility services from consumers and producers as viable tools to support energy transition objectives. DSOs have several methods to procure flexibility, including connection agreements, network tariffs, and market-based approaches. Several countries have already implemented and tested flexibility markets [5–7], and Italy launched its first local flexibility market, providing an end-to-end solution to acquire and dispatch flexibility services for addressing localized constraints for its largest DSO. Considering the lack of methods and metrics to quantify the theoretical benefits offered by RECs in the present scientific literature, the paper addresses the existing gap by providing a methodology to assess the impact on the flexibility offered to DSOs from the widespread implementation of RECs in low-voltage (LV) distribution networks. Papers addressing RECs have predominantly taken a system-level perspective [4], concentrating on potential market schemes or the dynamics within medium-voltage (MV) networks [8]. Although some studies have shifted attention to LV networks, these are often limited to standardized test systems or a single isolated network [9–11]. Furthermore, in these approaches, the energy community is generally confined to one part of the network, which does not capture the more complex scenario where community members are geographically dispersed across different LV segments. Another limitation is that many existing studies restrict their analyses to short time frames—days or months during specific seasons—which may neglect the annual variability and evolving patterns of renewable energy generation and consumption.

This paper directly addresses these shortcomings by providing a comprehensive assessment tool designed to evaluate the impact of widespread REC deployment on LV distribution networks over an entire year, through Monte Carlo simulations, capturing the variability of renewable energy generation and the stochastic nature of load demand, offering a robust framework for the analysis under uncertainty. Unlike previous work, this approach takes into account spatially distributed participants, multiple network segments, and long-term variability. In doing so, it fills a critical gap in the literature, providing more realistic insights into how RECs affect network operations and informing strategies for effective REC integration at the LV level.

In particular, the proposed study aims to assess whether the widespread development of RECs introduces operational challenges in the management of distribution networks. It evaluates the impact of RECs on LV networks, considering variations in the network type (rural or urban), the levels of self-consumption, and the number of REC participating users.

The paper is organized as follows: Section 2 describes the evolution of renewable energy communities, the regulatory framework, and the potential impact on distribution networks; Section 3 describes the status of applying flexibility in the distribution systems. Section 4 describes the methodology used for evaluating the impact of RECs on LV networks. Section 5 explains the energy scenarios assumed and gives information on the study cases. Finally, Section 6 presents the results of the methodology for the test networks. Final remarks on the impact and the potential of the RECs in the energy transition conclude the paper.

2. Renewable Energy Communities

2.1. Regulatory Framework

RECs represent collective initiatives where individuals, small businesses, and local authorities collaborate to produce, manage, and share energy, often from renewable sources.

While Europe has established a comprehensive regulatory framework for energy communities, the concept is also gaining traction in other regions, albeit with varying levels of regulatory clarity and support. The U.S. does not have a unified federal regulatory framework for energy communities, but several states have developed supportive policies, with the related challenges, like interconnection standards and utility opposition, which vary significantly across states [12,13]. Australia has a growing REC movement, particularly in rural and remote areas, but with complex grid access rules and high setup costs [14]. In Asia, the main challenges include financing, awareness, and uneven regulatory implementation [15,16], whereas, in Africa, RECs are driven by a need for rural electrification, characterized by the limited financing and regulatory clarity for long-term sustainability [17]. In Latin America, the focus is on social equity and rural electrification, but the political instability and inadequate regulatory support slow down the REC development [18]. Despite these challenges, RECs are proving to be a vital component in transitioning toward decentralized, renewable energy systems globally.

2.1.1. The EU Framework

ECs were first introduced in the European Union in 2016 under the “Clean Energy Package” [1], specifically within the “Renewable Energy Directive,” and have grown significantly since their inception. The plan led to the adoption of eight legislative measures between 2018 and mid-2019, marking a comprehensive reform of the European Union’s energy policy framework. Key among these are the revised Renewable Energy Directive 2018/2001 (REDII) and the Directive on Common Rules for the Internal Electricity Market 2019/944 (EMDII). Within this regulatory context, and particularly in REDII and EMDII, energy communities receive their first formal definition in European legislation. Particularly, the ECs considered in this paper align with the concept of renewable energy communities as defined under REDII. Typical RECs are connected to the public energy networks, and do not own the local distribution network, which is operated by the local DSO. However, with the European Directive 2019/944/CE, the regulatory boards are promoting closed distribution systems (CDSs) that can be owned and managed by RECs integrated within a specific confined area. A CDS is intended exclusively for the use of REC members and is not subject to regulated tariffs for network usage. EU policies do not restrict how RECs may distribute profits among the participants. Consequently, CDSs are expected to play a significant role, particularly in industrial sectors, helping to reduce the risk of relocation due to high energy costs and network access tariffs, with resulting economic benefits for the broader economy. The CDS will be essential for enabling large-scale energy communities, significantly influencing traditional public service networks [19,20].

Then, in 2019, the European Commission introduced the "European Green Deal" [2], a comprehensive policy agenda aiming to achieve EU carbon neutrality by 2050 through the extensive decarbonization of the energy sector and significant improvements in building energy efficiency.

2.1.2. The Italian Framework

In Italy, RECs were first introduced on an experimental basis through Decree Law 162/2019 [21] under Article 42-bis. This initial step was solidified with Decree 8/2020 [22], which formally incorporated RECs into the national regulatory framework. The subsequent adoption of the REDII Directive through Legislative Decree No. 199 of 2021 [23] adjusted the original restrictions on REC implementation. RECs are examined according to the guidelines outlined in the resolution 727/2022/R/eel by the Italian Regulatory Authority for Energy, Networks, and Environment (ARERA) [24], where energy communities are envisioned within a more complex framework that supports multiple forms of distributed self-consumption. This framework supports incentives for self-consumption by reducing losses on the HV grid. Similar proximity-based criteria for energy communities are encouraged in other European Union countries, although often defined more simply—such as by setting a maximum allowable distance between loads and generators within the community. In transposing RECs into national legislation, Italian legislators preserved the core principles of these communities, clearly defining eligible aggregation structures and participant types within the existing regulatory framework. They have not restricted RECs from offering a broad array of services to local members, such as energy market participation, the provision of both local and system-wide ancillary services, and launching initiatives beyond the energy sector. This approach encourages active engagement from community members, not limited to energy consumption or production.

In line with EU requirements, Italian regulations have introduced incentive tariffs for energy shared within an REC, enhancing their appeal to local communities. The Italian REDII implementation further mandates that REC members must be connected to the same primary substation, with each generation unit under REC control limited to a maximum capacity of 1 MW. The most recent ARERA resolution 15/2004/R/eel [25] modifies the Integrated Text in 727/2022/R/eel and positively verifies the technical rules for the self-consumption service. It regulates the incentive methods to support the electricity produced by RES plants integrated in configurations for widespread self-consumption and defines the criteria and methods for granting the expected contributions.

2.2. Energy Communities' Impact on the Distribution Grid

Reaching the EU and national ambitious goals presents a complex challenge, with RECs anticipated to play a critical role in this transition. While energy communities have the potential to introduce significant innovation, their overall impact on the EU's energy transition remains only partially understood. Further research is essential in order to better define and measure their potential at the local, regional, and national scales, as well as to assess their economic, environmental, and social impacts [26]. Additionally, such studies should explore the obstacles that limit individual and community participation in energy initiatives. Consequently, it is essential that we rigorously assess optimal REC design practices, promote public awareness, and examine their impacts on current infrastructures to guide their effective implementation.

The RECs' objectives are multifaceted: they aim to speed up the energy transition by enabling citizen participation, attracting private investment, and allowing citizens to gain economic benefits. Additionally, by promoting the use of locally generated renewable energy through internal community sharing, RECs are seen as a strategy to alleviate grid loading. Consequently, this grid loading reduction allows members to benefit from lower grid tariffs [27,28].

Moreover, recent studies indicate that, while RECs have a theoretically positive impact on the grid, their actual influence tends to be limited and varies significantly depending on the specific scenario [4,8].

In [8], the authors highlight the potential impact of energy communities on the MV distribution grid, which could suffer from increased losses, a worsened voltage profile, and an increased loading of the lines. The derived issues could be critical, motivating investments on the distribution grid. These aspects are typically under-investigated in the scientific literature, with a lack of methods and metrics to quantify the theoretical benefits offered by RECs.

In fact, in RECs, the incentive tariffs are specifically designed to promote self-consumption within the community. This focus encourages members to align their energy consumption patterns with the production of renewable energy generated locally. Consequently, participants are likely to modify their behavior to optimize self-consumption, which positively affect the grid operation, but increased participation may even lead to new contingencies on LV networks that would not have occurred otherwise and inadvertently reduce the flexibility available to the DSO managing the medium-voltage network. As a result, the DSO could face challenges in balancing supply and demand, potentially necessitating investments to reinforce the network infrastructure in the case of constraint violations. This scenario highlights the need for careful planning and coordination between energy communities and DSOs to ensure grid reliability while maximizing the benefits of self-consumption initiatives, and the need for new regulatory and incentive mechanisms that consider not only the benefits of ECs' individual users but also the additional services that ECs can offer to the grid.

3. Flexibility in Distribution Systems

The use of flexibility to ensure system stability is recognized as a key enabler for meeting Europe's long-term decarbonization goals [2]. In many countries, especially those with regulated DSOs, the application of flexibility in distribution networks has been either restricted or outright prohibited. Traditionally, the operation of MV and LV networks has centered on automation processes aimed at enhancing the continuity of service. However, recent advancements in ICT and the increased connection of distributed generation (DG) have prompted regulators and DSOs to explore flexibility services from consumers and producers as viable tools to support energy transition objectives. Effective collaboration between DSOs and transmission system operators (TSOs) is essential, as TSOs increasingly seek flexible resources to address the intermittent nature of rising shares of RES.

DSOs have several methods to procure flexibility, including connection agreements, network tariffs, and market-based approaches. Under Article 32 of the EU electricity market directive, market-based procurement is endorsed as the optimal solution, with competitive procurement mechanisms lowering costs compared to alternative methods [29]. Consequently, multiple research initiatives are examining potential structures for flexibility markets, and various pilot programs are underway in some countries [30]. These initiatives differ in terms of stakeholder involvement (DSOs, TSOs, or both), coordination mechanisms, timelines, congestion types and frequencies, and the types of services and products offered. Some research focuses on clarifying the roles and responsibilities of TSOs and DSOs in service procurement and utilization, as well as exploring distinct TSO–DSO coordination models [31–34].

Several countries have already implemented and tested flexibility markets, including France (ENEDIS flexibility tenders), Germany (ENERA Flexmarkt), the Netherlands (GOPACS), Norway (NorFlex), Sweden (sthlmflex), and the United Kingdom (with five tenders) [1–7]. Italy has selected Piclo, an independent British marketplace, to launch its first local flexibility market, providing an end-to-end solution to acquire and dispatch flexibility services for addressing localized constraints for its largest DSO.

To facilitate flexibility adoption and ensure transparent service procurement by network operators, evaluation tools have been created to assess the benefits of flexibility against traditional methods. In some regions, legal requirements mandate these comparisons, with regulators supplying methodologies for evaluating the value of flexibility. In the UK and Ireland, the Energy Networks Association (ENA) introduced the common evaluation methodology, along with a decision-support Excel tool for network investments [34,35]. In Norway, grid operators are required to perform socio-economic cost–benefit analyses for planning options, covering investment, operational, maintenance, energy losses, and congestion costs [36]. Similarly, France’s main DSO employs a methodology to assess flexibility against network investments, aiding planners in targeting only the most promising flexibility opportunities [37].

The Joint Research Centre has developed a smart-grid-based cost–benefit analysis approach, which is further detailed in [38]. A multi-criteria cost–benefit methodology for all stakeholders interested in evaluating various planning options is outlined in [39].

In December 2022, the largest Italian DSO e-distribuzione published the Pilot Project “Edge” [40], outlining the flexibility services it intends to acquire, along with the relevant procedures, to effectively address operational needs related to potential congestion and/or voltage regulation issues. These services are aimed at providing solutions both under normal operating conditions and during faults and/or scheduled maintenance activities.

In general, a local flexibility service, or local ancillary service, involves the upward or downward adjustment of active and/or reactive power exchanged with the grid by a connected resource, either individually or through a balancing service provider (BSP). The local flexibility services defined in the EDGE project involve the upward or downward modulation (re-profiling) of active power exchanged with the grid by a connected resource. This adjustment is intended to ensure compliance with distribution network constraints under normal operating conditions, as well as following reconfigurations due to faults and/or scheduled maintenance.

Flexibility products are also instrumental in reducing peak electricity demand, which can result from concurrent loads such as electric vehicle (EV) charging. These flexible solutions help mitigate the adverse impacts of RES by addressing the variability of power generation and preventing network congestion, including challenges like overvoltages and overcurrents. Together, these services are essential in supporting the energy transition, providing a viable alternative to conventional network reinforcement or expansion.

Flexibility as a product is characterized by several key parameters, including the extent of power modulation, duration, rate of change, response time, and location. DSOs can acquire flexibility through various mechanisms, such as connection agreements, network tariffs, or market-based transactions. Among these, market-based procurement is widely recognized as the most effective method, as it ensures transparency and cost-effectiveness, and fosters innovation.

Activating flexibility at the distribution level involves multiple stakeholders: the DSO (acting as an end-user of the service), flexibility providers, and possibly an aggregator serving as an intermediary. Flexibility providers span all levels of the power system, from generation (where DG can adjust output) to demand (where consumers can modify their consumption through demand response programs), and include both electrical and thermal storage systems, which can adjust schedules for energy injection or consumption. The need for an aggregator depends on the number and capacity of flexibility providers. For instance, in LV networks, which typically comprise small consumers and prosumers with limited flexible energy resources, the aggregator has a critical role. It aggregates flexibility from multiple small sources and negotiates optimal terms and prices in the service market. Thus, the aggregator not only acts as a bridge between distributed energy resources (DERs) and market operations but also manages its portfolio of DERs [41,42].

In fact, when operating and planning the MV distribution network, it is crucial that we also account for the underlying LV systems, as these can serve as valuable sources of flexibility by pooling small-scale resources scattered across that voltage level [43,44]. LV networks are witnessing a rapid rise in small photovoltaic (PV) installations, both with and without battery storage, as well as a broad range of customers eligible for demand response (DR) programs and a growing number of slow EV charging points. Few studies suggest using LV networks as flexibility sources for the operation of upstream systems. However, at the LV level, due to the typical setup—often radial networks supplied by transformers with off-load tap changers handling several unbalanced single-phase loads—voltage regulation issues and power congestion may occur. Consequently, a portion of the flexibility offered by DERs in LV networks must be allocated to the LV level itself, leaving only the excess flexibility potentially available for higher levels (i.e., MV distribution).

The same effect could be due to the REC integration at the LV level. In the paper, the impact of the widespread formation of new RECs on the LV systems is studied, considering the incentive tariffs that encourage community members to maximize the self-consumption of locally produced renewable energy. This behavior aligns energy usage with local production, but, in some cases, it could negatively affect the network operation (i.e., LV network contingencies occur if generation units and customers are in different feeders, geographically distributed across a wide area served by the same primary substation) and may reduce flexibility for the DSO. Consequently, this shift may challenge the DSO's ability to balance supply and demand, possibly leading to necessary investments in network infrastructure to avoid constraint violations.

4. Methodology for the Assessment of ECs' Impact on LV Networks

In the literature, various methodologies for estimating the impact of different generation/consumption patterns on networks have been proposed, including data-driven approaches (often based on test trial data), probabilistic forecasting (where consumers are categorized into flexible and non-flexible groups), scenario analysis, and optimization-based modeling (which uses objective functions to balance flexibility at each node while respecting operational constraints) [45,46]. However, not all potential flexibility can be made available due to factors such as internal utilization needs and contingencies introduced by flexibility use [42,47]. Furthermore, technical constraints and strategic operational choices by resource owners—such as prioritizing internal use to maximize self-consumption over market participation—can introduce new contingencies in the LV networks and further reduce the availability of flexibility. This poses a significant challenge for the DSO, with the need for further investments on LV networks.

In the paper, a stochastic methodology based on Monte Carlo simulations is proposed to evaluate the impact of RECs on LV distribution networks [47].

This approach enables a more realistic representation of complex system behaviors, including those caused by varying load demands, uncertain renewable energy production, and diverse network configurations. Specifically, load and PV generation profiles are based on measured data from MV/LV substations, individual LV customers' annual energy consumption, and statistical distributions. In addition, the model incorporated weekly and seasonal variations in consumption and production.

This approach takes into account spatially distributed participants, multiple network segments, and long-term variability. It provides more realistic insights into how RECs affect network operations and informing strategies for effective REC integration at the LV level. In fact, the REC model under consideration allows users connected to the same high-voltage (HV)/MV substation to establish an energy community and share energy via the public MV distribution network. This HV/MV substation requirement aligns with Italy's regulatory framework, specifically Resolution Arg/elt 727/2022 [24], which defines the local scope of energy communities.

The block diagram of the proposed procedure is shown in Figure 1.

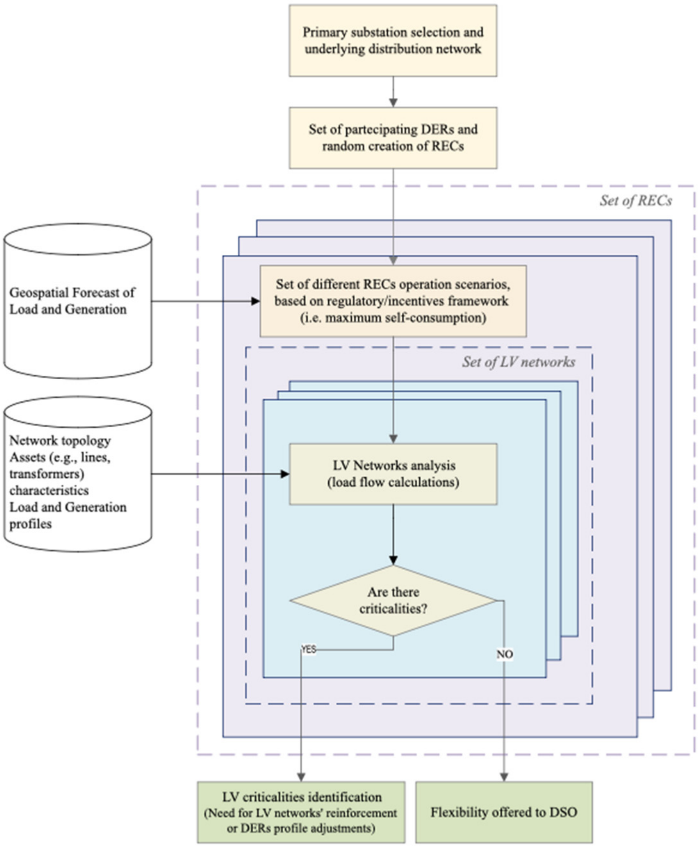

Figure 1. The procedure proposed for the estimation of the flexibility offered by LV RECs.

To assess the impact of energy communities on LV networks, the following procedure is proposed (Figure 1):

(a) Area and primary substation (PS) selection.

(b) Random generation of RECs in LV systems: The random generation of RECs is considered, involving LV networks and their respective elements. Based on a uniform distribution, MV and LV nodes are randomly selected. An example is reported in Figure 2, together with the possible constitution of different RECs. Under the primary substation, different MV/LV nodes and their underlying networks are shown. The yellow and green shaded areas represent two distinct RECs and the associated elements that form them.

(c) Assessment of LV network condition: Unbalanced load flow calculations (using OpenDSS [48]) for each network identified in step b are performed to estimate the expected profiles at the MV/LV interface and identify potential violations of voltage limits and thermal limits of cables and transformers in the LV network, in both cases (with and without considering the formation of new RECs). In this step, to capture the operational aspects that can affect the networks, the time variability of demand and generation has to be explicitly represented. Thus, probabilistic load flow algorithms or the more general Monte Carlo simulation approach, as well as clustering techniques, can be adopted [46].

(d) In the case of constraint violation in the LV network (overvoltage/undervoltage, maximum current, or transformer overloading), the network should be upgraded by means of LV networks' reinforcement or DER profile adjustments (i.e., contributing to active management) to solve the criticalities.

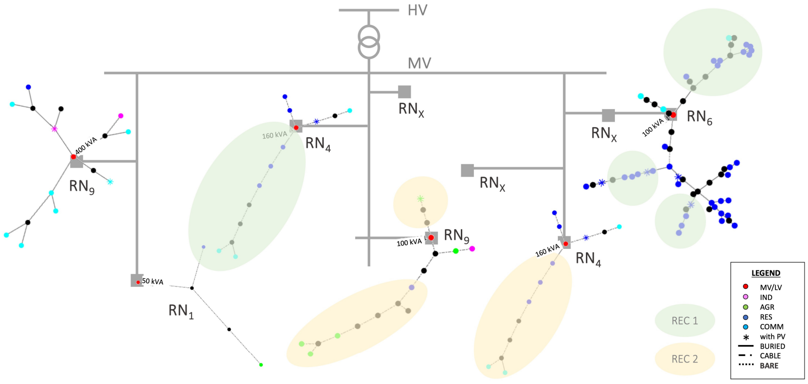

Figure 2. Example of a portion of a real distribution system in which LV networks are composed of various representative networks (RN$_X$). Potential formation of two different RECs (REC 1 and REC 2) connected to the same primary substation HV/MV.

5. Study Cases

In the paper, the establishment of RECs under a specific HV/MV primary station is considered, and their impact on the flexibility offered to the DSO is assessed.

The procedure described in Figure 1 has been implemented in a test network selected in the South of Italy.

The network underlined by the HV/MV substation is in a semi-urban area characterized by residential portions, rural areas, and small industries. Its total extension is about 47.3 km, and it is built predominantly with overhead insulated cables of different cross-sections. The PS supplies over 169 MV nodes, including both private and public substations. In the case study, REC participants are drawn from a set of low-voltage networks. The selection of LV nodes within the REC is based on a uniform distribution (as in step b), and representative networks are associated with actual nodes (only public MV/LV substations are considered).

The analysis of the LV system accommodating the RECs is conducted considering a portion of a real distribution network. The lack of data related to LV networks made it necessary to adopt representative networks belonging to the same region. The development of representative networks (RNs) is beyond the scope of this paper [49]. However, these networks are designed based on similar characteristics, such as length and density, and considering the MV/LV transformer capacity (in a range between 50 kVA and 630 kVA) derived from 2020 real network data. By 2030, each representative network could evolve differently, leading to developments with different growth levels of load and generation, as well as the emergence of an appropriate number of generators (and/or storage systems and charging stations) while maintaining the same topological characteristics. Starting from the current values, in the study case, the load demand is expected to increase by 10% by 2030, while the generation capacity is projected to grow fourfold its current level by 2030. The considered RNs are shown in Figure 3. The secondary substation is represented by a red node alongside the transformer size. Other nodes are color-coded based on the predominant user type (residential, commercial, industrial, or agricultural), and an asterisk marks the presence of photovoltaic generation, if applicable.

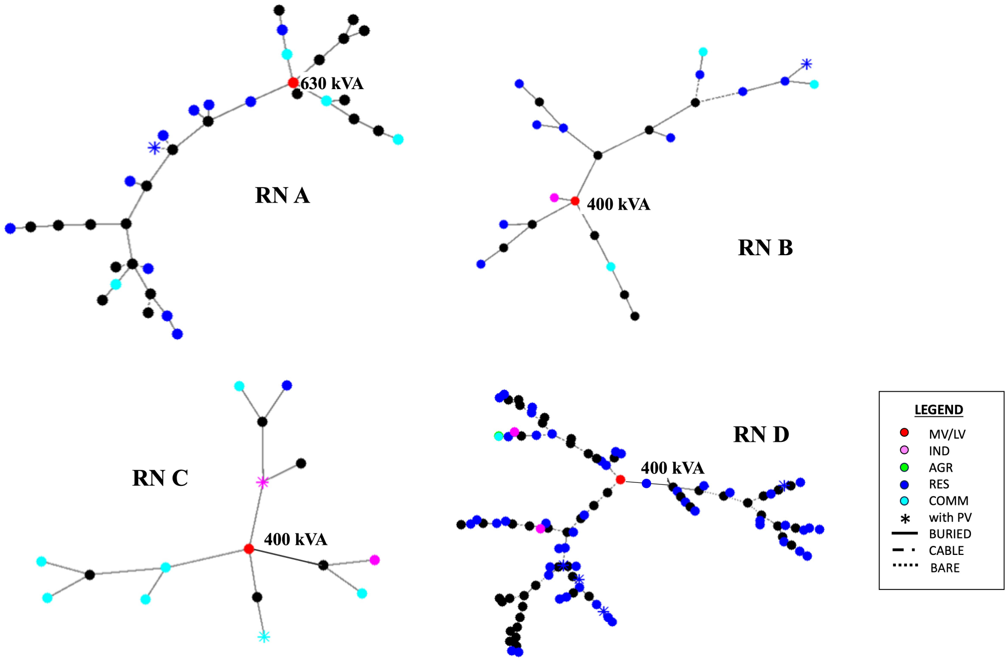

Figure 3. Representative networks adopted in the study.

For lines, the type (overhead, bare, or underground cable) is indicated by the section used in the connections, with details of the prevailing customer typology in the nodes, line type, and presence of generators.

Table 1 summarizes the main characteristics of the LV in which the REC is formed.

For each MV/LV node, the representative network associated with it is reported, as well as the most important parameters, including the installed load power (P Load), the load energy demand (E Load), and the installed PV power (Installed PV). It also identifies the participating resources within the REC (Nr. of customers and Nr. of PV generators). In order to indicate the composition and size of the networks and the resources actively contributing to the REC, the participating loads and generators are shown in brackets.

In the analyzed REC, n. 342 loads are considered, for a total nominal demand of about 2.67 MW, mainly formed by residential customers. Different PV plants (n. 76), both with a single phase and three phases, are connected at the LV level, resulting in a total PV power installation of around 414 kW. For the sake of simplicity, DGs in MV have not been considered in the RECs. The PV installed could determine reverse flows from the LV to the MV network during the central hours of the day. For the sake of simplicity and by analyzing the worst case, storage systems and charging stations are not considered in the study since they can impact the overall flexibility offered to the DSO.

Specific scenarios for demand, generation (e.g., PV), and REC (if applicable) are applied to these representative networks, starting from the already-in-place scenario and adopting a Monte Carlo procedure to represent the whole year in the study, constructed through the representation of 12 typical days (working, pre-holiday, and non-working days for each quarter), as described in [43].

For the sake of brevity, only the typical working days of the first and second quarters of the year (Q1, January–March, and Q2, April–June) are presented and discussed. However, similar conclusions could likely be drawn for other day types and for the remaining quarters (Q3, July–September, and Q4, October–December) as well.

Table 1. Main characteristics of the LV networks and participating resources in the REC.

MV/LV NODE (RN)	P Load (kW)	E Load (MWh)	Installed PV (kW)	Nr. of Customers	Nr. of PV Generators
	Total (REC)	Total (REC)	Total (REC)	Total (REC)	Total (REC)
1 (RN A)	1013 (476)	376 (218)	57 (45)	88 (44)	13 (9)
2 (RN B)	294 (124)	224 (108)	23 (13)	59 (23)	4 (3)
3 (RN C)	318 (76)	164 (71)	83 (33)	18 (7)	10 (5)
4 (RN A)	1013 (592)	279 (187)	23 (17)	88 (45)	5 (3)
5 (RN B)	294 (151)	224 (124)	131 (74)	59 (32)	22 (10)
6 (RN C)	318 (214)	164 (91)	28 (19)	18 (10)	4 (3)
7 (RN B)	294 (174)	224 (134)	49 (28)	59 (33)	9 (5)
8 (RN A)	1013 (371)	279 (80)	133 (77)	88 (37)	30 (17)
9 (RN B)	294 (148)	224 (109)	131 (78)	59 (26)	22 (13)
10 (RN B)	294 (128)	165 (77)	49 (15)	59 (27)	9 (3)
11 (RN C)	318 (25)	164 (31)	83 (11)	18 (2)	10 (3)
12 (RN D)	362 (193.5)	336 (165)	4 (4)	106 (56)	2 (2)

Three scenarios have been analyzed in line with the operating conditions considered in the study:

1. Networks as-is (CASE 0): The current network configuration (without RECs) is assessed to identify contingencies and issues, which are addressed preventively if needed. Feasible flexibility is also calculated under this configuration, by assuming that the maximum load curtailment of 50% of hourly consumption is considered. In this case, customers maintain their traditional consumption patterns for different typical days (TD) of the year. Figure 4 shows the total load demand and PV production profiles for the elements within the REC under CASE 0, where no self-consumption policy is applied. The curves are labeled LOAD TD1 to LOAD TD12 and PV TD1 to PV TD12, which correspond to 12 typical days of load demand and PV production, respectively, for the elements within the energy community. The figure highlights the non-homotheticity between the load demand and PV generation profiles.
2. Networks with RECs (CASE 1): In RECs, following the current regulatory framework, the incentive tariffs are specifically designed to promote self-consumption within the community. CASE 1 simulates the random user behavior within the REC, where self-consumption is not optimized. In CASE 1, customers act as members of the REC but do not completely understand that shifting consumption to the central hours of the day is beneficial. Therefore, the REC self-consumption is reduced, leading to

variations in their behavior. It is assumed that peak demand can be modified with a random flexibility shift of up to 30%, consistent with prior research estimates [50,51].

3. Networks with RECs Optimized for Self-Consumption (SC) (CASE 2): In the last case, due to incentive policies related to RECs, all customers within the REC aim to maximize energy self-consumption. Figure 5 shows the load demand and PV generation profiles for the elements within the REC, where self-consumption policies are applied. Compared to CASE 0, the figure reveals a visible reduction in the non-homotheticity between the load demand and PV generation profiles. The application of self-consumption policies results in smoother load profiles and a better alignment between energy generation and demand, particularly during the central hours of the day when PV production peaks.

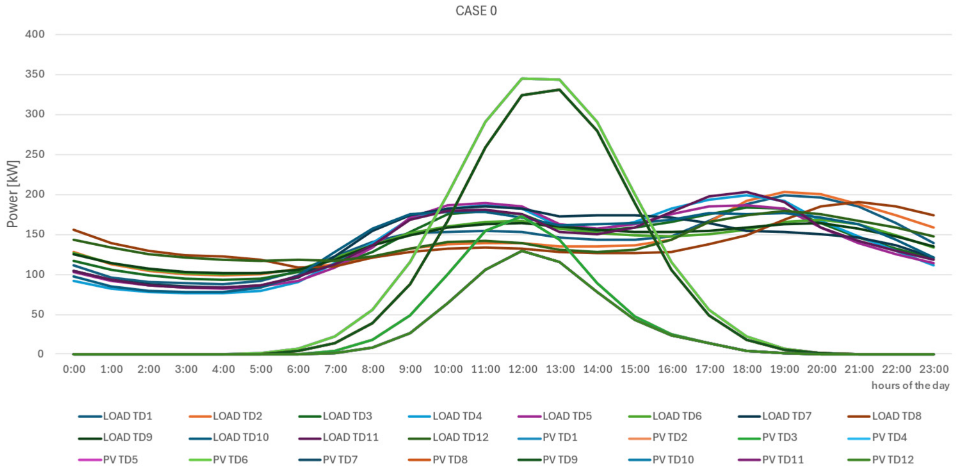

Figure 4. CASE 0—load and generation daily curves for typical days (working/pre-holiday/non-working days for each season).

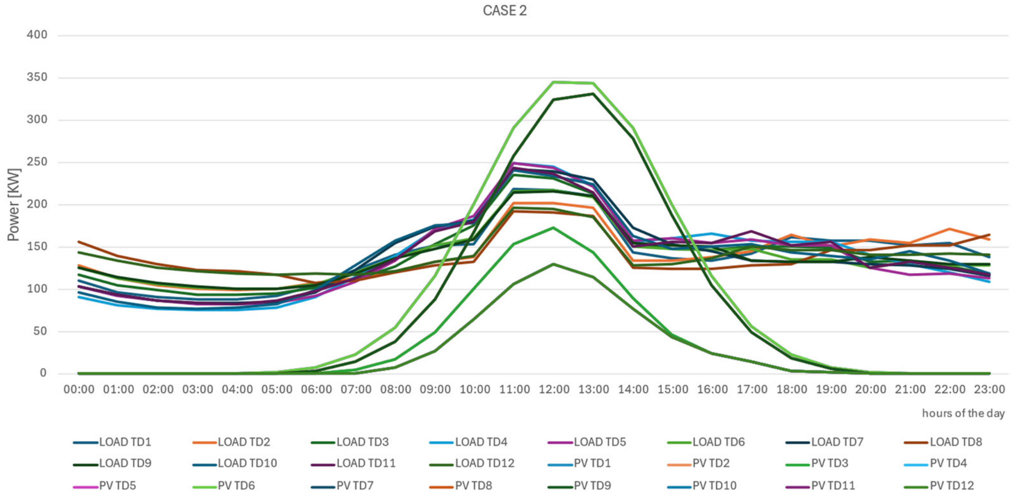

Figure 5. CASE 2—load and generation daily curves for typical days (working/pre-holiday/non-working days for each season).

The flexibility that LV networks can offer to the MV network for different REC scenarios is evaluated by defining various ranges of available flexibility. In the flexibility analysis, for the upward adjustment, a maximum curtailment of 50% of hourly consumption is considered, whereas the downward adjustment could reach 100% of the RES production.

6. Results and Discussion

By means of the unbalanced power flow calculations (using OpenDSS [48]) for each representative network, the impact that the REC could have on the LV networks and the flexibility that it can provide to higher voltage levels (i.e., MV) without causing internal issues within the LV network is estimated.

In CASE 0, the yearly REC SC is 77%, and self-sufficiency (SS) is 31%. Tables 2 and 3 report, respectively the detail for the typical Q1 working day and Q2 working days for the three cases analyzed. The highest SC (97.5%) is achieved on typical winter working days (Q1), while the peak SS (42.9%) occurs on the working days in Q2.

Table 2. Average self-consumption and self-sufficiency of the typical winter working days (Q1).

Case	Self-Consumption (%)	Self-Sufficiency (%)
CASE 0—No REC	97.5%	23.8%
CASE 1—Non optimized REC's SC	100.0%	24.4%
CASE 2—Optimized REC's SC	100.0%	24.4%

Table 3. Average self-consumption and self-sufficiency of the typical spring working days (Q2).

Case	Self-Consumption (%)	Self-Sufficiency (%)
CASE 0—No REC	69.2%	42.9%
CASE 1—Non optimized REC's SC	73.6%	45.7%
CASE 2—Optimized REC's SC	78.1%	48.4%

The high self-consumption rate is unsurprising, as Figure 6 shows that production consistently exceeds demand. The low self-sufficiency values are also attributed to the lack of storage systems, which limits the capacity to retain surplus PV energy in the central hours of the day for later use.

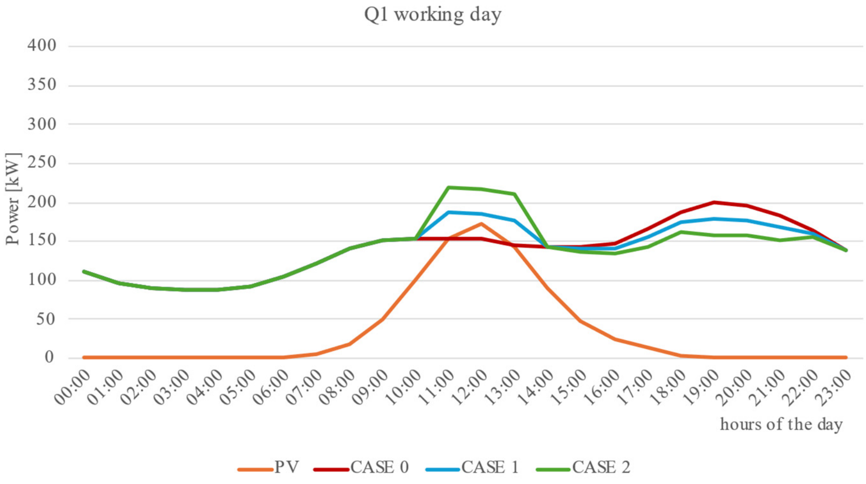

Figure 6. Mean load and generation daily curves for a typical winter working day (Q1).

Considering CASE 1, the yearly SC reaches 81%, while the SS is 32%. The maximum SC (100%) is achieved on all typical days in Q2 and on both working and non-working days in Q1, while the peak SS (45.7%) occurs on working days in Q2.

Finally, considering CASE 2, the yearly SC reaches 84%, while the SS is 34%. The load shift allows increasing the typical days with an SC equal to 100% (i.e., all typical days in Q1), while the peak SS (48.4%) occurs on working days in Q2.

Figures 6 and 7 show, respectively, the load demand and generation considering a Q1 working day and a Q2 working day, respectively, under the three analyzed cases, CASE

0 (red line), CASE 1 (blue line), and CASE 2 (green line), while PV generation is shown in orange.

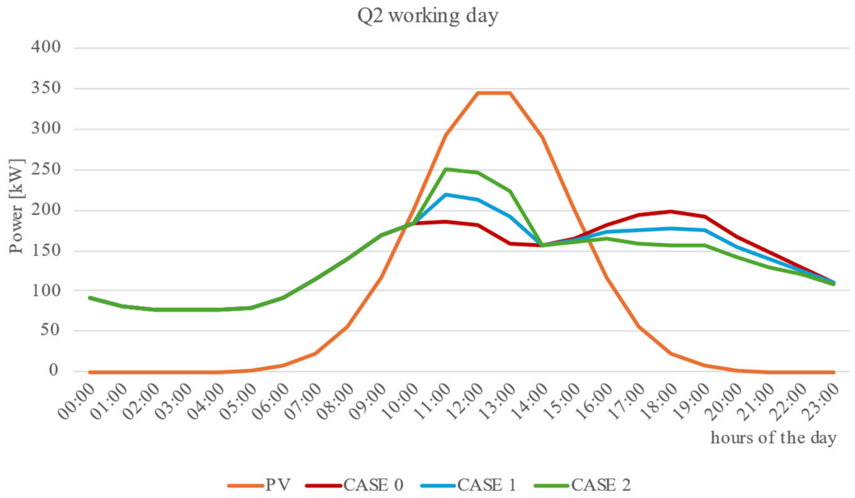

Figure 7. Mean load and generation daily curves for a typical spring working day (Q2).

It can be seen from the figures that the demand shift allows an increase in self-consumption. In Q1 (Figure 6), CASE 1 and CASE 2 demonstrate improved self-consumption compared to CASE 0, with both cases successfully aligning demand with PV production peaks. In Q2 (Figure 7), the effect of demand shifting becomes more evident, due to the seasonal increased production. CASE 2 achieves a more substantial increase in self-consumption by better aligning the load demand with the PV production peak compared to CASE 0 and CASE 1.

In particular, in urban networks with significant population density, characterized by high loads and the limited penetration of PV systems, the participation of some customers in the REC has a dual impact, which has been investigated.

For example, Node 12 (network D), on specific typical days (e.g., Q3), suffers voltage drops during the evening peak. Figure 8 shows the voltage profile along the network under CASE 0 for a pre-holiday Q3 day. The x-axis represents the distance from the MV/LV transformer (km), and the y-axis shows the voltage level (p.u.). The three phases are represented as Phase 1 (red), Phase 2 (green), and Phase 3 (blue). Notably, Phase 3 shows the most significant voltage drop, reaching a minimum of 0.951 p.u., which is very close to the regulatory limit of 0.95 p.u. This highlights both phase imbalance and voltage stability issues, particularly near the end of the network.

The consumption-shift in CASE 2 allows the evening peak to be eliminated, completely resolving these issues. This is evident in Figure 9, where the minimum voltage value reaches 0.961 p.u.

However, on a typical winter holiday situation, where no initial issues were recorded, the consumption shift results in a worsening of the voltage profile, further increasing the imbalance that characterizes this portion of the network. This condition is emphasized by the increasing participation level of the REC user in the node (i.e., passing from CASE 1 to CASE 2). Figures 10 and 11 show the voltage profile along the network as a function of the distance from the MV/LV transformer, in CASE 0 and CASE 2, respectively. The three phases are represented as Phase 1 (red), Phase 2 (green), and Phase 3 (blue). In Figure 11, it is possible to see the nodes that fall below the voltage threshold (i.e., 0.95 p.u.).

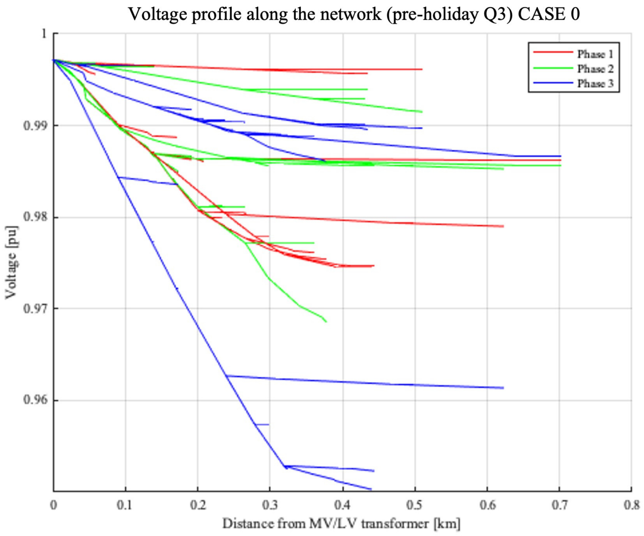

Figure 8. CASE 0—voltage profile (h 7 p.m.) along the network beyond Node 12, during pre-holiday (Q3).

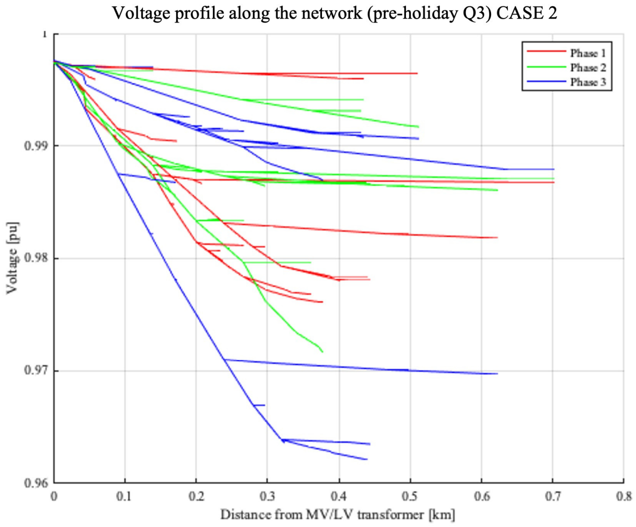

Figure 9. CASE 2—voltage profile (h 7 p.m.) along the network beyond Node 12, during pre-holiday (Q3).

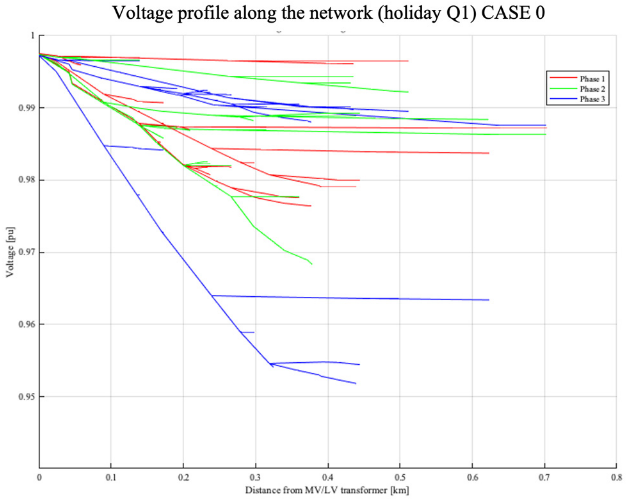

Figure 10. CASE 0—voltage profile (h 21) along the network beyond Node 12, during holiday (Q1).

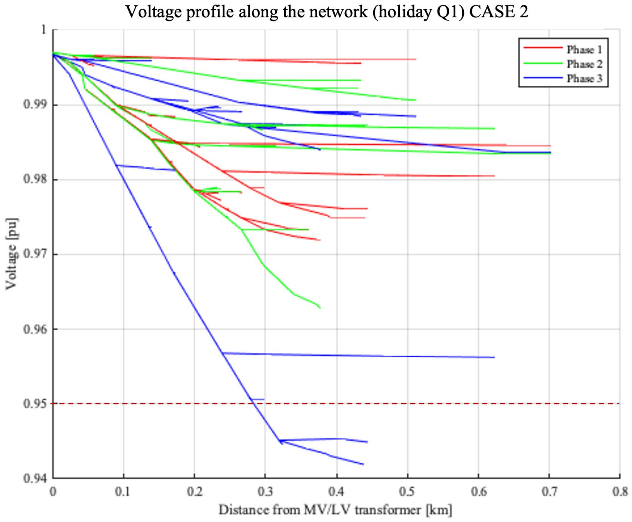

Figure 11. CASE 2—voltage profile (h 12) along the network beyond Node 12, during holiday (Q1).

These studies demonstrate that high levels of user participation in energy communities do not always yield a positive impact on the electrical system. In fact, while such participation can sometimes positively affect grid operation, increased participation can even lead to new contingencies that would not have occurred otherwise.

Concerning flexibility, the REC obviously leads to a reduction in the amount of energy to be shared with the DSO, as was expected, having made the energy demand more inelastic. Indeed, in CASE 0, customers and generators can offer the whole flexibility (i.e., totally curtailing the generation and halving the demand) without causing any contingency. The same goes for CASE 2: the yearly flexibility offered to overlying networks is reduced by 15% (upward) and 84% (downward), compared to CASE 0. Table 4 reports the upward and downward flexibility for the three cases analyzed in terms of the total energy and percentage of the total demand or production.

Table 4. Upward and downward flexibilities in the study cases.

Case	Upward Quantities	Downward Quantities
CASE 0—no REC	613 MWh 50%	492 MWh 100%
CASE 1—non-optimized REC's SC	439 MWh 36%	95 MWh 19%
CASE 2—optimized REC's SC	435 MWh 35%	79 MWh 16%

The simulations demonstrate that RECs have a significant impact on the LV networks, even if the distributed PV production locally consumed has a positive impact on the grid. Specifically, the high participation levels of REC-involved elements may also create new, unforeseen contingencies, by negatively affecting the network operation. In fact, LV network contingencies occur if generation units and customers are in different feeders, geographically distributed across a wide area served by the same primary substation.

Moreover, integrating RECs at MV/LV nodes may alter the flexibility that these nodes can offer to the DSO, since through demand shifting reduces the flexibility available to the upstream network by pre-emptively adjusting the demand profile. In such cases, if further load reductions are required, the DSO may be forced to rely on alternative resources, which may not always be available or adequate to address the system's needs. Additionally, this shift can create unforeseen demand peaks during typically non-critical periods, such as in the morning when residential loads are low but office and commercial demand are already active, potentially exacerbating grid management challenges.

The regulatory framework for energy communities should take into account that maximizing self-consumption without considering the technical constraints of the network may necessitate new reinforcements and DSO investments. Instead, it would be advisable to design innovative incentive systems aimed at addressing local challenges—for instance, by promoting energy communities formed within a limited perimeter, such as at the level of a secondary substation.

7. Conclusions

This study aims to assess the potential impacts of RECs on the operational stability of distribution systems, with particular emphasis on LV networks. By evaluating different scenarios—such as the network type, levels of REC self-consumption, and user participation—this research examines how RECs may contribute to operational challenges, including voltage regulation, particularly in densely interconnected LV systems. Indeed, if participation in the energy community is rewarded based on community self-consumption of the green power produced within the community, RECs can introduce operational rigidities capable of vanishing some of their local benefits. This might happen if the REC is wide enough to include different portions of the distribution grids with a non-homogeneous distribution of RESs and load characteristics. In this case, the load shifting in the community towards the time of highest RES production without any consideration of the network status can exalt voltage regulation issues and cause congestion. As shown by the results of the simulations, there are certainly cases where REC self-consumption has a positive effect (e.g., reducing the peak demand in the evening and thus improving the network voltage profiles), but this outcome cannot be generalized. Surely, only the full participation of the RECs in the local ancillary service market can really help DSOs face the challenge of the energy transition. The paper shows, with the aid of a designed methodology, that what is always good for power systems (i.e., increasing the self-consumption) is not necessarily good for distribution networks that could suffer unexpected criticalities which must be dealt with in a higher level of detail. As a general result, the creation of many small RECs in areas not bigger than the one covered by a secondary substation might be a solution for promoting self-consumption without burdening the distribution network. Otherwise, the regulation should promote the full exploitation of flexibility by remunerating self-consumption at the community level only when and where it is useful to the DSO.

Finally, the study explored how REC integration affects the flexibility demands placed on DSOs in MV networks, given the inherent variability of REC-generated power and differing self-consumption patterns. These insights underline the importance of developing advanced grid management strategies and making targeted investments in flexibility solutions to maintain reliable and efficient distribution networks in the context of REC expansion.

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