Community battery for Collective-Self-Consumption and Energy Arbitrage: a techno-economic study considering battery aging, grid impact and different market scenarios.

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Abstract

In the evolving realm of energy, two key players take the spotlight: Renewable Energy Communities and Battery Energy Storage Systems. The former encourages responsible energy practices through demand response incentives, while the latter empowers energy production shifting. Integrating a battery into a community allows to achieve high levels of collective self-consumption and collective self-sufficiency; but is it cost-effective?

The proposed techno-economic analysis relies on Net Present Value assessment and considers battery aging concerning its management for Collective-Self-Consumption and Energy Arbitrage. Various scenarios are simulated, considering factors such as customer number, energy market prices, battery cost, and the permission to perform energy arbitrage, either unrestricted or limited to the community's energy balances. For each scenario, a 20-year-long hourly simulation is conducted, where daily scheduling results from a MILP optimization.

The findings indicate that unrestricted energy arbitrage significantly reduces the payback time of investments but may have adverse effects on the electricity grid, necessitating limitations. In the latter case, economic viability is demonstrated when battery sizing is matched to the customer number inside the community and energy market prices, all with an initial investment cost not exceeding 200 €/kWh.

Abbreviations and symbols

AC	Activation Cost
AP	Activation Penalty
BC	Battery Cost
BESS	Battery Energy Storage System
EA	Energy Arbitrage
EMS	Energy Management System
EP	Energy Price
CEP	Clean Energy Package
CF	Cash Flow
CN	Customer Number
CSC	Collective Self-Consumption
CSS	Collective Self-Sufficiency
DSO	Distribution System Operator
MILP	Mixed-Integer Linear Programming
N	Needs
NPV	Net Present Value
P	Power
PV	Photovoltaic
R	Replacement
REC	Renewable Energy Community
RES	Renewable Energy System
S	Surplus
TSO	Transmission System Operator
y	year

Keywords

- Renewable Energy Community
- Battery scheduling
- Battery aging
- Collective self-consumption
- Energy Arbitrage

1. Introduction

Integrating decentralized renewable energy sources into the power grid poses challenges due to the intermittent nature of renewables. Effective optimization of energy distribution and harnessing renewable sources requires advanced technologies. Battery Energy Storage Systems (BESS) play a crucial role in achieving this goal.

Concurrently, evolving legislation supports the transition to renewable energy by incentivizing positive user behavior. This shift in focus has given rise to the concept of Renewable Energy Communities (RECs), which encourage Collective Self-Consumption (CSC) through economic incentives for consumers and prosumers who share energy, often generated by photovoltaic systems. These incentives motivate members to adapt their electricity usage during REC production periods, contributing to grid stability and sustainability. This study assesses the feasibility of integrating a high-capacity community BESS within a REC framework. The BESS can function as a controllable load during charging and as a generator during discharging. It plays a significant role in optimizing CSC and enables Energy Arbitrage (EA), involving charging the battery when electricity costs are low and discharging it when prices are high to maximize economic gains.

Evaluating the profitability of the BESS is complex due to various influencing factors. The study relies on Net Present Value assessment and considers battery aging in relation to its management for CSC and EA. Various scenarios are simulated, considering factors like customer number, energy market prices, battery cost, and permissions for EA, whether unrestricted or limited to the community's energy balances. Each scenario undergoes a 20-year-long hourly simulation, with daily scheduling determined through Mixed-Integer Linear Programming (MILP) optimization. All analyses comply with Italian regulations but are easily generalized by modifying the objective function gain components.

This manuscript is organized as follows:
Section 2 clarifies the European legislative framework concerning RECs and reviews the relevant literature to then clarify the novelty brought by the paper. Section 3 presents the specific Italian case studies under consideration, offers insight into the details of the applied MILP algorithm for battery scheduling, and outlines the economic analysis. Additionally, it introduces the simulated scenarios. In Section 4, the results are presented, which include a comparison of all the considered scenarios. Firstly, the energy balances are displayed, followed by a section that elucidates the relationship between battery management strategy and aging. Finally, an investment analysis is provided.

2. State of the Art on Renewable Energy Communities

*2.1 **Legislative Framework in Europe***

Recent developments in grid integration strategies for Distributed Generation from non-dispatchable Renewable Energy Sources (RES) have been introduced in Europe [1]. Key solutions aim to enhance demand-side flexibility through enabling technologies, such as Battery Energy Storage Systems (BESS) and Internet of Things devices for load and generator control. The primary objective is to increase renewable energy self-consumption, both for individual prosumers, microgrids, or virtual power plans. In Europe, this concept aligns with the creation of Renewable Energy Communities (RECs), which allows EU citizens to actively participate in the energy transition encouraged by the Clean Energy Package (CEP) [1]. The CEP comprises regulations and directives aimed at shaping energy policies within the EU, focusing on reducing greenhouse gas emissions and improving energy efficiency by increasing electricity consumption from RES [2], [3].

Directive 2019/944 introduces new guidelines to simplify the interaction of citizens with the electricity system as active participants and to improve the acceptance of RECs [4]. Such market participation could include aspects such as the generation, consumption, sharing, or trading of electricity, as well as the provision of flexibility services through demand response and energy storage. All these activities could be pursued individually as a self-consumer or through RECs, whose role is strengthened in Article 22 of the revision of the Renewable Energy Directive (RED II) 2018/2001 with particular attention to domestic consumers [5].

EU Member States are required to establish mechanisms that allow household consumers to participate in available schemes, ensuring equal involvement alongside larger participants. Italy has implemented the legislative framework for RECs through specific legal provisions and regulations [6]-[8]. In Italy, a REC is defined as a virtual community comprising consumers and RES-based energy producers, with no limitations on the number of customers. Energy sharing within RECs is calculated as the minimum hourly energy feed-in by generators and consumption by loads. Shared energy is called Collective Self-Consumption (CSC) and is incentivized by about 110 /MWh. A fuller explanation is in paragraph 3.1.

To maximize energy sharing, resources like BESS and manageable loads are deployed. This paper examines the impact of a community BESS on the energy balances and gains of a REC.

The introduction of RECs in Italy has also led to changes in the CEI 64.8 standard, specifically introducing the concept of Prosumer's low-voltage Electrical Installations (PEI) and defining the functionalities of the Electrical Energy Management System [9]. Considering this legislative and technical framework, this study addresses a shared PEI, where individual units constitute a REC connected to the Distribution System Operator (DSO) network under the same secondary substation.

2.2 Literature Review

Renewable energy communities (RECs) represent one of the most innovative topics in scientific literature and interest in these new entities is rapidly growing as their integration into modern smart grids will be a key aspect in the near future.

An extensive examination of RECs in the European context is discussed in [10], exploring various scenarios and emphasizing the unique traits of RECs across different regions. These distinctions are primarily shaped by available technologies, energy sources, regional peculiarities, and the evolving regulatory landscape. The regulatory environment influences the technical setup of RECs, favoring either physical or virtual configurations, and guides the organizational structures permitted.

Presently, in Europe, the organizational model predominantly chosen by RECs is Cooperatives (43%), followed by Partnerships (25%) and Associations (9%). Regarding the establishment of RECs, EU regulations allow for both physical and virtual configurations. In the former, a physical connection between the units within a REC is essential, necessitating specific infrastructure development. In the latter, the REC operates entirely virtually, using the national distribution network and relying on data extracted from meters. In the current Italian legislative framework, only the virtual configuration is permitted.

The physical or virtual nature of RECs represents the starting point for developing possible aggregation and management strategies and is one of the most interesting topics addressed in the scientific literature [11]-[14]. Then it is necessary to evaluate the economic aspects and the effect on the distribution networks.

Firstly, it's crucial to promote the REC concept and encourage citizens, including prosumers and consumers, to establish REC. Clear incentives and economic analyses that highlight collective benefits, environmental advantages, and efficiency gains are essential. For example, [15] provides a comprehensive overview of the economic aspects of RECs, comparing various business models. Additionally, [16] suggests an approach aimed at maximizing social welfare in local community markets by optimizing energy trading between different communities, encompassing both thermal and electrical energy. Moreover, [17] introduces a peer-to-peer market design from a game-theory perspective, modeling prosumers as self-interested agents seeking to maximize their profits in energy trading, considering the potential development of collective strategies among prosumers. In the context of Italy, [18] offers a comprehensive analysis to guide neighborhood energy retrofits by optimizing solar energy utilization. A similar approach is applied in [19] to assess smaller communities, each corresponding to a single condominium. In this study, the economic evaluation of the benefits achievable by members of the energy community who decide to install a common battery is at the center of the debate.

The effects of the massive integration of RES in transmission and distribution networks have been studied for several years in order to guarantee the stability of the electricity service during the transition from centralized to distributed generation [20], [21]. The most frequent critical issue concerns the impact of renewable generators on the dispatching phase, i.e., on the management of energy production carried out by the Transmission System Operator (TSO), or locally by the Distribution System Operator (DSO). In fact, the high variability of renewable generators introduces possible imbalances between production and consumption, thus introducing frequency variations and increases in losses which lead to other chain consequences. For this reason, many papers in the literature propose different approaches for the placement and management of systems powered by renewable sources [22]-[24]. In this context, the control of RECs also plays a fundamental role in contributing to the balancing of energy flows [25]-[27]. In this work, the energy flows between REC and the distribution network are balanced by introducing appropriate constraints in the optimization algorithm. In this way it is possible to avoid injection peaks from the REC generators and better compensate the consumption profile.

Once the fundamental aspects of RECs have been established, it is necessary to analyze the contribution of Battery Energy Storage Systems (BESS) on collective self-consumption (CSC) and their impact from the economic point of view. Therefore, one of the essential criteria used to classify BESS in a REC is centralized or decentralized installation.

Decentralized BESS are the prevalent configuration in distribution networks, characterized by multiple smaller units dispersed across the community. In this setup, select REC prosumers focus on optimizing individual self-consumption and reducing grid injections. This configuration's primary features include localized advantages, such as reduced transmission losses and immediate user benefits due to energy storage proximity to consumption points. Scalability is another strength, with the capacity for incremental expansion by adding units. Thus, RECs often comprise multiple distributed storage facilities connected to specific prosumers. However, centralized management, rather than individual control, is essential to maximize collective and not only individual prosumer benefits [28], [29].

Managing RECs with distributed BESS is a complex area, with various approaches developed in recent years. The overarching goal remains the implementation of an Energy Management System (EMS) capable of processing real or anticipated data related to renewable generators, consumption profiles and energy prices. A comprehensive review of these methods is provided in [30], highlighting the distinctions between optimization and rule-based approaches, as well as the characteristics of hybrid rule-based optimization methods.

Within rule-based approaches, [31] presents a general sharing economy model allowing residential communities to share solar production and manage distributed BESS. Similarly, [32] proposes a two-stage management strategy for optimal operation and billing in a virtual REC. Their aim is to develop a framework for effective energy resource management within the community while ensuring equitable distribution of benefits. In [33], the objective is to analyze the impact of a bi-objective strategy for optimizing BESS capacity in RECs with prosumers equipped with photovoltaic generators. The solution seeks to maximize REC collective-self-sufficiency (CSC) while minimizing BESS capacity for all REC members, considering factors such as voltage, losses, and CO2 emissions.

As for optimization methods, [34] and [35] present notable results. In the former, a strategy is proposed to program storage systems in a REC, optimizing economic revenues and minimizing annual operating costs. The study focuses on a REC operating within the Italian legislative framework, with photovoltaic systems, BESSs, and non-controllable loads. The strategy encompasses three modules: a machine learning-based prediction algorithm for one-day-ahead microgrid load and PV generation projections, a Mixed Integer Linear Programming (MILP) algorithm for BESS optimization to minimize operating costs and maximize self-consumption, and a decision tree algorithm for real-time BESS scheduling at an intra-hour level.

As regards the approach shown in [35], different decentralized battery management strategies in a REC are compared: two of them rule-based and one optimization-based, obtained from a MILP. The article shows that the latter does indeed lead to the best result, but that this is not so far removed from the management obtained with a rule-based design with community logic in mind.

However, it should be mentioned that only self-consumption and collective self-consumption are considered in that article and that the introduction of other services such as energy arbitrage or dispatching would inevitably require optimization-based logics.

What has been said so far about the control logic of decentralized batteries can also be extended to other storage technologies, e.g. the inertial storage of heat pumps [36], other technologies often found in the RECs.

While decentralized structures are the most common, there is a growing interest in solutions employing large energy storage systems to serve RECs for maximizing economic incentives and offering ancillary services [37]. BESS have versatile applications, including peak shaving [38], energy microgrid management [39], [40], and frequency and voltage regulation [41], [42]. Our study primarily focuses on managing BESS for collective self-consumption (CSC) and energy arbitrage (EA) within the REC. While ancillary services are not deeply explored in this paper, examining their potential and compensation remains a promising area for future research.

In cases involving centralized BESS, the development of Energy Management Systems (EMS) may necessitate rule-based techniques or optimization methods. For instance, E. Fernandez et al. [43] propose an EMS based on two optimization approaches, one maximizing combined revenue for sellers and buyers, and the other utilizing a game theoretical model to optimize consumer usage and the storage facility's revenue. Another noteworthy rule-based approach is presented in [18], which considers a scenario with centralized Photovoltaic (PV) systems and centralized BESS, expanding upon the discussion initiated by [43] by introducing a Power-to-Gas (P2G) structure with centralized BESS.

From an economic perspective, a situation analogous to the one explored in our study is presented in [44]. The study examines a residential REC with a set number of prosumers and a variable number of consumers, analyzing two management strategies: Power-to-Gas (P2G) and Power-to-People (P2P). The former optimizes individual users with their BESS, using surplus energy generated by the PV system. In contrast, P2P manages the state of charge of BESS to meet the community's energy consumption needs, thereby optimizing the community's overall benefit. Additionally, the paper investigates a specific scenario, P2P-C, where there is a single centralized BESS managed by a central Energy Management System. All these strategies are evaluated in terms of energy and economic performance, considering factors such as residential rooftop PV system costs, lithium battery storage costs, pre-COVID electricity prices, and the Italian incentive framework.

2.3 ***Paper novelty and aims.***

Within the context of the extensive body of scientific literature encompassing the subject matter at hand, it is crucial to underscore the distinctive contribution offered by this study. Our work is principally characterized by the comprehensiveness and breadth of the analyses conducted.

The comprehensiveness of our analyses stems from our approach, which combines technical and economic aspects, supported using energy balance models that result from daily scheduling optimization and also take into account battery aging. To the best of our knowledge, there are currently no papers in the literature that combine economic considerations with such sophisticated simulations.

Moreover, our analyses are broad, traversing a wide spectrum of potential market scenarios to investigate the key parameters governing the cost-effectiveness of battery investments. Notably, literature lacks a study that conducts such an extensive sensitivity analysis for a case study like ours, which entails the integration of a community battery within an energy community.

This dearth can likely be attributed to the nascent nature of the community concept in the energy sector.

In addition, our work stands out for its specific focus on a new avenue of revenue generation for community batteries, namely the incentive for collective self-consumption (CSC). The task of optimizing battery scheduling to maximize this incentive while engaging in energy arbitrage (EA) has not been fully explored before. In particular, the imperative to limit EA and its implications on grid exchanges and economics had remained uncharted territory. This necessitated the development of a new optimization model for scheduling that considers both cash flows, associated constraints, and a parameter that accounts for battery aging.

In this context, our paper also introduces a novel economic analysis approach, including the application of a transformation of Net Present Value (VAN) that facilitates the comparison of investments with varying battery lifetimes.

With this backdrop, the primary objective of this paper is to investigate whether a community battery can indeed be cost-effective, under which scenarios, and with which control strategies. Our focus extends beyond mere financial investment considerations, delving into the effects on energy balances as well.

The confluence of economic, technical, and analytical insights in the study underscores its novelty and importance, making it useful in increasing understanding of how batteries and energy communities may integrate into upcoming energy scenarios.

3. Materials and methods

This chapter commences by introducing the case study selected for simulations. It elucidates the concept of a Renewable Energy Community (REC) as defined within the framework of Italian regulations, outlining how a Battery Energy Storage System (BESS) can actively participate in both Collective Self-Consumption (CSC) and Energy Arbitrage (EA).

Following the case study introduction, the BESS model is expounded upon. A Mixed-Integer Linear Programming (MILP) approach is employed to compute BESS scheduling, encompassing the pertinent parameters and techniques required to account for battery aging effects.

Following that, the economic evaluation formulations are presented, forming the basis for assessing the financial feasibility of the proposed system. Lastly, the simulated scenarios are introduced, followed by a comparative analysis of these scenarios in the results chapter.

3.1 Case study

This study evaluates the integration of a stand-alone BESS within a REC (refer to Figure 1). The concept of RECs is rooted in a European directive [5] and is currently undergoing development across all member states. However, the regulatory framework employed in this research pertains specifically to the Italian context [45], [46]. The introduction of the main concepts follows.

A REC constitutes a legal entity formed by users within the same medium-voltage network. These users collectively utilize electricity generated from one or more renewable energy systems. Participation in a REC is open and voluntary, extended to individuals, local or public authorities, and small to medium-sized enterprises.

All REC configurations involve interaction with the electricity grid; developing private grids for peer-to-peer energy transactions is prohibited. Excess energy generated, not self-consumed at the utility level, is fed into the grid. A portion of this energy qualifies as Collective-Self-Consumption (CSC), attracting incentives of 110 €/MWh, which can be later redistributed among all members. CSC corresponds to the hourly self-consumed energy across the entire REC. It's defined as the minimum, on an hourly basis, between the energy fed into the grid by production systems and the energy drawn from the grid by REC end customers. Thanks to the presence of the incentive, which is guaranteed for 20 years, many kinds of RECs are flourishing.

Within this study, a REC (Figure 1) fueled by a cumulative 100 kWp from photovoltaic sources is exanimated, exclusively comprising residential customers. Three different scenarios are simulated as the number of customers changes from 80, to 135 and 205 (see paragraph 3.4 for details of this selection). The photovoltaic power remains constant to 100 kWp. A sensitivity analysis is performed to assess the battery size between 10 and 300 kWh.

In this context, the integration of a stand-alone community BESS is allowed to improve CSC and, consequently, the associated incentives. In detail, according to Italian regulations, the electricity recovered from BESS for subsequent feed-in to the grid contributes to the sum of the withdrawals used to calculate the hourly CSC.

Beyond its role in enhancing CSC, the battery also enables Energy Arbitrage (EA). This involves participating in the day-ahead energy market [47], purchasing energy during periods of low prices and subsequently selling it during peak-price periods. To evaluate the effect EA has on the grid balances and on the battery's cash flow, two scenarios are simulated: the first in which the battery is free to perform EA at any time of the day and the second in which EA is limited. That is, there is a gain due to the difference between the purchase and sale price of energy, but the battery can draw and feed energy only to generate CSC, i.e. when it is functional to the REC.

In summary, the examined case study assesses the purchase of a battery to be integrated within a residential REC. This investment can be recuperated through the earnings generated from the heightened incentives linked to CSC and from EA, which may or may not be limited.

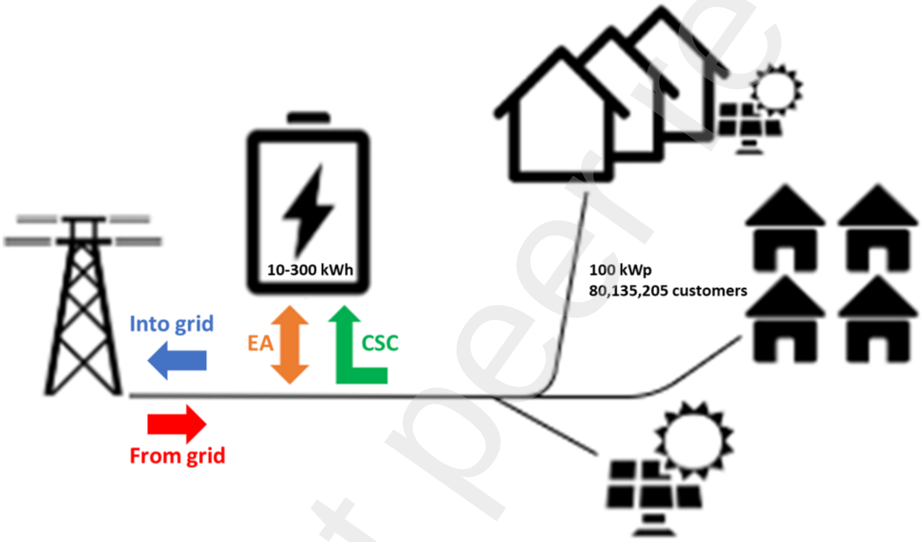

Figure 1 Case study definition

3.2 ***BESS model***

The simulations performed in this study have an hourly time step and a time horizon of 20 years. A Mixed-Integer Linear Programming (MILP) model was implemented to solve a 24-hour scheduling every day. Thus, each simulation is a combination of 365 per 20 optimizations.

It is assumed that each day the next day's energy price is known and also the surplus energy of the Renewable Energy Community (REC), the latter calculated assuming production from PV and consumptions. This study does not consider how forecasting errors may affect BESS scheduling.

A thorough description of the 24-hour scheduling model follows: objective function (equation 1) and constraints (equations 2,3,4 and 5).

$$f_{obj}(P) = \sum_{h=1}^{24} EA_h + CSC_h - AP_h \quad [€] \qquad 1$$

$$EA_h = P_h \cdot EP_h \qquad 1.1$$

$$CSC_h = \min\,[S_h, \max\,(0, P_h)] \cdot \text{inc} \qquad 1.2$$

$$AP_h = \frac{|B_h| \cdot AC}{2} \qquad 1.3$$

The objective function F_{obj} is an economic one. It is the sum on 24 hours of the revenue obtained from Energy Arbitrage (EA) and Collective-Self-Consumption (CSC) minus an Activation Penalty (AP), which is linked with BESS aging and replacement cost. Aim of the optimization problem is to maximize the objective function.

Power (P) is the variable to be optimized: a vector of length 24 representing the scheduling of the battery, that is, the battery's average power at each hour. P_h is negative, if the battery feeds energy into the grid, or positive, if the battery draws energy.

EP_h represents the hourly Price of Energy. The price is always negative, so if energy is withdrawn the product $P_h \cdot EP_h$ is a cost, while when it is fed it is a gain.

The gain for CSC is the product between the value of the incentive (inc = 110 €/MWh) and the energy drawn from BESS that is counted as CSC. The latter is the minimum between the REC energy Surplus (S_h) and the energy drawn by BESS, i.e., the positive values of P (max(0, Ph)).

The penalty due to activation linked with aging is the product of the amount of energy fed or withdrawn ($|P_h|$) and the Activation Cost (AC) parameter, whose function will be explained at the end of this paragraph. It is appropriate to first clarify what the constraints of the model are and show two examples of scheduling.

The constrains of the model are the following:

- $$SoC_{h+1} = SoC_h + P_h \cdot \eta \qquad 2$$

  Defining the State of Charge (SoC) variable, which is dependent on parameter P and considers an average charging and discharging efficiency (η) of 0.90 [36].

- $$C_{max} \cdot DoD \leq SoC_h \leq C_{max} \qquad 3$$
  $$0 \leq P_h \leq C_{max} \cdot P/C \qquad 4$$

  SoC and P box constrains considering BESS maximum capacity (C_{max}), depth of discharge (DoD) and power/capacity ratio (P/C). C_{max} remains constant for each simulation, but multiple scenarios with varying sizes are simulated (see paragraph 3.4). P/C is fixed to 1 and DoD is fixed to 0.10.

- $$-N_h \leq P_h \leq S_h \qquad 5$$

  Limitation of the EA. This constraint obliges the battery to only be able to charge with the surplus (S) energy of the REC and to only discharge to meet the REC's needs (N). Two scenarios are simulated with and without this constraint.

- There are also additional constraints and dummy variables in the model that serve for the linearization of functions absolute value, minimum and maximum.

Figure 2 illustrates two examples of solutions to the just explained 24 hours optimization problem and shows the difference between scheduling with free and limited Energy Arbitrage (EA).

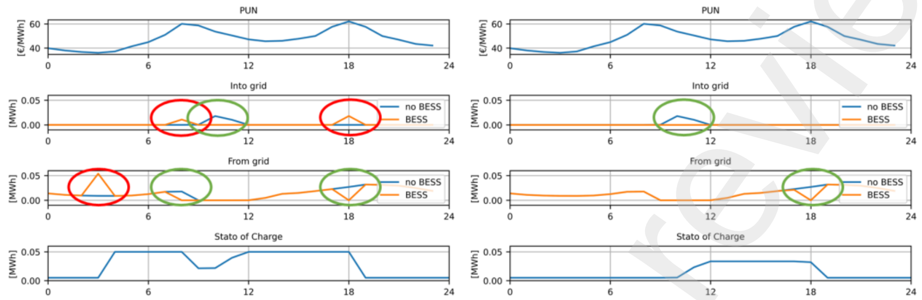

Figure 2 24h scheduling example with free (left) and limited (right) Energy Arbitrage considering Italian energy prices (PUN) and REC energy balances.

In the left scenario, where no limitations (equation 5) are imposed to EA, the optimal scheduling results in charging at 4 a.m. and 10 a.m. and discharging at 8 a.m. and 7 p.m. This result depends not only on the surplus and needs of the energy community (into grid no BESS and from grid no BESS respectively), but also, and above all, on Italian energy price (PUN) trend. Because of this, the energy fed into and withdrawn from the grid considering the battery as part of the community decreases at some times (green circles) but increases at others (red circles).

Instead, forcing the battery to only be able to charge with the surplus energy of the REC and to only discharge to meet the REC's needs, exchanges with the network never increase (no red circles). The resulting scheduling involves charging at 11 a.m. when there is surplus and discharging at 6 p.m. only the energy needed. By doing so, less battery is used, but the total daily gain is obviously decreased because the trend in the PUN is no longer exploited.

Now, the effect of Activation Cost (AC) parameter (see equation 1.3) inside the optimization problem is explained using examples in Figure 3 and its connection to battery ageing is made clear.

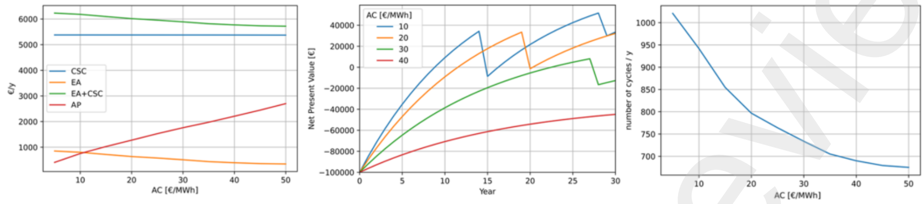

Figure 3 Effects of different Activation Cost (AC) values on cash flows due to Collective-Self-Consumption (CSC) and Energy Arbitrage (EA) (5a), on Net Present Value (NPV) (5b) and on number of cycles per year (5c).

Essentially, the AC value signifies the minimum price delta for which executing a charge and discharge cycle is beneficial. The division by 2 in equation 1.3 precisely aligns the AC value with the buy-and-sell price delta.

A high AC value corresponds to a low number of cycles and vice versa (Figure 5c). However, a low number of cycles results in lower earnings in EA (Figure 5a). The effects of this can be evaluated over a several-year analysis, during which the available battery capacity decreases until it reaches end-of-life and needs to be replaced. With high AC values, the battery ages more rapidly but annual earnings are higher; with low AC values, the battery lasts more years, but the earnings are lower. These effects can be observed in Figure 5a, which displays the Net Present Value (NPV) over the years (NPV calculation will be further elaborated upon in the next paragraph). Each scenario in this study was simulated several times with varying AC values (between 5 and 50) to calculate the best, i.e., the right trade-off between aging and cash flow.

To assess battery aging, a rain flow counting method [48] has been employed to calculate the equivalent number of cycles undergone by the BESS. Assuming that the BESS reaches its end-of-life after 8000 cycles with 80% remaining capacity [49], the available capacity is recalculated month after month in proportion at the number of equivalent cycles reached. Upon reaching 8000 cycles, the BESS is replaced.

3.3 Economic analysis

The economic assessment of BESS investment is based on the Net Present Value (NPV), calculate for 20 years (y) using equation 6.

$$NPV_y = NPV_{y-1} + CF_y/(1+i)^y \quad (6)$$

$$CF_y = EA_y + CSC_y - \mathrm{R}_{cost} \cdot R \quad (6.1)$$

$$NPV_0 = BESS_{size} \cdot BESS_{cost} = R_{cost} \quad (6.2)$$

NPV_0 represents the initial investment for BESS, CF_y denotes the annual cash flow, encompassing the sum gains from EA and CSC. The annual interest rate, denoted as i, is set at 5%. When BESS replacement occurs (R=1 otherwise R=0), Replacement cost (R_c) is incorporated into CF_y. R_c is assumed to be equal to the initial installation cost (NPV_0), which is equal to $BESS_{size}$ per $BESS_{cost}$. To facilitate the comparison of diverse investments with replacements occurring in different years, a transformation of NPV is employed in this study. Observing the left image in Figure 4, it proves challenging to discern which Activation Cost (AC) value results in the optimal NPV. Furthermore, the choice is contingent on the specific year for NPV calculation. However, utilizing the image on the right clarifies the most favorable AC value.

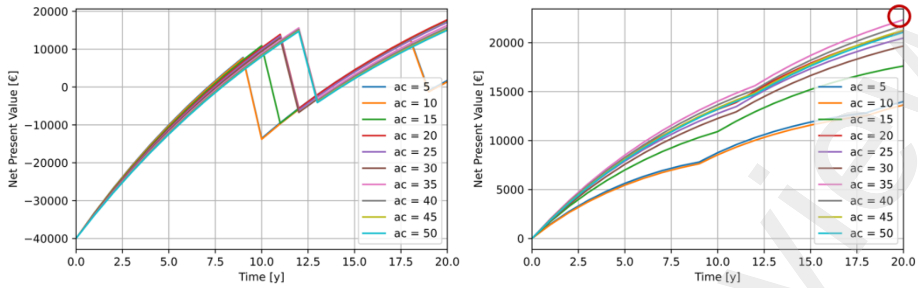

Figure 4 Net Present Value (NPV) (left) and NPV transformation (right) to compare different Activation Cost (AC) values.

The transformation used for NPV can be explained by observing Figure 5.

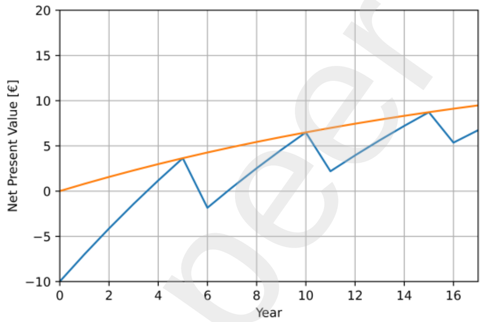

Figure 5 Net Present Value (NPV) (blue line) and NPV transformation (orange line)

The investment presented by the NPV line in blue can be transformed in the equivalent investment of the orange line which does not have discontinuity due to the replacement neither to the initial investment, which is equal to zero. To compute the transformation, it's essential to consider that both the initial investment cost and the replacement costs are not paid upfront. Instead, they are financed through a loan with a duration equivalent to the battery's lifespan and a loan interest rate chosen so that the original NPV and the transformed NPV are equal in the years when replacements occur. So, the transformed Cash Flow (CF*) for the transformed NPV must be recalculated to respect such conditions. The following equations synthesize how the NPV transformation can be calculated, where LF is the Loan Factor to be considered in the transformed cash flow.

$$NPV_y^* = NPV^*{}_{y-1} + CF_y^*/(1+i)^y \quad (7)$$

$$CF_y^* = EA_y + CSC_y - \text{LF} \quad (7.1)$$

$$LF = BESS_{size} \cdot BESS_{cost} \Big/ \sum_{y=0}^{BESS_{lifespam}} 1/(1+i)^y \quad (7.2)$$

$$NPV_0 = I_0 = R_{cost} = 0 \quad (7.3)$$

*3.4 **Simulated scenarios***

This study encompasses the simulation of 36 distinct scenarios aimed at evaluating the impact of four key parameters (Table 1): Renewable Energy Community (REC) number of customers, energy price, battery cost and the possibility of carrying out Energy Arbitrage (EA) in a free manner or limited to REC energy balances. The first parameter pertains to the Surplus (S) and Needs (N) within the REC, which the BESS can harness to derive gains through CSC. The second parameter influences earnings from EA. $BESS_{cost}$ has an impact on initial investment and replacement cost, so on NPV. EA limitation influences cash flow.

Table 1 Simulated scenarios

Parameter	Scenarios
Customer number (CN)	80, 135, 205 residential customers
Energy Price (EP)	Low and high prices (2020 and 2023*)
Battery cost ($BESS_{cost}$)	200, 400, 600 €/kWh
Energy Arbitrage limitation	Free / limited

Table 2 Sensitive analysis

Variable	Range
Battery size ($BESS_{size}$)	20 to 300 kWh
Activation Cost (AC)	5 to 60 €/MWh/2

Within each scenario, a substantial number of simulations are conducted to perform sensitivity analysis on two primary variables (Table 2): $BESS_{size}$ and AC. Therefore, for every combination of scenarios, $BESS_{size}$ values, and AC settings, a simulation spanning 365 days across 20 years is executed. Within this simulation, each day is an outcome of a MILP optimization process.

Energy Price (EP) is an array comprising 8760 values, corresponding to the number of hours in a year, and is repeated over 20 years. Also the vectors representing REC Energy Surplus (S) and REC Energy Need (N), which are calculated depending on customer number (CN), have the same dimension. What evolves annually is the available capacity of the BESS, which diminishes due to aging. The procedure for selecting the two EP scenarios and the three CN scenarios (from which S and N are dependent) is outlined below.

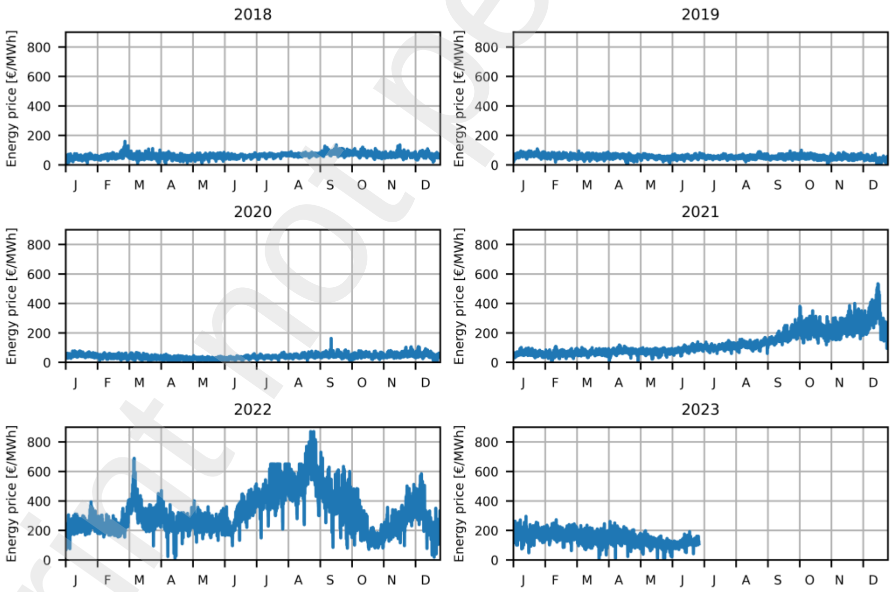

Figure 6 Hourly energy price in the Italian market from 2018 to 2023.

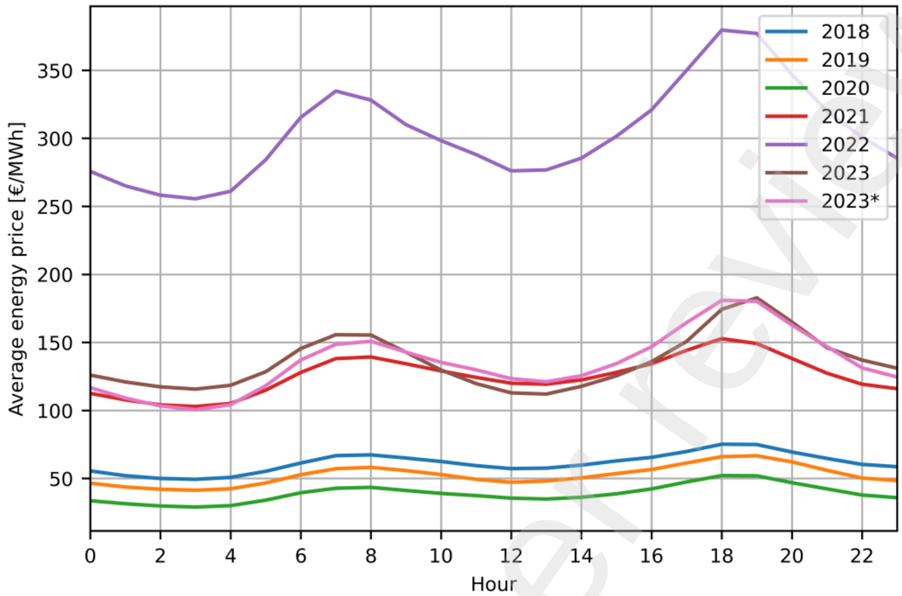

Figure 7 Average hourly energy price in the Italian market from 2018 to 2023

Considering the information about Energy Price (EP) in the Italian market report in Figure 8 and 9 [47], two different scenarios are selected. As a low-price scenario the EP of 2020 is chosen as the worst-case scenario, and as a high-price scenario, 2023* prices are considered. The years 2021 and 2022 were excluded due to their excessive anomalies and randomness. Since data for the entirety of 2023 is not yet available, the decision was made to scale the 2020 dataset in accordance with the average prices of 2023. This process resulted in the creation of the 2023* dataset.

Another reason for this choice is related to the dataset used for photovoltaic production. In fact, for both the 2020 and the 2023* scenarios, the dataset downloaded from PVgis [50] corresponding to the year 2020 was utilized. This approach ensured that the price trends remained consistent with the fluctuations in production. Notably, the production dataset for the year 2023 is not yet available. The input parameters for PVgis included the geographical coordinates of Florence, a tilt angle of 30°, an azimuth angle of 0°, and losses of 14%.

To calculate the Collective-Self-Consumption (CSC) of the REC and consequently its surplus (S) and need (N), in addition to the photovoltaic production series, the aggregated consumption series of all community members is required.

A load series representing a 3kWp typical residential consumers from Tuscany is generated by utilizing average hourly profiles provided by the Italian regulatory authority [51] (Figure 8). These profiles are differentiated based on the month and the type of day. The resulting load series is subsequently scaled by the number of customers within the considered REC, aggregating the total consumption pattern.

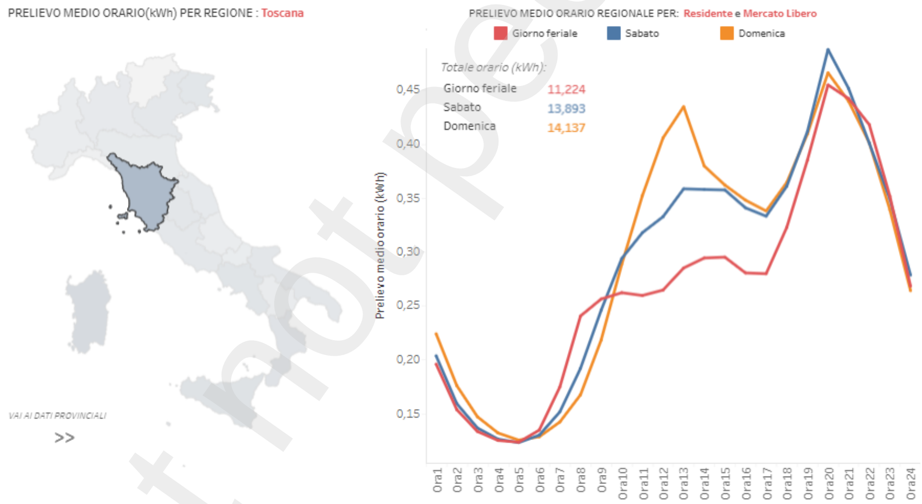

Figure 8 Average load profiles in January for a 3kWp residential customer in Tuscany.

Using the open-source multi-energy simulation software "MESSpy" [52] a sensitivity analysis of varying number of customers inside the REC is performed (Figure 9). As already mentioned, the photovoltaic power is fixed to 100 kWp. Thanks to this analysis three scenarios have been selected (

Table 3) to be simulated with the BESS: the three with a collective-self-consumption index of the community without battery of 40%, 60% and 80%.

Figure 9 not only identifies three potential scenarios but also clarifies why it makes sense to evaluate a battery within future RECs:

It is observable that as the number of customers increases, the collective-self-consumption index (ratio of collective-self-consumption to production) rises; contrary, the collective-self-sufficiency index (ratio of collective-self-consumption to demand) diminishes, and notably, the incentive per customers decreases too. In practical terms, with a greater number of users, the metaphorical "pie" must be divided into more portions, consequently leading to smaller individual slices.

This observation explains the impracticality of considering RECs with exceedingly high collective-self-consumption levels. It consequently suggests that in forthcoming RECs, surplus energy will invariably persist. The question arises: who will harness this surplus if not through standalone community batteries? Therefore, the graph aims to convey that RECs will consistently have surplus energy, justifying the evaluation of introducing a BESS to harness and capitalize on this surplus.

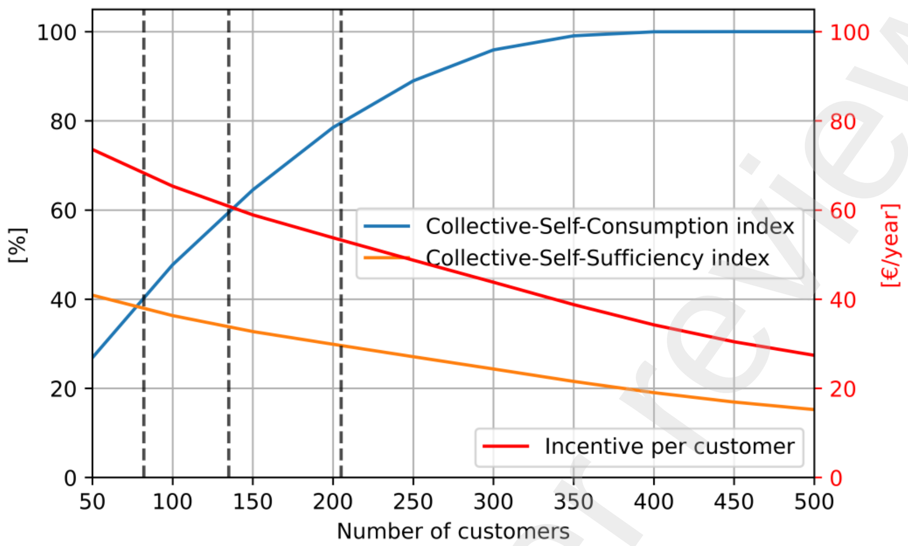

Figure 9 100 kWp REC key parameters varying customer number.

Table 3 Three scenarios selected for customer number.

Customer number [CN]	CSC [%]	CSS [%]	Surplus [MWh/year]	Need [MWh/year]
80	40	38	82	89
135	60	34	55	160
205	80	30	27	258

4. Results

The results are divided into three paragraphs. The first explains the influence the battery can have on community energy balances. The second illustrates the role of the activation cost (AC) parameter in relation to battery aging and Net Present Value. The third performs the economical optimal battery sizing in each scenario and evaluates the investments.

4.1 Energy balances

Following the introduction of a battery within an energy community, its independence from the grid increases. The collective self-consumption (CSC) index is defined as the ratio of collective self-consumption to the total electricity production from photovoltaic sources, while the collective self-sufficiency (CSS) index is the ratio of collective self-consumption to the total energy demand of the customers.

Figure 10 shows that these index values increase with the size of the installed battery. However, the achievable levels differ when free or limited Energy Arbitrage (EA) is allowed. In the case where the battery can be freely used for EA (left figure), the gain in terms of SCS is limited to a few percentage points and reaches an asymptote even with 50 kWh batteries. This is due to the current Italian regulation on batteries in REC which provides incentives only for withdrawal and not for subsequent injection. As a result, all the energy is fed into the grid during peak selling price periods, rather than gradually during the evening and night hours to meet the community's needs. Conversely, if the battery is required to follow the surplus and needs of the energy community (right figure), significant improvements in CSS are achieved with the introduction of increasingly larger batteries. The growth of CSC is slightly affected by the constraint, as the battery no longer has permission to discharge freely and then recharge with all available surplus. Nevertheless, the results remain significant.

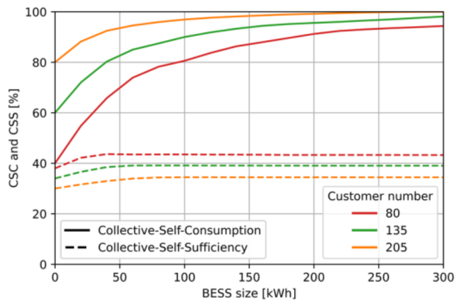

Figure 10 Free (left) vs limited (right) Energy Arbitrage: collective-self-consumption index and collective-self-sufficiency index for varying battery size and customer number.

Figure 11 and Figure 12 highlight one of the main findings and issues revealed by this study. Specifically, if there are no limits on the ability to perform EA, the energy community's dependence on the grid, considering the battery as part of the community itself, increases rather than decreases. In fact, when considering the total energy fed into the grid over 20 years and the energy withdrawn, it is observed that both quantities increase due to the presence of a battery. This is because the battery fed and withdraws energy independently of the REC's balances to profit from EA. Even though the energy fed and withdrawn from the original REC decreases, the amounts exchanged between the grid and the battery increase, resulting in an overall increase in total energy exchanged. To prevent this, as shown in the right-hand graphs, the approach is to limit the battery's use to charge only from the REC's surplus and discharge only to meet its needs. By doing so, the total energy fed and withdrawn decreases, effectively reducing REC energy dependence.

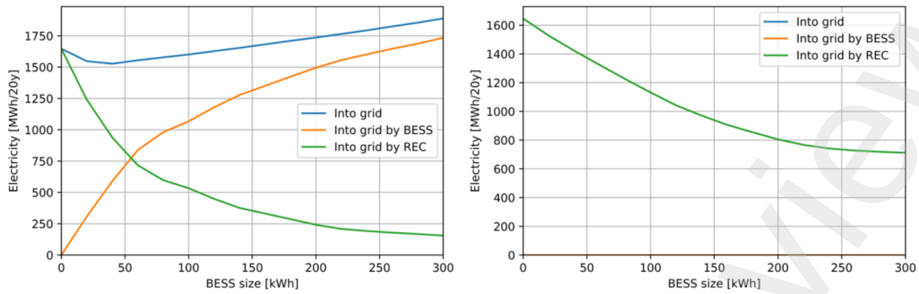

Figure 11 Free (left) vs limited (right) Energy Arbitrage: energy fed into the grid by varying BESSsize.

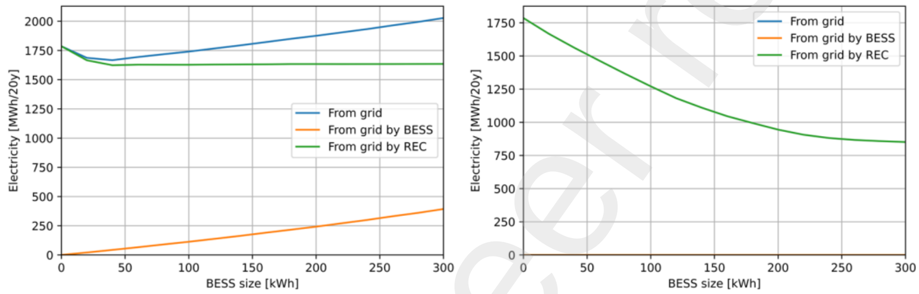

Figure 12 Free (left) vs limited (right) Energy Arbitrage: energy withdrawn from the grid by varying BESSsize.

4.2 *Optimal AC setting*

Adjusting the Activation Cost (AC) parameter at various levels leads to the computation of diverse optimal Battery Energy Storage System (BESS) schedules daily. Over a 20-year analysis period, these variations in AC values have a significant impact on cash flows and BESS lifetimes, consequently influencing the Net Present Value (NPV), which is highly dependent on AC. Simulations have been conducted for each scenario and BESS size with AC values ranging from 5 to 60.

Figure 13 summarizes the optimal AC values, those that maximize the NPV transformation (NPV*, see paragraph 3.3) over 20 years. These simulations pertain to the case where Energy Arbitrage (EA) is unrestricted. The results are presented with confidence intervals within which the NPV* values differ by less than 1% of the NPV* value.

The most influential parameter is the battery cost, which is also equal to the replacement cost at the end of its life. For low costs, it is advisable to set AC values between 20 and 30 to increase EA profits even at the expense of rapidly consuming the battery with many cycles. For higher costs, the optimal values shift towards 50, implying fewer cycles but highly profitable ones and batteries that last for many years. The graph shows that the battery size does not influence the choice of AC, except for allowing the reduction of AC values for high battery costs and in scenarios with low energy prices. The effect of energy prices is minimal and only narrows the confidence interval in the case of high prices. The customer number of the REC has no significant effects.

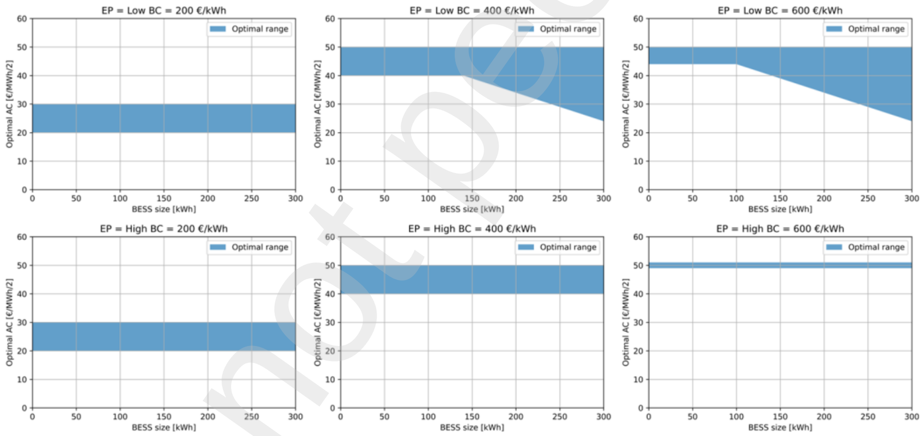

Figure 13 Free Energy Arbitrage: optimal Activation Cost (AC) values for varying Energy Price (EP), battery cost (BC) and battery size ($BESS_{size}$).

In the case of limited EA as shown in Figure 14, the parameter AC loses its significance. In fact, there is no difference between the different AC values, and the lines on the graphs collapse. The only exception is in the case of low energy prices, a high surplus energy community (customer number=80), and large batteries (high replacement cost). In this scenario, using high AC values increases the weight of the penalty in the objective function to the extent that it deters some cycles even if they would create CSC. This is not advantageous, as the best AC value is the lowest one.

Only the results for $BESS_{cost}$ = 200 are shown because the situation is analogous with other costs.

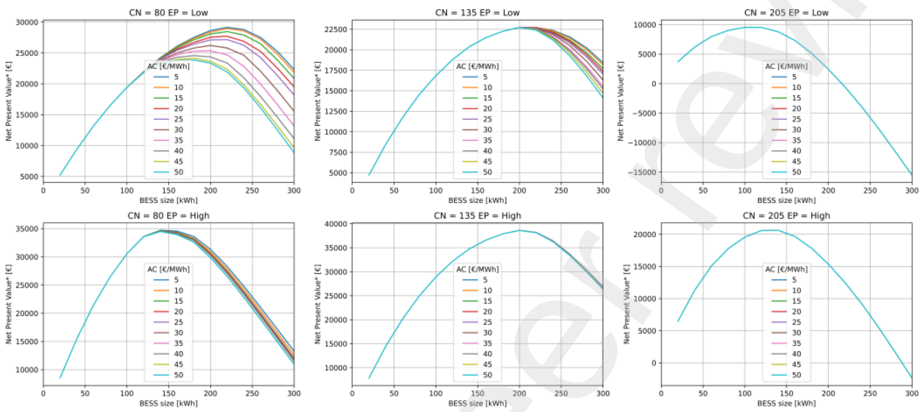

Figure 14 Limited Energy Arbitrage, $BESS_{cost}$ = 200 €/kWh: NPV for varying Activation Cost (AC), Customer Number (CN), Energy Price (EP) and $BESS_{size}$*

4.3 *Optimal BESS size and economic feasibility*

The results presented in this last paragraph are always and exclusively related to configurations with optimal Activation Cost values.

Figure 15 and Figure 16 elucidate the proportion in which the two primary cash flows, Energy Arbitrage (EA) and Collective-Self-Consumption (CSC), contribute to the investment's returns. The analysis demonstrates that in scenarios with free EA and characterized by low energy prices, the gain attributed to CSC significantly outweighs that achieved through EA, reaching approximately five times the magnitude. Consequently, investments in such scenarios predominantly hinge on REC incentives and are consequently reliant on the evolving of customer numbers over time. However, it is important to note that the incentives of 110 €/MWh for CSC are guaranteed by the Italian government for a span of 20 years, unlike the energy price, which varies unpredictably over time. With high energy prices, the profit from EA can indeed surpass that from CSC.

In the case of limited EA, the total cash flow decreases by several thousand euros per year, primarily due to the reduced EA profit but also due to the lower level of CSC. In these scenarios, EA still plays a crucial role, especially with high energy prices.

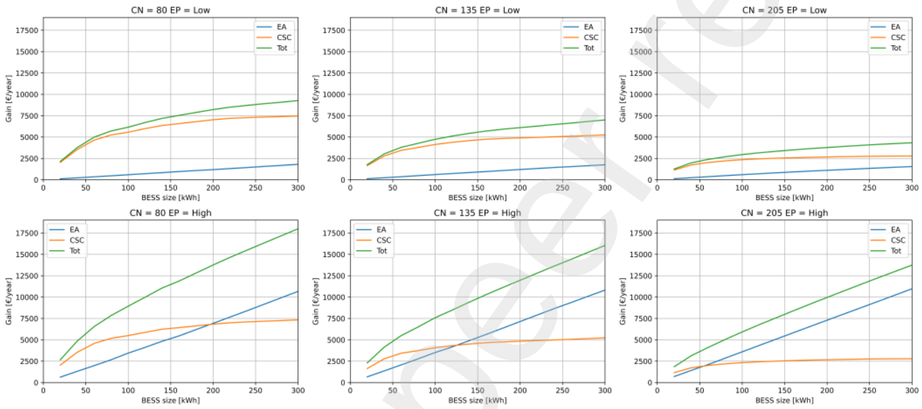

Figure 15 Free Energy Arbitrage: cash flow for varying Customer Number (CN), Energy Price (EP)and $BESS_{size}$.

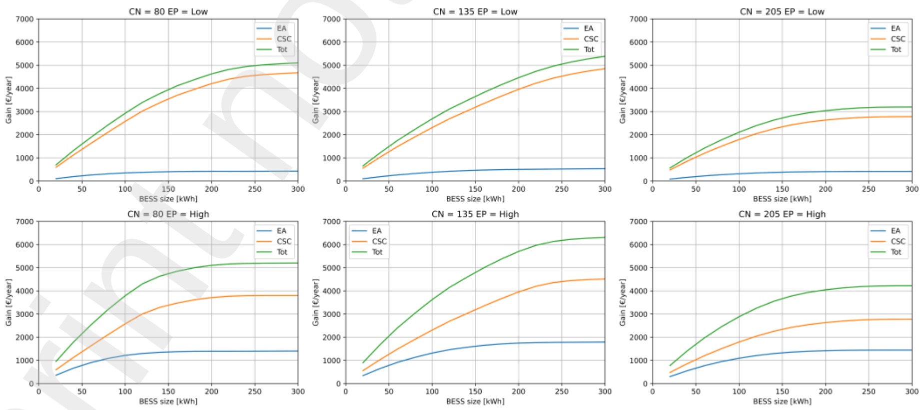

Figure 16 Limited Energy Arbitrage: cash flow for varying Customer Number (CN), Energy Price (EP) and BESSsize.

The graphs presented in Figure 17 and Figure 18 illustrate the transformed Neet Present Vale (NPV*) as it varies with BESS capacity, offering insights into the optimal BESS size for each scenario (Table 1).

If EA is free, it becomes evident that a cost of 600 €/kWh renders BESS installation economically unviable, as the optimal BESS size converges towards zero. In contrast, a cost of 400 €/kWh emerges as an attractive proposition for BESS integration within the REC, particularly evident in scenarios with high energy prices, where substantial BESS capacities are recommended, contingent on customer number: REC setups with considerable surplus (and relatively low CSC) endorse BESS capacities exceeding 300 kWh. Conversely, scenarios characterized by low energy prices diminish the investment's allure, signifying a preference for smaller BESS units, approximately 50 kWh in size. Finally, a cost of 200 €/kWh appears to strike the right balance, rendering BESS integration cost-efficient. This is evident across both high and low-price scenarios. In the latter, the optimal BESS size is influenced by customer number, with RECs featuring substantial surplus favoring larger battery capacities.

By comparing the graphs in Figure 17 with those in Figure 18, it becomes evident that limiting EA render investments in batteries less appealing. Doing so, the significance of a 400 €/kWh cost for battery acquisition diminishes significantly. Only batteries of sizes less than 100 kWh could be considered. However, a 200 €/kWh cost remains an attractive proposition, guaranteeing shorter payback periods contingent on the energy price scenario.

An intriguing aspect discernible from Figure 18, particularly pronounced in the 200 €/kWh scenario with high energy prices, is that not always a REC characterized by low CSC and high surplus constitutes the best match for battery integration, as under the current regulation. Indeed, coupling the BESS with a REC composed by 135 customers proves more economically viable than pairing it with a REC of 80 customers. This emerges because limiting EA, the battery gains do not only depend on the REC's surplus but also on its needs. As depicted in
Table 3 energy needs and surplus, i.e., CSC and CSS of the REC without BESS, exhibit opposite trends.

This observation is of interest as it suggests creating and aligning batteries with REC that tend toward an equilibrium point concerning CSC and CSS, meaning an optimal customers count. At present, REC with low levels of CSC, i.e., fewer users, are preferred.

In view of an increasingly integrated development of REC and BESS in the future energy landscape, this aspect should be taken into serious consideration.

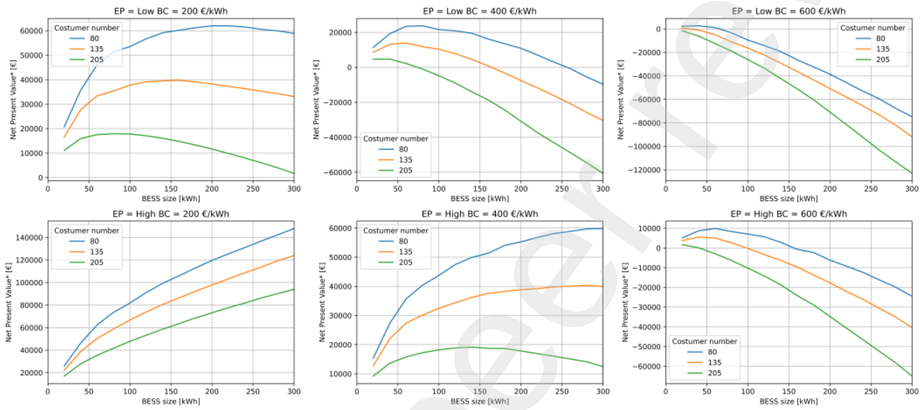

Figure 17 Free Energy Arbitrage: NPV varying Energy Price (EP), $BESS_{cost}$ (BC), customer number and $BESS_{size}$.*

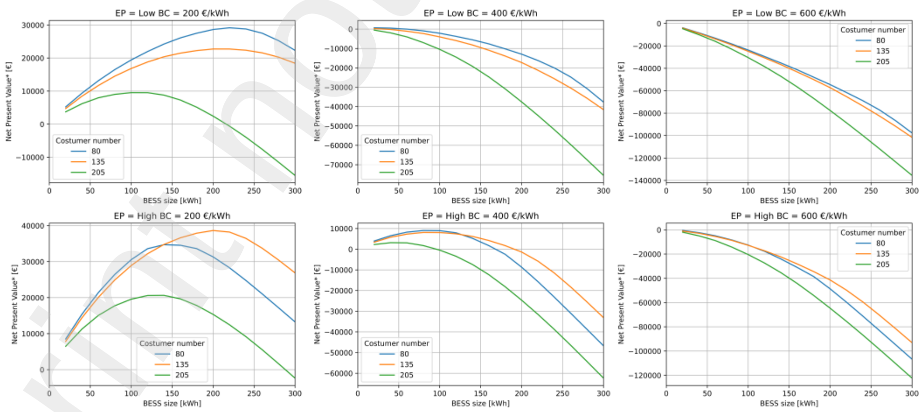

Figure 18 Limited Energy Arbitrage: NPV varying Energy Price (EP), $BESS_{cost}$ (BC), customer number and $BESS_{size}$.*

Figure 19 and Figure 20 further elucidate the concepts by depicting the NPV's progression, focusing on the original NPV rather than the transformed version. This illustration considers the best BESS size solution for each scenario. These curves provide a comprehensive perspective on investments, encompassing both NPV and payback time.

If EA is free, at a cost of 200 €/kWh, investments emerge as particularly compelling, ensuring a 5-year payback period in low-price scenarios and even shorter periods in high-price scenarios. Meanwhile, a cost of 400 €/kWh also allows for investments with payback times of less than 10 years, which is still favorable. However, in this case, the influences of energy prices and customer number exert more significant impact. Finally, as previously noted, 600 €/kWh is evidently an excessively high cost.

If EA is limited, it becomes evident that investments become less attractive. The payback periods extend by approximately 5 years, and the optimal battery sizes decrease, as the NPV does. Under this assumption, it is crucial for the battery cost to be around 200 €/kWh and not more.

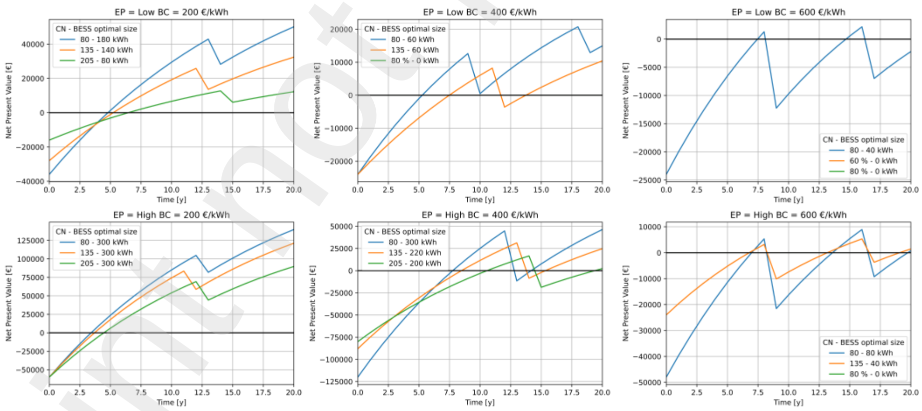

Figure 19 Free Energy Arbitrage: optimal investments assessment for varying Energy Price (EP), $BESS_{cost}$ (BC) and Customer Number (CN).

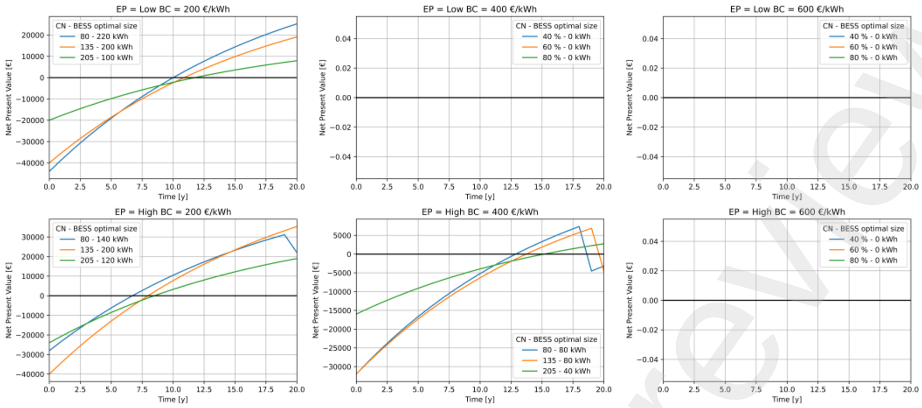

Figure 20 Limited Energy Arbitrage: optimal investments assessment for varying Energy Price (EP), $BESS_{cost}$ (BC) and Customer Number (CN).

5. Conclusions

In the context of a residential energy community powered by 100 kWp of photovoltaic capacity, a techno-economic analysis was conducted to assess the energy and economic impact of introducing a community battery. Various scenarios were evaluated, considering factors like the number of customers in the community, energy market prices, and battery costs.

Two primary sources of revenue were considered: collective self-consumption incentives, which the battery could access by capturing surplus community energy, and energy arbitrage, which involves purchasing energy when prices are low or selling it at higher rates. Energy arbitrage was evaluated under two conditions: unrestricted, allowing the battery to operate freely, and limited, permitting energy withdrawal only from the community surplus and injection only when the community needs energy.

A 20-year simulation was executed for each scenario, incorporating battery aging based on charge-discharge cycles and depth. Daily scheduling was determined using a Mixed Integer Linear Programming model, aimed at maximizing daily cash flow. A modified Net Present Value transformation was proposed to compare scenarios with varying replacement times effectively.

Analyzing energy balances in the initial section of the conclusions reveals that employing a common battery is crucial for boosting collective self-consumption and collective self-sufficiency. However, in scenarios without energy arbitrage restrictions, both total energy injected into the grid and total energy drawn from the grid increase compared to scenarios without a battery, indicating the need for limitations.

The section on activation costs demonstrates that this parameter is relevant when energy arbitrage is unrestricted, while it loses significance in the limited energy arbitrage scenario. In the latter case, the focus is on the high incentive for collective self-consumption, which is so significant that it makes more sense to use the battery with any activation cost.

Economic results highlight the optimal battery size for each scenario and underscore situations where the battery is cost-effective: limiting energy arbitrage should reduce costs to around 200 €/kWh, while unrestricted energy arbitrage allows a cost of 400 €/kWh to be a viable investment. In both scenarios, a higher energy price suggests installing a larger battery and shortens the payback period. Nevertheless, the primary gain is not derived from energy arbitrage and is, therefore, independent of energy prices; instead, it relies on incentives for collective self-consumption in energy communities, illustrating the current market's dependence on incentives.

Moreover, it is interesting to highlight that the most suitable energy community for the introduction of a battery is neither the one with the fewest customers, and thus minimal surplus, nor the one with the largest number of users and high energy demands. Instead, it is a community with an intermediate number of users that exhibits moderate surplus and demand levels. This holds true when energy arbitrage is limited. However, if energy arbitrage is unrestricted, the optimal choice is to install a battery in a community with the highest possible surplus.

A comparison between energy and economic optimal reveals their mismatch, suggesting that battery prices must further decrease, or the market should receive greater incentives for alignment. In terms of achievable energy independence, there are no doubts about the benefits.

Future studies could explore the potential of batteries in energy communities, not only for collective-self-consumption and energy arbitrage but also for providing local dispatch services, offering an additional revenue source critical for investment recovery. Furthermore, scheduling algorithms should consider forecast errors in production, consumption, and energy price time series data, which were utilized in the previous day's scheduling calculations.

CRediT authorship contribution statement

Mattia Pasqui: Term, Conceptualization, Methodology, Software, Validation, Formal analysis, Investigation, Data Curation, Writing – Original Draft, Visualization

Lorenzo Becchi: Term, Conceptualization, Methodology, Validation, Formal Analysis, Writing - Review & Editing

Marco Bindi: Term, Conceptualization, Methodology, Validation, Formal Analysis, Writing - Review & Editing

Matteo Intravaglia: Term, Conceptualization, Methodology, Validation, Formal Analysis, Writing - Review & Editing

Francesco Grasso: Resources, Writing - Review & Editing, Supervision, Funding acquisition.

Gianluigi Fioriti: Writing - Review & Editing, Supervision.

Carlo Carcasci: Resources, Writing - Review & Editing, Supervision, Project administration, Funding acquisition.

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