FACULDADE DE ENGENHARIA DA UNIVERSIDADE DO PORTO

# Sizing of Renewable Energy Communities for Participation in Energy and Reserve Markets

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# Resumo

A integração crescente de geração renovável distribuída e de recursos flexíveis reforça o papel das comunidades de energia renovável, mas torna também mais complexas as suas decisões de planeamento. O valor da capacidade fotovoltaica, do armazenamento de energia em baterias e da potência contratada depende da operação que estas decisões permitem e da interação da comunidade com os mercados. Neste contexto, a participação em reserva pode alterar o sinal económico associado ao investimento e não deve ser avaliada apenas como uma receita operacional aplicada a capacidades previamente instaladas.

Esta dissertação desenvolve e aplica uma extensão da ferramenta *Sizing Tool for Energy Communities*, baseada numa formulação determinística de programação linear inteira mista. O modelo determina conjuntamente a capacidade fotovoltaica, a capacidade de armazenamento e a potência contratada através da operação otimizada da comunidade ao longo de um horizonte anual. A extensão introduz a reserva de restabelecimento da frequência com ativação manual e relaciona de forma endógena a potência de reserva disponível com o armazenamento dimensionado. A ativação é limitada por envelopes históricos sujeitos a um fator de robustez, enquanto um parâmetro de escalamento define a potência de reserva associada à capacidade instalada.

A metodologia é aplicada a uma comunidade residencial de cinco membros, utilizando dados reais portugueses de consumo, tarifas, mercado de energia e balanço relativos a 2022, através de nove cenários. Os resultados mostram que a otimização conjunta reduz o custo anual líquido da comunidade de 6 958,5 para 1 074,5 €/ano, mesmo sem participação em reserva. A introdução deste mercado aumenta a capacidade de armazenamento de 48,73 kWh para o limite agregado adotado de 125 kWh e converte o custo anual de 1 074,5 € numa receita líquida de 12 682,4 €/ano. Os cenários de isolamento confirmam que o armazenamento estabelece a ligação direta entre capacidade instalada e valor da reserva, enquanto a capacidade fotovoltaica responde sobretudo aos sinais do mercado de energia. A análise operacional mostra ainda que a energia anual processada pelo armazenamento quase duplica e que a interação bidirecional com a rede aumenta quando se consideram mercados de reserva no planeamento.

A comparação entre condições de verão e inverno reforça a importância do horizonte anual. A consideração das 8760 horas incorpora a variabilidade sazonal numa única decisão de longo prazo e reduz o risco de subdimensionamento ou sobredimensionamento associado a um período isolado. Embora os resultados permaneçam condicionados pela formulação determinística, pelos limites de planeamento e pelas condições de mercado de 2022, a principal contribuição para o estado da arte reside em considerar conjuntamente os mercados de energia e de reserva como fatores endógenos do planeamento. A ferramenta desenvolvida constitui, assim, um quadro transparente de apoio à decisão, evidenciando como o acesso aos mercados, os pressupostos técnicos e a remuneração influenciam o dimensionamento, o desempenho económico e a operação da comunidade.

**Palavras-chave:** comunidades de energia renovável • dimensionamento conjunto de sistemas fotovoltaicos, armazenamento em baterias e potência contratada • participação nos mercados de energia e reserva • reserva de restabelecimento da frequência com ativação manual

# Abstract

The growing integration of distributed renewable generation and flexible resources strengthens the role of renewable energy communities, but also increases the complexity of their planning decisions. The value of photovoltaic capacity, battery energy storage and contracted power depends on the operation enabled by these decisions and on the interaction of the community with electricity markets. In this context, reserve participation may change the economic signal associated with investment and should not be assessed solely as an operational revenue stream applied to previously installed capacities.

This dissertation develops and applies an extension of the *Sizing Tool for Energy Communities*, based on a deterministic mixed-integer linear programming formulation. The model jointly determines photovoltaic capacity, storage capacity and contracted power through the optimised operation of the community over an annual horizon. The extension introduces manual frequency restoration reserve and endogenously links the available reserve power to the dimensioned storage capacity. Activation is bounded by historical envelopes subject to a robustness factor, while a scaling parameter defines the reserve power associated with the installed capacity.

The methodology is applied to a five-member residential community using real Portuguese demand, tariff, energy-market and balancing data for 2022 across nine scenarios. The results show that joint optimisation reduces the net annual community cost from 6 958.5 to 1 074.5 €/year, even without reserve participation. Introducing this market increases storage capacity from 48.73 kWh to the adopted aggregate limit of 125 kWh and converts the annual cost of 1 074.5 € into a net annual revenue of 12 682.4 €/year. The resource-isolation scenarios confirm that storage establishes the direct link between installed capacity and reserve value, while photovoltaic capacity responds mainly to energy-market signals. The operational analysis further shows that the annual energy processed through storage nearly doubles and that bidirectional grid interaction increases when reserve markets are considered in the planning process.

The comparison between summer and winter conditions reinforces the importance of the annual horizon. Considering all 8760 hours incorporates seasonal variability into a single long-term decision and reduces the risk of under-sizing or over-sizing associated with an isolated period. Although the results remain conditional on the deterministic formulation, the adopted planning limits and the 2022 market conditions, the main contribution to the state of the art lies in jointly considering energy and reserve markets as endogenous drivers of planning. The developed tool therefore provides a transparent decision-support framework, showing how market access, technical assumptions and remuneration influence sizing decisions, economic performance and community operation.

**Keywords:** renewable energy communities • joint photovoltaic, battery storage and contracted-power sizing • energy and reserve market participation • manual frequency restoration reserve

# UN Sustainable Development Goals

The United Nations Sustainable Development Goals (SDGs) provide a global framework for achieving a better and more sustainable future for all. The framework comprises 17 goals[1] that address the world's most pressing challenges, including poverty, inequality, climate change, environmental degradation, peace and justice. This dissertation contributes primarily to SDG 7 and SDG 9 through the development of a planning framework for renewable generation, energy storage and distributed flexibility. It is also indirectly aligned with SDG 13, although avoided greenhouse-gas emissions are not quantified.

The specific Sustainable Development Goals addressed have the following names:

**SDG 7** Affordable and Clean Energy

**SDG 9** Industry, Innovation and Infrastructure

**SDG 13** Climate Action

| SDG | Target | Contribution | Performance Indicators and Metrics |
|---|---|---|---|
| 7 | 7.2 | Supports the joint sizing of local photovoltaic generation, battery storage and contracted power in renewable energy communities, enabling renewable resources to be assessed together with their operation and market interaction. | Selected photovoltaic capacity (kW); annual photovoltaic generation (kWh/year); annual grid imports and exports (kWh/year); net annual community cost (€/year). |
| 9 | 9.4 | Develops a mixed-integer linear programming framework that links distributed energy infrastructure with energy and manual frequency restoration reserve markets. | Selected battery storage capacity (kWh); reserve bands (kW); annual activated energy (MWh/year); battery throughput (kWh/year); sensitivity across planning scenarios. |
| 13 | 13.2 | Indirectly supports the integration of renewable generation and flexibility considerations into long-term community planning by representing a complete year and seasonal operating conditions. | 8760-hour planning horizon; summer and winter operational comparison; results under alternative market and technical assumptions. Avoided emissions are not quantified. |

The contribution is therefore methodological and planning-oriented. The developed framework supports the assessment of investment and operation in renewable energy communities without claiming a direct measurement of wider social or environmental impacts.

[1] https://sdgs.un.org/goals

# Recognitions

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*"If I have seen further, it is by standing on the shoulders of giants."*

Isaac Newton

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# List of Acronyms

| | |
|---|---|
| **ACER** | European Union Agency for the Cooperation of Energy Regulators |
| **aFRR** | automatic Frequency Restoration Reserve |
| **AS** | Ancillary Services |
| **ATE** | Alliance for Energy Transition |
| **BESS** | Battery Energy Storage System |
| **BRP** | Balance Responsible Party |
| **BTN** | Normal Low Voltage |
| **CEC** | Citizen Energy Community |
| **CEMS** | Community Energy Management System |
| **CIEG** | Costs of General Economic Interest |
| **CSC** | Collective Self-Consumption |
| **DER** | Distributed Energy Resource |
| **DSO** | Distribution System Operator |
| **EBGL** | Electricity Balancing Guideline |
| **EC** | Energy Community |
| **EEM** | International Conference on the European Energy Market |
| **ENTSO-E** | European Network of Transmission System Operators for Electricity |
| **ERSE** | Entidade Reguladora dos Serviços Energéticos |
| **EU** | European Union |
| **EV** | Electric Vehicle |
| **FCR** | Frequency Containment Reserve |
| **IEEE** | Institute of Electrical and Electronics Engineers |
| **INESC TEC** | Institute for Systems and Computer Engineering, Technology and Science |
| **IRENA** | International Renewable Energy Agency |
| **MARI** | Manually Activated Reserves Initiative |
| **mFRR** | manual Frequency Restoration Reserve |
| **MIBEL** | Iberian Electricity Market |
| **MILP** | Mixed Integer Linear Programming |
| **MPC** | Model Predictive Control |
| **MPGGS** | Manual de Procedimentos da Gestão Global do Sistema |

| | |
|---|---|
| **MTU** | Market Time Unit |
| **NEMO** | Nominated Electricity Market Operator |
| **OMIE** | Iberian Electricity Market Operator |
| **OMIP** | Iberian Energy Derivatives Exchange |
| **P2P** | Peer-to-Peer |
| **PICASSO** | Platform for the International Coordination of Automated Frequency Restoration and Stable System Operation |
| **PRR** | Portuguese Recovery and Resilience Plan |
| **PV** | Photovoltaic |
| **REC** | Renewable Energy Community |
| **REN** | Redes Energéticas Nacionais |
| **RR** | Replacement Reserve |
| **SEL** | Smart Energy Lab |
| **SITEC** | Sizing Tool for Energy Communities |
| **SME** | Small and Medium-Sized Enterprise |
| **SoC** | State-of-Charge |
| **SOGL** | System Operation Guideline |
| **TERRE** | Trans European Replacement Reserves Exchange |
| **TSO** | Transmission System Operator |
| **V2G** | Vehicle-to-Grid |
| **VPP** | Virtual Power Plant |
| **VSS** | Virtual Storage System |

# Chapter 1

# Introduction

This chapter presents the motivation, scope and objectives of the dissertation. It begins by framing the role of the Renewable Energy Community (REC) concept in the transformation of the electricity sector, with a focus on distributed renewable generation, storage and flexibility. The main objectives of the work are then defined, followed by the related research project and scientific output associated with the dissertation. Finally, the overall structure and organisation of the remaining chapters are presented.

## 1.1 Context and Motivation

The European electricity system is undergoing a deep transformation, driven by climate targets, energy-security concerns and the need to integrate increasing shares of renewable generation. The European Climate Law establishes climate neutrality as a binding objective for 2050 and sets an intermediate target of reducing net greenhouse gas emissions by at least 55% by 2030, compared with 1990 levels [1]. More recently, the energy crisis reinforced the strategic need to reduce dependence on imported fossil fuels and accelerate domestic renewable deployment [2]. In Portugal, the updated National Energy and Climate Plan for 2030 follows the same direction by strengthening the role of renewable electricity, distributed generation, self-consumption and RECs in the national decarbonisation pathway [3]. These developments place the electricity sector at the centre of the energy transition and create the need for planning methodologies capable of jointly assessing investment, operation and flexibility.

This transformation is often described through three mutually reinforcing drivers, namely decarbonisation, decentralisation and digitalisation, as illustrated in Figure 1.1. Decarbonisation changes the generation mix by replacing fossil-based production with low-carbon resources. Decentralisation shifts part of the generation and flexibility potential towards distribution networks and end-users. Digitalisation enables the monitoring, coordination and optimisation of a much larger number of distributed assets [4]. Together, these drivers move power systems away from a strictly centralised paradigm and towards architectures where consumers, prosumers and local energy systems become active elements of system operation. This change is particularly visible in

the expansion of Photovoltaic (PV) generation, since distributed solar PV is expected to become one of the main contributors to renewable capacity growth in Europe by 2030 [5].

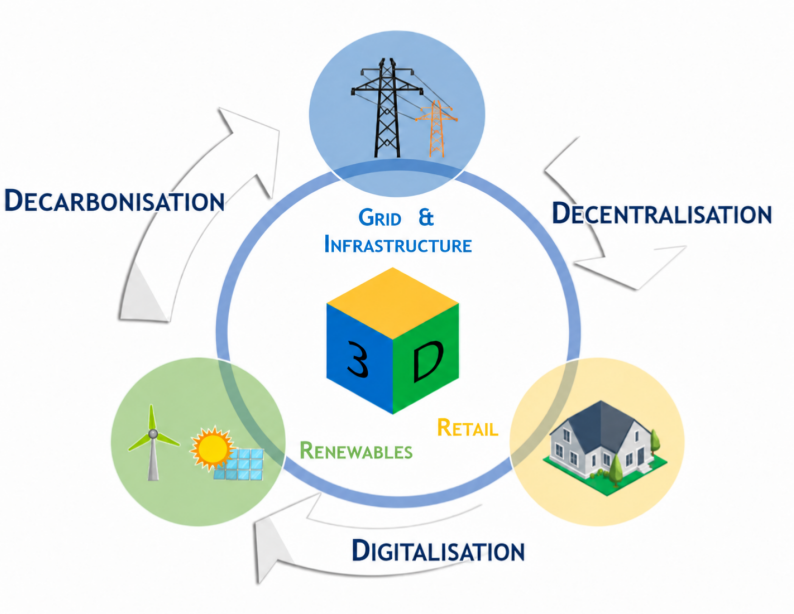



Figure 1.1: The 3 Ds of the electricity transition, decarbonisation, decentralisation and digitalisation. Adapted from [6].

At the local level, this transition is materialised through the Distributed Energy Resource (DER) concept, including PV systems, Battery Energy Storage System (BESS) units, controllable loads and, in some contexts, Electric Vehicle (EV) charging. PV generation allows renewable electricity to be produced closer to consumption points. BESS units make it possible to shift part of that production across time and reduce the mismatch between local generation and demand. Recent technology reports identify PV as a central pillar of the European energy transition [7]. The International Energy Agency also highlights BESS units as key assets for secure energy transitions and for supporting the integration of renewable electricity [8]. From a planning perspective, however, these technologies should not be assessed only by their installed capacity. Their value depends not only on how much energy is produced, but also on when it is generated, when it is consumed, how much can be stored, how much is exchanged with the grid, and how these energy flows interact with prices and tariffs.

RECs provide a natural setting for coordinating these local resources. Rather than treating PV systems, storage units and consumers as isolated elements, a REC allows generation, consumption and storage to be considered within a collective framework. This is relevant because RECs combine technical design choices with social and economic objectives, enabling members to pursue local benefits while contributing to the broader decarbonisation of the energy system [9]. In Portugal, the legal framework for the National Electricity System recognises Collective Self-Consumption (CSC) and RECs as part of the transition towards a more decentralised electricity

sector [10]. The concepts, roles and energy-sharing mechanisms associated with RECs are reviewed in Chapter 2, providing the theoretical basis for the modelling approach adopted.

The planning problem becomes challenging because investment decisions are strongly linked with future operation. The optimal PV capacity depends on local demand profiles, export conditions and the ability of the community to use or share renewable surplus. The value of BESS capacity depends on charging opportunities, demand peaks, tariff structures, market prices and the need to preserve stored energy for later periods. Contracted power also interacts with these decisions, since it affects fixed costs and the admissible level of grid interaction. Studies on distributed PV show that local generation can bring system-level benefits when properly represented in planning models, particularly by reducing demand peaks and distribution-capacity needs [11]. For a REC, this means that sizing cannot be separated from operation. Capacity decisions only become meaningful when evaluated through the way the community is expected to behave.

As renewable penetration increases, flexibility also becomes a more valuable part of community planning. Pan-European flexibility needs associated with demand and generation variability are expected to increase significantly in the coming years, especially for short-duration flexibility and ramping capability [12]. At the same time, European policy discussions emphasise the role of storage, demand response and distributed flexibility in integrating renewable generation and reducing market volatility [13]. In this context, manual Frequency Restoration Reserve (mFRR) can be interpreted as an additional value stream for a REC equipped with flexible assets, especially BESS units.

The relevance of mFRR in this dissertation is therefore not only operational. Reserving power and energy for reserve provision may change the economic value of storage, the interaction with the grid and, ultimately, the optimal sizing of PV, BESS and contracted power. This motivates the extension and application of Sizing Tool for Energy Communities (SITEC), which evaluates REC planning decisions through optimised operation and assesses the impact of flexibility-oriented opportunities within an integrated framework. In practice, the resulting optimisation framework, SITEC, enables the assessment of how reserve-market participation influences long-term investment decisions in RECs. Here, long-term refers to capacity investments in assets with multi-year service lives, whose operational value is assessed over a full representative year. The mathematical formulation of this framework is presented in Chapter 3.

## 1.2 Objectives

The context described in Section 1.1 shows that RECs are no longer only a way to increase local renewable generation and CSC. As PV systems, BESS units and other flexible resources become more relevant, planning these assets becomes a key factor for the technical and economic performance of the community. Accordingly, the central research problem addressed in this dissertation is the optimal sizing of local energy assets when investment, operation, energy sharing, grid interaction and reserve-market participation are considered simultaneously.

The main objective of this dissertation is to extend and apply the existing SITEC planning framework to determine the optimal sizing of PV capacity, BESS capacity and contracted power when energy and mFRR market participation are considered jointly. The extension links reserve-power capability to the installed BESS capacity and incorporates reserve remuneration and operating requirements into the sizing problem. Investment and operational decisions are optimised simultaneously, considering local energy sharing, retailer tariffs and market-indexed export remuneration.

Within the scope of the Alliance for Energy Transition (ATE) project, this work focuses on BESS as the source of flexibility for reserve provision. PV capacity remains part of the joint sizing problem, but direct reserve provision by PV systems is outside the scope of the case study.

To achieve this objective, the dissertation pursues the following specific goals:

- To review the role of RECs, DERs, local energy sharing, electricity markets and reserve services in decentralised power systems, and to position the proposed work within the existing literature, as presented in Chapter 2;
- To formulate an optimisation-based planning model capable of jointly assessing investment decisions and operational performance in a REC, as presented in Chapter 3;
- To determine the optimal sizing of PV systems, BESS units and contracted power under different community configurations and economic assumptions, as analysed in Chapter 4;
- To assess whether mFRR participation changes the optimal PV capacity, BESS capacity and contracted power of the community, as analysed in Chapter 4;
- To compare representative simulation scenarios in order to identify the technical and economic conditions under which flexibility-oriented planning becomes relevant, as analysed in Chapter 4.

Together, these objectives define the methodological roadmap of the dissertation and provide the basis for the modelling framework presented in Chapter 3 and the case-study analysis presented in Chapter 4.

## 1.3 Related Projects and Publications

The work developed in the scope of this dissertation is directly related to the objectives and activities of one research project, namely:

- **ATE**, a national mobilising agenda funded under the Portuguese Recovery and Resilience Plan (PRR), focused on accelerating the decarbonisation of the Portuguese energy sector through the integration of renewable energy sources, the digitalisation of energy systems and the development of innovative solutions across the energy value chain. The work developed in this dissertation contributes to the research activities carried out within this project, particularly in the area of planning and optimisation of RECs.

The work developed during this dissertation also resulted in the preparation of one scientific paper published in the proceedings of an international conference. The following should be referred to:

- Diogo Sousa, Igor Rezende, Tiago Soares and Sérgio Faria, "Unlocking Community Flexibility: Optimal Sizing and Coordinated Operational Setpoints in Joint Energy and Reserve Markets", *22nd International Conference on the European Energy Market (EEM)*, Trondheim, Norway, 22–24 June 2026, DOI: 10.1109/EEM68581.2026.11589744.

## 1.4 Structure of the Dissertation

The dissertation is organised into five chapters:

- Chapter 1 introduces the context, motivation and main objectives of the dissertation. It also presents the related research project, the resulting scientific publication and the overall structure of the document;
- Chapter 2 reviews the main concepts that support the proposed work, including RECs, DERs, local energy sharing, optimisation-based planning, electricity markets and reserve services, and closes with a comparative review that positions the dissertation within the existing literature;
- Chapter 3 presents the modelling framework and mathematical formulation of SITEC. It details the representation of PV, BESS and contracted power sizing, optimised community operation, CSC and mFRR participation;
- Chapter 4 describes the case study and simulation scenarios. It analyses the technical and economic results obtained under different sizing and reserve-participation configurations, and examines their operational implications for the community;
- Chapter 5 summarises the main conclusions of the dissertation, highlights its contributions and identifies possible directions for future research.

# Chapter 2

# State of the Art

This chapter presents the theoretical and scientific background that supports the modelling framework developed in this dissertation. It begins by introducing the Energy Community (EC) concept, with particular focus on RECs, CSC and local energy sharing. The role of DERs as sources of flexibility in RECs is then discussed, followed by a review of optimisation-based planning approaches for PV and BESS assets. The electricity-market and reserve-service background is subsequently presented, with emphasis on the mFRR market. Finally, the most relevant scientific contributions are compared and the proposed work is positioned within the existing literature.

## 2.1 Energy Communities

### 2.1.1 From Individual Self-Consumption to Energy Communities

The development of ECs is closely linked to the changing role of electricity consumers in decentralised power systems. In the traditional electricity sector, end-users were mainly passive consumers supplied through a centralised value chain, with limited influence over generation, operation or market participation. The growth of distributed renewable generation has gradually changed this role, allowing consumers to produce part of their own electricity and become active participants in the energy system. This transition is commonly associated with the emergence of the prosumer, an actor that both consumes and produces electricity, reducing the conventional separation between demand and supply [14]. Beyond this technical role, prosumerism is also connected to energy citizenship and participation, since citizens may become direct contributors to local energy transitions rather than only recipients of electricity services [15].

Individual self-consumption represents one of the first steps in this transition. It allows a final consumer to use electricity produced on-site, usually from a small-scale renewable installation. However, this model is often constrained by the physical link between one generation unit and one consumption point. This can limit the efficient use of renewable production, especially in multi-apartment buildings, urban areas or sites where production and demand profiles do not match. CSC extends this logic by allowing several consumers to share locally produced renewable energy, moving from a one-to-one configuration to one-to-many arrangements [16]. In this context, the

public distribution grid, smart metering and allocation mechanisms enable a form of virtual self-consumption, where shared electricity is not necessarily consumed behind the same meter but can still be accounted for within a collective framework [17]. This evolution from individual to collective arrangements is illustrated in Figure 2.1.

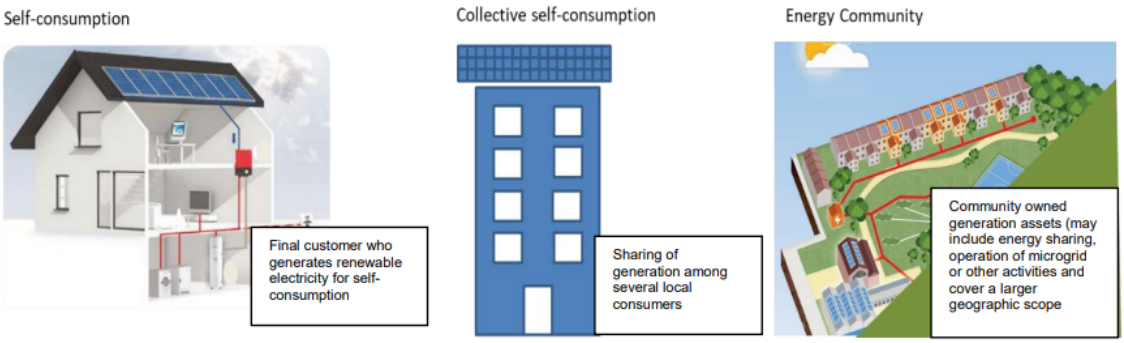



Figure 2.1: Evolution from self-consumption to CSC and EC [18].

The move from CSC to ECs introduces an additional organisational layer. CSC mainly concerns the shared use of locally produced electricity. An EC, by contrast, provides a broader framework for collective action, governance and benefit allocation. This distinction matters because energy sharing requires more than a technical method for allocating electricity flows. It also requires rules for participation, decision-making, ownership and the distribution of benefits. In this sense, ECs can act as organisational structures that allow citizens, local authorities and actors from the Small and Medium-Sized Enterprise (SME) sector to jointly exercise energy-related rights within a recognised framework [19]. Their development is also associated with social innovation, since these initiatives are usually designed to deliver environmental, economic or social benefits to their members or local areas rather than to maximise financial profit.

This evolution also clarifies the difference between internal sharing and external trading. Sharing refers to the internal allocation of renewable electricity among members to satisfy local demand. Trading refers to the commercial sale of electricity outside the collective arrangement [20]. This distinction helps explain why ECs should not be treated only as small electricity market platforms. They are also legal and organisational structures created to manage local participation, collective ownership and shared benefits. The progression from passive consumption to prosumerism, CSC and institutionalised ECs was gradually codified in European energy policy, leading to the formal definitions of RECs and the Citizen Energy Community (CEC) concept.

### 2.1.2 Concept, Definition and Principles of Energy Communities

This conceptual evolution was later formalised in the European Union (EU) regulatory framework through the Clean Energy for all Europeans package. This framework introduced ECs as legally recognised collective actors that support the active participation of citizens, local authorities and smaller organisations in the energy transition [21].

Two legal concepts are particularly relevant:

- The REC, introduced by Directive (EU) 2018/2001 [22];
- The CEC, introduced by Directive (EU) 2019/944 [23].

Their introduction reflects a broader shift in energy policy. The energy transition is no longer framed only around technologies and markets, but also around citizen participation, local ownership and new organisational forms [24].

A simplified representation of a REC is shown in Figure 2.2. It includes local members, distributed generation, storage, EVs, internal exchanges and external interactions with the wider electricity system.

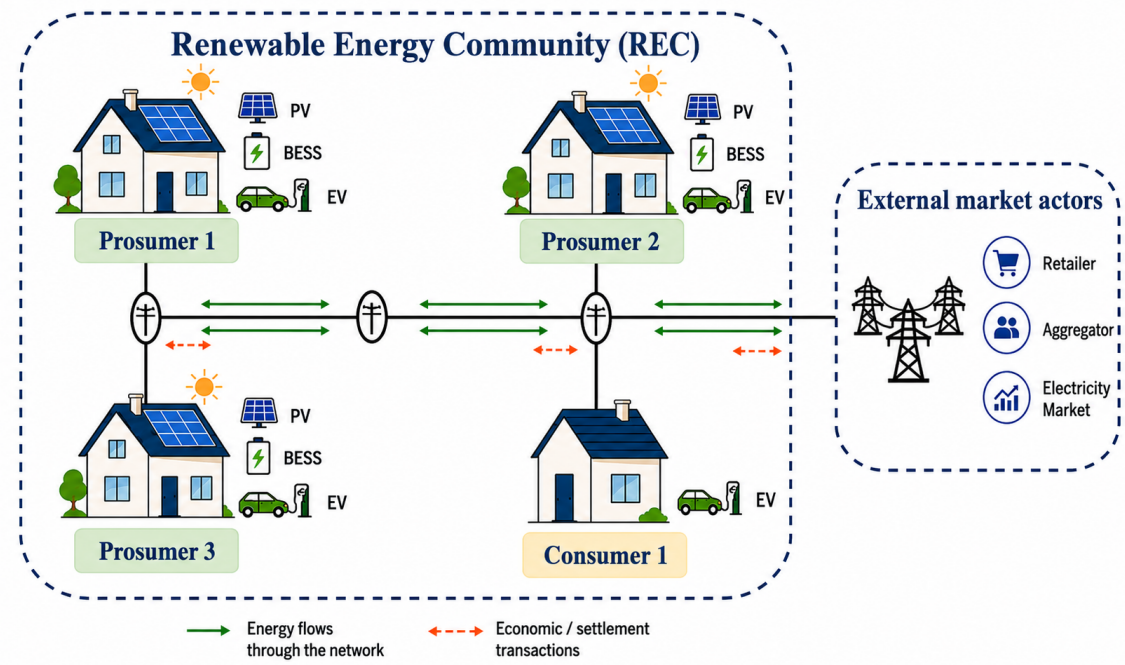



Figure 2.2: Simplified conceptual representation of a REC.

Although RECs and CECs are defined in different directives, they share a common community-oriented logic. Both are legal entities based on open and voluntary participation. Both are also expected to provide environmental, economic or social benefits to their members, shareholders or local areas, rather than being primarily driven by financial profit. This distinguishes ECs from conventional commercial energy actors. Their value is not assessed only through the amount of energy produced or traded, but also through who participates, who controls the initiative and who benefits from it. This emphasis on participation and benefit distribution is consistent with the process and outcome dimensions commonly used to understand community renewable energy projects [25]. In this sense, the concept of community is not only technical or legal. It is also organisational and social.

The two European definitions differ in scope, territorial logic and permitted activities. RECs are specifically linked to renewable energy projects and include a proximity requirement between the controlling members and the projects owned and developed by the community. CECs, by contrast, are defined within the electricity market framework and may cover a broader range of electricity-related activities, without an equivalent proximity requirement. Table 2.1 summarises the main distinctions between both concepts.

Table 2.1: Main differences between RECs and CECs under the European regulatory framework [22], [23], [26], [27].

| **Aspect** | **REC** | **CEC** |
|---|---|---|
| Legal basis | Directive (EU) 2018/2001, focused on renewable energy. | Directive (EU) 2019/944, focused on the internal electricity market. |
| Energy scope | Restricted to renewable energy sources, not necessarily limited to electricity. | Restricted to electricity, which may come from renewable or conventional sources. |
| Members and control | Natural persons, SMEs and local authorities, with effective control by members located near the renewable energy projects. | Natural persons, local authorities and small enterprises, with effective control by eligible members or shareholders. |
| Geographical link | Proximity between members and renewable energy projects is required. | No equivalent proximity requirement is specified. |
| Main activities | Production, consumption, storage, sale and sharing of renewable energy. | Generation, distribution, supply, consumption, aggregation, storage, energy efficiency services and EV charging services. |
| Typical application | Local renewable energy communities focused on collective self-consumption and shared generation. | Broader electricity-related services, not necessarily tied to renewable generation or geographic proximity. |

Given these distinctions, this dissertation adopts the REC framework as the most appropriate reference concept. Its focus on renewable generation, proximity and local community benefits is directly aligned with the planning of PV and storage assets within a geographically bounded community. RECs also preserve the collective nature of local energy initiatives, where members may cooperate to improve local self-consumption, share benefits and coordinate resources, while still interacting with wider electricity markets when appropriate [28]. Translating these conceptual definitions and regulatory principles into practical community implementation, however, depends on the governance models, stakeholders and operational roles.

### 2.1.3 Governance Models, Stakeholders and Operational Roles

The legal recognition of RECs does not, by itself, define how a community is organised, managed or operated in practice. Between the regulatory definition and the technical operation of shared resources, there is a governance layer that defines participation, ownership, decision-making, operational responsibilities and benefit allocation. This layer is particularly relevant because RECs combine social objectives, technical assets and economic arrangements within the

same structure. Their implementation therefore depends on the alignment between community governance, technological optimisation and the adopted business model [29]. Effective governance must also preserve autonomy and member control, allowing operational tasks to be delegated without enabling individual members, investors or external actors to dominate the community's decisions [30].

In practical terms, governance choices influence several dimensions of a REC:

- **Ownership and investment responsibility**, defining who finances and controls community assets [31];
- **Member participation**, determining how consumers, prosumers and other actors take part in decisions [29], [31];
- **Operational coordination**, establishing who manages information, contracts and resource scheduling [29], [31];
- **Benefit and cost allocation**, shaping how economic value is distributed among members [29], [31];
- **External representation**, defining how the community interfaces with suppliers, aggregators, network operators and regulators [31].

Several organisational models can be used in the implementation of RECs. Cooperative models emphasise member ownership and democratic participation, while community prosumerism, local energy market models, energy-service-company arrangements and third-party-sponsored communities introduce different combinations of asset ownership, financing and operational responsibility [31]. These alternatives show that there is no single governance model suitable for every REC. Citizen-led communities may prioritise local participation and collective ownership. Municipality-led or third-party-supported initiatives may reduce investment barriers and provide technical expertise. In all cases, more professionalised models must remain compatible with the community-oriented purpose of RECs, since participation is sustained not only by economic savings but also by civic engagement, trust and perceived collective value [32].

From an operational perspective, the first relevant distinction concerns the actors located inside the community. These actors define the local demand, renewable generation, storage capacity and participation conditions available to the REC. Their relevance for planning and operation is summarised in Table 2.2.

The main message from Table 2.2 is that internal actors should not be seen only as asset owners or passive consumers. Their behaviour affects local energy balances, the feasibility of coordinated operation and the perceived fairness of benefit distribution. In communities with shared or jointly optimised assets, the selected allocation method can strongly influence whether members perceive participation as economically attractive and equitable [35]. Governance is therefore a practical condition for maintaining trust and ensuring that community resources are used according to collective objectives.

Table 2.2: Internal stakeholders and operational roles in RECs [33], [34], [35].

| **Internal actor** | **Main role in the REC** | **Relevance for planning and operation** |
|---|---|---|
| Consumers | Consume electricity supplied by local generation, shared community resources or external suppliers. | Define demand profiles and influence the potential for local self-consumption and energy sharing. |
| Prosumers | Produce and consume renewable electricity, often through local PV assets. | Create local surplus, affect the community energy balance and support collective renewable energy use. |
| Storage owners | Provide controllable storage capacity through individual or shared BESS units. | Enable energy shifting, peak reduction and more coordinated operation of local resources. |
| Community manager | Coordinates administrative, contractual and operational interactions among members. | Supports internal management, information exchange, benefit allocation and implementation of community decisions. |

At the same time, a REC does not operate as an isolated energy system. Even when most activity is organised locally, the community remains connected to external actors that define residual supply, grid access, metering, market interaction and regulatory conditions. These interfaces determine whether internal community operation can be translated into legally valid, technically feasible and economically meaningful exchanges with the wider electricity system. Among these actors, the Distribution System Operator (DSO) provides the distribution-network interface, while the Transmission System Operator (TSO) maintains system-level balance and procures Ancillary Services (AS). Table 2.3 summarises the main external stakeholders and their interface with the community.

Table 2.3: External stakeholders and interfaces of RECs [33], [34], [36].

| **External actor** | **Interface with the REC** | **Relevance for governance and operation** |
|---|---|---|
| Supplier/Retailer | Supplies residual electricity not covered by local production or shared community resources. | Ensures continuity of supply when community generation is insufficient. |
| Aggregator | Represents or balances aggregated community resources in wider electricity market contexts. | Enables external market interaction while reducing the complexity faced by individual members. |
| DSO | Operates the distribution network and manages metering or grid-related data. | Supports grid connection, data validation and technically feasible energy exchanges. |
| TSO | Maintains system-level balance and procures AS. | Provides the wider system context for future flexibility and reserve-service interactions. |
| Regulator or public authority | Defines legal, tariff and support conditions for community operation. | Determines the regulatory feasibility, stability and scalability of the community framework. |

Together, the external stakeholders define the regulatory, commercial and technical environment within which a REC operates. The distinction between internal and external stakeholders clarifies where different responsibilities are located. Internal governance determines how local resources and benefits are coordinated among members. External interfaces define the conditions under which the community interacts with the wider electricity system. In particular, DSOs can act as neutral facilitators of RECs, since energy sharing depends on metering, data validation and grid-compatible exchanges [36]. Aggregators may also become relevant when community resources move beyond internal self-consumption and are represented in wider market or balancing contexts [34].

Overall, governance models and stakeholder roles define the practical conditions under which a REC can move from a legal entity to an operational energy system. A technically well-designed community may fail to deliver its intended benefits if decision-making rules are unclear, if members do not trust the allocation of benefits, or if external interfaces with suppliers, aggregators and network operators are not properly organised. Conversely, a clear governance structure can make local renewable generation, storage and demand more useful by assigning responsibilities and coordinating actions across members and external actors [35], [36]. This organisational perspective is itself a precondition for the mechanisms through which locally produced electricity is actually shared among members.

### 2.1.4 Local Energy Sharing and Collective Self-Consumption

After defining the governance structure and operational roles of a REC, it is necessary to understand how locally generated electricity is shared among its members. Local energy sharing transforms renewable generation from an individual asset into a collective resource, allowing locally produced electricity to be allocated across a defined group of consumers and prosumers. In this sense, CSC differs from individual self-consumption because the value of generation depends on its allocation across several demand profiles. It also differs from broader Peer-to-Peer (P2P) trading or transactive energy, which generally involve more market-oriented exchanges, direct participant interaction and higher transactional complexity [37].

The practical implementation of CSC depends on allocation coefficients, also referred to as sharing keys, which define how shared electricity is assigned to each participant for settlement purposes. These coefficients may be fixed before delivery, proportional to measured consumption, or dynamically calculated after metering data are available. Fixed approaches are simple and transparent, but may fail to use local renewable generation efficiently when member demand does not match predefined shares [38]. Dynamic coefficients can better reflect real consumption patterns and improve the use of local production, especially when allocation is adjusted after metering data are known [39]. The choice of sharing mechanism also affects fairness, since a rule that maximises CSC does not necessarily distribute benefits equitably across members with different demand profiles, installed capacities or investment contributions [40].

Energy sharing is therefore not only a technical settlement procedure. It is also a governance and regulatory choice. More flexible allocation methods improve the use of local renewable generation, but they require reliable metering, data validation and clear settlement rules [41]. In Portugal, the CSC framework established by Decree-Law 15/2022 [10] allows dynamic allocation coefficients based on real consumption measurements. This directly influences the local energy balances and economic outcomes of each member. The same regulatory approach underpins the energy sharing model adopted in this dissertation, as formalised in Chapter 3.

## 2.2 Distributed Energy Resources and Flexibility in Renewable Energy Communities

### 2.2.1 Distributed Energy Resources as Sources of Flexibility

In decentralised power systems, flexibility is no longer associated only with large conventional generators. It can also be provided by DERs, including renewable generation, storage units, flexible demand and EVs. From a technical perspective, distributed flexibility can be understood as the ability of a resource to modify its power injection or consumption profile within a given time interval. This capability is commonly described through attributes such as available capacity, direction, ramping capability, activation duration and cost [42]. Since these attributes vary across resources and time horizons, flexible resources are often represented according to their ability to increase, decrease, shift or store energy over time [43]. The main DERs that can provide flexibility within RECs, together with their typical flexibility-enabling mechanisms, are summarised in Figure 2.3.

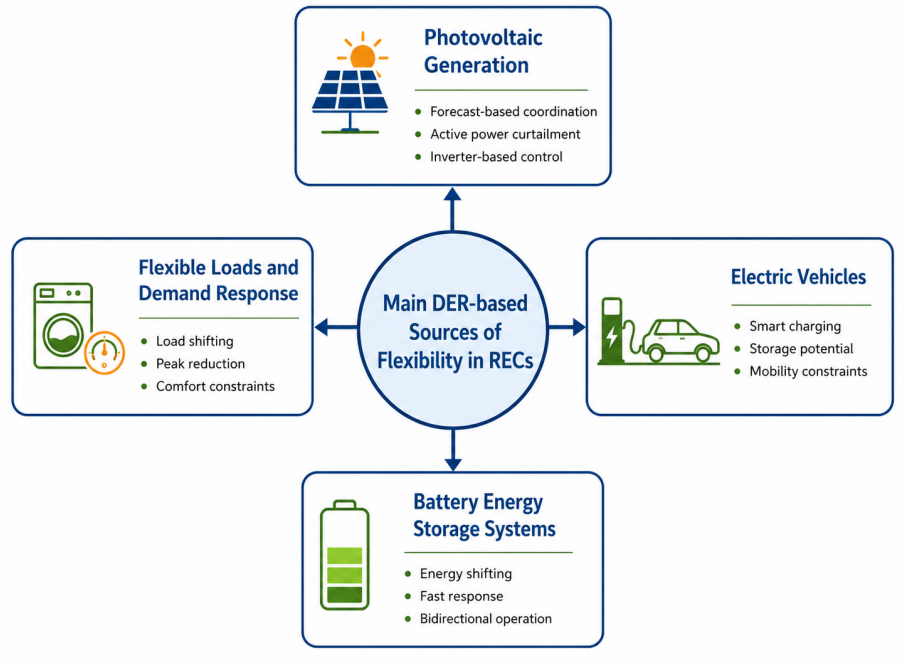



Figure 2.3: Main DERs that can act as sources of flexibility in RECs.

#### 2.2.1.1 Photovoltaic Generation

PV generation is variable and not dispatchable in the same way as conventional generation, since its output depends on solar availability and weather conditions. Nevertheless, it can still contribute to local flexibility when combined with forecasting, inverter-based control or active power curtailment. In RECs, the flexibility value of PV depends less on the resource alone and more on how its production is coordinated with demand, storage and energy sharing mechanisms. This matters because flexible resources should be assessed not only by installed capacity, but also by the extent to which their output can be adapted to operational needs [43].

#### 2.2.1.2 Flexible Loads and Demand Response

Demand-side flexibility is provided by loads that can be shifted, curtailed or operated within acceptable service limits. In community settings, this may include residential appliances, heating and cooling systems, commercial loads or other controllable consumption processes. Demand response can help move consumption away from expensive, congested or carbon-intensive periods, supporting both local energy management and distribution network operation [44]. However, the practical value of flexible demand is constrained by appliance availability, comfort requirements, rebound effects and user willingness to participate. For this reason, incentives and market arrangements are as important as technical controllability when mobilising distributed demand-side flexibility [45].

#### 2.2.1.3 Electric Vehicles

EVs introduce an additional source of flexibility because their charging process can often be shifted within the time window between arrival and departure. When coordinated with local renewable generation, smart charging can increase the use of local PV production, reduce peak demand and support a more balanced community load profile. In some configurations, EVs may also behave as storage-like resources. Their availability, however, remains limited by mobility needs, charging preferences and user behaviour. In more advanced configurations, Vehicle-to-Grid (V2G) operation can further expand the flexibility potential of EVs, although this functionality is not yet widely deployed. Their contribution to REC flexibility therefore depends on forecasting, coordination and participation conditions, rather than on technical charging capability alone [46].

#### 2.2.1.4 Battery Energy Storage Systems

Among the different DERs available in RECs, BESS are particularly relevant because they combine fast response, bidirectional operation and the ability to shift energy across time. By charging during periods of local renewable surplus and discharging when demand is higher, BESS can increase self-consumption, reduce grid imports and improve the controllability of the community energy balance. However, this flexibility only becomes a reliable service when supported by adequate monitoring, communication and control capabilities, especially when customer-owned

resources are coordinated as part of a wider portfolio [47]. This central role motivates the dedicated discussion of BESS in Subsection 2.2.2.

#### 2.2.1.5 Comparison of Flexibility Attributes across Distributed Energy Resources

Having characterised each DER individually, it is useful to summarise their main flexibility-related attributes in a comparative manner. Table 2.4 presents this comparison in terms of dispatchability, response time, duration and typical flexibility application.

Table 2.4: Comparison of the main DERs as sources of flexibility in RECs [42], [44], [45], [46], [47].

| DER | Dispatchability | Response time | Duration | Typical flexibility application |
|---|---|---|---|---|
| PV | Non-dispatchable; controllable only via inverter curtailment. | Slower than EVs, storage and controllable loads. | Limited to periods of solar production. | Voltage management and, when aggregated, reserve provision. |
| Flexible loads | Dispatchable under direct control; less certain under price-based response. | Rapid under direct control; slower for price-based response. | Short for interruptible loads; longer with thermal storage. | Peak shaving, load shifting and congestion management. |
| EVs | Controllable while connected; bidirectional with V2G. | Rapid when connected and remotely controllable. | Bounded by connection window and mobility needs. | Coordinated charging, aggregated capacity and V2G balancing. |
| BESS | Highly dispatchable and bidirectional. | Rapid; suited to AS activation. | Depends on stored energy and required power. | Time-shifting, peak shaving and AS. |

Although these resources provide different forms of flexibility, their practical availability is not equivalent to their theoretical potential. A resource may be technically capable of modifying its power profile but unavailable at a given time due to weather conditions, user behaviour, comfort constraints, mobility needs or operating limits. For RECs, the value of distributed flexibility therefore lies in coordinating heterogeneous resources under a common community-level management framework. Individual assets are often too small, uncertain or intermittent to support system operation on their own, while coordinated use can create a more predictable and valuable flexibility portfolio [46]. Meeting this coordination challenge ultimately depends on aggregation mechanisms, discussed later in this section. Therefore, given the particular importance of storage among these resources, BESS in community energy management is addressed.

### 2.2.2 Battery Energy Storage Systems in Community Energy Management

The ability of BESS to shift energy across time partially decouples local renewable generation from electricity consumption. This function is especially relevant in communities with high PV penetration, where surplus production often occurs during daytime periods while demand peaks

may appear later in the day. By storing part of this surplus and discharging it when local demand is higher, BESS can increase self-consumption, reduce grid imports and improve the internal balance between generation and demand. In prosumer communities, the combination of storage and local energy exchange can therefore reduce energy costs and improve self-sufficiency [48]. The way batteries are operated also affects the distribution grid, since different control strategies may lead to different levels of peak reduction, line loading and local balancing [49]. This basic flexibility role is illustrated in Figure 2.4.

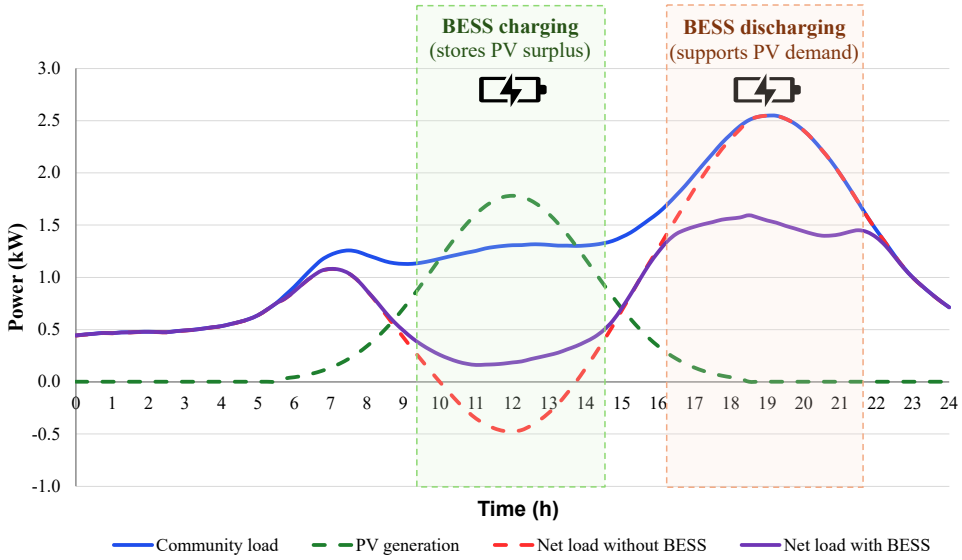



Figure 2.4: Illustrative role of a BESS in community energy management.

The value of storage depends not only on its technical characteristics, but also on how it is owned and operated within the community. Individual batteries installed behind the meter allow prosumers to prioritise their own self-consumption, but may reinforce differences between members with and without storage assets. Shared or community batteries, by contrast, can be managed as collective resources and scheduled according to community-level objectives. Different ownership and operation structures therefore affect economic efficiency, social welfare and benefit distribution among members [50]. The location and operation of shared batteries can also influence grid impacts, since storage may be used either to maximise local self-consumption or to reduce stress on specific parts of the distribution network [49].

From an economic perspective, the most direct value of BESS comes from avoiding electricity purchases from the grid. When stored local generation is used during periods of higher demand or higher prices, the community can reduce its dependence on external supply and increase the value of its renewable production. For this reason, optimised battery scheduling is commonly used to improve the economic performance of RECs compared with unmanaged storage operation [51]. However, self-consumption alone may not always justify the investment cost of storage. Additional value streams, such as energy arbitrage or combined operation with CSC, can improve investment attractiveness, although they may create a trade-off between economic profitability and

energy independence [52]. The best storage strategy therefore depends on whether the community prioritises lower bills, higher self-sufficiency, reduced grid impact or market-oriented operation.

The operation of BESS is constrained by technical limits that must be represented in community energy management models. Charging and discharging powers are limited by the converter rating, while the State-of-Charge (SoC) must remain within safe operating ranges to preserve availability and avoid excessive degradation. Round-trip efficiency also means that part of the stored energy is lost during each charge-discharge cycle. These constraints make scheduling decisions relevant, since excessive cycling or poorly designed arbitrage strategies can reduce battery lifetime and distort the expected economic benefits. For this reason, long-term storage assessment should account for degradation and lifetime management, rather than considering only short-term operating savings [53]. Operational models must therefore balance immediate economic gains with efficiency losses, ageing effects and the need to keep sufficient stored energy available for future periods [51].

At community level, the effective use of BESS requires coordination between individual assets, shared resources, local energy exchanges and the net interaction of the REC with the external grid. This coordination may be centralised, hierarchical or distributed, depending on the governance model and the available control infrastructure. In more advanced configurations, several distributed batteries can be aggregated and operated as a Virtual Storage System (VSS), allowing storage capacity dispersed across members to behave as a single controllable resource from the perspective of the community manager [54]. Coordinated storage can therefore support not only self-consumption and local balancing, but also flexibility provision and interaction with electricity markets. Turning distributed flexibility into a reliable community-level portfolio, however, requires the aggregation and coordination mechanisms discussed next.

### 2.2.3 Aggregation and Coordination of Community Flexibility

The availability of flexible DERs does not, by itself, ensure that a REC can provide reliable and useful flexibility. Community resources are usually owned by different members, located at different connection points and operated according to different preferences. If these resources respond independently to price signals or local objectives, their actions may shift peaks to other periods, create simultaneous charging or discharging behaviour, or increase stress on the distribution network. Coordination is therefore needed to align individual resource operation with collective objectives such as local balancing, self-sufficiency, cost reduction and grid-support capability [55].

Coordination strategies differ according to who makes decisions, how information is exchanged and whether the interaction between participants is cooperative or competitive. Centralised approaches rely on a single entity to schedule or dispatch resources according to a common objective. Decentralised or mediated approaches preserve greater member autonomy through prices, bids or coordination signals [55]. Local coordination can also rely on P2P exchange, CSC arrangements or transactive energy mechanisms, each with different governance rules, information requirements and settlement processes [56]. This distinction matters because the same physical

portfolio of DERs can lead to different outcomes depending on whether the community is managed as a cooperative system, a group of independent prosumers or a local market platform.

Aggregation provides the practical bridge between small-scale community resources and wider energy-system needs. Individual residential or commercial assets are often too small to participate directly in organised markets or to provide flexibility products with minimum capacity requirements. Aggregation is therefore required to create a portfolio with sufficient scale and controllability [57]. In this role, an aggregator, community manager or Virtual Power Plant (VPP) can combine generation, storage and flexible demand into a single controllable entity, even when the physical assets remain geographically distributed [58]. This process also reduces the complexity faced by individual members, since forecasting, dispatch, communication and settlement can be managed by an intermediary. Reliable aggregation, however, depends on adequate monitoring, interoperability and secure communication, especially when customer-owned equipment from different technologies and manufacturers is coordinated within the same portfolio [47].

This transition from individual flexibility to aggregated community flexibility is illustrated in Figure 2.5. The figure contrasts conventional flexibility provision by large centralised resources with a community-based configuration in which distributed DERs are coordinated through an aggregation layer before interacting with external system actors.

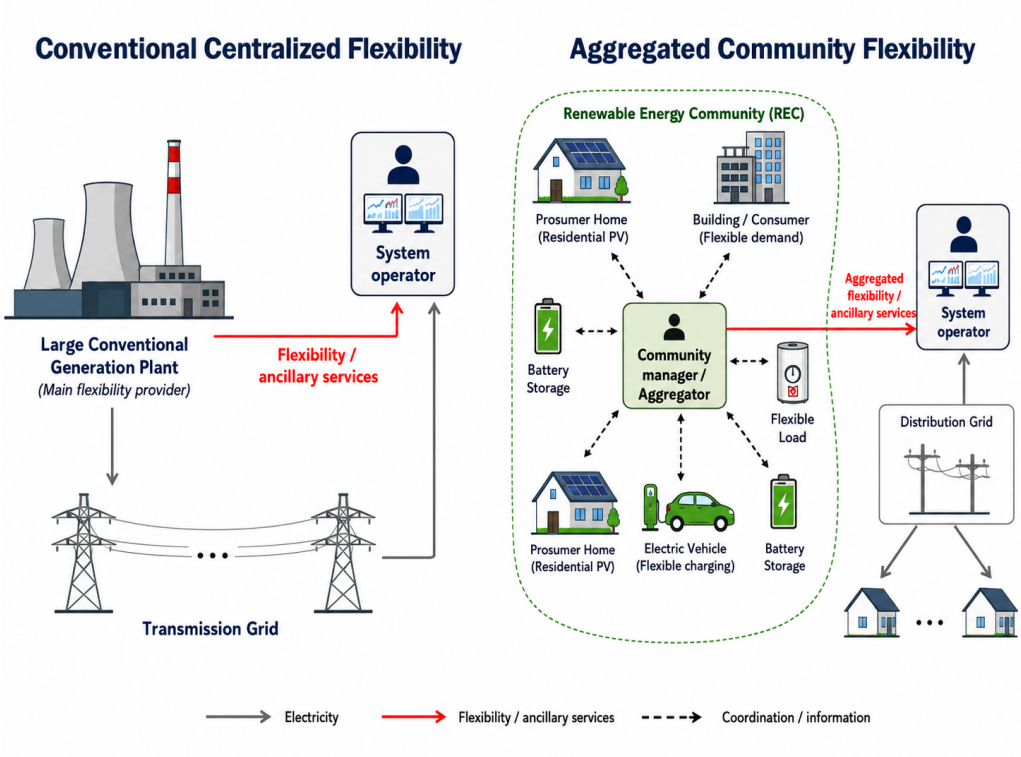



Figure 2.5: Conventional and aggregated community flexibility provision.

Within a REC, aggregation must also balance member-level interests with community-level objectives. Hierarchical management structures are useful for this purpose because individual

buildings or members can optimise their own operation while a higher-level community layer coordinates shared resources and aggregate flexibility [59]. This layered view is particularly relevant for community flexibility, since its value depends not only on the technical capability of individual devices, but also on coordinated participation, governance and operational planning [46].

## 2.3 Optimisation-Based Planning of Renewable Energy Communities

### 2.3.1 Operational Scheduling as a Basis for Planning

Operational scheduling is the modelling layer through which candidate planning decisions are evaluated under realistic operating conditions. In a REC, decisions such as PV capacity, BESS capacity and the use of flexible resources cannot be assessed only through installed power or annual energy balances. Their value depends on how they interact with demand, renewable generation, storage limits, user constraints, energy-sharing rules and economic signals over hourly or sub-hourly periods. For this reason, operational scheduling should not be treated as a separate stage after planning. It should be embedded within the planning model itself. Operational models are commonly used to quantify cost reduction, self-consumption, flexibility use and uncertainty effects associated with different community configurations [60]. This link is important because the same investment decision may lead to different outcomes depending on how the community is operated.

A typical REC scheduling model combines forecasts, technical constraints and economic rules. Load and PV time series define the energy balance, while grid import and export variables represent the interaction with the external system. Storage operation is represented through charging and discharging decisions, power limits, efficiency losses and SoC constraints. Flexible loads add further time-coupled constraints, since consumption can only be shifted within availability, comfort or process limits [61]. Standardised flexibility representations, such as Flex-Offer-based formulations, can also help describe shiftable or adjustable loads in a way that is compatible with scheduling algorithms [62]. In practice, the main elements of this operational layer can be summarised as follows:

- **Candidate planning decisions**, including PV capacity, BESS capacity, contracted power limits and shared or flexible assets, which define the feasible design space of the community [60];
- **Operational inputs and constraints**, including demand, renewable generation, prices, tariffs, resource availability, SoC limits and user constraints, which condition how each candidate configuration can be operated [61];
- **Scheduling decisions**, including grid imports and exports, battery charge and discharge, shifted or curtailed demand and local energy allocation, which translate installed resources into time-dependent operation [63];

- **Performance indicators**, including operating cost, self-consumption, self-sufficiency, peak demand, battery cycling, shared energy and flexibility use, which quantify the operational value of each planning configuration [64];
- **Planning evaluation**, based on the comparison of candidate solutions according to economic viability, technical adequacy and long-term usefulness, linking operational performance back to planning decisions [65].

The coupling between asset sizing and operational scheduling is represented in Figure 2.6: installed capacities constrain feasible operation, while the costs and benefits of that operation determine the economic value of each sizing decision. The figure highlights that operational scheduling is embedded within the REC planning optimisation framework rather than treated as a downstream step. Planning decisions define the capacities and limits available to the community. The operational layer then determines how those resources are dispatched under technical, economic and sharing constraints. The resulting performance indicators provide the evidence used to assess the quality of the planning configuration.

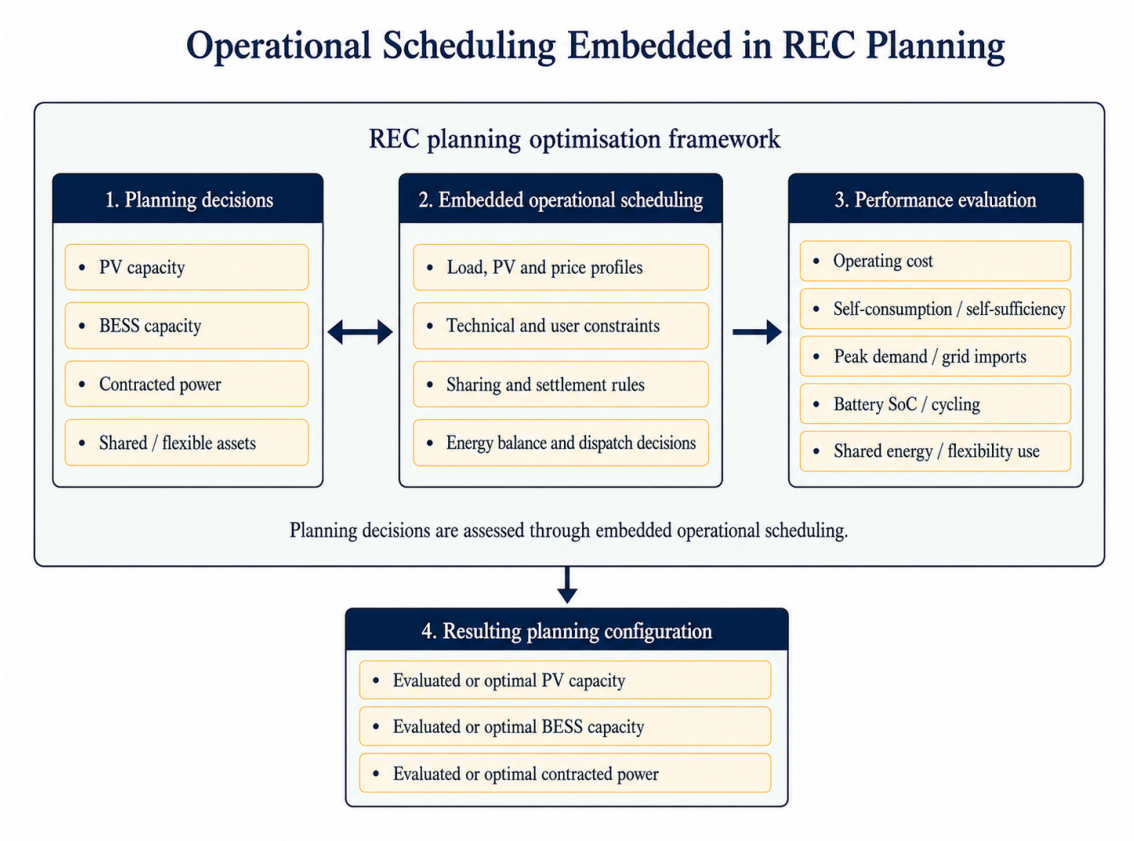



Figure 2.6: Operational scheduling embedded within REC planning models.

The objective function defines how the operational layer evaluates each candidate configuration. In many community scheduling formulations, cost minimisation is used to reduce grid purchases, increase local renewable use or exploit tariff differences. A system-centric Community En-

ergy Management System (CEMS) can achieve better community-level outcomes than prosumer-centric operation because individual resources are coordinated according to collective objectives rather than isolated household gains [63]. The objective function may also include welfare maximisation, local trading, emissions or participation incentives. For instance, willingness-to-pay can be used to represent the value that prosumers assign to local PV sharing and environmental benefits [66]. Similarly, variable sharing coefficients can improve the allocation of shared energy when compared with fixed rules, but they require an operational framework capable of updating decisions as new information becomes available [64].

From a methodological perspective, Mixed Integer Linear Programming (MILP) remains widely used because it can represent binary decisions, technical constraints and multiple resource types in a transparent way, and continues to be the predominant approach in REC planning due to its ability to provide globally optimal solutions for deterministic formulations. However, deterministic formulations often rely on perfect foresight of demand, renewable generation and prices, which can overestimate the operational value of a candidate planning solution [60]. Model Predictive Control (MPC) addresses part of this issue by repeatedly solving the scheduling problem over a moving horizon and updating decisions with new forecasts and measurements [65]. As communities become larger and more heterogeneous, scalability also becomes relevant, motivating decomposition, heuristic or learning-based approaches [61]. Learning-based methods can support REC management under uncertainty, although they remain less established than optimisation-based scheduling for transparent planning studies [67]. Overall, operational scheduling provides the short-term operational evidence through which planning alternatives are assessed, evidence drawn on directly when sizing PV and BESS assets below.

### 2.3.2 Optimal Sizing of Photovoltaic and Battery Storage Assets

The optimal sizing of PV and BESS in RECs is a collective planning problem rather than a simple extension of individual self-consumption sizing. In individual systems, generation and storage are usually dimensioned around a single demand profile. In a community, several consumption profiles, generation units and sharing arrangements interact within the same planning problem. This aggregation can create a synergy effect, since asynchronous demand profiles allow local renewable generation and storage capacity to be used more effectively across different members [68]. As a result, the optimal size of a shared asset is not necessarily equal to the sum of individually optimal systems. Ownership and control also become part of the sizing problem, because individual and shared storage configurations distribute investment costs, operational authority and benefits in different ways [69]. Therefore, PV and BESS sizing in RECs must account for technical capacity, collective use and the organisational conditions under which the assets are deployed.

Economic viability is one of the main drivers of PV and BESS sizing. Optimal capacities are shaped by investment cost, electricity tariffs, national incentives and the remuneration of surplus energy, since these factors determine the value of local generation, stored energy and grid exchanges [70]. Increasing PV capacity can raise local renewable production, but it may also

increase low-value surplus when demand and storage are insufficient. Increasing BESS capacity can improve self-consumption and self-sufficiency, but only up to the point where the extra stored energy justifies the additional investment. This creates a marginal-value logic. Beyond a certain capacity, the technical benefit of additional assets may increase slowly while capital cost continues to grow. Business models further affect this balance. In battery-as-a-service arrangements, for example, sizing depends on the value of allocating storage capacity to community use compared with the opportunity cost of using the same asset for external market applications [71]. The main criteria used to assess these trade-offs are summarised in Table 2.5.

Table 2.5: Main criteria for optimal PV and BESS sizing in RECs [68], [69], [70], [71], [72], [73].

| **Sizing criterion** | **Relevance for REC planning** |
|---|---|
| Economic viability | Assesses whether investment costs are justified by long-term savings, revenues and payback conditions. |
| Self-consumption and self-sufficiency | Measures how effectively local renewable generation is used within the community and how much external supply is avoided. |
| Load-profile diversity | Captures the benefit of aggregating members with complementary consumption patterns. |
| Ownership and benefit allocation | Determines who invests, who controls the storage asset and how economic benefits are distributed. |
| Flexibility revenues | Influence the economic attractiveness of storage when reserve-market participation is considered. |
| Grid constraints | Limits technically feasible capacity according to voltage, thermal or distribution-network restrictions. |
| Battery degradation and cycling | Accounts for the effect of operating intensity on lifetime, replacement needs and real storage value. |

A PV and BESS configuration that is economically attractive at community level may still be constrained by the physical behaviour of the distribution network. High PV penetration can create voltage rise, thermal loading or reverse power flows, while storage location and operation influence how these effects are mitigated. Distribution-level constraints can therefore be included in multi-objective sizing models to ensure compatibility with DSO operating limits [72]. In this context, larger storage capacity does not necessarily imply better planning performance. Once local demand, grid limits or operational objectives are satisfied, additional capacity may provide only marginal benefits. Net-load smoothing may also be considered when the community seeks to reduce fluctuations seen by the distribution network, even at the expense of short-term arbitrage returns [73].

Overall, optimal PV and BESS sizing should be understood as a techno-economic planning problem in which investment decisions are evaluated through their expected operational consequences. This links directly with the scheduling layer discussed in Subsection 2.3.1, although the focus here is on long-term capacity decisions rather than detailed dispatch. Annual simulations, representative periods and multi-objective formulations can assess whether candidate capacities create sufficient value under realistic demand, generation and price conditions. Storage-oriented

business models must also account for degradation and cycling, since short-term gains can be offset by accelerated battery ageing [71]. These considerations support the formulation developed in Chapter 3, where PV and BESS capacities are optimised jointly.

## 2.4 Markets and Reserve Services

### 2.4.1 Energy Market Participation and Price Signals

Electricity markets are organised through sequential timeframes that reflect how far transactions are made from physical delivery. Forward and futures markets allow participants to hedge exposure to future price variations. Day-ahead markets establish the main scheduled energy positions for the delivery day. Intraday markets then allow agents to adjust these positions closer to real time, while balancing mechanisms are used by system operators to manage residual deviations between scheduled and actual system conditions [74]. Balancing arrangements should not be interpreted as a single market stage occurring only after the intraday market. They include capacity procurement, where resources reserve availability before delivery, and balancing energy, where the TSO activates accepted bids closer to real time according to system needs. This temporal structure is represented in Figure 2.7 as a general framework, although the specific market arrangements and implementation details may differ across countries.

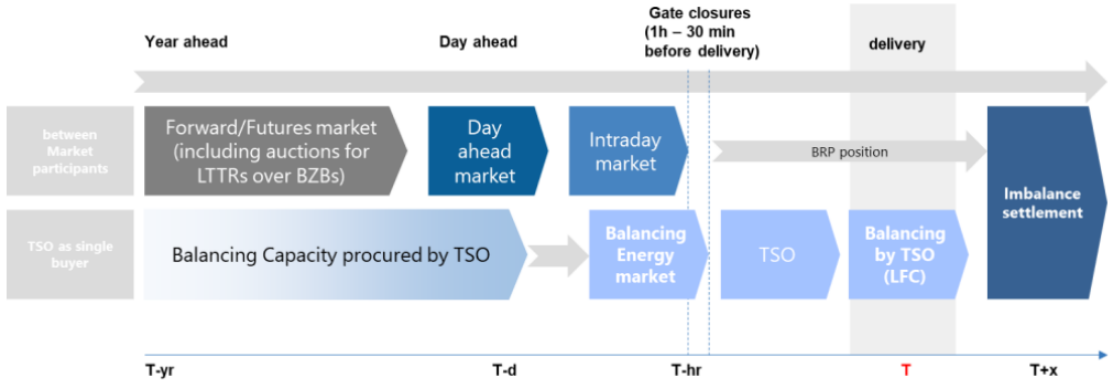



Figure 2.7: Simplified sequence of electricity market timeframes, separating energy-market stages from balancing-capacity procurement and balancing-energy activation. BRP denotes balance responsible party. Adapted from [74].

In the Iberian context, organised electricity trading takes place within the Iberian Electricity Market (MIBEL). Within this framework, Iberian Electricity Market Operator (OMIE) manages the day-ahead and intraday electricity markets, while forward-market activity is associated with Iberian Energy Derivatives Exchange (OMIP) [75]. The day-ahead market is especially relevant because it provides a transparent wholesale reference for scheduled electricity delivery, based on the matching of supply and demand bids submitted by market agents [76]. OMIE also publishes day-ahead prices for the Portuguese and Spanish electricity systems, making this market signal

a common reference for the external value of electricity in Iberian studies and planning exercises [77]. However, this wholesale reference should not be confused with the final price paid or received by consumers, suppliers or CSC arrangements. In practice, economic exposure depends on commercial contracts, regulated tariffs and the specific remuneration conditions applied to exported surplus electricity.

For consumers and RECs in Portugal, the relevant electricity-price structure is therefore broader than the wholesale market price alone. Consumers in the liberalised market may choose their electricity supplier, while regulated components remain defined under the national tariff and market-supervision framework [78]. The final electricity bill includes both energy-related components and regulated charges associated with the use of the electricity system [79].

From a planning perspective, the main price components can be summarised as follows:

- **Wholesale market reference**: The day-ahead market price published by OMIE, which provides a transparent reference for the value of electricity in the Iberian market [77];
- **Supply or retail energy price**: The energy price defined in the contract between the consumer and the electricity supplier. It may be fixed, indexed or structured according to time-of-use periods [78]. Regulated components also affect the final amount paid by consumers [79];
- **Export or feed-in remuneration**: The value received for surplus electricity injected into the grid, usually defined through a commercial arrangement or indexed to market conditions [78];
- **Network access tariffs**: Regulated charges associated with the use of electricity networks and reserve services, defined by Entidade Reguladora dos Serviços Energéticos (ERSE) and applied independently of the selected electricity supplier [79];
- **Contracted power term**: The cost associated with the maximum power level contracted by the consumer, which affects the fixed component of the electricity bill [79];
- **Taxes and other regulated charges**: Fiscal and regulatory components that contribute to the final electricity bill but are not directly determined by the wholesale energy market [79].

These components show why electricity-market participation and tariff design are relevant for long-term planning. Local renewable generation, storage and CSC do not simply reduce the amount of electricity exchanged with the grid. They also change how consumers and communities are exposed to wholesale references, retail contracts, export remuneration, network charges and contracted power costs. Consequently, market and tariff structures influence the economic attractiveness of PV generation, BESS capacity and flexibility-oriented operation.

### 2.4.2 European Harmonisation and Portuguese Balancing Framework

The operational role of balancing services is embedded in a wider European framework. Because Continental European power systems are strongly interconnected, frequency control and

balancing cannot be treated as purely national tasks. An imbalance in one control area can affect neighbouring systems, which makes cross-border coordination necessary to preserve operational security. The European framework has therefore moved towards common principles, coordinated products and harmonised rules for system operators [80]. Three institutional references are central to this framework:

- **European Network of Transmission System Operators for Electricity (ENTSO-E)** coordinates the European TSOs and supports the development and implementation of common network codes and balancing platforms [81];
- **System Operation Guideline (SOGL)** sets common rules for secure transmission-system operation, including operational security, regional coordination and load–frequency control [82];
- **Electricity Balancing Guideline (EBGL)** defines the European framework for electricity balancing, including common principles for the procurement and settlement of frequency containment, frequency restoration and replacement reserves [83].

Within this framework, balancing services are procured and activated by the TSOs, which are responsible for keeping the system balanced and the frequency stable in real time [83]. In Portugal, this role is performed by Redes Energéticas Nacionais (REN), the national TSO and overall technical manager of the system [84]. The national implementation is set out in the Manual de Procedimentos da Gestão Global do Sistema (MPGGS), which defines the procedures, products and operational rules for system management and balancing in the Portuguese system [85]. Balancing is therefore increasingly harmonised at European level, while the practical conditions for participation remain tied to national procedures and market-implementation choices.

From an operational perspective, reserve provision involves two distinct but related components: the availability of reserve capacity and the subsequent activation of balancing energy. Capacity provision requires a resource to maintain sufficient upward or downward flexibility, even when no activation occurs, while balancing-energy activation corresponds to the actual response requested by the TSO. This distinction is particularly relevant for storage-based resources. Reserving part of the available power may restrict their operation in the energy market, whereas an activation directly changes the stored energy and may require subsequent recovery of the SoC. Reserve participation therefore creates an intertemporal link between market availability, actual activation and the operational state of flexible resources [83].

The Continental European synchronous area, to which Portugal belongs, operates at a nominal frequency of 50 Hz. An imbalance between generation and demand causes the frequency to deviate from this value: a generation deficit leads to a frequency decrease, whereas a surplus leads to an increase. Frequency-related AS provide coordinated responses to contain these deviations and restore the balance between generation and demand. These services differ in their activation speed, control mechanism and operational purpose. Frequency Containment Reserve (FCR) initially arrests the frequency excursion, while automatic Frequency Restoration Reserve (aFRR)

and mFRR contribute to restoring the frequency to 50 Hz and the scheduled power exchanges. Replacement Reserve (RR), where used, subsequently replaces activated reserves and helps rebuild reserve availability [82], [83]. Figure 2.8 illustrates these complementary layers through a schematic frequency drop and subsequent recovery towards the nominal value.

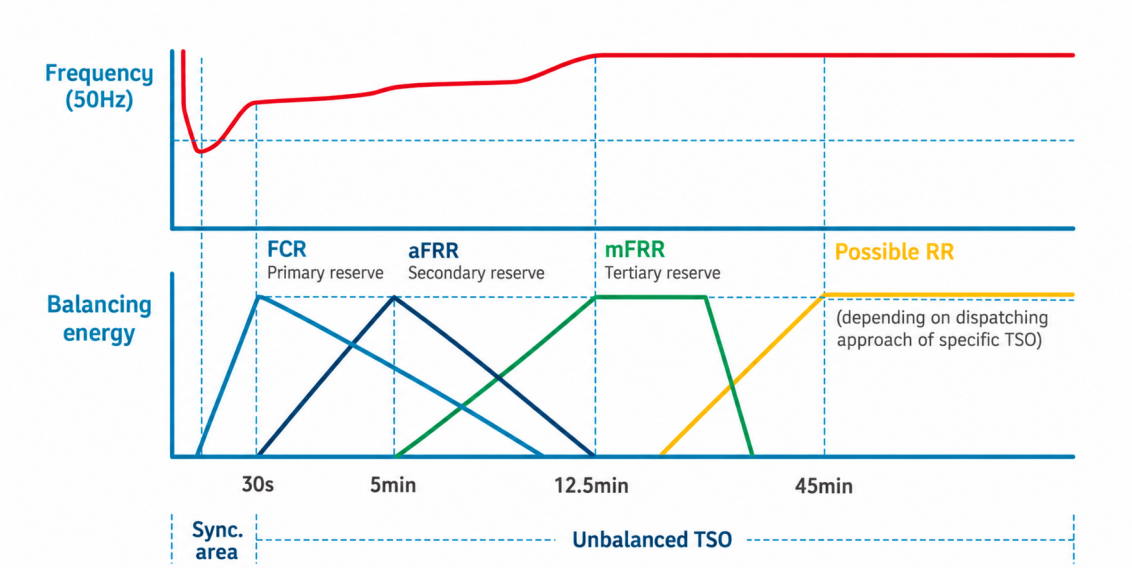



Figure 2.8: Layered activation of frequency control and balancing services. Adapted from [86].

The reserves shown in Figure 2.8 can be summarised as follows:

- **FCR** is the first automatic response to a frequency deviation. It acts locally within seconds to arrest the excursion and stop the frequency from drifting further from its nominal value [82];
- **aFRR** restores the frequency and the scheduled exchanges after the containment stage. It is activated automatically by the TSO through centralised control signals [83];
- **mFRR** is a manually activated restoration layer for larger or more sustained imbalances. It has a less immediate response requirement than FCR and aFRR [83];
- **RR** is the slowest layer. It has historically been used to restore or release previously activated reserves after prolonged imbalances [83].

European harmonisation has also led to common balancing-energy platforms, which pool national offers into shared cross-border merit orders. Platform for the International Coordination of Automated Frequency Restoration and Stable System Operation (PICASSO) supports the exchange of aFRR balancing energy [87]. Manually Activated Reserves Initiative (MARI) provides the corresponding platform for mFRR, which REN joined on 27 November 2024 [88]. Replacement reserves were exchanged through Trans European Replacement Reserves Exchange (TERRE) [89]. This platform has since been wound down, with operations ceasing on 30 December 2025, the date on which REN disconnected, and formal decommissioning taking place

in March 2026 [89]. This followed the 2024 reform of the EU electricity market design, introduced by Regulation (EU) 2024/1747 [90]. Its harmonised intraday gate-closure time, set at 30 minutes before real time, is incompatible with the long activation time of the replacement-reserve process [91]. Regulation (EU) 2019/943 requires each Nominated Electricity Market Operator (NEMO) to provide day-ahead and intraday trading intervals at least as short as the imbalance settlement period. In the Iberian market, 15-minute products were introduced in the intraday auctions and continuous market on 18 March 2025, while the day-ahead market transitioned from an hourly to a 15-minute Market Time Unit (MTU) for delivery from 1 October 2025 [92], [93], [94].

### 2.4.3 Manual Frequency Restoration Reserve as a Planning-Oriented Flexibility Product

Of the balancing products introduced above, mFRR is the one retained in this work. As a manually activated restoration layer, it sits between the fully automatic reserves and the now-discontinued replacement reserves. It also offers a more accessible entry point for aggregated community flexibility than faster balancing products. This subsection explains how mFRR is defined and implemented in Portugal, and why it is the balancing product best suited to a REC.

The mFRR is a standardised European product. Its core characteristics are defined in the EBGL [83] and, in more detail, in the methodology for a list of standard balancing-capacity products approved by European Union Agency for the Cooperation of Energy Regulators (ACER) under Decision No 11/2020 [95]. These rules are implemented nationally through the MPGGS [85]. The main parameters are summarised in Table 2.6.

Table 2.6: Main characteristics of the standard mFRR product as implemented in Portugal [85].

| **Characteristic** | **Value / description** |
|---|---|
| Activation mode | Manual, dispatched by the TSO |
| Full activation time | Up to 12.5 minutes |
| Scheduled-activation time | 12.5 minutes before the start of the delivery period |
| Minimum bid | 1 MW |
| Bid resolution | 1 MW |
| Direction | Upward or downward |
| Market time unit / validity | 15 minutes |
| Location | Portuguese load-frequency control area |
| Energy pricing | Marginal, based on the last accepted bid |

The mFRR is contracted in two distinct stages, namely capacity procurement and energy activation. The daily mFRR band is procured ahead of delivery, with reference to the next-day scheduling horizon, as established in Chapter XVI of the MPGGS, Articles 181-186 [85]. This follows the standard capacity-product characteristics defined in ACER Decision No 11/2020 [95]. The second stage concerns balancing energy. The contracted band may be activated close to real time and exchanged through the European MARI platform [96], under Article 20 of the EBGL [83]

and Chapter XVII of the MPGGS [85]. Each stage carries its own remuneration: contracted capacity is paid at the marginal price of the band, as established in Article 191 of Chapter XVI, while activated energy is remunerated at the corresponding marginal mFRR price, as established in Article 218 of Chapter XVII [85]. This two-stage structure is illustrated in Figure 2.9.

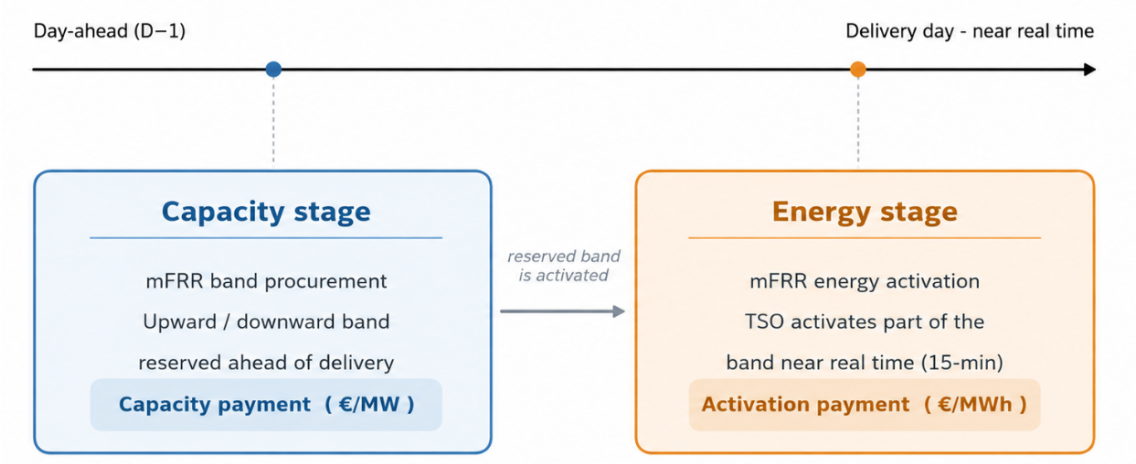



Figure 2.9: Two-stage structure of mFRR participation.

From a planning perspective, reserving storage capacity for mFRR introduces an opportunity cost. The power and energy reserved for reserve provision cannot simultaneously be used for alternative applications such as increasing self-consumption, reducing peak demand or performing energy arbitrage. Consequently, the economic attractiveness of reserve participation depends not only on the remuneration received for capacity reservation and energy activation, but also on the value of these foregone operational opportunities.

FCR is designed to correct instantaneous imbalances between generation and consumption through an immediate and autonomous response to frequency deviations. In the Portuguese framework, it is described as a mandatory and non-remunerated reserve service for technically capable production installations, as defined in Article 135 of the MPGGS [85]. Its provision is mainly associated with installations directly connected to the transmission network, as established in Article 137 [85]. The response requirement is also very demanding. Article 138 states that the resulting power variation must be delivered within 15 seconds for frequency deviations below 100 mHz, and linearly between 15 and 30 seconds for deviations between 100 and 200 mHz [85], conditions that limit the suitability of FCR for residential community resources.

aFRR also imposes demanding technical requirements on participating resources. It is activated automatically through centralised control and requires resources to follow automatic control signals associated with load-frequency control and area-control-error correction [83]. This requires communication, monitoring and control infrastructure capable of supporting continuous automatic activation. Such requirements are often difficult to satisfy with small distributed resources, especially when they are owned by different end-users and coordinated through a community framework. The need for fast and dedicated control capability is widely recognised as a barrier for DERs in faster frequency-response services [97].

mFRR has a different technical profile. It is manually activated through discrete instructions and has a full activation time of up to 12.5 minutes, as shown in Table 2.6. This makes its activation requirements less restrictive than those of FCR and aFRR. In practice, this type of product is more compatible with aggregated DERs, particularly BESS units, because the response does not require autonomous second-by-second frequency control. Aggregation and market representation remain important, since individual residential assets are generally too small to participate directly in organised balancing markets [80], [98].

In the context of asset sizing, the capacity band and the possible activation of balancing energy create an additional value stream whose magnitude depends on the available power and energy capacity of flexible resources.

Offering reserve also requires power and energy headroom, which links reserve provision to storage sizing, operational scheduling and contracted power limits. These aspects provide the theoretical basis for the optimisation model developed in Chapter 3.

## 2.5 Comparative Review and Research Positioning

### 2.5.1 Scope and Selection Criteria

After establishing the theoretical background on RECs, distributed flexibility, optimisation-based planning, electricity markets and reserve services, this section reviews the contributions that are closest to the scope of the dissertation.

Scientific sources were identified through academic databases and publisher platforms such as Scopus, Web of Science, Institute of Electrical and Electronics Engineers (IEEE) Xplore, ScienceDirect and Google Scholar. The search combined terms related to RECs, CSC, PV and BESS sizing, investment planning, energy sharing, reserve-market participation and flexibility provision. Additional sources were identified through cross-referencing.

Given the nature of SITEC as a planning decision-support tool, the reviewed works were selected according to their proximity to the investment and sizing perspective adopted in this dissertation. Priority was given to studies that address at least one of the following dimensions:

- Planning or sizing of PV, BESS or contracted power in RECs, where investment decisions are evaluated through optimised operation;
- Operational scheduling of community resources under energy-market, tariff or self consumption objectives, used as a basis for evaluating candidate sizing configurations;
- Participation of BESS or aggregated DERs in reserve markets, particularly when this affects the sizing or planning of storage assets;
- Combined planning-operation formulations where investment decisions and community operation are jointly evaluated.

Works focused exclusively on real-time market clearing, short-term dispatch without a planning perspective, or purely regulatory descriptions were not prioritised, since SITEC is a planning tool and not an operational market model. This selection allows a clear distinction between contributions that address investment decisions, those that evaluate operational flexibility, and those that link reserve participation to sizing outcomes.

### 2.5.2 Scientific Papers Review

A selection of scientific contributions is reviewed in this subsection to identify how existing optimisation-based approaches address planning, investment, storage sizing and flexibility provision in RECs. Rather than treating these dimensions independently, the reviewed works reveal a gradual progression from renewable investment and energy-sharing decisions towards storage coordination and, subsequently, participation in external flexibility and reserve markets. This progression is particularly relevant to the present dissertation, which combines these dimensions within a common planning framework.

At the investment level, [99] proposed an optimisation model for investment and energy-sharing decisions in a REC with multiple investing members. The model determines the optimal PV and wind generation capacities for each member and calculates the shared energy at each period, respecting site-specific deployment constraints. A case study with four REC members shows that CSC improves the economic performance relative to individual self-consumption and that the composition of the community influences how the benefits of shared generation are distributed. The work therefore establishes the relevance of considering investment and energy sharing jointly, although storage and reserve-market participation are not included as planning dimensions.

Extending this investment perspective to storage, [100] investigated the optimal sizing of PV and BESS systems for groups of jointly acting renewable self-consumers. The framework combines economic and environmental criteria and evaluates the trade-off between payback time, self-consumed energy, shared energy and carbon dioxide emissions. Across five progressively larger community configurations in Milan, collective operation improves both economic and environmental performance relative to individual prosumers. In contrast to the previous work, BESS capacity is therefore included in the sizing problem. However, the resulting operation is evaluated through a rule-based energy management system and neither contracted power nor reserve-market participation is considered.

The importance of the operational strategy adopted after sizing is further highlighted by [49]. In this case, a linear programming model jointly determines shared PV and communal BESS capacities and is soft-linked with power-flow analysis to assess the consequences of different community configurations, battery locations and operating strategies in urban, suburban and village distribution grids. The results show that the selected operating strategy can substantially modify both the optimal installed capacities and the resulting grid impact, with peak-shaving-oriented operation reducing low-voltage line loading by up to 58%. This establishes a direct link between planning and subsequent operation, but the value of storage remains associated with internal community and grid objectives rather than with external reserve provision.

Once storage is treated as an operationally flexible asset, a second line of research considers whether this flexibility can generate additional value through external services. In an REC context, [101] examined the role of BESS in enabling the provision of AS. Using the Savona campus of the University of Genoa as a case study, cooperative configurations with and without flexibility services are compared with a non-cooperative baseline. The analysis indicates that storage can simultaneously support community operation and create additional flexibility value for the grid, improving the economic performance of cooperative configurations when AS revenues are considered. However, the study primarily assesses the economic consequences of the considered configurations rather than making reserve participation an endogenous driver of the long-term sizing decision.

The economic value of using the same storage asset across several markets is explored more explicitly in [102]. The authors model a grid-connected BESS participating in energy, frequency-reserve and capacity markets and evaluate different combinations of revenue streams. The results show that stacking services can substantially outperform participation in individual markets, with joint energy and reserve participation increasing annual profits and producing a payback period of approximately 6.2 years after degradation and depreciation are considered. This work demonstrates that reserve revenues can materially change the economic value attributed to storage. Nevertheless, the framework is applied to an independent grid-connected BESS, rather than to an REC, and does not jointly optimise community generation, storage and contracted-power investment decisions.

The attractiveness of stacked revenues also makes the assumptions used to estimate them increasingly important. Building on this issue, [103] investigated how efficiency representation, operational uncertainty and battery degradation affect the economic assessment and sizing of a BESS participating in day-ahead and reserve markets. The authors show that simplified modelling assumptions can overestimate long-term profits by approximately 20–30%, with even larger deviations for some high power-to-energy configurations. The analysis also identifies power-to-energy ratios of 1 and 0.5 as the most profitable among the investigated configurations. These results demonstrate that reserve-related revenues cannot be treated independently of the assumptions used to represent actual operation, reinforcing the need for conservative representations of reserve availability in planning models.

Bringing these market-oriented considerations back to the community level, [104] investigated the simultaneous operation of an REC under CSC and mFRR provision. A MILP model schedules residential prosumers equipped with PV and BESS, explicitly representing battery SoC, subscription-power limits, reserve capacity and activated balancing energy. The formulation therefore captures the trade-off between using storage internally and maintaining flexibility for external balancing services. Using real data from a French REC, the authors report cost savings between 4.8% and 13.3%, mainly associated with upward regulation revenues. Among the reviewed contributions, this is one of the closest to the scope of the present dissertation because both CSC and mFRR are represented within the same optimisation framework. Its focus, however, remains operational: the installed PV and BESS capacities and the subscription-power levels are inputs rather

than planning variables.

A different way of linking community operation and storage value is proposed in [71], where an independent battery operator rents part of a grid-connected storage asset to an energy community while retaining the possibility of obtaining revenues from the day-ahead market. The framework determines economically viable rental prices and storage capacities and shows that the optimal amount of rented capacity depends strongly on the applicable tariff structure. For the analysed case, renting storage can generate meaningful annual savings for the community while maintaining profitability for the battery operator. This introduces an alternative ownership and stacked-revenue perspective in which storage sizing responds to both community and market value. However, reserve activation is not represented and the framework does not jointly determine PV, BESS and contracted power under reserve-market participation.

### 2.5.3 Overview of Reviewed Contributions and Research Positioning

The reviewed contributions show that the literature already addresses several important components of REC planning and operation, but these components are usually treated separately. Table 2.7 summarises the main modelling dimensions covered by each contribution and compares them with the scope of this dissertation. Although individual studies address several of these dimensions, no single framework simultaneously integrates all of them.

Table 2.7: Overview of reviewed scientific contributions.

| Reference | REC | Sizing PV | Sizing BESS | Sizing Contr. Power | Operation | Energy market | Reserve/AS |
|---|---|---|---|---|---|---|---|
| [99] | ✓ | ✓ | - | - | ✓ | ✓ | - |
| [100] | ✓ | ✓ | ✓ | - | ✓ | - | - |
| [49] | ✓ | ✓ | ✓ | - | ✓ | ✓ | - |
| [101] | ✓ | - | - | - | ✓ | ✓ | ✓ |
| [102] | - | - | - | - | ✓ | ✓ | ✓ |
| [103] | - | - | ✓ | - | ✓ | ✓ | ✓ |
| [104] | ✓ | - | - | - | ✓ | ✓ | ✓ |
| [71] | ✓ | - | ✓ | - | ✓ | ✓ | - |
| **This dissertation** | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ |

*Note:* ✓ = explicitly addressed; - = not addressed.

The comparison in Table 2.7 reveals three distinct groups. The first group, including Carvalho et al., Blasuttigh et al. and Weckesser et al., addresses PV and BESS sizing in RECs under energy-market and self-consumption objectives [49], [99], [100]. These works treat investment planning as the central problem but do not incorporate reserve-market revenues into the sizing decision, which means the value of maintaining storage headroom for flexibility provision is absent from the investment evaluation.

The second group, including Ferrucci et al., Mohamed et al. and Mustika et al., explicitly addresses reserve or ancillary service provision [101], [102], [103], [104]. These contributions

show that reserve participation can significantly improve the economic performance of storage assets and that modelling assumptions about activation constraints and degradation materially affect planning outcomes. However, these studies either assume fixed asset configurations or focus on operational dispatch rather than integrated sizing decisions.

The third group, represented by Pocola et al., introduces stacked-revenue thinking into an REC context but stops short of jointly optimising PV, BESS and contracted power as planning variables [71].

Among all reviewed works, Mustika et al. remains the closest to the scope of this dissertation because it explicitly models CSC and mFRR provision in an REC with SoC constraints and reserve activation [104]. Even so, the study is operational and does not optimise the installed capacities or the contracted power level.

The proposed dissertation therefore positions itself at the intersection of these three groups. It develops a planning decision-support framework for RECs that combines PV sizing, BESS sizing, contracted power optimisation, CSC, energy-market interaction and mFRR-oriented flexibility within a single tractable MILP formulation. The key contribution relative to the existing literature is that reserve participation is not treated as an operational add-on to fixed assets, but as a driver of long-term investment decisions: how much storage, generation and grid capacity should be planned when flexibility revenues are part of the economic picture. This positioning provides the basis for the mathematical formulation presented in Chapter 3.

# Chapter 3

# Modelling Framework for Joint Energy-Market and mFRR Participation in RECs

This chapter presents the modelling framework used to integrate mFRR participation into the planning of RECs. It begins by defining the community structure, its interaction with external markets and the aggregation boundary adopted for reserve provision. The SITEC planning framework is then presented, including its architecture, input structure and mathematical formulation for the joint sizing of PV, BESS and contracted power under energy and mFRR market participation.

The formulation implemented in Python builds on the SITEC framework previously developed at Institute for Systems and Computer Engineering, Technology and Science (INESC TEC) for the joint optimisation of PV, BESS and contracted power under energy-market operation [105]. The extension makes the reserve capability dependent on the storage capacity selected by the planning problem, allowing reserve revenues and operating requirements to affect the investment decision. This coupling is endogenous: the installed storage capacity and the associated reserve capability are determined jointly within the optimisation, rather than specified independently beforehand. SITEC is formulated as a deterministic, single-stage MILP and assumes perfect foresight of the exogenous input trajectories over the planning horizon.

## 3.1 REC Structure and Market Interaction

The REC is modelled as a pool-based community of residential prosumers connected through a local energy sharing structure, following the REC concept introduced in Subsection 2.1.2. Each member has an individual metering point equipped with behind-the-meter PV and BESS systems.

Within the REC, locally generated energy can be shared among members through internal transactions, which supports the collective management of distributed flexibility and improves the use of local renewable generation, in line with the sharing mechanisms reviewed in Subsection 2.1.4. At the same time, members remain connected to the external electricity market and can

import or export energy whenever local generation and consumption are not balanced within the community.

The flexibility considered for mFRR provision is supplied by the members' BESS units. Individual reserve contributions are determined subject to storage availability and technical operating limits and are aggregated at community level. The REC is therefore represented as a single flexibility resource for market participation, consistent with the aggregation framework discussed in Subsection 2.2.3 and with the mFRR product retained in Subsection 2.4.3.

Figure 3.1 illustrates the REC structure considered throughout this dissertation. The REC interacts with external electricity markets through retailers and OMIE-indexed transactions, while the proposed extension additionally considers participation in the reserve market (mFRR) through an aggregation mechanism.

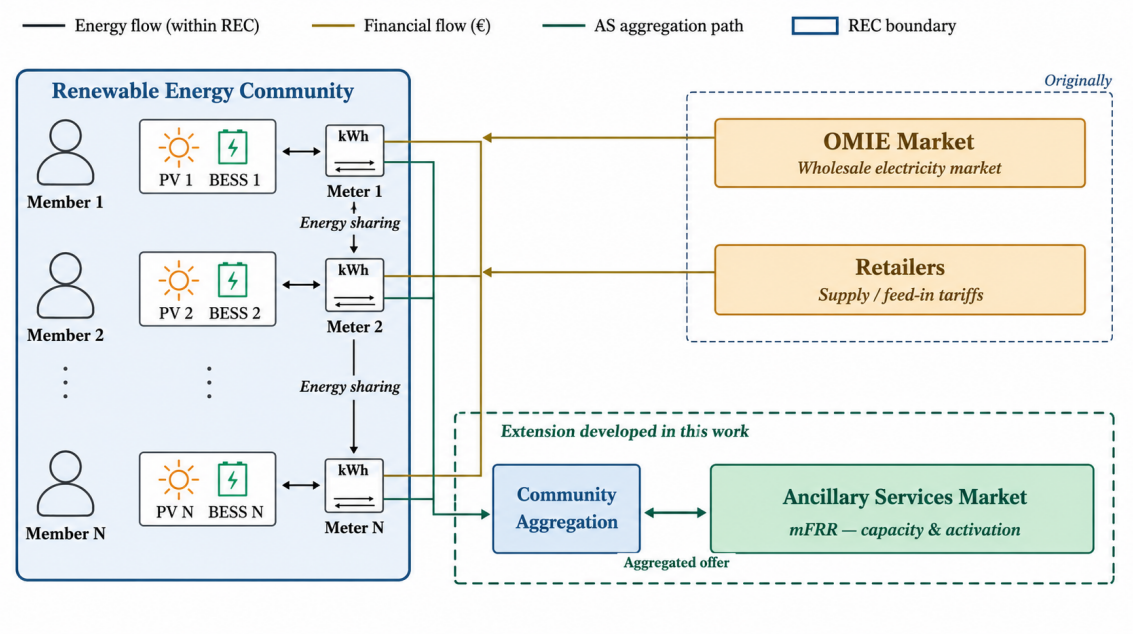



Figure 3.1: Conceptual REC structure and market interaction framework.

The economic boundary of the optimisation includes only cash flows directly attributable to the REC, as shown in Figure 3.2. These comprise electricity purchases and surplus sales through the retailer, contracted-power charges, PV and BESS investment costs and the gross reserve revenues associated with the REC's contribution to the aggregated mFRR offer. The remaining portfolio managed by the external aggregator is outside the formulation. Commercial arrangements such as remuneration sharing, market-access costs and portfolio-management fees are therefore not modelled.

For the residential REC examined in Chapter 4, the available reserve is also below the 1 MW standard mFRR minimum bid reported in Table 2.6. Therefore, the formulation further assumes that an aggregator combines the REC contribution with other flexibility resources and is always able to accommodate its contribution within a larger portfolio, without explicitly representing competition for pooled capacity or the possibility of the REC's offer being rejected.

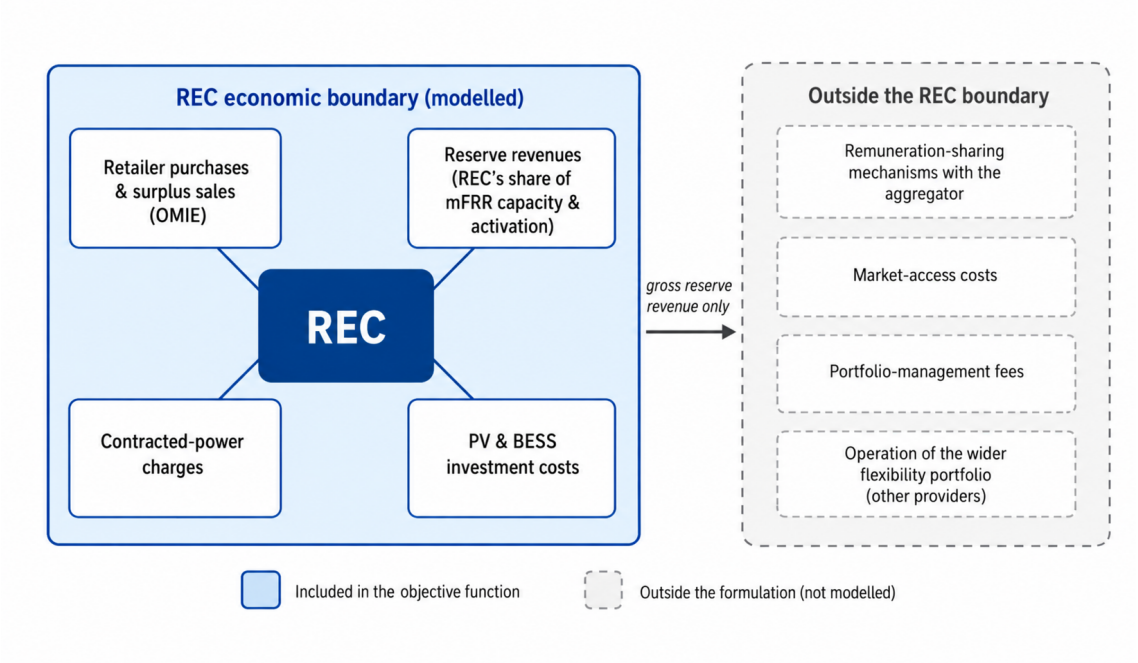



Figure 3.2: Economic boundary of the REC in the optimisation model, distinguishing modelled cash flows from aggregator-level arrangements outside the formulation's scope.

## 3.2 SITEC Planning Framework

### 3.2.1 SITEC Architecture and Optimisation Workflow

SITEC solves the planning problem as a single-stage community-level MILP in which investment and operation are co-optimised. The framework jointly determines the PV and BESS capacities and contracted power of each member while evaluating these decisions through the energy and reserve-market operation they enable.

Sizing decisions are not evaluated independently from the operation they enable. Instead, each investment decision is assessed through its consequences over the complete optimisation horizon, including energy exchanges, storage utilisation and reserve provision. This coupling is particularly relevant for the BESS, since its installed capacity determines both the energy available for operational scheduling and the reserve capability that can be offered to the mFRR market. Reserve participation is therefore incorporated directly into the planning decision rather than evaluated as an additional revenue stream after the capacities have been selected.

Figure 3.3 summarises the framework in three main layers. The input layer combines member demand and PV availability profiles with market signals and the technical and economic parameters required by the optimisation. These data are processed within SITEC, where operational scheduling and joint energy and mFRR participation are evaluated together with the sizing decisions. The resulting solution provides the selected PV and BESS capacities and contracted power, as well as the corresponding energy exchanges, BESS schedules, mFRR reserve allocation and economic performance indicators of the REC.

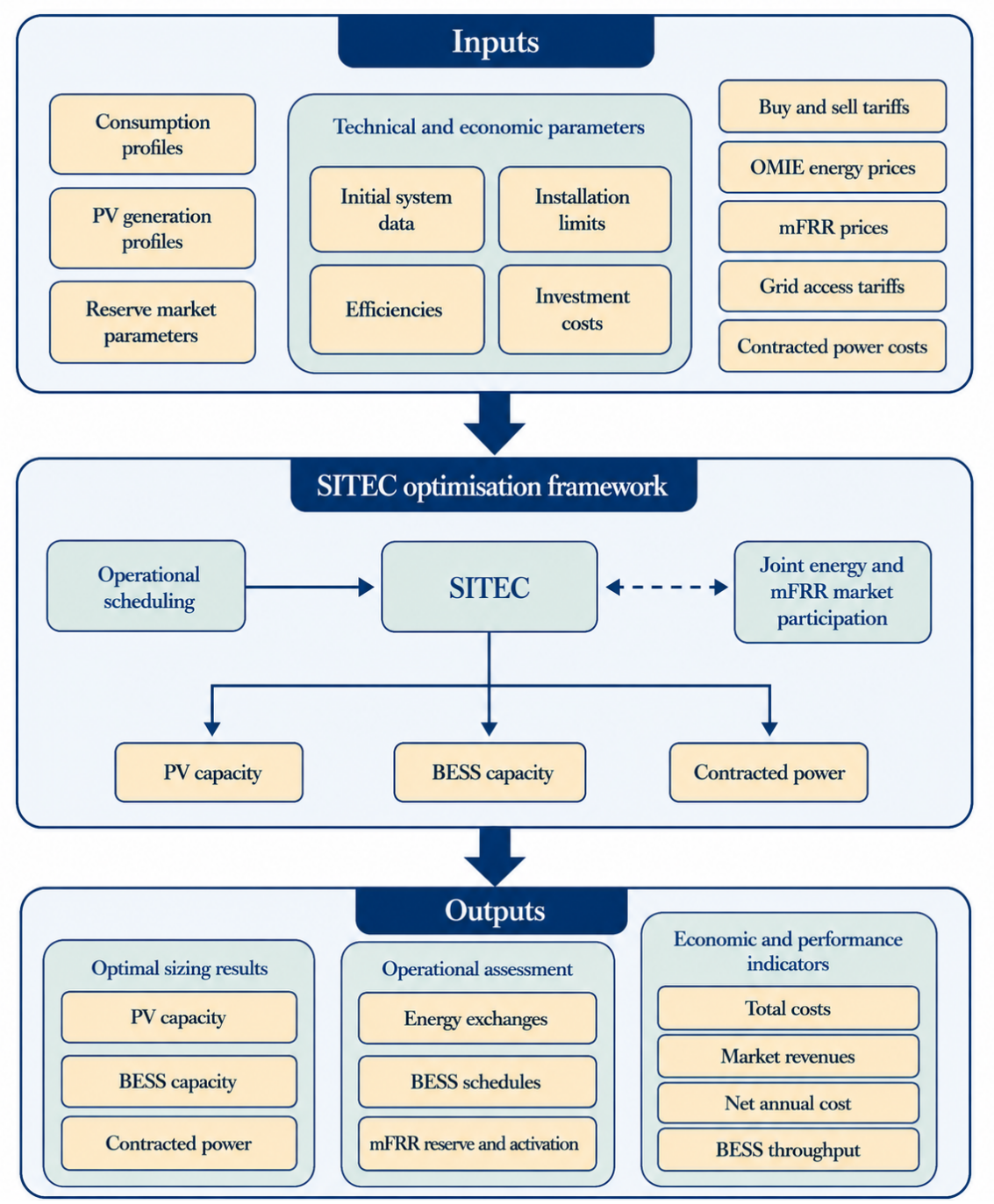



Figure 3.3: SITEC architecture and optimisation workflow.

### 3.2.2 SITEC Model Overview

The optimisation model is defined over a set of time intervals $t \in T$ and a set of community members, or connection points, $n \in N$. These index sets are used consistently throughout the formulation.

Figure 3.4 summarises the inputs required by SITEC. Member data include demand and PV availability profiles, retailer tariffs, the grid access tariff applied to CSC, the contracted-power tariff and the physical limit of each connection point. In the case study, $\hat{\lambda}^{buy}_{n,t}$ represents the retailer supply tariff, while $\hat{\lambda}^{sell}_{n,t}$ follows the OMIE day-ahead price for exported surplus. PV and BESS data include investment coefficients, admissible installation bounds, pre-existing capacities and the technical parameters governing storage efficiency, SoC and power capability.

The reserve-market inputs comprise capacity and activation prices, deterministic activation ratios $\hat{\rho}^{ACT,UP}_{t}$ and $\hat{\rho}^{ACT,DW}_{t}$, robustness factors $\hat{\varepsilon}^{UP}$ and $\hat{\varepsilon}^{DW}$, and the reserve power scaling parameter $\hat{\alpha}^{RES}_{n}$. The activation ratios define the historical activation envelope applied to each offered band, while the robustness factors reduce the share of that envelope considered available to the planner. The parameter $\hat{\alpha}^{RES}_{n}$ links the installed BESS energy capacity to the maximum reserve power admitted by the planning model. Their numerical construction and the values adopted in the case study are presented in Subsection 4.1.3. As SITEC is deterministic, all exogenous input trajectories are assumed known over the optimisation horizon.

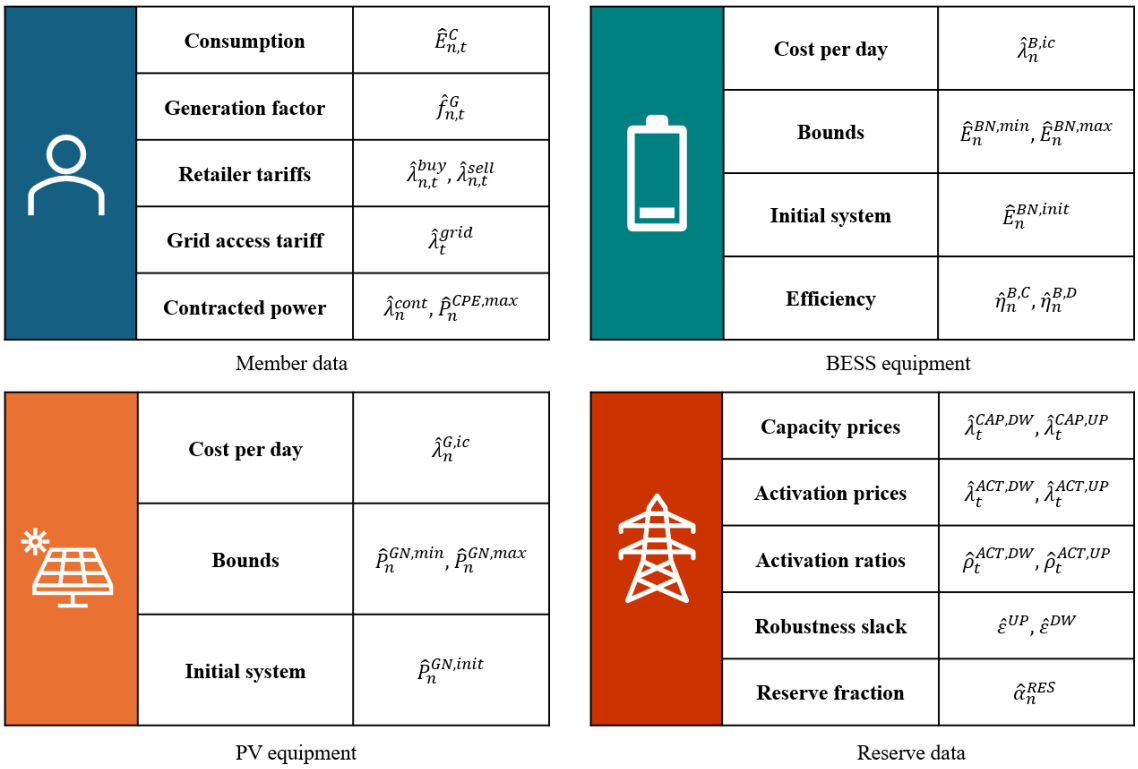



Figure 3.4: Input data for SITEC.

### 3.2.3 Mathematical Formulation of SITEC

The mathematical formulation combines the investment variables with the operating decisions required to evaluate each candidate configuration over the planning horizon. The objective function establishes the economic trade-off between energy operation, investment and reserve revenues, while the subsequent constraint blocks represent reserve participation, meter exchanges, asset sizing, BESS operation, local energy sharing and the variable domains, which specify whether each decision variable is non-negative, unrestricted in sign or binary.

The original SITEC formulation already co-optimised PV and BESS sizing, contracted power and community operation, including retailer exchanges, BESS scheduling and local energy sharing. The extension developed in this dissertation adds the mFRR layer at the points where reserve participation directly interacts with the planning problem. Reserve capacity and activation revenues are incorporated into the objective function, the offered reserve bands are coupled to the dimensioned BESS capacity in the reserve market participation block, and activated reserve energy is integrated into both the meter energy balance and the BESS operation constraints. The variable domains are also extended to include the additional reserve-related decisions, while the local energy sharing, self-consumption and allocation structure follows the original SITEC formulation.

Throughout the formulation, power quantities are expressed in kW and energy quantities in kWh. The parameter $\Delta t$ denotes the duration of each optimisation interval in hours, while $\hat{D}$ denotes the number of days in the optimisation horizon. Energy prices and tariffs are expressed in EUR/kWh, and reserve-capacity prices in EUR/(kW h). The contracted-power tariff and the PV investment coefficient are expressed in EUR/(kW day), whereas the BESS investment coefficient is expressed in EUR/(kWh day). Each term in Equation 3.1 therefore represents a monetary amount in EUR over the same optimisation horizon.

Multiplication by $\Delta t$ converts power into energy, or a capacity payment rate into the payment for one interval. Conversely, dividing interval energy by $\Delta t$ gives average power. No additional time factor is required when an energy price is multiplied directly by an energy quantity. The case study adopts $\Delta t = 1$ h.

#### 3.2.3.1 Objective Function

The objective function in Equation 3.1 minimises the total cost of the REC over the planning horizon, combining the operational cost of the community, the contracted-power and investment costs, and the revenues from reserve market participation.

$$\begin{aligned}\min \quad & \sum_{t\in T}\sum_{n\in N}\left(\hat{\lambda}_{n,t}^{buy}E_{n,t}^{SUP}-\hat{\lambda}_{n,t}^{sell}E_{n,t}^{SUR}+\hat{\lambda}_{t}^{grid}E_{n,t}^{SLC}\right)\\ & +\sum_{n\in N}\left(P_{n}^{CONT}\hat{\lambda}_{n}^{cont}\hat{D}+P_{n}^{GN}\hat{\lambda}_{n}^{G,ic}\hat{D}+E_{n}^{BN}\hat{\lambda}_{n}^{B,ic}\hat{D}\right)\\ & -\sum_{t\in T}\left(\hat{\lambda}_{t}^{CAP,DW}P_{t}^{RES,DW}+\hat{\lambda}_{t}^{CAP,UP}P_{t}^{RES,UP}\right)\Delta t\\ & -\sum_{t\in T}\left(\hat{\lambda}_{t}^{ACT,DW}E_{t}^{ACT,DW}+\hat{\lambda}_{t}^{ACT,UP}E_{t}^{ACT,UP}\right)\end{aligned} \tag{3.1}$$

The first term gathers the operational cash flows of every member. The energy imported from and exported to the retailer, $E_{n,t}^{SUP}$ and $E_{n,t}^{SUR}$, is priced at the supply and feed-in tariffs $\hat{\lambda}_{n,t}^{buy}$ and $\hat{\lambda}_{n,t}^{sell}$. The self-consumed energy $E_{n,t}^{SLC}$ is subject only to the applicable grid access tariff $\hat{\lambda}_{t}^{grid}$[1], thereby preserving the economic benefit of consuming locally shared energy instead of purchasing the equivalent amount from the retailer.

The second term gathers the contracted-power and investment costs. The contracted power $P_{n}^{CONT}$ and the new PV and BESS capacities $P_{n}^{GN}$ and $E_{n}^{BN}$ are priced through the tariffs $\hat{\lambda}_{n}^{cont}$, $\hat{\lambda}_{n}^{G,ic}$ and $\hat{\lambda}_{n}^{B,ic}$. These costs are expressed on an equivalent daily basis and multiplied by the number of days in the optimisation horizon $\hat{D}$, placing them on the same temporal basis as the operational cash flows.

The last two terms represent the reserve market revenues, which enter with a negative sign because they reduce the total cost of the community. They mirror the two-stage structure of mFRR participation described in Subsection 2.4.3, where reserve capacity and activated energy are remunerated separately. The capacity revenue rewards the upward and downward bands $P_{t}^{RES,UP}$ and $P_{t}^{RES,DW}$ that the REC keeps available, remunerated at $\hat{\lambda}_{t}^{CAP,UP}$ and $\hat{\lambda}_{t}^{CAP,DW}$, regardless of whether they are activated. The activation revenue rewards the energy actually delivered, $E_{t}^{ACT,UP}$ and $E_{t}^{ACT,DW}$, remunerated at $\hat{\lambda}_{t}^{ACT,UP}$ and $\hat{\lambda}_{t}^{ACT,DW}$, when the TSO activates the contracted reserve.

#### 3.2.3.2 Reserve Market Participation

Reserve participation must remain coupled to the storage capacity selected by the planning problem. A member can therefore offer reserve only within a power limit that reflects the capability of its dimensioned BESS. Before defining this coupling, it is necessary to distinguish the hourly planning representation adopted in SITEC from the sub-hourly technical requirement of the mFRR product. As established in Subsection 2.4.3, the committed reserve power must be fully reached within a maximum activation time of 12.5 min. Figure 3.5 illustrates this requirement through the limiting case in which the committed reserve power is reached at the maximum admissible time.

[1]The grid access tariff applied to CSC follows the Portuguese global system management procedures defined by ERSE [85]. In regulatory contexts where no such charge applies, this tariff can be set to zero.

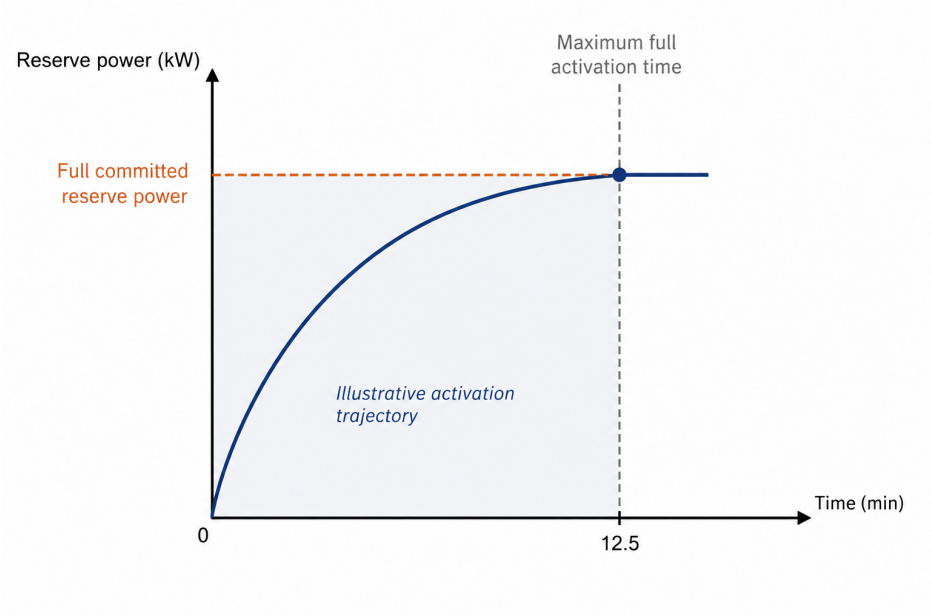



Figure 3.5: Conceptual representation of the mFRR full activation time requirement. The activation trajectory is illustrative and does not represent a technology-specific BESS response.

SITEC is a planning model and does not resolve the sub-hourly activation trajectory illustrated in Figure 3.5. The formulation therefore does not include explicit ramp variables or intermediate activation states within the 12.5 min interval. Compliance with this response-time requirement is assumed for the participating BESS, rather than verified by the hourly planning formulation. This abstraction preserves the tractability of the planning problem while avoiding the explicit representation of sub-hourly control dynamics that fall outside the scope of SITEC.

To couple reserve capability directly to the sizing decision, the maximum reserve power available from the BESS of each member is defined as a function of its installed energy capacity through Equation 3.2.

$$P_n^{max} = \hat{\alpha}_n^{RES} \frac{E_n^{BN,total}}{\Delta t} \qquad \forall n \in N \tag{3.2}$$

The variable $P_n^{max}$ represents the maximum reserve power that the BESS of member $n$ may make available for reserve provision, given the total installed BESS capacity $E_n^{BN,total}$ selected by the optimisation. The dimensionless parameter $\hat{\alpha}_n^{RES}$, with $0 \leq \hat{\alpha}_n^{RES} \leq 1$, scales the reserve power that may be associated with this installed energy capacity over the optimisation interval $\Delta t$. It therefore represents an assumption on the reserve-power capability available to the planning model rather than a fixed fraction of battery energy physically reserved or discharged for mFRR. This parameter limits the reserve power available to the planning model but does not establish compliance with the 12.5-minute full activation requirement, which would require a separate assessment of the BESS response and control capabilities. The numerical assumptions adopted for $\hat{\alpha}_n^{RES}$ are presented in Subsection 4.1.3 and Subsection 4.2.1.

This sizing-dependent formulation allows reserve participation to influence the storage investment decision. A larger dimensioned BESS capacity increases the reserve power that may be offered for a given value of $\hat{\alpha}_n^{RES}$, allowing the optimisation to account jointly for the investment cost of additional storage and the economic value obtained from reserve participation. Relative to the conference paper developed as part of this dissertation [106], where the reserve power limit was specified exogenously, the present formulation therefore allows this limit to evolve with the storage capacity selected by the planning problem.

The upward and downward reserve bands offered by each member are bounded by $P_n^{max}$ through Equations 3.3-3.4.

$$0 \leq P_{n,t}^{RES,UP} \leq P_n^{max} \qquad \forall t \in T, n \in N \tag{3.3}$$

$$0 \leq P_{n,t}^{RES,DW} \leq P_n^{max} \qquad \forall t \in T, n \in N \tag{3.4}$$

These constraints limit the reserve band that may be committed by each member rather than the physical power rating of the BESS itself. The charging and discharging capability is enforced separately in Equations 3.22-3.23, where scheduled BESS operation and reserve headroom must jointly remain within the storage power limit. The 1 MW minimum bid reported in Table 2.6 is not imposed at REC level because market access is represented through the external aggregation assumption defined in Section 3.1.

Contracting a reserve band does not imply that the full band will be activated. Actual TSO activation is uncertain and occurs on a shorter operational timescale than the planning problem. Since SITEC is deterministic, stochastic activation signals and intraday corrections are not modelled explicitly. Historical activation ratios $\hat{\rho}_t^{ACT,UP}$ and $\hat{\rho}_t^{ACT,DW}$ are therefore used to relate the offered reserve bands to the activation levels represented within each optimisation interval, as defined by Equations 3.5-3.6.

$$0 \leq E_{n,t}^{ACT,DW} \leq \hat{\rho}_t^{ACT,DW} \left(1 - \hat{\varepsilon}^{DW}\right) P_{n,t}^{RES,DW} \Delta t \qquad \forall t \in T, n \in N \tag{3.5}$$

$$0 \leq E_{n,t}^{ACT,UP} \leq \hat{\rho}_t^{ACT,UP} \left(1 - \hat{\varepsilon}^{UP}\right) P_{n,t}^{RES,UP} \Delta t \qquad \forall t \in T, n \in N \tag{3.6}$$

The activation ratios define a deterministic historical envelope for the activated energy associated with each offered reserve band over one optimisation interval. Relying directly on this historical envelope would, however, imply that past activation behaviour is fully representative of future operation. This would introduce an overly confident representation of activation availability into a planning model that otherwise operates under perfect foresight of its exogenous inputs.

To limit reliance on historical activation levels, directional factors $\hat{\varepsilon}^{UP}, \hat{\varepsilon}^{DW} \in [0,1]$ are introduced. They represent fixed parameters selected by the analyst, following the baseline-tolerance approach proposed by Rodrigues et al. [107]. They are neither random variables nor optimisation decisions. A value of zero retains the historical activation envelope, whereas larger values reduce

the maximum activation energy admitted by the model. These factors provide a deterministic sensitivity mechanism. They do not remove the perfect-foresight assumption or guarantee feasibility under all possible activation trajectories.

Equations 3.5-3.6 impose upper bounds rather than an exogenously prescribed activation trajectory. Within these bounds, activated energy is selected by the optimiser according to the objective function and the remaining constraints. In actual operation, activation is instructed by the TSO. The provider cannot freely select the most profitable activation after committing reserve. The formulation therefore represents a planning approximation that may overestimate the value of activation flexibility. The construction of the historical ratios and the selected parameter values are detailed in Subsections 4.1.3 and 4.2.1.

Although upward and downward reserve bands may be contracted simultaneously, their physical activation corresponds to opposite system responses and cannot occur simultaneously within the same optimisation interval. A common binary variable $\delta_t^{ACT,UP}$ is therefore introduced to enforce a single activation direction across all member BESS units. Equations 3.7-3.8 impose this community-wide directional exclusivity using a fixed reserve-power bound $\hat{P}_n^{RES,max}$, whose construction is discussed immediately afterwards.

$$0 \leq E_{n,t}^{ACT,UP} \leq \hat{\rho}_t^{ACT,UP} \hat{P}_n^{RES,max} \Delta t \, \delta_t^{ACT,UP} \qquad \forall t \in T, n \in N \tag{3.7}$$

$$0 \leq E_{n,t}^{ACT,DW} \leq \hat{\rho}_t^{ACT,DW} \hat{P}_n^{RES,max} \Delta t \left(1 - \delta_t^{ACT,UP}\right) \qquad \forall t \in T, n \in N \tag{3.8}$$

When $\delta_t^{ACT,UP} = 1$, downward activation is forced to zero for every member BESS, while $\delta_t^{ACT,UP} = 0$ forces upward activation to zero. These constraints select the activation direction only, whereas the tighter activation envelopes remain those imposed by Equations 3.5-3.6.

An important distinction between these two sets of constraints is the reserve-power term used on their right-hand side. Equations 3.5-3.6 can use the decision variables $P_{n,t}^{RES,DW}$ and $P_{n,t}^{RES,UP}$ directly because no product between decision variables is introduced. By contrast, replacing $\hat{P}_n^{RES,max}$ in Equations 3.7-3.8 with the sizing-dependent variable $P_n^{max}$ would create the product $P_n^{max} \delta_t^{ACT,UP}$, that is, a continuous decision variable multiplied by a binary decision variable. This bilinear term would break the linear MILP formulation.

To avoid this bilinearity, the fixed valid upper bound $\hat{P}_n^{RES,max}$ used in Equations 3.7-3.8 is defined by Equation 3.9 as follows.

$$\hat{P}_n^{RES,max} = \hat{\alpha}_n^{RES} \frac{\hat{E}_n^{BN,init} + \hat{E}_n^{BN,max}}{\Delta t} \qquad \forall n \in N \tag{3.9}$$

Unlike $P_n^{max}$, which varies with the storage capacity selected by the optimisation, $\hat{P}_n^{RES,max}$ is a fixed parameter constructed from the pre-existing BESS capacity $\hat{E}_n^{BN,init}$ and the maximum admissible additional capacity $\hat{E}_n^{BN,max}$. It therefore represents the largest reserve-power limit that could arise under any feasible sizing decision.

Using this fixed valid upper bound is a standard MILP linearisation device that preserves the directional logic without introducing a product between decision variables. Because $\hat{P}_n^{RES,max}$ is constructed from the maximum feasible BESS capacity, it does not further restrict the reserve capability already permitted by the sizing formulation. Its role in Equations 3.7-3.8 is solely to provide a valid constant bound that preserves the linear structure of the optimisation problem.

The community-level upward and downward reserve bands are additionally linked by the 2:1 proportion used under the Portuguese market conditions [108] represented by the 2022 case-study data. Equation 3.10 applies this historical relation at aggregate level.

$$P_t^{RES,UP} = 2P_t^{RES,DW} \qquad \forall t \in T \tag{3.10}$$

This relation is retained for consistency with the market framework underlying the historical inputs and should not be interpreted as a structural requirement of SITEC under other market designs.

The member-level reserve bands and activated energies are aggregated into the community quantities used in the objective function through Equations 3.11-3.12, consistent with the aggregation boundary defined in Section 3.1.

$$P_t^{RES,DW} = \sum_{n \in N} P_{n,t}^{RES,DW}, \qquad P_t^{RES,UP} = \sum_{n \in N} P_{n,t}^{RES,UP} \qquad \forall t \in T \tag{3.11}$$

$$E_t^{ACT,DW} = \sum_{n \in N} E_{n,t}^{ACT,DW}, \qquad E_t^{ACT,UP} = \sum_{n \in N} E_{n,t}^{ACT,UP} \qquad \forall t \in T \tag{3.12}$$

These equations aggregate the individual BESS contributions into the community-level reserve quantities represented in the optimisation model.

#### 3.2.3.3 Meter Energy Balance and External Market Interaction

The net metered energy $E_{n,t}^{CMET}$ is a signed variable representing the balance at each member connection point, with positive values denoting net import and negative values denoting net export. Its physical origin and commercial decomposition are linked through Equations 3.13-3.14.

$$E_{n,t}^{CMET} = \hat{E}_{n,t}^{C} - E_{n,t}^{G} + E_{n,t}^{B,C} + E_{n,t}^{ACT,DW} - E_{n,t}^{B,D} - E_{n,t}^{ACT,UP} \qquad \forall t \in T, n \in N \tag{3.13}$$

$$E_{n,t}^{CMET} = E_{n,t}^{SUP} - E_{n,t}^{SUR} + E_{n,t}^{PUR} - E_{n,t}^{SALE} \qquad \forall t \in T, n \in N \tag{3.14}$$

Equation 3.13 represents the physical balance at the member connection point. Exogenous demand $\hat{E}_{n,t}^{C}$, scheduled BESS charging $E_{n,t}^{B,C}$ and downward activation $E_{n,t}^{ACT,DW}$ increase net consumption. Behind-the-meter PV generation $E_{n,t}^{G}$, scheduled BESS discharging $E_{n,t}^{B,D}$ and upward activation $E_{n,t}^{ACT,UP}$ reduce it. In this way, reserve activation is propagated directly into the same meter balance used for ordinary energy operation.

Equation 3.14 represents the same net quantity from the commercial side. Imports and exports through the retailer are given by $E^{SUP}_{n,t}$ and $E^{SUR}_{n,t}$, while $E^{PUR}_{n,t}$ and $E^{SALE}_{n,t}$ represent internal purchases and sales, respectively. Equations 3.13-3.14 therefore enforce consistency between the physical operation of each member and the commercial allocation of its energy exchanges.

The power flowing through the connection point is bounded by the contracted power in both directions, as imposed by Equation 3.15.

$$-P^{CONT}_{n} \leq \frac{E^{CMET}_{n,t}}{\Delta t} \leq P^{CONT}_{n} \qquad \forall t \in T, n \in N \tag{3.15}$$

Within SITEC, $P^{CONT}_{n}$ is used as a symmetric connection-point exchange limit for both imports and exports. This is a modelling assumption adopted to represent the admissible power exchange at each member connection point. Unlike a fixed scheduling input, $P^{CONT}_{n}$ is a decision variable co-optimised with the asset-sizing and operational decisions and is priced in the objective function through Equation 3.1. The model therefore determines the contracted-power level jointly with the remaining planning decisions while ensuring that metered power remains within the selected limit at every interval. A physical upper bound is imposed by Equation 3.16, reflecting the hardware limit of the connection point.

$$P^{CONT}_{n} \leq \hat{P}^{CPE,max}_{n} \qquad \forall n \in N \tag{3.16}$$

#### 3.2.3.4 Generation and Storage Sizing

The core of the planning problem is the dimensioning of the distributed assets, where the installed PV and BESS capacities become decision variables instead of fixed inputs. The PV sizing is defined by Equations 3.17-3.18.

$$P^{GN}_{n} = P^{GN,total}_{n} - \hat{P}^{GN,init}_{n} \qquad \forall n \in N \tag{3.17}$$

$$\hat{P}^{GN,min}_{n} \leq P^{GN}_{n} \leq \hat{P}^{GN,max}_{n} \qquad \forall n \in N \tag{3.18}$$

The newly installed PV capacity $P^{GN}_{n}$ is the difference between the total capacity $P^{GN,total}_{n}$ and the pre-existing capacity $\hat{P}^{GN,init}_{n}$ and is bounded between the admissible installation limits $\hat{P}^{GN,min}_{n}$ and $\hat{P}^{GN,max}_{n}$. The optimiser therefore determines the additional PV capacity within the admissible design envelope. The generation enabled by the resulting total capacity is defined through Equation 3.19.

$$E^{G}_{n,t} = \hat{f}^{G}_{n,t} P^{GN,total}_{n} \Delta t \qquad \forall t \in T, n \in N \tag{3.19}$$

The generation profile factor $\hat{f}^{G}_{n,t}$ converts the dimensioned capacity $P^{GN,total}_{n}$ into the behind-the-meter energy $E^{G}_{n,t}$ at each interval. The generation entering the meter balance therefore scales directly with the PV capacity selected by the model. Equation 3.19 assumes that the available PV

generation is fully produced at each interval. Explicit PV curtailment is therefore not modelled, which constitutes a simplification of the operational representation.

Following the same rationale, the BESS sizing is defined by Equations 3.20-3.21.

$$E_n^{BN} = E_n^{BN,total} - \hat{E}_n^{BN,init} \qquad \forall n \in N \tag{3.20}$$

$$\hat{E}_n^{BN,min} \leq E_n^{BN} \leq \hat{E}_n^{BN,max} \qquad \forall n \in N \tag{3.21}$$

The newly installed storage energy $E_n^{BN}$ is the increment of $E_n^{BN,total}$ over the pre-existing capacity $\hat{E}_n^{BN,init}$ and is bounded by $\hat{E}_n^{BN,min}$ and $\hat{E}_n^{BN,max}$. The resulting total capacity $E_n^{BN,total}$ propagates into both the storage operation and the reserve-power limit defined in Equation 3.2.

#### 3.2.3.5 BESS Operation

The BESS constraints couple scheduled charging and discharging with reserve provision while enforcing the storage power and energy limits. In each direction, scheduled operation and the corresponding offered reserve band must fit within the power capability of the dimensioned BESS, as imposed by Equations 3.22-3.23.

$$\frac{E_{n,t}^{B,C}}{\Delta t} + P_{n,t}^{RES,DW} \leq E_n^{BN,total} \frac{\hat{P}^{B,ref}}{\hat{E}^{B,ref}} \qquad \forall t \in T, n \in N \tag{3.22}$$

$$\frac{E_{n,t}^{B,D}}{\Delta t} + P_{n,t}^{RES,UP} \leq E_n^{BN,total} \frac{\hat{P}^{B,ref}}{\hat{E}^{B,ref}} \qquad \forall t \in T, n \in N \tag{3.23}$$

The right-hand side scales the installed energy capacity $E_n^{BN,total}$ by the reference power-to-energy ratio $\hat{P}^{B,ref}/\hat{E}^{B,ref}$ and therefore represents the physical power capability associated with the selected storage technology. These constraints are distinct from the reserve limit defined through $\hat{\alpha}_n^{RES}$. The reserve parameter limits how much power may be committed to mFRR, while Equations 3.22-3.23 ensure that scheduled operation and reserve headroom remain jointly feasible within the BESS power rating.

No binary variable is used to impose a hard mutual exclusion between scheduled charging and discharging. The formulation instead relies on round-trip losses and the economic objective to discourage, rather than explicitly prohibit, simultaneous operation. Such exclusivity could be incorporated into the MILP using a binary operating-mode variable for each member and interval, together with fixed valid upper bounds on charging and discharging power. This extension is not included in the present formulation.

Reserve activation is represented as additional charging during downward activation and additional discharging during upward activation. The formulation does not explicitly represent alternative sub-hourly redispatch around the scheduled BESS baseline, such as reserve delivery through the reduction of an existing charging or discharging schedule. This is consistent with the simplified hourly representation adopted in SITEC.

The initial energy content of the BESS is defined as a fraction $\hat{\sigma}_n^{B,init}$ of the dimensioned capacity through Equation 3.24. The case-study value of this parameter is reported in Subsection 4.1.1.

$$E_n^{B,init} = \hat{\sigma}_n^{B,init} E_n^{BN,total} \qquad \forall n \in N \tag{3.24}$$

From this starting point, the stored energy evolves according to the balance in Equations 3.25-3.26. Equation 3.25 defines the SoC update for the first interval, $t = 0$, using the initial stored energy $E_n^{B,init}$, while Equation 3.26 applies the recursive update for the remaining intervals, $t > 0$.

$$E_{n,t}^{B} = E_n^{B,init} + \left(E_{n,t}^{B,C} + E_{n,t}^{ACT,DW}\right) \hat{\eta}_n^{B,C} - \frac{E_{n,t}^{B,D} + E_{n,t}^{ACT,UP}}{\hat{\eta}_n^{B,D}} \qquad t = 0, \forall n \in N \tag{3.25}$$

$$E_{n,t}^{B} = E_{n,t-1}^{B} + \left(E_{n,t}^{B,C} + E_{n,t}^{ACT,DW}\right) \hat{\eta}_n^{B,C} - \frac{E_{n,t}^{B,D} + E_{n,t}^{ACT,UP}}{\hat{\eta}_n^{B,D}} \qquad \forall t \in T \setminus \{0\}, n \in N \tag{3.26}$$

The stored energy at the end of each interval $E_{n,t}^{B}$ results from the previous level adjusted by the charged and discharged energy, weighted by the charge and discharge efficiencies $\hat{\eta}_n^{B,C}$ and $\hat{\eta}_n^{B,D}$. The reserve activation terms $E_{n,t}^{ACT,DW}$ and $E_{n,t}^{ACT,UP}$, introduced in Equations 3.5-3.6, are embedded directly in this balance. Downward activation adds to the charged energy and increases the stored level, while upward activation adds to the discharged energy and depletes it. Reserve activation is therefore reflected directly in the BESS energy state.

The stored energy is then kept within the admissible SoC window, as imposed by Equation 3.27.

$$\frac{\hat{SOC}_n^{B,min}}{100} E_n^{BN,total} \leq E_{n,t}^{B} \leq \frac{\hat{SOC}_n^{B,max}}{100} E_n^{BN,total} \qquad \forall t \in T, n \in N \tag{3.27}$$

Because the bounds scale with $E_n^{BN,total}$, the admissible energy window changes consistently with the sizing decision. An additional end-of-day condition limits inter-day energy carryover through Equation 3.28.

$$\hat{\sigma}_n^{B,reset,min} E_n^{BN,total} \leq E_{n,t}^{B} \leq \hat{\sigma}_n^{B,reset,max} E_n^{BN,total} \qquad \forall t \in T^{24}, n \in N \tag{3.28}$$

The set $T^{24} \subseteq T$ denotes the end-of-day intervals. At each of these steps, the stored energy must remain within the fractions $\hat{\sigma}_n^{B,reset,min}$ and $\hat{\sigma}_n^{B,reset,max}$ of the installed capacity. This prevents the optimiser from using unrestricted energy accumulation across days to distort the value of additional storage. The numerical reset bounds used in the case study are given in Subsection 4.1.1.

#### 3.2.3.6 Local Energy Sharing, Self-Consumption and Allocation

The remaining constraints govern how members trade internally, how self-consumed energy is represented and how surpluses and deficits are routed within the community. Since internal

trades only redistribute energy among members, the total energy purchased locally $\sum_{n\in N} E^{PUR}_{n,t}$ must equal the total energy sold at every interval $\sum_{n\in N} E^{SALE}_{n,t}$, as imposed by Equation 3.29.

$$\sum_{n\in N} E^{PUR}_{n,t} - \sum_{n\in N} E^{SALE}_{n,t} = 0 \qquad \forall t \in T \tag{3.29}$$

A member cannot import from and export to the retailer within the same interval because this would create an artificial arbitrage opportunity. A binary variable $\delta^{SUP}_{n,t}$ is therefore introduced to enforce this mutual exclusivity through Equations 3.30-3.31. The large constant $\hat{M}$ relaxes the inactive branch and is selected to exceed the feasible per-period energy exchanges implied by the connection-point limits, while the small positive tolerance $\hat{m}$ avoids numerical ambiguity at zero flow. These constants are implementation parameters and do not alter the economic interpretation of the exchange variables.

$$E^{SUP}_{n,t} \leq \hat{M}\,\delta^{SUP}_{n,t} + \hat{m} \qquad \forall t \in T, n \in N \tag{3.30}$$

$$E^{SUR}_{n,t} \leq \hat{M}\left(1 - \delta^{SUP}_{n,t}\right) + \hat{m} \qquad \forall t \in T, n \in N \tag{3.31}$$

The self-consumed energy $E^{SLC}_{n,t}$, which is subject only to the grid access tariff in the objective function, is formulated to represent the local energy effectively used by a member. More specifically, it corresponds to the smaller of the positive net metered energy $E^{CMET,+}_{n,t}$ and the positive net local allocation $E^{ALC,+}_{n,t}$ when the associated objective term is economically active. These auxiliary quantities are defined by Equations 3.32-3.33, while the binary variable $\delta^{SLC}_{n,t}$ selects the active lower bound in Equations 3.34-3.35.

$$E^{CMET,+}_{n,t} \geq E^{CMET}_{n,t} \qquad \forall t \in T, n \in N \tag{3.32}$$

$$E^{ALC,+}_{n,t} \geq E^{PUR}_{n,t} - E^{SALE}_{n,t} \qquad \forall t \in T, n \in N \tag{3.33}$$

$$E^{SLC}_{n,t} \geq E^{CMET,+}_{n,t} - \hat{M}\left(1 - \delta^{SLC}_{n,t}\right) \qquad \forall t \in T, n \in N \tag{3.34}$$

$$E^{SLC}_{n,t} \geq E^{ALC,+}_{n,t} - \hat{M}\,\delta^{SLC}_{n,t} \qquad \forall t \in T, n \in N \tag{3.35}$$

When $\delta^{SLC}_{n,t} = 1$, the active lower bound is associated with $E^{CMET,+}_{n,t}$, while $\delta^{SLC}_{n,t} = 0$ activates the bound associated with $E^{ALC,+}_{n,t}$. When the grid access tariff is positive, the minimisation objective tightens the auxiliary variables so that $E^{SLC}_{n,t}$ represents the smaller of the two quantities. If the grid access tariff is zero, this auxiliary variable is economically inactive and is not uniquely determined by the objective. In that case, self-consumption indicators must be evaluated consistently from the realised metered and local-allocation flows. This distinction does not affect the

physical energy balances or the sizing decisions because $E^{SLC}_{n,t}$ enters the optimisation objective only through the grid access tariff term.

The routing of internal trades follows the Portuguese CSC regulation [10]. The model first identifies whether the REC as a whole and each member individually are in surplus or deficit at each interval through Equations 3.36-3.39.

$$\sum_{n \in N} E^{CMET}_{n,t} \geq -\hat{M}\, \delta^{rec_balance}_{t} \qquad \forall t \in T \tag{3.36}$$

$$\sum_{n \in N} E^{CMET}_{n,t} \leq \hat{M} \left(1 - \delta^{rec_balance}_{t}\right) + \hat{m} \qquad \forall t \in T \tag{3.37}$$

$$E^{CMET}_{n,t} \geq -\hat{M}\, \delta^{meter_balance}_{n,t} \qquad \forall t \in T, n \in N \tag{3.38}$$

$$E^{CMET}_{n,t} \leq \hat{M} \left(1 - \delta^{meter_balance}_{n,t}\right) + \hat{m} \qquad \forall t \in T, n \in N \tag{3.39}$$

The binary variable $\delta^{rec_balance}_{t}$ classifies the aggregate condition of the community, while $\delta^{meter_balance}_{n,t}$ classifies each member individually. These two signals are then combined in Equations 3.40-3.43 to enforce the dynamic allocation rule. A member in surplus while the REC is in deficit must sell locally, while a member in deficit while the REC is in surplus must buy locally.

$$E^{SALE}_{n,t} \geq -E^{CMET}_{n,t} - \hat{M} \left(1 - \delta^{meter_balance}_{n,t} + \delta^{rec_balance}_{t}\right) \qquad \forall t \in T, n \in N \tag{3.40}$$

$$E^{SALE}_{n,t} \leq -E^{CMET}_{n,t} + \hat{M} \left(1 - \delta^{meter_balance}_{n,t} + \delta^{rec_balance}_{t}\right) \qquad \forall t \in T, n \in N \tag{3.41}$$

$$E^{PUR}_{n,t} \geq E^{CMET}_{n,t} - \hat{M} \left(1 - \delta^{rec_balance}_{t} + \delta^{meter_balance}_{n,t}\right) \qquad \forall t \in T, n \in N \tag{3.42}$$

$$E^{PUR}_{n,t} \leq E^{CMET}_{n,t} + \hat{M} \left(1 - \delta^{rec_balance}_{t} + \delta^{meter_balance}_{n,t}\right) \qquad \forall t \in T, n \in N \tag{3.43}$$

The term in parentheses in each inequality equals zero only under the specific binary combination that activates the corresponding rule. This forces either $E^{SALE}_{n,t} = -E^{CMET}_{n,t}$ or $E^{PUR}_{n,t} = E^{CMET}_{n,t}$ and routes the member's entire surplus or deficit through the internal market. In all other combinations, $\hat{M}$ relaxes both bounds and the member may interact with the external market according to the remaining constraints.

The remaining allocation constraints ensure that the net energy made available by a member to the local market does not exceed its physical net surplus, as imposed by Equations 3.44-3.45.

$$E^{SALE}_{n,t} - E^{PUR}_{n,t} \leq -E^{CMET}_{n,t} + \hat{M}\, \delta^{coeff}_{n,t} \qquad \forall t \in T, n \in N \tag{3.44}$$

$$E_{n,t}^{SALE} - E_{n,t}^{PUR} \leq \hat{M}\left(1 - \delta_{n,t}^{coeff}\right) \qquad \forall t \in T, n \in N \tag{3.45}$$

#### 3.2.3.7 Variable Domains

Finally, the domains of the decision variables are defined according to their indexing structure. All continuous variables listed below are constrained to be non-negative, while the signed metered-energy variable $E_{n,t}^{CMET}$ is unrestricted in sign.

**Member-level operational variables:**

$$\begin{aligned} &E_{n,t}^{G}, E_{n,t}^{B,C}, E_{n,t}^{B,D}, E_{n,t}^{SUP}, E_{n,t}^{SUR}, E_{n,t}^{PUR}, E_{n,t}^{SALE}, \\ &E_{n,t}^{SLC}, E_{n,t}^{CMET,+}, E_{n,t}^{ALC,+}, E_{n,t}^{B}, P_{n,t}^{RES,DW}, P_{n,t}^{RES,UP}, \\ &E_{n,t}^{ACT,DW}, E_{n,t}^{ACT,UP} \geq 0 \qquad \forall t \in T, n \in N \end{aligned} \tag{3.46}$$

**Member-level planning variables:**

$$\begin{aligned} &P_{n}^{CONT}, P_{n}^{GN}, P_{n}^{GN,total}, E_{n}^{BN}, E_{n}^{BN,total}, E_{n}^{B,init}, P_{n}^{max} \geq 0 \\ &\qquad\qquad\qquad\qquad\qquad\qquad\qquad\qquad\qquad\qquad \forall n \in N \end{aligned} \tag{3.47}$$

**Community-level reserve variables:**

$$P_{t}^{RES,DW}, P_{t}^{RES,UP}, E_{t}^{ACT,DW}, E_{t}^{ACT,UP} \geq 0 \qquad \forall t \in T \tag{3.48}$$

**Binary variables:**

$$\begin{aligned} &\delta_{t}^{ACT,UP}, \delta_{t}^{rec_balance} \in \{0,1\} && \forall t \in T, \\ &\delta_{n,t}^{SUP}, \delta_{n,t}^{SLC}, \delta_{n,t}^{meter_balance}, \delta_{n,t}^{coeff} \in \{0,1\} && \forall t \in T, n \in N. \end{aligned} \tag{3.49}$$

# Chapter 4

# Planning and Operation of a Residential REC with Reserve Market Participation

This chapter presents the case study used to evaluate the SITEC framework and discusses the resulting planning and operational outcomes. It begins by describing the residential REC considered throughout the dissertation, including the technical characterisation of its members, tariffs, investment costs and reserve market parameters. The simulation scenarios are then defined and the corresponding sizing and economic results are presented, followed by an examination of their operational implications. Finally, the main planning, economic and operational insights are consolidated and their implications for the use of SITEC as a decision-support framework are discussed.

## 4.1 Case Study Description

The case-study input data were provided by the Smart Energy Lab (SEL) for the ATE project. The simulations are conducted with an hourly optimisation step, $\Delta t = 1$ h. All input files used in the simulations, together with the full simulation reports for every scenario, are available in the same dataset [109]. Although the SITEC formulation presented in Subsection 3.2.3 supports different temporal resolutions, the hourly step is retained because the ATE project dataset refers to 2022, when the market inputs used in this study were available at hourly resolution.

### 4.1.1 Community Members and Technical Characterisation

The community is composed of five residential prosumers, each connected to the distribution grid through an individual metering point and already equipped with a PV system and a behind-the-meter BESS unit.

The main technical characteristics of the five members are summarised in Table 4.1. The BESS charge and discharge efficiencies are set to $\hat{\eta}_n^{B,C} = \hat{\eta}_n^{B,D} = 0.90$ for all $n \in N$, as introduced in Equations 3.25-3.26, representing charge and discharge efficiencies of 90% for the residential lithium-ion BESS units considered in the case study [110]. The additional installation bounds are

set to $\hat{P}_n^{GN,min} = 0$ kW and $\hat{P}_n^{GN,max} = 5$ kW for PV, and to $\hat{E}_n^{BN,min} = 0$ kWh and $\hat{E}_n^{BN,max} = 20$ kWh for BESS, for all members in scenarios where the corresponding sizing decision is active. The upper bounds are adopted as representative planning limits for an average residential setting. The 5 kW PV limit reflects the restricted rooftop area typically available for additional residential PV installation, while the 20 kWh BESS limit reflects the space and installation constraints typically associated with residential storage systems. These values therefore define realistic sizing ranges for the case study rather than universal technical limits. In scenarios where a given asset is not being dimensioned, its maximum additional capacity is set to zero, preventing expansion beyond the pre-existing installation.

Table 4.1: REC members characterisation.

| Parameter | User 1 | User 2 | User 3 | User 4 | User 5 |
|---|---|---|---|---|---|
| PV capacity $\hat{P}_n^{GN,init}$ (kW) | 2.47 | 0.57 | 0.51 | 3.31 | 2.39 |
| BESS capacity $\hat{E}_n^{BN,init}$ (kWh) | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 |
| BESS SoC min $\widehat{SOC}_n^{B,min}$ (%) | 10 | 10 | 10 | 10 | 10 |
| BESS SoC max $\widehat{SOC}_n^{B,max}$ (%) | 100 | 100 | 100 | 100 | 100 |
| Contracted power $\hat{P}_n^{CPE,max}$ (kW) | 6.90 | 3.45 | 13.80 | 6.90 | 4.60 |

The physical charging and discharging capability of each BESS is defined through the reference power-to-energy ratio $\hat{P}^{B,ref}/\hat{E}^{B,ref}$ introduced in Equations 3.22-3.23. A value of 1 kW/kWh is adopted for all members, corresponding to a maximum BESS power numerically equal to its installed energy capacity. This parameter defines the physical charging and discharging capability of the storage system and is distinct from $\hat{\alpha}_n^{RES}$, which limits the reserve power that may be associated with the installed BESS capacity.

Member electricity demand $\hat{E}_{n,t}^{C}$ is represented by historical smart-meter measurements collected throughout 2022. The raw data are available at 15-minute resolution and are aggregated to hourly intervals to match the optimisation step of $\Delta t = 1$ h. PV availability is represented through the normalised generation factor $\hat{f}_{n,t}^{G}$ defined in Equation 3.19, using the historical hourly PV production and the corresponding initial installed PV capacity. Both the demand and PV production time series span the full calendar year and are available in the accompanying dataset [109].

The initial SoC and the daily reset bounds used in Equations 3.24 and 3.28 are set uniformly to $\hat{\sigma}_n^{B,init} = 0.50$, $\hat{\sigma}_n^{B,reset,min} = 0.40$ and $\hat{\sigma}_n^{B,reset,max} = 0.80$ for all members, meaning that each BESS starts the horizon at 50 % of its capacity and must finish every day between 40 % and 80 %.

### 4.1.2 Tariffs, Market Prices and Investment Costs

The economic signals driving the optimisation in Equation 3.1 are sourced from regulated tariff structures, historical market data and typical capital cost assumptions for residential-scale DERs.

**Retail energy tariffs** - Each member is assigned a Normal Low Voltage (BTN) retail tariff cycle reflecting their contractual arrangement. Users 1 and 3 are on a tri-hourly cycle, Users 2 and 4 on a simple (flat) cycle, and User 5 on a bi-hourly cycle. The corresponding energy prices $\hat{\lambda}_{n,t}^{buy}$ are summarised in Table 4.2 [111]. Under the Portuguese CSC framework considered in this case study, self-consumed energy benefits from the applicable exemption from the Costs of General Economic Interest (CIEG), as established in Decree-Law 15/2022 [10]. Accordingly, the grid-access cost represented by $\hat{\lambda}_{t}^{grid}$ is set to zero throughout the simulations, making the corresponding $E_{n,t}^{SLC}\hat{\lambda}_{t}^{grid}$ term in Equation 3.1 economically inactive. The value of local energy sharing therefore arises from the internal allocation mechanism imposed by Equations 3.40-3.43, which routes member surpluses and deficits internally before the residual exchange with the retailer at $\hat{\lambda}_{n,t}^{buy}$ or $\hat{\lambda}_{n,t}^{sell}$.

Table 4.2: Retail energy tariff prices $\hat{\lambda}_{n,t}^{buy}$ by tariff [111].

| Cycle | Members | Off-peak (€/kWh) | Full hour (€/kWh) | Peak (€/kWh) |
|---|---|---|---|---|
| Simple (flat) | Users 2, 4 | 0.1220 | - | - |
| Bi-hourly | User 5 | 0.1369 | - | 0.2095 |
| Tri-hourly | Users 1, 3 | 0.1072 | 0.1721 | 0.3170 |

The time-of-use periods follow the ERSE schedule for BTN consumers. On workdays, the tri-hourly cycle defines off-peak hours between 00h00 and 07h00, full-hour periods at 07h00–09h00, 12h00–18h00 and 21h00–24h00, and peak periods at 09h00–12h00 and 18h00–21h00. The bi-hourly cycle applies off-peak from 00h00 to 07h00 and peak for the remaining hours. Sundays are treated as fully off-peak for both cycles, while Saturdays follow a mixed schedule [111].

**Contracted power cost** - The contracted-power term is represented through the member-specific cost coefficients $\hat{\lambda}_{n}^{cont}$ shown in Table 4.3, parameterised from the 2022 regulated tariff data [111]. These coefficients are applied to the continuous contracted-power decision variable $P_{n}^{CONT}$ in Equation 3.1. This representation preserves the linear structure of the planning problem and does not explicitly model transitions between discrete contractual power tiers.

Table 4.3: Contracted power limits and cost coefficients adopted per member [111].

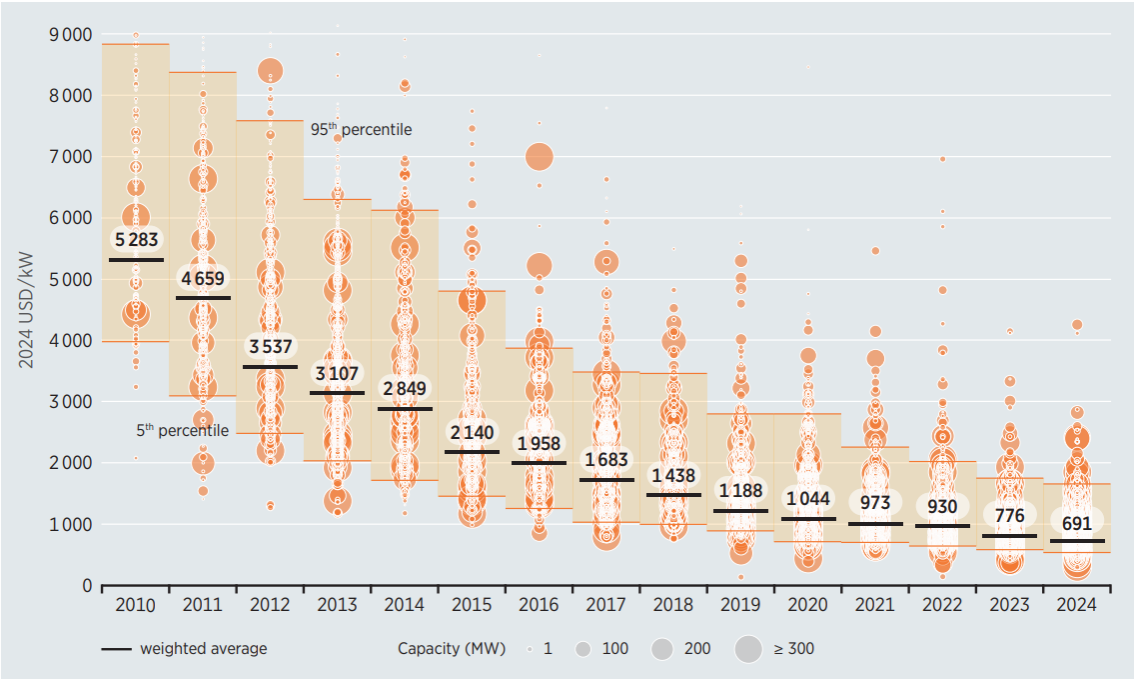
| Member | Tariff cycle | $\hat{P}_{n}^{CPE,max}$ (kW) | $\hat{\lambda}_{n}^{cont}$ (€/kW·day) |
|---|---|---|---|
| User 1 | Tri-hourly | 6.90 | 0.2567 |
| User 2 | Simple | 3.45 | 0.1283 |
| User 3 | Tri-hourly | 13.80 | 0.5134 |
| User 4 | Simple | 6.90 | 0.2567 |
| User 5 | Bi-hourly | 4.60 | 0.1711 |

**Feed-in price** - The energy export remuneration $\hat{\lambda}_{n,t}^{sell}$ follows the hourly OMIE day-ahead market price for the Portuguese bidding zone. The full 2022 time series was retrieved from the

REN DataHub [112] and is available in the accompanying dataset [109].

**Investment costs** - The annualised capital costs for PV and BESS installations are derived from the International Renewable Energy Agency (IRENA) *Renewable Power Generation Costs in 2024* report [113], using 2022 reference values for consistency with the market and reserve data used throughout this case study, and converted to euros at the 2022 annual average European Central Bank reference rate, 1 EUR = 1.0530 USD [114].

The PV cost is based on the global weighted-average total installed cost of utility-scale systems in 2022, 930 USD/kW, shown in Figure 4.1, and is amortised linearly over the 20-year planning horizon.




**Notes:** kW = kilowatt; MW = megawatt; USD = United States dollar.

[27] *TIC data in this report are expressed as per kW of direct current (DC) for solar PV only.*

Figure 4.1: Global weighted-average total installed cost of utility-scale PV, 2010-2024 [113].

$$\hat{\lambda}_n^{G,ic} = \frac{930 \text{ USD/kW}}{1.0530 \text{ USD/EUR} \times 20 \text{ years} \times 365 \text{ days/year}} = 0.12 \text{ €/kW·day} \qquad \forall n \in N \qquad (4.1)$$

The BESS cost is based on the 2022 European turnkey price of 385 USD/kWh reported for a 2-hour storage system, shown in Figure 4.2, which is adopted as a representative European storage-cost benchmark for the case study. One replacement after 10 years is assumed within the 20-year planning horizon.




**Based on:** (BNEF, 2024d).
**Notes:** In the lower half of the chart, the reference line represents the cost ratio compared to the global average; kWh = kilowatt hour; USD = United States dollar.

Figure 4.2: Turnkey BESS prices for Europe, 2022-2024 [113].

$$\hat{\lambda}_n^{B,ic} = \frac{2 \times 385 \text{ USD/kWh}}{1.0530 \text{ USD/EUR} \times 20 \text{ years} \times 365 \text{ days/year}} = 0.10 \text{ €/kWh·day} \qquad \forall n \in N \qquad (4.2)$$

Both parameters are used in the objective function through Equation 3.1. The use of these reference cost benchmarks is a simplification, since residential-scale installations in Portugal may face higher unit costs.

### 4.1.3 Reserve Market Parameters

The mFRR market inputs required by SITEC, introduced in Subsection 3.2.2, are derived from historical Portuguese balancing market data for 2022 retrieved from the REN DataHub [112]. The resulting input series are available in the accompanying dataset [109].

**Historical mFRR market inputs** - The capacity prices $\hat{\lambda}_t^{CAP,UP}$ and $\hat{\lambda}_t^{CAP,DW}$ and the activation prices $\hat{\lambda}_t^{ACT,UP}$ and $\hat{\lambda}_t^{ACT,DW}$ are passed directly to SITEC as hourly time series over the full 2022 horizon, following the same temporal resolution used for the feed-in price in Subsection 4.1.2. The historical activation ratios $\hat{\rho}_t^{ACT,UP}$ and $\hat{\rho}_t^{ACT,DW}$ used in Equations 3.5-3.6 were not available directly from the DataHub and were instead derived from the historical activated energies and contracted reserve bands as

$$\hat{\rho}_t^{ACT,UP} = \frac{\hat{E}_t^{ACT,UP,hist}}{\hat{P}_t^{BAND,UP,hist}\Delta t}, \qquad \hat{\rho}_t^{ACT,DW} = \frac{\hat{E}_t^{ACT,DW,hist}}{\hat{P}_t^{BAND,DW,hist}\Delta t} \qquad \forall t \in T. \tag{4.3}$$

The historical activated energies $\hat{E}_t^{ACT,UP,hist}$ and $\hat{E}_t^{ACT,DW,hist}$ and the contracted bands $\hat{P}_t^{BAND,UP,hist}$ and $\hat{P}_t^{BAND,DW,hist}$ are obtained from the REN DataHub [112] at the Portuguese system level. Since $\Delta t = 1$ h in this case study, the normalisation by the interval duration does not alter the numerical values obtained from the hourly data. The resulting ratios quantify the historical activated energy relative to the energy represented by the contracted reserve band over each hourly interval. They therefore describe historical activation intensity within the available reserve envelope rather than the probability or frequency of reserve activation. The resulting vectors are available in the accompanying dataset [109].

**Reserve power scaling parameter** - The reserve power scaling parameter $\hat{\alpha}_n^{RES}$, introduced in Equation 3.2, links the maximum reserve power available from each member to its installed BESS energy capacity. For a fixed $E_n^{BN,total}$ and $\Delta t$, increasing $\hat{\alpha}_n^{RES}$ therefore represents progressively greater assumed reserve-power capability, as illustrated in Figure 4.3. The parameter does not represent a fraction of BESS energy that is physically reserved or necessarily delivered during the mFRR activation period.

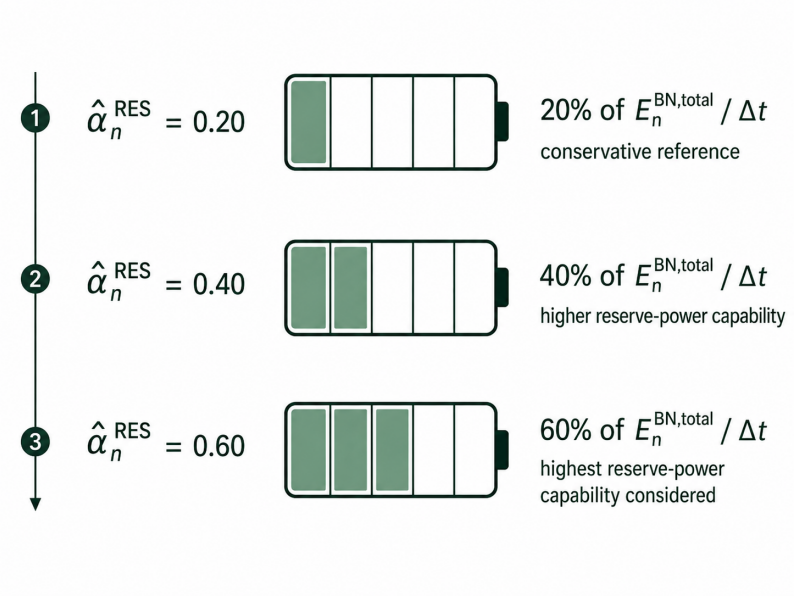



Figure 4.3: Illustration of the reserve power scaling parameter $\hat{\alpha}_n^{RES}$.

A value of $\hat{\alpha}_n^{RES} = 0.20$ is adopted for all members in the reserve-enabled reference configuration used to assess the effect of mFRR participation in Subsection 4.2.3, representing a conservative reserve-power capability assumption. The subsequent sensitivity analysis in Subsection 4.2.4 evaluates values of 0.40 and 0.60 to examine how progressively greater assumed reserve-power capability affects the planning results. All values considered are assumed to be technically compatible with the maximum 12.5-minute mFRR full activation requirement introduced in Subsection 2.4.3 and reflected in the modelling assumptions described in Subsubsection 3.2.3.2.

**Activation robustness parameter** - The robustness parameters $\hat{\varepsilon}^{UP}$ and $\hat{\varepsilon}^{DW}$ reduce the historical activation envelopes used in the deterministic reserve constraints, thereby limiting the share of historical activation that the planning problem can rely on. In the case study, the same value $\hat{\varepsilon}$ is applied to both reserve directions in each scenario, such that $\hat{\varepsilon}^{UP} = \hat{\varepsilon}^{DW} = \hat{\varepsilon}$.

Three activation assumptions are considered. The optimistic case adopts $\hat{\varepsilon} = 0.00$, retaining the full historical activation envelope without any additional robustness discount. The moderate case uses $\hat{\varepsilon} = 0.30$, allowing the planning problem to rely on up to 70% of the historical activation envelope. The pessimistic case adopts $\hat{\varepsilon} = 0.60$, meaning that 60% of the historical envelope is discounted and the planning problem can rely on at most the remaining 40%. These values do not represent probabilities of activation or non-activation by the TSO, but deterministic levels of conservatism applied to the historical activation information.

The pessimistic value $\hat{\varepsilon} = 0.60$, which is the most conservative activation assumption considered, is adopted in the reserve-enabled reference configuration used in Subsection 4.2.3. Given the deterministic planning formulation and the absence of a stochastic representation of future reserve activations, this choice limits the extent to which the sizing decision relies on the repetition of historical activation levels, consistent with the modelling approach described in Subsubsection 3.2.3.2. The influence of this assumption is subsequently assessed in the sensitivity analysis of Subsection 4.2.4, where the robustness parameter is relaxed to the moderate and optimistic values. The complete scenario configurations are specified in Subsection 4.2.1.

## 4.2 Simulation Scenarios and Results

The case study described in Section 4.1 is used to address three research questions that follow directly from the objectives stated in Section 1.2.

1. **Q1.** How does joint sizing of PV, BESS and contracted power change the community's configuration and cost relative to the pre-existing setup?

2. **Q2.** Does the possibility of offering mFRR reserve change those sizing decisions?

3. **Q3.** How sensitive are these decisions to the two key reserve parameters, the activation robustness parameter $\hat{\varepsilon}$ and the reserve power scaling parameter $\hat{\alpha}_n^{RES}$?

The scenario groups are structured progressively, with each group building on the conclusions of the previous one rather than constituting an independent experiment. This progressive structure allows the effects of joint sizing, reserve participation and reserve-related assumptions to be examined within a consistent optimisation framework. All simulations use the full 2022 calendar year to capture seasonal variations in demand, PV generation and market conditions while evaluating planning and economic performance over a common annual horizon. Nine scenarios are defined and grouped according to the research questions in Table 4.4. Each results subsection then addresses one of the three questions using the community-level outputs required for that analysis.

### 4.2.1 Scenario Definition

Table 4.4: Master overview of the nine simulation scenarios, grouped by research question.

| **Scenario** | **Sizing PV** | **Sizing BESS** | **Sizing $P^{CONT}$** | **Reserve** | $\hat{\varepsilon}$ | $\hat{\alpha}_n^{RES}$ |
|---|---|---|---|---|---|---|
| *Q1 - Effect of joint sizing on configuration and cost* | | | | | | |
| Baseline$^\star$ | - | - | - | - | - | - |
| S3 | ✓ | ✓ | ✓ | - | - | - |
| *Q2 - Effect of reserve participation on sizing decisions* | | | | | | |
| S3$^\star$ | ✓ | ✓ | ✓ | - | - | - |
| S1 | - | ✓ | - | ✓ | 0.6 | 0.2 |
| S2 | ✓ | - | - | ✓ | 0.6 | 0.2 |
| S4 | ✓ | ✓ | ✓ | ✓ | 0.6 | 0.2 |
| *Q3 - Sensitivity of sizing decisions to reserve parameters* | | | | | | |
| S4$^\star$ | ✓ | ✓ | ✓ | ✓ | 0.6 | 0.2 |
| S5 | ✓ | ✓ | ✓ | ✓ | **0.0** | 0.2 |
| S6 | ✓ | ✓ | ✓ | ✓ | **0.3** | 0.2 |
| S7 | ✓ | ✓ | ✓ | ✓ | 0.6 | **0.4** |
| S8 | ✓ | ✓ | ✓ | ✓ | 0.6 | **0.6** |

✓ = active or applied; - = inactive or not applicable. ($^\star$) reference scenario for the corresponding research question.

The first group isolates the effect of joint sizing. The Baseline fixes all assets at their pre-existing capacities and represents the community before any new planning decision, while S3 allows SITEC to co-optimise PV, BESS and contracted power for every member. S3 then becomes the no-reserve reference for the second group. S1 and S2 act as control cases in which only BESS or PV sizing is enabled, respectively, allowing the individual contribution of each asset to the reserve-enabled sizing response to be isolated. S4 combines full sizing with reserve participation under the conservative reference configuration $\hat{\varepsilon} = 0.6$ and $\hat{\alpha}_n^{RES} = 0.2$. Finally, S4 becomes the common reference for the third group. S5 and S6 relax the activation robustness assumption, while S7 and S8 consider progressively greater reserve-power capability for a given installed BESS capacity.

### 4.2.2 Effect of Joint Sizing on Configuration and Cost

Before reserve participation is introduced, the first question is whether jointly sizing PV, BESS and contracted power changes the community configuration and its economic performance relative to the pre-existing setup. The Baseline fixes the existing DER capacities and contracted-power values, whereas S3 allows SITEC to determine $P_n^{GN,total}$, $E_n^{BN,total}$ and $P_n^{CONT}$ for every member within the residential planning bounds defined in Subsection 4.1.1. Since both scenarios use the same operational formulation and exogenous input data, the comparison isolates the effect of coordinated planning before reserve revenues are introduced.

Table 4.5: Community-level results for the Baseline and S3 scenarios.

| Scenario | PV (kW) | BESS (kWh) | $P^{CONT}$ (kW) | Net annual cost (€/year) |
|---|---|---|---|---|
| Baseline$^{\star}$ | 9.25 | 25.00 | 35.65 | 6 958.5 |
| S3 | **34.25**$^{\dagger}$ | **48.73** | **19.43** | ↓ **1 074.5** |

$^{\star}$ reference scenario; $^{\dagger}$ value at its installation ceiling; ↓ indicates a reduction in net annual cost relative to the reference.

Table 4.5 shows that joint planning substantially changes all three planning decisions. Under the 2022 market and investment assumptions adopted in the case study, the hourly OMIE-based export remuneration increases the economic value of additional PV generation, since revenues from exported surplus offset part of the investment and operating costs represented in the objective function. The optimiser therefore expands PV from 9.25 to 34.25 kW, reaching the maximum capacity permitted within the residential design space. This expansion raises annual PV generation from 12.6 to 47.4 MWh and increases grid exports from 7.7 to 41.1 MWh, strengthening the community's net position relative to the retailer and contributing to the economic improvement later decomposed in Figure 4.4.

The resulting 34.25 kW should not be interpreted as an unconstrained optimal PV capacity, since the additional PV capacity of every member reaches the installation ceiling defined in Subsection 4.1.1. The qualitative insight is instead that, under the adopted assumptions, the trade-off between additional PV investment and the economic value obtained from the resulting generation remains favourable up to the boundary of the investigated residential design space.

The PV expansion also increases the amount of energy available for temporal shifting, creating a complementary investment signal for storage. BESS capacity consequently rises from 25.00 to 48.73 kWh, allowing part of the available energy to be shifted between periods according to its economic value within the optimisation. PV and BESS therefore act jointly in the planning problem, since the enlarged PV portfolio creates additional opportunities for temporal energy shifting, while the BESS provides the flexibility required to exploit those opportunities according to their economic value. Unlike PV, however, the BESS remains below its aggregate upper bound of 125 kWh. This provides a second qualitative insight. Within the no-reserve configuration, the optimiser expands storage only while the additional operational and contractual value compensates

for its annualised investment cost, resulting in an interior BESS solution within the investigated design space.

The combined PV and BESS expansion is also associated with a reduction in aggregate contracted power from 35.65 to 19.43 kW. This illustrates the interaction between investment and contractual decisions embedded in the joint formulation presented in Subsection 3.2.3, where contracted power is co-optimised with PV and BESS capacity. Rather than sizing each asset independently, SITEC trades additional DER investment against the operational and contractual costs that those assets can avoid or reduce.

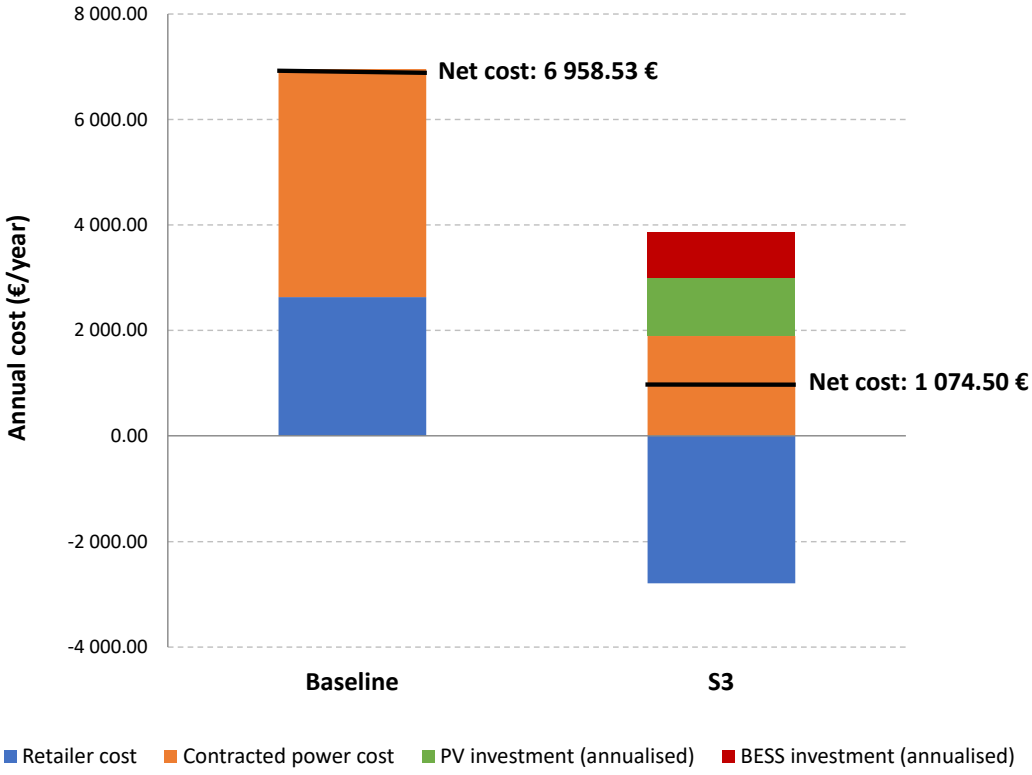



Figure 4.4: Objective function decomposition for the Baseline and S3 scenarios.

Figure 4.4 makes this trade-off explicit by decomposing the main economic terms of the objective function defined in Equation 3.1. The decomposition explains the sizing response reported in Table 4.5. Relative to the Baseline, the retailer balance changes from a cost of 2.63 k€/year to a net revenue of 2.79 k€/year in S3, becoming the only objective component that changes from a cost into a source of revenue. This improvement is closely linked to the larger PV portfolio and the resulting increase in exported energy, showing why the value obtained through the OMIE-based feed-in remuneration can justify the additional PV investment under the adopted conditions.

The BESS follows a different trade-off. Its annualised investment cost increases as storage expands, but the optimiser stops at 48.73 kWh because the additional value obtained from further

storage is no longer sufficient to justify further investment within the no-reserve configuration. At the same time, the combined operation of the enlarged PV and BESS portfolio contributes to reducing the contracted-power requirement, lowering its associated cost. Together, the improvement in the retailer balance and the reduction in contracted-power cost amount to 7.85 k€/year, compared with 1.97 k€/year of additional annualised investment. The resulting net annual cost therefore falls from 6.96 to 1.07 k€/year.

The aggregate result nevertheless hides important differences between individual members, which are reported in Appendix A. The per-member capacities and economic outcomes in Table A.1 and Figure A.1 show that the community-level planning signal does not translate into identical outcomes for all participants. Differences in initial PV capacity, demand profiles, tariff structures and contracted-power limits lead to different investment requirements and economic effects. Users 2 and 5 move from a net cost to a net revenue position under S3, while User 3 remains the highest-cost member despite a substantial improvement relative to the Baseline. This heterogeneity reinforces the role of SITEC as a planning decision-support tool, since the resulting capacities and economic outcomes remain dependent on member-specific characteristics and should not be interpreted as uniform investment prescriptions.

The main conclusion from Q1 is thus not simply that joint sizing leads to greater DER capacities. The economic terms of the objective function interact with the planning variables and create distinct investment signals for each asset. PV expansion remains economically attractive up to the imposed residential limit, while BESS reaches an interior solution determined by the trade-off between its additional investment cost and the operational value it provides. Contracted power adjusts simultaneously to the resulting operating capability of the community. Q1 therefore shows why co-optimising investment, operation and contracted power can produce a materially different planning outcome from evaluating these decisions independently.

### 4.2.3 Effect of Reserve Participation on Sizing Decisions

The no-reserve result in Subsection 4.2.2 leaves the BESS at an interior solution of 48.73 kWh, well below its installation ceiling. Under the adopted assumptions, the value obtained from energy-market operation and contracted-power management therefore justifies storage expansion only up to that point. Q2 examines whether introducing mFRR as an additional revenue stream changes this planning trade-off.

S3 is retained as the joint-sizing reference without reserve participation. S4 applies the same PV, BESS and contracted-power sizing scope while enabling reserve participation under the conservative reference configuration $\hat{\varepsilon} = 0.6$ and $\hat{\alpha}_n^{RES} = 0.2$ introduced in Subsection 4.1.3. S1 and S2 isolate the contribution of each asset by allowing only BESS or PV sizing, respectively, while reserve participation remains enabled.

Table 4.6: Community-level results for the scenarios addressing Q2.

| Scenario | PV (kW) | BESS (kWh) | $P^{CONT}$ (kW) | Reserve rev. (€/year) | Net annual cost (€/year) |
|---|---|---|---|---|---|
| S3⋆ | **34.25**† | 48.73 | 19.43 | - | 1 074.5 |
| S4 | **34.25**† | **125.00**† | **18.38** | 15 936.7 | ↓ −12 682.4 |
| S1 | 9.25 | **125.00**† | 35.65 | 15 941.6 | ↓ −7 439.1 |
| S2 | 24.14 | 25.00 | 35.65 | 3 162.3 | 1 643.3 |

⋆ no-reserve reference; † value at its installation ceiling. Green arrows indicate that the community moves into net annual revenue.

Table 4.6 shows that introducing reserve participation changes the planning outcome primarily through storage. In S3, PV is already at its 34.25 kW installation ceiling, while BESS reaches an interior solution of 48.73 kWh. Once mFRR participation is enabled in S4, PV remains unchanged, whereas BESS capacity increases to the 125 kWh installation ceiling. The additional market opportunity therefore creates a substantially different investment signal for storage.

This response follows directly from the reserve mechanism introduced in Subsubsection 3.2.3.2. Through Equation 3.2, installed BESS capacity determines the maximum reserve-power capability available to each member, meaning that additional storage can support larger reserve offers and the associated capacity and activation remuneration. Since these revenues are considered together with investment, operating and contractual costs in the objective function of Equation 3.1, the introduction of mFRR changes the trade-off governing the storage decision. Under the 2022 reserve-market inputs adopted in the case study, the additional reserve value remains sufficient to justify BESS expansion up to the imposed residential limit, a trade-off further illustrated by the economic decomposition in Figure 4.5.

As for the PV sizing result discussed previously, the resulting 125 kWh should not be interpreted as an unconstrained optimal storage capacity. Since the solution reaches the adopted installation ceiling, the qualitative insight is instead that the trade-off between additional BESS investment and the value obtained from energy and reserve-market participation remains favourable at the boundary of the investigated design space. The larger storage capacity is also associated with a further reduction in aggregate contracted power from 19.43 to 18.38 kW, reflecting the additional ability of the BESS to manage import peaks while contracted power is co-optimised with the DER capacities.

Relative to the joint-sizing analysis reported in the conference paper developed within this work [106], the present study further separates the sizing of each DER to identify which asset drives the reserve-enabled response observed in S4. In S1, PV remains fixed at 9.25 kW while BESS alone is allowed to expand, again reaching the 125 kWh ceiling and supporting reserve offers of 25 kW upward and 12.5 kW downward, with 15.94 k€/year of reserve revenue. This value is almost identical to that obtained in S4 despite the substantially lower PV capacity. Conversely, in S2, fixing BESS at 25 kWh limits the reserve offer to 5 kW upward and 2.5 kW downward and reduces reserve revenue to 3.16 k€/year, while PV expands only to 24.14 kW. These control

cases support the interpretation of S4 by showing that BESS is the asset directly linking installed capacity to reserve capability, whereas PV continues to respond mainly to the energy-market value identified in the no-reserve case.

The comparison between S1 and S4 further shows the value of joint planning. Although both scenarios obtain almost identical reserve revenue, S4 improves the net annual result from 7.44 to 12.68 k€/year, showing that BESS provides the direct link to reserve value while the simultaneous optimisation of PV, storage and contracted power captures additional energy-market and contractual benefits.

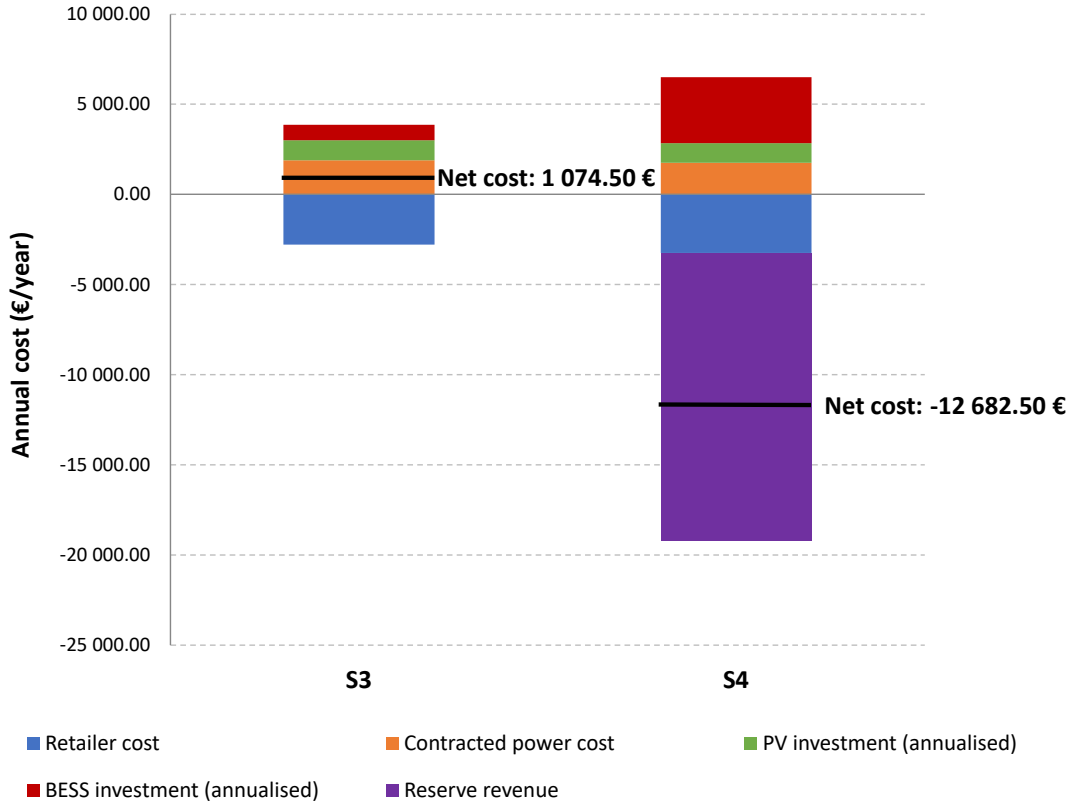



Figure 4.5: Objective function decomposition for the S3 and S4 scenarios.

Figure 4.5 makes the economic trade-off behind the sizing response in Table 4.6 explicit through the objective-function decomposition of Equation 3.1. PV investment remains essentially unchanged at 1.10 k€/year because PV is already at its planning ceiling in S3. BESS investment, however, increases from 0.87 to 3.65 k€/year as storage expands from 48.73 to 125 kWh. This additional investment is accompanied by 15.94 k€/year of reserve revenue, which more than compensates for the increase in annualised storage cost and explains why the optimiser moves the BESS to the boundary of the investigated design space.

The economic decomposition therefore closes the mechanism observed between S3 and S4. Without reserve participation, BESS investment is justified by its operational and contractual value, resulting in the interior solution described in the no-reserve case. With mFRR participation,

additional BESS capacity can also provide greater reserve capability and access to capacity and activation remuneration. The additional market value changes the investment trade-off sufficiently for the community to move from a net annual cost of 1.07 k€/year in S3 to a net annual revenue of 12.68 k€/year in S4.

The member-level results reported in Appendix B show that the aggregate reserve-enabled planning signal again produces heterogeneous outcomes across participants. The sizing decisions in Table B.1 reproduce the main aggregate mechanism, with BESS reaching the adopted ceiling for every member whenever storage sizing is enabled, while the economic outcomes in Table B.2 differ across members. User 3 is the only member remaining in net cost in S1 and obtains the lowest net revenue in S4, while under S2 both User 3 and User 4 remain in net cost. These differences reinforce that the community-level planning signal should not be interpreted as a uniform investment prescription for individual participants.

The main conclusion from Q2 is therefore not simply that reserve participation leads to a larger BESS. Introducing mFRR adds a revenue pathway that is endogenously linked to installed storage capacity and therefore changes the investment signal assigned to this flexible asset. Under the adopted assumptions, this shifts BESS from the interior 48.73 kWh solution of S3 to the imposed 125 kWh planning boundary in S4, without establishing an unconstrained optimal capacity. The qualitative result is that the market scope represented during planning can materially alter DER sizing decisions. BESS provides the direct mechanism for capturing reserve value, while its joint optimisation with PV and contracted power determines the overall economic benefit obtained by the community.

### 4.2.4 Sensitivity of Sizing Decisions to Reserve Parameters

The reserve-enabled reference scenario S4 adopts the conservative configuration introduced in Subsection 4.1.3, with $\hat{\varepsilon} = 0.6$ and $\hat{\alpha}_n^{RES} = 0.2$. The activation robustness parameter discounts 60% of the historical activation envelope, while the reserve power scaling parameter represents the conservative reserve-power capability assumed for the reference case.

Building on the joint-sizing analysis developed in the conference paper associated with this work [106], the present study further evaluates the sensitivity of the planning and economic results to these two reserve parameters. Scenarios S5 and S6 relax $\hat{\varepsilon}$ while maintaining $\hat{\alpha}_n^{RES} = 0.2$, whereas S7 and S8 increase $\hat{\alpha}_n^{RES}$ while maintaining $\hat{\varepsilon} = 0.6$. S4 is retained as the common reference for both sensitivity blocks. Table 4.7 consolidates the resulting reserve volumes, associated revenues and net annual cost, enabling the effects of each parameter to be assessed independently.

Table 4.7: Reserve outcomes and net annual cost for the Q3 sensitivity scenarios.

| Scenario | $\hat{\varepsilon}$ | $\hat{\alpha}_n^{RES}$ | Reserve band UP/DW (kW) | $E^{ACT,UP}$ (MWh) | $E^{ACT,DW}$ (MWh) | Cap. rev. (€/year) | Act. rev. (€/year) | Net annual cost (€/year) |
|---|---|---|---|---|---|---|---|---|
| *Block A - Sensitivity to $\hat{\varepsilon}$ at $\hat{\alpha}_n^{RES} = 0.2$* | | | | | | | | |
| S5 | **0.0** | 0.2 | 25 / 12.5 | 26.7 | 9.7 | 13 306 | 6 624 | ↓ −16 231 |
| S6 | **0.3** | 0.2 | 25 / 12.5 | 19.0 | 5.7 | 13 306 | 4 541 | ↓ −13 491 |
| S4⋆ | **0.6** | 0.2 | 25 / 12.5 | 10.8 | 3.5 | 13 306 | 2 631 | ↓ −12 682 |
| *Block B - Sensitivity to $\hat{\alpha}_n^{RES}$ at $\hat{\varepsilon} = 0.6$* | | | | | | | | |
| S4⋆ | 0.6 | **0.2** | 25 / 12.5 | 10.8 | 3.5 | 13 306 | 2 631 | ↓ −12 682 |
| S7 | 0.6 | **0.4** | 50 / 25 | 21.6 | 7.2 | 26 612 | 5 275 | ↓ −28 284 |
| S8 | 0.6 | **0.6** | 75 / 37.5 | 32.3 | 11.0 | 39 918 | 7 927 | ↓ −43 734 |

⋆ shared reference scenario between blocks. Green arrows indicate that the community moves into net annual revenue.

**Sensitivity to $\hat{\varepsilon}$** - Block A shows the effect of progressively relaxing the activation robustness assumption while keeping the reserve power scaling parameter unchanged. As defined by Equations 3.5-3.6, $\hat{\varepsilon}$ reduces the historical activation envelope available to the optimisation. Moving from the pessimistic value of 0.6 to the moderate and optimistic values of 0.3 and 0.0 therefore allows progressively greater activation energy. Upward activation increases from 10.8 to 26.7 MWh and downward activation from 3.5 to 9.7 MWh. The reserve bands remain unchanged at 25 kW upward and 12.5 kW downward across the three scenarios, consistent with the fact that $\hat{\varepsilon}$ acts on the activation constraints rather than directly on the reserve-power limit. Capacity revenue consequently remains constant at 13.31 k€/year, while activation revenue increases from 2.63 to 6.62 k€/year. This additional activation value improves the overall economic result, increasing net annual revenue from 12.68 k€/year in S4 to 16.23 k€/year in the optimistic S5 case.

**Sensitivity to $\hat{\alpha}_n^{RES}$** - Block B isolates the effect of increasing the reserve power scaling parameter introduced in Equation 3.2 and illustrated in Figure 4.3. For the same installed BESS capacity, increasing $\hat{\alpha}_n^{RES}$ allows greater reserve-power capability. Under the tested configurations, the optimal UP/DW reserve bands consequently increase from 25/12.5 kW in S4 to 50/25 kW in S7 and 75/37.5 kW in S8. The larger bands increase both the contracted reserve capacity and the activation energy that can be accommodated through Equations 3.5-3.6. Capacity and activation revenues therefore increase together, with total reserve revenue rising from 15.94 k€/year in S4 to 47.85 k€/year in S8. The stronger reserve capability consequently produces a much larger economic effect, with net annual revenue reaching 43.73 k€/year in the highest-capability scenario.

The sensitivity of the sizing decisions themselves cannot, however, be fully assessed from these scenarios. PV remains at 34.25 kW and BESS at 125 kWh throughout both sensitivity blocks. Since both assets already reach their imposed installation ceilings in the conservative S4 reference case, and the tested variations either relax the activation robustness assumption or increase the assumed reserve-power capability, the analysis cannot reveal any further upward sizing response. The absence of further sizing changes therefore does not demonstrate that the unconstrained optimal capacities are insensitive to $\hat{\varepsilon}$ or $\hat{\alpha}_n^{RES}$. Within this limitation, the sensitivity analysis still provides a clear qualitative result by showing how the two reserve parameters affect different parts of the formulation. The activation robustness parameter mainly controls the amount of reserve

activation that can be valued, whereas the reserve power scaling parameter changes the available reserve capability itself and consequently affects both capacity and activation remuneration.

The analysis therefore shows that reserve-market assumptions can materially affect the economic value attributed to flexibility even when their influence on asset sizing cannot be isolated within the bounded case study. SITEC should accordingly be interpreted as a decision-support tool for examining how planning decisions respond to alternative market representations and technical assumptions, rather than as a means of prescribing unique asset capacities independently of the design space considered.

## 4.3 Operational Results

While Section 4.2 focused on the annual sizing and economic outcomes, this section examines how the resulting planning decisions translate into the operation of the community. Subsection 4.3.1 compares S3 and S4 on the same representative day, showing the operational consequences of introducing reserve participation together with the associated change in the optimal planning solution. Subsection 4.3.2 then retains the reserve-enabled S4 configuration and compares representative summer and winter days to examine how the same planned community operates under contrasting seasonal conditions. Finally, Subsection 4.3.3 complements the daily analysis with an annual perspective on the community's energy exchanges and storage utilisation.

Representative days are selected by comparing aggregate daily community consumption and PV availability with their respective monthly median conditions. Daily community consumption is calculated as $\sum_{n\in N}\sum_{t\in T_d}\hat{E}^{C}_{n,t}$, while PV availability is represented by the corresponding daily average generation factor. A $\pm 10\,\%$ tolerance around both monthly median indicators is used to identify days representative of the prevailing seasonal conditions. This criterion selects **6 July 2022** for the summer analysis and **21 January 2022** for the winter analysis.

### 4.3.1 Operational Impact of Reserve Participation

The planning results in Subsection 4.2.3 showed that introducing mFRR participation changes the community configuration primarily through a substantial increase in BESS capacity. The operational consequence of this planning response is examined by comparing S3 and S4 over the same representative summer day, 6 July 2022. Since both scenarios use the same demand, PV availability and market conditions on that day, the comparison shows how the reserve-enabled planning solution changes the way energy is managed within the community.

Two complementary perspectives are considered. Figure 4.6 presents the behind-the-meter operation, including BESS charging, discharging and the modelled reserve activation represented in S4. Figure 4.7 then shows how these operational decisions translate into the community's aggregate interaction with the grid.

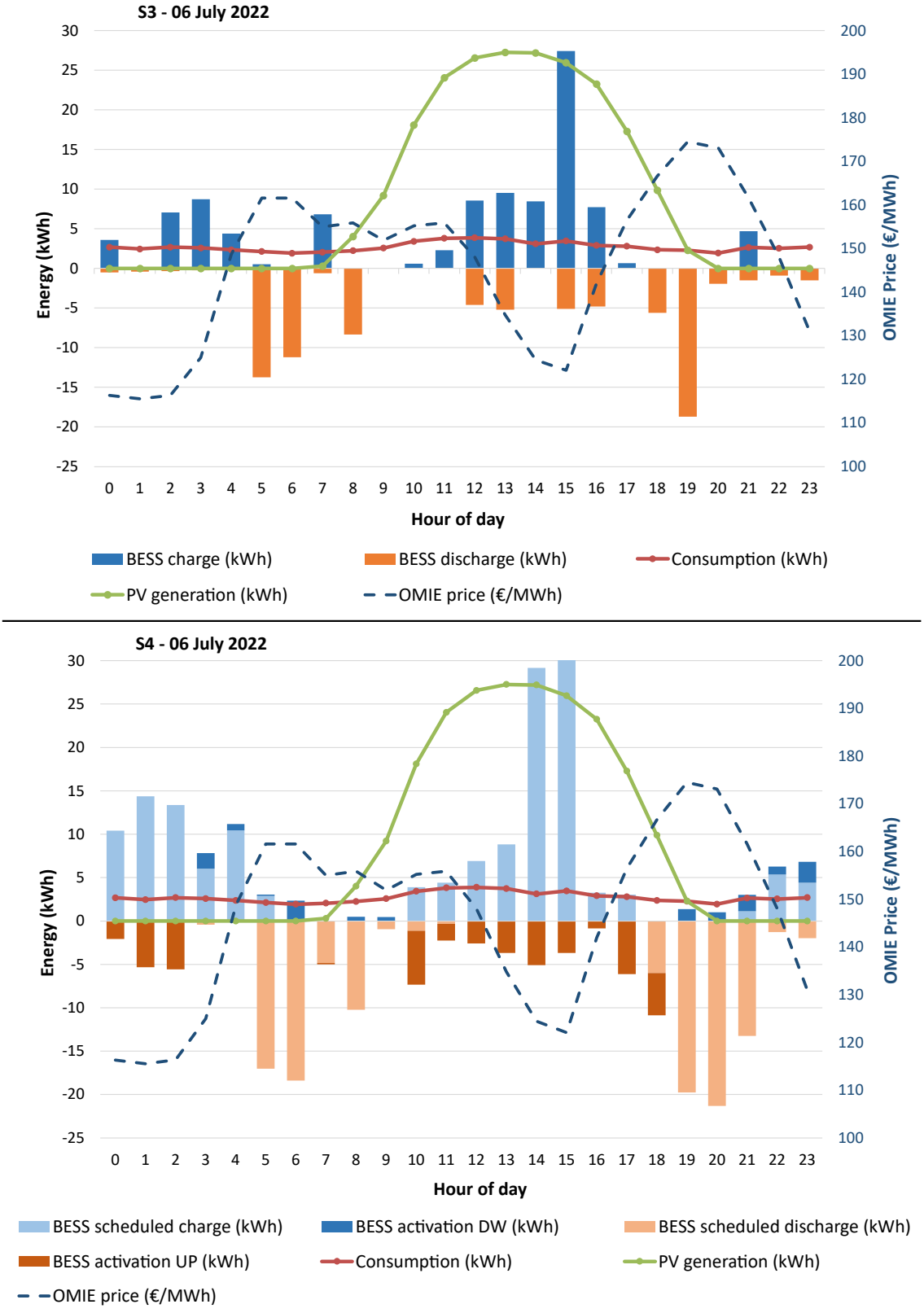



Figure 4.6: Behind-the-meter operation of the community on 6 July 2022 in S3 and S4.

Figure 4.6 first illustrates the different role assigned to storage in the two planning configurations. In S3, BESS operation is driven exclusively by the energy and contractual terms represented in the objective function. Charging occurs both during periods of available PV generation and, when economically favourable, through grid imports, while discharging is scheduled to serve demand or exploit periods in which stored energy has greater economic value. The largest discharge occurs at hour 19, when 18.69 kWh is delivered during the highest OMIE price of the day, 174.50 €/MWh, illustrating the contribution of price differences to the storage schedule.

The aggregated charging and discharging profiles overlap visually in some hours because the figure combines the schedules of all five member BESS units. This aggregate overlap cannot by itself be interpreted as simultaneous charging and discharging by an individual unit. As described in Subsubsection 3.2.3.5, the formulation does not impose a hard binary mutual-exclusion constraint on scheduled BESS charging and discharging, instead relying on round-trip losses and the economic objective to discourage inefficient simultaneous operation.

In S4, BESS activity becomes substantially more intensive and extends across the full day. The optimal solution maintains reserve offers of 25 kW upward and 12.5 kW downward throughout the analysed day while satisfying the 2:1 UP/DW relation imposed by Equation 3.10. These values are outcomes of the optimisation rather than quantities fixed by the 2:1 relation itself. The reserve offers interact directly with scheduled BESS operation through Equations 3.22-3.23, which require scheduled charging or discharging and the corresponding reserve headroom to remain jointly within the physical power capability of the dimensioned BESS. Storage operation must therefore coordinate energy-market value, SoC management and reserve availability simultaneously.

The reserve-enabled schedule also includes modelled activation energy. The variables $E_{n,t}^{ACT,UP}$ and $E_{n,t}^{ACT,DW}$ are bounded by the deterministic historical activation envelopes defined in Equations 3.5-3.6. The historical ratios $\hat{\rho}_t^{ACT,UP}$ and $\hat{\rho}_t^{ACT,DW}$ therefore represent historical activation intensity and define upper bounds on the activation that may be valued in each interval. They do not prescribe a fixed activation trajectory or represent the frequency with which the TSO calls the reserve product. The resulting activation enters the BESS SoC balance and consequently interacts with the scheduled charging and discharging decisions.

Although upward and downward reserve capacity may be offered simultaneously, their activation is mutually exclusive at community level through the binary direction variable $\delta_t^{ACT,UP}$ in Equations 3.7-3.8. The activation components represented in the figure therefore correspond to a single reserve direction within each optimisation interval.

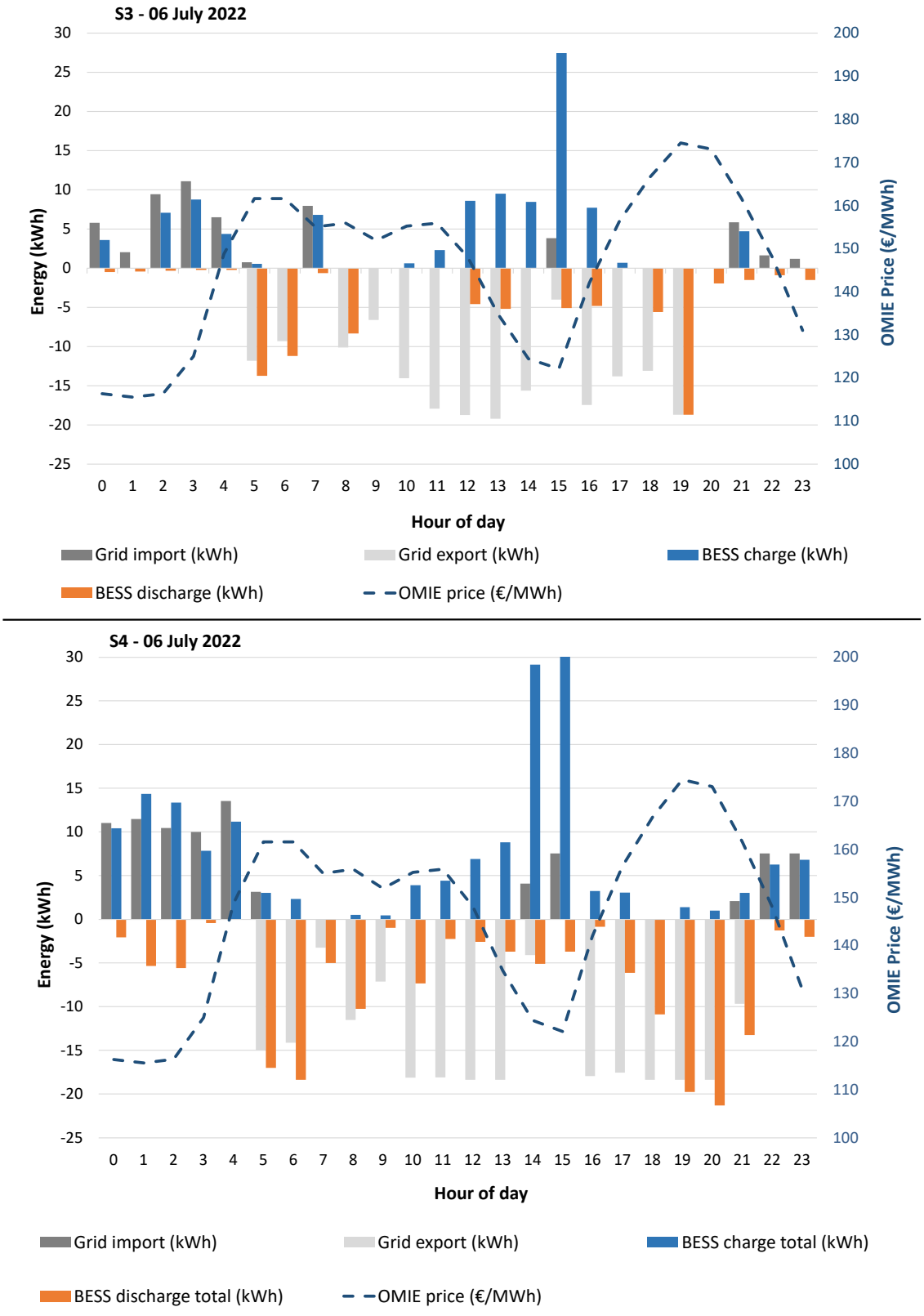



Figure 4.7: Grid interaction of the community on 6 July 2022 in S3 and S4.

Figure 4.7 presents the same comparison from the perspective of the community's aggregate interaction with the grid. In S3, imports occur mainly outside the main PV production period, while exports dominate during daylight hours. At the midday peak, aggregate export reaches approximately 19.43 kW, coinciding with the sum of the member-level contracted-power decisions reported for S3.

The grid-exchange pattern changes in S4 as the larger BESS and reserve-enabled schedule alter the timing of energy flows. Early-morning imports increase as storage operation is coordinated with demand, SoC requirements and reserve availability. During the PV production period, aggregate exports are shaped by the member-level contracted-power constraints of Equation 3.15, whose combined value decreases from 19.43 kW in S3 to 18.38 kW in S4. At hour 15, grid export falls to zero while aggregate BESS charging reaches 33.72 kWh, the highest charging level of the day. This illustrates how the optimiser may redirect available energy towards storage rather than immediate export when jointly coordinating energy-market operation, contracted-power limits, SoC requirements and reserve provision.

The stronger utilisation of storage can be quantified through daily BESS throughput, defined here as the total scheduled and modelled activation energy processed through charging and discharging. For S3, which does not include reserve activation, the aggregate daily throughput is

$$\text{Throughput}_d^{S3} = \sum_{n\in N}\sum_{t\in T_d}\left(E_{n,t}^{B,C} + E_{n,t}^{B,D}\right) = 101.1 + 85.5 = 186.6 \text{ kWh}.$$

For S4, the activation terms are also included because they enter the BESS SoC balance and represent modelled energy processed by the storage system,

$$\text{Throughput}_d^{S4} = \sum_{n\in N}\sum_{t\in T_d}\left(E_{n,t}^{B,C} + E_{n,t}^{ACT,DW} + E_{n,t}^{B,D} + E_{n,t}^{ACT,UP}\right) = 175.2 + 165.0 = 340.2 \text{ kWh}.$$

The modelled BESS throughput is therefore 1.82 times higher in S4 than in S3 over the same day. By contrast, the daily net grid balance changes only modestly, from 134.5 kWh of net export in S3 to 139.9 kWh in S4. The main operational effect observed on this representative day is therefore not a comparable change in the community's net grid position, but a substantial increase in the amount of energy processed through storage. The larger 125 kWh BESS identified in Table 4.6 supports a more intensive operating schedule in which ordinary energy management is combined with reserve availability and modelled activation.

This higher throughput also indicates a greater cycling burden on the BESS. Battery degradation is not explicitly monetised through a cycling-dependent term in the objective function, meaning that the economic results capture the additional reserve value and investment cost but do not directly price the operational wear associated with the increased storage utilisation. The comparison therefore provides an additional qualitative insight into the planning result. Reserve participation changes not only the economically attractive BESS capacity, but also the intensity and function of its subsequent operation.

### 4.3.2 Seasonal Operation

The previous comparison showed how the reserve-enabled planning solution changes storage operation relative to the no-reserve configuration. The next question is whether the operation of that same planned community changes substantially under different seasonal conditions. Scenario S4 is therefore retained unchanged and evaluated on the two representative days selected above, 6 July 2022 for summer and 21 January 2022 for winter.

The seasonal comparison is first examined through the cumulative net grid balance shown in Figure 4.8. For each hour $h$ of day $d$, the cumulative balance is defined as

$$\mathrm{Cum}_h = \sum_{n \in N} \sum_{\substack{t \in T_d \\ t \le h}} \left( E_{n,t}^{SUR} - E_{n,t}^{SUP} \right). \tag{4.4}$$

A positive value indicates that cumulative exports to the retailer exceed cumulative imports up to that hour, while a negative value indicates a net importing position.

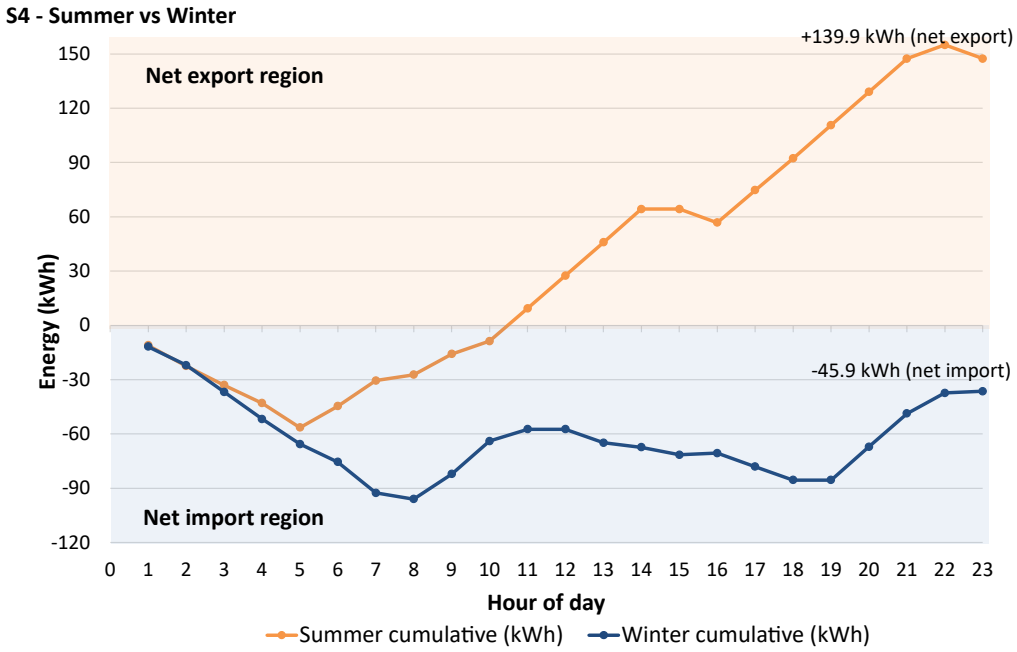



Figure 4.8: Cumulative net grid balance in S4 on representative summer and winter days.

The summer trajectory initially moves into negative territory as early-morning demand and storage operation are supplied before significant PV generation becomes available. As PV production increases, the accumulated deficit is progressively recovered and the balance crosses zero around hour 10. The community then becomes a cumulative net exporter, reaching approximately 155 kWh at hour 21 and closing the day at +139.9 kWh. The summer result therefore reflects the strong contribution of PV generation to local demand, storage charging and grid exports, allowing the community to end the representative day as a net supplier.

The winter trajectory shows the opposite overall position. The cumulative balance falls through the early morning and reaches approximately $-96.0$ kWh at hour 7, reflecting the greater reliance on grid imports under substantially lower PV availability. The balance partially recovers during the remainder of the day as PV generation and subsequent storage discharging reduce the accumulated deficit, but it never crosses zero and closes at $-45.9$ kWh. Under the same S4 planning configuration, the community therefore changes from a net exporter on the representative summer day to a net importer on the representative winter day.

Despite this pronounced reversal in the grid position, storage utilisation remains substantial in both periods. Aggregate BESS throughput decreases from 340.2 kWh on the summer day to 303.0 kWh on the winter day, corresponding to a reduction of approximately 11 %. The optimal S4 solution maintains reserve offers of 25 kW upward and 12.5 kW downward throughout both representative days while satisfying the 2:1 relation of Equation 3.10. The contrast is therefore greater in the community's external grid position than in the overall intensity of BESS utilisation. Within the two days analysed, reserve-enabled storage remains actively used under both seasonal conditions even though the balance between local generation and grid dependence changes substantially.

This result should not be interpreted as evidence that reserve operation is generally insensitive to seasonal variability. It shows only that, for the two representative days and the fixed S4 planning configuration considered here, the same reserve bands are maintained while the surrounding energy balance changes markedly. The operational comparison therefore highlights an important distinction between the reserve commitment and the broader energy position of the community. A similar reserve capability can coexist with very different patterns of grid import and export depending on the underlying demand and PV conditions.

The importance of representing these seasonal differences during planning was also observed in the conference paper developed within this work [106]. That earlier study solved the sizing problem separately for representative winter and summer periods, producing the aggregated capacities reported in Table 4.8.

Table 4.8: Aggregated PV and BESS sizing results [106].

| Season | Scen. | Sizing | Objective (€/day) | PV (kW) | BESS (kWh) |
|---|---|---|---|---|---|
| **Winter** | A$^\star$ | - | 8.019 | 9.24 | 25.00 |
| | B | - | $\downarrow$ 1.394 | 9.24 | 25.00 |
| | A | ✓ | $\downarrow$ 4.099 | 14.24 | 78.29 |
| | B | ✓ | $\downarrow$ 12.961 | 14.24 | 78.29 |
| **Summer** | A$^\star$ | - | 0.173 | 9.24 | 25.00 |
| | B | - | $\downarrow$ 13.457 | 9.24 | 25.00 |
| | A | ✓ | $\downarrow$ 12.009 | 34.24 | 31.01 |
| | B | ✓ | $\downarrow$ 25.820 | 34.34 | 30.64 |

$^\star$ reference scenario; $\downarrow$ indicates an improvement over the reference. Scenario A: without reserve participation; Scenario B: with reserve participation.

Table 4.8 shows that the earlier short-horizon planning exercise produced markedly different sizing signals between seasons. The winter optimisation selected approximately 14.24 kW of PV and 78.29 kWh of BESS, whereas the summer optimisation selected approximately 34.3 kW of PV and 31 kWh of BESS. These contrasting solutions reflect the different demand and PV conditions represented by each seasonal period and show how strongly a sizing result can depend on the horizon used to evaluate the investment.

Within each season, reserve participation produced little change in the selected capacities in the earlier formulation, despite substantially improving the objective value. This differs from the reserve-driven BESS response observed in the present dissertation, where reserve-power capability is endogenously coupled to the installed storage capacity through Equation 3.2. The comparison therefore also illustrates the methodological progression from the previous work towards the integrated sizing and reserve formulation adopted here.

More importantly, the strong difference between the winter and summer capacities demonstrates the limitation of deriving long-term planning decisions from an isolated seasonal period. A configuration optimised for one representative season may lead to under-sizing or over-sizing when extrapolated to annual operation, since the investment signal reflects only the demand, PV availability and market conditions observed during that period. A solution selected under winter conditions may therefore fail to capture investment opportunities that become attractive during periods of higher renewable availability, while a solution driven by summer conditions may allocate capacities whose value is not sustained throughout the remainder of the year. The present formulation instead evaluates the sizing problem over the complete 2022 calendar year, allowing the 8760 hourly demand, PV and market inputs to influence a single planning solution. In this way, seasonal variability is incorporated directly into the investment decision, reducing the risk that long-term capacities are under-sized or over-sized because they were derived from a single seasonal snapshot.

### 4.3.3 Annual Energy Exchanges

The daily analyses in Subsection 4.3.1 and Subsection 4.3.2 showed how the planning decisions affect storage operation and grid interaction under specific operating conditions. To complement these representative-day results, the Baseline, S3 and S4 scenarios are compared over the complete annual horizon using directly observable energy exchanges and BESS throughput.

The annual net grid balance is defined as the difference between the energy exported to and imported from the retailer,

$$E^{NET} = \sum_{n \in N} \sum_{t \in T} \left( E^{SUR}_{n,t} - E^{SUP}_{n,t} \right), \tag{4.5}$$

where a positive value represents an annual net exporting position and a negative value represents an annual net importing position. Annual BESS throughput follows the definition introduced in Subsection 4.3.1, extended over the complete annual horizon. It therefore includes scheduled charging and discharging in all scenarios and the modelled activation energy in S4.

Table 4.9: Annual energy exchanges and BESS throughput for the Baseline, S3 and S4 scenarios.

| Scenario | PV generation (MWh) | Grid import (MWh) | Grid export (MWh) | Net grid balance (MWh) | BESS throughput (MWh) |
|---|---|---|---|---|---|
| Baseline | 12.55 | 32.18 | 7.73 | −24.45 | 31.41 |
| S3 | 47.39 | 32.91 | 41.15 | +8.24 | 52.03 |
| S4 | 47.39 | 40.54 | 43.61 | +3.07 | 101.40 |

A positive net grid balance indicates annual net export, while a negative value indicates annual net import. BESS throughput includes scheduled charging and discharging and, in S4, modelled reserve activation energy.

Table 4.9 shows that joint sizing substantially changes the annual grid position of the community. Between the Baseline and S3, PV generation increases from 12.55 to 47.39 MWh and grid exports rise from 7.73 to 41.15 MWh. The annual net grid balance consequently changes from 24.45 MWh of net import to 8.24 MWh of net export. Grid imports remain at a similar level, increasing slightly from 32.18 to 32.91 MWh. This result shows that the economically optimal planning solution does not seek to minimise grid exchanges themselves. Instead, the enlarged PV and BESS portfolio combines local generation, storage operation and external market exchanges according to their contribution to the objective function.

The transition from S3 to S4 produces a different operational response. PV generation remains unchanged because both scenarios use the same total PV capacity of 34.25 kW. Annual grid imports increase from 32.91 to 40.54 MWh, while exports increase from 41.15 to 43.61 MWh. Since the increase in imports is larger, the annual net exporting position decreases from 8.24 to 3.07 MWh. At the same time, BESS throughput rises from 52.03 to 101.40 MWh, corresponding to an increase by a factor of approximately 1.95. The larger storage capacity and the incorporation of reserve provision therefore coincide with substantially more intensive BESS utilisation over the annual horizon.

This annual result reinforces the operational mechanism observed in Subsection 4.3.1. The main operational consequence of the reserve-enabled planning solution is the greater amount of energy processed through storage rather than an improvement in the net grid position of the community. The increased grid interaction in S4 is consistent with the substantially better economic result reported in Subsection 4.2.3, since SITEC minimises the combined investment and operating objective while accounting for reserve remuneration. It does not explicitly minimise grid imports or maximise energy autonomy.

The results therefore reveal an important planning trade-off. Under the case-study conditions, the configuration with reserve participation achieves greater economic value while simultaneously requiring more intensive storage utilisation and greater bidirectional interaction with the external grid. Improved economic performance should therefore not be interpreted as necessarily implying reduced grid dependence or lower storage use.

## 4.4 Summary

The case study shows that the configuration selected for a REC depends materially on the market opportunities represented during planning. Jointly sizing PV, BESS and contracted power reduces the annual cost relative to the pre-existing configuration, but the resulting investment signals differ across assets. Under energy-market participation alone, the value of additional generation drives PV capacity to the adopted planning boundary, while BESS remains at an interior solution determined by the balance between investment cost, energy shifting and contracted-power savings. When mFRR participation is introduced, reserve remuneration creates an additional value stream directly associated with storage capacity. The resulting expansion of the BESS from 48.73 to the imposed ceiling of 125 kWh, together with the transition from annual cost to net annual revenue, demonstrates that reserve participation can change the planning decision itself rather than merely providing additional revenue from assets whose capacities were determined beforehand.

The sensitivity analysis further shows that this result depends on how reserve provision is represented. The activation robustness parameter $\hat{\varepsilon}$ changes the activation energy that may be valued, whereas the reserve power scaling parameter $\hat{\alpha}_n^{RES}$ changes the reserve-power capability associated with the installed BESS. These assumptions consequently affect reserve revenue through distinct mechanisms. Their effect on further capacity expansion cannot be observed because the PV and BESS solutions are already located at their adopted planning boundaries under the conservative reference configuration. The results should therefore be interpreted as evidence of continued investment pressure within the investigated design space, rather than as identification of an unconstrained optimal capacity.

The operational results connect these planning decisions to the subsequent use of the selected assets. The representative-day analysis shows how the larger reserve-enabled BESS coordinates energy-market operation, SoC management, reserve availability and modelled activation, altering both storage schedules and grid exchanges. Although this comparison illustrates the mechanism for a specific day, the annual results confirm a broader increase in storage utilisation, with BESS throughput rising from 52.03 MWh in S3 to 101.40 MWh in S4 alongside greater bidirectional interaction with the grid. The seasonal comparison also shows that the same reserve-enabled configuration can operate under markedly different surrounding energy balances. Moreover, the contrasting capacities obtained when winter and summer were previously optimised separately demonstrate why an isolated seasonal period may provide a misleading long-term investment signal. The full-year horizon adopted in SITEC allows the variability of demand, PV availability and market conditions across all 8760 hourly intervals to influence a common planning decision.

Taken together, these results demonstrate the contribution of SITEC as a planning decision-support framework. By evaluating investment decisions through the optimised operation of the community, the model makes it possible to trace how market access and technical assumptions affect asset sizing, economic performance and operational requirements within a consistent formulation. SITEC does not prescribe a universally optimal REC configuration, since the results remain conditional on the deterministic representation, the 2022 market conditions and the planning

limits adopted in the case study. Within these boundaries, however, the analysis shows the importance of considering reserve participation endogenously during sizing and of evaluating long-term investments over a horizon capable of representing seasonal variability. The framework therefore supports a more informed assessment of the opportunities and trade-offs involved in planning RECs for joint energy and reserve-market participation.

# Chapter 5

# Conclusion

This chapter presents the main conclusions drawn from the work developed in this dissertation. It summarises the principal methodological, economic and operational findings, while critically discussing the scope of the proposed framework and its contribution to REC planning. Finally, possible directions for extending and applying the developed work are identified.

## 5.1 Conclusions

The increasing deployment of distributed renewable generation and flexible resources creates new opportunities for RECs, but also makes their planning more complex. Investment decisions concerning PV, BESS and contracted power depend on how these assets are expected to operate, interact with the grid and respond to market signals throughout their lifetime. This dissertation addressed this challenge by investigating whether mFRR participation should be considered during the sizing process itself, rather than treated only as an additional operational revenue stream after the community assets have already been selected.

To address this problem, an extension of the SITEC framework was developed and applied as an optimisation-based planning tool for RECs. The proposed MILP formulation jointly determines PV capacity, BESS capacity and contracted power while evaluating each candidate configuration through its optimised operation. The model represents local energy sharing, interaction with the retailer, energy-market prices, investment costs and mFRR participation within a common economic framework. Reserve capability is endogenously linked to the dimensioned BESS, allowing the value of flexibility provision to influence the storage investment decision directly. The use of a complete annual horizon further ensures that demand, PV availability and market conditions across all 8760 hourly intervals contribute to the same long-term planning decision.

The residential case study showed that joint sizing substantially improves the economic performance of the community even without reserve participation. Relative to the pre-existing configuration, the coordinated sizing of PV, BESS and contracted power reduced the net annual cost from 6 958.5 to 1 074.5 €/year. The different assets nevertheless responded to distinct economic signals. The value of additional generation and exports maintained investment pressure for PV up

to the adopted installation boundary, whereas BESS capacity remained at an interior solution determined by the balance between investment cost, temporal energy shifting and contracted-power savings. This demonstrates the importance of optimising the assets jointly, since their value cannot be determined independently from the operational and contractual conditions of the community.

The introduction of mFRR participation materially changed this planning result. Reserve remuneration created an additional value pathway directly associated with storage capacity, increasing the selected BESS from 48.73 kWh to the imposed aggregate ceiling of 125 kWh. The modelled net annual objective consequently changed from a cost of 1 074.5 € to a net revenue of 12 682.4 € before aggregator fees, market-access costs and cycling-dependent degradation costs. The asset-isolation scenarios confirmed that this investment response was primarily driven by the direct relationship between BESS capacity and reserve-power capability, rather than by a comparable effect on PV sizing. The results therefore show that reserve participation can alter the configuration selected for the community and should not necessarily be evaluated only after investment decisions have been made. Since the BESS reached the adopted planning boundary, however, the result represents continued investment pressure throughout the investigated design space and does not identify the unconstrained optimal storage capacity.

The reserve sensitivity analysis also demonstrated that modelling assumptions affect the economic results through different mechanisms. The robustness discount applied to the historical activation envelope changes the amount of activation energy that may be valued, while the reserve power scaling parameter changes the reserve-power capability associated with a given BESS capacity. More favourable assumptions increased reserve revenues, although their effect on further capacity expansion could not be observed because PV and BESS were already located at their respective planning boundaries in the reference reserve-enabled configuration. These findings reinforce the need to interpret sizing results together with the assumptions used to represent reserve availability and activation.

The operational analysis provided the physical interpretation of these planning decisions. The larger reserve-enabled BESS supported a more intensive operating schedule in which energy management, SoC requirements, reserve availability and modelled activation were coordinated simultaneously. Annual BESS throughput increased from 52.03 MWh without reserve participation to 101.40 MWh when mFRR was included. This change was accompanied by greater annual imports and exports, showing that the improved economic result was associated with more intensive storage utilisation and bidirectional grid interaction rather than with a direct reduction in grid dependence. Since cycling-dependent degradation was not monetised in the objective function, the calculated economic value does not fully capture the additional wear associated with this increased utilisation.

Seasonal operation further showed why long-term sizing should not be based on a single operating period. The same reserve-enabled configuration acted as a net exporter under the representative summer conditions and as a net importer during the representative winter day, while maintaining the selected reserve bands in both cases. Moreover, the previous seasonal sizing analysis produced markedly different PV and BESS capacities when winter and summer were optimised

separately. By considering the complete calendar year, SITEC prevents the investment decision from being determined by an isolated favourable or unfavourable seasonal period and provides a more representative basis for evaluating long-term capacity choices.

The quantitative results remain conditional on the deterministic formulation, perfect foresight assumptions, historical activation envelopes, adopted planning limits and the 2022 market conditions represented in the case study. In particular, reserve activation is represented through deterministic upper bounds derived from historical activation ratios, rather than through exogenous real-time activation trajectories or stochastic activation scenarios. Since actual activation is determined by the TSO, the resulting activation revenues should be interpreted as planning outcomes under the adopted representation and not as guaranteed market revenues. The results are also specific to a small residential community whose access to mFRR is assumed to occur through an external aggregator. These conditions limit the direct generalisation of the selected capacities and economic values to other communities and market contexts. Nevertheless, they do not invalidate the planning mechanisms identified by the analysis.

The main contribution of the extension developed in this dissertation is therefore not the prescription of a universally optimal REC configuration. Its value lies in providing a transparent and tractable decision-support framework that reveals how market access, technical assumptions and remuneration mechanisms propagate through operational decisions and change the economic value assigned to each asset. By representing reserve participation as an endogenous driver of sizing, the framework supports a more informed assessment of the opportunities and trade-offs involved in planning RECs for joint participation in energy and reserve markets.

## 5.2 Future Work

The results obtained in this dissertation suggest the following directions for future research:

- Develop a stochastic formulation to represent uncertainty in demand, PV generation, market prices and reserve activation. Intraday re-optimisation could also be considered to update operational decisions as new information becomes available;

- Increase the temporal resolution of the reserve formulation to represent 15-minute market time units and sub-hourly activation requirements. This extension could verify reserve headroom, SoC feasibility and recovery between consecutive activations more accurately;

- Include BESS degradation costs in the planning problem. This would allow the additional reserve revenue to be evaluated against the increased cycling and storage utilisation observed in the reserve-enabled scenarios;

- Represent the commercial and operational relationship with the external aggregator, including revenue-sharing mechanisms, market-access fees, offer acceptance, availability requirements and penalties for non-delivery. This would allow the gross reserve revenues represented in the current framework to be translated into a more realistic net value for the community;
- Extend reserve provision to other flexible DERs, including EVs, V2G resources and controllable loads. Their coordination with the BESS could increase the aggregate reserve capability of the community and distribute the operational response among different resources;
- Integrate distribution-network constraints or couple SITEC with a power-flow model. Voltage limits, thermal loading, connection-point restrictions and reverse power flows could then be considered jointly with the economic sizing decisions;
- Apply SITEC to larger commercial or industrial communities. Their greater consumption, installed capacity and flexibility could be used to assess whether a REC may satisfy the applicable mFRR participation requirements directly, without relying on an external aggregator;
- Link the continuous sizing results to commercially available equipment and real investment costs. Discrete BESS and inverter capacities, installation costs, net present value and payback period could be considered to assess the practical viability of the selected configurations. The community-level objective could also be extended to consider benefit allocation and fairness among members, allowing different cost- and revenue-sharing mechanisms to be evaluated alongside the economic viability of the selected investments.

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# Appendix A

# Effect of Joint Sizing on Configuration and Cost

Table A.1: Per-member sizing and cost results for the Baseline and S3 scenarios.

| | Baseline* | | | | S3 | | | |
|---|---|---|---|---|---|---|---|---|
| **Member** | **PV (kW)** | **BESS (kWh)** | $P^{CONT}$ **(kW)** | **Cost (€/yr)** | **PV (kW)** | **BESS (kWh)** | $P^{CONT}$ **(kW)** | **Cost (€/yr)** |
| User 1 | 2.47 | 5.00 | 6.90 | 904.0 | 7.47 | 11.42 | 3.94 | 73.4 |
| User 2 | 0.57 | 5.00 | 3.45 | 309.6 | 5.57 | 6.40 | 3.45 | −737.0 |
| User 3 | 0.51 | 5.00 | 13.80 | 3 754.7 | 5.51 | 15.85 | 3.79 | 1 331.3 |
| User 4 | 3.31 | 5.00 | 6.90 | 1 486.0 | 8.31 | 7.73 | 4.48 | 659.0 |
| User 5 | 2.39 | 5.00 | 4.60 | 504.4 | 7.39 | 7.33 | 3.77 | −252.2 |
| **Community** | 9.25 | 25.00 | 35.65 | 6 958.5 | 34.25 | 48.73 | 19.43 | 1 074.5 |

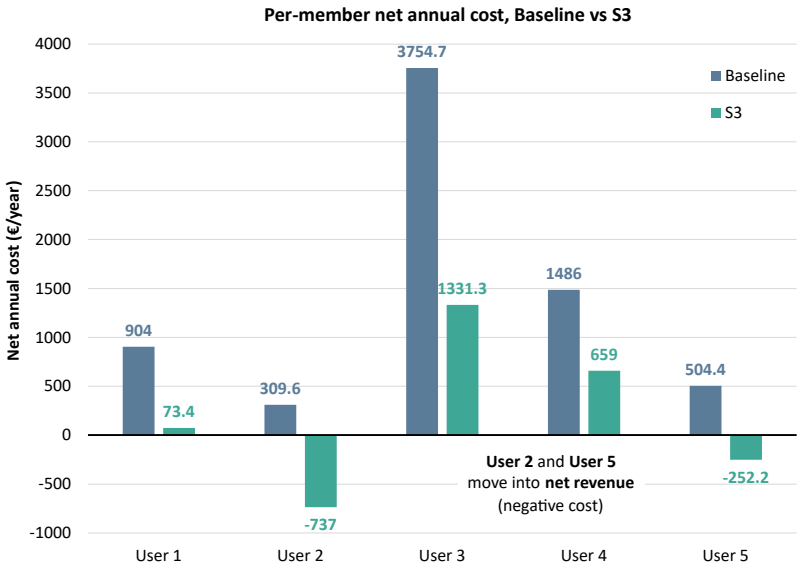



Figure A.1: Per-member net annual cost, Baseline vs S3.

# Appendix B

# Effect of Reserve Participation on Sizing Decisions

Table B.1: Sizing decisions per member for S3, S1, S2 and S4.

| | PV (kW) | | | | BESS (kWh) | | | | $P^{CONT}$ (kW) | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Member** | **S3** | **S1** | **S2** | **S4** | **S3** | **S1** | **S2** | **S4** | **S3** | **S1** | **S2** | **S4** |
| User 1 | 7.47 | 2.47 | 5.88 | 7.47 | 11.42 | 25.00 | 5.00 | 25.00 | 3.94 | 6.90 | 6.90 | 4.25 |
| User 2 | 5.57 | 0.57 | 3.33 | 5.57 | 6.40 | 25.00 | 5.00 | 25.00 | 3.45 | 3.45 | 3.45 | 3.45 |
| User 3 | 5.51 | 0.51 | 2.94 | 5.51 | 15.85 | 25.00 | 5.00 | 25.00 | 3.79 | 13.80 | 13.80 | 3.15 |
| User 4 | 8.31 | 3.31 | 6.87 | 8.31 | 7.73 | 25.00 | 5.00 | 25.00 | 4.48 | 6.90 | 6.90 | 4.08 |
| User 5 | 7.39 | 2.39 | 5.13 | 7.39 | 7.33 | 25.00 | 5.00 | 25.00 | 3.77 | 4.60 | 4.60 | 3.45 |
| **Community** | 34.25 | 9.25 | 24.14 | 34.25 | 48.73 | 125.00 | 25.00 | 125.00 | 19.43 | 35.65 | 35.65 | 18.38 |

Table B.2: Net annual cost per member for S1, S2 and S4.

| **Member** | **S1 (€/year)** | **S2 (€/year)** | **S4 (€/year)** |
|---|---|---|---|
| User 1 | −1 763.9 | −237.3 | −2 669.9 |
| User 2 | −2 324.9 | −793.2 | −3 334.4 |
| User 3 | 695.0 | 2 755.2 | −1 350.8 |
| User 4 | −1 610.6 | 432.3 | −2 030.0 |
| User 5 | −2 434.7 | −513.8 | −3 297.4 |
| **Community** | −7 439.1 | 1 643.3 | −12 682.4 |