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School of Industrial Engineering

Optimizing Energy Use in Agricultural Energy Communities  
through Flexible Demand and Electrification Strategies

Master's Thesis

Master's Degree in Energy Technologies for Sustainable  
Development

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ACADEMIC YEAR: 2025/2026



**UNIVERSITAT  
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**ESCUELA TÉCNICA  
SUPERIOR INGENIEROS  
INDUSTRIALES VALENCIA**

**Universitat Politècnica de València**

Escuela Técnica Superior de Ingeniería Industrial

Master's Degree in Energy Technologies for Sustainable Development

**Optimising Energy Use in Agricultural Energy  
Communities through Flexible Demand and  
Electrification Strategies**

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València, 02 2026



## Acknowledgement

Desidero ringraziare la mia famiglia — mamma, papà, Silvia, Andrea ed Emanuele — per il supporto costante e sincero che non è mai venuto meno durante questa esperienza.

Ringrazio i miei amici, vicini e lontani, per la loro presenza e per aver dimostrato una vicinanza che ha superato ogni distanza.

Ringrazio l'Universitat Politècnica de València, e in particolare Álvaro e David, per la disponibilità, il supporto e per aver contribuito a restituirmi entusiasmo e fiducia in questo percorso.

## Abstract

The application of demand-side flexibility to energy communities (ECs) is playing an increasingly central role in the transition toward cleaner, more resilient and decentralized energy systems. By enabling local renewable generation, collective self-consumption and active participation of end users, ECs enhanced by flexible demand can better address the challenges associated with the integration of non-dispatchable renewable energy sources. This approach is particularly relevant in rural areas, where energy demand is highly seasonal, closely linked to agricultural activities and still largely dependent on fossil fuels.

Despite the rapid expansion of renewable energy technologies, the variability of generation often leads to mismatches between supply and demand, limiting economic performance. In agricultural settings, electricity consumption for irrigation offers significant potential for demand-side flexibility, but is constrained by site-specific, operational and regulatory factors. This study investigates a flexible agricultural energy community located in the farmland south of the city of Valencia, Spain, where irrigation demand interacts with local renewable generation under different tariff conditions.

The study analyses how alternative technical configurations and electricity tariff schemes influence the economic performance of the energy community. A submersible well pump system is modelled under different configurations, including integration with a 50 kWp photovoltaic system, grid connection and a shared lithium-ion battery energy storage system with a capacity of 40 kWh and a power of 20 kW. Three representative electricity tariffs are considered: a fixed-rate tariff, a period-of-use tariff and a market-indexed tariff. A mathematical optimization model is employed to identify optimal energy allocation coefficients—static, variable or dynamic—aimed at maximizing economic benefits through increased self-consumption and load flexibility.

A techno-economic assessment based on key performance indicators is used to compare the different scenarios and identify the most cost-effective solutions. The results highlight the role of demand-side flexibility in shaping the economic viability and operational behavior of agricultural energy communities. These findings provide useful insights into how flexible demand, local renewable generation and appropriate tariff structures can support the energy transition in Spain's rural and agricultural landscapes.

**Keywords:** Battery Energy Storage System; Collective Self-Consumption; Energy Communities; Flexible Demand; Mathematical Optimization Model; Photovoltaic Installation; Renewable Energy Sources.

## Resumen

La incorporación de la flexibilidad de la demanda a las comunidades energéticas (ECs) está cobrando una importancia creciente en la transición hacia sistemas energéticos más limpios, resilientes y descentralizados. Al facilitar la generación renovable local, el autoconsumo colectivo y la participación activa de los usuarios finales, las ECs con demanda flexible pueden responder de forma más eficaz a los retos asociados a la integración de fuentes renovables no despachables. Este enfoque resulta especialmente relevante en los entornos rurales, donde la demanda energética es altamente estacional, está estrechamente vinculada a la actividad agrícola y sigue dependiendo en gran medida de los combustibles fósiles.

A pesar del rápido despliegue de las tecnologías renovables, la variabilidad de la generación provoca con frecuencia desajustes entre la oferta y la demanda, lo que limita el rendimiento económico de los sistemas. En contextos agrícolas, el consumo eléctrico destinado al riego presenta un elevado potencial de flexibilidad de la demanda, aunque se ve condicionado por factores específicos del emplazamiento, así como por restricciones operativas y regulatorias. En este marco, el presente estudio analiza una comunidad energética agrícola flexible situada en las tierras de cultivo al sur de la ciudad de Valencia, España, donde la demanda de riego interactúa con la generación renovable local bajo distintos esquemas tarifarios.

El trabajo examina cómo diferentes configuraciones técnicas y esquemas tarifarios eléctricos influyen en el rendimiento económico de la comunidad energética. Para ello, se modeliza un sistema de bombeo de pozo con bomba sumergible en distintas configuraciones, incluyendo su integración con una instalación fotovoltaica de 50 kWp, la conexión a la red eléctrica y un sistema compartido de almacenamiento mediante baterías de ion-litio, con una capacidad de 40 kWh y una potencia de 20 kW. Se consideran tres tarifas eléctricas representativas: tarifa de precio fijo, tarifa por periodos de uso y tarifa indexada al mercado. Asimismo, se emplea un modelo de optimización matemática para determinar coeficientes óptimos de asignación energética—estáticos, variables o dinámicos—orientados a maximizar los beneficios económicos mediante un mayor autoconsumo y una gestión flexible de la demanda.

El análisis tecnoeconómico, basado en indicadores clave de rendimiento, permite comparar los distintos escenarios e identificar las soluciones más rentables. Los resultados muestran la importancia de la flexibilidad de la demanda en la viabilidad económica y en el comportamiento operativo de las comunidades energéticas agrícolas. Además, aportan una mejor comprensión de cómo la demanda flexible, la generación renovable local y un esquema tarifario adecuado pueden contribuir a la transición energética en los entornos rurales y agrícolas de España.

**Palabras Clave:** Autoconsumo Colectivo; Comunidades Energéticas; Demanda Flexible; Fuentes Renovables; Instalación Fotovoltaica; Modelo de Optimización Matemática; Sistema de Almacenamiento con Baterías.

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## Nomenclature

### Acronyms

<i>BESS</i>	Battery Energy Storage System
<i>CAPEX</i>	Capital Expenditure
<i>EC</i>	Energy Community
<i>ESCO</i>	Energy Service Company
<i>IC</i>	Irrigation Community
<i>MILP</i>	Mixed-Integer Linear Programming
<i>PV</i>	Photovoltaic
<i>SoC</i>	State of Charge

### Parameters

$B_{MAX}^{Ch}$	BESS maximum charging power [kW]
$B_{MAX}^{Ds}$	BESS maximum discharging power [kW]
$BESS_{MIN}$	BESS Minimum State of Charge
$BESS^{CAPEX}$	BESS CAPEX [€]
$BESS^{Cycles}$	BESS cycles before replacement
$C_{t,0}^G$	Cost of electricity purchased from the retail company at period $t$ in the initial situation [€]
$CF_t$	Capacity factor of the PV system at period $t$

### Index

$j$	Consumption points index
$k$	Battery modules index
$m$	Billing periods index [months]
$n$	Year of operation index [yr]
$p$	Tariff period index
$t$	Time index [h]
$w$	Weeks of a month index

$COST_0$	Annual cost of energy for the initial situation [€/yr]
$d$	Market discount rate
$\Delta t$	Time step duration [h]
$E_{CAP}^B$	BESS energy storage capacity [kWh]
$E_m^{req}$	Total monthly irrigation demand for month $m$ [kWh]
$I^{MAX}$	Maximum irrigation power [kW]

### Sets

$J$	Set of all consumption points
$K$	Set of all battery modules
$M$	Set of all billing periods
$N$	Set of all years of operation
$P$	Set of all tariff periods
$T$	Set of all time periods
$W$	Set of all weeks of a month

$LCOS$	Levelized Cost of Storage [€/kWh]
$OM$	Operation and maintenance annual expenses [€/yr]
$POW_{j,0}$	Contracted power at consumption point $j$ in the initial situation [kW]
$PV_t$	Power generated by the PV system at time $t$ [kW]

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$PV_{nom}$	Nominal power of the PV system [kW]	$C^G$	Annual bill of electricity purchased from retail company [€/yr]
$\eta^{B,Ch}$	BESS charging efficiency		
$\eta^{B,Ds}$	BESS discharging efficiency	$C^{pow}$	Annual cost of power term of electricity contracted from the retail company [€/yr]
$\Pi_p^{pow}$	Price of power term per period from Access Tariff [€/kW]		
$\Pi_p^{en}$	Price of energy term per period from Access Tariff [€/kWh]	$C^{en}$	Annual cost of energy term of electricity contracted from the retail company [€/yr]
$\Pi_t^{pur}$	Price of purchasing electricity from retail company at time $t$ [€/kWh]	$C_t^{pur}$	Cost of electricity purchased from the retail company at period $t$ [€]
$R_t$	Water level related to irrigation water usage $g$ at time $t$ [m <sup>3</sup> ]	$C_t^{sold}$	Cost of revenue from electricity sold to the grid at period $t$ [€]
$R_0$	Water level at the beginning of the time period considered [m <sup>3</sup> ]	$C_t^V$	Cost of variable term of electricity from the retail company at period $t$ [€]
$R_T$	Water level at the end of the time period considered [m <sup>3</sup> ]		
$SC_{j,t}$	Power consumed instantly from the PV system by consumption point $j$ [kW]	$COST_{EC}$	Annual cost of energy for the EC [€/yr]
$SOLD_{j,t}$	Power sold to grid by consumption point $j$ at time $t$ [kW]	$D_{j,t}$	Power demand at $j, t$ [kW]
		$E_t^B$	Energy stored in BESS at time $t$ [kWh]
		$E_{t-1}^B$	Energy stored in BESS at time $t-1$ [kWh]
	<b>Variables</b>	$E_m^{week}$	Weekly irrigation targets in month $m$ [m <sup>3</sup> ]
$A_{j,t}$	Power allocated by the EC to consumption point $j$ at time $t$ [kW]	$E_t^{irr}$	Irrigated water at time $t$ [m <sup>3</sup> ]
$B_t^{Ch}$	Power charged to BESS during period $t$ [kW]	$GIFT$	Power given to the grid without monetary revenue for the EC [kW]
$B_t^{Ch,pur}$	Power charged to BESS from retail company during period $t$ [kW]	$I_t$	Irrigation power at time $t$ [kW]
$B_t^{Ch,sc}$	Power charged to BESS from self-consumption during period $t$ [kW]	$INV_n$	Investment of the EC in year $n$ [€]
$B_t^{Ds}$	Power discharged from BESS during period $t$ [kW]	$POW_j$	Contracted power at consumption point $j$ [kW]

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$PUR_{j,t}$	Power purchased from the retail company by consumption point $j$ [kW]	$CAP$	Storage capacity [kWh]
		$EC$	After EC implementation
$R_t$	Water level related to irrigation water usage $g$ at time $t$ [m <sup>3</sup> ]	$MAX$	Maximum power [kW]
		$MIN$	Minimum SoC of BESS [kW]
$SC_{j,t}$	Power consumed instantly from the PV system by consumption point $j$ [kW]		
			<b>Superscripts</b>
$SOLD_{j,t}$	Power sold to the grid by consumption point $j$ at time $t$ [kW]	$B$	BESS related term
		$Ch$	Charging
$Pw_{j,t}$	Power related to irrigation of consumption point $j$ at time $t$ [kW]	$Ds$	Discharging
		$G$	Billed by retail company
$\alpha_j$	Conversion coefficient of consumption point $j$ [m <sup>3</sup> /kWh]	$INV$	Investment
		$OM$	Operation and maintenance
$\beta_{j,t}$	Allocation coefficient of consumption point $j$ at time $t$	$POW$	Contracted power
		$pur$	Purchased from retail company
$\gamma_{j,t}$	Binary variable indicating the on/off status of the irrigation pump $j$ at time $t$ (1 = on, 0 = off)	$req$	Required
		$SAV$	Savings
		$sc$	Self-consumption based
		$sold$	Sold to the grid
		$V$	Variable term
		$week$	Weekly
	<b>Subscripts</b>		
0	Initial situation		

**Part I**

**CHAPTERS**

# 1 Introduction

## 1.1 Current situation of the energy sector and energy communities

For decades, the energy sector has been dominated by a centralised model of electricity generation. Large-scale power plants—often powered by fossil fuels or nuclear energy—are typically located far from the end users, requiring extensive transmission infrastructure to deliver electricity across vast distances (Fig. 1). This structure, while efficient on a technical scale, has also contributed to a concentration of control within a handful of major energy corporations, limiting both the active role of consumers and the flexibility of local actors.

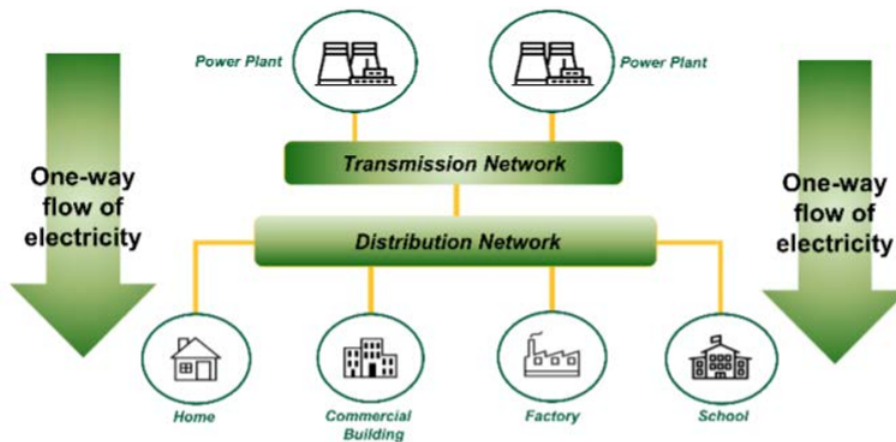


Figure 1: Traditional centralised power system – (U.S. Department of Energy, NYISO, 2016).

However, in the past few years, this landscape has started to shift. A growing awareness of the limitations of centralised systems—specifically their vulnerability to external shocks—has sparked a broader discussion about the future of energy’s production and management. The recent geopolitical instability, particularly the war in Ukraine, has made these vulnerabilities especially visible. The risk of over-dependence on imported energy resources has exposed many countries to severe price volatility as supply chains are disrupted and reliance on foreign fossil fuels becomes increasingly unsustainable. The consequences of these dynamics are experienced most severely at the local level. Energy poverty, for example, remains a pressing issue, not only in the Global South but also in many parts of developed nations, where vulnerable households struggle to afford basic energy services. Structural inefficiencies, such as distribution losses from long-distance transmission within low-voltage networks, further intensify both environmental and social costs. Beyond these chronic issues, acute events have also highlighted the fragility of centralised systems. The widespread blackout that affected Spain and Portugal in April 2025 is a striking example: a single failure can cascade through the grid, leading to halting transportation, communication blackouts and economic losses estimated between €2.25 and €4.5 billion (Reuters, 2025). Such incidents highlight the critical importance of energy resilience, both to handle ongoing problems and to deal with sudden disruptions.

Given these circumstances, Renewable Energy Communities (RECs) are gaining importance as part

of a broader shift toward a more decentralised and resilient energy system. By distributing energy generation closer to the point of consumption, systems such as microgrids and distributed renewable sources reduce dependence on centralised infrastructure and allow for faster recovery during crisis. Their distributed nature not only enhances technical resilience but also supports greater energy security at the local level. Renewable energy communities are therefore emerging as a grassroots response to the need for greater resilience, equity and sustainability in energy production and distribution. By enabling citizens, municipalities and small businesses to collectively generate, share and manage energy—through renewable sources—RECs challenge the traditional top-down paradigm. They offer the potential to reduce dependency, enhance local autonomy and create a more democratic and inclusive energy transition. This evolving model has not gone unnoticed at the policy level. In Europe, for instance, the European Commission's "Clean Energy for All Europeans Package" (ACER, 2019) has provided a framework to support the growth of energy communities, recognizing their role in accelerating the decarbonization process while promoting social cohesion and economic development at the local scale. Additionally, the "EU Strategy for Energy System Integration" (European Commission, 2020), as part of the European Green Deal, emphasizes the need for a more interconnected and coordinated energy network, facilitating the integration of renewable resources and enhancing efficiency. This approach supports the optimization of the energy system to deliver decarbonized and reliable energy services at the least possible cost.

## **1.2 Challenges and opportunities towards a flexible and sustainable future**

The ongoing energy transition involves not only a shift from fossil to renewable energy sources, but also a structural rethinking of how energy is produced, consumed and managed. While renewable energy sources help reduce carbon emissions, they also introduce new challenges, such as variability and imbalance in supply and demand. A central concept in addressing these challenges is energy flexibility, the system's capacity to adapt dynamically to fluctuations in supply and demand while ensuring reliability, efficiency and sustainability.

### **1.2.1 Technical challenges in the transition**

One of the primary challenges in renewable-based systems is the intermittency of energy generation: solar and wind power, the most widely used renewable sources, are indeed variable and non-dispatchable. This intermittency makes it difficult to balance energy supply and demand in real-time, particularly in isolated or rural contexts, such as agricultural communities reliant on irrigation systems with seasonal and time-sensitive load profiles (Tronchin et al., 2018). To address this, storage and demand side management have emerged as possible solutions. On the one hand, energy storage systems (ESS) (Table 1) have become indispensable: technologies like lithium-ion batteries, pumped hydro storage, compressed-air energy storage and even vehicle-to-grid (V2G) integrations are being deployed to store excess energy for use during periods of low generation (Balakumar et al., 2023). Moreover, emerging storage approaches based on green hydrogen offer long-duration storage potential and contribute to grid flexibility. It is also true, however, that deploying ESS at scale

## Optimising Energy Use in Agricultural Energy Communities through Flexible Demand and Electrification Strategies

presents significant economic and environmental challenges, including high initial investment costs and uncertain return, lifecycle impacts of batteries materials and lack of harmonized grid integration frameworks (Komarnicki et al., 2017).

Electrical	Electrochemical	Hydrogen based	Mechanical	Thermal
Supercapacitors energy storage system (CESS)	Lead Acid Batteries	Power-to-Power (fuel cells...)	Pumped Hydro Storage (PSH)	Sensible–Molten Salt, Chilled Water
Superconducting Magnetic Energy Storage (SMES)	Lithium-ion Batteries (Li-ion)	Power-to-Gas	Gravity Storage Technologies	Latent-ice Storage, Phase Change Materials (PCM)
	Flow Batteries		Compressed Air Energy Storage (CAES)	Thermochemical Storage
	Zinc Batteries		Flywheel Energy Storage System (FESS)	
	High Temperature Technologies			

**Table 1:** Energy storage technologies for smart grids.

On the other hand, Demand-Side Management (DSM) has emerged as a complementary strategy to storage. By shifting energy consumption in response to generation forecasts or pricing signals, DSM enables better alignment of demand with intermittent renewable output. Advanced DSM techniques, which will be discussed in more detail in the following sections, now leverage machine learning algorithms and AI for real-time forecasting and optimization of distributed energy resources (DERs) (Čaušević et al., 2021; Tepe et al., 2024).

Beyond these two key strategies, the transition to renewable-based decentralised systems faces a broader set of technical and regulatory challenges:

- **Grid integration and infrastructure:** Most existing grids were designed for centralised generation and must be upgraded to support bidirectional flows, interconnection and real-time control. Smart grids, supported by digitalization, IoT sensors and automated control systems, are essential to enable a flexible and reliable decentralised network.
- **System stability:** The variable nature of RES affects frequency and voltage stability. To maintain operational security, decentralised systems require robust grid-forming inverters, local balancing mechanism and continuous real-time monitoring.
- **Planning and permitting bottlenecks:** The acceleration of renewable installations is often delayed by complex authorization processes. Streamlining regulatory procedures are essential to scale up microgrids and local generation projects efficiently.

- **Equity and access:** From a socio-technical standpoint, ensuring that decentralised energy systems are affordable and accessible—especially in developing countries or underserved rural areas—remains a priority. This involves supporting low-cost microgrid models, encouraging technology transfer and designing inclusive financing mechanisms.

Understanding these challenges is essential to identify viable solutions and design strategies that can enhance the resilience and sustainability of decentralised renewable energy systems, such as agricultural energy communities.

Finally, meeting global climate and energy targets requires unprecedented scale-up of renewable deployment. According to the IEA, renewable capacity must triple by 2030 to stay on track for net-zero emissions by 2050. Achieving this objective means overcoming not only technical limitations but also systemic barriers, including market redesign, the development of flexibility services, improved grid resilience and, lastly, long-term investment strategies.

### 1.2.2 Citizens as prosumers and active participants

A major paradigm shift in the energy transition is the evolving role of citizens from passive consumers to prosumers. According to the literature: "*Renewable Energy Source (RES) prosumers are individuals or groups that both consume and produce RES-based energy or offer energy services to the system, such as flexibility or storage. Unlike utility companies, delivering energy services is not a prosumer's main commercial activity.*" – (European Environment Agency, 2022). Prosumers seem therefore to contribute to grid stability through local generation, to participate in demand response programs and to engage with energy communities to share resources. This active participation marks a shift not only in energy flows, but also in how the energy system is governed and who is empowered to act. As a result, this transition requires both technical tools and cultural transformation, as well as institutional support. Public engagement strategies, educational initiatives and financial incentives—such as feed-in tariffs or dynamic pricing schemes—are essential to encourage citizen participation. In addition, digital platforms and smart devices enable households to monitor and manage their energy usage, contributing actively to system-wide flexibility.

However, the large-scale integration of prosumers brings challenges of coordination, data security and equity. Not all users have equal access to technology or capital to invest in rooftop solar batteries or automation systems. In this regard, privacy-preserving technologies such as *federated learning* are gaining attention: they allow decentralised data analysis and forecasting without compromising personal data, making it possible for more users to participate in energy flexibility markets without losing control over their information. By empowering prosumers and embedding them into the operational logic of smart, decentralised grids, the energy system becomes not only more resilient and efficient, but also more democratic and inclusive, reflecting a broader vision of the energy transition as a societal and not merely technological process.

### 1.3 Objectives of the project

The main objective of this project is to optimise energy flexibility in an Energy Community (EC), focusing on its economic performance and operational dynamics, through the development and application of a methodological framework. This framework aims to identify how distinct technical configurations and electricity pricing schemes can jointly influence the community's transition toward a more sustainable and efficient energy model. In addition, the project seeks to understand how a flexible energy community operates under real operational conditions, such as the maximum power limits of electric pumps, exploring how flexibility can be effectively managed within these limits. A central goal is to maximize collective self-consumption and enhance the integration of renewable energy sources through the implementation of intelligent and adaptable energy allocation strategies.

To achieve this, the project systematically investigates the combined operation of a proposed 50 kWp photovoltaic (PV) generation system, a shared 40 kWh lithium-ion battery energy storage system (BESS) and the management of irrigation load within an agricultural community located in the farmland of the Valencian district of Pobles del Sud. This involves the operation of electric pumps supported by the PV system and when necessary by grid electricity. The modeling approach builds upon the mathematical optimization model presented by Manso-Burgos et al. (Manso-Burgos et al., 2024), further extending it to analyze how flexibility strategies behave under real power and tariff constraints. This makes the study particularly innovative as it begins to explore how flexible demand should operate, how it can be coordinated with electricity markets and how it can be characterized across different contexts.

The project evaluates three representative electricity tariff models: a flat-rate tariff in which a single price is applied to all consumed energy, a period-of-use tariff in which different prices are applied depending on the time period, and an indexed-price tariff in which the energy price is linked to daily market prices. These pricing options are analyzed in relation to flexible irrigation load profiles and the PV generation patterns typical of the agricultural context. Using an advanced mathematical optimization model previously developed and validated in the scientific literature, the study determines optimal energy allocation coefficients (static, variable or dynamic) that maximize economic benefit through enhanced self-consumption and strategic load flexibility. At its core, the broader objective is to thoroughly identify and quantify how different forms of energy sharing methods can influence operational performance and economic outcomes when combined with the specific technical configurations and electricity tariff schemes considered in the study.

In light of the aspects discussed, specific objectives of this work include:

- **Evaluating Demand-Side Management (DSM) Effectiveness:** Assessing the efficacy of demand-side management strategies, with particular emphasis on the role of flexible irrigation load control as a key enabler of system adaptability, in improving overall system efficiency and reducing dependence on grid electricity, thereby contributing to the community's energy autonomy.
- **Understanding Operational Behavior under Power Constraints:** Investigating how the

energy community's operation changes under specific power limitations, identifying optimal strategies to manage flexibility and drawing insights that can be generalized to other sectors.

- **Battery Storage System Management:** Analyzing the behavior and contribution of the lithium-ion battery storage system under varying charging and discharging conditions, with a focus on its role in absorbing excess PV generation, providing essential flexibility and ensuring a more reliable energy supply to the electric pumps. In addition, the analysis will explicitly examine the extent to which the integration of the BESS enhances the system's overall flexibility, not only by enabling more effective load shifting and peak reduction, but also by increasing operational adaptability across different tariff structures and technical configurations, thereby strengthening the robustness and responsiveness of the entire energy management framework.
- **Impact of Energy Allocation Coefficients and Tariff Structures:** Assessing the comparative impact of different types of energy allocation coefficients and the three distinct electricity tariff models on the system's techno-economic performance, highlighting how tariff design influences the value of local generation and flexibility within the EC.

Through this multi-dimensional approach, the project aims to deliver a stronger and broader contribution to the field of energy flexibility by demonstrating the complexity and novelty of integrating flexible demand and tariff strategies into real community operations while relying on advanced mathematical optimization and scenario simulation as the key analytical framework that enables the achievement of these objectives. In particular, the use of mathematical optimization tools to simulate hourly energy flows within the energy community provides a detailed techno-economic representation of system behavior under diverse operating conditions and tariff structures and supports a rigorous evaluation of key performance indicators across multiple scenarios similar to methodologies applied in integrated multi-energy system optimization. By combining these analytical capabilities with the broader vision of enhancing operational flexibility and economic performance the project generates data-driven insights that can guide how future energy communities should operate flexibility while balancing local generation under realistic power constraints, ultimately contributing to the development of flexible cost-effective and sustainable energy communities in rural agricultural regions across Spain.

#### 1.4 Motivation and relevance of the topic

The motivation behind this research lies in the increasing relevance of decentralised and sustainable energy systems as a response to today's pressing challenges of sustainability. As previously stated, Energy Communities are emerging as a promising model to drive the energy transition at the local level especially in rural and agricultural contexts. These settings present unique constraints and opportunities that make the development and optimization of ECs both scientifically valuable and practically impactful. This work aims to contribute to a growing body of research focused on designing resilient, efficient and inclusive energy systems that align with global sustainability objectives. In fact, the development and optimization of Energy Communities (ECs) particularly in the aforementioned

agricultural settings hold significant multi-faceted relevance addressing critical, social, environmental and engineering challenges of our time. Beyond these established motivations, this study introduces an additional and less-explored dimension: understanding how flexibility operates in modeled community energy systems, based on a real case study. While recent literature has demonstrated the role of shared storage systems in enhancing energy community resilience and operational robustness (Ahmadi et al., 2024; Mar et al., 2024), the dynamic behavior of flexible demand and its interaction with operational constraints remains insufficiently explored. Analyzing how flexible demand behaves, how it should buy and sell energy and how it can adapt under power constraints represents a complex and novel research field that has not yet been extensively developed. This project therefore takes an important step toward operationalizing flexibility moving from theoretical definitions to measurable real-world behavior. The work also emphasizes that flexibility is not merely a technical variable but a dynamic resource that requires accurate modeling, economic evaluation and operational understanding to be effectively integrated into the energy system.

From a social perspective, ECs play a central role in promoting energy democracy and resilience at the local level, supporting a *just transition* by ensuring equitable participation and enhancing social acceptance among community members. They empower citizens and local stakeholders transitioning them from passive consumers to active participants in the energy system. In rural and agricultural contexts such as the Valencian farmland explored in this study, ECs can play a crucial role in mitigating energy poverty by reducing reliance on volatile fossil fuel prices and lowering the overall cost of energy supply for irrigation which directly impacts agricultural productivity and economic stability. By promoting collective self-consumption and shared energy storage solutions, energy communities improve local energy independence and contribute to economic vitality through localized investment and employment generation, as also highlighted in recent community-scale storage studies (Ahmadi et al., 2024). Moreover, the study provides valuable insight into how flexibility can strengthen the economic and social sustainability of these communities paving the way for new energy-sharing and trading mechanisms at the local level. In this sense, the capacity to manage demand and adapt consumption patterns in response to price or generation conditions becomes a decisive factor in ensuring the long-term viability of decentralised energy systems.

The environmental relevance of this topic is clear: energy communities are fundamental drivers in the decarbonization of local energy systems directly contributing to climate change mitigation efforts. Specifically, this project addresses the consequences of maximizing the integration of renewable energy sources in agricultural practices, while optimizing their utilization through battery storage. ECs exemplify a tangible pathway towards achieving Sustainable Development Goals (SDGs) (Fig. 2) (Naciones Unidas, 2015) and this work specifically focuses on SDGs 7 and 11: "Affordable and Clean Energy" and "Sustainable Cities and Communities". The focus on Valencia, recently recognized as the European Green Capital 2024, further underscores the regional commitment to decarbonization and positions this study within a broader local and European sustainability agenda. The relevance of this work extends beyond the agricultural context as the principles governing flexible energy management can be applied to a wide range of sectors and use cases from local energy cooperatives to complex industrial or service-oriented systems wherever flexibility and coordinated consumption play a key role in system optimization. The concepts and modeling approach proposed here can therefore serve as a reference for future research aimed at improving flexibility management strategies across diverse

scales and applications.



Figure 2: SDGs of the 2030 Agenda for Sustainable Development – (United Nations, 2025).

From an engineering perspective, this project tackles a complex and highly relevant problem with substantial innovation potential. It integrates various cutting-edge concepts including renewable energy generation, advanced battery storage management, demand-side flexibility and mathematical optimization. The challenge of optimizing energy allocation coefficients under different tariff schemes and highly seasonal load profiles as presented by agricultural irrigation demands sophisticated modeling and analytical tools. In particular, the work demonstrates that understanding and quantifying flexibility requires the combination of physical system modeling, economic behavior and operational constraints—elements rarely addressed together in the literature. This multidisciplinary approach which combines principles of electrical engineering with energy system optimization offers a unique opportunity to contribute to the body of knowledge on the design of robust, efficient and adaptable energy solutions for rural settings. Ultimately, the methodologies and findings of this work can inform future studies and applications across different domains where flexible energy management is essential for achieving efficient and sustainable operation. By bridging theoretical modeling and real-world application, this research provides a concrete framework to study flexibility in a replicable way, supporting both academic progress and practical implementation in the field.

All things considered, this thesis represents the application of theoretical knowledge to an impactful real-world challenge, that directly contributes to the energy transition of this region.

## 1.5 Scope and limitations of the project

This project focuses on the detailed analysis of the irrigation habits of an agricultural Energy Community. The core of the study is indeed centered around a mathematical model specifically designed to simulate the energy dynamics of this type of community. The primary components considered within the model's framework include solar photovoltaic generation and a dedicated battery energy storage system, with a particular emphasis on managing the demands of the electrified irrigation system as

the main controllable load.

For its implementation, the mathematical model leverages the Julia programming language in conjunction with the *JuMP* (Julia for Mathematical Programming) and *Gurobi* optimization packages. This combination allows for the precise formulation and efficient resolution of complex energy optimization problems. Key operational variables are systematically integrated into the model to reflect real-world complexities and enable robust optimization. These critical parameters include dynamic electricity prices (reflecting different tariff structures), the specified storage capacity of the batteries and the demand profiles of the irrigation pumps. The objective of the model is to determine optimal energy allocation strategies, such as the best charging/discharging cycles for the battery and the utilization of photovoltaic generation, to maximize the economic benefit and self-consumption of the EC. Data for the year 2024 are utilized for energy consumption and generation profiles. In addition, the annual photovoltaic generation data is obtained using *PVGIS* simulation tool. The results derived from the optimization model are subsequently processed and analyzed for economic profitability using *MATLAB*, with the aim of comprehensively assessing the influence of the identified critical variables.

While this project aims to provide comprehensive techno-economic insights, it operates under several defined limitations to maintain analytical clarity:

- **Data Simplification:** The model employs standardized or simplified data for certain inputs, particularly regarding consumption profiles. For instance, electric irrigation pump demands are based on typical or aggregated patterns that vary hourly and according to seasonal agricultural habits.
- **Non-Inclusion of Non-Technical Dimensions:** This study is strictly limited to the technical and economic performance aspects of the agricultural EC. Consequently, it does not delve into the complex legal frameworks, social dynamics (e.g., community governance, collective decision-making processes, or equity considerations), or specific behavioral dimensions of participants that could influence the real-world deployment and long-term success of such energy communities. The focus remains on the energetic and financial optimization of the system's hardware and operational strategies.
- **System Boundary and Technology Scope:** The model is specifically configured for the defined set of technologies (PV, BESS, electric pumps) within the agricultural context. It does not explore alternative energy generation technologies (e.g., wind, biomass) or other types of loads beyond irrigation, nor does it consider the integration of electric vehicles or other stationary storage technologies beyond lithium-ion batteries. Furthermore, the case study is specifically based on "Comunidades de Regantes" (*Irrigation Communities*) which represent a relevant and widespread form of collective water management in Spanish agriculture. Although the study identifies some promising optimization opportunities that could enhance the system performance, such as the installation of variable speed drivers (VSDs) on pumps, preventive maintenance of existing infrastructure, replacement of inefficient pumping systems or power factor correction, they are deliberately excluded from the objectives.

## **Optimising Energy Use in Agricultural Energy Communities through Flexible Demand and Electrification Strategies**

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These limitations are intentional and necessary to enable a focused and tractable analysis of the core optimization challenges. They also allow for greater agility in obtaining results, as including too many variables can make the model computationally infeasible. Within this well-defined scope, the project offers robust insights into how renewable generation, storage and load flexibility can be coordinated to enhance the efficiency and economic viability of Agricultural Energy Communities.

## 2 Regulatory and conceptual framework of energy communities

### 2.1 Overview of energy communities in Europe

Energy Communities (ECs) have become a key pillar of the European Union’s strategy to achieve a decentralized energy transition, as shown in Fig. 3. While they have recently gained formal legal recognition, their roots stretch back to the 1970s and 1980s, when grassroots energy cooperatives in countries like Denmark, Germany and the Netherlands began experimenting with community-owned renewable projects in response to oil shocks and growing ecological awareness (Roberto et al., 2023). These early initiatives demonstrated the feasibility and value of decentralizing energy generation, especially when communities take ownership of energy decisions.



Figure 3: Launch of the energy communities repository’s interactive map – (European Commission, 2023).

This historical momentum eventually converged with European policy through the “Clean Energy for All Europeans” package. The package consists of eight legislative acts—four regulations and four directives—adopted between 2018 and 2019. Among these, two directives have played a central role in this process: Directive (EU) 2018/2001 (RED II), which introduced the concept of Renewable Energy Communities (RECs), and Directive (EU) 2019/944, which defined Citizen Energy Communities (CECs). Both aim to empower citizens, local authorities and SMEs to produce, consume, store and sell energy in a decentralized way, although RECs are limited to renewable energy sources and proximity, while CECs can use any type of energy and are not geographically restricted. Despite their many differences (Table 2), ECs share a number of common traits: they are associative legal entities characterized by open and voluntary participation, with decision-making power resting in the hands of the members themselves. Moreover, ECs do not primarily aim to generate profits or financial returns from their activities.

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	Renewable Energy Communities (REC)	Citizen Energy Communities (CEC).
<b>Legal structure</b>	Legal entities based on open and voluntary participation	Legal entities based on open and voluntary participation
<b>Primary objective</b>	Their main goal is to deliver environmental, economic, or social benefits to members or local areas, rather than generating financial profit	Their main goal is to deliver environmental, economic, or social benefits to members or local areas, rather than generating financial profit
<b>Scope of activities</b>	May generate renewable electricity, supply it to their members, and offer aggregation or other energy services, subject to relevant regulatory rules	May generate renewable electricity, supply it to their members, and offer aggregation or other energy services, subject to relevant regulatory rules
<b>Type of energy</b>	<b>Involved in the production and consumption of any type of renewable energy, not limited to electricity</b>	May generate electricity from renewable or non-renewable sources
<b>Eligible members</b>	Members must be individuals, small enterprises, or local authorities	Any entity can participate, including large companies, but effective control must remain with individuals, local authorities (including municipalities), or small companies
<b>Geographical scope</b>	Members must be located in close proximity to the renewable energy projects owned by the legal entity	No proximity requirement is established
<b>Activities</b>	Not specified beyond production and consumption of renewable energy	May also participate in energy distribution, storage, efficiency services, and electric vehicle charging services
<b>Autonomy requirement</b>	Must be autonomous	No autonomy requirement is explicitly stated
<b>Ownership of installations</b>	Must own at least part of the energy installations	No obligation to own generation facilities

Table 2: REC and CEC legislation.

These EU-level definitions brought conceptual clarity to a previously fragmented landscape, yet Energy Communities remain highly diverse in their structure and purpose. According to Fichera et al.: "...ECs operate across three dimensions: environmental (proximity-based clean energy generation), social (community governance and participation) and economic (local reinvestment and cost reduction)" (Fichera et al., 2023). Among the activities typically promoted by ECs is, in fact, the engagement of end-users in the energy transition, as well as the dissemination of greater public acceptance of renewable energy sources, with the aim of maximizing both social and environmental benefits in the local context. This multidimensional nature is precisely what makes them effective tools for promoting energy justice and regional development. By reducing dependence on large utilities and fossil imports, ECs offer both environmental benefits and economic resilience. Moreover, the success of ECs in southern Europe hinges not only on legislative action, but also on trust-building, capacity development and access to financing. Without these enabling conditions, communities may struggle to take advantage of the legal opportunities provided by EU law (Losada-Puente et al., 2023). All things

considered, their future impact will depend on how well national frameworks remove remaining barriers while preserving the democratic and inclusive spirit that defines these initiatives.

### 2.1.1 Energy communities in Spain

In Spain, the previously mentioned directives (*UE*) 2018/2001 ( “Directive (EU) 2018/2001”, 2018) and (*UE*) 2019/944 ( “Directive (EU) 2019/944”, 2019) have been transposed through legal instruments such as *Real Decreto 244/2019* ( “Real Decreto 244/2019”, 2019) and *Real Decreto 23/2020* ( “Real Decreto-ley 23/2020”, 2020). These norms laid the foundation for both individual and collective self-consumption, and formally introduced the figure of the Renewable Energy Community (REC) into Spanish law. According to the transposition, RECs are legal entities based on open and voluntary participation, effectively controlled by citizens, SMEs, or local authorities located near the renewable projects they own and operate. Their primary objective must be to provide environmental, economic, or social benefits to their members or the local area, rather than profit maximization. The concept of *Comunidad Energética Local* (CEL) initially emerged in Spanish policy and academic debates, inspired by draft of directives that envisioned CELs as citizen-led, value-driven collectives involved in decentralized energy production, grid management, or aggregation activities – sometimes even across borders. Despite their early prominence, CELs never acquired an independent legal status. Over time, their characteristics were absorbed into the REC framework established by *Directive (EU) 2018/2001* on renewable energy and *Directive (EU) 2019/944* on the internal electricity market, which also introduced the parallel figure of the Citizen Energy Community (CEC), as previously stated. Unlike RECs, CECs may use non-renewable sources and are not required to operate near the consumption points. This legal evolution has effectively repositioned CELs as expressions of RECs or CECs, depending on their scope and energy source. Beyond legal definitions, Spain has also developed concrete mechanisms for collective self-consumption, a key operational form of community energy. According to *Real Decreto 244/2019*, collective self-consumption occurs when multiple consumers share energy produced by nearby generation facilities. In this case, proximity is legally defined through specific technical criteria, such as sharing the same low-voltage network or being within 500 meters (expanded to 2,000 meters for rooftop installations as of *Real Decreto-ley 18/2022*). These criteria are critical to determine eligibility and access to compensation mechanisms for energy surplus.

Technical refinements have also been introduced to optimize collective energy sharing. Initially, the energy distribution among participants was based on static coefficients – fixed ratios agreed in advance and constant year-round. However, with *Orden TED/1247/2021*, variable coefficients were enabled, allowing hourly adjustments and increasing the potential for more precise and equitable energy sharing. More recently, *Real Decreto-Ley 7/2025 (art.38)* has further updated this regulatory framework: the maximum distance among participants for collective self-consumption has been raised from 2km to 5km, and the threshold capacity has been increased to 5MW, significantly enhancing the scale and flexibility of Renewable Energy Communities (European Parliament and Council of the European Union, 2018). The regulation also anticipates the future adoption of dynamic (ex-post) coefficients, enabling real-time adaptation based on actual consumption and production.

Despite the regulatory advances, the practical development of energy communities in Spain faces

significant hurdles. As Khorrami et al. (2023) highlight, "*The implementation remains uneven across regions, with persistent obstacles in financing, administrative complexity, and grid access...Particularly in rural or economically vulnerable areas.*"(Khorrami et al., 2023). Moreover, although collective self-consumption mechanisms offer a pathway to energy democratization, they often lack the deeper social and participatory dimension originally envisioned for CELs.

All things considered, Spain's trajectory illustrates a progressive but fragmented path toward embedding community energy into its broader energy transition strategy. While the legislative structure is largely aligned with EU directives, the spirit of CELs – rooted in democratic governance, local empowerment and sustainability – remains only partially realized. Unlocking the full potential of energy communities in Spain will require not just legal recognition but also investment in trust-building, technical support and participatory capacity at the local level.

## **2.2 Agricultural energy communities and irrigation**

Another important concept within the broader landscape of energy communities is that of so-called Irrigation or Agricultural Energy Communities. Although not an official EU designation, the term is often used to refer to collective energy initiatives led by farming or irrigation associations. These are public-law entities formally registered with the management authority of the corresponding river basin, as established under Spanish water legislation. They possess legal personality and autonomous assets and operate under their own internal statutes and governance structures.

According to Article 81 of the Spanish *Ley de Aguas*: "*Water users who share access to a common withdrawal point or concession are required to organize into user communities*" – (Gobierno de España, 2001). When the primary use of water is irrigation, these entities are referred to as *comunidades de regantes*; in other cases, they take on a designation that reflects the specific collective use of the water resource. The core function of these communities revolves around the distribution and management of allocated water for agricultural purposes, which inherently includes the operation of irrigation infrastructure. Among the most energy-intensive components of this system are water abstraction points and pumping stations, which are essential for ensuring adequate pressure throughout the distribution network. The energy demand of these installations is highly variable and depends on several technical factors: the origin of the water (whether from surface or groundwater sources), the type of irrigation system in use (such as gravity-fed, drip, or sprinkler), and the elevation difference between the water intake point and the agricultural plots being served. When elevation differences are unfavorable, or when pressure-intensive systems are used, energy costs can increase substantially. Ultimately, the source of the water and the design of the irrigation network are decisive in shaping the energy profile of these communities, making energy efficiency and renewable integration critical issues in their long-term sustainability.

Recent studies show that energy communities in agricultural contexts are still at an early stage of development, with only a limited number of implemented cases and a strong prevalence of bioenergy-based solutions, while electricity sharing among farms remains largely unexplored (Nykyri et al., 2024). However, given their unique combination of legal structure and resource management

responsibilities, these communities represent a particularly compelling case study. As such, Irrigation or Agricultural Energy Communities will be the focus of analysis in this project, offering valuable insights into how decentralized energy solutions can support sustainable agriculture.

### **2.3 Demand-side flexibility modelling**

In the transition towards a more sustainable and resilient energy system, demand-side flexibility (DSF) is gaining increasing relevance. This concept refers to the ability to reduce, shift or increase energy consumption in a smart and timely manner, in response to signals from the electricity system. This approach enables so-called passive consumers to become active consumers, meaning they can automatically adjust their energy usage based on grid conditions, fluctuations in renewable generation or economic incentives. Through participation in demand-response schemes, users can not only reduce their electricity bills but also actively contribute to grid stability, for instance, by injecting unused or stored energy back into the network. In this context, the so-called prosumers are emerging: users who, beyond consuming energy, also produce and store it, offering flexibility in both consumption and generation. DSF can be implemented both individually and in aggregated forms, such as in energy communities or other energy-sharing schemes, where citizens and small businesses cooperate to balance energy supply and demand on a local scale.

To understand the crucial role of demand flexibility, it is useful to analyze how a country's energy supply is structured at different times of the day. Some generation sources, like nuclear power, cover up to 25% of demand in many European countries. This source is stable, predictable and classified as low-carbon. Another important source is hydropower, which contributes a smaller share but offers key advantages in flexibility: it can ramp its output up or down in less than a minute while remaining environmentally sustainable. Wind and solar energy, while clean, are highly variable and less predictable, with production that can fluctuate significantly from day to day. When these sources are insufficient to meet demand, the system often relies on natural gas, a polluting and costly fossil fuel, but highly dispatchable. In exceptional situations, when demand peaks and other sources are exhausted, coal plants may be reactivated, even though they are more polluting and economically burdensome than gas. In this complex scenario, the need for constant balance between supply and demand becomes evident.

However, rather than relying solely on increasing supply—especially from fossil fuels—it is now possible to act on the demand side. Demand-flexibility schemes allow users to reduce or shift their energy use during critical periods, providing a sustainable alternative to traditional generation sources. Periods of low demand can destabilize the grid too and, in this sense, DSF is a bidirectional tool that helps maintain grid stability, making the system more resilient, efficient and clean.

To fully harness this potential and integrate it into the operation of the grid, demand-side flexibility must be accurately modelled. The design of effective DSF models is not only a technical requirement but a strategic necessity to ensure that flexibility becomes a reliable and predictable component of the future energy system. The aim of DSF modelling is to address a variety of objectives: from enhancing user comfort and reducing electricity costs, to ensuring grid stability and integrating renewable

energy. Much of the current literature focuses on establishing a comprehensive definition of DSF and identifying its main goals, which include:

- Peak demand reduction (peak shaving)
- Load profile flattening
- Improved self-consumption of renewable energy
- Grid balancing and frequency stability
- Grid congestion management
- Reduction of energy costs for end-users

Without accurate and reliable modelling, it is not possible to quantify flexibility potential, optimize scheduling strategies, or design efficient control systems. In other words, demand flexibility modelling is a prerequisite for unlocking the full value of DSF, especially in smart grids where the interaction between prosumers, aggregators and utilities must be dynamically managed in real time. As previously discussed, an effective representation of DSF is essential to support the operation of future decentralized energy systems. The choice of modelling technique plays a crucial role, as it determines the level of accuracy, scalability and computational efficiency of the analysis. As stated in (Luo et al., 2022), different modelling approaches can be classified based on the level of detail with which the flexible system is represented:

- **White-box models** rely on physical principles (e.g., thermodynamics, electric circuits) to describe in detail the internal dynamics of appliances or systems. These are primarily used in simulations and parametric studies, especially in conditions that are hard to reproduce in the real world. However, they are complex and time-consuming to develop and calibrate, making them less feasible for large-scale or real-time applications.
- **Black-box models**, conversely, do not require physical knowledge of the system. They rely on input–output data to identify mathematical relationships, often using statistical or machine learning techniques. These models are advantageous when physical modelling is impractical, but they require large amounts of high-quality data and tend to lack interpretability and generalizability. Data-driven modelling approaches of this kind are adopted in the present work to capture system behaviour under real operating conditions.
- **Grey-box models** combine elements of both approaches, incorporating partial physical knowledge alongside data-driven components. They offer a compromise between accuracy and scalability and are increasingly used in DSF modelling.

The above classification shows that no single model fits all use cases: the best choice depends on the context, objectives and data availability.

Despite the variety of available modelling techniques, one of the key challenges in DSF modelling lies in representing human behavior, which is inherently unpredictable and highly heterogeneous.

Unlike appliances, user habits and preferences vary greatly depending on individual, regional and socioeconomic factors. As highlighted in Ribo Perez et al. (Ribó-Pérez et al., 2021), socioeconomic and geographical disparities strongly affect the flexibility potential across different households. For instance, high-income families often have more and higher-performance appliances (including smart devices and storage systems), which allow them to offer significantly more flexibility. This disparity leads to what is often called a “flexibility gap” between social groups. Geography also plays a key role. In southern Mediterranean regions, due to a greater reliance on electric cooling and heating systems, the technical flexibility potential is significantly higher compared to northern countries, where traditional or centralized heating systems are more common. These findings emphasize the importance of integrating behavioral and demographic variables into DSF models. Without accounting for these dynamics, flexibility potential may be overestimated or underestimated, leading to flawed system design or unfair policy outcomes.

In conclusion, demand-side flexibility represents a powerful tool in the shift toward a smarter, cleaner and more resilient energy system. However, to truly unlock its potential, accurate and inclusive modelling is essential. This requires not only a solid understanding of technical systems but also a nuanced grasp of user behavior and social dynamics. As the energy landscape evolves toward decentralization and consumer participation, demand-flexibility modelling becomes not just a technical enabler, but a key pillar of the energy transition.

## **2.4 Agricultural energy communities with flexible demand**

### **2.4.1 Existing works and literature review**

Demand flexibility plays a crucial role in the context of energy communities, particularly in rural or agricultural settings where achieving full self-sufficiency through renewable sources remains a significant challenge due to seasonal variability and the resulting mismatches between supply and demand. This section aims not only to review the most relevant studies in this area but also to position the present work within a research line that increasingly recognizes flexibility as a central design principle for future ECs, rather than a supplementary feature added after technological deployment.

A growing body of literature has begun to formalize the role of flexibility using advanced optimization techniques. Among the latest contributions, Shahi et al. (Shahi et al., 2024) demonstrated that under conditions of high renewable penetration and progressive electrification of the demand flexibility becomes a structural requirement for ensuring reliable operation maintaining balance between supply and demand and ultimately containing system costs. Their mixed-integer linear programming formulation showed that distributed flexibility assets can be orchestrated to improve community-level performance in a systematic and quantifiable manner. Building upon this perspective the present work also adopts an optimization-oriented lens to examine how flexible load coordination and tailored control strategies can strengthen the operational robustness of rural energy communities where agricultural processes impose additional variability and technical constraints.

One recurring theme across the literature is the value of load coordination and demand-side man-

agement in enhancing community-level energy flexibility. Studies frequently highlight the potential of controllable loads to align local consumption with renewable generation. Heat pumps, electric vehicle chargers, irrigation pumps, cold storage units and greenhouse heating systems can all be scheduled or modulated to reduce curtailment and increase self-consumption when supported by accurate forecasting and sufficiently adaptive control strategies (Barnes et al., 2023; Golmohamadi et al., 2023).

In agricultural environments this flexibility is particularly valuable because many energy-intensive operations follow seasonal biological or climatic cycles that can be partially shifted without compromising productivity. Timed irrigation cycles or post-harvest cooling processes for instance can be aligned with mid-day solar peaks allowing communities to capture more value from local generation and reduce dependence on external supply. The success of these flexibility strategies, however, is strongly influenced by the composition of the community and the structural characteristics of its loads. As noted by Ercoli et al., 2023, smaller and more homogeneous clusters tend to exhibit higher flexibility potential because their usage patterns are more predictable and more easily harmonized with renewable availability. Regular agricultural routines such as feeding livestock managing greenhouse climates or processing produce often follow daily or weekly patterns that create opportunities for coordinated action across users. In contrast larger or more heterogeneous communities may struggle to extract the same benefits because variability in behavior complicates aggregation and may introduce conflicting flexibility needs. Under these conditions additional mechanisms such as shared storage systems enhanced forecasting or participatory governance frameworks may be required to coordinate user actions effectively.

The literature also emphasizes that flexibility is not merely a technical property, but a socio-technical attribute shaped by infrastructure design user engagement and institutional arrangements. Even when flexible loads exist, their effective utilization depends on the extent to which users accept automated control strategies and perceive the benefits of coordination. Studies in rural contexts indicate that cooperatives and agricultural associations often demonstrate relatively high willingness to coordinate due to shared economic objectives although alignment with local practices remains essential. Successful implementations therefore require an integrated approach that considers technological capabilities behavioral aspects and local governance structures. To support this integration, various energy management systems (EMS) and optimization methods have been proposed. Centralized EMS architectures which rely on predictive models incorporating weather data PV forecasts and user routines have proven particularly effective for orchestrating flexible loads in real time (Golmohamadi et al., 2023). Forecasting tools further strengthen these systems by anticipating seasonal agricultural cycles and enabling more precise scheduling of flexible activities (Massaoudi et al., 2023). Peer-to-peer energy trading also emerges as a promising complement to flexibility strategies as it allows members to exchange excess energy locally and respond to internal price signals. Gjorgievski's work (Gjorgievski et al., 2023) shows that combining P2P platforms with shiftable loads enhances the value of local generation and fosters greater user participation in community energy markets. A complementary line of research highlights how MILP-based formulations can also support more advanced coordination mechanisms within energy communities. For example, Al-Sorour et al. (Al-Sorour et al., 2022) used a mixed-integer model to schedule peer-to-peer energy exchanges and household batteries in order to maximise local PV self-consumption and minimise interactions with the main grid. Their results

underline how MILP can capture discrete operational decisions and complex constraints, offering a powerful analytical framework for communities that rely heavily on distributed flexibility resources.

Despite these advances, significant gaps still remain. Most studies either focus on theoretical flexibility potential or analyze communities with residential loads that differ substantially from agricultural ones. Moreover only a limited number of works including that of Shahi et al. examine how MILP-based operational planning can be systematically integrated into the day-to-day functioning of energy communities. The present work therefore extends these early efforts by applying flexibility-oriented optimization specifically to agricultural settings and by exploring how coordinated control of irrigation loads storage assets and renewable generation can reinforce stability, economic viability and long-term self-sufficiency in rural energy communities under different contextual scenarios and tariff structures.

#### **2.4.2 Limitations of demand flexibility in agricultural energy communities**

Belonging to an agricultural energy community can be a strategic factor in enhancing the flexibility of irrigation demand, particularly thanks to the alignment between water use and renewable energy generation. This is made possible by the availability of self-consumption infrastructures such as photovoltaic systems and shared lithium-ion battery storage units. However, the scientific literature also highlights several critical situations that restrict such flexibility. In practice, its application in agriculture faces real agronomic, technical and socio-economic limitations.

From an agronomic and environmental perspective, weather conditions and particularly rainfall play a decisive role. Irrigating immediately after heavy rain not only wastes water but can also damage crops by creating waterlogging or root stress. Evaporation losses are another well-documented issue: irrigation during the hottest hours of the day, especially in summer, is highly inefficient, as a substantial portion of the applied water is lost before it can be absorbed by the soil and taken up by plants. Studies show that midday irrigation can lead to losses of up to 30 – 40% of applied water, whereas early morning or late afternoon irrigation is significantly more efficient, as supported in Cheung et al. (Cheung et al., 2024) thesis.

Seasonal cycles further affect flexibility: many agricultural processes are tied to fixed phenological stages, such as sowing, flowering or harvesting. For example, vegetable crops may require intensive irrigation in spring and summer, but much less in winter, meaning that the flexibility of demand cannot always follow energy signals; instead, it must respect the biological needs of plants.

Equally important are the water availability constraints. In many rural areas, access to irrigation water is regulated through consortia, rotational schedules or basin storage capacities. Farmers may only be allowed to irrigate during specific time slots, regardless of the optimal alignment with PV generation or electricity tariffs. In such cases, water governance becomes a stronger limiting factor than energy availability.

From a technical and operational standpoint, the limited programmability of pumps and agricultural machinery may restrict flexibility. Frequent start-ups and stops can cause equipment wear and reduce efficiency, making detailed scheduling impractical. A lack of adequate energy storage infrastructure or

overly small clusters also diminishes flexibility, while load heterogeneity – common in large or mixed agricultural cooperatives – reduces the predictability and aggregation of demand profiles, making the coordination of load shifting more complex.

Economically speaking, time-of-use tariffs can pose challenges: it may not always be cost-effective to irrigate during specific periods, even if these coincide with PV production peaks. Moreover, maximizing self-consumption does not necessarily align with maximizing water-use efficiency: energy cost reductions should never come at the expense of agricultural yields, making the trade-off between energy and agricultural performance a critical balance to manage.

Finally, social and institutional dimensions also limit flexibility. Farmers may initially be reluctant to change long-standing irrigation routines or to delegate operational decisions to an energy management system. In addition, agricultural energy communities must coordinate diverse stakeholders – farmers, cooperatives and possibly agro-industrial facilities. This introduces governance challenges, particularly when irrigation schedules must alternate between different fields or members. Rotational irrigation, while necessary to share limited water resources, often restricts individual flexibility.

All the above imitations demonstrate that demand flexibility in agricultural energy communities is highly context-dependent. Successful implementation requires balancing energy optimization with agronomic conditions, water constraints, equipment limits and user acceptance, while also addressing institutional coordination challenges.

### **2.4.3 Thesis contributions within the academic debate**

The rapid growth of EC has demonstrated their potential to reshape the energy system. However, the academic debate still presents serious gaps, particularly when considering rural and agricultural contexts. Most contributions have so far concentrated on residential or mixed-use settings, while the role of agriculture has somehow remained more marginal. However, agriculture represents not only a cornerstone of Mediterranean economies but also a sector with distinctive energy needs and consumption profiles.

Recent reviews of RECs in rural areas highlight that agriculture is often mentioned only as a secondary component of community projects, despite its strong potential for integrating bioenergy, photovoltaics and storage systems (Shi et al., 2024). Rural regions are particularly well suited for the development of decentralized renewable systems, thanks to the abundance of solar irradiation, the availability of agricultural residues for bioenergy and the opportunities for hybrid systems combining multiple source. Nonetheless, as stated by Shi et. Al, these opportunities are frequently threatened by barriers such as limited infrastructure, financial constraints or fragmented policy support.

On the one hand, agriculture holds a unique position at the intersection of energy and food systems. Farmers are increasingly seen not only as food producers but also as potential energy suppliers, capable of investing in and operating renewable energy technologies. Their participation in the sustainable transition, however, is conditioned by profitability and policy stability. As shown by Hahn et al. (Hahn et al., 2025), farmers often perceive renewable investments as a pathway self-sufficiency, but they

also express skepticism towards institutional frameworks that appear inconsistent or burdensome. This dual perspective reflects the complexity of integrating agriculture into broader EC initiatives: a significant potential with inadequate enabling conditions.

A second research gap concerns the role of billing schemes and tariff structures in shaping EC performance. Most existing analyses treat technology deployment – such as solar PV, storage, or demand response – as the primary determinant of community outcomes. Yet, as highlighted in recent studies, the economic distribution of benefits within an EC is strongly affected by the adopted sharing and billing mechanisms. For instance, different tariff models can alter not only the payback periods of investments but also the fairness and attractiveness of participation for community members. Despite this, systematic comparisons across multiple tariff frameworks remain limited, particularly in agricultural contexts where load profiles are irregular, seasonal and highly sensitive to electricity price volatility.

Flexibility is another dimension insufficiently integrated into EC analyses. In their study, Shi et al. (Shi et al., 2024) underline that rural energy communities increasingly move from localised, single-technology solutions towards hybrid systems and smart grids. Nevertheless, explicit modelling of flexibility—such as shifting irrigation loads, optimizing storage operation or adjusting cooling and processing schedules in farms—remains scarce. Taken together, these observations reveal a fragmented picture: the literature tends to isolate dimensions (technology portfolios, tariff models, flexibility) rather than considering their combined impact. In practice, however, these elements are deeply interdependent. For example, the effectiveness of storage integration depends on the tariff system in place, while the benefits of demand response hinge on the specific agricultural processes involved. A comprehensive approach that simultaneously accounts for these dimensions is therefore needed to accurately capture EC performance in real-world agricultural contexts. Against this background, the present thesis provides several contributions. First, it examines the performance of ECs under different technological configurations, assessing how combinations of renewable generation and flexible assets influence both operational and economic outcomes. Second, it incorporates a comparative analysis of billing tariffs, exploring how alternative schemes reshape benefit distribution and affect the feasibility of ECs in rural and agricultural domains. Third, it limits the analysis specifically within the agricultural sector, thereby addressing an important yet underexplored field that is crucial for Mediterranean economies. Finally, it emphasizes the role of flexibility strategies, not only as technical optimizations but as enablers of resilience and competitiveness for farmers facing volatile energy costs and evolving policy landscapes.

By integrating these perspectives, this thesis contributes to bridging the existing gaps in literature and offers a comprehensive framework for understanding how ECs can be effectively designed, managed and sustained in agricultural contexts.

### 3 Methodology

This section describes the methodological framework adopted to address the objectives of the thesis. First, the problem is defined and the system boundaries are established, with particular reference to the selected EC configuration. The overall modelling approach and the data workflow are then introduced. Subsequently, the mathematical formulation of the optimization model is presented in detail, including the representation of energy flows, battery operation, irrigation constraints and electricity billing mechanisms. Finally, the financial evaluation methodology is described, outlining the indicators used to assess the economic performance of the proposed scenarios.

#### 3.1 Problem definition and system boundaries

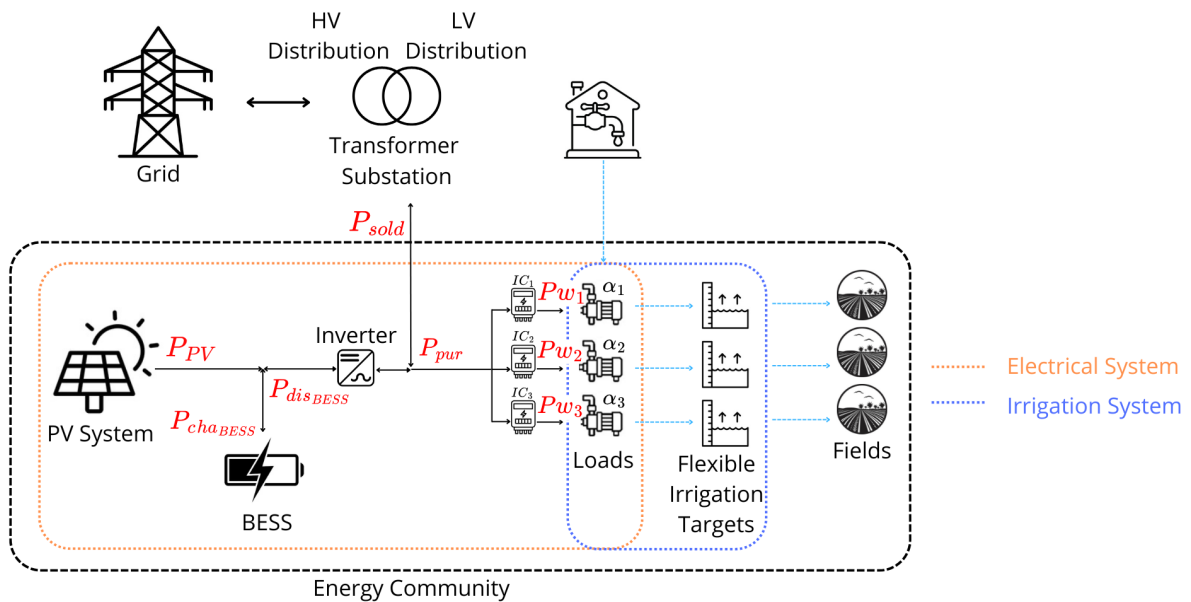


Figure 4: EC flowchart scheme.

This chapter investigates the research problem related to the flexibility of irrigation processes within the three Irrigation Communities (IC). The analysis is then extended to a broader scenario, in which these communities are aggregated into a single EC equipped with a photovoltaic system and a BESS. While the following chapter will provide detailed description of the scenarios, the present one is devoted to their definition, analytical framework and mathematical modelling. For completeness, the modelling approach is developed with reference to the most advanced configuration, namely the one following the implementation of the EC. The study is summarised by the EC system scheme depicted in Figure 4.

The depicted modelling framework (Figure 5) is based on structured input and output data, provided in hourly resolution and stored in .CSV or .XLSX format. The input dataset includes a file containing the parameters of the selected scenario, such as the allocation coefficient type, the installed PV capacity,

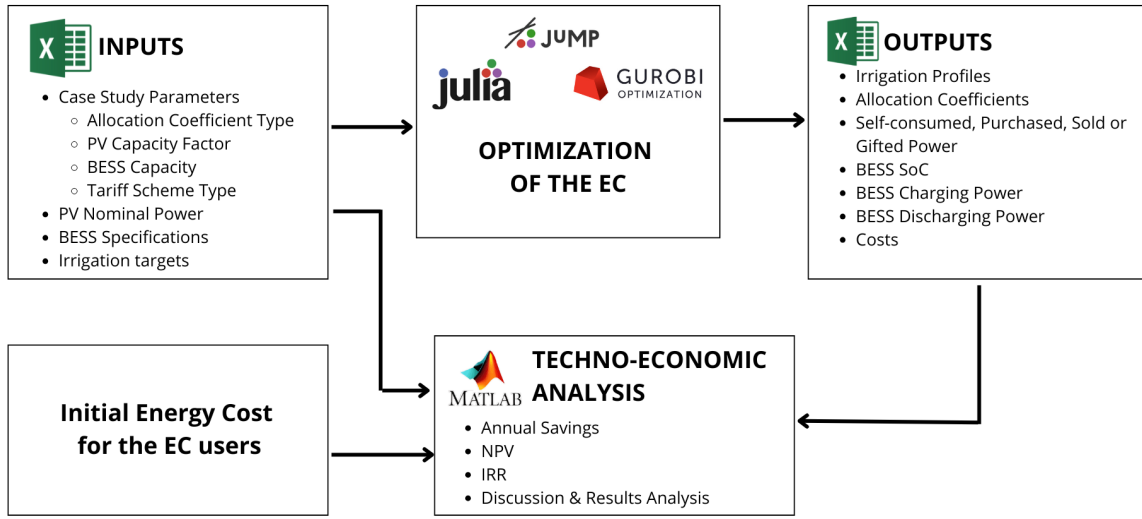


Figure 5: Methodology tools.

the BESS size, and the adopted tariff scheme. The optimization is carried out through a Mixed-Integer Linear Programming (MILP) model developed in Julia, using the JuMP package and Gurobi solver. This process enables the determination of key variables, such as irrigation profiles, allocation coefficients, self-consumed, sold or shared power, as well as BESS state of charge, charging, and discharging power. The choice of a MILP model is motivated by its ability to capture both continuous and discrete decision variables, allowing for realistic representation of system operation while maintaining mathematical rigor and global optimality guarantees for linear problems. Complementary to this, data processing and visualization are performed in MATLAB, a numerical computing environment particularly suited for data manipulation and graphical representation. The results of the optimization are compared against the baseline energy costs of EC participants, allowing for the computation of financial Key Performance Indicators (KPIs) required for scenario assessment, such as annual savings, Net Present Value (NPV) and Internal Rate of Return (IRR).

### 3.2 Mathematical formulation of the optimization model

The optimization model aims to minimize the overall costs of the EC, Eq. (1). To this end, we consider both the electricity billed by the retail company to meet the loads' demand and the cost associated with operating the BESS.

$$\min(COST_{EC}) = \min \left( C^G + \sum_{t=1}^T (B_t^{Ch} + B_t^{Ds}) \Delta t \right) \quad \forall t \in T \quad (1)$$

### 3.2.1 EC operation: energy distribution and system balancing

All the electricity produced within the EC must be properly distributed to satisfy the system loads or otherwise exported to the grid. Consequently, at each instant, the generated power equals the product of the nominal capacity and the capacity factor of the PV system, as shown in the Eq. (2) below.

$$PV_t = PV_{nom} CF_t \quad \forall t \in T \quad (2)$$

In the same way, the energy assigned to each load on an hourly basis corresponds to the product of the generated power and the allocation coefficient, Eq. (3).

$$A_{j,t} = PV_t \beta_{j,t} \quad \forall t \in T, j \in J \quad (3)$$

However, the assigned electricity seldom coincides exactly with the real demand. In the case of an excess, as expressed in Eq. (4), while a portion of the allocated energy is self-consumed, another part can either be exported to the grid through sales or transferred without compensation.

$$A_{j,t} = SC_{j,t} + SOLD_{j,t} + GIFT_{j,t} \quad \forall t \in T, j \in J \quad (4)$$

Conversely, when there is a shortfall, the EC must purchase electricity from the grid to meet demand, as indicated in Eq. (5). A BESS is available to improve the balance between supply and demand.

$$SC_{j,t} + PUR_{j,t} + \eta^{B, Ds} B_t^{Ds} = D_{j,t} + \frac{B_t^{Ch}}{\eta^{B, Ch}} \quad \forall t \in T, j \in J \quad (5)$$

The sum of allocation coefficients across all loads must always equal unity, Eq. (6).

$$\sum_{j \in J} \beta_{j,t} = 1 \quad \forall t \in T \quad (6)$$

In this work, these coefficients may be static, variable or dynamic. Static coefficients remain constant throughout the year for each consumption point, ensuring that power distribution follows a fixed pattern. Dynamic coefficients can vary hourly and are defined *ex-post*, that is, determined after consumption (at billing time), allowing adaptation of energy sharing to each user's demand at any moment. Finally, an intermediate case is given by variable coefficients, which can also change from hour to hour but must be communicated to the electricity retailer in advance. Thus, the actual consumption of each user is unknown to the optimisation model, but average daily profiles can be used under the assumption that participants do not radically alter their habits.

### 3.2.2 Energy Storage: BESS

A BESS is integrated into the EC to provide electrical flexibility by storing surplus generation and by purchasing cheaper electricity to be released during peak price periods. The energy stored in the

BESS, as shown in Eq. (7), equals the state of charge at the previous time step plus or minus the energy injected or extracted, adjusted by the corresponding charging and discharging efficiencies.

$$E_t^B = E_{t-1}^B + \eta^{B,Ch} B_t^{Ch} \Delta t - \frac{1}{\eta^{B,Ds}} B_t^{Ds} \Delta t \quad \forall t \in T \quad (7)$$

Eqs. (8) and (9) restrict the charging and discharging power of the batteries, while Eq. (10) and (11) characterize the charging and discharging processes of the BESS as the aggregation of the interactions at each consumption node.

$$0 \leq B_t^{Ch} \leq B_{MAX}^{Ch} \quad \forall t \in T \quad (8)$$

$$0 \leq B_t^{Ds} \leq B_{MAX}^{Ds} \quad \forall t \in T \quad (9)$$

$$B_t^{Ch} = \sum_{j=1}^J (B_{j,t}^{Ch,sc} + B_{j,t}^{Ch,pur}) \quad \forall t \in T \quad (10)$$

$$B_t^{Ds} = \sum_{j=1}^J B_{j,t}^{Ds} \quad \forall t \in T \quad (11)$$

Eq. (12) limits the total amount of energy that can be stored to preserve battery lifespan, which depends on the number of modules and their own capacity, Eq. (13)

$$BESS_{MIN} E_{CAP}^B \leq E_t^B \leq E_{CAP}^B \quad \forall t \in T \quad (12)$$

$$E_{CAP}^B = k \cdot E_{CAP,k} \quad \forall k \in K \quad (13)$$

Furthermore, Eq. (14) requires that the energy stored at the beginning and at the end of the simulation horizon be identical, ensuring energy conservation.

$$E_0^B = E_T^B \quad (14)$$

The investment cost of the BESS has been estimated as shown in Eq. (15), where  $BESS^{cost\_e}$  [€/kWh] and  $BESS^{cost\_p}$  [€/kW] correspond to industry-standard values.

$$BESS^{CAPEX} = BESS^{cost\_e} \cdot E_{CAP}^B + BESS^{cost\_p} \cdot B^{MAX} \quad (15)$$

Although the levelized cost of storage is not explicitly included in the model, a small but non-zero value was introduced in order to discourage excessive cycling of the battery. This approach preserves the useful life of the BESS while avoiding unrealistically low economic spreads that could otherwise lead the model to over-utilize the storage system.

### 3.2.3 Irrigation constraints definition

The irrigation process is modeled by analogy with a Battery Energy Storage System that must be “fully discharged” on a weekly basis. To achieve this, both the energy balance and the irrigation water balance must be considered. The energy balance is formulated as in equation (5), where  $D_{j,t}$  specifically corresponds to the required power for irrigation,  $P_w$ . This variable is subject to operational constraints that depend on the on/off state of the irrigation pump. In particular, a binary variable  $\gamma_{j,t}$  has been introduced to indicate whether the pump is operating at time  $t$  for load  $j$  ( $\gamma_{j,t} = 1$ ) or not ( $\gamma_{j,t} = 0$ ). The introduction of this binary variable turns the optimization problem from a Linear Program into a Mixed-Integer Linear Program, thereby increasing the model’s computational complexity but allowing a more realistic representation of the pump’s operational logic.

Consequently, the operating power is constrained between a minimum and the rated power. Assuming an hourly time step and a practical requirement that the pump must run for at least 20 minutes when switched on, we impose a minimum hourly energy equivalent of one third of the rated hourly energy. This yields the following bounds Eq. (16):

$$\frac{1}{3} P_{pump,j} \gamma_{j,t} \leq P_{w,j,t} \leq P_{pump,j} \gamma_{j,t} \quad \forall j \in J, t \in T \quad (16)$$

This refinement ensures that whenever the pump is switched on, it must operate within a feasible range of power output, thus avoiding unrealistic fractional operation levels. Accordingly, the energy balance can be expressed as in the following equation Eq. (17):

$$SC_{j,t} + PUR_{j,t} + \eta^{B,Dis} B_t^{Dis} = P_{w,j,t} + \frac{B_t^{Ch}}{\eta^{B,Ch}} \quad \forall t \in T, j \in J \quad (17)$$

The irrigation power requirement is related to the irrigation water volume defined as input and a conversion coefficient  $\alpha$  [ $m^3/kWh$ ] which links electricity consumption to pumped water, as shown in Eq. (18):

$$E_{t,j}^{week} = P_{w,t,j} \cdot \alpha_j \quad \forall t \in T, j \in J \quad (18)$$

The water balance states that the water level at a given time step equals the level at the previous time step plus the pumped water minus the weekly irrigation target, over the hourly horizon  $T$ , Eq. (19):

$$R_t = R_{t-1} + E_t^{week} - E_m^{week} \quad \forall t \in T \quad (19)$$

In every time moment, this quantity must stay positive, Eq. (20):

$$0 \leq R_t \quad \forall t \in T \quad (20)$$

Finally, the water level is required to be zero at both the beginning and the end of the optimization horizon, similarly to the battery case, as well as at the end of each week, due to the imposed weekly release target, Eq. (21):

$$R_0 = R_T = 0 \quad (21)$$

### 3.2.4 Retail company electricity billing

The cost of electricity purchased from the retail company is determined by the variable energy costs together with the access tariff charges ("*Tarifa de acceso*"), which consist of the power term and the energy term, as shown in Eq. (22). It is assumed that all loads are subject to the same access tariff.

$$C^G = \sum_{t=1}^T C_t^V + C^{pow} + C^{en} \quad \forall t \in T \quad (22)$$

On one side, the variable component is determined hourly as the difference between the price of electricity acquired and the remuneration for electricity sold back to the retail company as shown in Eq. (23). Both prices depend on the selected tariff scheme.

$$C_t^V = C_t^{pur} - C_t^{sold} = PUR_{j,t} \Delta t \Pi_t^{pur} - SOLD_{j,t} \Delta t \Pi_t^{sold} \quad \forall t \in T, j \in J \quad (23)$$

The access tariff charges are regulated annually by law (*BOE*) and reflect the costs associated with *Transmission and Distribution* and *System Charges*. The power term is computed by multiplying the contracted power by the corresponding regulated tariff prices, that vary per period, while the energy term is obtained by multiplying the annual electricity purchased from retail company in each period by the corresponding energy tariff prices. Specifically, the cost of the power term is calculated as reported in Eq. (24), while the cost of the energy term is determined by Eq. (25).

$$C^{pow} = \sum_{j=1}^J \left( \sum_{p=1}^P \Pi_{p,j}^{pow} \cdot POW_j \right) \quad \forall p \in P, j \in J \quad (24)$$

$$C^{en} = \sum_{j=1}^J \left( \sum_{p=1}^P \Pi_{p,j}^{en} \cdot PUR_{p,j} \right) \quad \forall p \in P, j \in J \quad (25)$$

Purchased electricity reflects the residual load demand together with the BESS arbitrage.

According to Spanish regulation, the monthly bill must always remain positive, meaning that the cost of electricity purchased in each month must be greater than or equal to the value of the electricity sold. This restriction is represented by Eq. (26). In cases where the EC produces a surplus exceeding what can be sold or stored, the excess is transferred to the grid without compensation.

$$\sum_{m=1}^M PUR_{j,t} \Pi_t^{pur} \geq \sum_{m=1}^M SOLD_{j,t} \Pi_t^{sold} \quad \forall m \in M \quad (26)$$

### 3.2.5 Initial cost of the EC

The baseline for assessing the potential savings of the different EC configurations is the energy cost of the members in the initial situation. In this configuration, the grid fully covers the electricity demand, which is computed as the sum of the variable and access tariff components, Eq. (27). All electricity demand is considered purchased, so the initial electricity cost per customer  $j$  is:

$$C_{j,0}^G = \sum_{t=0}^T \sum_{j=0}^J (D_{j,t}) \Delta t \Pi_t^{pur} + C^{pow} + C^{en} \quad \forall t \in T, j \in J \quad (27)$$

### 3.2.6 Financial analysis

The economic performance of the Energy Community (EC) is assessed through the NPV. Eq. (28) defines the EC NPV as the difference between the present value of the economic savings, the operation and management expenses, and the investment costs over the project lifetime.

$$NPV_n^{EC} = NPV_n^{SAV} - NPV_n^{OM} - NPV_n^{INV} \quad (28)$$

In practice, this economic balance is computed through a cash flow–based formulation, in which savings, operation and management costs, and investment costs are consistently accounted for over the project horizon. The investment cost is incurred upfront at year  $n = 0$  and is therefore represented as a single negative cash flow, while savings and operation and management costs occur during the operational phase and are aggregated into annual net cash flows.

Accordingly, the cash flows are defined as in Eqs. (29) and (30):

$$CF_0 = -INV, \quad (29)$$

$$CF_n = NET_{ann} \quad \forall n = 1, \dots, N \quad (30)$$

where  $NET_{ann}$  denotes the annual net cash flow, defined as the difference between yearly economic savings and operation and management costs.

The Net Present Value of the EC is then obtained by discounting each cash flow at the discount rate  $d$  and summing the discounted values over the entire project lifetime, Eq (31):

$$NPV^{EC} = \sum_{n=0}^N \frac{CF_n}{(1+d)^n} \quad (31)$$

On the one hand, investments cover the acquisition of assets such as the PV system and the BESS. On the other hand, savings for the EC are represented by the difference between the initial electricity costs and the billing borne by EC members, as stated in Eq. (32).

$$SAV = COST_0 - COST_{EC}. \quad (32)$$

Finally, the operation and management costs are estimated using industry-standard values. The IRR is determined as the discount rate for which the final NPV of the EC equals zero, as expressed in Eq. (33).

$$IRR = d \iff NPV_N^{EC} = 0 \quad (33)$$

## 4 Case study

### 4.1 Location and general characteristics

The case study focuses on three irrigation communities (IC) located in the rural district of *Pobles del Sud*, on the southern edge of the Valencia metropolitan area, Spain (Tab. 3). The entities are Motor Pozo Castellar, Font el Bonet and Alter Romaguera. They are separated by less than one kilometer, as shown in Fig. 7, which ensures that they share comparable geographical, hydrological and climatic conditions. These irrigation communities belong to the traditional network historically governed by the *Jurisdicció de Francs, Marjals i Extremals*, a centuries-old water management institution in the region. The proximity of the three IC makes them particularly suitable for a joint analysis of their energy performance and the potential integration of renewable technologies.

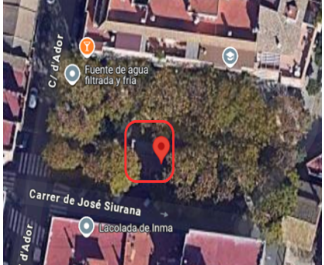


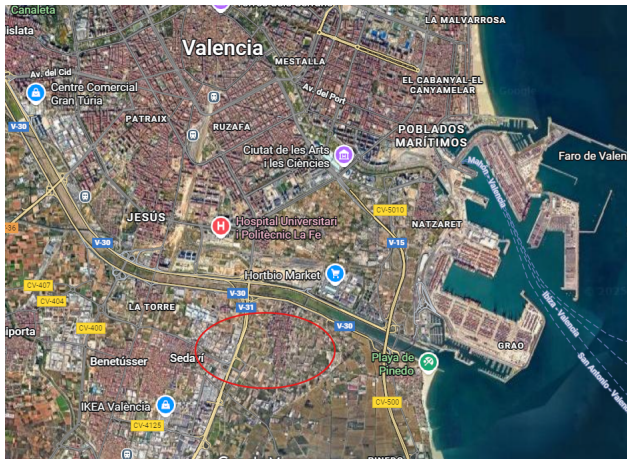
		
<b>Motor Pozo Castellar</b>	<b>Agrupación de Regantes Font el Bonet</b>	<b>Sociedad Motor Alter Romaguera</b>
<b>Registered office address</b>	<b>Registered office address</b>	<b>Registered office address</b>
C/ José Siruana 13, 46026 (Valencia)	C/ Doctor Ricardo Aparisi 1, 46026 (Valencia)	Avenida Ausias March, S/N, 46026 (Valencia)
<b>Type of supply</b>	<b>Type of supply</b>	<b>Type of supply</b>
Irrigation	Irrigation	Irrigation
<b>Total irrigated area (ha)</b>	<b>Total irrigated area (ha)</b>	<b>Total irrigated area (ha)</b>
39	25	33

Table 3: General information about the three irrigation communities in Pobles del Sud.

Water delivery in these systems is organised without central storage or regulation infrastructure. Farmers request irrigation turns by writing their names and desired time slots on a board, and at the scheduled moment they activate the intake by inserting a token. Tokens are available in units of 20 or 60 minutes and the allocation follows the order in which farmers have registered their demand. Consequently, water is not supplied sequentially from the head to the tail of the canal system, but rather according to the individual bookings. This operating scheme reflects the persistence of traditional irrigation practices in the area, where the infrastructure and management rely heavily on collective self-organisation.



**Figure 6:** Satellite view of the city of Valencia – (Google Maps, 2026).



**Figure 7:** Location of the three irrigation communities (Motor Pozo Castellar, Font el Bonet, Alter Romaguera) in *Pobles del Sud*.

From an energy–water perspective, field measurements and subsequent estimations indicate that the average water-to-energy ratio in these systems remains relatively stable across the communities. Specifically, Motor Pozo Castellar achieves about  $10.84 \text{ m}^3/\text{kWh}$ , while Font el Bonet and Alter Romaguera reach  $10.37 \text{ m}^3/\text{kWh}$  and approximately  $10.5 \text{ m}^3/\text{kWh}$ , respectively. These values suggest that, despite differences in pumping hours and seasonal water demand, the energy efficiency of water extraction is comparable among the three entities. A detailed validation of the results is provided in 9.1. Monthly irrigation volumes fluctuate significantly because of water demand, crop cycles and climatic variability.

### 4.2 Environmental and solar resource context

The study area is located within the Mediterranean climatic zone, which is characterised by mild winters, hot summers, scarce annual precipitation and a high degree of solar exposure. According to the Spanish State Meteorological Agency (AEMET), the mean monthly temperatures vary from approximately  $6^\circ\text{C}$  in January to more than  $30^\circ\text{C}$  in August (Agencia Estatal de Meteorología (AEMET), 2023), as shown in Figure 8. Precipitation levels are low and irregular throughout the year, with two distinct maxima in summer and autumn, as shown in Figure 9.

The region benefits from a substantial number of clear-sky days. Average daily sunshine duration ranges from about 10 hours at the winter solstice to nearly 15 hours at the summer solstice (WeatherSpark, 2023). These values highlight the abundance of solar radiation available to support renewable energy applications. Data from the European Commission’s Photovoltaic Geographical Information System (PVGIS) further confirm this potential.

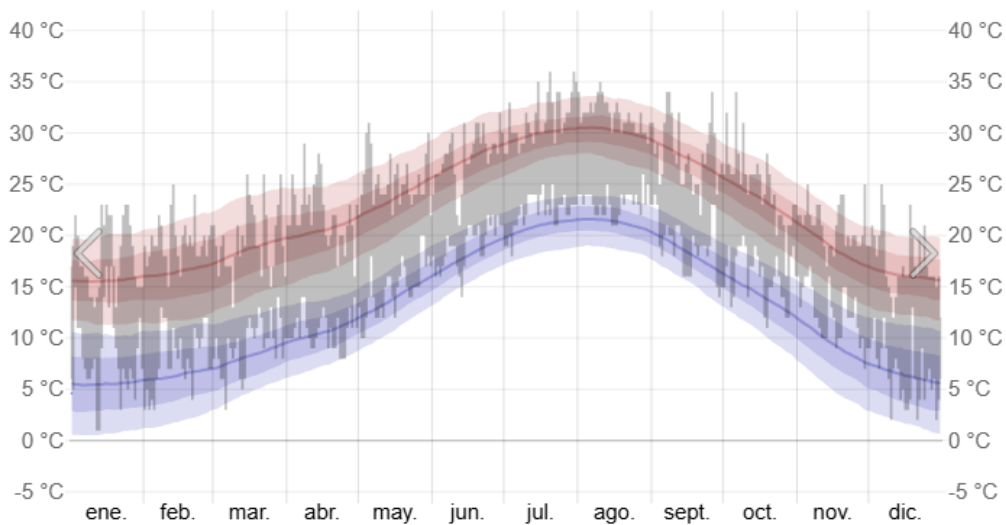


Figure 8: Temperature (°C) of Valencia throughout year 2024 – (Meteostat, 2026).

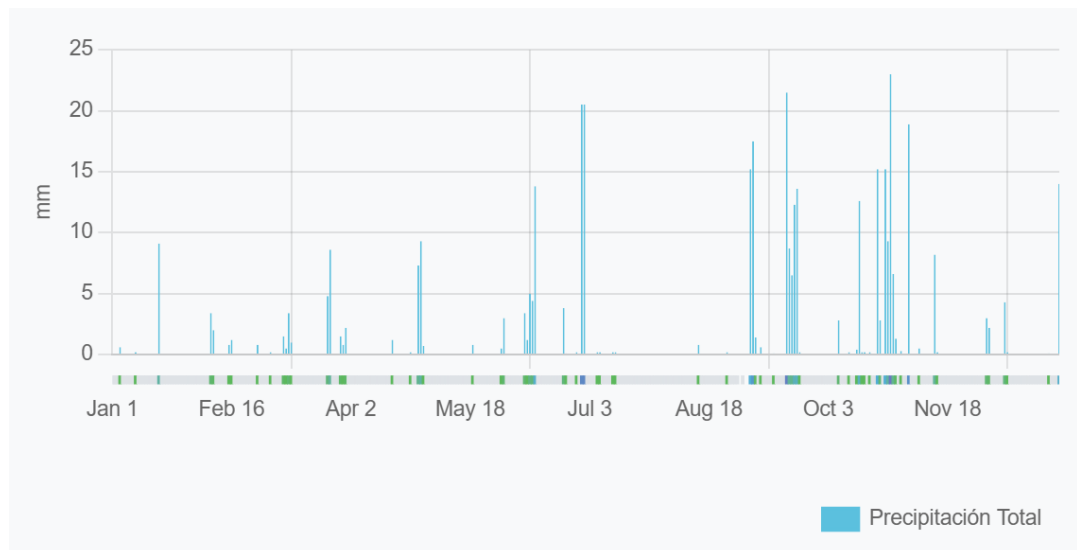


Figure 9: Precipitations (mm) in Valencia throughout year 2024 – (Meteostat, 2026).

Taken together, these climatic and solar resource conditions define a favourable environment for photovoltaic deployment.

### 4.3 Elements of the EC

The case study energy community is composed of a set of interconnected elements that together define its operational structure (Figure 4: *EC flowchart scheme*). The points of consumption correspond to three pumping stations, which supply the irrigation water distribution network of the agricultural fields and act as electricity demand nodes. On the supply side, the system integrates a photovoltaic installation with a nominal capacity of 50 kWp and a community battery storage system of 40 kWh.

In addition, the community is connected to the external electricity grid, which allows the purchase of energy when local production and storage are insufficient, as well as the sale of surplus electricity during periods of excess generation.

This configuration establishes a bidirectional interaction between the irrigation system and the energy infrastructure: the water demand of the pumps determines the load profile, while photovoltaic generation and battery storage contribute to reducing grid dependency and enhancing local energy self-sufficiency.

#### **4.3.1 PV system description**

For the estimation of the photovoltaic capacity factor required for the installation, the PVGIS, developed by the Joint Research Centre of the European Commission, was employed (PVGIS, 2025). This tool enables the assessment of solar energy production based on geographical, climatic and system-specific parameters, providing a reliable framework for preliminary PV performance evaluation.

In this first stage of the analysis, the following site parameters were introduced into PVGIS:

- **Latitude / Longitude:**  $39.491^{\circ}$  ,  $-0.355^{\circ}$
- **Altitude:** 11 m

These geographical inputs define the location of the case study and are used by PVGIS to determine solar irradiance levels, estimate system losses and compute the expected hourly energy yield. The photovoltaic system considered in this study consists of a 50 kWp crystalline silicon (c-Si) PV array connected to the grid through a single inverter. This configuration corresponds to a typical medium-scale installation suitable for self-consumption schemes and energy community applications, enabling the evaluation of realistic hourly production profiles under standard operating conditions.

Regarding the system layout, the following technical parameters were assumed:

- **Slope:**  $39^{\circ}$  (optimum)
- **Azimuth:**  $3^{\circ}$  (optimum)
- **System losses:** 14%

The selected slope and azimuth correspond to the optimal configuration identified by PVGIS for the given geographical location. The tilt angle is chosen to maximize the annual global irradiance incident on the plane of the array, accounting for the local latitude and the seasonal solar path. Similarly, the azimuth angle, close to due south, ensures optimal exposure to solar radiation throughout the year, minimizing angular losses associated with non-ideal panel orientation. System losses account for the aggregate effects of several factors that reduce the actual energy output compared to the theoretical production under standard test conditions. These include temperature losses, inverter

inefficiencies, ohmic losses in cables, module mismatch, degradation and soiling. In PVGIS, such losses are represented through standardized assumptions derived from empirical data, providing a realistic estimation of PV system performance under typical operating conditions.

#### **4.3.2 Battery Energy Storage System description**

BESS units play a key role in enhancing the flexibility and reliability of renewable-based installations. Lithium-ion batteries, in particular, represent one of the most suitable technologies for residential and community-scale applications due to their high energy density, compact size, fast response time and ability to efficiently manage daily charge–discharge cycles. These characteristics make them especially appropriate for supporting photovoltaic self-consumption, peak-shaving strategies and collective energy management within energy communities.

The battery model selected for this study is based on lithium-ion technology and provides a combination of high energy density, long operational lifetime and modular scalability, making it an efficient and reliable solution for the considered community energy system. The main technical parameters of the BESS are summarized in Table 4.

<b>Parameter</b>	<b>Units</b>	<b>Value</b>
Battery energy capacity	kWh	40
Maximum power rating	kW	20
Depth of discharge (DoD)	%	80
Round-trip efficiency	%	90
Cycle life	cycles	6000
Battery cost	€	18800

**Table 4:** Technical parameters of the selected BESS.

#### **4.3.3 Technical summary of the energy system**

In Table 5, the technical characteristics of the entire system are presented:

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Parameter	Unit	Value
PV nominal power	kWp	50
PV installation cost	€/kWp	1,100
BESS capacity	kWh	40
Battery cost	€	18,800
PV O&M cost	%	2
BESS O&M cost	%	2
Discount rate	%	5
Project lifetime	yr	25

Table 5: Technical characteristics of the complete energy system.

### 4.4 Electricity grid and tariffs overview

As previously mentioned, the three individual loads, as well as the energy community itself, are connected to the national electricity grid. Depending on the contracted tariff scheme, the grid applies different purchase and selling prices for electricity. In this paragraph, the three tariff options considered in this study—namely the *fixed tariff*, the *period tariff* and the *indexed tariff*—are analyzed in detail. Regarding the purchase price, the fixed-rate tariff applies a single hourly rate of 0.1425 €/kWh throughout the entire year. In contrast, the period tariff defines monthly three distinct prices per day, each corresponding to one of the three time-of-use periods into which every day of a month is divided. When including system charges and transmission and distribution costs, both the fixed and period tariffs follow the 3.0TD tariff structure, which is illustrated in Figure 10.

TARIFF 3.0TD													
Hours	January	February	March	April	May	June	July	August	September	October	November	December	Sat/Sun/Holidays
0:00-1:00	P6	P6	P6	P6	P6	P6	P6	P6	P6	P6	P6	P6	P6
1:00-2:00	P6	P6	P6	P6	P6	P6	P6	P6	P6	P6	P6	P6	P6
2:00-3:00	P6	P6	P6	P6	P6	P6	P6	P6	P6	P6	P6	P6	P6
3:00-4:00	P6	P6	P6	P6	P6	P6	P6	P6	P6	P6	P6	P6	P6
4:00-5:00	P6	P6	P6	P6	P6	P6	P6	P6	P6	P6	P6	P6	P6
5:00-6:00	P6	P6	P6	P6	P6	P6	P6	P6	P6	P6	P6	P6	P6
6:00-7:00	P6	P6	P6	P6	P6	P6	P6	P6	P6	P6	P6	P6	P6
7:00-8:00	P6	P6	P6	P6	P6	P6	P6	P6	P6	P6	P6	P6	P6
8:00-9:00	P2	P2	P3	P5	P5	P4	P2	P4	P4	P5	P3	P2	P6
9:00-10:00	P1	P1	P2	P4	P4	P3	P1	P3	P3	P4	P2	P1	P6
10:00-11:00	P1	P1	P2	P4	P4	P3	P1	P3	P3	P4	P2	P1	P6
11:00-12:00	P1	P1	P2	P4	P4	P3	P1	P3	P3	P4	P2	P1	P6
12:00-13:00	P1	P1	P2	P4	P4	P3	P1	P3	P3	P4	P2	P1	P6
13:00-14:00	P1	P1	P2	P4	P4	P3	P1	P3	P3	P4	P2	P1	P6
14:00-15:00	P2	P2	P3	P5	P5	P4	P2	P4	P4	P5	P3	P2	P6
15:00-16:00	P2	P2	P3	P5	P5	P4	P2	P4	P4	P5	P3	P2	P6
16:00-17:00	P2	P2	P3	P5	P5	P4	P2	P4	P4	P5	P3	P2	P6
17:00-18:00	P2	P2	P3	P5	P5	P4	P2	P4	P4	P5	P3	P2	P6
18:00-19:00	P1	P1	P2	P4	P4	P3	P1	P3	P3	P4	P2	P1	P6
19:00-20:00	P1	P1	P2	P4	P4	P3	P1	P3	P3	P4	P2	P1	P6
20:00-21:00	P1	P1	P2	P4	P4	P3	P1	P3	P3	P4	P2	P1	P6
21:00-22:00	P1	P1	P2	P4	P4	P3	P1	P3	P3	P4	P2	P1	P6
22:00-23:00	P2	P2	P3	P5	P5	P4	P2	P4	P4	P5	P3	P2	P6
23:00-00	P2	P2	P3	P5	P5	P4	P2	P4	P4	P5	P3	P2	P6

Figure 10: 3.0TD tariff structure used in this study – (Boletín Oficial del Estado, 2024).

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Taking into account the taxes and charges previously described (Boletín Oficial del Estado, 2024), the fixed tariff shows a maximum value of 0.19094 €/kWh, a minimum value of 0.14469€/kWh, and an average value of 0.15445 €/kWh. In contrast, the period tariff presents a maximum value of 0.24474 €/kWh, a minimum value of 0.12549€/kWh, and an average value of 0.15163 €/kWh. Finally, the indexed tariff is a dynamic pricing scheme in which the electricity purchase price varies hour by hour, directly reflecting the fluctuations of the wholesale electricity market. As a consequence, users under this tariff face real-time price variability, which may lead to either cost savings or higher expenses depending on the temporal profile of their consumption. Regarding this tariff, the corresponding price signal presents a maximum of 0.24201 €/kWh, a minimum of 0.00549 €/kWh and an average value of 0.08680 €/kWh.

It is important to mention that all three options rely on the same electricity selling price set by the grid operator, as shown in Figure 11. This price signal exhibits a maximum of 0.19203 €/kWh and a minimum of -0.00454 €/kWh, with an average value of 0.061742 €/kWh.

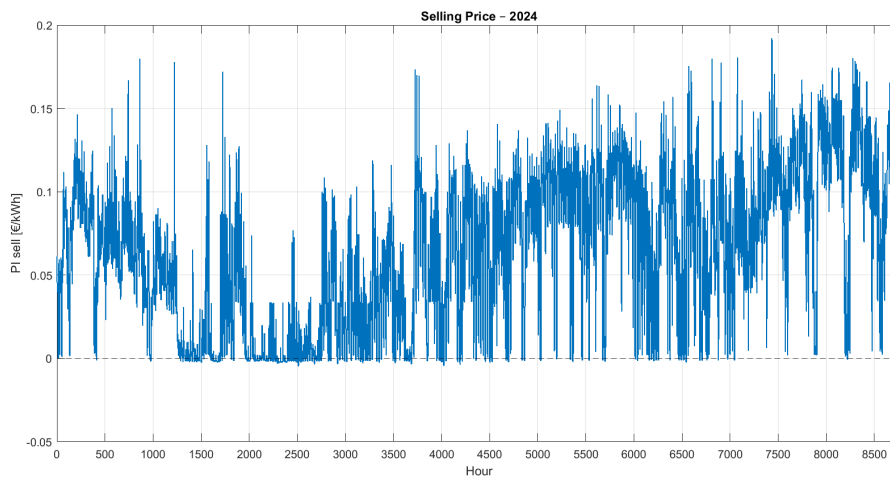


Figure 11: Electricity selling price profile used in this study – (ESIOS Red Eléctrica de España, 2024).

### 4.5 Preliminary considerations

Before the implementation of the energy community, the three pumping stations of the three irrigation communities (IC1, IC2 and IC3) operated independently, directly connected to the grid and fully dependent on external electricity supply. The loads had a contracted power of 20, 25 and 26.4 kW.

#### 4.5.1 Initial energy consumption

The loads' profiles are strongly conditioned by irrigation demand, which varies throughout the year and generates both a characteristic seasonality in water consumption and variability in energy use. Figure 12 shows the aggregated monthly electricity consumption (kWh) of the three loads, while Figure 13 presents the corresponding aggregated monthly water demand (m<sup>3</sup>). These graphs clearly

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illustrate the seasonal patterns, with pronounced peaks during spring and summer months that coincide with the highest irrigation requirements and reduced values in autumn and winter.

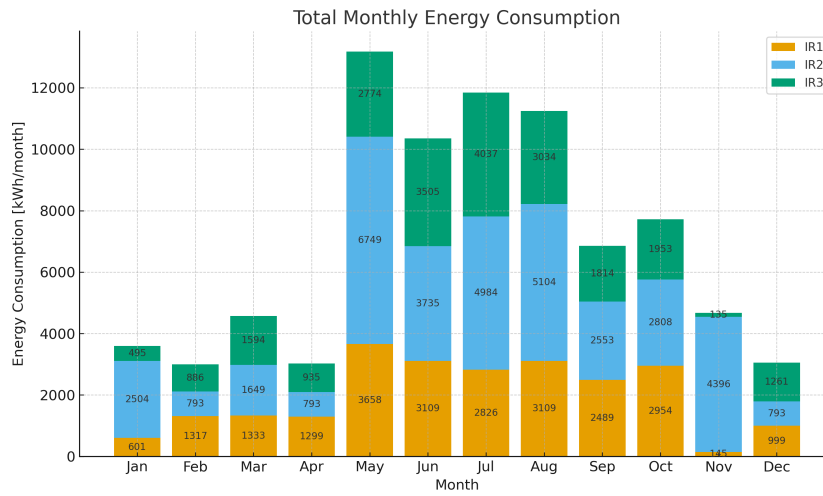


Figure 12: Monthly electricity consumption (kWh) of the three pumping stations.

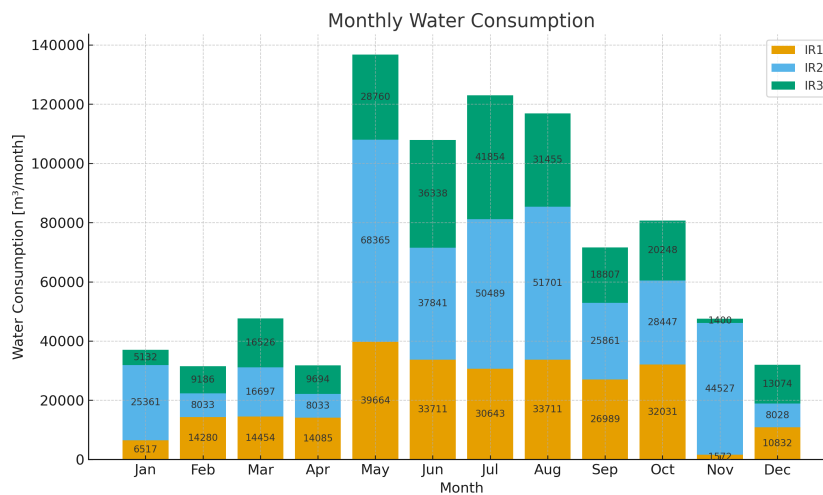


Figure 13: Monthly water consumption (m<sup>3</sup>) of the three pumping stations.

### 4.5.2 Initial energy billing

From an economic perspective, the baseline scenario considers the annual electricity costs of each community under three different tariff schemes: a fixed-rate plan, a period-of-use plan, and a market-indexed tariff. Table 6 summarises the results for each pumping station. The breakdown includes the energy term, the power term, the cost of consumed energy, the subtotal without taxes, the taxable base and the total invoice amount including taxes. Specifically, taxes include a special electricity tax of 5.11269%. The comparison highlights the significant impact of the tariff structure on the final annual expenditure, with indexed tariffs generally reducing costs compared to fixed and period-based

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schemes, although at the expense of greater exposure to market price volatility.

<b>Energy Term (€)</b>				
<b>Load 1</b>	<b>Load 2</b>	<b>Load 3</b>	<b>Total</b>	
407	609	429	1445	

<b>Power Term (€)</b>				
<b>Load 1</b>	<b>Load 2</b>	<b>Load 3</b>	<b>Total</b>	
758	947	1001	2706	

<b>Electricity Consumption + Energy &amp; Power terms (€)</b>					
<b>Tariff</b>	<b>Load 1</b>	<b>Load 2</b>	<b>Load 3</b>	<b>Total</b>	<b>Total after tax</b>
<b>Fixed</b>	4562	6809	4625	15996	16814
<b>Period</b>	4705	6993	4835	16532	17377
<b>Indexed</b>	2943	4510	3148	10600	11142

**Table 6:** Electricity costs by tariff: energy and power terms, load-specific costs and total values.

## 5 Results

This chapter presents the results derived from the examination of several different scenarios, in order to quantify both the energetic and economic impacts of the proposed system. To this aim, an energy balance analysis and the subsequent economic evaluation were conducted, following the implementation of the EC.

In the first scenario, the flexible demand is analyzed in the absence of photovoltaic generation and battery energy storage systems. The second scenario includes PV generation, while the third one combines PV and a BESS. The objective across all scenarios is to assess how energy flows evolve under three different tariff structures and, in the second and third scenarios, for three distinct allocation coefficients. The analysis also explores the economic outcomes, including the estimation of cost savings, the NPV and the IRR. Furthermore, the results are broken down by consumption point, that is, the three irrigation pumps, to assess how their operation correlates with photovoltaic generation and BESS discharge.

This comparative approach allows for the identification of the most advantageous configuration, not only from an energy perspective but also in terms of long-term project profitability. In this way, both the technical and economic feasibility of each proposed alternative are comprehensively assessed.

### 5.1 SCENARIO 1: Flexible irrigation without PV system and without BESS

#### 5.1.1 Investment cost of the system

In this scenario, no initial investment cost is considered, as neither the PV nor the BESS is implemented. The mathematical model optimises the irrigation demand, which stands out for its flexibility, according to the given tariff structures.

To better highlight the combined influence of seasonality and tariff design, the figures below present the irrigation demand profiles for the weeks with highest total irrigation demand recorded throughout the year. The following analysis compares the same tariff structure under contrasting demand conditions, enabling a direct assessment of how irrigation scheduling adapts to both seasonal variations and price schemes.

Under the **fixed-rate tariff** (Figure 14), specifically in winter, irrigation patterns show a clear distinction between weekdays and weekends. During weekends, irrigation takes place throughout most hours of the day, as all hours fall within period P6, which applies a single, uniform tariff rate. On the other hand, from Monday to Friday, the tariff structure is divided into three distinct time periods which, despite sharing the same hourly energy price, are subject to specific Distribution & Transmission and System charges. This results in variations in the effective hourly electricity cost across the day. Consequently, irrigation demand, and thus the power purchased for this purpose, is mainly concentrated during the cheapest hours, between midnight and 8 a.m. As total demand increases, as observed during the summer months, this pattern becomes less pronounced, since

higher irrigation needs force operation also during weekdays and at less economical hours.

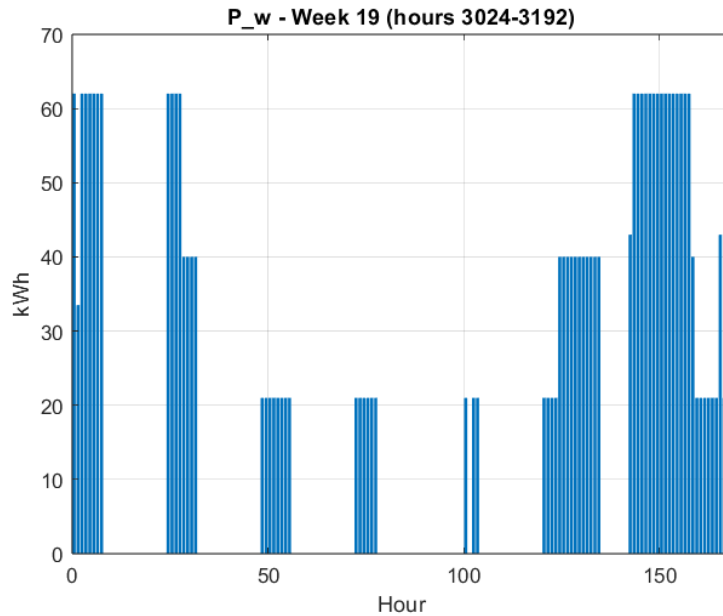


Figure 14: Fixed-rate tariff — Electricity demand for irrigation during the week with maximum total demand.

For the **period-of-use scheme** (Figure 15), a similar behavior is observed. During the winter week with minimum demand, irrigation only occurs over Sunday, with no activity during weekdays. In the high-demand summer week, besides the two days of the weekend, irrigation extends to non-weekend days.

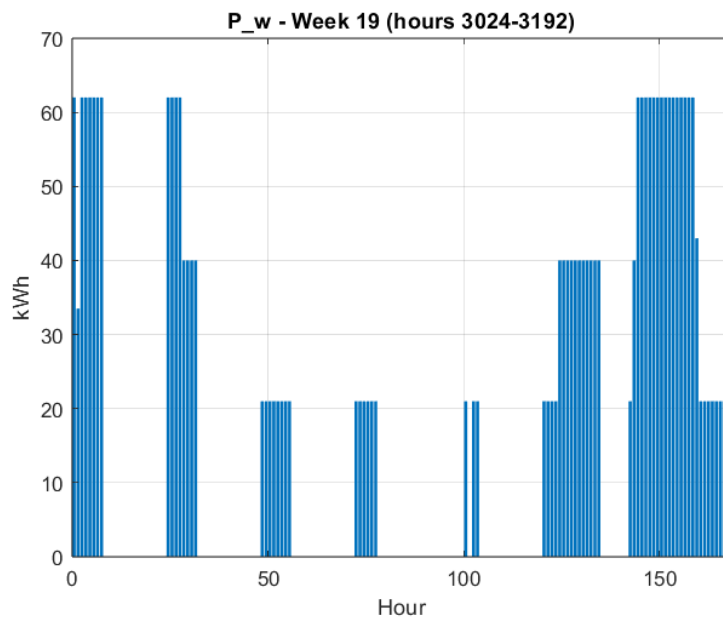


Figure 15: Period-of-use tariff — Electricity demand for irrigation during the week with maximum total demand.

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For the indexed tariff (Figure 16), irrigation during the low-demand week is mainly concentrated on Saturday. A redistribution pattern is observed during the high-demand week, as irrigation extends into the daytime hours of every day to meet the increased water requirements.

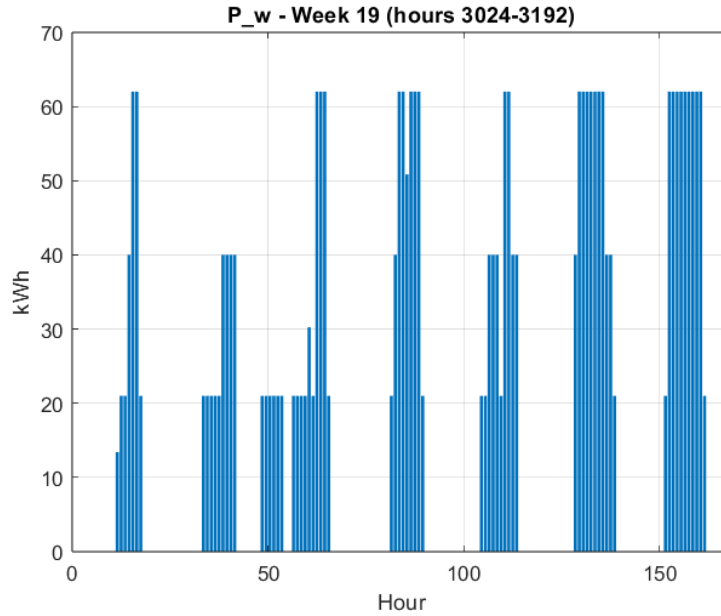


Figure 16: Indexed tariff — Electricity demand for irrigation during the week with maximum total demand.

For completeness, Figures 17 and 18 illustrate the irrigation profiles for representative winter and summer weeks, respectively, under fixed rate-tariff.

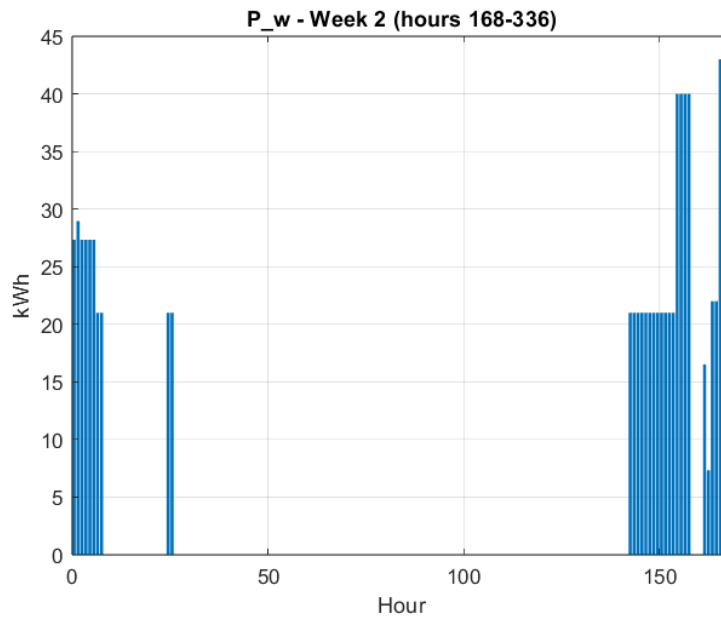


Figure 17: Fixed-rate tariff — Electricity demand for irrigation of week 2 (Mon 8 Jan–Sun 14 Jan).

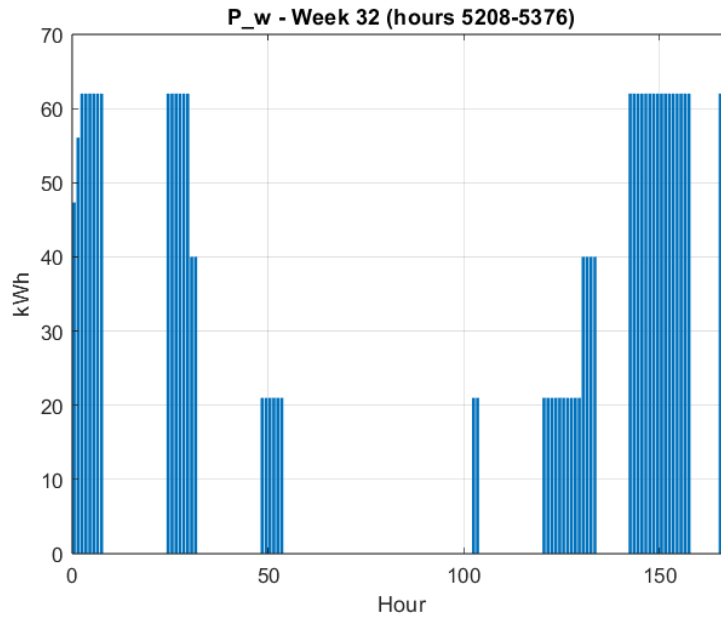


Figure 18: Fixed-rate tariff — Electricity demand for irrigation of week 32 (Mon 5 Aug–Sun 11 Aug).

The aim of these figures is to show the general trend of the corresponding season, instead of the extreme cases of minimum or maximum demand. The irrigation demand during summer is significantly higher than in winter, mainly due to climatic conditions affecting crop water requirements.

### 5.1.2 Energy balance

In the absence of an on-site photovoltaic generation and storage system, the system must acquire all the electricity from the grid. Consequently, the energy balance collapses to a purchased power equal to the demand. Moreover, because there is no local generation, the selling balance does not translate into surplus to sell or gift.

Scenario	$P_{\text{pur}}$ (%)	$P_{\text{sold}}$ (%)	$P_{\text{gift}}$ (%)
Flexibility	100	0	0

Table 7: Percentages values for  $P_{\text{pur}}$ ,  $P_{\text{sold}}$  and  $P_{\text{gift}}$ .

### 5.1.3 Billing and savings

In this first scenario where the entire energy demand is supplied by the main grid, the system incurs a total electricity cost as reported in the following table (Table 8). As previously highlighted, the distinctiveness of this case consists in optimizing a flexible irrigation demand.

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Tariff	Load 1	Load 2	Load 3	Total excl. taxes	TOTAL
Fixed	4208.29	6285.98	4247.38	14741.65	15495.35
Period	3750.45	5577.59	3816.54	13144.58	13816.62
Indexed	1503.98	2596.24	1693.93	5794.14	6090.38

**Table 8:** Electricity bill by tariff (electricity tax assumed at 5.11269%).

From these results, it becomes clear that the indexed tariff offers the highest economic benefit. Its pricing structure, combined with the application of demand flexibility, allows for substantially greater savings compared to the fixed and period tariffs. Although the latter two exhibit smaller cost reductions, demand flexibility still enables a meaningful decrease in energy expenses under both configurations.

Overall, these findings highlight how the ability to shift or reshape the load—rather than the tariff structure alone—plays a central role in achieving cost reductions. This comparison is summarised in Table 9.

Tariff	Load 1	Load 2	Load 3	Total
<b>Fixed</b>	7.75%	7.68%	8.17%	7.84%
<b>Period</b>	20.28%	20.24%	21.06%	20.49%
<b>Indexed</b>	48.89%	42.43%	46.19%	45.34%

**Table 9:** Percentage savings in electricity costs compared to the original configuration.

## 5.2 SCENARIO 2: Energy community with PV system

### 5.2.1 Investment cost of the EC

In this scenario a total operational lifetime of 25 years for the photovoltaic installation is considered. The overall investment cost of the system has been estimated in Table 10.

Unit	Cost [€]
PV Installation	55,000

**Table 10:** Total investment cost for the photovoltaic system.

### 5.2.2 Allocation coefficients of the different consumption points analysis

The allocation coefficients for collective self-consumption are now taken into account. These sharing coefficients enable a fair distribution of the generated energy, which can be adjusted to the participants' needs through either fixed or dynamic allocation methods.

For the **static**, **variable** and **dynamic coefficients** cases, the allocation values per load are summarised in Table 11.

Tariff	Load 1	Load 2	Load 3
<b>Static coefficients</b>			
Fixed	0.2854	0.4739	0.2407
Period	0.2878	0.4642	0.2480
Indexed	0.2497	0.5003	0.2500
<b>Variable coefficients</b>			
Fixed	0.6855	0.2131	0.1015
Period	0.6003	0.1942	0.2054
Indexed	0.5964	0.1832	0.2204
<b>Dynamic coefficients</b>			
Fixed	0.6304	0.1401	0.0759
Period	0.6251	0.1423	0.0724
Indexed	0.5804	0.1134	0.0419

**Table 11:** Allocation coefficients for each load under static, variable and dynamic coefficient schemes.

With variable and dynamic coefficients the first load receives higher allocation coefficient values, which indicates that the first pump benefits the most from the photovoltaic installation. Second and third load, on the other hand, obtain the lowest—and in some cases almost negligible—shares.

### 5.2.3 Energy balance

This section analyses the energy balance for the configuration including the PV system, taking into account that the irrigation profile is again a flexible, optimised decision variable. Since the model determines the pumping hours, both the timing and the amount of irrigation vary depending on the applied tariff and the allocation coefficient.

Despite this internal variability, clear weekly patterns emerge when the energy flows are grouped by

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season, reflecting the cyclical nature of irrigation needs throughout the year.

To illustrate these mechanisms, the below figures are presented, showing a typical winter and summer week for each tariff, combined with static, variable and dynamic allocation coefficients.

When considering the **static coefficients**, under the **fixed-rate tariff** the energy purchases outside PV production hours are more pronounced, whereas under the **indexed tariff** this pattern is slightly less marked yet clearly persistent, indicating that off-PV consumption remains relevant even when the price signal is indexed. See figures below (Figure 19, Figure 22 and Figure 25).

With the **variable coefficients**, the **period-of-use scheme** appears to be the most affected by this pattern of energy purchased outside the PV production hours (Figure 23); however, overall, the three tariffs show no major differences in their general behaviour (Figure 20 and Figure 26).

When considering **dynamic coefficients** during winter, the **period-of-use scheme** is among the most affected (Figure 24, together with the indexed tariff (Figure 27 and (Figure 21)). What clearly emerges is that during summer (right panels of all figures) this effect almost disappears: to meet the high irrigation demand, the entire PV production is used for self-consumption across all coefficients, leaving no surplus for sale to the grid except with the indexed tariff.

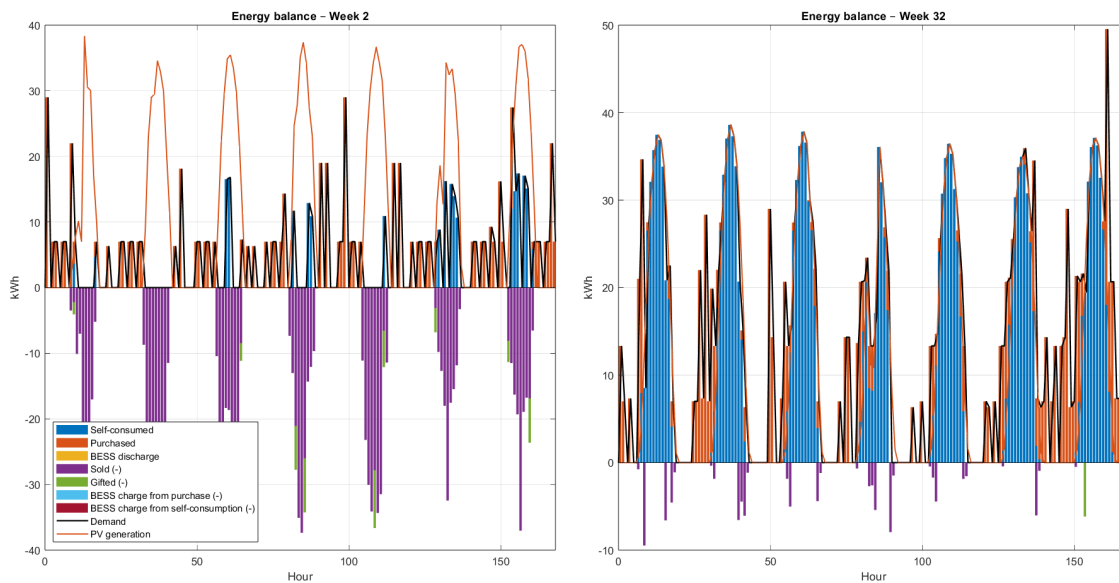
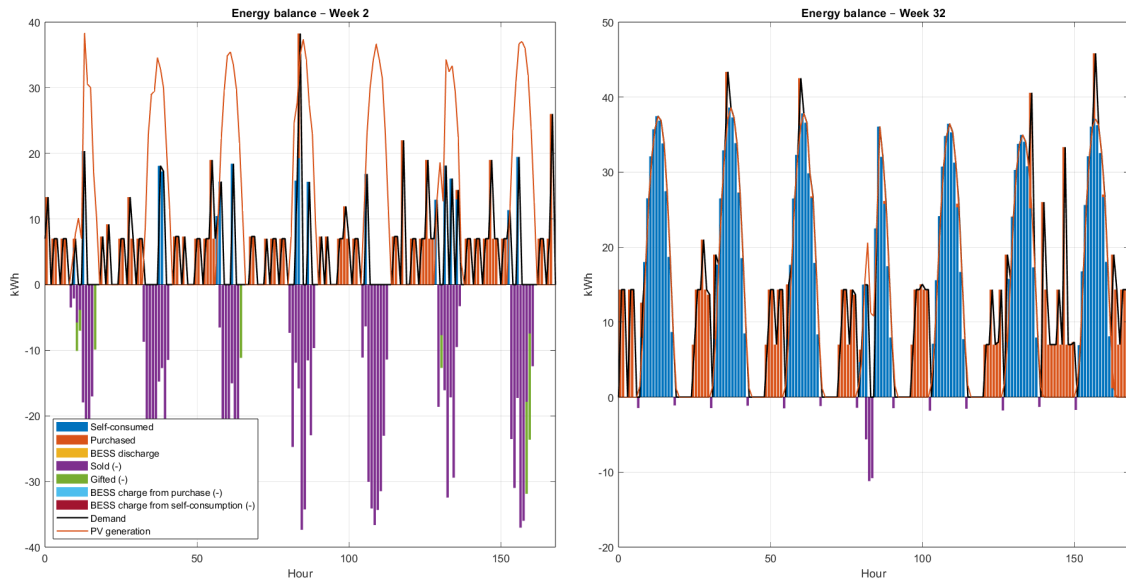
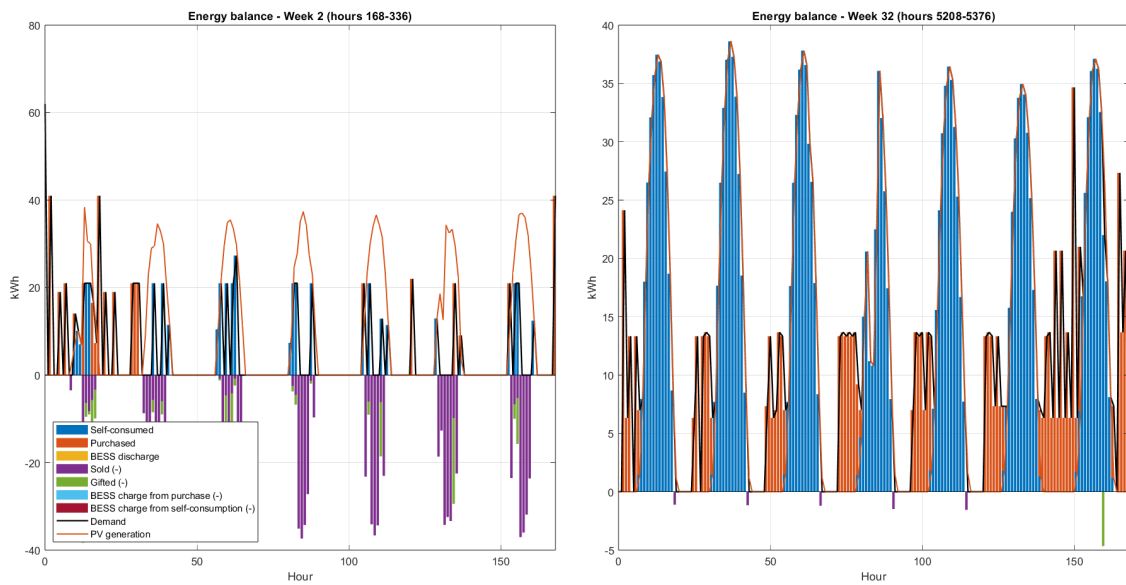


Figure 19: Fixed-rate tariff — Weekly energy balance under static coefficients.

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**Figure 20:** Fixed-rate tariff — Weekly energy balance under variable coefficients.



**Figure 21:** Fixed-rate tariff — Weekly energy balance under dynamic coefficients.

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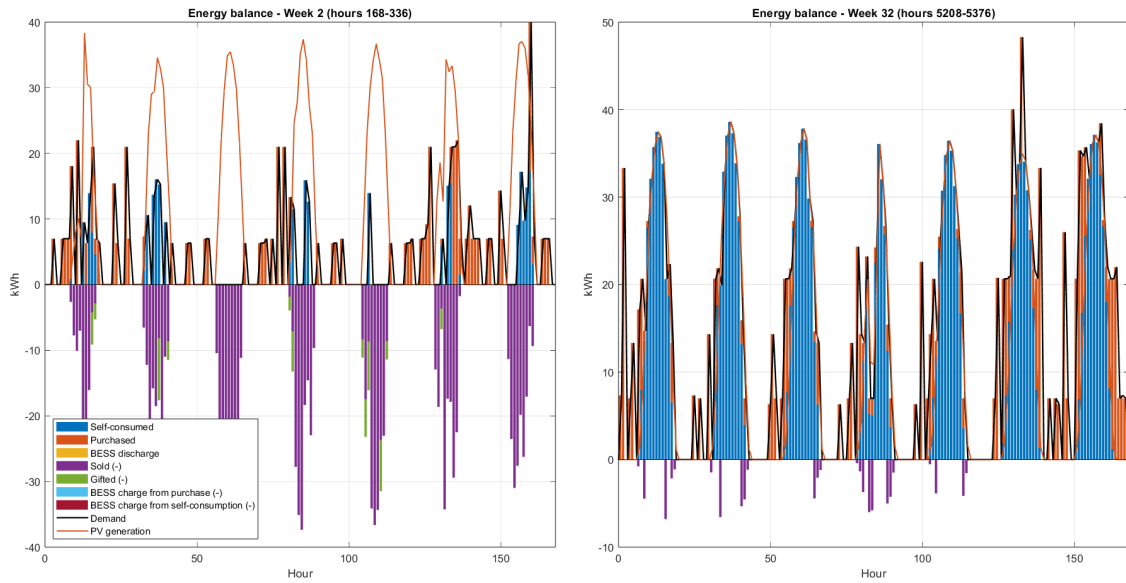


Figure 22: Period-of-use scheme — Weekly energy balance under static coefficients.

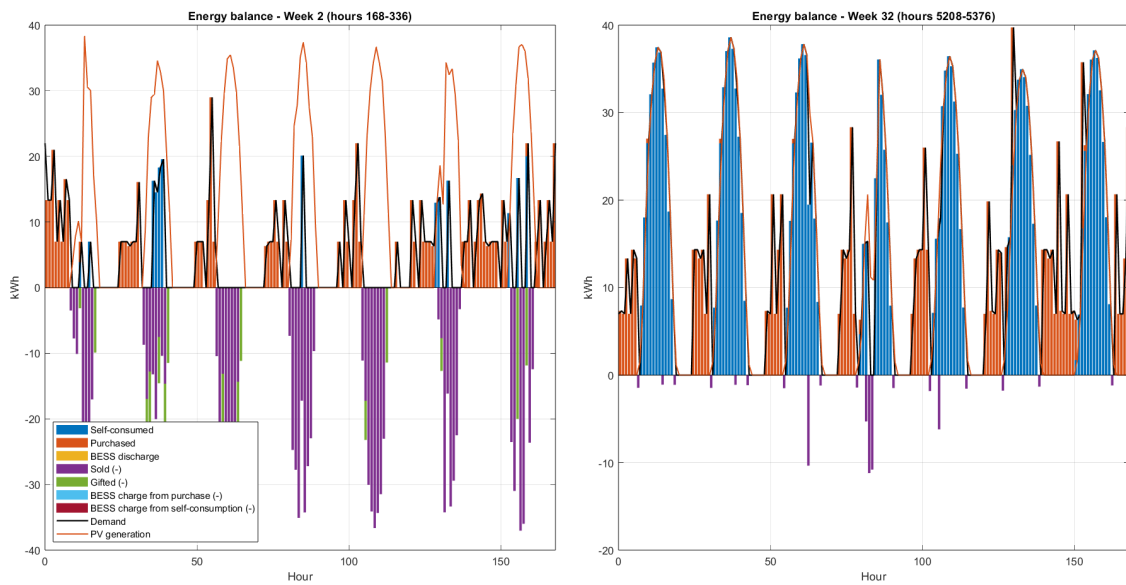
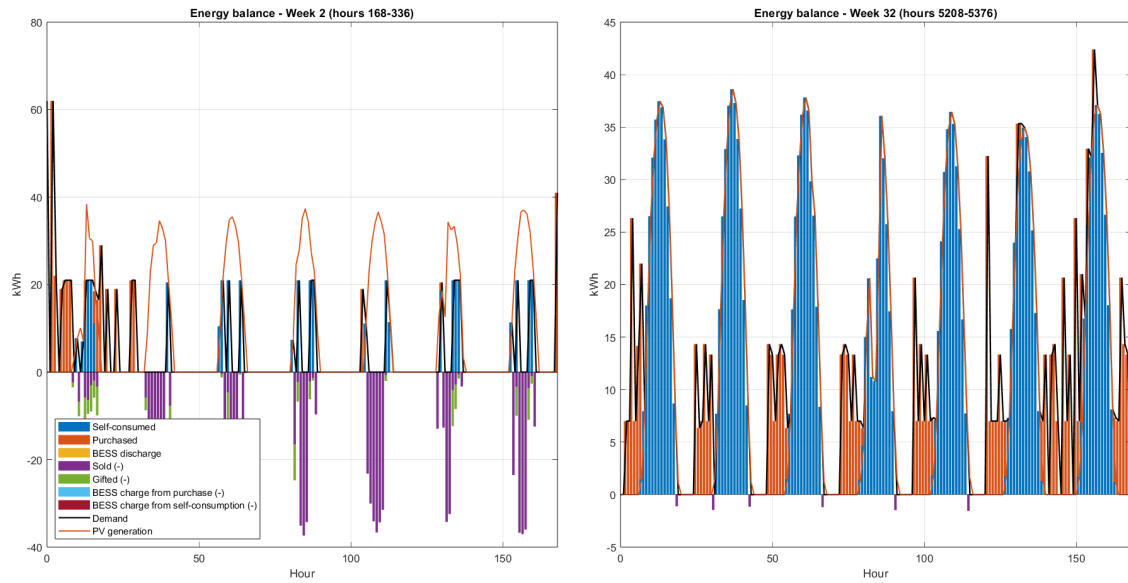
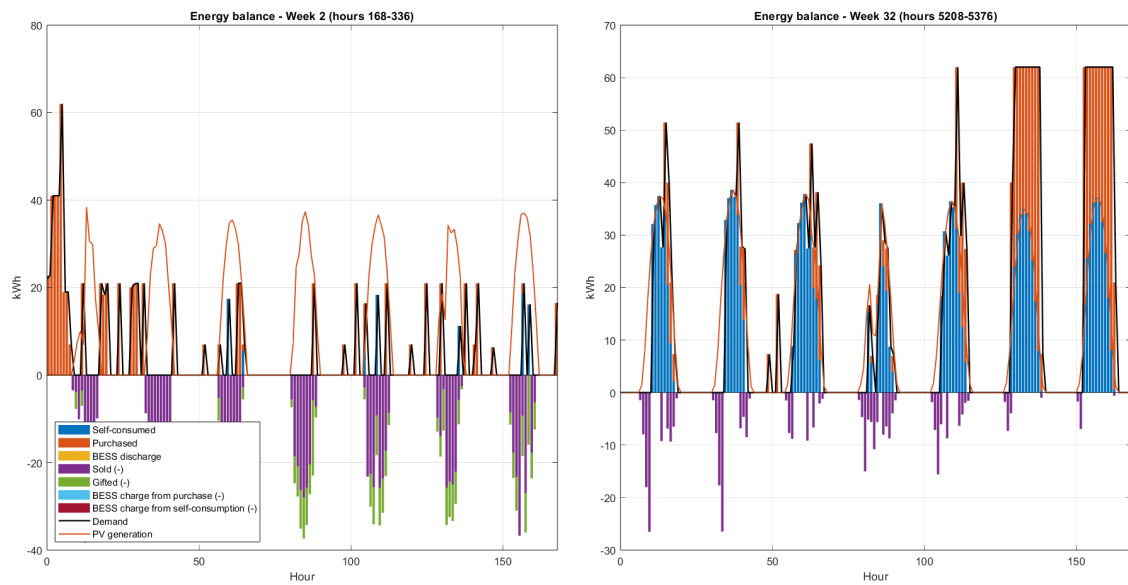


Figure 23: Period-of-use scheme — Weekly energy balance under variable coefficients.

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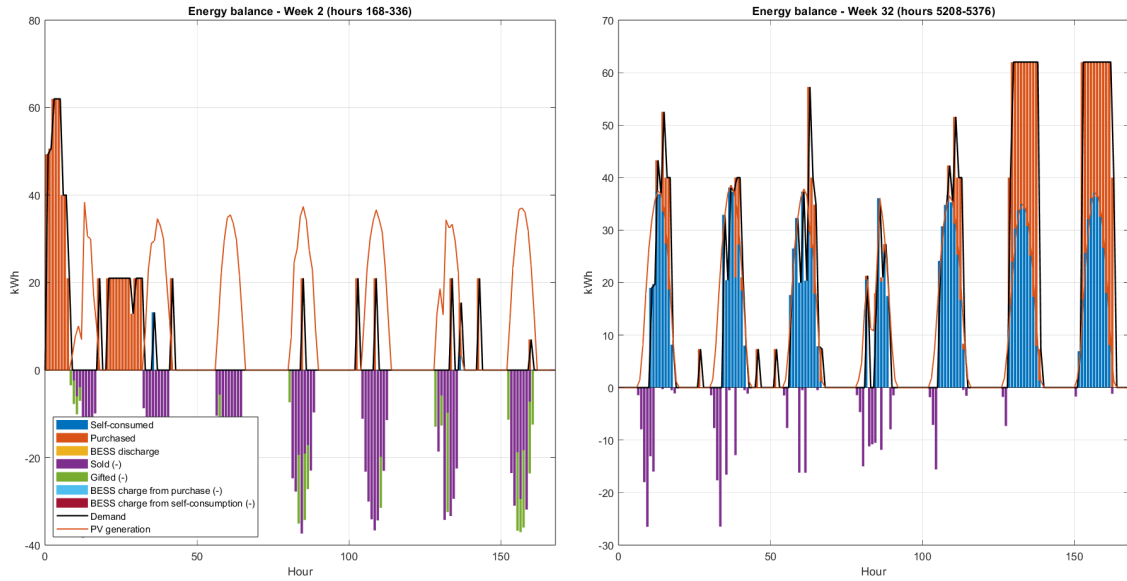


**Figure 24:** Period-of-use scheme — Weekly energy balance under dynamic coefficients.

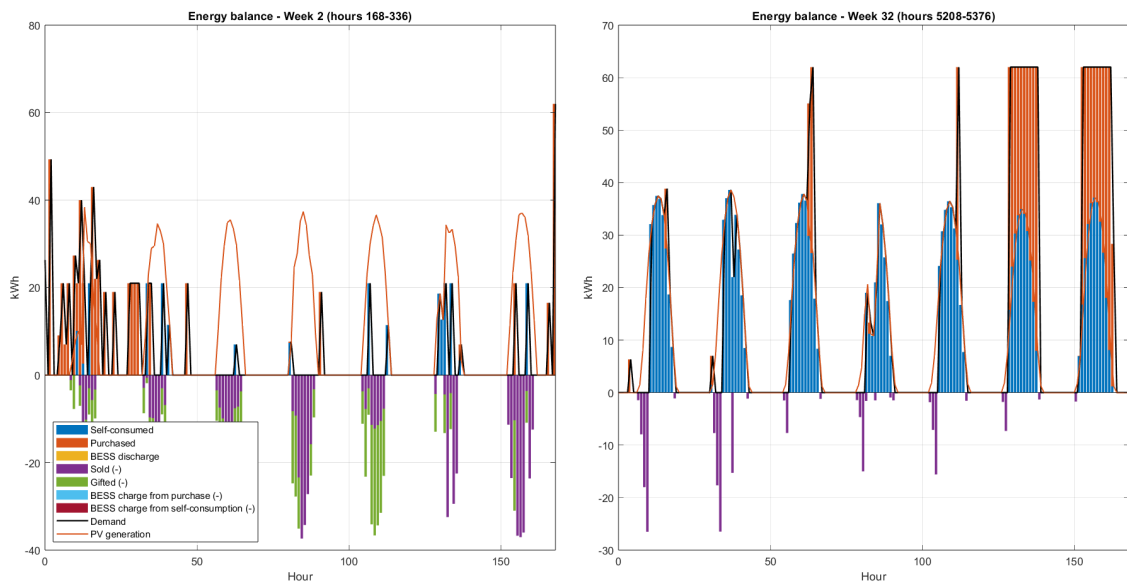


**Figure 25:** Indexed tariff — Weekly energy balance under static coefficients.

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**Figure 26:** Indexed tariff — Weekly energy balance under variable coefficients.



**Figure 27:** Indexed tariff — Weekly energy balance under dynamic coefficients.

To better visualize the energy balance, the percentage shares of self-consumed energy and purchased energy are reported. Energy sold to the grid and gifted to the community is also reported. These indicators are computed for each season and for the whole year. The seasonal results for this scenario under the three different tariffs are summarised in tables 12,31,16 and the corresponding annual shares in tables 13,15,17.

**Optimising Energy Use in Agricultural Energy Communities through Flexible Demand and Electrification Strategies**

Coef.	Season	Seasonal (%)					Seasonal (kWh)			
		Demand		Generation			$P_{sc}$	$P_{pur}$	$P_{sold}$	$P_{gift}$
		$P_{sc}$	$P_{pur}$	$P_{sc}$	$P_{sold}$	$P_{gift}$				
Static	Spring	67.68	32.32	68.72	9.67	21.60	16,822	8,035	2,367	5,288
Static	Summer	68.86	31.14	92.52	7.16	0.32	21,848	9,880	1,691	76
Static	Autumn	64.17	35.83	56.19	34.86	8.95	10,469	5,847	6,496	1,668
Static	Winter	59.87	40.13	30.89	58.18	10.93	6,155	4,125	11,595	2,179
Variable	Spring	68.64	31.36	69.43	9.15	21.42	16,996	7,766	2,239	5,242
Variable	Summer	71.69	28.31	96.47	3.37	0.15	22,781	8,995	797	37
Variable	Autumn	67.46	32.54	58.67	28.18	13.15	10,932	5,274	5,251	2,450
Variable	Winter	63.29	36.71	33.14	51.94	14.92	6,605	3,831	10,351	2,973
Dynamic	Spring	71.32	28.68	–	25.03	74.97	17,616	7,084	1,717	5,144
Dynamic	Summer	73.57	26.43	–	93.68	6.32	23,373	8,397	227	15
Dynamic	Autumn	75.01	24.99	–	90.32	9.68	12,247	4,079	5,768	618
Dynamic	Winter	67.24	32.76	–	74.47	25.53	6,984	3,402	9,641	3,304

Table 12: PV-only, fixed tariff: unified seasonal results in percentage and absolute terms.

Coefficient	Annual (%)					Annual (kWh)			
	Demand		Generation			$P_{sc}$	$P_{pur}$	$P_{sold}$	$P_{gift}$
	$P_{sc}$	$P_{pur}$	$P_{sc}$	$P_{sold}$	$P_{gift}$				
Static	66.47	33.53	63.81	25.56	10.63	55,294	27,887	22,149	9,210
Variable	68.90	31.10	66.14	21.51	12.35	57,314	25,867	18,638	10,701
Dynamic	72.39	27.61	–	65.65	34.35	60,219	22,962	17,353	9,082

Table 13: PV-only, fixed tariff: unified annual results in percentage and absolute terms.

**Optimising Energy Use in Agricultural Energy Communities through Flexible Demand and Electrification Strategies**

Coef.	Season	Seasonal (%)					Seasonal (kWh)			
		Demand		Generation			$P_{sc}$	$P_{pur}$	$P_{sold}$	$P_{gift}$
		$P_{sc}$	$P_{pur}$	$P_{sc}$	$P_{sold}$	$P_{gift}$				
Static	Spring	67.63	32.37	68.79	9.87	21.34	16,838	8,059	2,415	5,224
Static	Summer	68.85	31.15	92.41	7.30	0.29	21,822	9,873	1,725	68
Static	Autumn	62.38	37.62	54.37	35.43	10.19	10,132	6,110	6,603	1,899
Static	Winter	57.70	42.30	29.95	56.77	13.27	5,969	4,377	11,314	2,645
Variable	Spring	67.67	32.33	68.56	10.43	21.01	16,780	8,018	2,554	5,143
Variable	Summer	69.72	30.28	93.77	5.94	0.30	22,143	9,615	1,402	70
Variable	Autumn	63.06	36.94	54.89	32.66	12.45	10,228	5,991	6,086	2,319
Variable	Winter	57.36	42.64	29.95	51.95	18.09	5,969	4,437	10,353	3,606
Dynamic	Spring	71.09	28.91	–	26.93	73.07	17,573	7,147	1,859	5,045
Dynamic	Summer	73.39	26.61	–	98.33	1.67	23,319	8,457	291	5
Dynamic	Autumn	72.88	27.12	–	87.79	12.21	11,895	4,426	5,915	823
Dynamic	Winter	61.79	38.21	–	77.42	22.58	6,405	3,961	10,470	3,054

**Table 14:** PV-only, period-of-use tariff: unified seasonal results in percentage and absolute terms.

Coefficient	Annual (%)					Annual (kWh)			
	Demand		Generation			$P_{sc}$	$P_{pur}$	$P_{sold}$	$P_{gift}$
	$P_{sc}$	$P_{pur}$	$P_{sc}$	$P_{sold}$	$P_{gift}$				
Static	65.83	34.17	63.20	25.45	11.35	54,762	28,419	22,057	9,835
Variable	66.27	33.73	63.61	23.54	12.85	55,120	28,061	20,395	11,139
Dynamic	71.16	28.84	–	67.49	32.51	59,191	23,990	18,535	8,927

**Table 15:** PV-only, period-of-use tariff: unified annual results in percentage and absolute terms.

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Coef.	Season	Seasonal (%)					Seasonal (kWh)			
		Demand		Generation			$P_{sc}$	$P_{pur}$	$P_{sold}$	$P_{gift}$
		$P_{sc}$	$P_{pur}$	$P_{sc}$	$P_{sold}$	$P_{gift}$				
Static	Spring	51.12	48.88	51.75	22.23	26.02	12,668	12,113	5,441	6,368
Static	Summer	47.98	52.02	64.78	33.28	1.94	15,298	16,583	7,858	459
Static	Autumn	24.33	75.67	21.41	60.79	17.80	3,989	12,408	11,327	3,317
Static	Winter	12.54	87.46	6.37	65.38	28.25	1,269	8,853	13,030	5,630
Variable	Spring	52.21	47.79	52.91	23.08	24.01	12,950	11,855	5,649	5,878
Variable	Summer	50.08	49.92	67.61	31.27	1.13	15,965	15,911	7,383	266
Variable	Autumn	26.05	73.95	22.86	52.90	24.23	4,260	12,093	9,858	4,515
Variable	Winter	10.52	89.48	5.36	57.19	37.46	1,067	9,078	11,396	7,465
Dynamic	Spring	57.19	42.81	–	44.35	55.65	14,120	10,571	4,594	5,764
Dynamic	Summer	53.85	46.15	–	99.93	0.07	17,202	14,741	6,408	4
Dynamic	Autumn	51.16	48.84	–	69.58	30.42	8,278	7,904	7,205	3,150
Dynamic	Winter	32.78	67.22	–	63.68	36.32	3,398	6,967	10,527	6,003

Table 16: PV-only, indexed tariff: unified seasonal results in percentage and absolute terms.

Coefficient	Annual (%)					Annual (kWh)			
	Demand		Generation			$P_{sc}$	$P_{pur}$	$P_{sold}$	$P_{gift}$
	$P_{sc}$	$P_{pur}$	$P_{sc}$	$P_{sold}$	$P_{gift}$				
Static	39.94	60.06	38.34	43.46	18.20	33,224	49,957	37,656	15,774
Variable	41.17	58.83	39.52	39.57	20.92	34,243	48,938	34,286	18,125
Dynamic	51.69	48.31	–	65.82	34.18	42,998	40,183	28,734	14,921

Table 17: PV-only, indexed tariff: unified annual results in percentage and absolute terms.

#### 5.2.4 Billing and savings of the EC

The optimised electricity expenditures of the EC for the static, variable and dynamic coefficient settings are reported in Tables 18–20, while the corresponding percentage savings with respect to the base case are summarised in Tables 21–23. A comparative analysis of the results shows that, across all coefficient configurations, the optimization process consistently reduces expenditures relative to the base case of Table 6. Although the extent of the savings varies across tariffs and consumption levels, a clear trend emerges: in all scenarios, the indexed tariff delivers the lowest total cost when compared to the fixed and period alternatives. The static and variable coefficient settings exhibit

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similar behaviours, but the dynamic coefficients yield the lowest total expenditures among all three configurations. Allowing the coefficients to vary dynamically therefore results in systematically lower costs than those obtained with static or variable coefficients, while maintaining coherent and realistic cost structures across all tariff types.

Tariff	Load 1	Load 2	Load 3	Total excl. taxes	TOTAL
<b>Fixed</b>	1543.93	1849.22	2036.00	5429.16	5706.73
<b>Period</b>	1417.49	1776.64	1857.71	5051.83	5310.12
<b>Indexed</b>	794.16	999.54	1063.64	2857.35	3003.43

**Table 18:** Electricity bill by tariff for the scenario with PV system and static coefficients (electricity tax assumed at 5.11269%).

Tariff	Load 1	Load 2	Load 3	Total excl. taxes	TOTAL
<b>Fixed</b>	1345.23	1936.54	1982.23	5264.00	5533.13
<b>Period</b>	1324.21	1797.78	1846.31	4968.30	5222.32
<b>Indexed</b>	772.65	1006.74	1035.59	2814.98	2958.90

**Table 19:** Electricity bill by tariff for the scenario with PV system and variable coefficients (electricity tax assumed at 5.11269%).

Tariff	Load 1	Load 2	Load 3	Total excl. taxes	TOTAL
<b>Fixed</b>	1489.24	1955.40	1518.65	4963.29	5217.05
<b>Period</b>	1370.29	1772.23	1506.19	4648.71	4886.38
<b>Indexed</b>	771.45	986.96	1014.98	2773.39	2915.18

**Table 20:** Electricity bill by tariff for the scenario with PV system and dynamic coefficients (electricity tax assumed at 5.11269%).

Tariff	Load 1	Load 2	Load 3	Total
<b>Fixed</b>	66.16%	72.84%	55.98%	66.06%
<b>Period</b>	69.87%	74.59%	61.58%	69.44%
<b>Indexed</b>	73.01%	77.84%	66.21%	73.04%

**Table 21:** Percentage savings vs. base “Subtotal excl. taxes” — PV, static coefficients.

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Tariff	Load 1	Load 2	Load 3	Total
<b>Fixed</b>	70.51%	71.56%	57.14%	67.09%
<b>Period</b>	71.85%	74.29%	61.81%	69.95%
<b>Indexed</b>	73.74%	77.68%	67.10%	73.44%

Table 22: Percentage savings vs. base “Subtotal excl. taxes” — PV, variable coefficients.

Tariff	Load 1	Load 2	Load 3	Total
<b>Fixed</b>	67.35%	71.28%	67.17%	68.97%
<b>Period</b>	70.87%	74.66%	68.85%	71.88%
<b>Indexed</b>	73.78%	78.11%	67.76%	73.84%

Table 23: Percentage savings vs. base “Subtotal excl. taxes” — PV, dynamic coefficients

Overall, the evidence indicates that the optimization approach benefits the EC under any parameterization. However, the most advantageous configuration is clearly the indexed tariff with dynamic coefficients, which consistently achieves the lowest total costs across the scenarios evaluated.

### 5.2.5 NPV and IRR analysis

To assess the project’s economic feasibility and overall profitability, the analysis now focuses on the expected monetary savings on electricity bills and the costs incurred by both the EC and its participating users. Although photovoltaic generation and self-consumption significantly reduce the amount of electricity that must be purchased from the grid, they are not sufficient to fully meet the community’s demand, making occasional grid supply still necessary. Tables 24, 25 and 26 summarises the annual bill savings achieved through the EC compared with the initial expenditures, together with the total investment, the allocated investment per consumption point, and the corresponding operation and maintenance (O&M) costs. In addition, the table reports the resulting NPV, IRR and PB, providing a comprehensive overview of the project’s economic performance.

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<b>System-level</b>					
<b>Parameter</b>	<b>Unit</b>	<b>Static</b>	<b>Variable</b>	<b>Dynamic</b>	
Annual Savings	€	10,567	10,732	11,033	
Investment	€	55,000	55,000	55,000	
O&M	€	1,100	1,100	1,100	
NPV	€	78,429	80,757	84,995	
IRR	%	17	17	18	
Payback Period	years	5.81	5.71	5.54	

<b>Load-level</b>					
<b>Parameter</b>	<b>Unit</b>	<b>Load</b>	<b>Static</b>	<b>Variable</b>	<b>Dynamic</b>
		Load 1	314	335	303
O&M	€	Load 2	521	507	498
		Load 3	265	258	300
NPV	€	Load 1	22,413	23,833	23,912
		Load 2	36,497	36,200	36,497
		Load 3	19,519	20,723	24,586
IRR	%	Load 1	17	17	18
		Load 2	17	17	17
		Load 3	17	18	18

**Table 24:** Economic indicators for the fixed-rate tariff under different allocation coefficients.

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<b>System-level</b>					
<b>Parameter</b>	<b>Unit</b>	<b>Static</b>	<b>Variable</b>	<b>Dynamic</b>	
Annual Savings	€	11,480	11,564	11,883	
Investment	€	55,000	55,000	55,000	
O&M	€	1,100	1,100	1,100	
NPV	€	91,298	92,475	96,979	
IRR	%	19	19	19	
Payback Period	years	5.30	5.26	5.10	

<b>Load-level</b>					
<b>Parameter</b>	<b>Unit</b>	<b>Load</b>	<b>Static</b>	<b>Variable</b>	<b>Dynamic</b>
		Load 1	317	330	303
O&M	€	Load 2	511	505	508
		Load 3	273	266	289
NPV	€	Load 1	26,041	26,523	27,564
		Load 2	40,787	40,853	41,009
		Load 3	24,469	25,098	28,406
IRR	%	Load 1	18	18	20
		Load 2	18	18	18
		Load 3	20	20	21

**Table 25:** Economic indicators for the period tariff under different allocation coefficients.

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System-level					
Parameter	Unit	Static	Variable	Dynamic	
Annual Savings	€	7,743	7,785	7,827	
Investment	€	55,000	55,000	55,000	
O&M	€	1,100	1,100	1,100	
NPV	€	38,623	39,220	39,806	
IRR	%	11	11	11	
Payback Period	years	8.28	8.23	8.18	

Load-level					
Parameter	Unit	Load	Static	Variable	Dynamic
O&M	€	Load 1	275	320	287
		Load 2	550	537	569
		Load 3	275	244	244
NPV	€	Load 1	12,678	10,083	12,177
		Load 2	14,199	14,982	13,212
		Load 3	11,746	14,155	14,417
IRR	%	Load 1	13	11	12
		Load 2	10	10	9
		Load 3	12	15	15

**Table 26:** Economic indicators for the indexed tariff under different allocation coefficients.

When comparing the three tariff structures, the economic indicators must be interpreted relative to the baseline cost associated with each pricing scheme. The *Indexed Tariff* yields the lowest annual savings and NPV not because the optimised operation is less effective, but because its baseline electricity expenditure is already lower, leaving a reduced margin for additional improvements. Conversely, the *Period Tariff* exhibits the highest annual savings and the strongest profitability metrics precisely because its baseline costs are higher, enabling the optimised operation to unlock a larger economic benefit.

In absolute terms, the *Period Tariff* provides the highest NPV (approximately €97,000) and the highest IRR (around 19%), together with the shortest payback period (about 5.1 years), making it the most financially advantageous configuration among the three. Overall, the comparison indicates that the magnitude of the economic benefit primarily reflects the tariff-dependent baseline rather than differences in optimization performance, while all tariff schemes still lead to economically favourable outcomes.

### 5.3 SCENARIO 3: Energy community with PV system and BESS

#### 5.3.1 Investment cost of the EC

This paragraph presents the configuration in which the energy community deploys both a PV plant and a community battery energy storage system; a setup that increases self-consumption, shifts energy from sunny hours to demand peaks and reduces exposure to grid prices. The computational model was updated to explicitly incorporate storage, including the operational and financial interactions between PV and the BESS. In this scenario, the community battery system is added as asset and included in the total capital expenditure of the installation. The initial investment costs of the system are shown in table 27, while in the following section a further analysis will also account for the residual value of the battery at the end of the project lifetime of the energy community. Accordingly, the final total investment cost will comprise both the photovoltaic system and the battery storage system, and the life-cycle assessment tracks replacements and residual values to reflect the full economic picture.

Unit	Cost [€]
PV investment	55,000
BESS initial investment	18,800
<b>Total initial investment</b>	<b>73,800</b>

Table 27: Initial investment cost of the system.

#### 5.3.2 Allocation coefficients of the different consumption points analysis

The allocation coefficients used for collective self-consumption are re-estimated for the PV with BESS scenario and summarised in Table 28.

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Tariff	Load 1	Load 2	Load 3
<b>Static coefficients</b>			
Fixed	0.3915	0.4960	0.1125
Period	0.3936	0.4935	0.1130
Indexed	0.2895	0.4228	0.2877
<b>Variable coefficients</b>			
Fixed	0.5307	0.2376	0.2317
Period	0.5822	0.2503	0.1674
Indexed	0.4855	0.2121	0.3024
<b>Dynamic coefficients</b>			
Fixed	0.6168	0.1476	0.0933
Period	0.6155	0.1446	0.0872
Indexed	0.5805	0.1109	0.0386

**Table 28:** Allocation coefficients for each load under static, variable and dynamic coefficient schemes, PV with BESS scenario.

### 5.3.3 Energy balance

The energy balance of this particular configuration is now taken into examination. This scenario represents the most complex case because, in addition to photovoltaic production and optimised irrigation schedule, there is a storage system that shifts energy over time. The irrigation profile is optimised and therefore its timing and magnitude vary with the tariff and with the allocation coefficient. As stated in the previous scenario, this endogeneity means that the degree of temporal overlap between pumping hours and the solar window changes across simulations, and the battery reacts to those choices through three distinct channels. The BESS can charge either by purchasing electricity from the grid or through self-consumption from the PV system, and it can also discharge as needed. To illustrate these mechanisms considering the integration of the BESS, the following figures are presented, showing a typical winter and summer week for each tariff, combined with static, variable and dynamic allocation coefficients.

When analysing the winter weeks under the **static coefficients**, the **fixed-rate tariff** still shows some energy purchases from the grid to meet the demand during hours without PV generation. However, these purchases are noticeably lower compared to the case without the BESS, as the battery now partially discharges during non-generating periods to cover part of the load. The **period-of-use tariff** exhibits a similar behaviour, whereas under the **indexed tariff** most of the grid purchases occurring outside PV production hours are instead devoted to charging the BESS (*BESS charge from purchase*). (Figure 28–Figure 31–Figure 34)

With the **variable coefficients**, a slightly different pattern emerges. The **indexed tariff** displays

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many hours of grid purchases aimed at satisfying the demand outside PV generation periods, while in the **fixed-rate tariff** these purchases are primarily used to charge the battery rather than directly supply the load. The **period-of-use tariff** behaves in an intermediate way between the two cases. (Figure 29–Figure 32–Figure 35)

With the **dynamic coefficients**, the **indexed tariff** is the one showing the highest number of purchases outside photovoltaic generation hours, although the other two tariff schemes do not exhibit a significantly different trend (Figure 30–Figure 33–Figure 36).

During the summer weeks, the three tariffs show broadly comparable trends. Virtually all PV generation is directly self-consumed to meet the high irrigation demand, and since this production alone is not sufficient, additional electricity is purchased from the grid even during PV production hours. Overall, the battery operates in a moderate way, being charged mostly from the grid rather than from the PV system, as most of the available solar generation is already absorbed by on-site consumption.

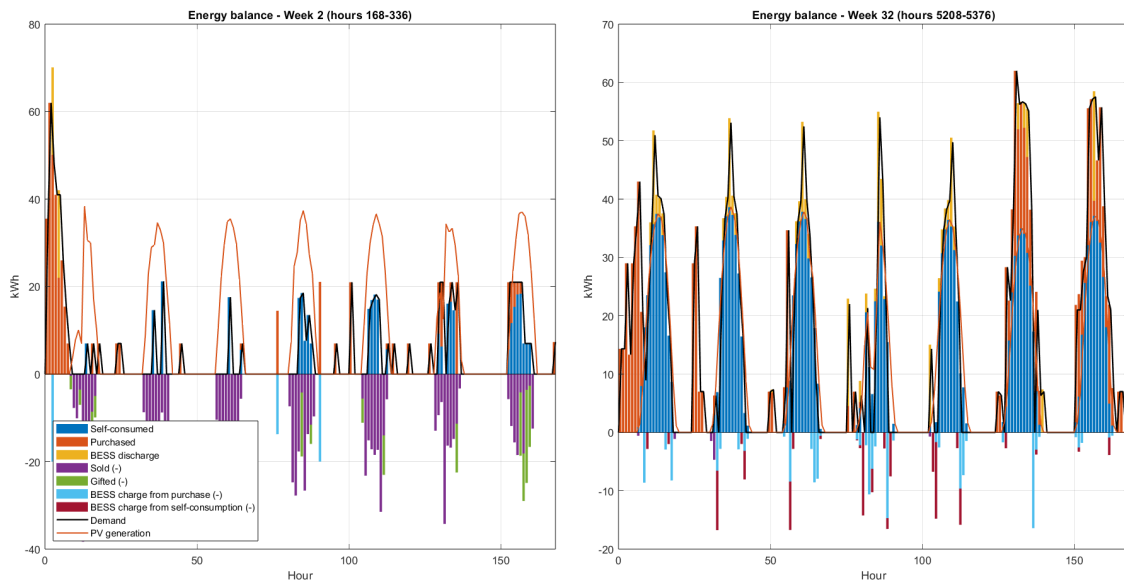


Figure 28: Fixed-rate tariff — Weekly energy balance under static coefficients with BESS.

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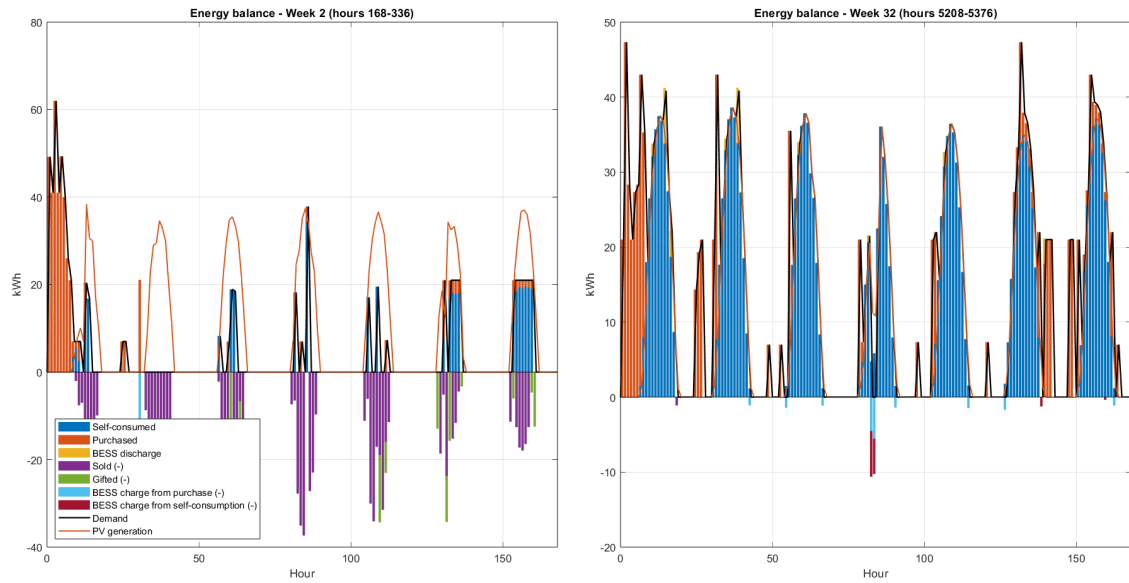


Figure 29: Fixed-rate tariff — Weekly energy balance under variable coefficients with BESS.

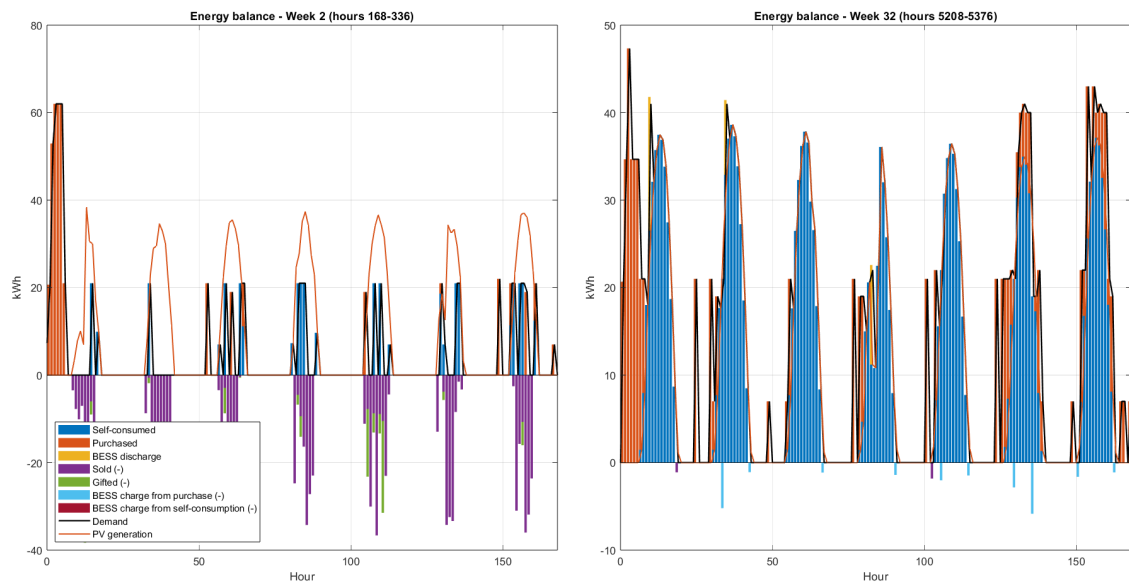


Figure 30: Fixed-rate tariff — Weekly energy balance under dynamic coefficients with BESS.

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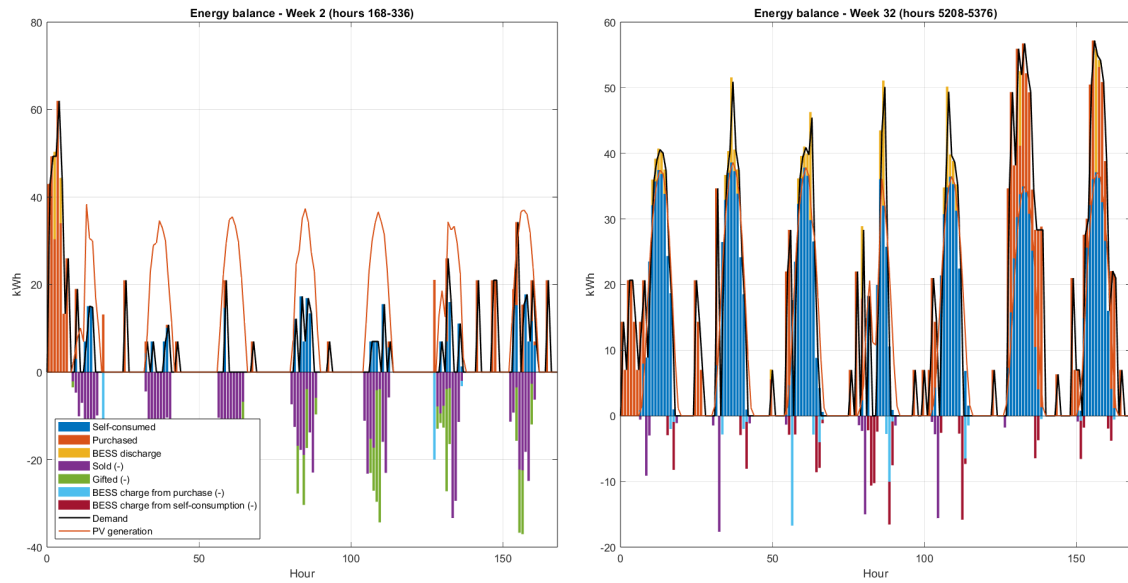


Figure 31: Period-of-use scheme — Weekly energy balance under static coefficients with BESS.

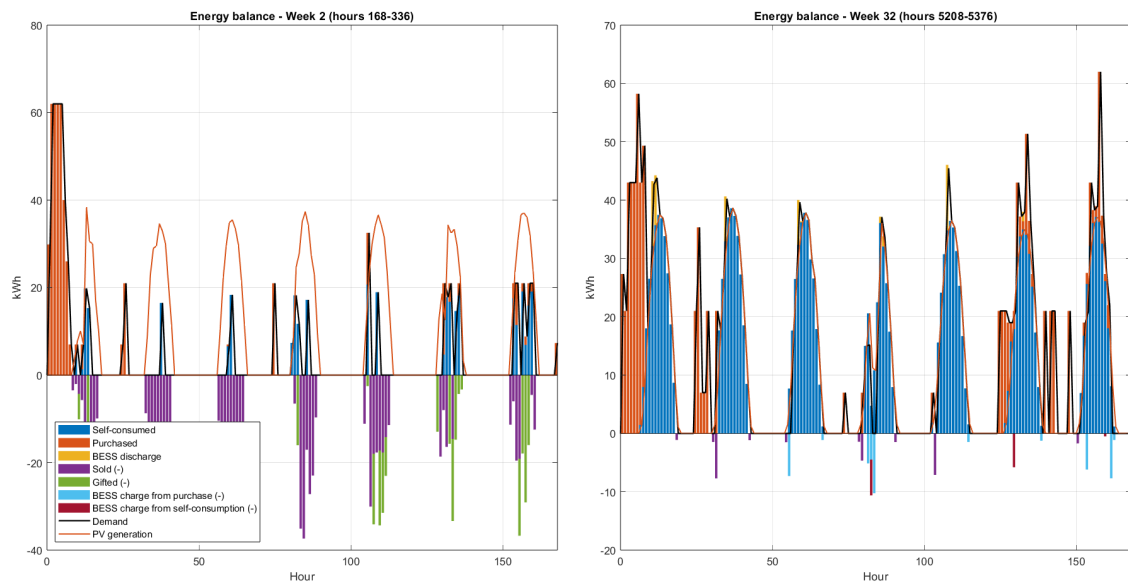


Figure 32: Period-of-use scheme — Weekly energy balance under variable coefficients with BESS.

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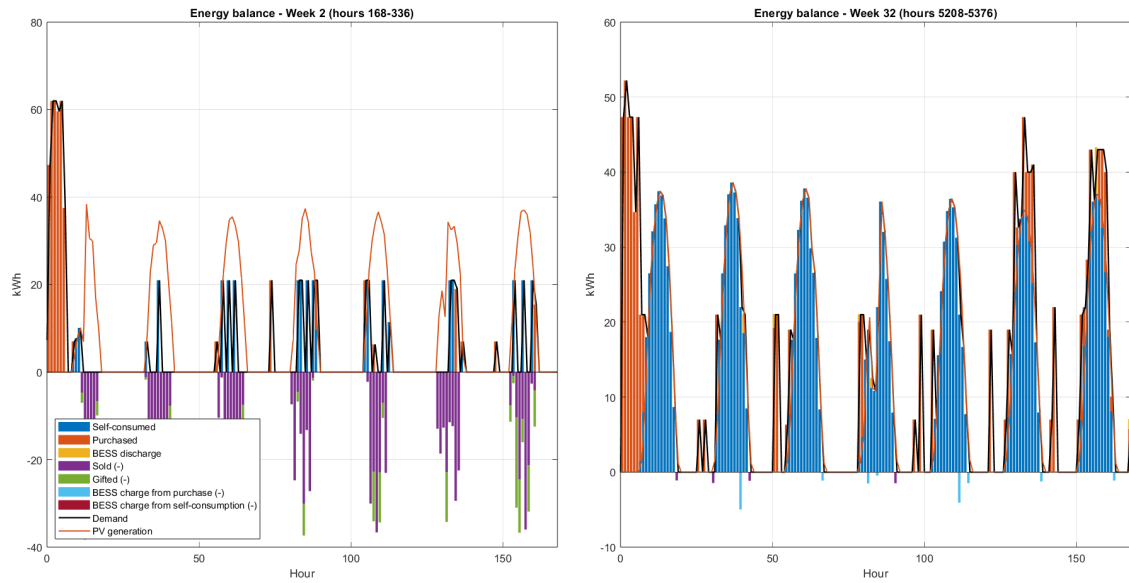


Figure 33: Period-of-use scheme — Weekly energy balance under dynamic coefficients with BESS.

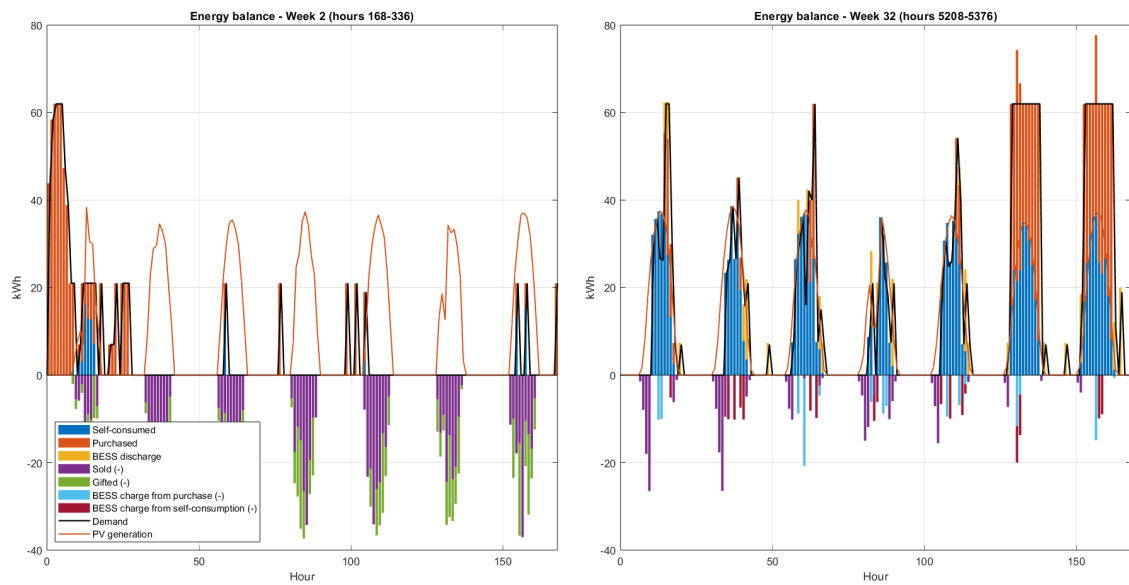
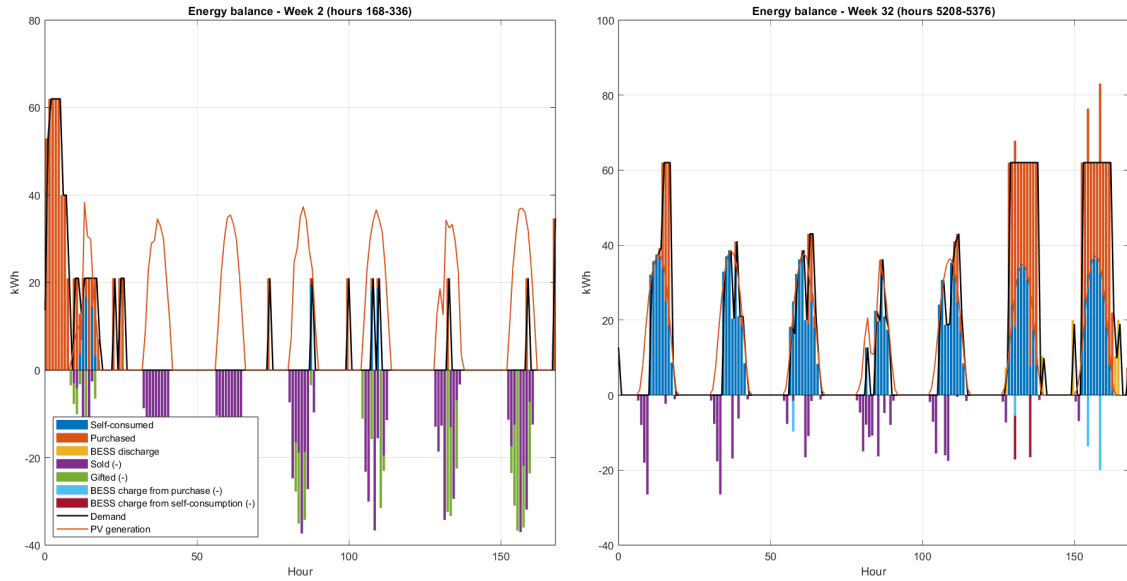
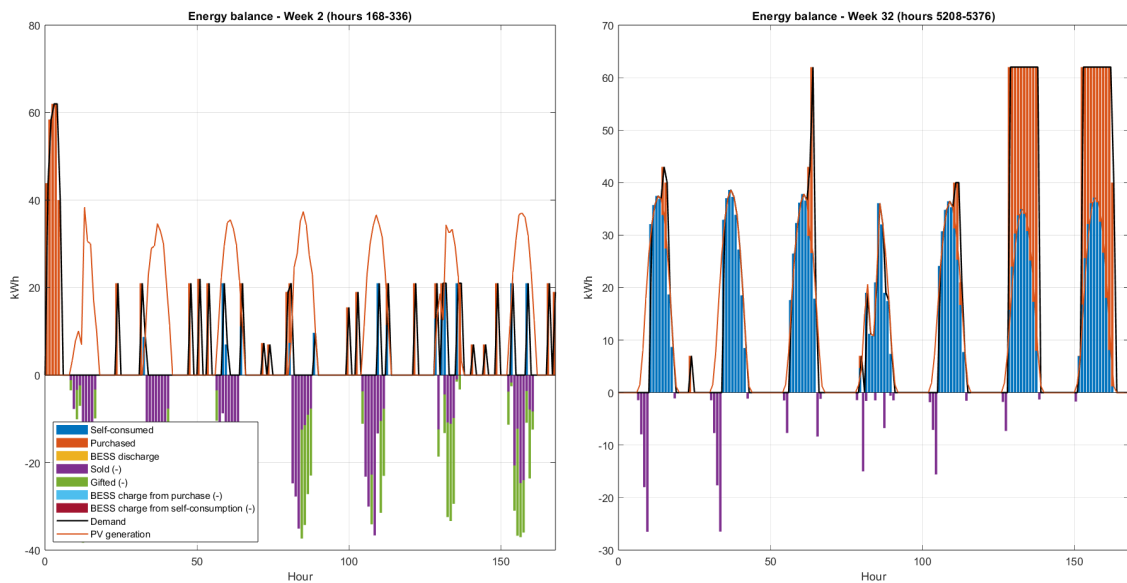


Figure 34: Indexed tariff — Weekly energy balance under static coefficients with BESS.

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**Figure 35:** Indexed tariff — Weekly energy balance under variable coefficients with BESS.



**Figure 36:** Indexed tariff — Weekly energy balance under dynamic coefficients with BESS.

To better visualize the energy balance, the percentage shares of self-consumed energy and purchased energy are reported. Energy sold to the grid and gifted to the community is also reported. Another key performance indicator is self-sufficiency, defined as the proportion of total demand that is met through self-consumed energy. These indicators are once again computed for each season and for the whole year. The seasonal results for this scenario under the three different tariffs are summarised in Tables 29,31, 33 and the corresponding annual shares in Tables 30,32,34.

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Coef.	Season	Seasonal (%)							Seasonal (kWh)					
		Demand			Generation									
		$P_{sc}$	$P_{pur}$	$BESS_{dis} \cdot \sqrt{\eta}$	$P_{sc}$	$P_{sold}$	$P_{gift}$	$BESS_{cha,sc} / \sqrt{\eta}$	$P_{sc}$	$P_{pur}$	$BESS_{dis} \cdot \sqrt{\eta}$	$P_{sold}$	$P_{gift}$	$BESS_{cha,sc} / \sqrt{\eta}$
Static	Spring	61.99	28.62	9.39	67.41	7.93	19.36	5.30	16,501	7,619	2,498	1,940	4,739	1,297
Static	Summer	64.98	26.37	8.65	93.16	0.65	0.00	6.19	21,999	8,925	2,928	155	0	1,461
Static	Autumn	59.15	24.32	16.53	59.12	29.79	3.44	7.65	11,016	4,530	3,078	5,551	641	1,425
Static	Winter	55.01	31.71	13.28	32.40	47.85	16.80	2.95	6,458	3,723	1,558	9,536	3,347	588
Variable	Spring	68.37	29.11	2.52	70.94	7.10	20.91	1.05	17,364	7,394	641	1,738	5,119	256
Variable	Summer	72.51	25.47	2.02	98.92	0.28	0.00	0.80	23,359	8,205	651	67	0	189
Variable	Autumn	64.10	24.28	11.62	62.34	28.52	4.87	4.27	11,615	4,400	2,106	5,314	908	796
Variable	Winter	65.48	33.86	0.65	34.41	46.60	18.93	0.06	6,858	3,547	68	9,287	3,772	11
Dynamic	Spring	68.65	28.97	1.09	–	27.58	72.42	0.00	17,229	7,271	274	1,910	5,015	0
Dynamic	Summer	71.28	25.48	1.48	–	100.00	0.00	0.00	23,009	8,225	478	36	0	0
Dynamic	Autumn	69.95	27.98	1.12	–	89.86	9.93	0.22	11,581	4,633	185	6,196	684	15
Dynamic	Winter	62.68	37.26	0.00	–	81.81	18.19	0.00	6,510	3,870	0	10,973	2,439	0

**Table 29:** Seasonal results with percentages and energy totals of the PV with BESS scenario, fixed tariff scheme applied.

Coefficient	Annual (%)							Annual (kWh)					
	Demand			Generation									
	$P_{sc}$	$P_{pur}$	$BESS_{dis} \cdot \sqrt{\eta}$	$P_{sc}$	$P_{sold}$	$P_{gift}$	$BESS_{cha,sc} / \sqrt{\eta}$	$P_{sc}$	$P_{pur}$	$BESS_{dis} \cdot \sqrt{\eta}$	$P_{sold}$	$P_{gift}$	$BESS_{cha,sc} / \sqrt{\eta}$
Static	61.62	27.30	11.08	64.60	19.83	10.07	5.51	55,974	24,796	10,063	17,181	8,727	4,771
Variable	68.67	27.31	4.02	68.31	18.93	11.31	1.44	59,196	23,546	3,466	16,406	9,799	1,252
Dynamic	69.17	28.46	1.11	–	70.10	29.85	0.05	58,329	24,000	937	19,114	8,139	15

**Table 30:** Annual results with percentages and energy totals of the PV with BESS scenario, fixed tariff scheme applied.

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Coef.	Season	Seasonal (%)							Seasonal (kWh)					
		Demand			Generation									
		$P_{sc}$	$P_{pur}$	$BESS_{dis} \cdot \sqrt{\eta}$	$P_{sc}$	$P_{sold}$	$P_{gift}$	$BESS_{cha,sc} / \sqrt{\eta}$	$P_{sc}$	$P_{pur}$	$BESS_{dis} \cdot \sqrt{\eta}$	$P_{sold}$	$P_{gift}$	$BESS_{cha,sc} / \sqrt{\eta}$
Static	Spring	61.07	29.25	9.68	65.23	8.08	19.45	7.24	15,966	7,647	2,532	1,978	4,761	1,772
Static	Summer	63.73	28.76	7.51	89.15	3.11	0.00	7.73	21,053	9,501	2,482	735	0	1,826
Static	Autumn	55.06	28.71	16.23	55.35	31.76	5.52	7.37	10,313	5,377	3,041	5,918	1,029	1,374
Static	Winter	52.62	34.89	12.49	29.75	49.21	17.47	3.56	5,930	3,933	1,408	9,808	3,482	709
Variable	Spring	67.83	29.20	2.96	70.58	7.05	21.12	1.25	17,277	7,438	754	1,726	5,169	306
Variable	Summer	72.00	26.02	1.98	97.94	1.02	0.00	1.03	23,129	8,357	637	242	0	244
Variable	Autumn	58.18	29.70	12.12	56.50	32.67	5.56	5.28	10,527	5,373	2,192	6,087	1,036	983
Variable	Winter	62.09	36.72	1.18	32.81	45.93	21.20	0.05	6,539	3,867	124	9,154	4,226	10
Dynamic	Spring	68.15	28.82	1.38	–	27.24	72.76	0.00	17,113	7,238	346	1,893	5,056	0
Dynamic	Summer	71.48	26.01	1.15	–	100.00	0.00	0.00	23,009	8,371	372	168	0	0
Dynamic	Autumn	70.14	28.05	0.83	–	79.12	20.61	0.26	11,529	4,611	136	5,492	1,431	18
Dynamic	Winter	60.16	39.70	0.00	–	72.50	27.50	0.00	6,303	4,160	0	9,868	3,744	0

**Table 31:** Seasonal results with percentages and energy totals of the PV with BESS scenario, period-of-use tariff scheme applied.

Coefficient	Annual (%)							Annual (kWh)					
	Demand			Generation									
	$P_{sc}$	$P_{pur}$	$BESS_{dis} \cdot \sqrt{\eta}$	$P_{sc}$	$P_{sold}$	$P_{gift}$	$BESS_{cha,sc} / \sqrt{\eta}$	$P_{sc}$	$P_{pur}$	$BESS_{dis} \cdot \sqrt{\eta}$	$P_{sold}$	$P_{gift}$	$BESS_{cha,sc} / \sqrt{\eta}$
Static	59.72	29.67	10.61	61.47	21.28	10.70	6.56	53,262	26,457	9,462	18,438	9,272	5,681
Variable	66.66	29.04	4.30	66.32	19.86	12.04	1.78	57,472	25,036	3,709	17,209	10,430	1,543
Dynamic	68.81	28.95	1.01	–	62.96	36.97	0.07	57,954	24,379	854	17,421	10,231	18

**Table 32:** Annual results with percentages and energy totals of the PV with BESS scenario, period-of-use tariff scheme applied.

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Coef.	Season	Seasonal (%)							Seasonal (kWh)					
		Demand			Generation				$P_{sc}$	$P_{pur}$	$BESS_{dis} \cdot \sqrt{\eta}$	$P_{sold}$	$P_{gift}$	$BESS_{cha,sc} / \sqrt{\eta}$
		$P_{sc}$	$P_{pur}$	$BESS_{dis} \cdot \sqrt{\eta}$	$P_{sc}$	$P_{sold}$	$P_{gift}$	$BESS_{cha,sc} / \sqrt{\eta}$						
Static	Spring	49.51	42.68	7.81	52.91	20.51	22.61	3.97	12,950	11,165	2,043	5,020	5,535	972
Static	Summer	44.54	50.86	4.60	62.22	33.90	0.44	3.44	14,692	16,774	1,517	8,006	103	813
Static	Autumn	29.33	68.79	1.89	26.35	52.26	21.18	0.21	4,910	11,515	316	9,737	3,947	40
Static	Winter	21.99	78.01	0.00	11.32	46.37	42.31	0.00	2,256	8,002	0	9,241	8,432	0
Variable	Spring	50.75	43.02	6.23	53.40	20.48	22.84	3.28	13,070	11,078	1,605	5,014	5,590	803
Variable	Summer	47.05	49.52	3.43	65.21	32.13	0.34	2.32	15,400	16,208	1,122	7,586	80	548
Variable	Autumn	30.35	67.80	1.85	27.18	51.38	21.26	0.19	5,065	11,315	309	9,573	3,961	35
Variable	Winter	21.82	78.18	0.00	11.35	50.37	38.28	0.00	2,263	8,109	0	10,038	7,628	0
Dynamic	Spring	52.06	42.53	3.95	–	50.01	49.99	0.00	13,526	11,049	1,027	5,287	5,286	0
Dynamic	Summer	52.37	46.75	0.61	–	99.98	0.02	0.00	16,826	15,020	197	6,701	2	0
Dynamic	Autumn	46.72	53.24	0.00	–	74.23	25.77	0.00	7,626	8,690	0	8,167	2,835	0
Dynamic	Winter	32.16	67.71	0.00	–	49.22	50.71	0.07	3,296	6,940	0	8,180	8,428	11

**Table 33:** Seasonal results with percentages and energy totals of the PV with BESS scenario, indexed tariff scheme applied.

Coefficient	Annual (%)							Annual (kWh)					
	Demand			Generation				$P_{sc}$	$P_{pur}$	$BESS_{dis} \cdot \sqrt{\eta}$	$P_{sold}$	$P_{gift}$	$BESS_{cha,sc} / \sqrt{\eta}$
	$P_{sc}$	$P_{pur}$	$BESS_{dis} \cdot \sqrt{\eta}$	$P_{sc}$	$P_{sold}$	$P_{gift}$	$BESS_{cha,sc} / \sqrt{\eta}$						
Static	40.41	55.09	4.50	40.17	36.93	20.79	2.11	34,809	47,457	3,876	32,004	18,016	1,825
Variable	41.85	54.60	3.55	41.31	37.17	19.92	1.60	35,798	46,709	3,035	32,211	17,259	1,386
Dynamic	48.74	49.24	1.45	–	63.11	36.86	0.02	41,274	41,700	1,225	28,335	16,550	11

**Table 34:** Annual results with percentages and energy totals of the PV with BESS scenario, indexed tariff scheme applied.

### 5.3.4 Billing and savings of the EC

For this particular scenario, the optimised results corresponding to the tariffs under the three allocation coefficient settings are presented in Tables 35–37. These tables report both the energy and power components (excluding taxes) and the total invoice, which incorporates the 5.11269 % electricity tax. The percentage savings relative to the base “Subtotal excl. taxes” configuration are summarised in Tables 38–40.

A joint analysis of these results confirms a trend already observed in the previous case: the Indexed tariff continues to deliver the highest economic benefit. This behaviour is largely explained by the intrinsic compatibility between indexed pricing and a flexible demand structure. When the load can be shifted in time, the optimization can selectively concentrate consumption during low-price hours, exploiting the temporal variability that characterizes indexed tariffs far more effectively than fixed or period-based price structures. The coefficient setting further influences the extent of the achievable savings. While both static and variable coefficients already reduce costs relative to the base case,

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dynamic coefficients consistently lead to the lowest expenditure. Their adaptive nature allows the model to track changes in consumption patterns more precisely, enabling a more efficient distribution of energy among the loads and enhancing the overall performance of the optimization.

In this scenario, the presence of both the PV system and the BESS strengthens these effects. The photovoltaic generation provides inexpensive local energy during daylight hours, reducing reliance on grid imports, while the battery system introduces temporal decoupling between production and consumption. The BESS smooths the demand profile by storing energy during low-price or high-PV-production periods and releasing it when prices rise or local generation declines. This synergy expands the optimization space and enables deeper cost reductions compared to the base case, yielding savings that are even more significant than in the previous configuration without storage support.

<b>Tariff</b>	<b>Load 1</b>	<b>Load 2</b>	<b>Load 3</b>	<b>Total excl. taxes</b>	<b>TOTAL</b>
<b>Fixed</b>	1029.11	1817.12	2283.09	5129.32	5391.57
<b>Period</b>	963.88	1676.50	2151.91	4792.29	5037.31
<b>Indexed</b>	776.81	973.13	1012.32	2762.26	2903.49

**Table 35:** Electricity bill by tariff for the scenario with PV system and BESS with static coefficients (electricity tax assumed at 5.11269%).

<b>Tariff</b>	<b>Load 1</b>	<b>Load 2</b>	<b>Load 3</b>	<b>Total excl. taxes</b>	<b>TOTAL</b>
<b>Fixed</b>	1025.02	2241.44	1713.96	4980.42	5235.06
<b>Period</b>	976.02	2074.44	1615.35	4665.82	4904.37
<b>Indexed</b>	775.76	981.25	1002.75	2759.76	2900.86

**Table 36:** Electricity bill by tariff for the scenario with PV system and BESS with variable coefficients (electricity tax assumed at 5.11269%).

<b>Tariff</b>	<b>Load 1</b>	<b>Load 2</b>	<b>Load 3</b>	<b>Total excl. taxes</b>	<b>TOTAL</b>
<b>Fixed</b>	1303.04	2113.95	1541.77	4958.75	5212.28
<b>Period</b>	1248.54	1899.13	1496.66	4644.33	4881.78
<b>Indexed</b>	758.20	977.59	1019.58	2755.37	2896.24

**Table 37:** Electricity bill by tariff for the scenario with PV system and BESS with dynamic coefficients (electricity tax assumed at 5.11269%).

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Tariff	Load 1	Load 2	Load 3	Total
<b>Fixed</b>	77.44%	73.31%	50.64%	67.93%
<b>Period</b>	79.51%	76.02%	55.49%	71.01%
<b>Indexed</b>	73.60%	78.42%	67.84%	73.94%

**Table 38:** Percentage savings vs. base “Subtotal excl. taxes” — PV with BESS, static coefficients.

Tariff	Load 1	Load 2	Load 3	Total
<b>Fixed</b>	77.53%	67.08%	62.94%	68.87%
<b>Period</b>	79.25%	70.33%	66.59%	71.78%
<b>Indexed</b>	73.64%	78.24%	68.15%	73.96%

**Table 39:** Percentage savings vs. base “Subtotal excl. taxes” — PV with BESS, variable coefficients.

Tariff	Load 1	Load 2	Load 3	Total
<b>Fixed</b>	71.44%	68.95%	66.67%	69.00%
<b>Period</b>	73.46%	72.84%	69.04%	71.91%
<b>Indexed</b>	74.23%	78.32%	67.61%	74.01%

**Table 40:** Percentage savings vs. base “Subtotal excl. taxes” — PV with BESS, dynamic coefficients.

Overall, when all these elements are combined—flexible demand, dynamic allocation coefficients, photovoltaic generation and battery storage—the most advantageous configuration for the EC is clearly the indexed tariff paired with dynamic coefficients, which provides the lowest total costs and maximizes the economic benefit across all scenarios evaluated.

### 5.3.5 NPV and IRR analysis

Building on the analysis carried out for the photovoltaic-only configuration, the economic assessment is now extended to the scenario in which battery storage is also deployed. As discussed previously, photovoltaic generation alone already enables a substantial reduction in electricity purchases from the grid; however, the addition of storage further enhances self-consumption by shifting surplus energy to hours of higher demand. This leads to deeper bill savings, though a portion of grid supply remains necessary during periods of low generation or when the battery is depleted. Tables 41, 42 and 43 present the resulting annual bill savings for each tariff option, together with the total investment cost, the allocation of investment shares to individual users, and the corresponding operation and

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maintenance expenses. The tables also report the NPV, IRR and PB, thus providing a comprehensive overview of the long-term financial performance when storage is integrated in addition to photovoltaic generation.

<b>System-level</b>					
<b>Parameter</b>	<b>Unit</b>	<b>Static</b>	<b>Variable</b>	<b>Dynamic</b>	
Annual Savings	€	10,867	11,016	11,038	
System Initial Investment	€	73,800	73,800	73,800	
BESS Total Investment	€	25,548	18,800	18,800	
BESS Residual	€	4,187	3,215	4,927	
BESS Lifetime	years	20	59	222	
O&M	€	1,476	1,476	1,476	
NPV	€	52,768	61,651	62,487	
IRR	%	12	12	12	
Payback Period	years	8	8	8	

<b>Load-level</b>					
<b>Parameter</b>	<b>Unit</b>	<b>Load</b>	<b>Static</b>	<b>Variable</b>	<b>Dynamic</b>
O&M	€	Load 1	578	528	431
		Load 2	732	556	646
		Load 3	166	391	399
NPV	€	Load 1	10,486	16,335	18,748
		Load 2	20,564	29,096	25,439
		Load 3	21,718	16,221	18,300
IRR	%	Load 1	9	10	12
		Load 2	10	14	12
		Load 3	26	12	13

**Table 41:** Economic indicators for the fixed-rate tariff with battery storage under different allocation coefficients.

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<b>System-level</b>						
<b>Parameter</b>	<b>Unit</b>	<b>Static</b>	<b>Variable</b>	<b>Dynamic</b>		
Annual Savings	€	11,740	11,866	11,888		
System Initial Investment	€	73,800	73,800	73,800		
BESS Total Investment	€	24,921	18,800	18,800		
BESS Residual	€	4,783	3,030	4,973		
BESS Lifetime	years	22	55	240		
O&M	€	1,476	1,476	1,476		
NPV	€	65,912	73,578	74,484		
IRR	%	13	14	14		
Payback Period	years	7	7	7		

<b>Load-level</b>						
<b>Parameter</b>	<b>Unit</b>	<b>Load</b>	<b>Static</b>	<b>Variable</b>	<b>Dynamic</b>	
O&M	€	Load 1	581	543	431	
		Load 2	728	554	654	
		Load 3	167	379	392	
NPV	€	Load 1	13,547	18,072	21,564	
		Load 2	25,802	34,162	30,580	
		Load 3	26,563	21,345	22,340	
IRR	%	Load 1	9	11	14	
		Load 2	12	15	13	
		Load 3	30	15	15	

**Table 42:** Economic indicators for the period-of-use tariff with battery storage under different allocation coefficients.

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System-level					
Parameter	Unit	Static	Variable	Dynamic	
Annual Savings	€	7,838	7,840	7,845	
System Initial Investment	€	73,800	73,800	73,800	
BESS Total Investment	€	18,800	18,800	18,800	
BESS Residual	€	2,938	3,493	4,719	
BESS Lifetime	years	53	67	167	
O&M	€	1,476	1,476	1,476	
NPV	€	16,774	16,982	17,424	
IRR	%	7	7	7	
Payback Period	years	12	12	12	

Load-level					
Parameter	Unit	Load	Static	Variable	Dynamic
O&M	€	Load 1	427	485	467
		Load 2	624	620	726
		Load 3	425	371	283
NPV	€	Load 1	3,396	-182	1,308
		Load 2	10,231	10,435	3,965
		Load 3	3,147	6,729	12,150
IRR	%	Load 1	7	5	6
		Load 2	8	8	6
		Load 3	6	8	12

**Table 43:** Economic indicators for the indexed tariff with battery storage under different allocation coefficients.

Regarding annual savings, the same considerations observed in the PV-only scenario apply here. Across all tariff structures, the dynamic allocation coefficient generally yields slightly higher annual savings and NPV compared with the static and variable methods, although the differences remain moderate. The BESS lifetime varies considerably between methods, especially under dynamic allocation coefficients, reflecting different usage intensity of the battery. Compared to the previous PV-only scenario, adding the BESS results in lower NPVs and slightly longer payback periods, indicating a decline in financial performance. This suggests that, under current tariffs and cycling behaviour, the battery does not increase profitability and may in fact reduce the economic advantage provided by PV alone.

## 6 Discussion of results

This section presents a comprehensive discussion of the results obtained in the previous chapter with the aim of evaluating the overall effectiveness of the proposed methodology. The discussion is organized to directly address each of the specific objectives defined for the study, as specified in section "Objective of the project" 1.3. Building on this foundation, the system's flexibility is the central element that connects all the evaluated scenarios with different tariff structures and allocation coefficients. Therefore, the discussion aims to explore how the proposed configurations leverage demand-side flexibility and the coupling of renewable systems such as photovoltaic generation with battery energy storage systems to improve self-consumption and optimise community performance. The comparative analysis of these scenarios allows for the identification of meaningful insights regarding the technical, economic and operational feasibility of the energy community.

### 6.1 Evaluation of demand-flexibility effects on system performance

Demand-side flexibility ultimately allows the system analysed in this work to achieve its highest operational and economic performance. In particular, even when applied as the sole optimisation measure, without the integration of PV generation or BESS, the system achieves a 45% reduction in annual energy costs compared to the original non-flexible configuration. Demand-side flexibility represents one of the key elements that make this project both functional and effective. The first analysed scenario already differs substantially from the original base case because of the introduction of a flexible demand profile. This capability allows irrigation loads to be shifted to more favorable tariff periods, reducing costs without modifying either the infrastructure or the total energy consumption. The results further confirm that even this initial layer of flexibility produces notable improvements across all performance dimensions, primarily by synchronizing irrigation activities with the lowest-cost time slots defined by the tariff structure (Table 44). Such behaviour highlights how operational adaptability alone can generate immediate economic benefits and therefore forms the focus of the following discussion.

Scenario	Billing [€/yr]			
	Load 1	Load 2	Load 3	Total
Original	2942.52	4509.58	3147.86	10599.96
Optimised Flexible Irrigation	1503.98	2596.24	1693.93	5794.14

**Table 44:** Comparison between original and optimised flexible irrigation billing, taxes included. Best case analysis: indexed tariff.

In the scenarios incorporating photovoltaic generation (Table 45) and battery energy storage (Table 46), the role of flexibility becomes even more strategic. When the load is allowed to adjust dynamically, the system can coordinate consumption, production and storage in a far more efficient manner. In concrete terms, flexible demand not only increases self-consumption of PV energy but also reduces battery cycling during unfavorable periods, thereby enhancing the effective lifetime of the

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storage system. This coordinated behaviour enables the system to exploit renewable generation peaks, minimise peak-tariff purchases and operate the BESS only when economically justified. Flexibility, therefore, emerges as the mechanism that “unlocks” the interaction between generation and storage, ensuring that both resources are used in a way that maximizes their economic value.

Scenario	Billing [€/yr]			
	Load 1	Load 2	Load 3	Total
Original	2942.52	4509.58	3147.86	10599.96
Optimised Flexible Irrigation (PV only)	771.45	986.96	1014.98	2773.39

**Table 45:** Comparison between original and optimised flexible irrigation with PV system, taxes included. Best case: indexed tariff with dynamic coefficients.

Scenario	Billing [€/yr]			
	Load 1	Load 2	Load 3	Total
Original	2942.52	4509.58	3147.86	10599.96
Optimised Flexible Irrigation (PV + BESS)	758.20	977.59	1019.58	2755.37

**Table 46:** Comparison between original and optimised flexible irrigation with PV and BESS billing, taxes included. Best case: indexed tariff with dynamic coefficients.

In the present work, the role of demand flexibility has been extensively discussed, particularly with regard to its capacity to shift, reshape or temporarily reduce consumption profiles in response to price signals and operational constraints. As demonstrated in the previous chapter, flexibility consistently allows the system to achieve optimal performance under a wide range of configurations. Its broader relevance becomes even clearer when compared to typical performance levels reported in the literature, where the absence of flexible demand generally constrains the achievable cost reductions. A systematic examination of this wide-ranging topic has shown, for instance, that large-scale analyses of solar–battery systems for U.S. households indicate that average savings under net-billing schemes typically remain within the 14–15% range (Sun et al., 2025). Likewise, studies focused on optimizing energy community costs through tariff clustering or consumer grouping methods seldom exceed 10–15% savings, particularly when load profiles are assumed to be fixed and non-responsive, as in the tariff-clustering framework proposed by Lezama *et al.* (Lezama et al., 2024). These studies belong to a broader category of optimization models that primarily rely on tariff structures, community aggregation or generation scheduling rather than demand adaptation, which inherently limits the achievable economic benefits. In comparison to these benchmarks, the 45% reduction in annual energy costs achieved through demand flexibility alone, without the contribution of PV generation or battery storage, substantially exceeds the values typically reported for non-flexible energy communities. Moreover, when demand flexibility is integrated with additional energy technologies—such as on-site PV generation and distributed storage—the potential savings can even double, as evidenced by the results obtained in this study and reported in sections 5.2.4 and 5.3.4. This finding confirms that flexibility is not merely an additional refinement but rather a transformative

capability that significantly enhances the economic value of any generation or storage asset installed in the system.

Overall, flexible demand is what ultimately allows the system to achieve its highest operational and economic performance. By enabling consumption patterns to dynamically adapt to tariff structures and on-site renewable availability, flexibility unlocks a level of efficiency that surpasses the cost-reduction limits commonly found in the literature, positioning it as a central component for the design of future economically optimised energy communities.

## **6.2 Understanding the opportunity cost of EC consumption: self-consuming vs. selling electricity**

One of the most notable findings emerging from the results analysis of both energy community configurations—namely, the PV-only system and the PV system coupled with battery energy storage—is that, contrary to intuitive expectations, the optimization model frequently schedules irrigation demand not solely during photovoltaic generation hours, but also across other periods of the day, including nighttime, early morning and, in certain configurations, even evening hours. At first glance, this behavior may appear counterintuitive, as fully aligning irrigation demand with PV production would intuitively seem to represent the most economically advantageous operational strategy. Nevertheless, a more in-depth examination indicates that this outcome arises from the interaction of three key elements within the optimization framework, with the concept of *opportunity cost* playing a central and unifying role in shaping the optimal schedules.

### **6.2.1 Introducing opportunity cost through a case study: definition, interpretation and implications**

#### **Case Study presentation**

The solver's decision to optimise the demand profile in such a way that the load is scheduled to operate during nighttime hours is fundamentally driven by the primary economic objective of the optimization framework, namely the minimization of total electricity costs over the scheduling horizon. Under the prevailing tariff conditions and system constraints considered in the model, this configuration emerges as the most cost-effective operational alternative available, as will be analytically demonstrated and quantitatively supported in the following paragraph.

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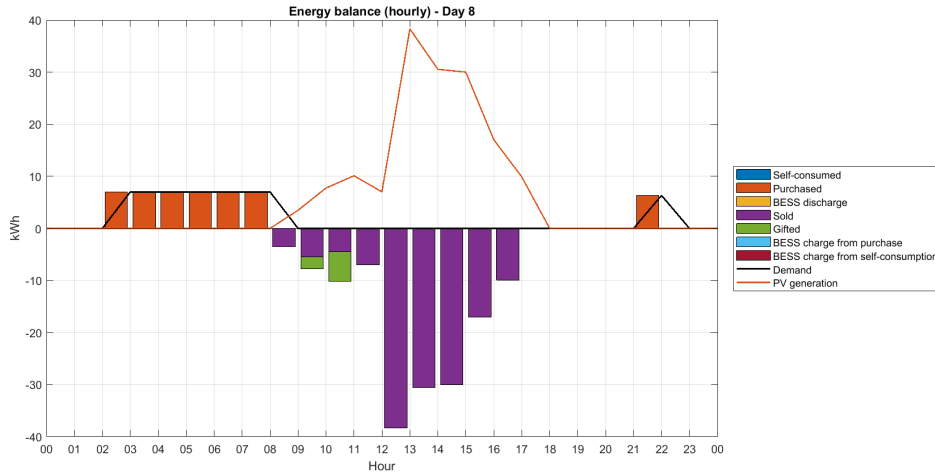


Figure 37: Energy balance on the 8<sup>th</sup> of January 2024 showing the unutilised PV generation between.

Figure 37 presents as an illustrative example the energy balance observed on the 8<sup>th</sup> of January 2024 for the simulated energy community configuration characterized by on-site PV generation and a fixed-rate electricity tariff and static allocation coefficients. As shown in the figure, photovoltaic production is not directly exploited to satisfy the irrigation demand which is instead supplied predominantly during nighttime and early morning hours through electricity purchased from the grid. While this operational pattern may initially appear counterintuitive particularly in light of the availability of on-site renewable generation it reflects the optimization model's ability to identify scheduling choices that minimise overall economic trade-offs under the applied tariff structure and system constraints. The underlying rationale behind this outcome is examined in detail through a formal mathematical analysis in the following section.

More specifically, in the current optimised scenario, between 02:00 and 03:00 a.m., the second load purchases a power  $P_{pur}$  at a buying price  $PI_{pur}$ , resulting in a total expenditure of:

$$\text{Cost}_{pur} = P_{pur} \cdot \Pi_{pur} = 7 \text{ kWh} \cdot 0.144692 \text{ €/kWh} = 1.012844 \text{ €} \quad (34)$$

During the PV generation hour (10:00–11:00 a.m.), the income from selling energy is computed as:

$$\text{Cost}_{sell} = P_{sell} \cdot \Pi_{sell} = 4.447096 \text{ kWh} \cdot 0.10899 \text{ €/kWh} = 0.484689 \text{ €} \quad (35)$$

The total cost in this case can thus be expressed as:

$$\text{Cost}_{opt} = P_{pur} \cdot \Pi_{pur} - P_{sold} \cdot \Pi_{sell} = 0.528154 \text{ €} \quad (36)$$

If, alternatively, the demand was shifted to the PV generation hour (10:00–11:00 a.m.), exploiting the available solar power, the cost components would change as follows:

- The purchased power would be reduced by the amount self-consumed by the second load (*pump 2*), that is:

$$P_{pur} - P_{sc,2} = 7 \text{ kWh} - 1.956246 \text{ kWh} = 5.043754 \text{ kWh} \quad (37)$$

purchased at the corresponding daytime price  $PI_{\text{pur}} = 0.190943 \text{ €/kWh}$ .

- The sold power would decrease accordingly:

$$P_{\text{sold}} - P_{\text{sold},2} = 4.447097 \text{ kWh} - 1.956246 \text{ kWh} = 2.490851 \text{ kWh} \quad (38)$$

with a selling price of  $PI_{\text{sell}} = 0.10899 \text{ €/kWh}$ .

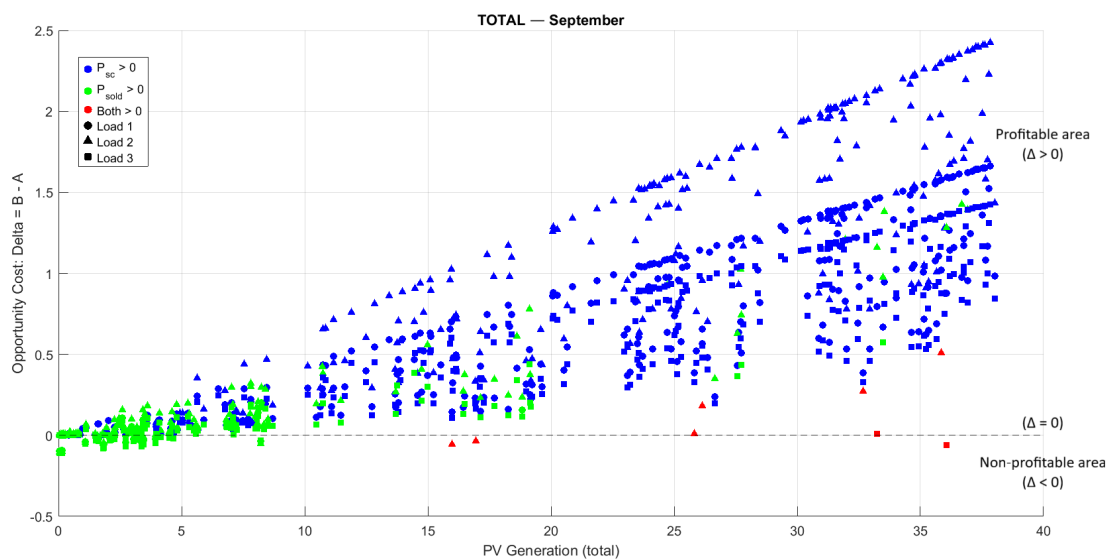
- The resulting cost would therefore be:

$$\text{Cost}_{\text{alt}} = (P_{\text{pur}} - P_{\text{sc},2}) \cdot PI_{\text{pur}} - (P_{\text{sold}} - P_{\text{sold},2}) \cdot PI_{\text{sell}} = 0.691592 \text{ €} \quad (39)$$

This value exceeds the cost obtained by the solver under the optimised configuration, thereby indicating that shifting a portion of the demand toward daytime hours—even in the presence of available PV generation—is not economically advantageous within the given tariff structure and prevailing price signals. Beyond the sole comparison between electricity purchase and sale prices, this outcome is strongly influenced by the minimum power requirement needed to activate the irrigation pumps. In particular, each pump requires a minimum operating power equal to one third of its rated power in order to be switched on. When the instantaneous PV production is insufficient to meet this threshold, the remaining power must be supplied by the grid. As a result, the pump operation is partially supported by grid electricity during daytime hours, which often coincide with higher purchase tariffs. Under these conditions, the economic benefit of utilizing PV generation is offset by the costly grid contribution required to reach the minimum activation power, making such demand shifting suboptimal from a cost-minimization perspective.

### Definition and interpretation

The following paragraph clarifies this behaviour by focusing on the formal definition and implications of the concept of opportunity cost.



**Figure 38:** Opportunity cost trend of the EC for the month of September.

To conduct this analysis, the *opportunity cost* parameter ( $\Delta = B - A$ ) is introduced as a quantitative economic indicator designed to evaluate, for each hour and for each individual load, the relative convenience between self-consumption of locally generated energy and its potential sale to the electricity grid. This value provides a systematic measure of the economic trade-off associated with allocating photovoltaic production to alternative uses within the energy community framework. In practical terms, the opportunity cost captures the economic trade-off involved in deciding whether a given unit of PV-generated electricity should be used locally to satisfy demand or exported to the grid, thereby indicating which option delivers the greater economic benefit under the prevailing tariff structure and market conditions. When the opportunity cost takes on positive values, self-consumption is economically preferable because the saving obtained by avoiding the purchase of energy from the grid is greater than the revenue that would be obtained by selling; on the contrary, negative values indicate that selling is more convenient or that there is no real benefit in retaining the energy for internal use. When the value approaches zero, both options produce similar economic effects, and the optimiser therefore tends to divide the generation between self-consumption and sale. From this perspective, the opportunity cost provides a direct quantitative interpretation of how demand flexibility is exploited within the system. It explicitly reveals whether flexibility is used to increase self-consumption, to enable profitable energy export, or to balance the two strategies when their economic outcomes are comparable. In doing so, it establishes a clear link between how photovoltaic generation is allocated and how consumption is shifted in time, thereby clarifying the role of flexibility as an economically driven coordination mechanism between generation and demand. To demonstrate this, for each hour with available photovoltaic generation, two quantities were calculated:  $A$ , which represents the actual cost of the chosen strategy, and  $B$ , which corresponds to the theoretical cost in the case where all the energy was managed at the weekly minimum purchase price of electricity. The difference between these two quantities,  $\Delta = B - A$ , makes it possible to quantify the economic efficiency of the hourly decision.

The formulas used for the calculation of the opportunity cost are reported below (Eq.40 and 41) and describe the formulations of the terms  $A$  and  $B$  under the different operating conditions of the system.

$$A = \begin{cases} P_{\text{pur}} \cdot \Pi^{\text{PUR}} + P_{\text{sc}} \cdot \Pi^{\text{SELL}}, & \text{if } P_{\text{sc}} > 0, \\ (P_{\text{min}} - P_{\text{sell}}) \cdot \Pi^{\text{PUR}} + P_{\text{sell}} \cdot \Pi^{\text{SELL}}, & \text{if } P_{\text{sc}} = 0 \text{ and } 0 < P_{\text{sell}} < P_{\text{min}}, \\ P_{\text{sell}} \cdot \Pi^{\text{SELL}}, & \text{if } P_{\text{sc}} = 0 \text{ and } P_{\text{sell}} \geq P_{\text{min}}. \end{cases} \quad (40)$$

Similarly, the term  $B$  is defined as

$$B = \begin{cases} (P_{\text{sc}} + P_{\text{pur}}) \cdot \Pi^{\text{MIN\_PUR}}, & \text{if } P_{\text{sc}} > 0, \\ P^{\text{min}} \cdot \Pi^{\text{MIN\_PUR}}, & \text{if } P_{\text{sc}} = 0 \text{ and } 0 < P_{\text{sell}} < P_{\text{min}}, \\ P^{\text{sell}} \cdot \Pi^{\text{MIN\_PUR}}, & \text{if } P_{\text{sc}} = 0 \text{ and } P_{\text{sell}} \geq P_{\text{min}}. \end{cases} \quad (41)$$

If at a given moment the self-consumed power ( $P_{\text{sc}}$ ) is positive,  $A$  and  $B$  are calculated based on the

purchase and selling price of electricity in that tariff period; if instead the sold power ( $P_{sold}$ ) is positive, the formulation varies depending on whether the amount sold exceeds or not a minimum threshold, that is, the minimum power required to start each pump ( $P_{min}$ ). In the case where both powers are positive, the system combines the two formulas, reflecting a situation in which the generation fully covers the demand and also produces a surplus.

In the above figure (Figure 38), the x-axis shows the allocated photovoltaic generation, while the y-axis represents the opportunity cost  $\Delta$ . The blue points represent the hours in which self-consumption occurs ( $P_{sc} > 0$ ), the green ones the hours of sale ( $P_{sold} > 0$ ), and the red ones the moments in which both conditions occur simultaneously ( $P_{sc} > 0$  and  $P_{sold} > 0$ ). This total plot displays the behavior of all three loads together: circles correspond to Load 1, triangles to Load 2, and squares to Load 3. To enhance the interpretation of the plot, three conceptual regions were added: a profitable area ( $\Delta > 0$ ), an indifferent area around  $\Delta \approx 0$ , and a non-profitable area ( $\Delta < 0$ ). These regions are delimited by subtle dashed reference lines. The distribution of the points highlights the dynamic behavior of the optimiser and the relationship between generation availability and economic convenience.

It can be observed that the green points are concentrated in the lower or slightly negative part of the graph, where generation is limited and selling proves to be more advantageous, or when the load demand is already covered and the residual energy is fed into the grid.

The blue points, on the other hand, form a clear upward diagonal: this represents the progressive increase in the economic benefit associated with self-consumption as the allocated generation grows. In other words, the more energy is destined for local consumption, the greater the saving on the purchase cost of electricity. The different loads show different slopes of this diagonal depending on the allocation coefficients: the loads with a higher coefficient reach higher maximum values of  $\Delta$ , since they can exploit the available generation to a greater extent.

The red points, which are mainly concentrated in the areas with high photovoltaic generation and  $\Delta$  values close to zero, indicate the hours in which the system has enough energy to meet the demand and simultaneously sell the surplus. In these cases, the economic difference between the two options is minimal, and the optimiser tends to divide the generation between self-consumption and sale in order to maintain the system balance and respect possible net billing constraints.

It is interesting to note that in the lower (negative) part of the graph no blue points appear, which indicates that self-consumption is not chosen when its economic value is lower than that of selling.

Another relevant aspect is that, in an annual representation, six “starting levels” for the green points would appear, corresponding to the six tariff periods defined by the pricing system. However, in the monthly graph shown above, only three are visible, since in each month only three tariff bands alternate. This reflects how the model integrates seasonal and tariff variability in the optimization process, adapting the self-consumption and sale strategy to the economic and generation conditions of the period considered.

## Implications

Overall, the joint analysis of opportunity cost, system constraints and solver behaviour reveals that demand flexibility is exploited in a structured and economically consistent manner. Consumption is systematically shifted toward the hours that yield the greatest economic benefit, while photovoltaic generation is allocated to the most favourable use by balancing self-consumption and electricity export whenever their economic outcomes are comparable. Scheduling patterns that may initially appear as unexpected peaks or counterintuitive operating choices are therefore not arbitrary but instead reflect a coherent economic rationale, driven by the minimization of opportunity cost under realistic tariff structures and operational constraints.

### 6.2.2 Effects of the net balance constraint and other influencing factors

As discussed in section "*Mathematical formulation of the Julia optimization model*" (Section 3.2), several constraints define the feasible solution space of the optimization problem. Of particular interest here is the net balance constraint, which for each of the twelve months of the year requires that the total monthly revenue from energy sold to the grid cannot exceed the total cost of purchasing electricity, according to the following condition:

$$P_{pur} \cdot PI_{pur} \geq P_{sold} \cdot PI_{sell}$$

where  $P_{pur}$  and  $P_{sold}$  represent the power purchased from and sold to the grid, and  $PI_{pur}$  and  $PI_{sell}$  are their respective hourly prices as defined by the applied tariff.

From an algorithmic perspective, when the optimization reaches a condition where the net balance equals zero—that is, both sides of the inequality are equal—the solver no longer prioritizes *how* this equilibrium is achieved, but only that it *is* achieved. In other words, the optimization engine treats all combinations of purchase and sale operations that satisfy this constraint as equally valid. This means that if the model finds an opportunity to buy electricity at a favorable price during one period and sell it later at a similarly favorable price outside of PV generation hours, this solution can be considered as profitable as directly consuming photovoltaic energy for irrigation. Consequently, the solver might prefer to allocate part of the irrigation demand outside daylight hours, since this still fulfills the economic equilibrium imposed by the constraint while potentially offering marginal gains under specific tariff conditions. Such behavior reflects the model's logic of satisfying economic parity rather than strictly prioritizing self-consumption. It is important to emphasize that, in this work, multiple scenarios considering different combinations of tariffs and allocation coefficients during the winter months satisfy the net balance condition.

An additional factor contributing to the non-intuitive shape of the optimised demand curve concerns the influence of the *mip gap* in the optimization process. In MILP problems, the presence of binary variables—in this case, the pump state variables  $\gamma_{j,t}$ —significantly increases the computational burden. To reduce computation time, solvers allow the introduction of a tolerance parameter, called the *mip gap*, which defines the maximum acceptable percentage difference between the best feasible solution found and the lower bound of the theoretical optimum. When the relative difference between the current objective value and the best bound becomes smaller than the predefined *mip gap*, the

algorithm stops and the solution is considered “optimal” within that tolerance threshold.

However, setting a non-negligible mip gap may introduce noticeable inaccuracies in the solution, especially in models that are sensitive to discrete decisions, such as those determining the on/off operation periods of the irrigation pump. In such cases, the solver may terminate before identifying the truly optimal combination of binary variables, thereby generating sub-optimal operating patterns that manifest as load distributions not fully consistent with the expected economic or energetic logic.

In the specific context of this analysis, this effect can explain the occurrence of unexpected demand peaks during hours not coinciding with photovoltaic production: the obtained solution satisfies the optimality conditions within the imposed mip gap threshold, but it may not represent the true global minimum of the operational cost or overall objective function. Nevertheless, in this study, the mip gap value was kept sufficiently low to ensure that the resulting deviation remains negligible and does not compromise the overall validity of the optimization outcomes or the consistency of the optimised demand behavior.

### **6.3 Economic viability of battery storage**

This section now aims to discuss the economic viability and strategic relevance of battery energy storage systems use in energy communities, specifically agricultural ones, based on a comparative analysis of the EC configurations with photovoltaic generation only and with photovoltaic generation coupled with battery storage. The discussion is framed within the broader objective of understanding *whether*, and *under which* conditions, battery storage effectively contributes to system flexibility, economic performance and overall robustness when demand-side flexibility is already available. Rather than focusing on individual loads, the analysis adopts a comprehensive-system perspective, which is more appropriate for evaluating investment decisions and long-term planning strategies in energy communities.

#### **6.3.1 System-level economic performance comparison between PV and PV with BESS configurations**

From an economic perspective, the comparison between the PV-only and PV with BESS configurations reveals a clear and consistent pattern. While the integration of battery storage leads to a modest increase in annual savings, this improvement is relatively small when compared to the substantial increase in total investment and operational costs associated with the BESS. Specifically, the total system investment rises significantly with the introduction of storage, while operation and maintenance costs also increase due to battery-related degradation and management requirements. This imbalance is directly reflected in the key financial indicators previously presented in Tables 24, 25 and 26, as well as in Tables 41, 42 and 43 in the "Results" chapter. The most significant parameters for the indexed tariff scenario are summarized in Table 47 below.

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Parameter	Unit	PV only			PV + BESS			$\Delta$		
		Static	Variable	Dynamic	Static	Variable	Dynamic	Static	Variable	Dynamic
NPV	€	38623	39220	39806	16774	16982	17424	21848	22238	22382
IRR	%	11.23	11.32	11.41	7.14	7.16	7.2	4.10	4.17	4.21
PB	years	8.28	8.23	8.18	11.60	11.60	11.59	3.32	3.37	3.41

**Table 47:** Comparison of NPV, IRR and PB indicators for the indexed tariff under PV-only and PV with BESS configurations, with corresponding corresponding absolute differences.

The PV-only configuration achieves substantially higher values of NPV and IRR, together with shorter payback periods, across all allocation strategies. By contrast, the PV system coupled with battery storage exhibits markedly lower NPVs, reduced IRRs, and more extended payback periods, indicating a deterioration of overall economic performance at the system level. Importantly, this outcome is consistently confirmed by the corresponding load-level indicators, which show that the economic advantages associated with battery integration remain limited or unevenly distributed among individual loads. Among the different allocation schemes, the variable coefficient configuration exhibits the smallest NPV reduction when moving from the PV-only to the PV with BESS case, mitigating the economic impact of battery integration. Such coefficients are better able to absorb the additional investment and operational costs associated with the BESS, thereby narrowing the economic gap between the two configurations. These results collectively suggest that, under the analysed conditions, the additional revenues enabled by battery storage are insufficient to compensate for its capital and operational costs.

This outcome does not imply that the battery fails to perform its intended technical function. On the contrary, the BESS does contribute to absorbing excess photovoltaic generation, smoothing power exchanges with the grid and enabling additional operational degrees of freedom. However, from a system-level economic standpoint, these benefits remain marginal when compared to the performance already attainable through an optimised and flexible demand profile. In other words, the battery improves operational behavior but does not translate that improvement into proportional financial gains.

This finding is particularly relevant in the analysed energy community, where irrigation loads are inherently suitable for temporal shifting. The ability to adapt consumption schedules directly in response to tariff signals allows the system to capture most of the value of photovoltaic generation without relying on electrochemical storage. As a result, the economic role of the battery is diminished, and its contribution becomes secondary rather than decisive in determining system profitability.

### 6.3.2 Battery storage as a flexibility provider

The system-level results highlight a fundamental insight regarding the relationship between battery storage and demand-side flexibility: both serve as mechanisms for providing flexibility, and their economic value depends on whether they complement or substitute each other. In energy communities

characterized by rigid and inflexible demand, the battery plays a crucial role by compensating for the inability of loads to adapt to generation availability or tariff variability. In such cases, the BESS acts as the primary flexibility resource, enabling energy shifting in time and making renewable integration economically viable. In the present work, however, demand flexibility is already embedded within the system and can be fully exploited by the optimization framework. Flexible consumption allows the system to respond directly to price signals, shift loads toward economically favorable periods by coordinating energy use with both generation availability and tariff structures. Under these conditions, the battery no longer provides a unique source of flexibility, but rather overlaps with capabilities that are already present at the demand level.

From this perspective, battery storage can be interpreted as a bridging asset, whose primary function is to connect inflexible generation with inflexible consumption. When neither side of the system is capable of adapting, the battery becomes the central element enabling flexibility and economic optimization. Conversely, when either generation or demand is already flexible, the marginal value of storage decreases significantly. In a system where demand adaptation effectively aligns consumption with economic and operational objectives, the battery contributes only limited additional flexibility, which is not sufficient to justify its cost.

This key and somewhat unexpected interpretation explains why, despite its technical advantages, the BESS does not emerge as an economically attractive investment at the system level in the analysed scenarios. The flexibility required to optimise system operation is already provided by demand-side mechanisms, and the battery therefore does not unlock new value streams but merely refines existing ones. As a consequence, the system achieves higher economic performance by prioritizing flexible demand over electrochemical storage.

Globally, this result directly supports the third project objective by demonstrating that the strategic role of the BESS lies not in universally enhancing flexibility, but in addressing specific flexibility gaps that cannot be efficiently resolved through demand adaptation alone.

#### **6.4 Interaction between tariff structures and PV power allocation coefficients**

The last main finding of this study concerns the interaction between the electricity tariff structure and the coefficients used for allocating the photovoltaic power among the different consumption points in the community. Different combinations of these two parameters led to distinct optimization outcomes, each influenced by the specific characteristics required to achieve the economic objective of the mathematical model. It is important to recall that each allocation coefficient represents the proportion of PV energy assigned to a participant and that the sum of all coefficients must equal one. Consequently, these coefficients determine how closely each consumption point is correlated with the PV generation profile, directly affecting the level of self-consumption that can be achieved and the extent to which each load can benefit from the available renewable energy.

The three tariff schemes analysed in this study exhibit different internal structures in terms of price variability, number of periods and spread between buying and selling prices, but they remain broadly comparable from an overall economic standpoint, as demonstrated in section 4.4. The hourly

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distribution of electricity buying and selling prices under each tariff is one of the main drivers of the model's optimization process. Depending on the tariff structure, the model selects different allocation strategies in order to minimise total electricity cost. It is therefore not possible to identify a single tariff scheme as universally optimal in a purely theoretical sense, since the best-performing option depends on the specific priorities and boundary conditions defined within each configuration.

From an economic perspective, however, a clear pattern emerges when focusing on electricity billing. When demand flexibility is applied without the support of photovoltaic generation or battery storage, the indexed tariff proves to be the most advantageous option in terms of annual electricity costs. The same conclusion holds true in the scenario that includes the PV system and the PV system combined with a BESS, where the indexed tariff remains the most cost-effective alternative across all allocation schemes. This behaviour becomes particularly evident when examining the heatmap of annual billing for the PV-only configuration (Figure 39), where each cell represents the combined effect of a given tariff scheme and a given allocation strategy. Under identical allocation coefficients, the indexed tariff systematically yields lower billing values than the fixed-rate or period-of-use tariffs, highlighting the economic benefit associated with a more flexible price structure.

Coefficient \ Tariff	Fixed	Period	Indexed
<b>Static</b>	5,706.73 €	5,310.12 €	3,003.43 €
<b>Variable</b>	5,533.13 €	5,222.32 €	2,958.90 €
<b>Dynamic</b>	5,217.05 €	4,886.38 €	2,915.18 €

**Figure 39:** Heatmap of annual electricity billing for the PV-only configuration under indexed tariff with different allocation coefficients.

A similar trend is also observed in the combined PV with BESS configuration, where the indexed tariff again provides the lowest overall costs. The corresponding heatmap for this scenario (Figure 40) confirms that, for the same allocation coefficients, the most flexible tariff structure consistently leads to the most favourable economic outcome. In other words, when the tariff itself is highly responsive to market conditions, the optimisation model can better adapt the operation of the system to the underlying price signals, thereby extracting additional value from both generation and flexibility. This reinforces the idea that flexibility should not be understood solely in terms of demand behaviour, but also as a property of the economic environment in which the system operates.

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<b>Electricity Billing</b>			
<b>Tariff Coefficient</b>	<b>Fixed</b>	<b>Period</b>	<b>Indexed</b>
<b>Static</b>	5,391.57 €	5,037.31 €	2,903.49 €
<b>Variable</b>	5,235.06 €	4,904.37 €	2,900.86 €
<b>Dynamic</b>	5,212.28 €	4,881.78 €	2,896.24 €

**Figure 40:** Heatmap of annual electricity billing for the PV with BESS configuration under indexed tariff with different allocation coefficients.

Within this framework, the role of the allocation coefficients becomes particularly important. These coefficients define how photovoltaic generation is virtually partitioned among the different consumption points and, as such, they determine how closely each load is linked to the PV production profile and to the associated economic opportunities. When the tariff structure is rigid, allocation choices can only partially compensate for the lack of price variability; however, when the tariff is indexed and therefore highly flexible, the allocation scheme has a much stronger impact on system performance. The results show that, under the indexed tariff, dynamic coefficients consistently provide the best economic outcomes. By allowing the share of PV power assigned to each load to vary in time according to the optimisation logic, dynamic allocation enables the system to match generation and demand more effectively whenever price conditions are favourable. In this sense, the heatmaps of annual billing clearly demonstrate that the combination of the indexed tariff with dynamic allocation coefficients is, overall, the most profitable configuration among those analysed. Under the same tariff, different allocation strategies lead to visibly different billing levels, and under the same allocation scheme, more flexible tariffs almost always outperform more rigid ones. This observation supports a broader conclusion that runs throughout the study: greater flexibility tends to translate into greater economic benefits. Being flexible in consumption (through demand-side management), flexible in the allocation of shared generation (through dynamic coefficients), and flexible with respect to the external system (through an indexed tariff) forms a triple layer of flexibility that maximises the ability of the energy community to respond to changing conditions. Naturally, increased flexibility also implies greater exposure to price volatility and operational uncertainty, which may introduce additional risk from the perspective of individual participants. Nevertheless, the optimisation results obtained in this work show that, under the analysed conditions, the net effect remains positive: higher flexibility in consumption patterns, in allocation rules and in tariff design leads to lower overall electricity costs and better utilisation of the available photovoltaic generation. In summary, the allocation coefficients act as a key lever through which the benefits of tariff flexibility and demand flexibility can be transmitted to the different loads, shaping the distribution of economic gains within the energy community and reinforcing the central role of coordinated flexibility in its overall performance.

## 6.5 Limitations of the study

While the optimization results consistently highlight the central role of demand-side flexibility in improving the economic and operational performance of the energy community, it is essential to acknowledge that the modelling framework inevitably relies on a set of assumptions and simplifications. These modelling choices, already outlined in the project scope and limitations section, introduce limitations that must be carefully considered when interpreting the results presented in the previous sections. The system achieves high efficiency levels and optimal performance across the analysed configurations precisely because a relatively wide flexibility envelope was assumed for the irrigation demand. In particular, the irrigation loads were allowed to be freely shifted within each week, subject only to the fulfilment of predefined weekly irrigation targets and to an hourly constraint imposed by the minimum operating power of the pumps. This modelling approach grants the optimization algorithm substantial freedom to reorganize irrigation events across different days and hours, effectively representing an upper bound of achievable flexibility in agricultural energy systems. At the same time, these assumptions were intentionally adopted to maintain coherence with the defined project scope and to isolate the effects of flexibility within a controlled analytical environment. By limiting the constraints to weekly water requirements and minimum pump operation thresholds, the model captures the fundamental trade-offs between energy prices, photovoltaic availability and demand shifting, without introducing excessive complexity that could obscure the interpretation of results. As such, the flexibility implemented in the model should be understood as realistic in principle, but optimistic in magnitude.

### 6.5.1 Modelling demand flexibility and real-world agronomic constraints

In real-world irrigation management, full demand flexibility is rarely achievable without compromising agronomic efficiency or operational feasibility. Irrigation during the hottest hours of the day is often deliberately avoided, as high solar radiation and elevated air temperatures significantly increase evapotranspiration losses and surface evaporation, thereby reducing overall water-use efficiency and potentially placing additional stress on crops. Applying water under such unfavorable thermal conditions may also exacerbate soil sealing or surface runoff phenomena, further diminishing irrigation effectiveness and long-term soil quality.

Beyond these considerations, irrigation scheduling is strongly influenced by a range of meteorological variables, including rainfall, wind speed and relative humidity. Irrigating during windy or rainy conditions can result in uneven water distribution, unnecessary energy consumption and poor soil infiltration, ultimately undermining both agronomic and energetic efficiency. In addition, agronomic factors such as soil moisture retention characteristics, crop type, root depth and growth stage impose further constraints on when and how irrigation can be safely postponed or advanced without negatively affecting crop yields. In many practical contexts, regulatory or environmental restrictions on water abstraction and energy use also limit the operational freedom available to farmers and irrigation communities.

Within this context, the weekly constraints adopted in the optimization model represent a deliberate

compromise between realism and analytical tractability. On the one hand, they ensure that total water requirements are consistently met; on the other, they still allow the system to dynamically react to daily tariff variations and changing generation conditions. The inclusion of a minimum operating power for the pumps introduces an additional layer of realism, since empirical observations indicate that irrigation events typically last at least twenty minutes per activation and cannot be arbitrarily fragmented without affecting system reliability or pump efficiency. Together, these assumptions aim to approximate real operational practices while preserving the generality and transparency of the optimization framework.

More broadly, these limitations reflect a general principle already highlighted in the introductory chapter: demand flexibility must always be interpreted within the physical and operational boundaries of the process under study. Although the methodological framework adopted in this work is transferable to application domains beyond agriculture, the effective degree of flexibility achievable in practice will inevitably depend on sector-specific constraints and local operating conditions. Consequently, the results presented in this work should be understood as realistic yet optimistic estimates of the benefits that flexibility can unlock when such constraints are respected but not fully binding.

Lastly, this level of demand-side flexibility may also generate relevant social co-benefits. By enabling the rescheduling of irrigation activities away from night-time hours and towards periods with photovoltaic availability, the optimised operation can reduce the reliance on nocturnal irrigation practices. This shift can improve working conditions for farmers by allowing irrigation tasks to be more aligned with regular daytime activities, thereby facilitating a better balance between agricultural operations and personal time. While these aspects are not explicitly quantified within the modelling framework, they represent an important qualitative dimension of flexibility-oriented optimization in agricultural energy communities.

### **6.5.2 Influence of seasonal demand patterns on the effectiveness of flexibility**

Another fundamental limitation that emerges from the results analysis is related to the strong seasonal nature of irrigation demand. Seasonality plays a decisive role in shaping both the demand profile and the corresponding optimization outcomes, as irrigation needs vary significantly between summer and winter periods.

During the summer months, irrigation is required more frequently and with higher intensity, resulting in a relatively uniform and predictable demand profile. In these conditions, a large share of the weekly water requirement must be delivered within relatively narrow time windows dictated by agronomic necessity. As a result, the degrees of freedom available to the optimiser are reduced: while irrigation events can still be shifted or slightly reshaped to respond to tariff signals, the overall flexibility potential becomes constrained by the magnitude and regularity of demand. As observed in the energy balance results discussed earlier, summertime irrigation often aligns naturally with photovoltaic generation. When irrigation is required on most days of the week, locally generated PV energy is largely absorbed by the system, and grid exports tend to be limited. In some instances, the optimization shifts part of the pumping activity outside peak solar hours to reduce midday

surpluses and further improve self-consumption. In other cases, the coincidence between demand and generation leads to an almost automatic balance between production and consumption, leaving limited room for additional economic optimization through demand shifting. In contrast, winter and low-demand periods exhibit markedly different dynamics. Irrigation occurs less frequently and with less regular patterns, providing the optimiser with substantially greater scheduling freedom. Under these conditions, the model can concentrate pumping activities in low-tariff hours or reorganize irrigation events across the week without violating water requirements. Although this increases flexibility in relative terms, the absolute economic impact remains modest due to the smaller energy volumes involved.

These seasonal dynamics demonstrate that the effectiveness of demand flexibility is fundamentally linked to both the shape and the magnitude of the underlying demand profile. Systems characterized by high and concentrated baseline demand offer fewer rescheduling opportunities, while systems with dispersed or intermittent demand enable greater optimization freedom. Recognizing this seasonal interplay is essential for correctly interpreting the results of this study and for understanding how flexibility strategies perform across the full annual operating cycle of agricultural energy communities.

## 7 Conclusions

This thesis investigates how demand-side flexibility and local renewable generation affect the operational and economic performance of agricultural energy communities. The analysis focuses on a real agricultural community located in the Valencian region and addresses a context that remains relatively underexplored within the energy transition literature: rural energy systems in which electricity demand is largely driven by irrigation needs and is therefore intrinsically flexible, but also constrained by strong seasonality operational limits and exposure to electricity price volatility.

A central outcome of this work is the clear identification of demand-side flexibility as the main driver of system performance. The analysis shows that, even in the absence of local generation or storage systems, flexible management of irrigation loads enables substantial cost reductions by shifting consumption toward more favorable tariff periods. When photovoltaic generation is available flexibility allows the system to increase economically efficient self-consumption and to reduce exposure to high purchase prices. The magnitude of the observed savings confirms that flexibility plays a fundamental role in the economic performance of agricultural energy communities especially in renewable-dominated systems.

Building on this result the thesis provides a detailed interpretation of how photovoltaic generation is allocated between self-consumption and sale to the grid through the concept of opportunity cost. By explicitly comparing the economic value of using locally generated electricity versus exporting it the analysis clarifies several behaviors that may initially appear counterintuitive such as selling energy during daylight hours or scheduling demand outside solar production periods. These outcomes are shown to arise from coherent economic logic once tariff structures, pumps minimum power constraints and net balance mechanisms are jointly considered. Framing these decisions in terms of opportunity cost improves the transparency of the optimization results and provides a transferable interpretative tool for analysing energy community behavior.

The economic viability of battery energy storage is also examined. The results indicate that when demand is already highly flexible the integration of a battery does not necessarily lead to additional cost savings because of its high investment cost. While storage offers technical advantages such as absorbing surplus photovoltaic generation, its economic contribution remains limited under the analysed conditions. Rather than suggesting that storage is ineffective in general, this finding highlights that in systems with highly shiftable loads, flexibility already captures a large share of the available economic benefit. In renewable-dominated contexts the effective use of flexibility therefore plays a key role in achieving cost savings and storage becomes more relevant when such flexibility is limited.

Another important contribution of this thesis concerns the interaction between photovoltaic power allocation coefficients and electricity tariff structures. The results show that correct choice of allocation coefficients is what has the stronger impact on the system performance. Dynamic coefficients which allow photovoltaic generation to be redistributed among loads in response to system conditions significantly enhance the ability of the energy community to exploit flexibility. Tariff structures remain relevant as they shape the external economic signals to which the system responds but their effect is

secondary compared to the internal flexibility enabled by adaptive energy sharing coefficients. The indexed tariff consistently provides favorable outcomes because its variability can be exploited by the optimizer when sufficient flexibility is available. Taken together these results define a clear hierarchy of flexibility mechanisms.

The analysis also highlights that flexibility is inherently bounded by real-world constraints. Agronomic requirements, meteorological conditions and operational limits restrict the extent to which irrigation demand can be shifted. The results should therefore be interpreted as realistic if estimated under plausible operating assumptions. This does not reduce their relevance but rather emphasizes the importance of contextualizing flexibility within sector-specific constraints.

Overall the findings of this thesis reinforce the idea that energy communities can play a significant role in improving the economic efficiency and resilience of rural energy systems when flexibility is explicitly modeled and actively managed. In agricultural contexts electrified irrigation combined with smart demand management represents a particularly effective pathway to increase renewable integration and reduce exposure to volatile electricity markets.

Finally, although this study focuses on agricultural energy communities as case-study, the analytical approach developed here can be extended to other systems characterized by flexible demand such as electric vehicle charging or heating and cooling of buildings. In conclusion this thesis shows that the success of future energy communities depends less on the mere deployment of technologies and more on the intelligent integration of flexibility into system operation. By grounding the analysis in real operational constraints and electricity pricing schemes, the work contributes to a more realistic understanding of how decentralized community-based energy systems can support an effective and sustainable energy transition.

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## 9 Annexes

### 9.1 Annex I: Input data and calculation of the water-to-energy ratio

This annex reports the input data used to compute the water-to-energy ratio adopted in the model for each IC. The ratio links pumped water volumes to electricity consumption and is used to convert irrigation electricity demand into delivered water volumes.

#### 9.1.1 Definition

For each community  $j$ , the water-to-energy ratio  $\alpha_j$  is defined as:

$$\alpha_{j,m} = \frac{V_{j,m}}{E_{j,m}} \quad [\text{m}^3/\text{kWh}] \quad (42)$$

where  $V_{j,m}$  is the pumped water volume in month  $m$  ( $\text{m}^3$ ) and  $E_{j,m}$  is the corresponding electricity consumption (kWh). Values reported in the tables are rounded to two decimal places.

#### 9.1.2 Motor Pozo Castellar

Month	$V$ [ $\text{m}^3$ ]	$E$ [kWh]	$\alpha$ [ $\text{m}^3/\text{kWh}$ ]
Jan	6517	601	10.84
Feb	14280	1317	10.84
Mar	14454	1333	10.84
Apr	14085	1299	10.84
May	39664	3658	10.84
Jun	33711	3109	10.84
Jul	30643	2826	10.84
Aug	33711	3109	10.84
Sep	26989	2489	10.84
Oct	32031	2954	10.84
Nov	1572	145	10.84
Dec	10832	999	10.84

**Table 48:** Monthly input data and computed water-to-energy ratio for Motor Pozo Castellar (2024).

### 9.1.3 Font el Bonet

Month	$V$ [m <sup>3</sup> ]	$E$ [kWh]	$\alpha$ [m <sup>3</sup> /kWh]
Jan	25361	2504	10.13
Feb	8033	793	10.13
Mar	16697	1649	10.13
Apr	8033	793	10.13
May	68365	6749	10.13
Jun	37841	3735	10.13
Jul	50489	4984	10.13
Aug	51701	5104	10.13
Sep	25861	2553	10.13
Oct	28447	2808	10.13
Nov	44527	4396	10.13
Dec	8028	793	10.12

Table 49: Monthly input data and computed water-to-energy ratio for Font el Bonet (2024).

### 9.1.4 Alter Romaguera

Month	$V$ [m <sup>3</sup> ]	$E$ [kWh]	$\alpha$ [m <sup>3</sup> /kWh]
Jan	5132	495	10.37
Feb	9186	886	10.37
Mar	16526	1594	10.37
Apr	9694	935	10.37
May	28760	2774	10.37
Jun	36338	3505	10.37
Jul	41854	4037	10.37
Aug	31455	3034	10.37
Sep	18807	1814	10.37
Oct	20248	1953	10.37
Nov	1400	135	10.37
Dec	13074	1261	10.37

Table 50: Monthly input data and computed water-to-energy ratio for Alter Romaguera (2024).

## 9.2 Annex II: Annual opportunity cost representation

This annex complements the analysis presented in paragraph *Opportunity Cost Definition and interpretation* by extending the interpretation of the opportunity cost to an annual time horizon. While the monthly representation highlights the short-term behavior of the optimizer, the annual view provides additional insight into how tariff structures and seasonal variability influence the allocation between self-consumption and energy export over the entire year.

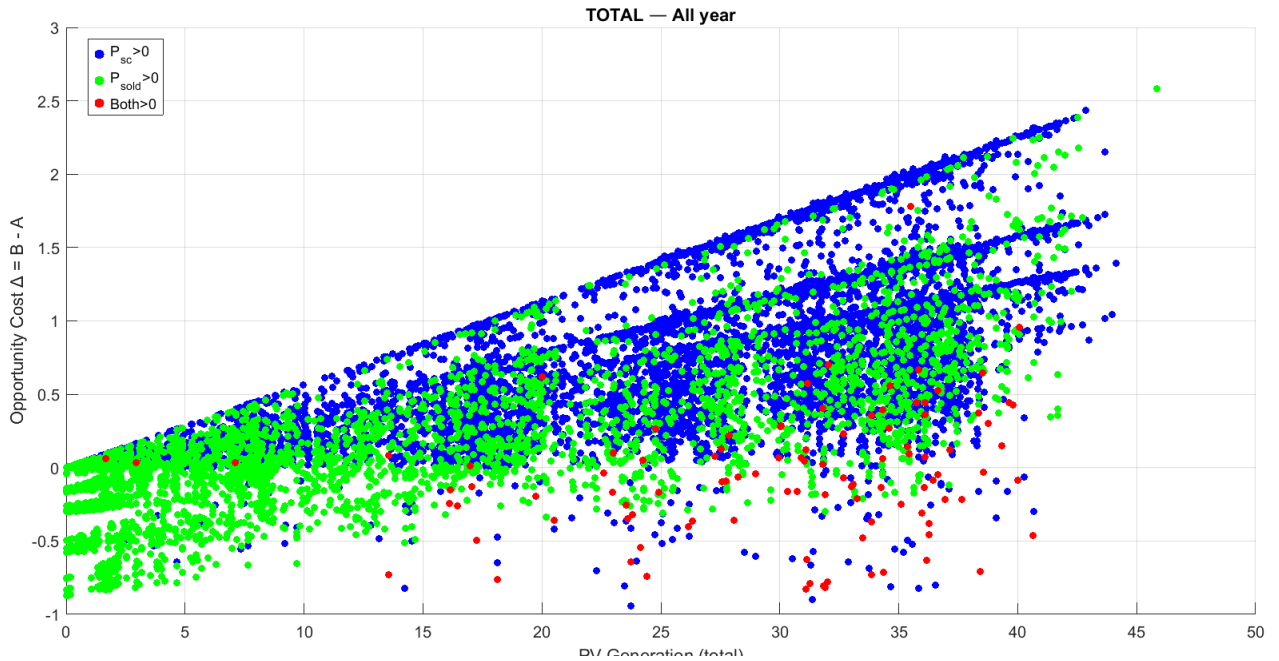


Figure 41: Annual opportunity cost representation of the energy community under indexed static tariff conditions.

Figure 41 shows the annual distribution of the opportunity cost  $\Delta$  as a function of the allocated photovoltaic generation for all loads of the energy community. As in the monthly case, the x-axis represents the photovoltaic energy allocated to the loads, while the y-axis reports the corresponding opportunity cost. The color coding follows the same convention adopted in the main analysis: blue points indicate hours characterized by self-consumption ( $P_{sc} > 0$ ), green points correspond to energy export ( $P_{sold} > 0$ ), and red points represent hours in which both self-consumption and selling occur simultaneously.

Compared to the monthly representation, the annual plot reveals a more articulated structure for the green points. In particular, six distinct “starting levels” can be observed along the opportunity cost axis. These levels directly correspond to the six tariff periods defined by the annual pricing scheme. Each level reflects a different minimum selling convenience threshold, which depends on the purchase and selling prices associated with the specific tariff band active during that period.

This behavior is not visible in the monthly plots, where only three starting levels appear, since only three tariff bands alternate within a single month. The annual representation therefore provides a clearer visualization of how the optimizer adapts its selling strategy to the full set of tariff conditions

encountered throughout the year.

The blue points continue to form upward-sloping trends, confirming that the economic benefit of self-consumption increases with the amount of locally utilized photovoltaic generation. Differences in slope among the loads remain visible and are linked to their respective allocation coefficients, indicating heterogeneous access to photovoltaic resources within the community.

The red points are primarily concentrated in regions characterized by high photovoltaic availability and opportunity cost values close to zero. These points identify operating conditions in which the system is able to satisfy demand while exporting the surplus, and where the economic outcomes of self-consumption and selling are nearly equivalent. In such cases, the optimizer naturally balances the two options in order to comply with operational and regulatory constraints, including net billing mechanisms.

Overall, the annual opportunity cost representation confirms the consistency of the optimization logic observed at the monthly scale, while additionally highlighting the role of tariff seasonality in shaping the economic thresholds that govern self-consumption and energy export decisions.

**Part II**

**Budget planning**

## 10 Preliminary considerations

This section addresses the estimation of the costs associated with assessing the economic viability of an agricultural energy community. The analysis was conducted over an eleven-month period and was based on a review of the scientific literature on energy community modelling, together with an evaluation of the system cost structure and its expected evolution. The study involved the development and progressive refinement of a mathematical model implemented in Julia, incorporating irrigation constraints and the operational requirements of the agricultural context, as well as the preparation and supervision of the final report. The budget aims to quantify the development costs of the project by accounting for its main phases. The analysed resources include labour costs related to the personnel involved, depreciation costs associated with equipment and specialised software, and indirect costs such as transportation and other project-related expenses.

## 11 Budget

### 11.1 Labour costs

Labour costs reflect the time and professional contribution of the student and the two supervisors involved in the project. The activities carried out include a review of the relevant literature, data collection, methodological development, implementation through a case study and the preparation of the final document. The two supervisors provided continuous guidance throughout all stages of the work, including methodological support, review of results and feedback on the final structure. The following table summarises the total human resources costs.

Task	Time allocation	Role	Unit cost	Cost
Literature review	200 h	Junior Engineer	30 €/h	6,000
Data acquisition	40 h	Junior Engineer	30 €/h	1,200
Methodology design	100 h	Junior Engineer	30 €/h	3,000
Methodology design	180 h	Supervisor 1	70 €/h	12,600
Methodology design	180 h	Supervisor 2	70 €/h	12,600
Julia modelling	130 h	Junior Engineer	30 €/h	3,900
Julia modelling	230 h	Supervisor 1	70 €/h	16,100
Julia modelling	230 h	Supervisor 2	70 €/h	16,100
Writing	110 h	Junior Engineer	30 €/h	3,300
Review and feedback	100 h	Supervisor 1	70 €/h	7,000
Review and feedback	130 h	Supervisor 2	70 €/h	9,100
<b>TOTAL</b>	<b>1,660 h</b>	–	–	<b>90,900</b>

Table 51: Human resources costs

## 11.2 Software and hardware amortization costs

The hardware equipment used in the project consists of a laptop owned by the junior engineer and two desktop computers belonging to the two supervisors. The junior engineer’s equipment was depreciated over an eleven-month period, while the remaining hardware was depreciated based on the effective hours of use reported in table 51, which were approximated to one month.

The software employed in the project includes a Microsoft 365 Personal package for each of the three individuals involved. A MATLAB licence was used by the junior engineer together with the MATLAB Financial Toolbox, which supported the financial analysis. In addition, the mathematical model was developed using the Julia programming language within the Atom editor and the JuMP (Julia for Mathematical Programming) optimisation package. These tools are currently available free of charge and therefore do not entail any associated costs. Finally, the document was written in  $\LaTeX$  using the Overleaf editor, which is also freely available at present.

Equipment	Price	Depreciation period	Usage time	Cost
Acer Aspire Go 15 (JE)	1,000 €	6 years	11 months	152.78 €
HP Gaming PC (SP1)	1,000 €	6 years	1 month	13.89 €
PC Pentium IV 2 GHz (SP2)	1,500 €	6 years	1 month	20.83 €
Microsoft 365 Personal (JE)	62 €/year	–	11 months	56.83 €
Microsoft 365 Personal (SP1)	62 €/year	–	1 month	5.17 €
Microsoft 365 Personal (SP2)	62 €/year	–	1 month	5.17 €
MATLAB and Simulink Student Licence (JE)	69 €	2 years	11 months	31.63 €
MATLAB Financial Toolbox (JE)	7 €	2 years	11 months	3.21 €
<b>TOTAL</b>				<b>289.79 €</b>

Table 52: Software and hardware depreciation costs

## 11.3 Indirect costs

Indirect costs are estimated as 10% of the previously calculated costs and include the following items:

- Transportation expenses related to travel to the workplace.
- Costs associated with the workplace itself, such as office supplies and rental expenses.
- Utility expenses, including internet services, heating and cooling of office spaces.

## 11.4 Budget summary

This section aggregates all the costs discussed in the previous subsections in order to obtain the overall gross budget of the project. In addition to the direct development costs, an industrial profit margin is included to reflect a realistic commercial scenario. Taxes are also applied to determine the final budget.

The resulting total budget amounts to one hundred twenty-eight thousand six hundred sixty-eight.

<b>Component</b>	<b>Cost (€)</b>
Labour costs	90,900.00
Software and hardware depreciation	289.79
Indirect costs (10%)	9,118.979
Industrial margin (6%)	6,028.43
Taxable base	106,337.20
VAT (21%)	22,330.81
<b>TOTAL BUDGET</b>	<b>128,668.01</b>

Table 53: Final project budget