

Impact of electrical energy storage on the performance of photovoltaic systems in building retrofits

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ABSTRACT

This study investigates the impact of integrating electrical energy storage (EES) into photovoltaic (PV) systems serving existing buildings that have already undergone energy retrofitting. Focusing on representative locations in Southern Europe, the analysis considers both residential and tertiary buildings with typical configurations. The buildings are assumed to have maximum rooftop PV coverage and are equipped with heat pumps using low-GWP R290 refrigerant, in line with recent regulations. Dynamic simulations were carried out to assess the benefits of varying storage capacities, with particular attention to both energy performance and economic feasibility. To achieve the target of zero-emission buildings (ZEBs), the renewable share of the energy supplied from the grid was also taken into account. Furthermore, a new index was introduced to quantify the ability of EES to mitigate grid disturbances caused by PV generation. The Discounted Cash Flow (DCF) method was applied to determine the optimal storage sizes. Results show that, in residential buildings, storage sized according to a 10-year Net Present Value (NPV) criterion provides positive returns, with peak energy performance reached below the economic break-even point. Conversely, for the tertiary sector, the investment is not economically viable under current conditions, mainly due to daytime-concentrated electricity use, which reduces storage benefits, and lower electricity purchase costs, which limit the advantage of self-consumption. Nonetheless, storage still improves key energy performance indicators. In some cases, EES integration enables the PV system to cover 100% of annual electricity demand. The integration of EES also leads to a reduction in grid disturbance of up to 61.2%. Overall, the study confirms that appropriately sized EES can significantly enhance self-consumption, reduce grid disturbances, and support buildings in approaching net-zero emission targets.

1. Introduction

1.1. Research background

The 2024 recast of the Energy Performance of Buildings Directive (EPBD) marks a decisive step in the European Union's pathway toward climate neutrality by 2050. The revision introduces minimum energy performance standards for the worst-performing buildings, mandates zero-emission buildings (ZEBs) for all new constructions by 2030, phases out fossil-based heating systems, and requires national renovation plans aligned with EU climate targets [1–3].

As nearly 75 % of the European building stock still fails to meet current standard [3] the decarbonization of the built environment cannot rely solely on new constructions but must involve the deep renovation of existing buildings. Improving envelope insulation, adopting high-efficiency equipment and low-energy technologies, and integrating renewable energy systems represent the key steps toward ZEB status. In this framework, rooftop photovoltaic (PV) installations and electrified systems based on heat pumps (HPs) offer an effective pathway to reduce both operational energy demand and greenhouse gas emissions [4–12].

Buildings equipped with PV-powered HPs act as prosumers, simultaneously producing and consuming electricity. Their overall

Abbreviations: ASHP, Air Source Heat Pump; BIPV, Building-integrated Photovoltaic; BOS, Balance-Of-System; DCF, Discounted Cash Flow; DHW, Domestic Hot Water; DPB, Discounted Payback; EC, Embodied Carbon; EES, Electrical Energy Storage; EPBD, Energy Performance of Buildings Directive; ESEER, European Seasonal Energy Efficiency Ratio; EXP, PV energy exported; GHG, greenhouse gas emission; GWP, Global Warming Potential; HP, Heat Pump; HVAC, Heating, Ventilation and Air Conditioning; LCZ, Local Climatic Zone; NPV, Net Positive Value; PV, photovoltaic; R290, propane refrigerant; WUDAPT, World Urban Database and Access Portal Tools; ZEB, Zero Emission Building.

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Nomenclature

Symbols

COP	Coefficient Of Performance in heating mode (—)
CPP	Carbon Payback Period (yr)
CR	Capacity Ratio P/P_{fl} (—)
$E_{delivery}$	annual electricity import by the building (kWh)
E_{demand}	annual total electricity demand (kWh)
E_{export}	annual electricity exported to the grid E_{export} (kWh)
EER	Energy Efficiency Ratio in cooling mode (—)
Exc	total exchange ($E_{delivery} + E_{export}$) relative to E_{demand} (—)
SF	share of building electricity demand covered by PV generation (%)
SF1	share of building electricity demand covered by renewable energy (%)
NC	normalized capacity P_{fl}/P_{nom} (—)
P	actual capacity of the heat pump (kW)
P_{fl}	full load heat pump capacity (kW)
P_{nom}	nominal heat pump capacity (kW)
PLF	Part Load Factor (—)
SCR	share of PV energy used by the building (%)
%RedExc	percentage reduction in Exc due to storage, relative to the value without storage (%)
%NPV	normalized NPV referred to maximum NPV (%)

performance depends on the dynamic balance between generation and demand. A more rigorous decarbonization strategy should therefore focus on eliminating the non-renewable share of grid-supplied electricity, allowing renewable exports and non-renewable imports to be compared on a consistent basis [13].

The building's carbon footprint can be assessed by quantifying its contribution to greenhouse gas (GHG) emissions, which are primarily associated with the use of non-renewable energy sources. In most cases, on-site electricity generation is provided by PV systems and is therefore classified as renewable energy. In contrast, electricity drawn from the grid typically consists of a mix of non-renewable sources (e.g., fossil fuel-based or nuclear power plants) and renewable sources (e.g., solar, wind, geothermal, biomass, and hydropower). Consequently, an accurate evaluation of a building's carbon footprint must focus specifically on the non-renewable portion of electricity consumed from the grid. All components of the energy balance should be expressed using a consistent metric, enabling a clear comparison between the renewable energy exported to the grid and the non-renewable energy imported from it.

The energy performance of a building is also highly dependent on its morphology and the characteristics of the surrounding urban environment [14]. Elements such as structural configuration, geometry, and the potential for integrating energy systems play a pivotal role in determining the feasibility of reaching ZEB status. To systematically address this variability, urban settings can be categorized using the Local Climate Zones (LCZ) framework [15,16], which provides a consistent methodology for describing the physical and thermal characteristics of both urban and rural areas.

Furthermore, climatic conditions have a substantial influence on ZEB performance, particularly with regard to heating and cooling demands and the potential for on-site renewable energy production. Regional climate differences must therefore be taken into account when designing or retrofitting buildings toward ZEB targets. To allow for broader applicability of the results, the ASHRAE climate zone classification [17] can be used, which enables generalization and comparison of simulation outcomes across diverse geographic regions [18,19].

1.2. State of the art and research gap

A further step towards the elimination of the greenhouse effect is the progressive replacement, in reverse-cycle systems used for refrigeration and air conditioning, of fluorinated refrigerants—commonly referred to as F-gases—which exhibit a high Global Warming Potential (GWP), with synthetic or natural refrigerants characterized by significantly lower GWP values[20,21]. Recent regulations, such as the European Regulation 573/2024 [22–24], have restricted the use of high-GWP fluorinated gases in refrigeration and air-conditioning systems, promoting low-impact alternatives. The best environmental outcomes are obtained with natural refrigerants, such as ammonia (GWP = 0), carbon dioxide (CO_2 , GWP = 1), and propane (GWP = 3) [25]. As substances naturally occurring in the environment, natural refrigerants are generally less expensive to produce and are not subject to the regulatory restrictions imposed on F-gases. Moreover, their availability is not tied to patents or complex industrial synthesis processes. Nevertheless, their use requires specific safety considerations: ammonia (R717) is toxic and corrosive; CO_2 (R744) operates at significantly higher pressures than other refrigerants; and propane (R290), being a hydrocarbon, is flammable and thus necessitates precautions during installation and maintenance [20]. Despite these challenges, current technologies and established best practices enable the effective and safe use of natural refrigerants across a wide range of applications. Among them, propane (R290) is gaining widespread adoption in air conditioners and heat pumps for building climate control. This is due to its high performance, coupled with a low refrigerant charge, contained within compact, sealed, and tightly controlled systems. In retrofit pathways toward the ZEB objective, the adoption of this natural refrigerant as an alternative to conventional synthetic fluids becomes a relevant design parameter to be investigated alongside envelope and system improvements. Accordingly, the present analysis considers R290-based heat pumps as the reference technology for building climate control.

In parallel, the large-scale integration of renewables poses new challenges for grid stability.

Solar and wind generation, being inherently intermittent and non-dispatchable, introduce fluctuations in power output that can lead to voltage instability, frequency deviations, and congestion in the transmission network[26,27]. By storing excess energy during periods of overproduction and releasing it during demand peaks or supply shortages, storage systems act as dynamic buffers that smooth out these fluctuations [28]. They enable frequency regulation, voltage support, ramp-rate control, and load shifting, thereby reducing the need for fast-response fossil-fueled peaker plants [29,30]. Additionally, distributed storage can mitigate localized congestion, shifting energy use from periods of high grid demand to periods of surplus solar generation and in this way can reduce peak load stress on the electrical grid, thereby deferring or eliminating the need for costly investments in transmission and distribution infrastructure [31–34]. In grid-connected scenarios, advanced storage technologies integrated with smart inverters and energy management systems can also contribute to overall grid reliability, flexibility, and operational efficiency.

At the single-building scale, the integration of EES into PV installations significantly enhances system efficiency and economic viability. While PV systems generate electricity primarily during daylight hours, consumption patterns can exhibit higher demand in the evening. This temporal mismatch often results in surplus energy being exported to the grid at relatively low feed-in tariffs. By incorporating storage, excess solar energy can be retained on-site and utilized during periods of low or no generation, thereby increasing the self-consumption ratio and reducing dependence on grid electricity [13,35–37]. Moreover, storage systems contribute to load balancing, improve power quality, and provide backup power during grid outages[38]. However, a quantitative indicator to describe this effect is still lacking, and its definition would provide a clearer understanding of how distributed storage contributes to local grid stability.

Battery storage not only supports energy autonomy and grid stability but also improves the overall return on investment of PV systems [38,39]. In fact, at the consumer level, the increment of the self-consumption can contribute to significant avoided costs reducing electricity purchases from the grid and avoiding costs associated with energy tariffs, demand charges, and grid fees [40,41]. Nevertheless, the actual adoption of storage systems in buildings remains limited. With regard to new PV systems installed in Europe in 2024, only 57 % of those in residential buildings were coupled with EES, and this share decreases to 10 % for tertiary buildings [42,43]. It is therefore evident that the deployment of EES in civil buildings needs to be further promoted, also by deepening and consolidating the certainties about the opportunities and limitations of their use. The primary purpose of this study was therefore to conduct additional investigations on the role that EES can play when integrated with PV systems in civil buildings.

1.3. The specific objectives of this study

This study investigates the role of EES integrated with PV systems in buildings retrofitted to achieve ZEB status. All configurations considered in this work include electric HPs combined with rooftop PV systems, whose surface area was maximized for energy harvesting purposes.

Specifically, this research addressed the following objectives:

- i) to quantify the actual energy savings and carbon emission reductions within the framework of economic feasibility;
- ii) to assess the improvement of the interaction with the electrical grid;
- iii) to evaluate the contribution of EES integration toward achieving the ZEB condition.

By integrating these aspects into a unified assessment, the study provides a novel contribution, offering a deeper understanding of the role of storage not only at the individual building scale but also within a broader and replicable urban context, through the application of the LCZ classification system.

A set of scenarios featuring different building typologies and climatic

conditions was analyzed, acknowledging that variations in energy demand and solar generation significantly influence battery utilization. To generalize the results and enhance their applicability to the urban morphology of European cities, the LCZ classification was employed for building typology identification and performance analysis [44]. The analysis focused on a limited area of Southern Europe to avoid excessive generalizations that could have been misleading. For this reason, regarding climate variability, three Southern European cities: Milan, Rome, and Palermo, were selected. The three selected Italian cities, well distributed across the territory of Southern Europe, provide three representative climatic conditions while sharing the same regulatory framework and tariff structure. This allows the influence of climate to be assessed independently of other contextual factors.

2. Methodology

2.1. The workflow of the study

Fig. 1 summarizes the methodological framework. The diagram outlines the input assumptions, the simulation models, and the performance indicators used to evaluate PV + EES integration in retrofitted buildings.

The research approach is based on three models operating in cascade. The building performance model relies on dynamic hourly simulations conducted with EnergyPlus [45], providing time-resolved data on heating, cooling, and electrical loads (e.g., appliances and lighting), as well as PV power generation. These outputs are then processed by a complementary quasi-steady-state calculation procedure implemented in a spreadsheet environment, which integrates the algorithms of the HP model. This enables a detailed hourly assessment of HP performance and, consequently, of the building's total electricity demand. Within the same computational framework, the EES model is incorporated to simulate storage system dynamics. Finally, the combined results yield the data required to calculate the performance indices adopted in this study. The structure and functions of these three models are described in detail in the subsequent sections.

As specified in the following sections, the methodology is based on

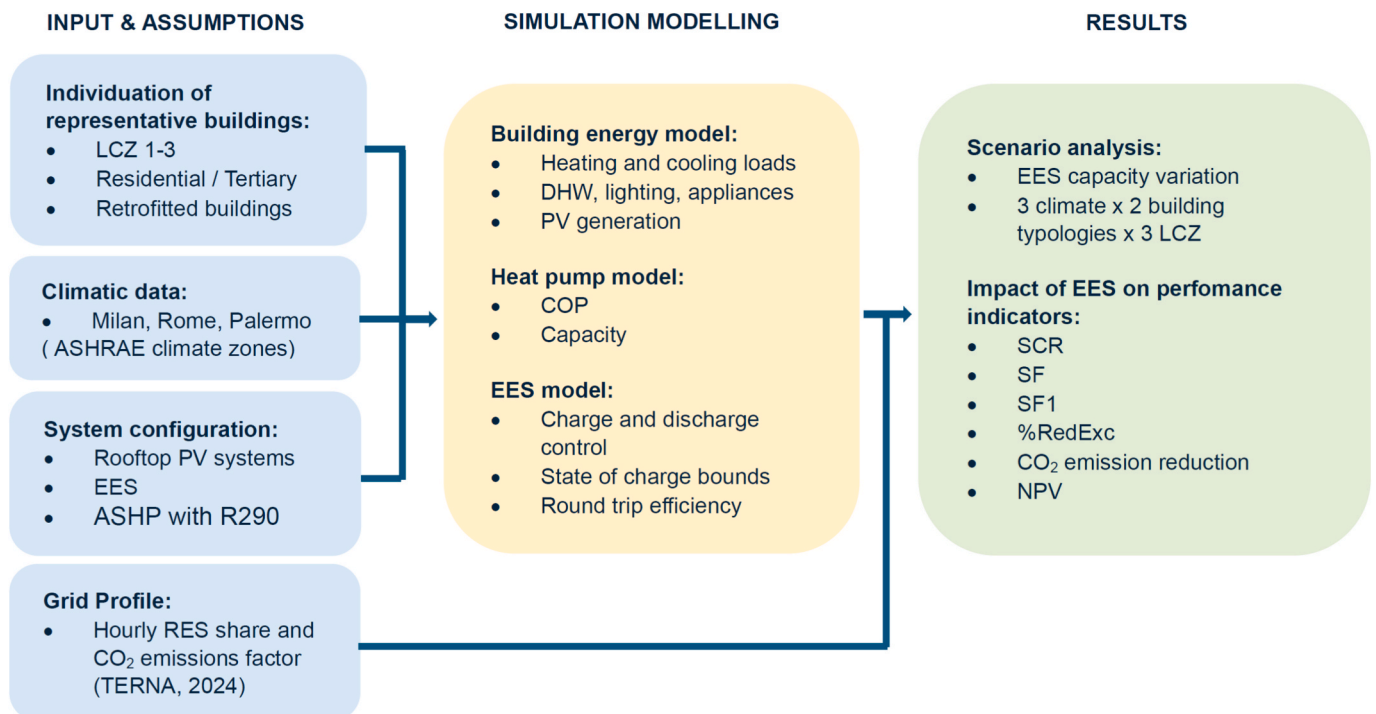


Fig. 1. The workflow of the study.

component models widely validated in the scientific literature and on technical data certified by manufacturers in accordance with current standards.

2.2. Building energy model: Case-study buildings

The fundamental parameters defining each Local Climate Zone (LCZ) include building height and spacing, the percentage of permeable surfaces, tree density, and soil moisture [46]. Seventeen LCZ types have been established, ten of which are associated with urban canopy characteristics, while the remaining seven correspond to land-cover categories. Most classification methods rely on the automated LCZ mapping procedure proposed by [14], which has been adopted by the World Urban Database and Access Portal Tools (WUDAPT) project to generate consistent LCZ maps for entire cities [47–49].

Urban centers are predominantly characterized by three compact LCZ types: LCZ 1 (compact high-rise), LCZ 2 (compact mid-rise), and LCZ 3 (compact low-rise) [50]. These categories represent the most common urban typologies in the central areas of many European cities [51,52]. In urban areas across Europe, 72 % of the population lives in flats [53], confirming the dominance of multi-family buildings in cities. Regarding the tertiary sector, offices account for a major share of non-residential floor area and electricity demand, often hosting commercial functions at ground level in urban fabrics [54,55]. For this reason, a multi-family residential block and an office building were selected as representative urban archetypes within the compact LCZ framework, and deemed appropriate for the objectives of this study.

Two existing twelve-story buildings were selected as reference cases: a residential block and a tertiary-use building with commercial functions on the ground floor and offices above. Fig. 2 shows the two simulation models derived from these real buildings, characterized by fully available rooftop areas for PV installation and partial shading from adjacent structures. Particular attention was paid to assessing the influence of building height on energy performance. To this end, the height of both reference buildings was modified to correspond to three compact LCZ categories, while all other parameters were kept constant. Specifically, the study analyzed three height variants: three-story buildings corresponding to LCZ 3 (compact low-rise), seven-story buildings for LCZ 2 (compact mid-rise), and twelve-story buildings for LCZ 1 (compact high-rise). Hourly energy loads were simulated using EnergyPlus, based on building models developed in DesignBuilder [56]. The residential building includes four residential units per floor. Each floor covers 345.5 m², and the total building height is 36 m, measured up to the top slab of the upper floor. The tertiary building has a floor area of 501 m² per story and reaches a total height of 41.5 m up to the top floor slab. Although the existing buildings do not meet current standards, we assume standard retrofits. These upgrades include thermal insulation through external wall cladding, roof insulation beneath the tiles, and the installation of high-performance windows. In addition, a smart lighting system with sensor-based illuminance control is considered. During the cooling season, solar shading devices are activated to

reduce solar heat gains.

Table 1 reports the envelope layers and U-values used in the simulations for the three climate zones, as defined by the national regulation [57], and summarizes key simulation parameters.

The scope of the analysis was broadened to include three Southern European cities: Milan, Rome, and Palermo, each representing a distinct ASHRAE climate zone: Milan (4A – Mixed-Humid), Rome (3A – Warm-Humid), and Palermo (3B – Warm-Dry) [17]. Table 2 outlines the main scenarios analyzed.

2.3. Building energy model: PV system

PV generation on building rooftops was simulated using high-efficiency PV modules. The modules are commercially available monocrystalline Si panels [58]. The key technical specifications of the selected modules are presented in Table 3.

A single module contains 104 monocrystalline cells. Monocrystalline panels represent the dominant segment of the European PV market, owing to their high efficiency and widespread adoption in new residential and commercial installations [59].

The PV system performance was modeled on an hourly basis using the EnergyPlus PV module, which employs a one-diode equivalent circuit model [60,61]. Cell temperature follows Ulleberg's dynamic method [62]. The one-diode model is a standard approach for representing the electrical behavior of PV cells, incorporating an ideal diode, a photocurrent source driven by solar irradiance, a series resistance reflecting internal conduction losses, and a shunt resistance representing leakage pathways. The method decouples thermal and electrical domains to better estimate cell temperature. In this formulation, the current cell temperature is a function of its prior state and the thermal mass of the PV module materials. This dynamic approach enhances the accuracy of PV performance simulations under fluctuating irradiance and ambient temperature conditions. The governing equations of the one-diode PV model are fully described in the EnergyPlus Engineering Reference [63]. The one-diode and dynamic temperature models implemented in EnergyPlus have been validated in several studies available in the scientific literature [64–66].

Hourly irradiance and temperature data for the three selected cities were obtained from EPW (EnergyPlus Weather) files derived from Typical Meteorological Years (TMY) [67]. The EPW files adopted as current references in this study cover the period 2007–2021 [68], as reported in the databases of the National Centers for Environmental Information (NCEI) [69] and the ERA5 climate reanalysis [70]. Shading effects caused by building geometry and solar position were explicitly considered by EnergyPlus, which computes incident irradiance on each surface based on hourly climate data and obstruction profiles.

Although larger pitches may accommodate more modules, the maximum number is ultimately limited by the physical dimensions of the selected commercial PV module. Smaller module sizes allow for greater surface coverage, thereby influencing the total PV array area that can be installed. Thus, the achievable PV-covered area on a given

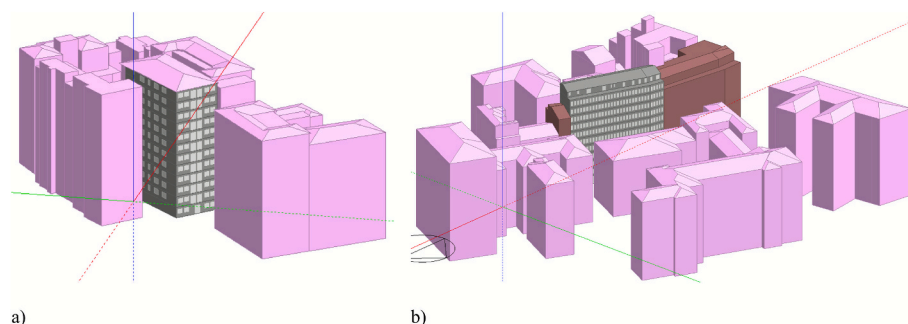


Fig. 2. Simulation models of the two reference buildings: a) residential case, b) tertiary case.

Table 1
Characteristics and simulation parameters of the buildings.

Heating set point temp. (°C)	20
Cooling set point temp. (°C)	26
Heating schedule (h)	7am-9pm ^a or 7am-7pm ^b or 7am-6pm ^c
Cooling schedule (h)	11am-7am ^a or 9am-7pm ^b or 8am-6pm ^c
DHW needa (l/m2day)	1.43 ^a
DHW schedulea	0 % (12am-6am), 30 % (6am-9am), 10 % (9am-12 pm), 15 % (12 pm-3 pm), 10 % (3 pm-6 pm), 30 % (6 pm-10 pm), 5 % (10 pm-12am)
Occupancy (Pers/m2)	0.035 ^a or 0.1 ^{b,c}
Occupancy schedule:	
Dwellings	100 % (10 pm-6am), 70 % (6am-8am), 20 % (8am-4 pm),
Commercial areas	50 % (4 pm-6 pm) 90 % (6 pm-10 pm)
Offices	0 % (7 pm-8am), 10 % (8am-9am), 80 % (9am-1 pm), 30 % (1 pm-3 pm) 90 % (3 pm-7 pm)
	0 % (6 pm-7am), 10 % (7am-9am), 90 % (9am-1 pm), 50 % (1 pm-2 pm) 90 % (2 pm-6 pm)
Appliances gain (W/m2)	2.8 ^a or 6 ^b or 14.6 ^c
Appliances gain schedule	7am-11pm ^a or 8.30am-12.30pm ^b and 3.30 pm-7pm ^b or 8am-6pm ^c
Lighting (W/m2)	0.83 W/m2x100 lux with 200 lux ^a or 300 lux ^b or 500 lux ^c
Lighting schedule	7am-11pm ^a or 8.30am-7pm ^b or 8am-6pm ^c
Air change rate (vol/h)	Infiltration 0.5 ^{a,b,c} or Mechanical ventilation 1 ^{b,c}
Air change rate schedule	Infiltration 24 h ^a 7 pm-7am ^b 6 pm-7am ^c or Ventilation 7am-7pm ^b 7am-6pm ^c
Walls	Plaster
Milan	(1.5 cm), polyurethane (10 cm) brick (40 cm), plaster (2 cm) – U = 0.26 W/m2KPlaster
Rome	(1.5 cm), polyurethane (9 cm) brick (40 cm), plaster (2 cm) – U = 0.29 W/m2KPlaster
Palermo	(1.5 cm), polyurethane (5 cm) brick (40 cm), plaster (2 cm) – U = 0.43 W/m2K
Windows	
Milan	Double glazing 4–16–4, low-e, Argon, U = 1.4 W/m2K – SHGC = 0.55 (–)
Rome	Double glazing 4–12–4, neutral selective coating, Argon, U = 1.8 W/m2K – SHGC = 0.60 (–)
Palermo	Double clear glazing 4–12–4, uncoated, Air, U = 3.0 W/m2K – SHGC = 0.75 (–)
Roof U-value	Plaster
Milan	(1.5 cm), concrete (20 cm), polyurethane (13 cm), tiles (2 cm) – U = 0.22 W/m2KPlaster
Rome	(1.5 cm), concrete (20 cm), polyurethane (11 cm), tiles (2 cm) – U = 0.26 W/m2KPlaster
Palermo	(1.5 cm), concrete (20 cm), polyurethane (8 cm), tiles (2 cm) – U = 0.35 W/m2K
	1.61
	1.99
	2.05

referred to:

^a Dwellings

^b Commercial: except on Monday and Sunday, when all systems are off except Infiltration, which remains on 24 h.

^c Offices: except on Saturday and Sunday, when all systems are off except Infiltration, which remains on 24 h.

pitch is inherently dependent on the module type. For comparability, we assume full roof coverage (as with PV tiles or edge-to-edge BIPV). This assumption enables the estimation of the maximum PV generation capacity for each pitch.

To derive a standardized metric for comparison, the energy yield from the simulated PV array was normalized by the total area of the installed modules, resulting in a unitary PV production expressed per

Table 2
The main scenarios investigated.

Scenario	City	ASHRAE climate zone	Number of floors	LCZ classification
1	Milan	4A (Mixed Humid)	3	LCZ 3 (Compact low-rise)
2	Rome	3A (Warm Humid)		
3	Palermo	3B (Warm Dry)		
4	Milan	4A (Mixed Humid)	7	LCZ 2 (Compact mid-rise)
5	Rome	3A (Warm Humid)		
6	Palermo	3B (Warm Dry)		
7	Milan	4A (Mixed Humid)	12	LCZ 1 (Compact high-rise)
8	Rome	3A (Warm Humid)		
9	Palermo	3B (Warm Dry)		

Table 3
Principal data of the PV module.

Nominal Power	400 W
Nominal panel efficiency	22.6 %
Rated Voltage (Vmpp)	65.8 V
Rated Current (Impp)	6.08 A
Open-circuit Voltage (Voc)	75.6 V
Short-circuit Current (Isc)	6.58 A
Temperature coefficient of Voc	–0.175 V/K
Temperature coefficient of Isc	+0.0029 A/K
NOCT cell temperature (°C)	43 °C (Tamb = 20 °C; G = 800 W/m ²)
Solar cells	Monocrystalline
Module surface	1.046x1.690 = 1.758 m ²
Inverter efficiency	96 %

square meter. Specifically, simulation results from an array of 20 modules (covering 35.16 m²) were used to calculate unit values of incident solar radiation and PV output for each pitch. These unitary values were then multiplied by the area of each roof pitch to estimate its respective PV production. The total PV output of the entire roof was obtained by aggregating the contributions from all pitches.

For the tertiary buildings, two pitches are considered, with a total PV surface area of 422 m² (208 m² facing southwest and 214 m² southeast). For the residential buildings, all four pitches are utilized, with a total PV surface area of 243 m² (163 m² northwest, 165 m² southeast, 56 m² southwest, and 59 m² northeast).

2.4. HP model: R290-based unit

Among the different types of HPs, air-source HPs (ASHPs) were selected due to their widespread application in buildings for space conditioning and domestic hot water (DHW) production. In line with decarbonization goals, the ASHPs use the low-GWP natural refrigerant R290.

In this study, ASHPs are designed to fully meet the space heating demand during winter, provide space cooling during summer, and supply DHW year-round, exclusively for residential buildings. Each building has a centralized heat-pump system with fan-coil terminals. The modeling is based on a commercially available HP unit. Each unit features a single refrigerant circuit operating with R290 and includes two identical scroll compressors arranged in tandem. An inverter modulates capacity from 30 % to 100 % of nominal. The external heat exchanger is an air coil, while the internal heat exchanger is a stainless-steel plate-type. Depending on the operating mode (heating or cooling), these exchangers alternately function as the condenser or evaporator through the activation of a reversing valve.

The HP model is characterized by its nominal capacity and efficiency. The nominal capacity (P_{fl}) refers to the maximum thermal output in either heating or cooling mode. Heating efficiency is expressed by the Coefficient of Performance (COP), defined as the ratio of thermal output to electrical input. In cooling mode, efficiency is quantified using the Energy Efficiency Ratio (EER), similarly defined as the ratio of

cooling output to electrical input. Manufacturers provide these metrics from standardized tests [71], as functions of evaporator and condenser fluid temperatures. In this study, the HP performance data are sourced from [72]. For the fan coil units selected as terminal devices, the supply water temperature from the heat pump is set to 45 °C for heating and 7 °C for cooling. Once these supply temperature levels are established, the performance of the heat pump can be expressed as a function of the outside air temperature, which serves as the heat source in heating mode (exchanging with the evaporator) and as the heat sink in cooling mode (exchanging with the condenser).

Figs. 3a and 3b present the full load performance curves of the heat pump in heating and cooling modes, respectively, expressed in terms of the coefficient of performance (COP_{fl}) and energy efficiency ratio (EER_{fl}). In the case of an air-source heat pump, outside air is moved by fans integrated within the unit; therefore, the reported EER and COP values inherently account for the electrical power consumption of the fans. The corresponding normalized capacity (NC) is also shown in Figs. 3a and 3b for heating and cooling modes, respectively. NC represents the thermal capacity normalized with respect to the nominal value, i.e., the ratio between the full load capacity (P_{fl}) and the nominal capacity (P_{nom}), as defined in Eq. (1).

$$NC = P_{fl} / P_{nom} \quad (1)$$

In heating mode, the nominal capacity (P_{nom}) corresponds to an outside air temperature of 7 °C with a relative humidity of 90 %, while in cooling mode, it is defined at an outside air temperature of 35 °C. The use of the normalized capacity (NC) enables the performance data presented in Fig. 3 to be scaled for heat pumps with different nominal capacities, allowing application across buildings of varying sizes. Specifically, the hourly thermal load of each building, calculated through EnergyPlus simulations, determines the annual peak load that the heat pump must satisfy. This peak load, in turn, guides the selection of the appropriate HP size based on manufacturers' technical specifications, thereby defining its P_{nom}. During normal operation, the heat pump's control system modulates the delivered capacity to match the contemporary building load. As a result, the system frequently operates under part-load conditions, which can significantly affect its efficiency. To account for the effects of part-load operation, a part-load factor (PLF) is introduced to adjust the full-load efficiency values derived from Figs. 3a and 3b [73–75]. Fig. 3c shows the variation of PLF as a function of the capacity ratio (CR), defined as the ratio between the actual thermal capacity and the maximum capacity deliverable by the HP

under the same operating temperatures. It is noteworthy that the PLF exceeds unity across a wide range of CR values, indicating improved performance under part-load conditions relative to full-load operation. This effect arises from the configuration of the heat pump, in which two compressors operate within a single refrigerant circuit and are driven by an inverter. Under part-load conditions, the heat exchangers effectively become oversized relative to their design performance at full load, leading to enhanced heat transfer efficiency and, consequently, higher system performance.

The PLF trend is derived from part-load performance data corresponding to 30 %, 40 %, 50 %, 60 %, 70 %, 80 %, and 100 % of the maximum capacity, as provided by the manufacturer. These data, obtained through standardized laboratory testing [76], are used by manufacturers to calculate seasonal performance indicators, such as the European Seasonal Energy Efficiency Ratio (ESEER) [77]. In addition to this, the same dataset enables the determination of the PLF [78], and is used to interpolate the PLF curve between the seven measured capacity points. For CR values below 30 %, interpolation is replaced by a simplified estimation algorithm, as recommended by EN 14825 for systems operating with on-off control [76,77].

For residential DHW, each building includes a suitably sized storage tank. During the time period allocated for reheating the storage tank, the heat pump operates exclusively in DHW mode, producing hot water at 50 °C. The COP specific to DHW production is determined based on manufacturer-provided specifications [72].

The HP model adopts a quasi-steady-state calculation approach, implemented through a spreadsheet-based framework and applied individually to each building. At each hourly time step, the required HP capacity is set equal to the building thermal load P, as determined by EnergyPlus simulations. In heating mode, the COP_{fl} and the NC are provided as functions of the outdoor air temperature, as shown in Fig. 3a. Based on the NC value and the known P_{nom}, the actual full-load capacity P_{fl} of the HP is computed using Eq. (2). This value is then used to determine the CR via Eq. (3).

$$P_{fl} = P_{nom} NC \quad (2)$$

$$CR = P / P_{fl} \quad (3)$$

Fig. 3c provides the PLF used in Eq. (4). to obtain the actual COP.

$$COP = COP_{fl} PLF \quad (4)$$

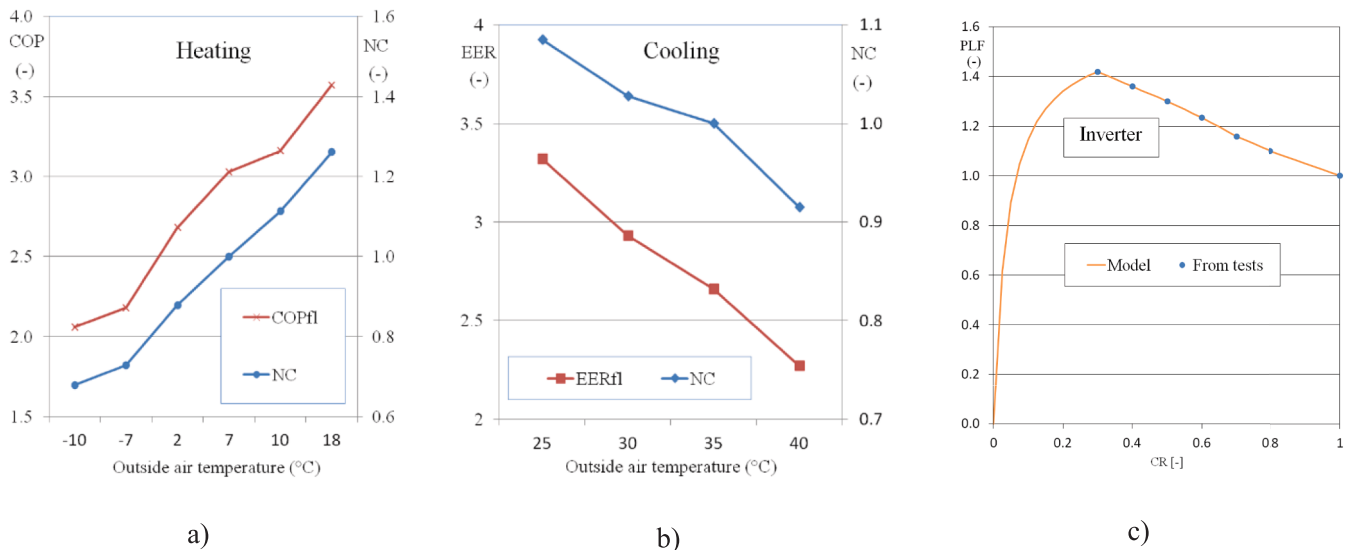


Fig. 3. COP_{fl} or EER_{fl} and normalized capacity NC as a function of the outside air temperature in heating mode (a) and in cooling mode (b). PLF as a function of CR (c).

The electricity consumption of the HP is calculated as the ratio of the actual thermal capacity P to the corresponding simultaneous COP. The seasonal average COP for heating is then determined by dividing the total heating energy delivered during the winter period by the cumulative electrical energy consumed over the same timeframe. In cooling mode, the calculation follows the same methodology, using cooling loads and HP performance data derived from Fig. 3b. For DHW production, the annual average COP is computed as the ratio of the total annual DHW energy demand met by the HP to the associated electricity consumption, following the same procedure used for space heating.

2.5. EES model

The integration of battery-based electrical storage was also evaluated. To simulate storage performance, a model was developed based on the specifications of a representative commercial lithium-ion battery system [79]. The reference unit provides a usable energy capacity of 13.5 kWh, supports a maximum charge/discharge power of 5 kW, and exhibits a round-trip efficiency of 90 %. Instead of modeling a discrete number of battery packs, the simulation allows for a continuous variation in total usable storage capacity. The charge/discharge power-to-capacity ratio is fixed at 0.37 (5/13.5). 3 %/year capacity fade was assumed, totaling ~ 30 % loss over 10 years. This maximum degradation value is warranted by the reference battery manufacturer [80].

Hourly surplus PV first charges the battery; any remaining excess is exported. When PV generation is insufficient to meet demand, the battery discharges up to its available capacity, and any additional demand is met by grid electricity. State of charge updates account for charge/discharge energy, round-trip efficiency, and power limits. This approach enables a realistic simulation of storage behavior in response to hourly variations in production and consumption. Fig. 4 illustrates the flow-chart of the EES model calculations performed at each timestep.

2.6. EES cost-benefit analysis

For each building and location, the size of the electrical storage system was optimized through a cost-benefit analysis. A battery cost of €480 per kWh was assumed, reflecting the current market price of the

selected battery pack [81]. The primary benefit is reduced grid purchases relative to a PV-only case. The corresponding economic benefit was calculated using average 2024 electricity prices for EU countries: €0.2889/kWh for residential and €0.1867/kWh for tertiary applications [82,83]. An annual capacity charge of €28/kW for residential and €25/kW for tertiary buildings was also considered [84].

In addition to on-site consumption, exported PV electricity must also be considered, as self-consumption increases with storage integration, reducing the share of exported energy. Export compensation schemes vary across Europe. In Italy, the traditional net metering scheme is expected to be phased out and replaced by a dedicated withdrawal scheme. Under this arrangement, surplus PV electricity fed into the grid is credited to the producer by the national energy services operator (GSE) [85], with an assumed average compensation rate of €0.10 per kWh [86]. Fiscal incentives also play a significant role in enhancing the overall economic benefit of PV systems. In particular, 50 % of the investment cost for solar systems, including associated battery storage, is currently tax-deductible over a ten-year period. Over the past decade, the cost of lithium-ion battery storage has declined by approximately 90 % (2010–2023) [87]. Despite these reductions, the widespread adoption of battery storage in PV systems still largely depends on supportive policy measures. Many countries have introduced financial incentives, such as tax deductions and subsidies for stored energy, that have proven essential in lowering initial investment barriers and promoting broader adoption [88,89].

In this study, electrical storage sizing was guided by an economic criterion: a maximum acceptable payback period of ten years, consistent with the typical warranty period offered by battery manufacturers [90,91]. Discounted Cash Flow (DCF) analysis was adopted, as it is generally preferred for such evaluations. This method requires the assumption of average values for several financial parameters over the analysis period, namely the next decade. Firstly, the discount rate was established under the assumption that capital is readily available; thus, the discount rate corresponds to the return of the best alternative investment. A value of 2.43 % was assumed, based on the yield of the German Bund [92]. The projected inflation rate over the next decade was set at 2 % [93,94], while the annual electricity price growth rate was assumed to be 3 % [95].

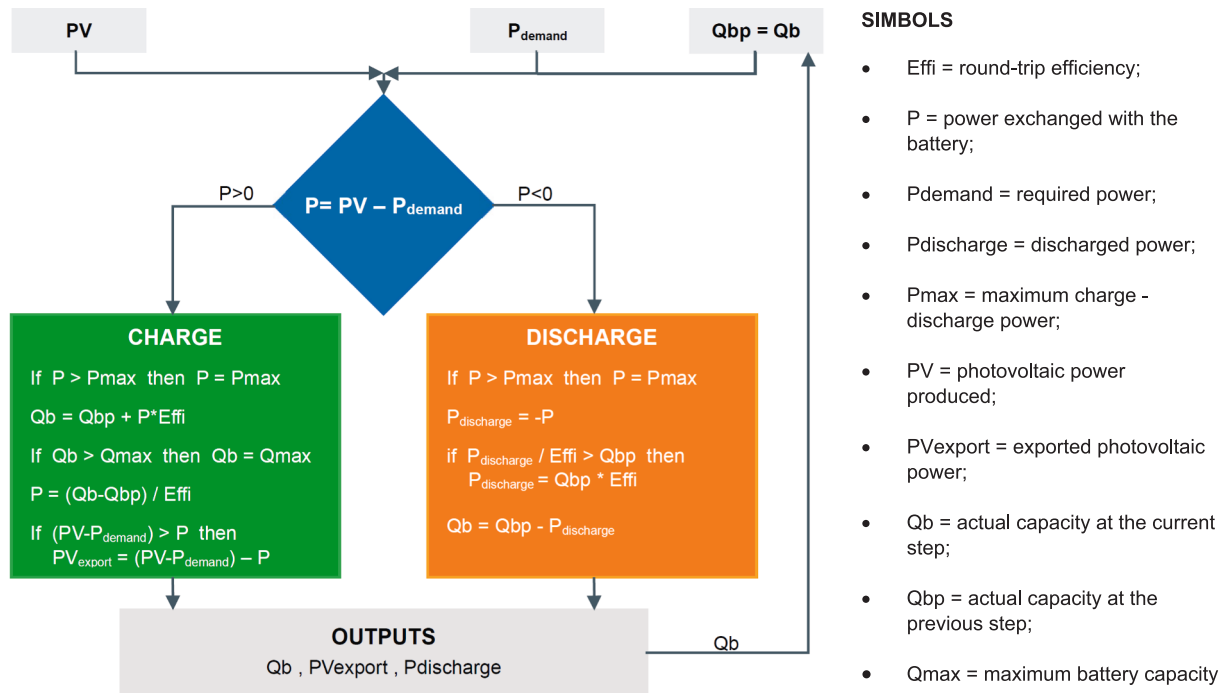


Fig. 4. The flowchart of the battery model.

The DCF analysis yielded both the Discounted Payback Period (DPB) and the Net Present Value (NPV), which were used to optimize the electrical storage size. The NPV method is expressed as follows:

$$NPV = \sum_{t=1}^n \frac{S(1+g')^t}{(1+r')^t} - I \quad (5)$$

Where:

S = annual savings due to the EES

I = EES investment cost

i = inflation rate

g = nominal electricity price growth rate

r = nominal discount rate

g' = deflated electricity price growth rate, calculated as $g' = \frac{g-i}{1+i}$

r' = deflated discount rate, calculated as $r' = \frac{r-i}{1+i}$

n = total number of years considered in the NPV analysis

The NPV was calculated over ten years for different storage capacities, assuming a fixed PV surface. The goal was to identify two optimal storage sizes: the first one maximizing NPV over the decade (i.e., economically optimal), and the second corresponding to a ten-year payback period (NPV = 0) while minimizing grid perturbation. The latter configuration still represents a positive return for the investor, equivalent to that of the best alternative investment considered and maximizes the %RedExc index, as defined in Equation (7). This dual-criteria approach was used to determine the optimal storage size for each building across the three locations considered in the study.

2.7. Performance indicators for evaluating PV + EES systems

To evaluate the performance of the PV + EES system installed in each building, a set of annual reference indicators was adopted in this study. SCR is the share of PV production used on-site. SF is the share of total demand met by self-produced PV. The remaining portion is supplied by the electricity grid.

However, in order to properly assess a building's progress toward achieving the ZEB target, it is essential to consider that a significant share of the electricity delivered by the grid also originates from renewable sources. This share should therefore be added to the locally self-consumed renewable energy produced by the PV system. By combining these two contributions, the total fraction of renewable energy used in the building with respect to its total electricity consumption is obtained. This combined metric is here referred to as SF1. To accurately estimate the renewable share of grid-supplied electricity, an analysis with hourly resolution is required. For this purpose, annual profiles were used that provide the hourly percentage of renewable energy in the electricity mix supplied by the grid. Specifically, three different profiles provided by TERNA, the Italian transmission system operator, were used. These profiles correspond to the three geographical zones analyzed in this study and refer to the year 2024[96]. From the same source, hourly profiles of the CO₂ emissions factor (kgCO₂/kWh) for the three zones were also used to calculate the annual CO₂ emissions resulting from the production of the electricity supplied by the grid to each building under different scenarios. The same hourly profiles were used to estimate the CO₂ savings resulting from the export of surplus PV electricity to the grid. The net annual CO₂ saving was thus obtained as the difference between the emissions avoided through PV exports and those generated by residual grid imports. To assess the overall environmental benefit of PV + EES integration, the Carbon Payback Period (CPP) was then evaluated. This indicator compares the embodied carbon (EC) of the PV + EES system with the annual net CO₂ savings achieved during operation. The CPP, expressed in years, was calculated as the ratio between the EC of the PV + EES system and the annual reduction of CO₂ emissions achieved by the PV + EES installation compared to the baseline scenario without PV. For this purpose, cradle-to-gate embodied carbon values were adopted from recent literature. The EC of

monocrystalline silicon PV modules was assumed to be 580 kg CO₂-equivalent per nominal kilowatt-peak (kWp) installed, consistent with the range reported in [97] (480–810 kg CO₂-eq/kWp, depending on manufacturing location). The EC of balance-of-system (BOS) components—including mounting structures, inverter, and cabling—was assumed to be 100 kg CO₂-eq/kWp, in line with values reported in [97–99]. The EC of lithium-ion batteries was taken as 80 kg CO₂-eq/kWh, consistent with recent *meta*-analyses and life-cycle assessments published in [100,101].

Building-integrated photovoltaic (BIPV) systems can introduce disturbances to the electrical grid due to their decentralized nature and variable power output. Reducing the bidirectional energy exchange between BIPV systems and the electrical grid enhances grid performance by minimizing voltage fluctuations, power flow imbalances, and grid congestion. When local PV generation is primarily self-consumed or coupled with on-site storage, it decreases the need for energy export to, or import from, the grid. This localized energy management mitigates reverse power flows and reduces the strain on distribution transformers and feeders, particularly in low-voltage networks. Furthermore, limiting these exchanges contributes to grid stability by lowering the variability introduced by intermittent solar production, facilitating more predictable load profiles and easing the requirements for grid regulation, protection coordination, and infrastructure reinforcement.

A new index is introduced in this paper to quantify the perturbation caused to the electrical grid by a BIPV system. Over the course of a year, the total electrical exchange with the grid is calculated as the sum of the absolute values of the electricity imported by the building (E_{delivery}) and the electricity exported to the grid (E_{export}). The proposed index, referred to as Exchange (Exc), expresses this total exchange relative to the building's total annual electricity demand (E_{demand}), as defined in Eq. (6). This formulation allows for a generalized comparison of grid interaction across different buildings by normalizing the absolute value of electrical fluxes with respect to the annual demand.

$$\text{Exc} = \frac{E_{\text{delivery}} + E_{\text{export}}}{E_{\text{demand}}} \quad (6)$$

To quantify the benefit in terms of grid exchange stability resulting from the integration of a specific EES, this paper evaluates the difference between the Exchange index (Exc) in the absence of storage (Exc no storage) and that in the presence of the EES (Exc storage) within the same BIPV system. A new index, termed Percentage Reduction in Exchange (%RedExc), is introduced and defined in Eq. (7). This index represents the percentage reduction in Exc relative to the value without storage, thereby quantifying the improvement in grid interaction due to the EES.

$$\% \text{RedExc} = 100 \frac{\text{Exc}_{\text{no storage}} - \text{Exc}_{\text{storage}}}{\text{Exc}_{\text{no storage}}} \quad (7)$$

Electrical exchanges between PV-equipped buildings and the grid are not inherently positive or negative; rather, they always represent a perturbation that the system operator must balance. Such interactions can bring both benefits and challenges, depending on their temporal coincidence with demand and the availability of renewable energy in the grid mix. The authors in [102] investigated the potential benefits of energy exchanges enabled by advanced control strategies for managing PV generation and electric devices such as heat pumps. These systems can exploit real-time electricity pricing schemes designed to encourage users to absorb or supply electricity according to grid imbalances. However, the present study refers to the current considered context, where such pricing mechanisms are not widespread. Even assuming the presence of dynamic pricing, EES plays a key role in regulating power exchanges with the grid. The %RedExc index quantifies the capability of the EES to modulate and reduce the share of electricity exchanged with the grid compared to a configuration without storage. In the investigated scenario, storing electricity when PV production exceeds demand

reduces energy exports and subsequently allows part of the demand to be met without drawing from the grid. Overall, the reduction in exchanges solely attributable to the integration of EES is consistently advantageous, as it decreases grid losses and mitigates the operational burden on the network.

3. Results

3.1. Electrical demand of the buildings

Fig. 5a reports annual electricity demand for two archetypes (residential, tertiary) in Milan, Rome, and Palermo. Demands include all end-uses: space conditioning, lighting, equipment, and, only for residential, DHW. The simulations were performed using hourly dynamic modelling in EnergyPlus for three different urban morphologies, corresponding to LCZ 3, LCZ 2, and LCZ 1 (representing buildings with 3, 7, and 12 stories, respectively). Floor area per level is fixed; height varies, altering conditioned volume, S/V ratio, and solar exposure. This approach allows for isolating the effect of vertical geometric configuration and assessing the influence of morphology on energy demand under equal urban density conditions.

Results indicate a systematic increase in electricity demand with building height, although the magnitude of this increase varies significantly between building uses and climates.

In residential buildings, the transition from LCZ 3 to LCZ 1 leads to an increase in annual consumption from 73 to 177 MWh in Milan, from 31 to 125 MWh in Rome, and from 29 to 117 MWh in Palermo. This trend is consistent with the growth in conditioned volume. For the tertiary sector, the increase is even more pronounced: from 54 to 271 MWh in Milan, from 52 to 271 MWh in Rome, and from 50 to 261 MWh in Palermo. The steeper rise reflects higher internal loads (lighting, equipment) and mechanical ventilation in the tertiary sector. At the same LCZ, tertiary demand is consistently higher than residential.

The climate-related North–South variation is particularly evident in low-rise buildings: in residential LCZ 3, demand drops from 73 MWh/year in Milan to 29 MWh/year in Palermo (–60 %), mainly due to reduced heating needs. In high-rise buildings (LCZ 1), the decrease is more limited (from 177 to 117 MWh/year, –34 %). In the tertiary sector, this variation is much smaller: –7% in LCZ 3 (from 54 to 50 MWh/year) and nearly negligible in LCZ 1 (–4%, from 271 to 261 MWh/year). As floors increase, envelope-driven (climate-sensitive) loads matter less than internal loads, which vary little with latitude.

Fig. 5b details the percentage breakdown of total annual electricity demand for the same cases presented in Fig. 5a, disaggregated into five end-use categories: heating, cooling, DHW production, lighting, and appliances. The data, expressed as a share of the total electricity demand of each building, reveal significant differences in load distribution

according to building use, urban morphology (LCZ), and climate.

In the residential sector, heating accounts for a significant share of total energy use in Milan, up to 25 % for LCZ 3, but drops sharply in Rome (approximately 6 %) and is almost negligible in Palermo (around 1 % across all configurations), highlighting the strong climate dependency of heating demand. Conversely, cooling demand increases progressively from North to South, ranging from 5–6 % in Milan to about 10 % in Rome and 11–12 % in Palermo. DHW shares remain relatively stable between Rome and Palermo (17–18 %) but are lower in Milan (11–14 %) due to the greater share of heating. Daylighting control proves effective, with its contribution decreasing from 22–29 % in Milan to 18 % in Rome and 19 % in Palermo. Appliance loads remain the dominant end-use across all locations, ranging from 36 % to 52 %, with higher shares in warmer climates where other loads are reduced.

In the tertiary sector, total electricity demand is overwhelmingly dominated by equipment loads, ranging from 69 % (Milan and Rome, LCZ 1) to 76 % (Palermo, LCZ 3), followed by lighting, which increases significantly with building height (up to 13 % in Milan and Rome, LCZ 1). Cooling remains a relevant component across all climates (13–17 %), whereas heating is secondary: 10 % in Milan LCZ 3, 6 % in Rome LCZ 1, and negligible in Palermo LCZ 1, also due to the compensating effect of internal gains.

Overall, the figure shows that residential buildings feature a more diversified mix of loads, with heating playing a more substantial role, although appliances remain the primary source of consumption. In the tertiary sector, internal electric loads are even more predominant. These variations in percentage composition, driven by both morphological and climatic differences, have direct implications for the effectiveness of PV + EES integration, due to the differing temporal profiles of electric loads.

3.2. Seasonal matching between electricity demand and photovoltaic production

First, using the procedure described in Subsection 2.4, the PV production was evaluated. Table 4 reports annual PV generation for each location and building use. Importantly, within the same city and building category, the PV production remains consistent across buildings regardless of the number of floors modeled.

Table 4

Total annual PV production of the roof (kWh).

	Residential	Tertiary
Milan	119,265	111,694
Rome	130,711	127,841
Palermo	155,215	144,416

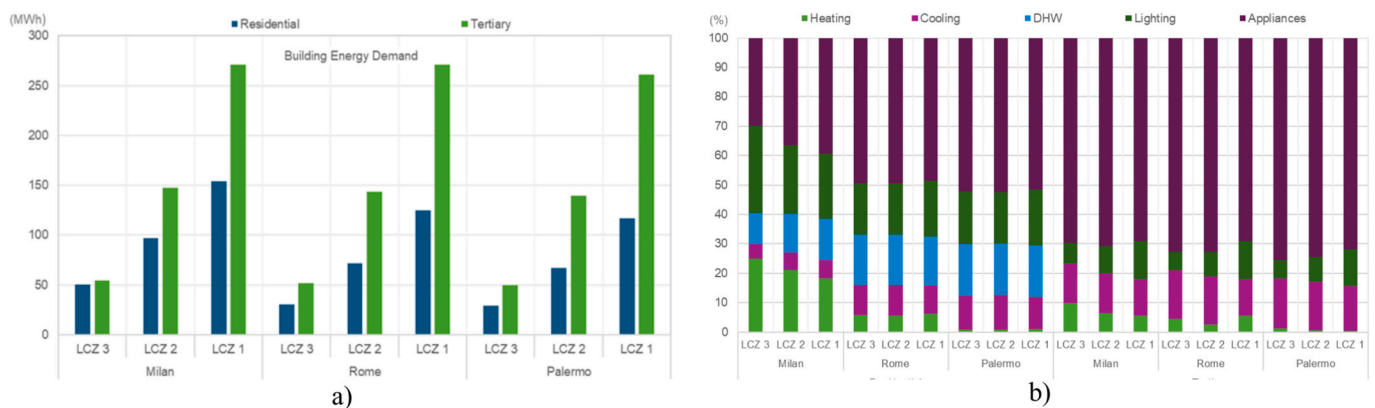


Fig. 5. Total annual electricity demand (MWh/year) a) and percentage breakdown of total annual electricity demand b) for residential and tertiary buildings simulated in the three climatic locations and for each LCZ.

Figs. 6a and 6b show the monthly profiles of total electricity demand and PV production in the three climatic contexts (Milan, Rome, and Palermo), for the three LCZ configurations, respectively for residential and tertiary building uses. The plots compare monthly PV generation with monthly demand. Monthly demand data are derived from hourly dynamic simulations of the building-system configuration and are consistent with the annual results previously presented in Fig. 5. PV production was computed as described earlier.

In the residential sector (Fig. 6a), electricity demand exhibits marked seasonality, particularly in Milan and Rome, with winter peaks attributable to space heating and the reduced efficiency of heat pumps during the coldest months. For instance, in Milan LCZ 1, monthly demand ranges from approximately 28,700 kWh in January to 9,043 kWh in September. Conversely, PV production follows the typical summer-centered profile, with a maximum of 20,027 kWh/month in July in Palermo. The seasonal mismatch between demand and generation is clearly visible: during winter months, available PV production is limited compared to demand, whereas in summer months, potential surpluses may be available for self-consumption, especially during nighttime if adequate storage systems are present. In southern climates (e.g., Palermo), this seasonal decoupling is less pronounced, although summer overproduction and residual winter demand remain relevant. As building height increases (from LCZ 3 to LCZ 1), electricity demand rises significantly, while the seasonal pattern remains similar, directly affecting storage system sizing.

In the tertiary sector (Fig. 6b), the analysis reveals a very different behavior. Electricity demand is less seasonal and more stable throughout the year, with a predominance in summer due to cooling loads and the continuous operation of equipment and lighting during daytime hours. For example, in Milan LCZ 1, demand varies between approximately 18,337 kWh/month (March) and 30,279 kWh/month (August), with a profile that exhibits better temporal alignment with PV generation. This synchronicity makes PV-alone more effective in tertiary buildings. In Palermo, tertiary configurations in LCZ 1 approach nearly full summer coverage of electricity demand by PV production. As in the residential case, electricity demand increases with height, but here without significantly affecting the temporal coherence between load and production.

Overall, the two figures confirm that the compatibility between solar generation patterns and load profiles strongly depends on both building use and morphology. In the residential sector, the decoupling between the two profiles is more pronounced, especially during winter and in colder climates, and also due to the lack of coincidence between production and consumption hours. In contrast, the tertiary sector benefits from more favorable timing for instantaneous self-consumption, further supported by the lower impact of winter heating loads.

In Fig. 7, the hourly profiles of energy demand and PV production are shown for two representative days, one in winter (10 December) and one

in summer (23 July) for the LCZ 2 building in Milan. Fig. 7a illustrates that during the winter day, the modest PV surplus observed in the residential case during sunny hours can be stored and later used in the evening, whereas in the tertiary case no surplus is available. During the summer day (Fig. 7b), the PV surplus allows full coverage of the evening demand through EES in the residential case. In the tertiary case, the midday reduction in demand due to the work break leads to a surplus that can be stored and utilized during other periods.

3.3. Impact of storage capacity on PV system performance

Figs. 8–10 show how performance indicators vary with storage capacity, for both residential and tertiary sectors. The analysis is performed for three LCZ configurations and across the three climatic contexts of Milan, Rome, and Palermo.

The reported indicators include: the share of photovoltaic energy used on-site (SCR), two load matching indices (SF and SF1), and the reduction in net electricity exchanges with the grid (%RedExc). Capacity increases in 10 kWh steps. The trend of the normalized NPV (%NPV), referred to its maximum value, is also reported to clarify the cost-benefit evolution and identify the economically viable range of storage sizes.

For the residential sector (Figs. 8a, 9a, 10a), the benefits of introducing storage are also assessed in economic terms: for each LCZ, the maximum value on the x-axis represents the threshold beyond which the DPB exceeds 10 years and the NPV over 10 years becomes negative. This threshold identifies the maximum economically sustainable storage capacity for a user. Additionally, a circle on the x-axis marks the capacity that maximizes the 10-year NPV. In Milan, these optimal capacities are 40, 70, and 100 kWh for LCZ 3, 2, and 1, respectively; in Rome, 30, 80, and 110 kWh; in Palermo, 30, 90, and 130 kWh.

In Milan LCZ 3, self-consumption (SCR) increases from 29.5 % to 41.3 %, SF1 reaches 76.0 %, SF 65.2 and %RedExc peaks at 25.3 %. Thus, at low demand, storage reduces exchanges less effectively. In LCZ 2, SCR reaches 60.8 %, SF1 is 73.7 %, SF 62.3 % and %RedExc rises to 34.1 %. In LCZ 1, the impact of storage is more pronounced: up to 80.3 % self-consumption, SF1 of 70.2 %, SF of 54.1 %, and %RedExc of 37.4 %. Results show a clear increase in SCR and a decline in SF and SF1 as building height, and thus electricity demand, increases. The consistent gap between SF and SF1 confirms the importance of accounting for the renewable share of grid-supplied electricity.

In Rome, performance improves across all configurations due to higher annual solar radiation and lower electricity demand. In LCZ 3, SF and SF1 can reach 98.5 % with maximum storage, but SCR remains limited to 23.1 % and %RedExc to 20.6 %, indicating that storage cannot significantly improve these two indicators under very low demand conditions, which result in substantial grid export. In LCZ 2, the upper threshold for storage capacity is 130 kWh, beyond which further increases do not lead to significant performance gains. This storage size

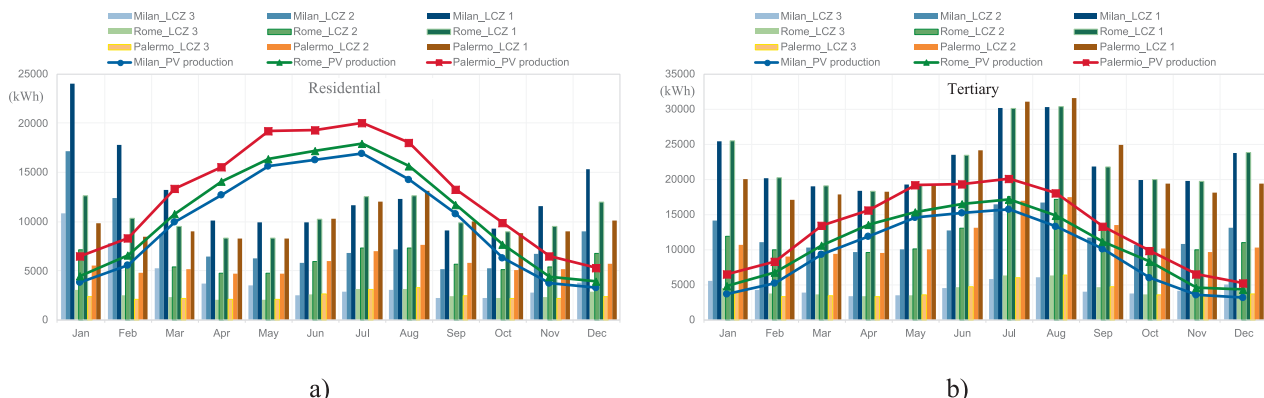


Fig. 6. Monthly demand vs PV production by city and LCZ: (a) residential, (b) tertiary.

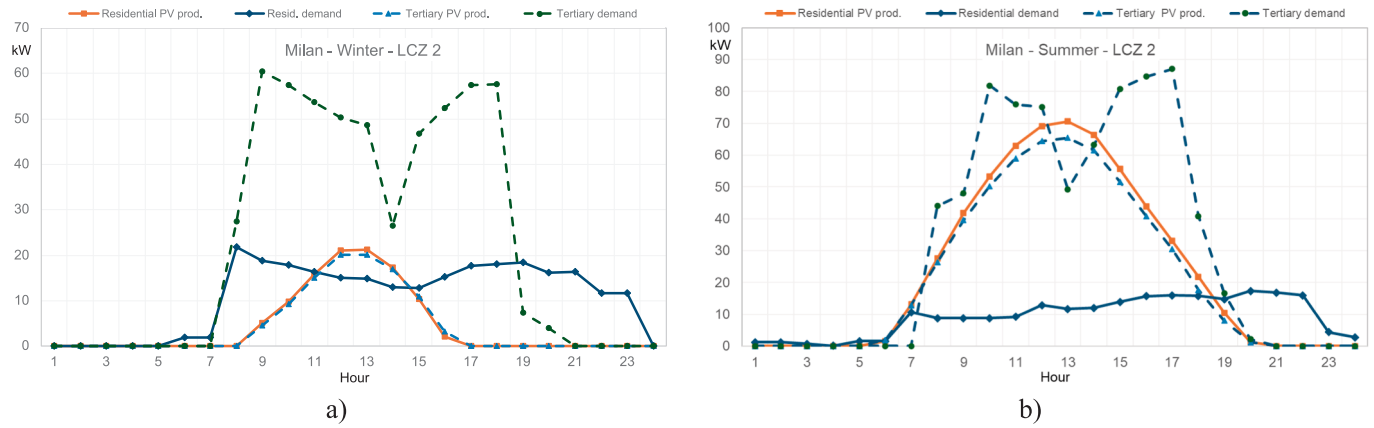


Fig. 7. Hourly profiles of energy demand and PV production for residential and tertiary cases on a winter day (a) and a summer day (b) for the LCZ 2 building in Milan.

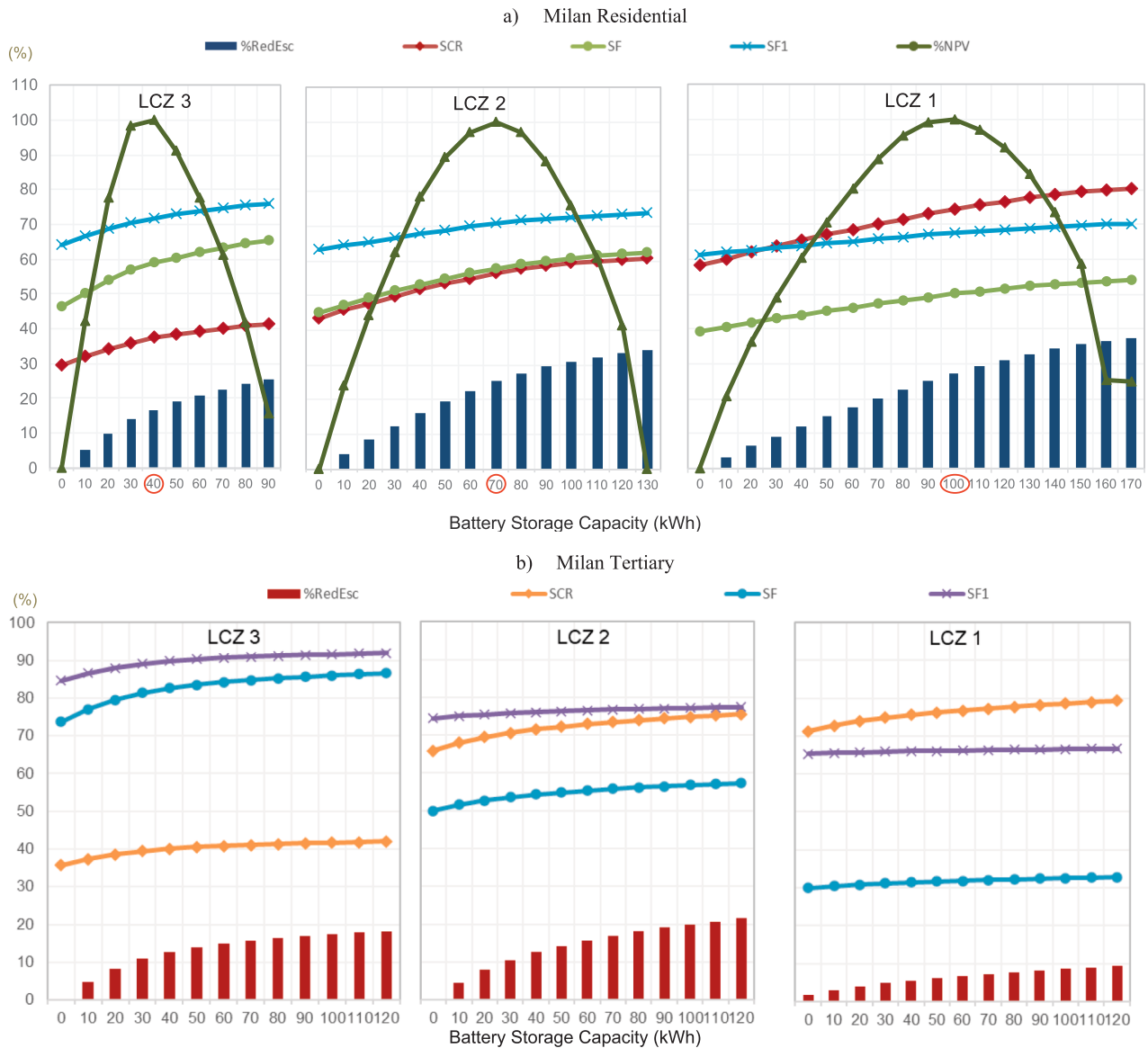


Fig. 8. SCR, SF, SF1, and %RedExc as a function of EES capacity for residential (a) and tertiary (b) buildings in the three LCZ configurations of Milan. For residential buildings, the %NPV trend is also reported, and the EES capacities that maximize the ten-year NPV are highlighted with circles.

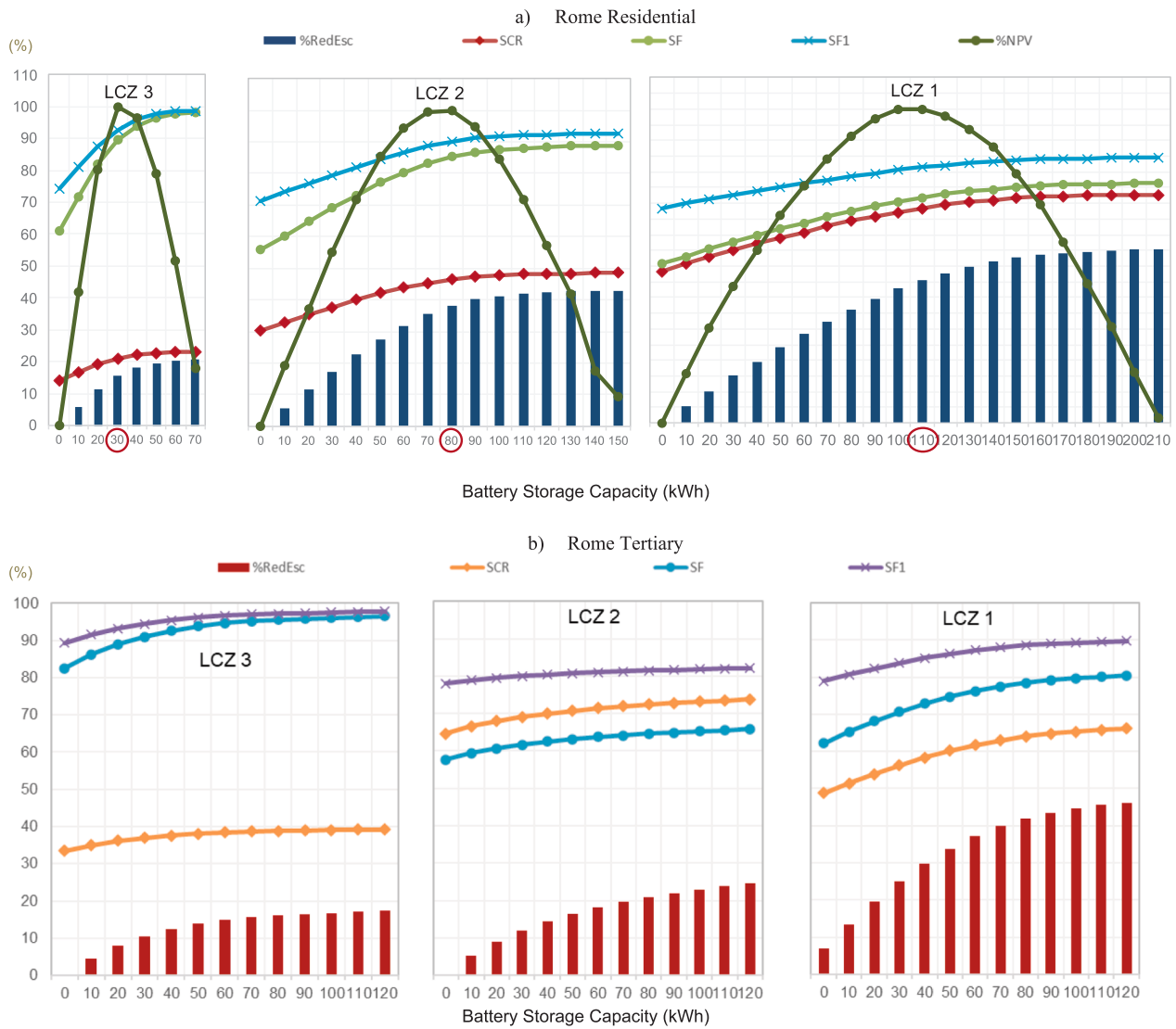


Fig. 9. SCR, SF, SF1, and %RedExc as a function of EES capacity for residential (a) and tertiary (b) buildings in the three LCZ configurations of Rome. For residential buildings, the %NPV trend is also reported, and the EES capacities that maximize the ten-year NPV are highlighted with circles.

achieves 48.3 % self-consumption, 92.4 % SF1, and 42.7 % %RedExc, demonstrating greater effectiveness in reducing grid impacts as self-consumption increases. In LCZ 1, the upper threshold is 190 kWh of storage, which enables 72.6 % SCR, 84.4 % SF1, and 55.0 % %RedExc. The storage sizes that maximize NPV shift to higher values than in Milan, indicating that better solar conditions and demand profiles improve the economic feasibility of larger batteries.

In Palermo, the PV + EES system shows the best performance among the three cities. High solar availability and a demand profile dominated by summer cooling make storage particularly beneficial. In LCZ 3, SF1 reaches 100 % with only 50 kWh of storage, but SCR is limited to 18.6 % and %RedExc to 16.7 %, due to low daily demand relative to PV generation. In LCZ 2, performance improves substantially: the upper threshold for storage is 130 kWh, which yields 42.1 % self-consumption, 98.1 % SF1, and 41.3 % %RedExc. In LCZ 1, the threshold is 200 kWh, achieving 65.8 % SCR, 91.6 % SF1, and 61.2 % %RedExc. In all cases, the storage capacity maximizing NPV is higher than in Rome and Milan (30–80–130 kWh), confirming that Southern Italy's climate enables more efficient and economically viable storage deployment.

In the tertiary sector (Figs. 8b, 9b, 10b), the analysis focuses exclusively on the technical effectiveness of storage, as in all cases the DPB exceeds 10 years. This outcome is due to several factors. First, electricity

consumption in the tertiary sector is concentrated during daytime hours when PV production occurs, making storage less useful. Secondly, under the assumptions adopted, the electricity purchase cost for the tertiary sector is significantly lower than that for the residential sector, reducing the economic benefit of self-consumption. It should also be noted that this assessment is strongly linked to the cost of storage systems, and a further cost reduction in the coming years, as recent trends suggest, could influence the result.

The x-axis is consistent across configurations, covering a range from 0 to 120 kWh, where performance generally stabilizes. This provides a technically meaningful range for evaluating storage effects on grid interaction, independent of economic feasibility under the assumed financial conditions. In Milan–LCZ 3, self-consumption is already high without storage (35.7 %) due to strong overlap between PV generation and daytime loads typical of tertiary buildings. Adding storage brings moderate gains: with 120 kWh, SCR rises to 42.0 %, SF1 to 91.9 %, SF to 86.6 %, and %RedExc to 18.2 %. In LCZ 2, starting from 65.9 % self-consumption, storage raises it to 75.5 %, with SF of 57.4 %, %RedExc of 21.5 %, and SF1 reaching 77.4 %.

In LCZ 1, self-consumption is already very high without storage (71.3 %) and reaches 79.3 % with 120 kWh; SF1 is 66.6 %, SF is only 32.8 %, and %RedExc is limited to 9.0 %, suggesting limited added value

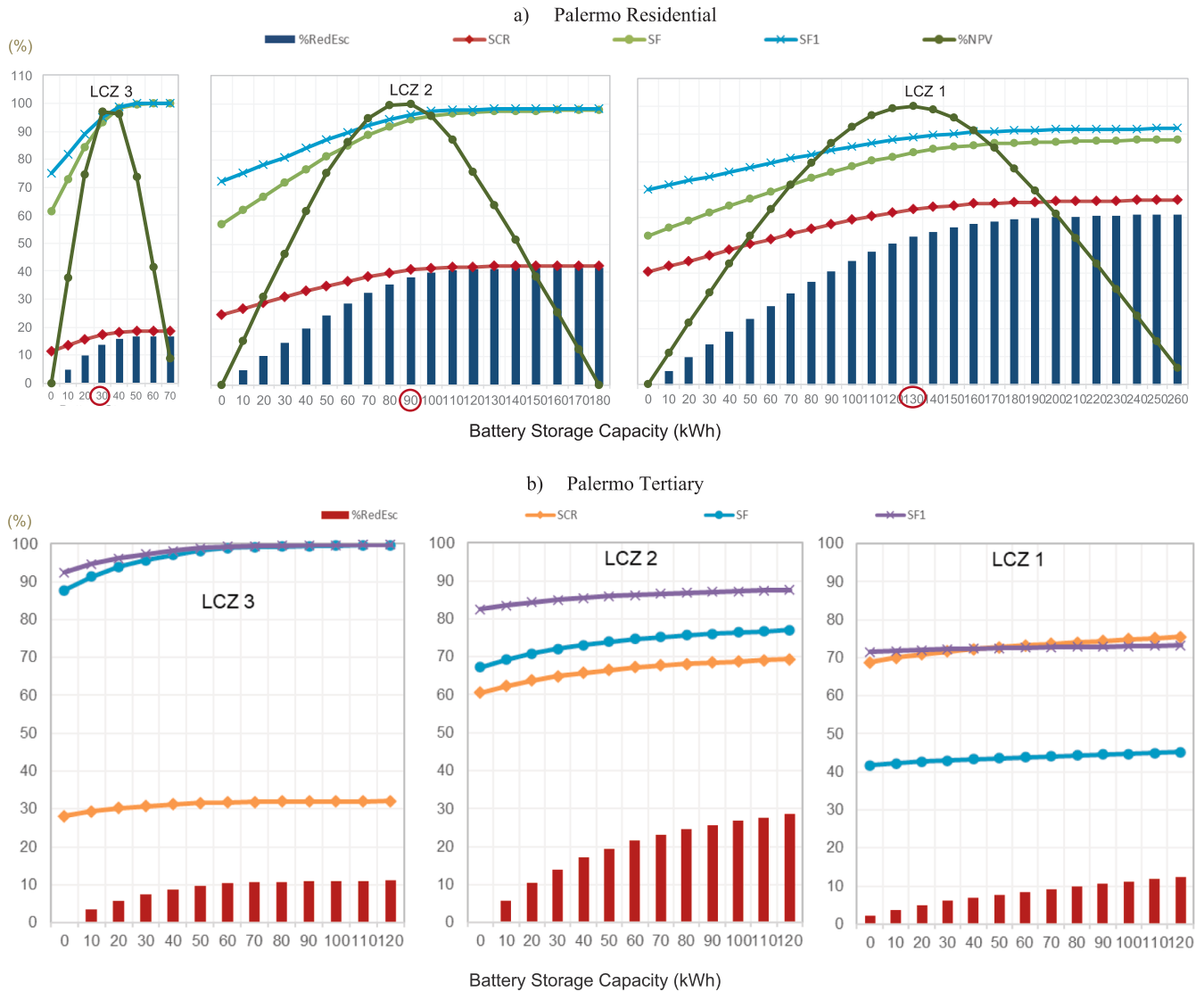


Fig. 10. SCR, SF, SF1, and %RedExc as a function of EES capacity for residential (a) and tertiary (b) buildings in the three LCZ configurations of Palermo. For residential buildings, the %NPV trend is also reported, and the EES capacities that maximize the ten-year NPV are highlighted with circles.

of storage when most PV is already self-consumed. The frequent gap between SF1 and SF further confirms the importance of considering the renewable share of grid electricity, which is more available during the day when tertiary demand peaks.

In Rome, more favorable demand and generation profiles further enhance storage performance. In LCZ 3, 120 kWh of storage raises SCR from 33.5 % to 39.2 %, with SF1 at 97.7 % and %RedExc at 17.3 %, again, a modest impact. In LCZ 2, self-consumption increases from 64.8 % to 73.8 %, with SF1 at 82.2 % and %RedExc at 24.7 %. In LCZ 1, SCR rises from 48.8 % to 66.1 %, SF1 reaches 89.6 %, and %RedExc climbs to 46.2 %, reflecting a better synergy between load and solar generation.

In Palermo, tertiary PV + EES performance is the highest among the three cities, due to a combination of stable electricity demand (driven by cooling loads) and high solar irradiance. In LCZ 3, storage raises SCR from 28.2 % to 32.0 %, with SF1 reaching 100 %, and %RedExc at 11.1 %, as in other low-demand cases. In LCZ 2, self-consumption reaches 69.3 %, SF1 87.6 %, and %RedExc 28.5 %, with low sensitivity to storage size. In LCZ 1, with 120 kWh of storage, self-consumption peaks at 75.5 %, SF1 at 73.1 %, and %RedExc at 11.8 %.

Overall, the tertiary sector exhibits significant technical advantages from storage integration, even in the absence of economic profitability. Moreover, geographic location strongly affects performance: Palermo

and Rome outperform Milan in both self-consumption and grid exchange reduction, underlining the importance of jointly considering climate, urban morphology, and building use when optimizing PV + EES systems. Finally, high-rise buildings (LCZ 1) benefit most from storage, due to higher and more continuous electricity demand, which enables more effective management of PV production.

3.4. Impact of storage integration on CO₂ emissions reduction

The final part of the analysis focuses on quantifying the environmental benefit of storage integration in terms of CO₂ emissions reduction associated with grid-supplied electricity.

Fig. 11 shows percent CO₂ reduction relative to a no-PV baseline, for the building configurations already simulated. Three PV system integration strategies are compared: PV system without storage (PV only), storage sized to maximize NPV (max-NPV), and storage sized to maximize %RedExc (max-%RedExc). For tertiary, we report PV-only and a 120 kWh storage case.

In the residential sector (Fig. 11a), the integration of electrical storage clearly enhances emissions reduction across all climatic zones and morphologies. The gap between the PV-only and PV + storage scenarios becomes particularly evident in warmer climates such as Rome

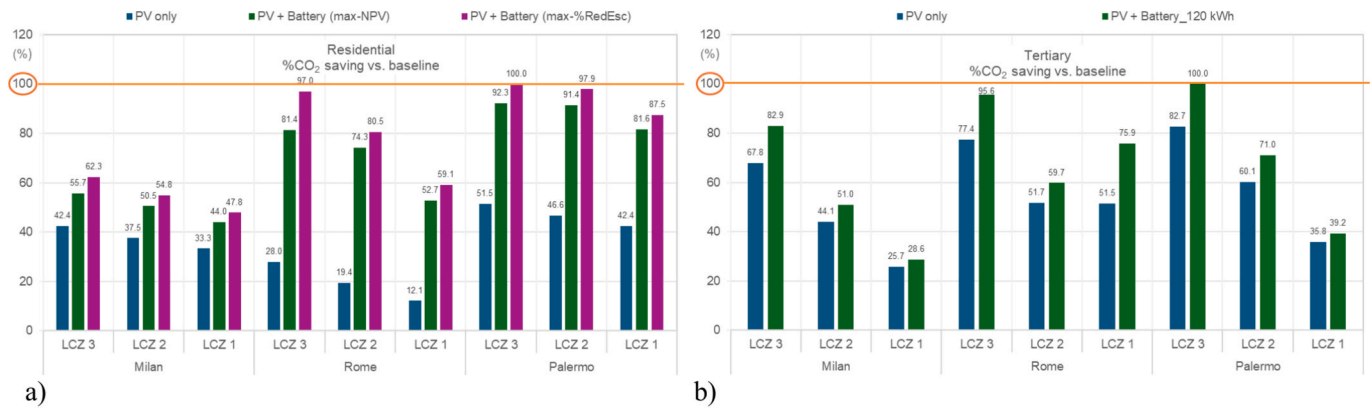


Fig. 11. CO₂ emission reduction vs. baseline without PV, for residential (a) and tertiary (b) buildings. Strategies: PV only, storage for max NPV (max-NPV), storage for max % reduction (max-%RedExc). For tertiary: PV only and 120 kWh battery.

and Palermo, where higher solar availability allows for more effective utilization of the EES. Low-rise (LCZ 3) benefits most; in Palermo, CO₂ reductions reach full decarbonization.

In the tertiary sector (Fig. 11b), although storage is not economically viable under the current assumptions, it still delivers appreciable environmental benefits, especially in locations with abundant solar radiation. CO₂ savings are again particularly high in LCZ 3 configurations. Compared to the residential sector, the savings are even greater due to the more favorable alignment between PV generation and daytime electricity demand. An exception is LCZ 1, where higher demand limits PV effectiveness. Overall, the additional contribution of storage is generally less pronounced in the tertiary sector than in the residential one, as substantial CO₂ reductions are already achieved in the PV-only scenario, thanks to the high self-consumption typical of tertiary buildings.

These findings confirm that the integration of EES with rooftop PV installations can significantly enhance the decarbonization potential, particularly in southern climates and in buildings with lower electricity demand, enabling the achievement of ZEB conditions in some cases.

Within the framework of the overall environmental benefit analysis, the CPP calculation was carried out. Table 5 reports the resulting CPP values, illustrating the dual-criteria approach adopted in this study for determining the optimal storage capacity of the EES. Specifically, for residential buildings, the configuration maximizing the NPV (max NPV) was selected, while for tertiary buildings the configuration minimizing grid perturbation (max %RedExc) was chosen. Results are presented for three local climate zones (LCZs) under the three representative climatic conditions.

The short CPP values highlight the substantial environmental benefits associated with the two proposed system configurations.

4. Discussion

4.1. Overall interpretation of results

The results highlight how urban morphology, climate, and building use jointly influence the technical, economic, and environmental performance of PV + EES systems. The LCZ-based framework adopted in

this study proved effective in linking building-scale behavior to city-scale representativeness, allowing differences in demand profiles, solar irradiation, and morphology to be captured within a unified structure. This methodological approach enhances the transferability of results to other urban contexts. The findings confirm the positive role of electrical storage in improving self-consumption and reducing energy costs. This investigation extends existing evidence [35–41] by providing detailed confirmation within a context where the penetration of electrical storage systems remains limited despite the rapid expansion of rooftop PV [42,43].

From a grid perspective, the observed divergence between residential and tertiary configurations is not only related to load and PV production but also to the hourly profiles of the renewable share and CO₂ emissions of the electricity imported from the grid. The introduction of the SF1 and %RedExc indicators provides a novel framework for quantifying the interaction between buildings and the grid. SF1, by accounting for the renewable share of grid electricity, extends the conventional interpretation of self-sufficiency toward a grid-aware perspective, which gains importance under progressive grid decarbonization. Conversely, the %RedExc index offers an operational metric for assessing a dimension seldom captured by traditional indicators. Together, these two indicators support a more comprehensive evaluation of building-level strategies, bridging the gap between local self-consumption optimization and grid stability objectives.

4.2. Limitations

The sample is statistically representative but not exhaustive, motivating the need to extend the analysis to different contexts. Nevertheless, the study provides a detailed definition of an operational methodology based on standardized classification schemes of urban form, climate, and energy performance parameters, allowing its replication and potential generalization to other contexts. Similarly, the new %RedExc index was tested within the analyzed framework, while its applicability and relevance under different grid scenarios are left for future research.

5. Conclusions

This study evaluated the integration of EES into PV systems by applying the LCZ framework across representative Southern European climates. This methodological choice ensured the robustness of the analysis and allowed the findings to be extended to different urban contexts. Results show divergent economic outcomes for residential vs. tertiary buildings. In residential cases, capacities meeting the 10-year NPV criterion yield positive outcomes; SF1, SCR, and %RedExc peak below the break-even size. By contrast, tertiary cases show negative 10-

Table 5

CPP (yr) for residential and tertiary buildings with two optimized EES configurations across the studied LCZs and climates.

	Residential PV + EES max NPV			Tertiary PV + EES max %RedExc		
	LCZ 3	LCZ 2	LCZ 1	LCZ 3	LCZ 2	LCZ 1
Milan	3.9	4.0	4.1	4.4	4.4	4.4
Rome	3.5	3.7	3.8	3.8	3.8	3.8
Palermo	2.9	3.1	3.2	3.1	3.1	3.1

year NPV under current assumptions despite clear technical gains, highlighting the decisive role of load profiles and tariffs. These findings indicate that, unlike in the residential sector, in other building uses the economic viability of EES integration cannot always be achieved through financial optimization of system sizing. Nevertheless, the technical benefits of storage remain evident also in this case, which highlights the importance of further supportive policy frameworks to foster the wider adoption of storage systems. Among the indicators, hourly SF1 is especially informative because it adds the grid's renewable share to self-consumed PV, giving a more accurate measure of progress toward ZEB. This contribution becomes especially relevant when demand is concentrated during daytime hours. When compared to the condition without EES, it is noteworthy to highlight the performance of the analyzed indexes achieved by implementing EES systems in correspondence to the maximum capacity allowed by the 10-year net present value constraint ($NPV = 0$). In the Milan residential LCZ 1 case, the SCR increases from 58.2 % to 80.3 %. The SF1 index reaches 100 % in Palermo LCZ 3, up from 74.8 % in the residential and 92.4 % in the tertiary cases. The %RedExc index attains its peak value of 61.2 % in Palermo LCZ 1. For decarbonization, CO_2 reductions from storage are larger in residential cases, due to lower demand – PV coincidence and the ability to cover night-time loads when the grid mix is more carbon-intensive. Findings indicate that batteries are often essential to approach, and in some cases achieve, ZEB, especially in lower-demand buildings. The proposed %RedExc index represents an additional original contribution, as it quantifies the reduction of grid disturbances enabled by EES. When applied at the design stage, this index can be compared with a minimum threshold required from the battery at the grid interface and incorporated into policy requirements or incentive schemes aimed at promoting the deployment of EES. In this sense, SF1 and %RedExc together provide a novel framework for linking building-level storage optimization to grid stability and decarbonization objectives.

CRedit authorship contribution statement

Luigi Schibuola: Writing – review & editing, Methodology, Conceptualization. **Chiara Tambani:** Writing – original draft, Visualization, Validation, Software, Methodology, Formal analysis, Data curation, Conceptualization.

Declaration of competing interest

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

Data availability

Data will be made available on request.

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