

Article

Study of a University Campus Smart Microgrid That Contains Photovoltaics and Battery Storage with Zero Feed-In Operation

Panagiotis Madouros ¹, Yiannis Katsigiannis ^{2,*}, Evangelos Pompodakis ², Emmanuel Karapidakis ² and George Stavrakakis ¹

¹ School of Electrical and Computer Engineering, Technical University of Crete, GR-73100 Chania, Greece; panagiotismadour@gmail.com (P.M.); gstavrakakis@tuc.gr (G.S.)

² Department of Electrical and Computer Engineering, Hellenic Mediterranean University, GR-71410 Heraklion, Greece; bobodakis@hotmail.com (E.P.); karapidakis@hmu.gr (E.K.)

* Correspondence: katsigiannis@hmu.gr

Abstract

Smart microgrids are localized energy systems that integrate distributed energy resources, such as photovoltaics (PVs) and battery storage, to optimize energy use, enhance reliability, and minimize environmental impacts. This paper investigates the operation of a smart microgrid installed at the Hellenic Mediterranean University (HMU) campus in Heraklion, Crete, Greece. The system, consisting of PVs and battery storage, operates under a zero feed-in scheme, which maximizes on-site self-consumption while preventing electricity exports to the main grid. With increasing PV penetration and growing grid congestion, this scheme is an increasingly relevant strategy for microgrid operations, including university campuses. A properly sized PV–battery microgrid operating under zero feed-in operation can remain financially viable over its lifetime, while additionally it can achieve significant environmental benefits. The study performed at the HMU Campus utilizes measured hourly data of load demand, solar irradiance, and ambient temperature, while PV and battery components were modeled based on real technical specifications. The study evaluates the system using financial and environmental performance metrics, specifically net present value (NPV) and annual greenhouse gas (GHG) emission reductions, complemented by sensitivity analyses for battery technology (lead–carbon and lithium-ion), load demand levels, varying electricity prices, and projected reductions in lithium-ion battery costs over the coming years. The findings indicate that the microgrid can substantially reduce grid electricity consumption, achieving annual GHG emission reductions exceeding 600 tons of CO₂. From a financial perspective, the optimal configuration consisting of a 760 kWp PV array paired with a 1250 kWh lead–carbon battery system provides a system autonomy of 46% and achieves an NPV of EUR 1.41 million over a 25-year horizon. Higher load demands and electricity prices increase the NPV of the optimal system, whereas lower load demands enhance the system's autonomy. The anticipated reduction in lithium-ion battery costs over the next 5–10 years is expected to provide improved financial results compared to the base-case scenario. These results highlight the techno-economic viability of zero feed-in microgrids and provide valuable insights for the planning and deployment of similar systems in regions with increasing renewable penetration and grid constraints.

Keywords: smart microgrids; renewable energy; photovoltaics; battery storage; zero feed-in; energy transition; optimization; university campus



Academic Editors: Philippe Poure and Shamsodin Taheri

Received: 3 November 2025

Revised: 25 December 2025

Accepted: 20 January 2026

Published: 3 February 2026

Copyright: © 2026 by the authors.

Licensee MDPI, Basel, Switzerland.

This article is an open access article

distributed under the terms and

conditions of the [Creative Commons](https://creativecommons.org/licenses/by/4.0/)

[Attribution \(CC BY\)](https://creativecommons.org/licenses/by/4.0/) license.

1. Introduction

1.1. Motivation

In recent decades, there has been a global shift from conventional electricity generation methods that are based on fossil fuels to renewable energy sources (RESs) such as photovoltaics, wind turbines, and hydroelectric power plants [1]. This energy transition is driven by the need to address climate change, reduce greenhouse gas emissions, promote sustainable development, and enhance energy security [2,3].

However, the intermittent nature of many RES technologies necessitates their integration with energy storage systems, primarily battery energy storage systems (BESSs), to manage fluctuations and uncertainties in renewable energy generation [4]. While the installation of BESSs increases the overall system cost, it significantly enhances flexibility by storing excess electricity and supplying power during peak demand or outages.

The combination of RES technologies and BESSs with advanced operational capabilities, such as supervision, control, monitoring, and energy optimization, enables the development of smart microgrids. These advanced types of microgrids connect to the distribution level of an electric power system and can operate either autonomously or can be connected with the main power grid [5,6]. A particularly promising application of smart microgrids is in university campuses, where they combine smart technologies with the university's physical infrastructure in order to provide improved services and enhance energy transition [7]. From this perspective, university campus smart microgrids can be viewed as small-scale smart cities [8].

The integration of a smart microgrid incorporating RES technologies (primarily photovoltaics (PVs)) with the main power grid can be achieved through three (3) key mechanisms: net metering, net billing, and zero feed-in. In net metering, electricity generated by the PV system is offset against on-site electricity consumption over a monthly or annual settlement period. When the electricity demand exceeds PV generation, the deficit is supplied by the grid and charged at the retail electricity tariff. Conversely, when PV generation exceeds consumption, the surplus energy is exported to the grid without financial compensation to the customer. However, it has been discontinued in Greece [9] and several other countries [10] due to the pronounced mismatch between photovoltaic generation and consumption and the associated operational burden on distribution networks. In net billing, electricity generated by rooftop photovoltaic systems is sold to the grid at the prevailing wholesale market price, while electricity imported from the grid is charged at the retail tariff. The settlement is performed in monetary terms rather than energy units, creating incentives for increased self-consumption and the integration of BESSs. In zero feed-in, PV power is not allowed to be injected into the grid [11]. As a result, the surplus PV energy has to be stored in BESSs to prevent waste. While the larger battery capacity needed in a zero feed-in system increases overall costs, it also enhances the system's autonomy. Moreover, zero feed-in systems reduce the risks associated with fault currents, substation/transformer loading, and neutral voltage displacement [12].

1.2. Literature Review and Contribution

There are numerous studies related to smart microgrids on university campuses. In [13], the American University of Beirut is analyzed, supplied by PVs, batteries, the electric grid, and in extreme cases a diesel generator. Similarly, the University of the Ryukyus in Okinawa is examined in [14], focusing on an advanced model for electric vehicle (EV) charging, PV and battery installations, and grid connectivity. A location and sizing optimization approach for PV systems and EV chargers in a Brazilian university microgrid is proposed in [15]. A microgrid implementation procedure with a four-year horizon for the university campus of UNICAMP in Brazil is presented in [16], featuring a PV

system and a combined heat and power unit using natural gas, lithium-ion batteries, and a grid connection controller. A university campus system that contains PVs, batteries, and an electricity exchange with grid and demand response is modeled in [17]. The evaluation of this system considers economic and environmental criteria. A microgrid system which includes PV installation, batteries, and an electricity energy management system in the Democritus University of Thrace, Greece, is examined in [18].

A campus microgrid integrating PVs, wind turbines, a diesel generator, batteries, demand response mechanisms, and a grid connection was optimized in [19] based on economic and environmental criteria. The operation of a campus microgrid incorporating PVs, batteries, and EV charging was explored in [20], with a particular focus on the role of EVs as energy sources when needed. This capability provides significant benefits, including cost savings and peak load reduction. A study of a university campus in Okinawa, based on real-world data, was presented in [21]. The examined system included PVs, batteries, and grid connection, and it was evaluated using three key indicators: loss of power supply probability, waste of energy, and total cost. Recent studies have also highlighted the integration of the Internet of Things (IoT) for microgrid energy management in university campuses, primarily focusing on data acquisition, communication networks, application layers, and cloud computing [22,23]. Regarding the island of Crete, a smart campus microgrid at HMU in Heraklion was analyzed in [24]. This system included PVs, wind turbines, batteries, EV chargers, and a bidirectional grid connection. Its performance was assessed using financial and environmental criteria, along with a sensitivity analysis.

The techno-economic performance of shared energy storage in a grid-connected prosumer community operating under feed-in power limitations is examined in [25]. Both electricity imports from and controlled exports to the grid are permitted. Using a two-stage optimization framework and market-based settlement mechanisms, the study shows that energy storage can increase photovoltaic self-consumption, improve power quality, and enhance economic performance, particularly in the presence of policy incentives. Reference [26] assesses rooftop photovoltaic self-sufficiency potential in university buildings based on energy consumption simulations; the present study addresses the optimal design and techno-economic performance of a campus microgrid operating under strict zero feed-in constraints, incorporating energy storage, regulatory considerations, and spatial feasibility. The results indicate that rooftop photovoltaic self-sufficiency varies significantly across building types, with sports facilities and academic buildings achieving rates above 60%, while libraries exhibit the lowest performance, below 20%. At the campus level, rooftop photovoltaics provide an average annual self-sufficiency rate of approximately 35%, demonstrating their potential to substantially reduce overall electricity consumption in university campuses.

Reference [27] investigates the techno-economic impact of different electricity pricing policies of PV–battery systems in a residential microgrid in the Netherlands, including net metering, feed-in tariffs with time-of-use, real-time pricing, and subsidized batteries. The results show that, although real-time pricing (RTP) significantly increases the self-consumption rate, it leads to a higher levelized cost of electricity (LCOE) and longer payback periods; however, these drawbacks can be mitigated through battery subsidies. A diesel-backed islanded PV–BESS microgrid is studied in [28], supplying an industrial load in Germany, with the core contribution being a comparative techno-economic assessment of two dispatch strategies (Load-Following vs. Cycle-Charging) under a loss of power supply probability constraint ($LPSP \leq 0.03$). The study focuses on controller selection and generator–battery coordination rather than on market- or regulation-driven operating schemes such as zero feed-in or net metering.

The zero feed-in mechanism combined with RES technologies and BESSs has been used in power system applications with a considerable variance in peak load, which however does not include university campuses. An economic assessment of a PV and battery storage system in Madeira Island is analyzed in [29], from which it was concluded that zero feed-in and batteries will improve the value of PV installations by increasing considerably the rates of self-consumption. In [30], the advantages and disadvantages of net metering and zero feed-in systems are examined for Crete's regional public buildings. The effect of zero feed-in in DC link topology under static and dynamic power system events, i.e., thermal limits and short-circuit limits in distribution systems, is studied in [11]. The zero feed-in scheme was also used as a mechanism for specific periods of the year in order to optimize electrical and thermal storage in a high school building of Central Greece [31].

The literature also includes studies addressing numerous additional aspects of smart microgrid operation that lie outside the scope of this paper, which focus on the economic integration of hybrid RES–BESSs under a zero feed-in scheme [32]. These aspects include frequency regulation [33]; reactive power compensation [34]; power quality improvement [35]; control on inverters [36]; microgrid protection, which includes communication technologies [37], fault analysis, identification, and separation [38]; model predictive control [39]; and cybersecurity for protection from cyber-attacks [40].

In this paper, a smart microgrid that is located on the HMU Campus is modeled and analyzed. The system consists of PVs and batteries that are connected to the main distribution grid of Heraklion city in Crete, Greece. This system operates with the zero feed-in mechanism, which enhances energy self-consumption and leads to significant amounts of battery storage. The performance of the university smart microgrid is evaluated based on financial and environmental criteria, specifically the net present value (NPV) and annual greenhouse gas (GHG) emission reduction. Additionally, this paper examines the effect of two alternative battery technologies (lead–carbon and lithium-ion), various load demands, and different electricity prices. The main contributions of this paper are as follows:

- Although the grid-connected PV is the most common configuration in university campus microgrids [41], to the best of our knowledge, this is the first study to investigate a university campus microgrid operating under a zero feed-in scheme. Following the discontinuation of net metering, the current Greek legislative framework increasingly promotes zero feed-in configurations, as they effectively address several operational challenges associated with the high penetration of utility-scale PV systems. In recent years, electric grid operators have frequently imposed curtailments on large PV plants—reaching up to 15% of annual energy production—particularly during periods of network congestion, thereby limiting the effective exploitation of the country's solar potential. In contrast, zero feed-in microgrids do not export electricity to the grid and therefore impose no additional burden on it. Moreover, zero feed-in schemes involve significantly lower administrative and regulatory complexity compared to feed-in tariffs or net metering frameworks, simplifying the permitting process and enabling faster deployment.
- This study offers policy-relevant insights by demonstrating that zero feed-in campus microgrids can achieve substantial economic and environmental benefits while simultaneously alleviating grid congestion, supporting system stability, and facilitating the large-scale integration of distributed renewable energy resources in regions facing increasing network constraints.
- The analysis is based on measured meteorological and load consumption data from HMU, while the characteristics of the system components are derived from real technical specifications, enhancing the realism of the study.

- The financially optimal solution identified for the base-case scenario is further validated through a spatial feasibility analysis, taking into account the available installation area at the HMU Campus. Moreover, a detailed electrical installation diagram of the whole system is provided.
- In the simulation process, the annual degradation of battery capacity and PV power is taken into account. While this assumption increases computational time, it further enhances the accuracy of the results.

In this context, the proposed study can serve as a representative example for similar university campuses aiming to implement smart microgrids under zero feed-in schemes. As the penetration of PV systems continues to rise, many distribution networks face grid bottlenecks, reverse power flows, and stability challenges, making zero feed-in increasingly relevant as a strategy to limit stress on the grid while maximizing local self-consumption. Therefore, the methodology and findings of this work can be generalized to guide decision-making for sustainable energy planning in regions with comparable climatic conditions, regulatory frameworks, and load profiles, especially where grid constraints are becoming a critical issue. Moreover, by incorporating real-world data and detailed component specifications, this study provides valuable insights into the techno-economic feasibility of zero feed-in projects. Table 1 summarizes the main methodology approaches and results reported in the existing literature on university campus microgrids and compares them with the main contributions of this study. The paper is organized as follows. Section 2 provides details about the examined HMU Campus in Heraklion, Crete Island. Section 3 describes the smart microgrid operation under the zero feed-in mechanism. Section 4 shows the economic and environmental results for the examined cases. Section 5 concludes the paper.

Table 1. Summary of the existing literature related to university campuses and comparison with the main contributions of this work.

Refs.	Scope
[13]	➤ Techno-economic optimization of a university campus microgrid under unreliable grid conditions, enabling bidirectional grid exchange and diesel backup, with PV–battery sizing aimed at improving reliability and reducing energy costs.
	✓ Reduces diesel annual operating cost from 53.7% to 3.4%.
	✓ Reduced levelized cost of electricity (LCOE) from 0.137 USD/kWh to 0.088 USD/kWh the 1st year, and from 0.144 USD/kWh to 0.1 USD/kWh the 10th year.
	✗ The zero feed-in regulatory constraint is not considered.
	✗ No spatial analysis and/or detailed electrical installation is provided.
[14]	➤ Multi-objective techno-economic optimization of a university campus microgrid with high penetration of electric vehicles, incorporating PV generation, EV charging/discharging (V2G/G2V), and constant power support from the main grid.
	✓ Peak-to-valley load ratio increases up to 14× without control, while coordinated EV charging/discharging significantly smooths the load profile.
	✓ Total life cycle cost (20 years) reduced from JPY 5.73×10^9 to JPY 4.88×10^9 as EV participation increases to 30%.
	✓ Waste energy reduced from 7.21×10^5 kWh to 1.86×10^5 kWh, and CO ₂ emissions reduced from 3.88×10^8 t to 3.07×10^8 t with higher EV response levels.
	✗ The zero feed-in regulatory constraint is not considered.

Table 1. Cont.

Refs.	Scope
[15]	➤ Two-stage techno-economic optimization for a smart university campus, focusing on the optimal siting and sizing of PV systems and EV charging stations, with the objective of minimizing electrical losses and improving campus sustainability under grid-connected operation. ✓ Optimal PV allocation of 600 kWp leads to a 13.48% reduction in monthly operating cost, primarily due to reduced electrical losses. ✓ Sensitivity analysis shows that increasing EV chargers at high-load buses can increase network losses by approximately 5%, highlighting trade-offs between electric mobility expansion and grid efficiency. ✗ The study focuses on loss minimization rather than regulatory frameworks; zero feed-in operation is not considered.
[16]	➤ Case study on the design and real-world implementation of a university campus microgrid that integrates PV, battery energy storage, and combined heat and power and diesel generation with centralized energy management system, monitoring, and communication infrastructure under grid-connected and islanded operation. ✓ Installed and planned DER capacity exceeding 3 MVA, including ~337 kWp of installed PV with plans for an additional ~600 kWp, and a 525 kW/810 kWh BESS. ✓ Demonstrates the capability to supply 100% of campus loads for up to 1.5 h in islanded mode using BESS, with extended operation enabled through dispatchable thermal generation. ✗ No techno-economic optimization; zero feed-in regulatory constraints not considered.
[17]	➤ Techno-economic scheduling of a grid-connected campus prosumer microgrid incorporating PV generation, battery energy storage, and price-based demand response, with the objective of minimizing operating cost through optimal energy management. ✓ Optimal scheduling achieves up to ~22% reduction in daily operating cost compared to uncontrolled operation under time-varying electricity prices. ✓ Peak demand is reduced by approximately 18%, demonstrating the effectiveness of coordinated battery dispatch and demand response. ✗ Operates under bidirectional grid interaction with electricity trading and price-based demand response; therefore, zero feed-in regulatory constraints are not considered.
[18]	➤ Development of a simulation platform for smart microgrids in university campuses that include PVs, a BESS, and an electricity energy management system. ✓ The proposed methodology minimizes electricity costs and also optimizes the size of the microgrid components, design of the campus energy management, and load control operations. ✓ GUI implementation to interact in a friendly environment with the user. ✓ Consideration of peak-shaving through voluntarily user participation, as well as lighting control. ✗ The zero feed-in regulatory constraint is not considered.
[19]	➤ Mixed-integer linear programming optimization of a university campus microgrid that includes PVs, wind turbines, a diesel generator, and a BESS. ✓ Grid electricity costs reduction of 38%. ✓ The daily reductions in GHG emissions are 365.34 kg per 1000 kWp of installed PV capacity. ✓ LCOE varies in the interval 0.055–0.0988 USD/kWh. ✓ Cash flow analysis for a 10-year period. ✗ The zero feed-in regulatory constraint is not considered.
[20]	➤ Optimal sizing of a university campus microgrid that includes a PV system, a BESS, and EV chargers using linear programming. ✓ Consideration of peak and off-peak electricity prices. ✓ Three alternative cases were developed: (1) grid only; (2) grid with PV and BESS; (3) grid with PV, BESS, and EV. ✗ Average daily profiles were used and not real-time annual data. ✗ The zero feed-in regulatory constraint is not considered.

Table 1. *Cont.*

Refs.	Scope
[21]	➤ Multi-objective optimization of a university campus microgrid that includes PVs and a BESS using the non-dominated sorting genetic algorithm II (NSGA-II). ✓ Three objectives were used: (1) loss of power supply probability; (2) life cycle cost; (3) waste of energy. ✓ Three alternative cases were examined: (1) PV–battery and real-time power from the infinity bus; (2) constant power throughout the year; (3) daily constant power. ✓ Costs of cases 2 and 3 were 62.8% and 63.3% less than case 1. ✓ Case 1 had 15.2% and 16.7% less carbon emissions than case 2 and case 3, respectively. ✗ The zero feed-in regulatory constraint is not considered.
[22]	➤ An IoT-based architecture for a university campus microgrid that consists of a wind turbine, a PV system, a BESS, and a diesel generator. ✓ The performance has been evaluated with respect to end-to-end delay using Ethernet-based and Wi-Fi-based communication architectures. ✓ Sufficient performance for the operation using Fast Ethernet and Gigabit Ethernet. ✓ Focus on the communication aspects of the microgrid. ✗ No component size optimization; no economic or environmental cost estimation. ✗ The zero feed-in regulatory constraint is not considered.
[24]	➤ Simulation of a university campus microgrid that includes PVs, wind turbines, BESSs, and EV chargers. ✓ Utilization of measured load data and RES data. ✓ Multi-objective optimization using economic. ✓ Sensitivity analysis of battery cost reduction. ✗ The zero feed-in regulatory constraint is not considered. ✗ No spatial analysis and/or detailed electrical installation is provided.
[26]	➤ Examination of the potential for rooftop PV installations across five typical building types in a university campus. ✓ The examined building types were teaching buildings, sports halls, dormitories, dining halls, and libraries. ✓ The rooftop PV self-sufficiency changes with the building type and can vary from under 20% to more than 60%. ✗ No batteries are included in the analysis. ✗ The zero feed-in regulatory constraint is not considered.

2. Description of the Examined University Campus Microgrid

On the island of Crete, there are five HMU Campuses in five different towns. The case study of this paper refers to the Heraklion city campus, which is by far the largest of them all. Load demand hourly data for the whole campus for the year 2022 are available, provided by the Hellenic Electricity Distribution Network Operator (HEDNO). Moreover, for the same year, hourly meteorological data on solar radiation and ambient temperature were utilized to estimate PV electricity generation. These data were obtained from measurements conducted by the Laboratory of Energy and Photovoltaic Systems of HMU. Figure 1a shows the hourly load demand for HMU Campus and Figure 1b shows the monthly electricity load. The peak load power is 619.7 kW, and there is a reduced demand in specific months of the year because April and August include the Easter and summer vacations, respectively. Peak monthly demands belong to months with low temperatures due to the operation of heat pumps, with the exception of December due to Christmas vacations.

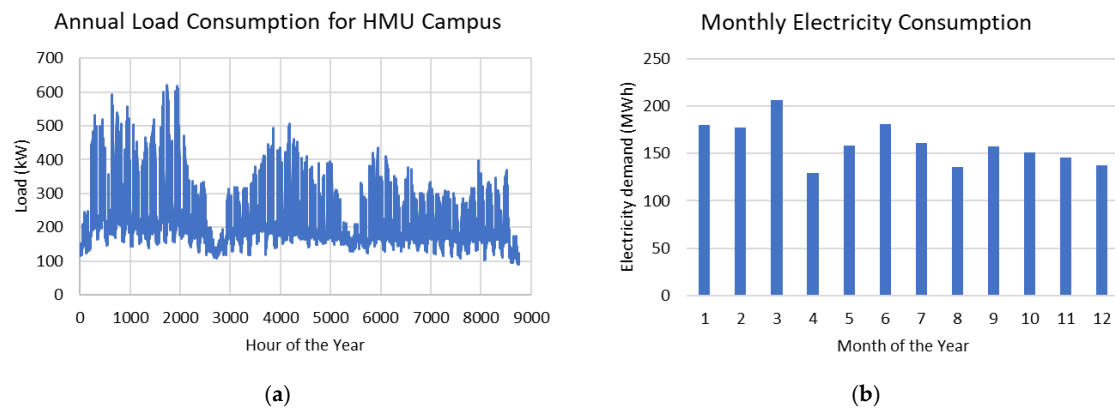


Figure 1. Load demand data for HMU Campus in Heraklion, Crete: (a) hourly load; (b) total monthly load.

At the moment, the overall electricity demand of the campus is exclusively serviced from the main electrical grid at a medium-voltage level (20 kV). Therefore, the aim is to significantly reduce the demand supplied from the electrical grid, taking as input the data of the following study. Figure 2 shows the load duration curve, from which it can be concluded that, for almost half the hours of the year, the demand exceeds 200 kW.

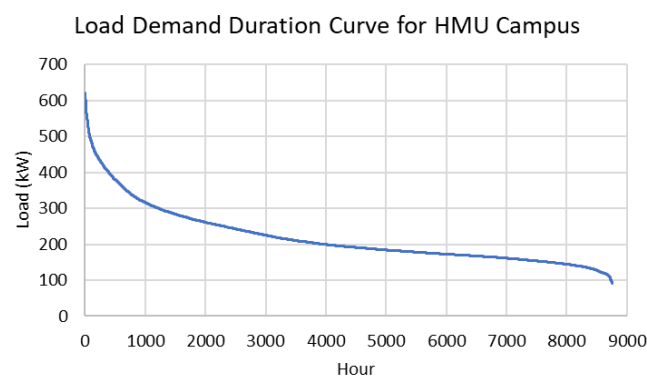


Figure 2. Load duration curve for HMU Campus in Heraklion.

As mentioned before, the considered smart campus microgrid contains PVs and BESSs. The output power P_{PV} (kW) of the PV array is calculated as follows [42]:

$$P_{PV} = f_{PV} P_{STC} \frac{G_A}{G_{STC}} [1 + (T_C - T_{STC}) C_T], \quad (1)$$

where f_{PV} is the PV derating factor, which accounts for losses related to dust cover and the unreliability of the PV array (typical value: 0.95); P_{STC} (kWp) is the peak power of the PV array; G_A is the global solar irradiance incident on the PV array (kW/m^2); $G_{STC} = 1 \text{ kW}/\text{m}^2$ is the solar irradiance under PV Standard Test Conditions (STC); T_C is the temperature of the PV cells ($^{\circ}\text{C}$); T_{STC} is the PV temperature under STC (25°C); and C_T is the PV temperature coefficient ($-0.34\%/^{\circ}\text{C}$). T_C can be estimated from the ambient temperature T_a ($^{\circ}\text{C}$) and the global horizontal solar irradiance G (kW/m^2) [43]:

$$T_C = T_a + \frac{(NOCT - 20)}{0.8} G, \quad (2)$$

where $NOCT$ is the normal operating cell temperature, which is considered 45°C . From Equations (1) and (2), the required weather data for P_{PV} calculations are the following: (1) the global incident solar irradiance G_A , (2) the global horizontal solar irradiance G , and (3) the ambient temperature T_a . For all three parameters, hourly data from HMU

Campus are available for the year 2022. Moreover, the linear degradation of PV panels over their lifetime due to aging is considered. Based on real technical data from [44], the annual power degradation of PV panels is assumed to be 0.55%. Details on BESS characteristics will be given in Section 3, which also contains a description of the two alternative battery options.

3. Description of Zero Feed-In Mechanism and Smart Microgrid Operation

The zero feed-in mechanism ensures that the PV station produces energy exclusively for on-site use, with no excess electricity exported to the grid. Energy flows are managed by an energy direction sensor at the point of common coupling. This sensor monitors whether power is being injected into or absorbed from the grid and accordingly adjusts the charging or discharging of the batteries. The energy storage system operates independently from the grid, with charging and discharging limited to internal microgrid processes.

Under the Greek legislative framework, the maximum installed capacity for PV systems is limited to the agreed consumption capacity of the installation. For the Hellenic Mediterranean University (HMU) in Heraklion, this limit is set at 1330 kW.

When on-site generation is insufficient to meet demand, the needed electricity is supplied from the grid at medium-voltage tariffs. In such cases, the energy storage system can discharge to supplement grid energy, minimizing grid dependency. Conversely, during periods of surplus PV generation, excess energy is directed to charge the batteries, allowing the stored energy to be used later to meet peak demand. When there is a risk of surplus energy feeding into the grid, the sensor control system curtails generation, either by lowering the setpoints of the PV inverters or by disconnecting the inverters entirely. This ensures a strict compliance with the zero feed-in requirement. During periods of high demand, energy can be drawn simultaneously from the PV generation and storage systems to ensure adequate supply.

Figure 3 illustrates the operational procedures of the smart microgrid, detailing the interactions between on-site generation, energy storage, and grid dependence based on the conditions outlined above.

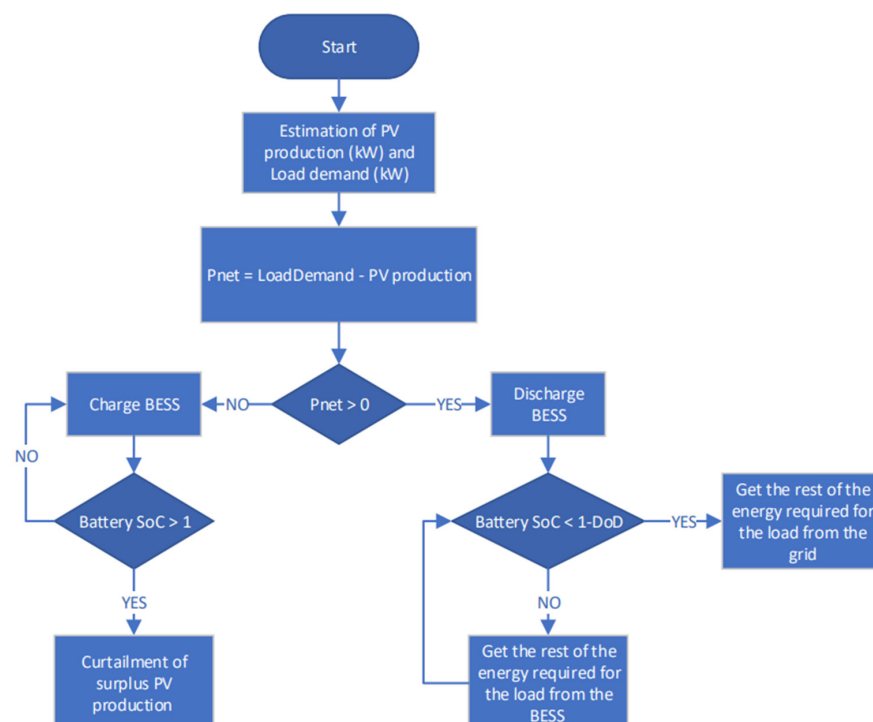


Figure 3. Operational procedures of examined university campus microgrid.

4. Results and Discussion

This section presents the developed scenarios to assess the increased HMU demand driven by the integration of PV stations and the use of different battery storage technologies. These scenarios include the following:

1. PV station and energy storage system with lead–carbon technology;
2. PV station and energy storage system with lithium technology.

A tariff of 0.20 EUR/kWh for purchasing electricity from the grid was considered, and a discount rate of 6% was applied to estimate cash flows over the lifespan of the investment. The investment cost for the PV array, inverter, and controller is considered 700 EUR/kWp, the operating cost 10 EUR/kWp, and the lifetime is equal to 25 years. Table 2 shows the needed information for the two alternatives in energy storage that both are manufactured from Narada [45]. The lead–carbon battery system has a lower installation cost, less usable capacity, and shorter operational life compared to lithium batteries. More specifically, the lead–carbon battery system operates at a 40% depth of discharge (DoD), with a lifespan of 5000 cycles (~13 years). On the other hand, the lithium-ion battery system provides a longer lifespan of 6000 cycles (~16 years) and operates at a 60% DoD, though its capital cost is more than double. Both BESS options have an overall efficiency of 96.5%, while their operating cost is considered equal to 2% of their investment cost. Additionally, the gradual linear degradation of battery capacity due to aging was taken into account. For both battery technologies, the actual capacity at the end of their lifespan is assumed to be 70% of their nominal value.

Table 2. Cost and lifetime characteristics of the examined battery storage technologies.

Component	Investment Cost	Operating Cost	Lifetime
Lead–Carbon Energy Storage	EUR 100/kWh	EUR 500/250 kWh	5000 cycles (40% DoD, ~13 years)
Lithium Energy Storage	EUR 225/kWh	EUR 1125/250 kWh	6000 cycles (60% DoD, ~16 years)

The simulation of such systems can be performed using either specialized software tools (such as HOMER [46] and iHOGA/MHOGA [47]) or programming languages. In our case, a Python-based technical simulation (v. 3.13.7) was conducted to give the optimal sizing of PV and energy storage for HMU's smart microgrid, based on the flowchart depicted in Figure 3. The optimization procedure is implemented through complete enumeration, using 20 kWp as an increment step for PV power and 250 kWh as an increment step for both types of batteries. The upper bounds for PV array size and battery capacity were 1000 kWp and 3000 kWh, respectively. The latter value is based on technical data provided by the Narada battery manufacturer.

4.1. Basic Scenario Results and Analysis—Comparison of Battery Storage Alternatives

The financial evaluation for the considered HMU Campus smart microgrid uses the NPV, which is calculated from the following:

$$NPV = \sum_{i=0}^N \frac{R_t}{(1+i)^t}, \quad (3)$$

where R_t is the net annual cash flow for the year t , i is the annual discount rate, and N is the lifetime of the project, which is considered 25 years. In the analysis that follows, all costs are considered negative cash flows, whereas the annual reduction in HMU's electricity costs due to the internal PV generation is considered as a positive cash flow. For the whole

lifetime of the project, the electricity price, which calculates the cost reduction, is considered equal to 0.20 EUR/kWh. The annual discount rate is assumed to be equal to 6%.

Tables 3 and 4 present the PV and lead–carbon battery optimal capacities. As can be seen, the optimal number of batteries is five (250 kWh each), with a battery replacement in year 13. The maximum NPV is EUR 1,414,857, which makes the investment profitable. This solution provides an average annual energy autonomy of 46% for PVs and BESSs, so the contribution of the electricity grid to the annual load demand is 54%. From the data of Table 4, it can be observed that the annual average electricity savings—directly associated with the level of energy autonomy achieved by the HMU Campus—are substantial and exceed the battery replacement cost in year 13. In addition, the investment cost of the PV system is considerably higher than the corresponding battery cost.

Table 3. Optimal solution characteristics for lead–carbon batteries.

Component	Capacity	Investment Cost	Operating Cost	Lifetime
Lead–Carbon Energy Storage	1250 kWh	EUR 125,000	EUR 2500	~13 years
PV Array + Inverter + Controller	760 kWp	EUR 532,000	EUR 7600	25 years

Table 4. Annual cash flows for lead–carbon batteries optimal solution.

Parameter	Value
Initial Investment	EUR –657,000
Annual Maintenance Costs	EUR –10,100
Average Annual Energy Savings	EUR 176,759
Battery Replacement (Year 13)	EUR –125,000
Net Present Value (NPV)	EUR 1,414,857

Tables 5 and 6 present the PV and lithium battery optimal capacities. In this case, the significant higher cost of lithium batteries surpasses their operational benefits and leads to zero capacity, so this solution contains only PVs. The NPV (EUR 1,189,428) is lower compared to the previous case, so the installation of lead–carbon batteries provides better results compared to both the alternatives of lithium batteries and no battery installation.

Table 5. Optimal solution characteristics for lithium batteries.

Component	Capacity	Investment Cost	Operating Cost	Lifetime
Lithium Energy Storage	0 kWh	EUR 0	EUR 0	N/A
PV Array + Inverter + Controller	640 kWp	EUR 448,000	EUR 6,400	25 years

Table 6. Annual cash flows for lithium battery optimal solution.

Parameter	Value
Initial Investment	EUR –448,000
Annual Maintenance Costs	EUR –6400
Average Annual Energy Savings	EUR 134,490
Battery Replacement (Year 16)	EUR 0
Net Present Value (NPV)	EUR 1,189,428

Figure 4 shows graphically the cash flows of the optimal solution (760 kWp PVs and 1250 kWh lead–carbon batteries with NPV = EUR 1,414,857). Moreover, Figure 4 illustrates the declining positive cash flows caused by PV and battery degradation over time. However, in year 13, the positive cash flow temporarily increases due to the battery replacement. The annual operating costs of both the PV system and the BESS are negligible compared to the annual cost savings achieved through microgrid operation.

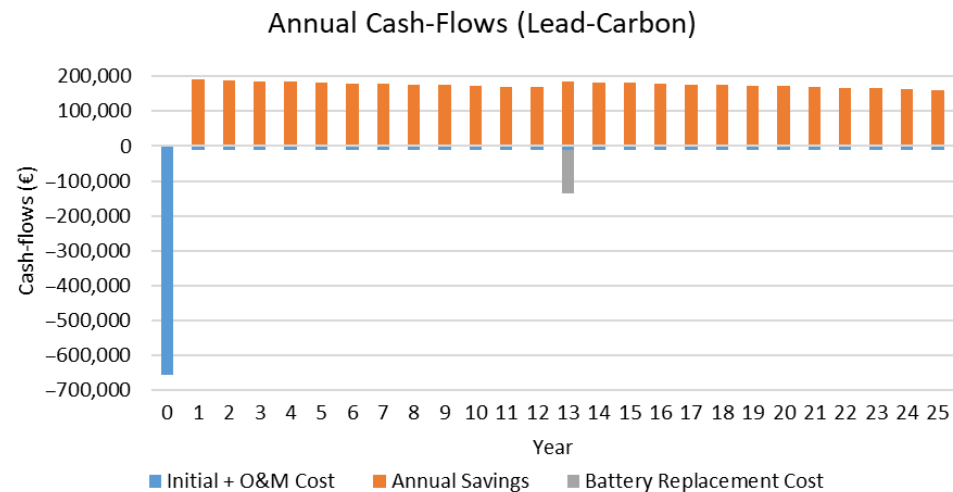


Figure 4. Annual cash flows for the optimal solution (lead–carbon batteries).

The characteristics of the PV system generation throughout the whole year are depicted in Figure 5. More specifically, Figure 5a shows the hourly values of PV power. It can be seen that, in the summer period, the PV power is much denser, so the monthly generated PV energy is expected to be higher, which is presented in Figure 5b. Conversely, the PV system reaches its maximum peak power during certain hours in the spring, when optimal generation conditions—high solar irradiance combined with relatively low ambient temperatures—occur simultaneously.

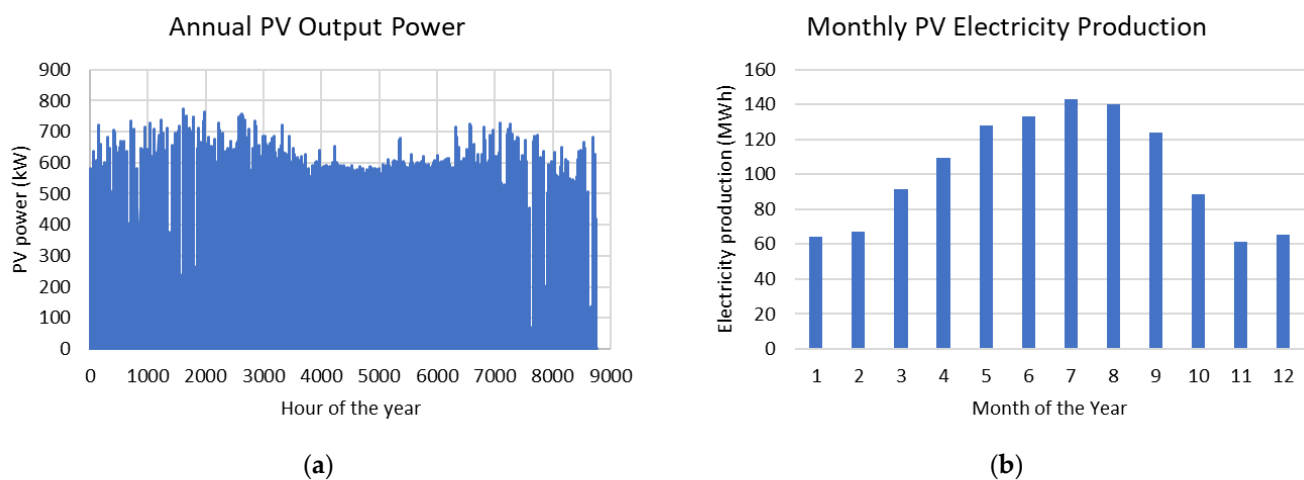


Figure 5. PV system generation for the optimal solution (lead–carbon batteries, first year of operation): (a) hourly values of PV power; (b) total monthly values of PV electricity.

Data for the batteries' annual operation are presented in Figure 6. Figure 6a shows the hourly values of total battery stored energy. The minimum value of 750 kWh corresponds to 60% of the battery's nominal capacity, reflecting the maximum allowable depth of discharge (DoD) of 40% for lead–carbon batteries. The higher average monthly state of charge (SoC) values for July and August (Figure 6b) can be explained by the significant PV generation combined with the decreased load demand at HMU Campus.

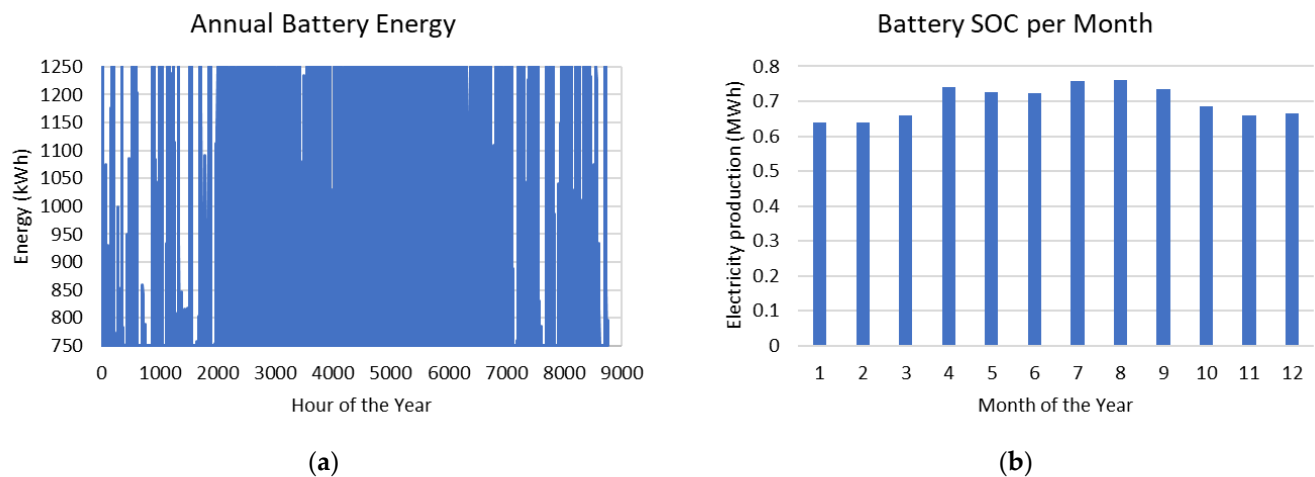


Figure 6. BESS operation for the optimal solution (lead–carbon batteries, first year of operation): (a) hourly values of battery energy; (b) average monthly values of battery SoC.

Figure 7 illustrates the coordinated operation of all system components under the zero feed-in mechanism for a representative day in June. The PV system has a significant daily electricity generation. The lead–carbon battery is operating during the early night hours (19:00–21:00), and when the battery SoC is reduced to its lower value, the (low) night loads were served by the distribution grid.

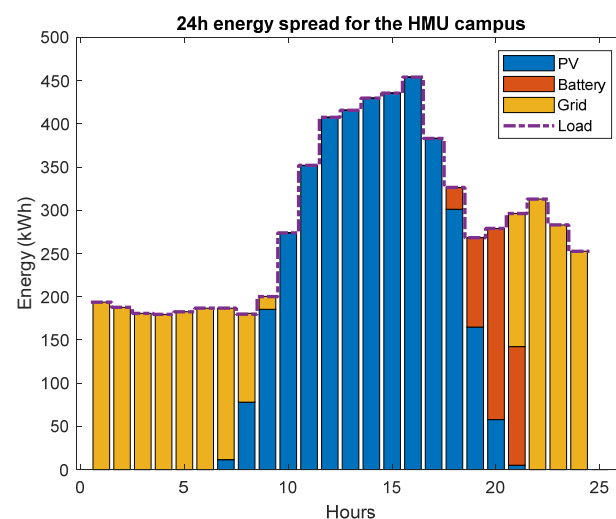


Figure 7. Daily share for different microgrid technologies (June, first year of operation).

To enable a comparison with similar studies, the levelized cost of electricity (LCOE) is used, as university campus microgrids may differ in size and load demand, making direct NPV comparisons less meaningful. LCOE normalizes the net present cost (NPC)—the NPV of total system costs—of the electricity generated from the microgrid over the system lifetime, and it is calculated as follows [13,48]:

$$\text{LCOE} = \frac{\text{NPC}}{\text{NPV}(E_{mg}, i)}, \quad (4)$$

where E_{mg} is the annual electricity generated from the microgrid (in kWh). The resulting value is 0.075 EUR/kWh, and it is comparable with LCOE values that can be found in similar works (see Table 7). The LCOE value would be even lower if the HMU Campus load demand was higher in July and August, as the PV generation during daytime hours is significant and currently cannot be fully utilized.

Table 7. LCOE value comparison of current study (HMU Campus) with similar works.

Current Study (HMU)	Reference [13]	Reference [19]
0.075 EUR/kWh	0.088–0.100 USD/kWh	0.055–0.0988 USD/kWh

For this optimal solution, a detailed technical analysis follows, as well as a spatial representation using a 3D software (SketchUp version 2023.0) that includes real data for the available space. The PV installation of 760 kWp consists of 1900 LONGi LR5-54HIB solar panels [44], each with a capacity of 400 Wp, connected into two parallel arrays of 950 panels (380 kWp) each.

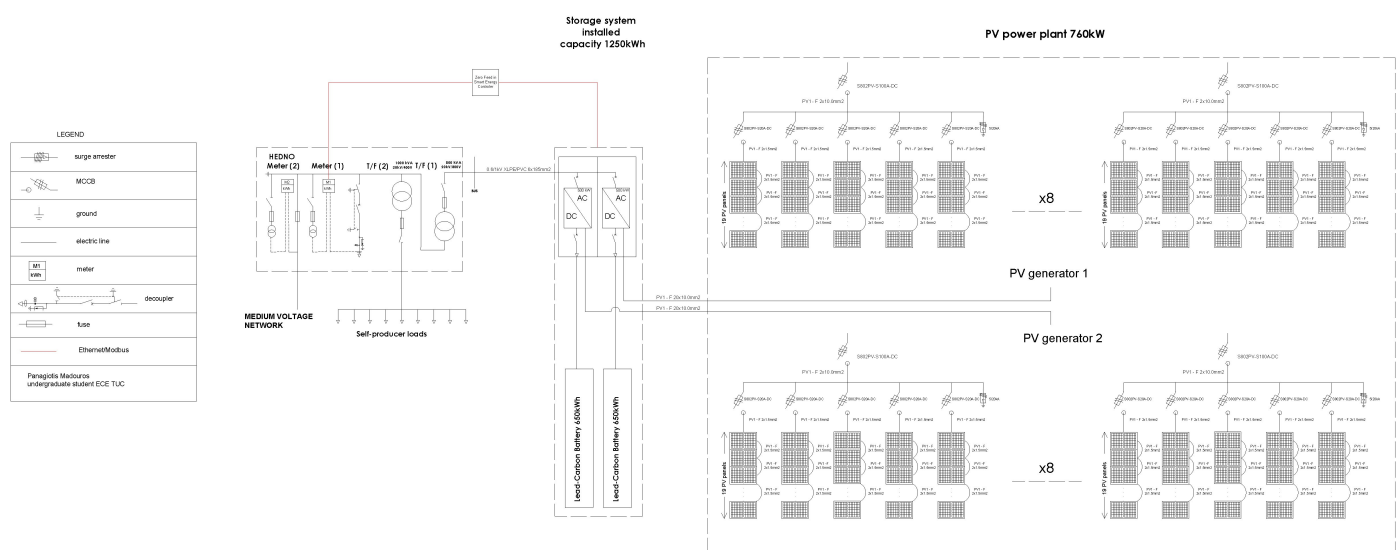
PV panels will be connected through a combination of series and parallel configurations to achieve the necessary voltage and current capacity. Wiring will utilize 1.5 mm² cables for the panels and 10 mm² cables for the string connections, all protected within conduits suitable for outdoor installation. Safety features include circuit breakers rated at 20 A-DC and surge protectors for every five strings, with IP65-rated switchboards installed for accessibility and security.

The energy storage system will comprise two lead–carbon batteries, each with a capacity of 650 kWh, featuring integrated inverters and DC/DC converters for seamless connections. A three-phase integrated inverter will connect to each PV array, ensuring efficient energy management.

The electrical infrastructure includes Transformer 1 (T/F (1)), rated at 800 kVA (800 V/20 kV), and Transformer 2 (T/F (2)), rated at 1000 kVA (20 kV/400 V), with the latter already installed at HMU. Metering equipment (Meter (1) and Meter (2)) will be installed next to T/F (2), certified for use by the HEDNO.

In order to achieve optimal energy management and avoid energy injection into the grid, a monitoring and control system is installed, featuring a PLC and SCADA. This setup allows for communication with the battery management system and metering equipment via Ethernet and Modbus.

The entire installation will be grounded using 25 mm² copper conductors and constructed in accordance with current technical standards and regulations, ensuring a reliable and efficient energy production system. Figure 8 shows the whole electrical installation diagram of the zero feed-in system and its components. Figure 9 depicts a 3D representation of the installed system in an empty area of HMU Campus that faces South.

**Figure 8.** Electrical installation diagram of the whole PV–battery zero feed-in system.

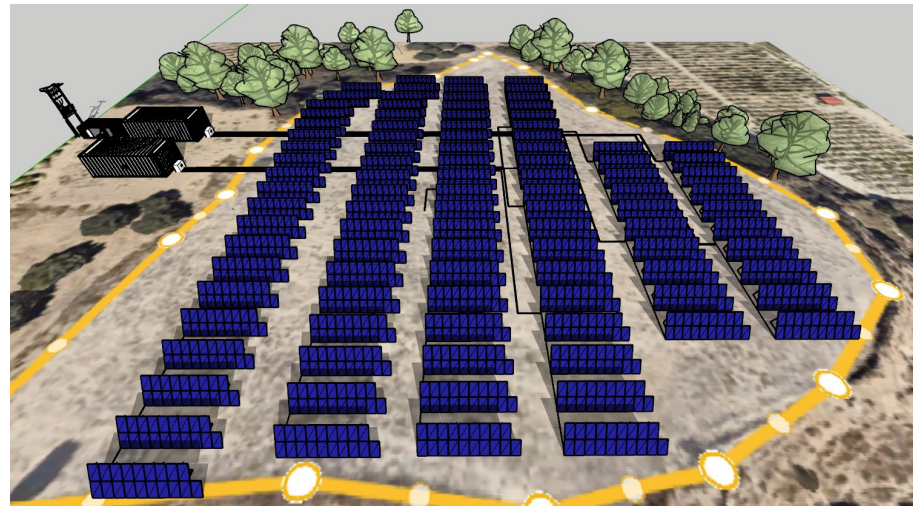


Figure 9. Three-dimensional representation of the installed system.

4.2. Consideration of Load Demand and Electricity Price Variation

To evaluate the performance of the HMU Campus microgrid under various operating conditions, a sensitivity analysis was implemented considering different load demand levels and electricity prices. Load demand variations of $\pm 20\%$ were analyzed while maintaining the same load pattern. For electricity prices, additional values of 0.15, 0.25, and 0.30 EUR/kWh were examined. In all scenarios, the integration of lead–carbon batteries provided superior results. Table 8 presents the optimal solutions for the different parameter combinations. Apart from the battery capacity, PV system installed power, and NPV, Table 8 also provides the average annual energy autonomy of the system.

Table 8. Sensitivity analysis results (lead–carbon batteries).

Load Scenario	Battery Capacity	PV System	Average Autonomy	NPV
Electricity price 0.15 EUR/kWh				
Base load	1250 kWh	760 kWp	46%	EUR 849,964
–20%	1000 kWh	740 kWp	54%	EUR 806,479
+20%	1250 kWh	760 kWp	40%	EUR 923,646
Electricity price 0.20 EUR/kWh				
Base load	1250 kWh	760 kWp	46%	EUR 1,414,857
–20%	1250 kWh	760 kWp	56%	EUR 1,355,912
+20%	1250 kWh	760 kWp	40%	EUR 1,513,100
Electricity price 0.25 EUR/kWh				
Base load	1250 kWh	760 kWp	46%	EUR 1,979,751
–20%	1250 kWh	760 kWp	56%	EUR 1,906,069
+20%	1250 kWh	760 kWp	40%	EUR 2,102,554
Electricity price 0.30 EUR/kWh				
Base load	1250 kWh	760 kWp	46%	EUR 2,544,644
–20%	1250 kWh	760 kWp	56%	EUR 2,456,226
+20%	1500 kWh	780 kWp	42%	EUR 2,809,175

The analysis of Table 8 shows that, as electricity prices increase, the savings due to microgrid operation also rise. Additionally, for a given electricity price, higher savings were achieved at higher load demands due to the fact that more excess electricity from PVs is absorbed. Moreover, the optimal configuration from Section 4.1 remains unchanged in most cases. This is primarily because the battery increment step is relatively large (250 kWh), leading to significant changes in the overall system cost. In most scenarios, these additional costs outweigh the benefits of reduced electricity bills due to larger battery capacities. Exceptions to this are the combinations of low electricity prices–low demand (lower battery capacity) and high electricity prices–high demand (higher battery capacity).

4.3. Study on the Reduction of Lithium Batteries Cost

In the evaluation of lithium batteries, the main characteristic that led to the results of Table 5—where no batteries are included—is their significantly higher cost compared to lead–carbon batteries (more than twice the cost per kWh). However, lithium battery technology is rapidly evolving, and substantial cost reductions are expected in the coming years. In this context, Figure 10 presents the estimated literature values for utility scale storage systems (expressed in USD/kWh), based on 2024 values. From the range of reported projections, a representative cost for lithium batteries can be assumed to be 80% of the current value by 2030 and 60% by 2035. Considering a current cost of 225 EUR/kWh for lithium batteries, the corresponding projected costs are 180 EUR/kWh for 2030 and 135 EUR/kWh for 2035.

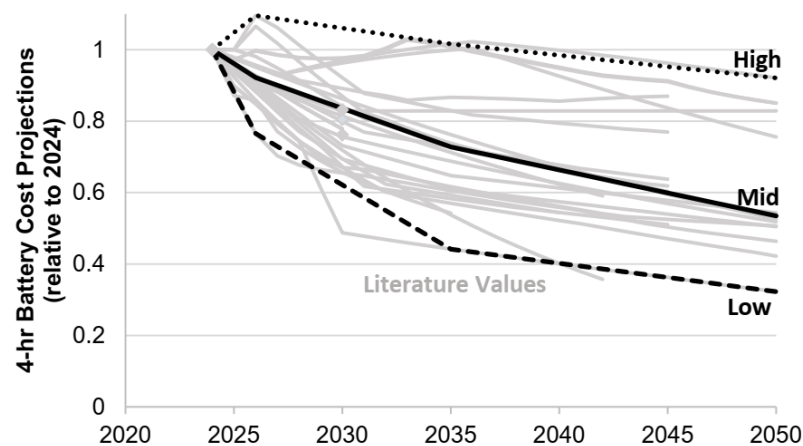


Figure 10. The literature estimated costs for utility-scale lithium-ion BESSs for years 2025–2050, with values normalized in USD/kWh [49].

The results for the reduced lithium BESS costs are presented in Table 9. As can be seen, even a 20% cost reduction for lithium batteries—expected in 2030—results in an optimal installed capacity of 500 kWh and a total HMU Campus system operation NPV that exceeds the corresponding value of the optimal lead–carbon battery solution shown in Table 4. Further lithium energy storage cost reduction, expected around 2035, leads to a double storage capacity, increased autonomy, and even higher NPV.

Table 9. Effect of lithium energy storage cost reduction on HMU Campus microgrid.

Scenario for Lithium Battery Storage Cost Reduction	Battery Capacity	PV System	Average Autonomy	NPV
20% cost reduction (180 EUR/kWh)—Expected in year 2030	500 kWh	720 kWp	41%	EUR 1,448,375
40% cost reduction (135 EUR/kWh)—Expected in year 2035	1000 kWh	760 kWp	46%	EUR 1,666,008

4.4. Financial and Environmental Analysis of Optimal Solutions

The environmental analysis estimates the annual GHG emissions reduction in the whole power system of Crete. It has to be noted that, from 2021, the island of Crete is weakly interconnected (via an AC subwater cable) with the mainland grid. The term weakly means that the interconnection covers a part of the total Cretan electricity needs, while the remainder is generated from units that are installed on the island. The estimation of GHG emissions reduction is implemented using RETScreen 4.0 software [50], and it uses as inputs the energy mix data of Crete Island for the year 2022. Table 10 provides all the needed input data for RETScreen, as well as the obtained results. More specifically, the first two columns provide the input data, and the summation of the last column gives the annual

GHG emissions reduction value of 0.624 tCO₂/MWh. In this table, data for the first three rows were provided by the Cretan department of HEDNO [51], whereas interconnection data (rows 4–7) were provided by the Hellenic Independent Power Transmission Operator (IPTO) [52].

Table 10. Fuel mix and calculation of GHG emissions reduction for Crete in year 2022.

Fuel Type	Percentage	GHG Reduction (tCO ₂ /MWh)
RES (Crete)	23.2%	0.000
Mazut (heavy oil—Crete)	44.8%	0.878
Diesel (Crete)	19.2%	0.872
Natural gas (interconnection)	6.4%	0.488
Diesel (interconnection)	1.3%	0.986
Lignite (interconnection)	2.6%	1.110
RES (interconnection)	2.6%	0.000
Total	100%	0.624

The combination of financial and environmental analysis will be implemented for the HMU Campus microgrid that contains PVs and lead–carbon batteries, since this configuration provided the optimal financial results under the base-case scenario (see Tables 3 and 4). In this concept, all feasible solutions will be taken into account (the complete enumeration method was used), and for each one of them the total GHG emissions reduction for the zero feed-in system will be calculated, compared to the current situation of HMU Campus power grid operation in which all electricity was provided by the HEDNO network with the energy mix that is described in Table 10. The calculation formula for the annual GHG reduction (in tCO₂) is as follows:

$$\text{Annual GHG reduction} = 0.624 \cdot E_{ins,an}, \quad (5)$$

where $E_{ins,an}$ is the annual inserted electricity (in MWh) for the HMU microgrid from the grid. Then, a set of non-dominated solutions according to financial and environmental criteria (NPV and annual GHG emissions reduction) will be constructed. This set consists of solutions that are better in one criterion and worse in the other criteria, and is also known as the Pareto-optimal set. Figure 11 depicts this set, which consists of 15 non-dominated solutions.

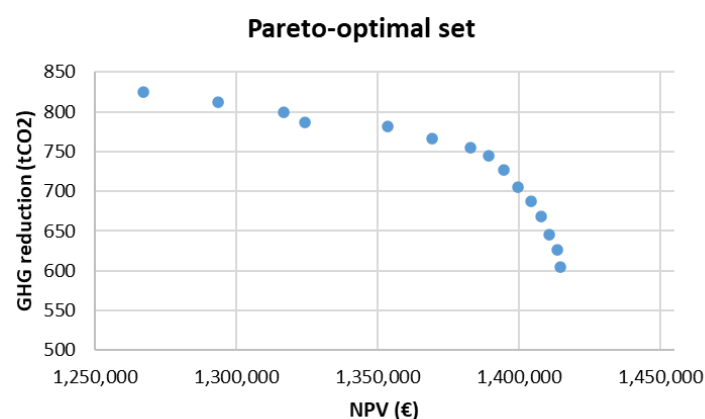


Figure 11. Pareto-optimal set of annual GHG reduction and NPV for the PV–lead–carbon battery configuration considering base load and 0.20 EUR/kWh electricity price.

5. Conclusions

The zero feed-in system, combined with energy storage, presents an efficient strategy for integrating renewable energy technologies. It maximizes self-consumption, protects the external electricity grid, and enables operation in areas with limited infrastructure.

Additionally, with the increased capacity of battery energy storage systems, it ensures a safer and more reliable way for autonomous operation within the context of smart microgrids. This study investigates for the first time a university campus smart microgrid under a zero feed-in scheme, using measured data and realistic component models, an approach that enhances the adoption of renewable energy, promotes sustainability, and reduces greenhouse gas emissions.

More specifically, this paper investigates multiple scenarios by varying PV and battery capacities, considering two different battery technologies: lead–carbon and lithium-ion. The scenarios are further evaluated under different campus load demand levels, electricity price variations, and projected reductions in lithium battery costs, thereby capturing a wide range of realistic operating conditions. The installation of a 760 kWp PV array with a 1250 kWh lead–carbon battery system is the optimal combination for the majority of alternative cases. Under the base load scenario, this combination achieves approximately a 46% annual energy autonomy. From a financial perspective, the zero feed-in scheme proves to be highly profitable, achieving a net present value of EUR 1,414,857 over a 25-year investment horizon, based on an electricity price of EUR 0.20/kWh. The levelized cost of electricity for this system is 0.075 EUR/kWh, which is comparable to the values reported for similar microgrids in the literature. The system substantially decreases electricity imports from the main grid, allowing the microgrid to operate autonomously for extended periods. In addition, it delivers notable environmental benefits, achieving an annual reduction of more than 600 tons of CO₂ emissions, thereby contributing significantly to the decarbonization of the campus and the surrounding region.

The findings of the paper provide key information for the planning and design of zero feed-in microgrids in conditions with increasing renewable penetration and grid congestion. In particular, they highlight the critical role of appropriate system sizing, load characteristics, and battery technology selection in balancing self-consumption, autonomy, and economic viability. In summary, the performed analysis confirms the techno-economic feasibility and positive environmental impacts of zero feed-in operation for university campus microgrids, and additionally provides practical guidance for implementing similar systems in other areas with comparable grid limitations and sustainability goals.

Future extensions of this approach could include (1) the integration of electric vehicle (EV) charging infrastructure at the HMU Campus; (2) the implementation of demand response strategies; (3) the incorporation of additional energy storage systems (e.g., sodium-ion batteries); (4) the installation of additional renewable energy technologies (e.g., small wind turbines) and/or energy saving technologies (e.g., combined heat and power units, advanced heat pumps); (5) an assessment of whether the proposed microgrid remains dynamically stable under zero feed-in constraints (e.g., voltage and frequency stability, transient behavior); and (6) an investigation of the proposed microgrid's resilience, considering extreme events such as earthquakes and cyber-attacks, as well as the recovery capabilities of its components.

Author Contributions: Conceptualization, P.M., Y.K. and E.K.; methodology, P.M. and Y.K.; software, P.M.; validation, P.M., Y.K. and E.P.; formal analysis, P.M.; investigation, Y.K. and E.K.; resources, E.K.; data curation, P.M. and E.P.; writing—original draft preparation, P.M. and E.P.; writing—review and editing, Y.K., E.K. and G.S.; visualization, E.P.; supervision, E.K. and G.S.; project administration, Y.K.; funding acquisition, Y.K. All authors have read and agreed to the published version of the manuscript.

Funding: This work was supported by the project “Enhancing resilience of Cretan power system using distributed energy resources (CResDER)” (Proposal ID: 03698) financed by the Hellenic Foundation for Research and Innovation (H.F.R.I.) under the Action “2nd Call for H.F.R.I. Research Projects to support Faculty Members and Researchers”.

Data Availability Statement: The raw data supporting the conclusions of this article will be made available by the authors on request.

Conflicts of Interest: The authors declare no conflicts of interest.

References

1. Rahman, A.; Farrok, O.; Haque, M.M. Environmental Impact of Renewable Energy Source Based Electrical Power Plants: Solar, Wind, Hydroelectric, Biomass, Geothermal, Tidal, Ocean, and Osmotic. *Renew. Sustain. Energy Rev.* **2022**, *161*, 112279. [\[CrossRef\]](#)
2. Rabbi, M.F.; Popp, J.; Máté, D.; Kovács, S. Energy Security and Energy Transition to Achieve Carbon Neutrality. *Energies* **2022**, *15*, 8126. [\[CrossRef\]](#)
3. Kabeyi, M.J.B.; Olanrewaju, O.A. Sustainable Energy Transition for Renewable and Low Carbon Grid Electricity Generation and Supply. *Front. Energy Res.* **2022**, *9*, 743114. [\[CrossRef\]](#)
4. Wang, W.; Yuan, B.; Sun, Q.; Wennersten, R. Application of Energy Storage in Integrated Energy Systems—A Solution to Fluctuation and Uncertainty of Renewable Energy. *J. Energy Storage* **2022**, *52*, 104812. [\[CrossRef\]](#)
5. Robyns, B. *Electrical Energy Storage for Buildings in Smart Grids*; Electrical Engineering Series; ISTE Ltd.: London, UK; John Wiley & Sons Inc.: Hoboken, NJ, USA, 2019.
6. Tsikalakis, A.G.; Hatziargyriou, N.D. Centralized control for optimizing microgrids operation. In *Proceedings of the IEEE Power and Energy Society General Meeting, Detroit, MI, USA, 24–29 July 2011*; IEEE: New York, NY, USA, 2011; pp. 1–8. [\[CrossRef\]](#)
7. Min-Allah, N.; Alrashed, S. Smart Campus—A Sketch. *Sustain. Cities Soc.* **2020**, *59*, 102231. [\[CrossRef\]](#)
8. Alrashed, S. Key Performance Indicators for Smart Campus and Microgrid. *Sustain. Cities Soc.* **2020**, *60*, 102264. [\[CrossRef\]](#)
9. PV Magazine (Website). Available online: <https://www.pv-magazine.com/2024/06/18/greece-shuns-net-metering/> (accessed on 12 December 2025).
10. PV Magazine (Website). Available online: <https://www.pv-magazine.com/2024/11/15/dutch-parliament-approves-end-of-net-metering-in-2027/> (accessed on 12 December 2025).
11. Paspatis, A.; Adebisi, B.; Orfanoudakis, G.; Siderakis, K.; Karapidakis, E.; Hatziargyriou, N. A DC Link-Based Approach to Realize Zero Feed-in Under Both Static and Dynamic Power System Events. In *2024 IEEE 18th International Conference on Compatibility, Power Electronics and Power Engineering (CPE-POWERENG)*; IEEE: Gdynia, Poland, 2024; pp. 1–6. [\[CrossRef\]](#)
12. Kumar, P.; Malik, N.; Garg, A. Comparative Analysis of Solar—Battery Storage Sizing in Net Metering and Zero Export Systems. *Energy Sustain. Dev.* **2022**, *69*, 41–50. [\[CrossRef\]](#)
13. Chedid, R.; Sawwas, A.; Fares, D. Optimal Design of a University Campus Micro-Grid Operating under Unreliable Grid Considering PV and Battery Storage. *Energy* **2020**, *200*, 117510. [\[CrossRef\]](#)
14. Huang, Y.; Masrur, H.; Lipu, M.S.H.; Howlader, H.O.R.; Gamil, M.M.; Nakadomari, A.; Mandal, P.; Senjyu, T. Multi-Objective Optimization of Campus Microgrid System Considering Electric Vehicle Charging Load Integrated to Power Grid. *Sustain. Cities Soc.* **2023**, *98*, 104778. [\[CrossRef\]](#)
15. Henrique, L.F.; Silva, W.N.; Silva, C.C.A.; Dias, B.H.; Oliveira, L.W.; Almeida, M.C.D. Optimal Siting and Sizing of Distributed Energy Resources in a Smart Campus. *Electr. Power Syst. Res.* **2023**, *217*, 109095. [\[CrossRef\]](#)
16. Quadros, R. Implementation of Microgrid on the University Campus of UNICAMP- Brazil: Case Study. *J. Electron. Adv. Electr. Eng.* **2021**, *1*, 21–25. [\[CrossRef\]](#)
17. Muqet, H.A.U.; Ahmad, A. Optimal Scheduling for Campus Prosumer Microgrid Considering Price Based Demand Response. *IEEE Access* **2020**, *8*, 71378–71394. [\[CrossRef\]](#)
18. Elenkova, M.Z.; Papadopoulos, T.A.; Psarra, A.I.; Chatzimichail, A.A. A Simulation Platform for Smart Microgrids in University Campuses. In *2017 52nd International Universities Power Engineering Conference (UPEC)*; IEEE: Heraklion, Greece, 2017; pp. 1–6. [\[CrossRef\]](#)
19. Javed, H.; Muqet, H.A.; Shehzad, M.; Jamil, M.; Khan, A.A.; Guerrero, J.M. Optimal Energy Management of a Campus Microgrid Considering Financial and Economic Analysis with Demand Response Strategies. *Energies* **2021**, *14*, 8501. [\[CrossRef\]](#)
20. Nasir, T.; Raza, S.; Abrar, M.; Muqet, H.A.; Jamil, H.; Qayyum, F.; Cheikhrouhou, O.; Alassery, F.; Hamam, H. Optimal Scheduling of Campus Microgrid Considering the Electric Vehicle Integration in Smart Grid. *Sensors* **2021**, *21*, 7133. [\[CrossRef\]](#)
21. Huang, Y.; Masrur, H.; Shigenobu, R.; Hemeida, A.M.; Mikhaylov, A.; Senjyu, T. A Comparative Design of a Campus Microgrid Considering a Multi-Scenario and Multi-Objective Approach. *Energies* **2021**, *14*, 2853. [\[CrossRef\]](#)
22. Eltamaly, A.M.; Alotaibi, M.A.; Alolah, A.I.; Ahmed, M.A. IoT-Based Hybrid Renewable Energy System for Smart Campus. *Sustainability* **2021**, *13*, 8555. [\[CrossRef\]](#)
23. Ali, A.; Muqet, H.A.; Khan, T.; Hussain, A.; Waseem, M.; Niazi, K.A.K. IoT-Enabled Campus Prosumer Microgrid Energy Management, Architecture, Storage Technologies, and Simulation Tools: A Comprehensive Study. *Energies* **2023**, *16*, 1863. [\[CrossRef\]](#)

24. Paspatis, A.; Fiorentzis, K.; Katsigiannis, Y.; Karapidakis, E. Smart Campus Microgrids towards a Sustainable Energy Transition—The Case Study of the Hellenic Mediterranean University in Crete. *Mathematics* **2022**, *10*, 1065. [CrossRef]
25. Tercan, S.M.; Demirci, A.; Gokalp, E.; Cali, U. Maximizing self-consumption rates and power quality towards two-stage evaluation for solar energy and shared energy storage empowered microgrids. *J. Energy Storage* **2022**, *51*, 104561. [CrossRef]
26. Gao, L.; Wang, S.; Mao, M.; Liu, C.; Li, T. Study on the Energy Consumption Characteristics and the Self-Sufficiency Rate of Rooftop Photovoltaic of University Campus Buildings. *Energies* **2024**, *17*, 3535. [CrossRef]
27. Norouzi, F.; Shekhar, A.; Hoppe, T.; Bauer, P. Analysing the impact of the different pricing policies on PV-battery systems: A Dutch case study of a residential microgrid. *Energy Policy* **2025**, *204*, 114620. [CrossRef]
28. Keskinis, S.; Elmasides, C.; Kosmadakis, I.E.; Raptis, I.; Tsikalakis, A. Techno-Economic Photovoltaic-Battery Energy Storage System Microgrids with Diesel Backup Generator: A Case Study in Industrial Loads in Germany Comparing Load-Following and Cycle-Charging Control. *Energies* **2025**, *18*, 6463. [CrossRef]
29. Pereira, L.; Cavaleiro, J. On the Value Proposition of Battery Energy Storage in Self-Consumption only Scenarios: A Case-Study in Madeira Island. In Proceedings of the IECON 2019—45th Annual Conference of the IEEE Industrial Electronics Society, Lisbon, Portugal, 14–17 October 2019; Volume 1, pp. 4569–4574.
30. Markaki, M.; Karapidakis, E.; Katsigiannis, Y.; Apostolaki, M.; Kornilakis, G.; Floyris, P. Extensive Use of Net-Metering in Crete's Region Public Buildings. *E3S Web Conf.* **2023**, *404*, 01003. [CrossRef]
31. Roumpakias, E.; Zogou, O.; Stamatellou, A.-M. Optimization of Electrical and Thermal Storage in a High School Building in Central Greece. *Energies* **2024**, *17*, 1966. [CrossRef]
32. Shahgholian, G. A Brief Review on Microgrids: Operation, Applications, Modeling, and Control. *Int. Trans. Electr. Energy Syst.* **2021**, *3*, e12885. [CrossRef]
33. Singh, A.; Suhag, S. Trends in Islanded Microgrid Frequency Regulation—A Review. *Smart Sci.* **2019**, *7*, 91–115. [CrossRef]
34. Gayatri, M.T.L.; Parimi, A.M.; Pavan Kumar, A.V. A Review of Reactive Power Compensation Techniques in Microgrids. *Renew. Sustain. Energy Rev.* **2018**, *81*, 1030–1036. [CrossRef]
35. Urquizo, J.; Singh, P.; Kondrath, N.; Hidalgo-Leon, R.; Soriano, G. Using D-FACTS in Microgrids for Power Quality Improvement: A Review. In *2017 IEEE Second Ecuador Technical Chapters Meeting (ETCM)*; IEEE: Salinas, CA, USA, 2017; pp. 1–6. [CrossRef]
36. Llaría, A.; Cúrea, O.; Jiménez, J.; Camblong, H. Survey on Microgrids: Unplanned Islanding and Related Inverter Control Techniques. *Renew. Energy* **2011**, *36*, 2052–2061. [CrossRef]
37. Gutierrez-Rojas, D.; Nardelli, P.H.J.; Mendes, G.; Popovski, P. Review of the State of the Art on Adaptive Protection for Microgrids Based on Communications. *IEEE Trans. Ind. Inform.* **2021**, *17*, 1539–1552. [CrossRef]
38. Zhang, L.; Tai, N.; Huang, W.; Liu, J.; Wang, Y. A Review on Protection of DC Microgrids. *J. Mod. Power Syst. Clean Energy* **2018**, *6*, 1113–1127. [CrossRef]
39. Hu, J.; Shan, Y.; Guerrero, J.M.; Ioinovici, A.; Chan, K.W.; Rodriguez, J. Model Predictive Control of Microgrids—An Overview. *Renew. Sustain. Energy Rev.* **2021**, *136*, 110422. [CrossRef]
40. Wang, X.; Hu, M.; Luo, X.; Guan, X. A Detection Model for False Data Injection Attacks in Smart Grids Based on Graph Spatial Features Using Temporal Convolutional Neural Networks. *Electr. Power Syst. Res.* **2025**, *238*, 111126. [CrossRef]
41. Alhawsawi, E.Y.; Salhein, K.; Zohdy, M.A. A Comprehensive Review of Existing and Pending University Campus Microgrids. *Energies* **2024**, *17*, 2425. [CrossRef]
42. Thomson, M.; Infield, D.G. Impact of Widespread Photovoltaics Generation on Distribution Systems. *IET Renew. Power Gener.* **2007**, *1*, 33–40. [CrossRef]
43. McEvoy, A.; Markvart, T.; Castaner, L. *Practical Handbook of Photovoltaics Fundamentals and Applications*, 2nd ed.; Academic Press: Cambridge, MA, USA, 2012.
44. LONGi LR5-54HIB PV Panel. Available online: https://static.longi.com/LR_5_54_HIB_400_415_M_V17_824efc613d.pdf (accessed on 20 December 2025).
45. Narada BESS Series Container-Type and Movable Energy Storage Power Station Datasheet. Available online: https://cdn.enfsolar.com/Product/pdf/storage_system/5b3dde212f25f.pdf (accessed on 28 December 2025).
46. HOMER Microgrid and Hybrid Power Modeling Software. Available online: <https://www.ul.com/software/ultrus/homer-microgrid-and-hybrid-power-modeling-software> (accessed on 20 December 2025).
47. iHOGA/MHOGA, Simulation and Optimization of Stand-Alone and Grid-Connected Hybrid Renewable Systems. Available online: <https://ihoga.unizar.es/en/> (accessed on 20 December 2025).
48. Fraunhofer Institute for Solar Energy Systems ISE. *Levelized Cost of Electricity—Renewable Energy Technologies*; Fraunhofer ISE: Freiburg, Germany, 2024. Available online: <https://www.ise.fraunhofer.de/en/publications/studies/cost-of-electricity.html> (accessed on 20 December 2025).
49. Cole, W.; Ramasamy, V.; Turan, M. *Cost Projections for Utility-Scale Battery Storage: 2025 Update*; National Renewable Energy Laboratory: Golden, CO, USA, 2025. Available online: <https://docs.nrel.gov/docs/fy25osti/93281.pdf> (accessed on 20 December 2025).

50. Canada, N.R. RETScreen®Clean Energy Management Software. Available online: <https://natural-resources.canada.ca/maps-tools-publications/tools-applications/retscreen> (accessed on 20 December 2025).
51. Hellenic Electricity Distribution Network Operator S.A. (HEDNO). Available online: <https://deddie.gr/en/> (accessed on 20 December 2025).
52. Independent Power Transmission Operator S.A. (IPTO), Monthly Energy Reports. Available online: https://www.admie.gr/en/market/reports/monthly-energy-balance?_wrapper_format=html&page=0 (accessed on 20 December 2025).

Disclaimer/Publisher’s Note: The statements, opinions and data contained in all publications are solely those of the individual author(s) and contributor(s) and not of MDPI and/or the editor(s). MDPI and/or the editor(s) disclaim responsibility for any injury to people or property resulting from any ideas, methods, instructions or products referred to in the content.