

## Article

# Comparative Designs for Standalone Critical Loads Between PV/Battery and PV/Hydrogen Systems

Ahmed Lotfy <sup>1,\*</sup>, Wagdy Refaat Anis <sup>2</sup>, Fatma Newagy <sup>2</sup>  and Sameh Mostafa Mohamed <sup>3</sup>

<sup>1</sup> Faculty of Engineering, Ain Shams University, Cairo 11517, Egypt

<sup>2</sup> Electronics and Communication Engineering Department, Faculty of Engineering, Ain Shams University, Cairo 11517, Egypt; wagdyanis51@yahoo.com (W.R.A.); fatma\_newagy@eng.asu.edu.eg (F.N.)

<sup>3</sup> Egyptian Chinese College for Applied Technology, Suez Canal University, Ismailia 41522, Egypt; s\_m\_elsayed@yahoo.com

\* Correspondence: alotfy718@gmail.com

## Abstract

This study presents the design and techno-economic comparison of two standalone photovoltaic (PV) systems, each supplying a 1 kW critical load with 100% reliability under Cairo's climatic conditions. These systems are modeled for both the constant and the night load scenarios, accounting for the worst-case weather conditions involving 3.5 consecutive cloudy days. The primary comparison focuses on traditional lead-acid battery storage versus green hydrogen storage via electrolysis, compression, and fuel cell reconversion. Both the configurations are simulated using a Python-based tool that calculates hourly energy balance, component sizing, and economic performance over a 21-year project lifetime. The results show that the PV/H<sub>2</sub> system significantly outperforms the PV/lead-acid battery system in both the cost and the reliability. For the constant load, the Levelized Cost of Electricity (LCOE) drops from 0.52 USD/kWh to 0.23 USD/kWh (a 56% reduction), and the payback period is shortened from 16 to 7 years. For the night load, the LCOE improves from 0.67 to 0.36 USD/kWh (a 46% reduction). A supplementary cost analysis using lithium-ion batteries was also conducted. While Li-ion improves the economics compared to lead-acid (LCOE of 0.41 USD/kWh for the constant load and 0.49 USD/kWh for the night load), this represents a 21% and a 27% reduction, respectively. However, the green hydrogen system remains the most cost-effective and scalable storage solution for achieving 100% reliability in critical off-grid applications. These findings highlight the potential of green hydrogen as a sustainable and economically viable energy storage pathway, capable of reducing energy costs while ensuring long-term resilience.

**Keywords:** PV system; battery size; reliability; electrolyzer; fuel cell; levelized cost of energy



Academic Editors: Denis Candusso and Guo-Ming Weng

Received: 14 May 2025

Revised: 27 June 2025

Accepted: 30 June 2025

Published: 5 July 2025

**Citation:** Lotfy, A.; Anis, W.R.;

Newagy, F.; Mohamed, S.M.

Comparative Designs for Standalone Critical Loads Between PV/Battery and PV/Hydrogen Systems. *Hydrogen* **2025**, *6*, 46. <https://doi.org/10.3390/hydrogen6030046>

**Copyright:** © 2025 by the authors. Licensee MDPI, Basel, Switzerland. This article is an open access article distributed under the terms and conditions of the Creative Commons Attribution (CC BY) license (<https://creativecommons.org/licenses/by/4.0/>).

## 1. Introduction

This paper presents a comparative study of two energy storage systems used in standalone photovoltaic (PV) setups: traditional lead-acid batteries and green hydrogen storage. Both the systems rely on solar energy generated during the day to power loads. This study focuses on two types of loads—the constant load and the night load—while excluding the daily load, as its minimal storage requirements have a negligible impact on the system performance.

To evaluate these storage solutions under challenging conditions, the system is evaluated based on a worst-case weather scenario in Egypt: three consecutive cloudy days, which require storage to cover four full days of demand.

The constant load refers to a 24 h uninterrupted demand, typical of critical applications such as military operations or field hospitals, where reliability is essential. The night load requires the storing of solar energy generated during the day for use at night.

This study includes a comparison of system sizing, battery state-of-charge (SOC), and hydrogen tank capacity, along with performance metrics such as cost and reliability. It emphasizes use cases that demand uninterrupted energy availability, especially in off-grid or critical infrastructure contexts.

Hydrogen is gaining attention across multiple sectors due to its potential to decarbonize energy systems. Green hydrogen is increasingly viewed as a clean energy carrier with applications spanning fuel cells, industrial heating, transportation, and electricity generation. Fuel cells powered by hydrogen offer a zero-emissions alternative to traditional combustion engines, particularly in heavy-duty transport and long-haul applications [1].

Recent technological advancements in green hydrogen production, storage, and distribution are accelerating its integration into modern energy systems. Improved methods for hydrogen storage, such as liquefaction, compression, and chemical storage, are making it more efficient and cost-effective [2,3]. Green hydrogen also addresses a key challenge of solar and wind energy: intermittency, helping to ensure a stable energy supply.

The global energy demand continues to drive fossil fuel use, contributing to climate change. As a result, alternative energy sources like solar and wind are increasingly adopted. However, their variability necessitates effective energy storage solutions to ensure grid reliability [4].

This paper presents a comprehensive mathematical model for both lead-acid battery and hydrogen-based systems. It also compares two energy management strategies: one using batteries for short-term storage, and another employing hydrogen for long-term storage. Among renewable sources, solar energy is advantageous for its year-round availability and zero emissions [5].

PV system output is highly dependent on sunlight and can fluctuate under cloudy conditions, leading to instability [6]. To mitigate this, robust energy storage is essential. While batteries are common in PV setups, they often fall short during prolonged cloudy periods. A promising alternative is the hydrogen fuel cell (HFC), which generates electricity from stored hydrogen and enhances long-term system efficiency.

A Proton Exchange Membrane (PEM) electrolyzer is modeled in this study due to its high efficiency, rapid dynamic response, and compatibility with variable solar input. This makes it well-suited for integration with standalone PV systems. Hydrogen can be produced through water electrolysis and stored in tanks for future use, unlike batteries, which are typically short-term solutions. In PV/HFC systems, excess daytime solar energy powers an electrolyzer to produce hydrogen, which is stored and later converted into electricity via a fuel cell during the night or cloudy periods [7].

PEM (Proton Exchange Membrane) fuel cells offer advantages like fast startup, compact size, and long-term stability [8]. Hydrogen storage is suited for long-term energy needs, while batteries serve medium- and short-term applications [9].

This paper uses a Python-based simulation tool that dynamically calculates the sizing of system components, solar panels, electrolyzers, fuel cells, and batteries. The tool also simulates solar radiation based on the location and the time, and adjusts the energy supply according to environmental inputs and user-defined parameters. It tracks the battery SOC and optimizes the energy management to improve the system performance. Previous studies have explored the techno-economic performance of standalone PV systems using either battery or hydrogen-based storage.

Nasser and Hassan compared the PV/Battery and PV/Hydrogen systems for powering street lighting as a night load in New Borg El-Arab City, Egypt. Although the battery

system had a higher energy efficiency (17.8%), the hydrogen system proved more economical, with a lower Levelized Cost of Energy (LCOE) of 1.06 USD/kWh compared to 2.80 USD/kWh for the battery system [10]. The hydrogen system also achieved a shorter payback period of 6.44 years versus 11.7 years, highlighting its cost-effectiveness despite the lower efficiency.

Nousir and Anis developed GUI-based software to calculate the PV and battery sizes for various load types, including constant, daily, and night loads. Their tool provides system sizing, cost analysis, and reliability metrics under real climatic conditions in Egypt. For a 1 kW off-grid system, they found that the LCOEs for daily, night, and constant loads were 0.14 USD/kWh, 1.05 USD/kWh, and 0.60 USD/kWh, respectively [11]. These results underline the higher cost of systems designed for continuous energy supply under adverse weather.

Miled et al. [12] examined a PV–electrolyzer–fuel cell (PVEFC) system for an off-grid green villa in Tunisia. Using HOMER software version 3.14.2, they optimized a system consisting of a 20 kW PV array and a 6 kW fuel cell. The system produced 306 kg of hydrogen annually and met 87% of the villa’s energy needs through solar energy. With a total LCOE of 97,577.6 EUR—73% of which was attributed to the fuel cell—the study emphasized the importance of optimal PV tilt angle and solar potential in cost reduction.

Farhani et al. [13] assessed a hybrid solar hydrogen system for an agricultural farm in Kairouan, Tunisia. Their 140 kW PV array generated 234,765 kWh/year and produced 1991 kg of hydrogen annually. The system’s capital cost was 809,121,000 EUR, and the optimization process using HOMER Pro confirmed its feasibility for remote applications, despite the high initial investment.

In another study, Farhani et al. [14] evaluated a hybrid solar–wind–hydrogen system in the Tunisian Sahel. With a PV capacity of 3000 kWp and a hydrogen output reaching 101.8 kg/day, the region’s favorable solar and wind conditions proved ideal for such hybrid systems. The study highlighted the feasibility of combining renewables with hydrogen storage to achieve a sustainable, off-grid energy supply.

Okonkwo et al. [15] investigated PV system sizing for hydrogen refueling stations in Oman. A 3 MWp grid-connected PV system produced 58,615 kg of hydrogen annually with a Levelized Hydrogen Cost (LHC) of 5.5 EUR/kg. Standalone PV systems with batteries or fuel cells resulted in slightly higher LHCs of 5.74 EUR/kg and 7.38 EUR/kg, respectively. The system also achieved significant CO<sub>2</sub> reductions, illustrating the environmental benefits of integrating green hydrogen.

The main comparison in this study focuses on green hydrogen and lead-acid battery storage systems. A supplementary cost analysis using lithium-ion batteries is also included to highlight the potential trade-offs of more advanced battery technologies.

While several studies have evaluated PV systems with either battery or hydrogen storage, most focus on a single load type or use generic sizing tools such as HOMER. This work introduces a custom-built Python simulation tool that dynamically calculates the system performance under both constant and night load scenarios using actual solar radiation data from Cairo, Egypt. Unlike earlier works, this study simulates a worst-case scenario of 3.5 consecutive cloudy days and compares the two systems in terms of reliability, storage behavior, and economic indicators, including the LCOE and the payback period. The dual comparison across two load profiles under the worst conditions provides a new layer of insight for critical standalone system planning in off-grid environments.

## 2. System Description

This section compares two standalone energy storage configurations: A PV/Hydrogen (PV/H<sub>2</sub>) system and a PV/Battery system.

As shown in Figure 1a., the PV/H<sub>2</sub> system uses solar panels to generate electricity during the day. This electricity powers an electrolyzer, which splits water into hydrogen and oxygen. The hydrogen is then compressed and stored in a tank, which is one of the most widely accepted methods for on-site hydrogen storage.

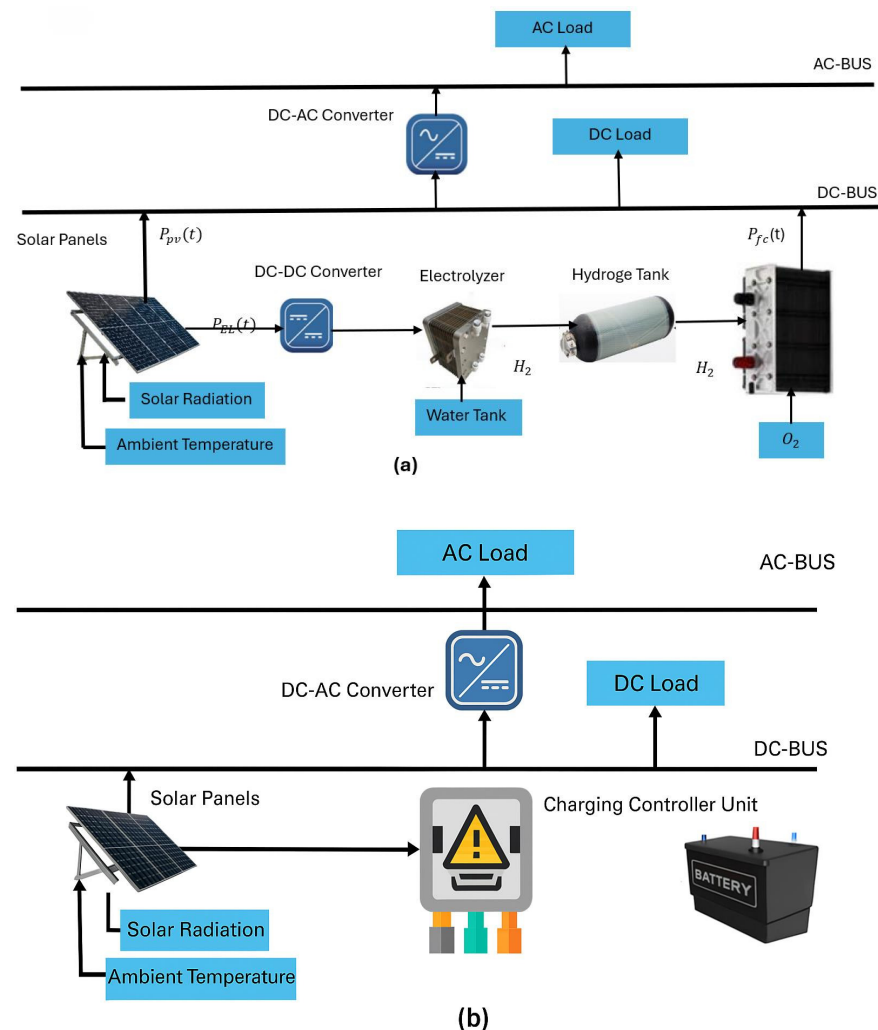


**Figure 1.** Schematic diagram of the comparison systems (a) off-grid PV/H<sub>2</sub> (b) off-grid PV/Batteries.

This configuration is designed to store hydrogen during surplus production periods (e.g., summer months) and utilize it during low-production periods (e.g., winter months). At night, or when solar radiation is unavailable, a fuel cell converts the stored hydrogen into electricity to meet both the constant and the night load demands.

As shown in Figure 1b., the PV/Battery system consists of PV panels, a battery storage bank, a charge controller, and a DC/AC inverter. During daylight hours, the PV array supplies power to the load and charges the battery bank. During the night, the stored electricity in the batteries powers the load through the DC/AC converter.

This system is commonly used for off-grid applications or backup power systems, especially where energy demand must be met consistently.

The solar time at the study location in Cairo, Egypt, ranges from 6 to 12 h per day, as shown in Figure 2a: solar radiation is the highest between April and September, leading to increased power generation. The excess energy produced during these periods is stored (in batteries or as hydrogen) for later use during the months with lower solar radiation.

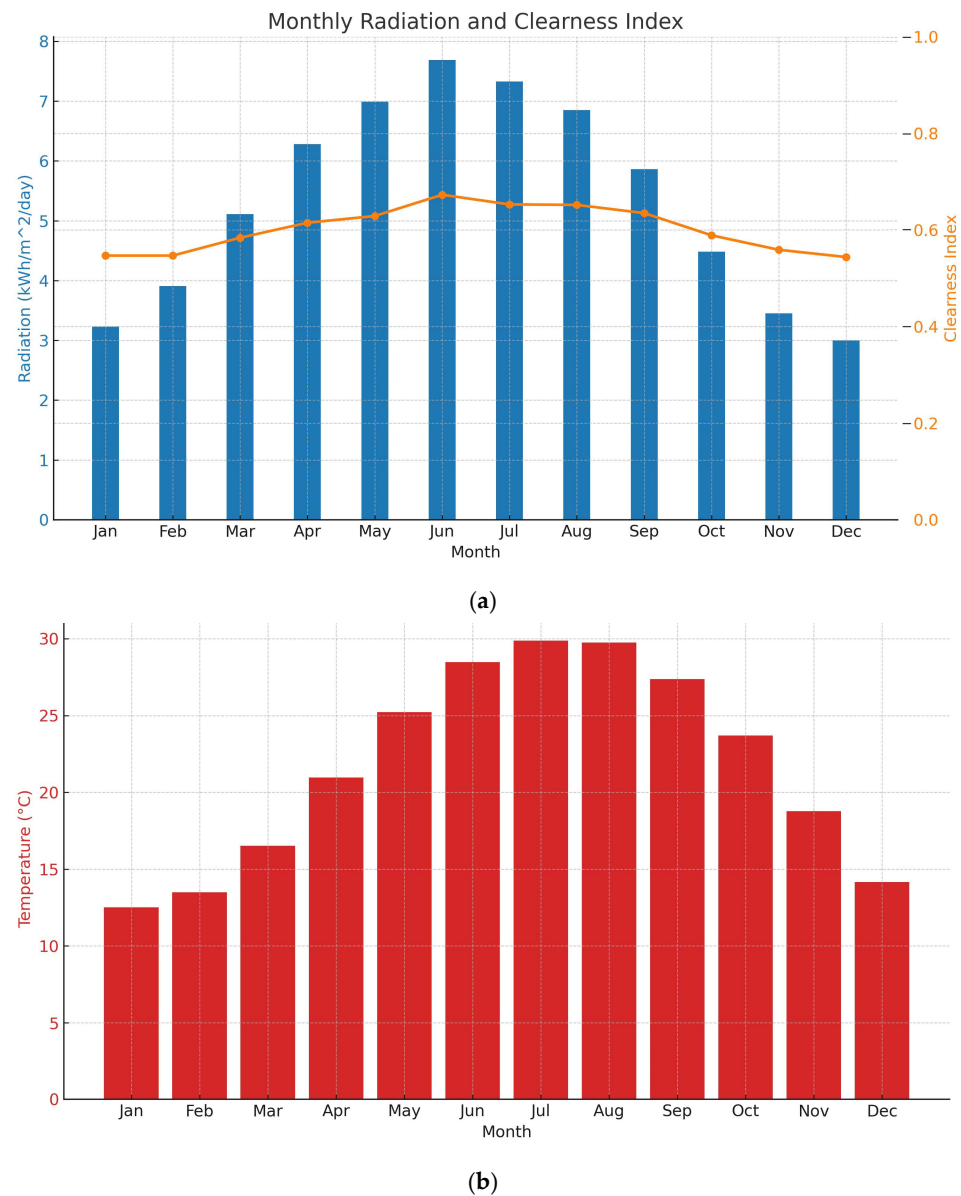


**Figure 2.** (a) Monthly solar global horizontal irradiance @Cairo, Egypt (30° N) (b) Monthly average ambient temperature.

Figure 2a,b presents the monthly average global solar radiation ( $H_T$ ) and the ambient temperature for Cairo, Egypt, based on long-term meteorological data extracted from HOMER software using the Surface Meteorology and Solar Energy (SSE) database [16]. According to simulations using HOMER software, daily solar irradiation at the site reaches a peak of 7.69 kWh/m<sup>2</sup>/day in June, while the lowest value is 3.0 kWh/m<sup>2</sup>/day in December. A constant 1 kW load is assumed throughout the study.

The fuel cell is modeled based on the electrochemical reaction of hydrogen and oxygen to produce electricity and water. Its efficiency is influenced by several parameters, including: the operating pressure, the current density, the temperature, the fuel cell coefficient, and the hydrogen-to-electricity conversion ratio. These values are selected based on typical commercial fuel cell systems [2–17].

Both the electrolyzer and the fuel cell operate in a loop, where the electrolyzer produces hydrogen during surplus solar generation and the fuel cell consumes it to generate electricity during low or no solar periods. These dynamic supports both the constant and night load scenarios.

### 3. A Mathematical Model of the System

This study utilizes actual environmental data specific to Cairo, Egypt (Latitude: 30.0444° N, Longitude: 31.2357° E), to simulate and evaluate the performance of two energy storage systems. Three scenarios are considered, corresponding to different numbers of continuous cloudy days (NC = 1, 2, 3) occurring during January and December. These cases are used to investigate the impact of prolonged cloudy conditions on the required storage capacity and overall system cost.

This system is designed to supply a continuous 1 kW load throughout the year, under both constant and night load profiles. To optimize solar energy capture, photovoltaic (PV) panels are installed at a 30° tilt angle facing south, which is typical for this latitude [16].

The simulation is implemented using Python, performing an hourly energy balance analysis over a full year (8760 h). Component sizes, including PV arrays, batteries, electrolyzers, hydrogen storage tanks, and fuel cells, are determined based on the hourly power demand and solar availability.

The simulation process begins with input data: load profiles, solar irradiance, the temperature, and system duration. Control component efficiencies are included to ensure realistic power flow estimates. Both the systems are analyzed under identical load and weather conditions, and an economic model is integrated to evaluate the capital cost, Levelized Cost of Energy (LCOE), and payback period, enabling a comprehensive comparison between the PV/Battery and PV/Hydrogen configurations.

#### 3.1. PV Panels Model

The photovoltaic (PV) array consists of multiple silicon-based modules connected in series and in parallel. Each module is rated at 200 W under Standard Test Conditions (STC), which correspond to solar radiation of 1000 W/m<sup>2</sup>, a cell temperature of 25 °C, and an air mass (AM) of 1.5. Each panel generates 8.27 A at 24 V under these conditions [18]. To estimate the solar energy availability, the global radiation on a tilted surface ( $G_T$ ) is calculated using standard solar geometry equations that account for the hour angle, declination, latitude, and panel tilt angle [19]:

$$G_T = \frac{\pi}{24} H_T \left( \frac{\cos w + \tan \delta \tan(\phi - \beta)}{\sin W'_S + W'_S \tan \delta \tan(\phi - \beta)} \right) \quad (1)$$

where:

$H_T$  Global radiation (Kwh/m<sup>2</sup>/day) (direct and diffused radiation on tilted surface)

$w$  hour angle

$W'_S$  The sunset hour angle on tilted surface

$\delta$  declination angle

$\phi$  latitude of location

$\beta$  tilted angle

Figure 3 illustrates the monthly radiation and clearness index, calculated using HOMER-derived data for Cairo. The clearness index represents the ratio between global and extraterrestrial radiation and the seasonal variation of solar radiation on a tilted surface in Cairo. The radiation levels peak during the summer (June–August) and fall in the winter months (November–December), reflecting the impact of seasonal solar availability on energy production. The current, power, and energy generated by the PV array are determined as follows:

$$I = I_{sc0} \times G_T - I_0 \times e^{\frac{V_A}{V_T \times n}} \quad (2)$$

where:

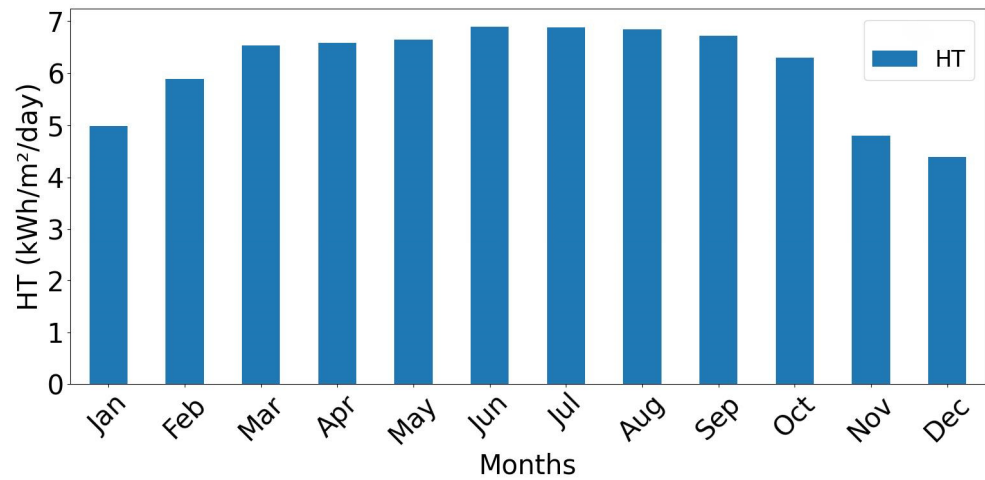


**Figure 3.** Global radiation @Cairo, Egypt (30° N) (direct and diffused radiation on tilted angle 30°).

$I_{sc0}$  the short circuit current of PV array under standard test condition (STC)

$V_A$  array voltage

$\eta$  perfection factor

$V_T$  thermal voltage

$I_0$  reverse saturation current

$$P_A = I \times V_A \quad (3)$$

where:  $P_A$  is the array power

$$E = E_0 + P_A \times \Delta_T \quad (4)$$

where:

$\Delta_T = 0.1$  h

$E_0$  is the energy present in the array at previous ( $\Delta_T$ )

$E$  output energy from PV array

These equations allow hourly energy output to be tracked over time, accounting for changing solar conditions and system performance.

### 3.2. Battery Model

The batteries in the standalone PV system store energy for nighttime use. Battery capacity during charging and discharging can be expressed using the following equation:

$$I_B = I - I_L \quad (5)$$

where  $I_B$  is battery current and  $I_L$  is load current.

A critical parameter for battery sizing is the State of Charge (SOC), which represents the available energy in the battery relative to its capacity. This increases during charging and decreases during discharging. The SOC is updated using [20]:

If  $I > I_L$ , then the battery is charging, as:

$$SOC_{ch} = SOC_0 + \frac{I_B \times \eta_{ch} \times \Delta_T}{AH} \quad (6)$$

where:

$\eta_{ch}$  = Charging efficiency for battery is set at 85%.

$AH$  is the amount of current a battery can provide over a while.

$SOC_0$  is the ratio of stored energy in the battery at previous moment.

If  $I < I_L$ , then battery is discharging.

$$SOC_{disch} = SOC_0 - \frac{I_B \times \Delta T}{\eta_{disch} \times AH} \quad (7)$$

where  $\eta_{disch}$  is the discharging efficiency for the battery set at 85%, and  $SOC = 0.8$  for January first.

To ensure reliable operation, the battery SOC is maintained between 20% and 95%, avoiding deep discharges and overcharging. A key design assumption is that the SOC at the start of each year equals the end-of-year SOC (0.8), ensuring energy continuity across annual cycles.

During the winter solstice (21 December), Cairo experiences its longest night, approximately 14 h. In a worst-case scenario of three consecutive cloudy days ( $NC = 3$ ), the system must store 3.5 days of energy. During cloudy periods, solar radiation is assumed to drop to 15% of the normal values. The Battery Factor (BF) as shown in Equation (8), represents the number of storage hours required, following the formulation in [11].

$$BF = \frac{\text{Battery energy (wh)}}{\text{average load power (w)}} \quad (8)$$

A Python program has been developed, and the result obtained is shown in Figure 4, showing the instantaneous SOC of the battery for one year, with the array size 10 kWp, assuming 6 cloudy days (3 consecutive days during December and 3 consecutive days during January). During cloudy days, the solar irradiance is supposed to be 15% of that during sunny days. It is shown that the SOC drops significantly during the cloudy days in January and December. However, the SOC is always higher than the minimum acceptable value (0.2).

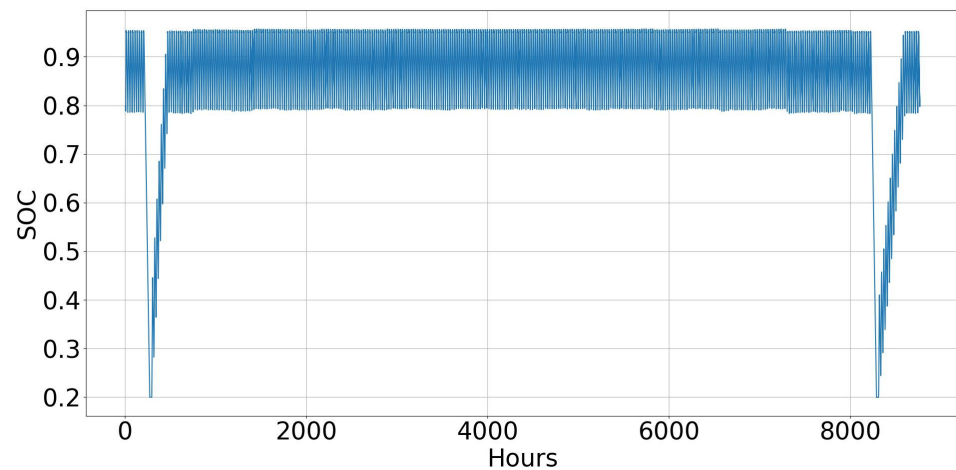


**Figure 4.** The SOC variation during the entire year @  $NC = 3$ ,  $BF = 140$ , Array Size 10 kWp, tilted angle  $30^\circ$ .

The battery design assumes the SOC at the beginning of each year remains consistent with that at the year's end (0.8), ensuring no energy loss at the start of the following year.

The design is made so that the SOC never decreases below 0.2, so that the power is always available for the load (i.e., 100% reliability). Also, the design discussed in this work considers the system reliability, which is defined as:

$$\text{Reliability} = \frac{(L_d \times d - T_{off})}{L_d * d} \quad (9)$$

$L_d$  Load duration in hours per day

$T_{off}$  Number of hours during which no power is supplied to the load during the year (unmet load)

$d$  Number of days during the year

Figure 5 compares the reliability of the PV/Battery system under two load profiles, the constant and the night load, assuming three consecutive cloudy days ( $NC = 3$ ). The results show that the reliability increases with the battery capacity in both cases. However, to achieve 97% reliability, the constant load system requires only 30 kWh of battery storage, whereas the night load system requires approximately 50 kWh. This is due to the misalignment between the energy production (daytime) and the energy consumption (nighttime), which makes the night load more demanding in terms of the storage capacity. These findings emphasize the importance of considering the load timing in the battery storage system design.

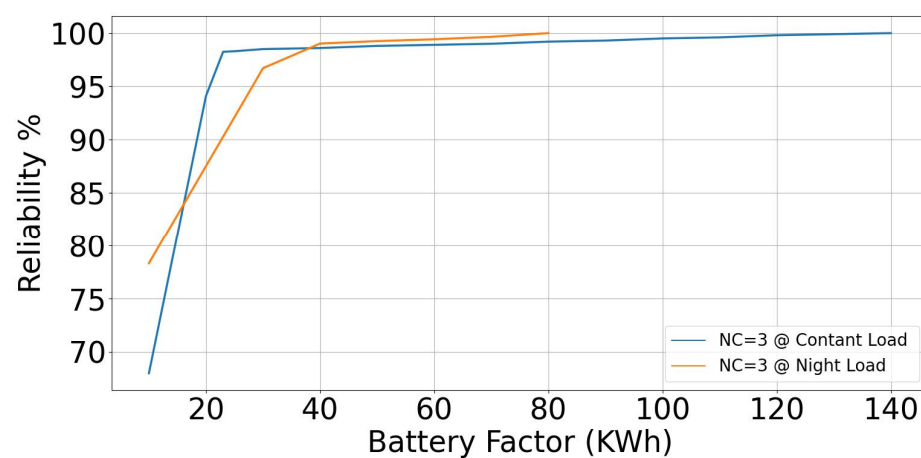


**Figure 5.** Battery Factor versus Reliability @ different number of cloudy days.

The simulation results show that, for a constant 1 kW load in Cairo ( $30^\circ$  N latitude), increasing the battery capacity to 140 kWh with a 10 kWp PV array reduces the annual system downtime ( $T_{off}$ ) to zero hours per year. In comparison, under a night load scenario, only 80 kWh of the battery storage with an 8 kWp PV array is required to achieve the same zero-downtime condition. This demonstrates that the night load configuration requires nearly half the storage capacity to maintain full reliability, primarily due to the better alignment between the energy generation and the consumption.

As shown in Tables 1 and 2, the system reliability has a direct and significant impact on the overall cost. Even a small reduction in reliability can lead to substantial cost savings in the battery and PV sizing. The Python-based simulation tool developed in this study dynamically calculates the system reliability versus the cost by tracking the total number of hours during the year when the load is not served ( $T_{off}$ ).

**Table 1.** A 1 kW constant load standalone PV/Battery system ( $NC = 3$ ).

| Battery Factor (BF) | Array Size (kWp) | $T_{off}$ (h) | Reliability | Initial Cost USD | Cost USD/kWh |
|---------------------|------------------|---------------|-------------|------------------|--------------|
| 20                  | 10               | 516.84        | 94.1%       | 10,334.18        | 0.10         |
| 30                  | 10               | 131.4         | 98.5%       | 13,938.78        | 0.14         |
| 40                  | 10               | 122.64        | 98.6%       | 17,543.37        | 0.17         |
| 60                  | 10               | 96.36         | 98.9%       | 24,752.55        | 0.24         |
| 80                  | 10               | 70.08         | 99.2%       | 31,961.73        | 0.31         |
| 120                 | 10               | 17.52         | 99.8%       | 46,380.12        | 0.45         |
| 140                 | 10               | 0             | 100%        | 53,589.28        | 0.52         |

**Table 2.** A 1 kW night load standalone PV/Battery system (NC = 3).

| Battery Factor (BF) | Array Size (kWp) | $T_{off}$ (h) | Reliability | Initial Cost USD | Cost USD/kWh |
|---------------------|------------------|---------------|-------------|------------------|--------------|
| 20                  | 8                | 257.5         | 97.06%      | 9709.18          | 0.25         |
| 30                  | 8                | 151.6         | 98.27%      | 13,313.78        | 0.32         |
| 40                  | 8                | 116.7         | 98.67%      | 16,918.37        | 0.39         |
| 50                  | 8                | 84.1          | 99.04%      | 20,522.96        | 0.46         |
| 60                  | 8                | 66.7          | 99.24%      | 24,127.55        | 0.53         |
| 70                  | 8                | 15.3          | 99.65%      | 27,732.14        | 0.60         |
| 80                  | 8                | 0             | 100%        | 31,336.73        | 0.67         |

To model realistic worst-case conditions, the simulation assumes three consecutive cloudy days in both January (days 10–12) and December (days 349–351). During these periods, the solar irradiance is reduced to 15% of the normal values, forcing the system to rely solely on stored energy. The tool helps the designers balance the critical load requirements and economic constraints by showing the cost and reliability trade off, depending on the intended application.

### 3.3. Electricity Controller Unit

The controller's primary function is to supply the electricity efficiently. It includes a DC/DC converter that maximizes the hydrogen production by matching the PV array and the electrolyzer characteristics (power point tracking), along with an inverter for the AC loads. The controller is assumed to operate with an efficiency of 95% [21].

### 3.4. Electrolyzer

The electrolyzer is directly connected to the DC bus and uses excess electricity generated by the PV panels to produce hydrogen through electrolysis. This hydrogen is then stored for later use in the fuel cell. The DC/DC converter ensures optimal power delivery to both the electrolyzer and the compressor, matching the PV array output via power point tracking [22]. The annual energy consumption of the compressor is approximately 1% of the total generated energy. The electrolysis process splits the water into hydrogen and oxygen, and the hydrogen is stored in a dedicated tank. The hydrogen production rate of the electrolyzer is modeled as:

$$mh_2(t) = \frac{P_{EL} \times \eta_{EL} \times 3600}{HHV_{H2}} \times \Delta_T \quad (10)$$

where  $P_{EL}$  is the rating of electrolyzer (kW),  $\eta_{EL}$  is the efficiency of electrolyzer and  $HHV_{H2}$  is the heating value of hydrogen in MJ/kg, respectively. In the mathematical modeling of an electrolyzer, the hydrogen is produced in kg/h.

For a 1 kW electrolyzer and 90% efficient electrolyzer with the heating value of the hydrogen being 143 MJ/kg, which equals 39.44 kWh/kg, the mass flow rate of the hydrogen will be 0.02268 kg/h/kW. Therefore, a 1 kW electrolyzer will produce 0.02268 kg/h hydrogen [2–17], taking into account  $\Delta_T = 0.1$  h. The electrolyzer produces hydrogen, which is stored in a proposed tank for night usage to produce electric power through the fuel cell.

### 3.5. Fuel Cells

The fuel cell subsystem is responsible for converting stored hydrogen into electricity through an electrochemical reaction with oxygen. In this study, a proton exchange membrane (PEM) fuel cell is used, which is known for its compact size, high energy density, and quick startup time [23].

The electrolytic process utilizes a thin membrane that allows positive ions to pass while preventing electrons and neutral gases. Hydrogen from the electrolyzer enters through the anode, while oxygen enters through the cathode, initiating a chemical reaction that dissociates into protons and electrons [24].

This creates a concentration gradient across the membrane, with protons diffusing toward the cathode and electrons flowing from the anode to the cathode, generating an electrical current. The fuel cell model used here is based on a linear approximation of the hydrogen consumption as a function of the power output, rather than a fixed efficiency percentage. The hydrogen consumption rate is calculated as:

$$R_{H2} = \gamma_1 P_{fc}^r + \gamma_2 P_{fc}(t) \quad (11)$$

where  $R_{H2}$  is the mass flow rate of the hydrogen,  $\gamma_1$  and  $\gamma_2$  are the fuel cell intercept coefficient in kg/h/kW rated and the fuel cell slope curve in kg/h/kW, respectively, and  $P_{fc}^r$  is the rated capacity of the fuel cell in kW. For a 1 kW FC rating, considering  $\gamma_1$  and  $\gamma_2$  to be 0.0003 and 0.058 kg/h/kW, respectively, these factors determining the efficiency of the fuel cell,  $R_{H2}$  is calculated as 0.059 kg/h. Therefore, 0.059 kg/h of hydrogen is required to generate 1 kW of power by FC [11–19]. The hydrogen low heating value (LHV) is 33.3 kWh/kg [25]. The coefficients  $\gamma_1$  and  $\gamma_2$  play a crucial role in modeling hydrogen consumption in fuel cell systems.  $\gamma_1$  represents the baseline hydrogen consumption rate per unit of rated fuel cell capacity, while  $\gamma_2$  accounts for the hydrogen required relative to the fuel cell's actual power output at any given time. These coefficients help to refine the system's hydrogen flow calculations, ensuring a more accurate estimation of hydrogen consumption during both steady-state and variable operating conditions.

This approach better reflects real fuel cell behavior, including idle consumption and dynamic load response. In contrast, fixed-efficiency models (e.g., 50–60%) do not account for changes in operating conditions. By using intercept and slope coefficients, this model enables more accurate sizing and hydrogen flow tracking, which improves the reliability and system optimization.

### 3.6. Hydrogen Tank

A constant mass flow of hydrogen is required for power generation by FC. Therefore, the size of the hydrogen tank becomes a critical parameter to ensure the reliability of the power generation system. The hydrogen tank stores the hydrogen produced by the electrolyzer and supplies it to the fuel cells for power generation. The hydrogen generated daily is stored to ensure a continuous supply during the periods when solar radiation is unavailable. The size of the hydrogen tank, measured in kilograms, is treated as a decision variable in the system model. The hydrogen storage system designed for this work operates on a small scale, meeting a 1 kW load and ensuring a continuous power supply over 24 h a day, 365 days a year, in constant load and from sunset to sunrise periods in night load. Unlike large-scale industrial hydrogen storage systems, this system operates at low pressure and stores a limited volume of hydrogen, which significantly reduces associated risks. Therefore, while hydrogen storage systems of any scale require careful safety considerations, the risks associated with this small-scale design are substantially lower compared to large-scale applications [26,27]. The modeling of hydrogen gas utilizes steady-state properties and the ideal gas law, assuming ideal behavior under standard conditions. This approach simplifies the analysis and allows for efficient estimation of hydrogen's thermodynamic behavior during storage and system operations. While the optimal conditions for hydrogen storage have been applied in this design, it is essential to consider that, in practical applications, safety factors such as pressure relief systems, leak

detection, and material durability must be rigorously addressed to ensure the system's reliability and safe operation.

The Python-based simulation tool developed in this study is fully flexible and user-configurable. It allows users to input different values for key system parameters such as the tilt angle, the latitude, PV module characteristics, the battery depth of discharge (DOD), and various electrolyzer and fuel cell efficiencies. This makes the model highly adaptable to different locations, system scales, and operational strategies. It can be used not only for standalone systems under Cairo's climate but also for broader applications across diverse environmental and technical conditions.

### 3.7. Model Validation and Assumption Justification

The parameters used in this simulation are based on real data and technical specifications, most of which are described in detail in Section 3: hourly solar radiation and temperature data for Cairo. The PV module selected for this study has an open-circuit voltage of 33 V, a short-circuit current of 8.27 A, voltage at a maximum power point of 25 V, and a current at a maximum power point of 8 A [18]. The panel is installed with a fixed 30° tilt angle facing south. Battery efficiency (70% efficiency), electrolyzer sizing assumptions (90% efficiency), and PEM fuel cell behavior (using voltage coefficients) are based on published values and typical commercial systems. The hydrogen consumption was set at 0.058 kg/kWh. Economic inputs, including capital and replacement costs, follow recent literature values. The simulation assumes a worst-case scenario of 3.5 consecutive cloudy days (NC = 3), requiring four days of full autonomy. All the technical values and sources are listed in the relevant system description and model sections.

## 4. Energy Management Strategy

Efficient and reliable operation of a standalone PV/H<sub>2</sub> system requires a well-defined energy management strategy. This strategy ensures that the load demands are continuously met, either through direct PV generation or through stored energy in the form of hydrogen.

The energy management system monitors the following:

- Power supplied to the load
- Excess PV energy is used for hydrogen production via the electrolyzer
- Power generation by the fuel cell using stored hydrogen

The loads demands must be satisfied by solar PV generation  $P_{pv}(t)$  during the day and fuel cells during the night to supply the load. The difference between power generation is calculated as:

$$\Delta P(t) = P_{pv}(t) - P_L(t) \quad (12)$$

Therefore, depending on  $\Delta P(t)$  three Scenarios are formed as follows:

**[Scenario:1]** If  $\Delta P(t) > 0$ , i.e., the generation is more than the load, the following steps have been implemented [17].

**Step:1** The excess power ( $P_{EL} = \Delta P(t)$ ) is fed to the electrolyzer. The amount of hydrogen generated by the electrolyzer per ( $\Delta_T$ ) as explained in Equation (10).

**Step:2** The amount of hydrogen accumulated per  $\Delta_T$ , ( $G_{H2}(t)$ ) in the storage tank is calculated as:

$$G_{H2}(t) = G_{H2}(t-1) + mh_2(t) \quad (13)$$

where  $G_{H2}(t-1)$  is the hydrogen present in the tank at the previous moment.

**Step:3** In the case of storing hydrogen as shown in Equation (10), the volume of hydrogen becomes larger than the volume of the tank ( $G_{H2}^r$ ), i.e.,  $G_{H2}(t) > G_{H2}^r$ . Then the electrolyzer is not turned on because there is no volume available in the hydrogen tank.

**[Scenario:2]** If  $\Delta P(t) = 0$ , then no power exchange is there; the total demand is met by the solar power generation only.

**[Scenario:3]** If  $\Delta P(t) < 0$ , the load demand is more than the power generated by the PV cells, and the required power to meet the load is provided by fuel cells and the PV during the day; during the night all power is supplied by the fuel cell. The power is managed as follows:

**Step:1** As a first step, check the hydrogen availability in the hydrogen tank. The power required to be produced by the fuel cell is calculated as:

$$P_{fc}(t) = P_L(t) - P_{pv}(t) \quad (14)$$

**Step:2** The amount of hydrogen consumed by the FC from the hydrogen tank at a particular time to produce  $P_{fc}(t)$  is given by Equation (14). The hydrogen storage tank is updated after taking hydrogen; the remaining hydrogen in the tank is calculated as:

$$G_{H2}(t) = G_{H2}(t-1) - R_{H2}(t) \quad (15)$$

where  $G_{H2}(t-1)$  is the hydrogen in the tank at time  $(t-1)$ .

**Step:3** In case the hydrogen tank does not have sufficient hydrogen i.e.,  $R_{H2} \geq G_{H2}(t)$ , this was taken into account in the design to avoid any energy loss because the load is critical.

To ensure efficient energy management and reduce the energy loss, careful sizing of all major system components is essential. These include photovoltaic panels ( $P_{pv}$ ), fuel cells ( $P_{fc}^r$ ), the electrolyzer ( $P_{EL}$ ), and hydrogen storage tank size ( $G_{H2}^r$ ).

These parameters were tuned to handle worst-case weather conditions, specifically three consecutive cloudy days on 10–12 January and December 349–351. These scenarios are embedded in the Python version 3.13.5-based simulation, which tracks the hydrogen levels, the battery SOC (for comparison), and the power flows hourly.

Figure 6 illustrates the full energy flow logic of the system, showing the generation, storage, and load management under dynamic environmental and load conditions.

Figure 7 illustrates the full-year hydrogen production and storage cycle, assuming three consecutive cloudy days in both January and December. At the start of the year, the hydrogen production and storage levels are low due to reduced solar radiation in the winter. As the spring and the summer arrive, increased solar energy enables greater hydrogen generation, allowing the system to accumulate surplus hydrogen. This reserve is then used in the autumn and the winter to maintain the load supply. The hydrogen storage level at the end of the year closely matches the starting value, ensuring energy continuity into the following year. This seasonal balance confirms the system's ability to meet load demand year-round with no energy loss.

The results clearly show that the hydrogen storage is at its minimum during the winter and reaches its maximum in the summer, due to higher solar energy availability in the summer months. Notably, the amount of stored hydrogen at the end of the year is approximately equal to the amount at the beginning of the next year, indicating that the hydrogen generated annually is fully utilized to meet the load demand.

Figures 7 and 8 present an analysis based on a system configuration under the assumption of three consecutive cloudy days. The system operates with a constant load of 1 kW. During the day, the photovoltaic (PV) array has a capacity of 10 kWp, and the electrolyzer is sized at 8 kW. For the night load, the array size is reduced to 8 kWp, and the electrolyzer is downsized to 5 kW. These sizing choices are made to ensure that the maximum current generated by the solar panels can be effectively utilized. Additionally, a 1 kW fuel cell is included to match the load demand during the periods without sunlight.

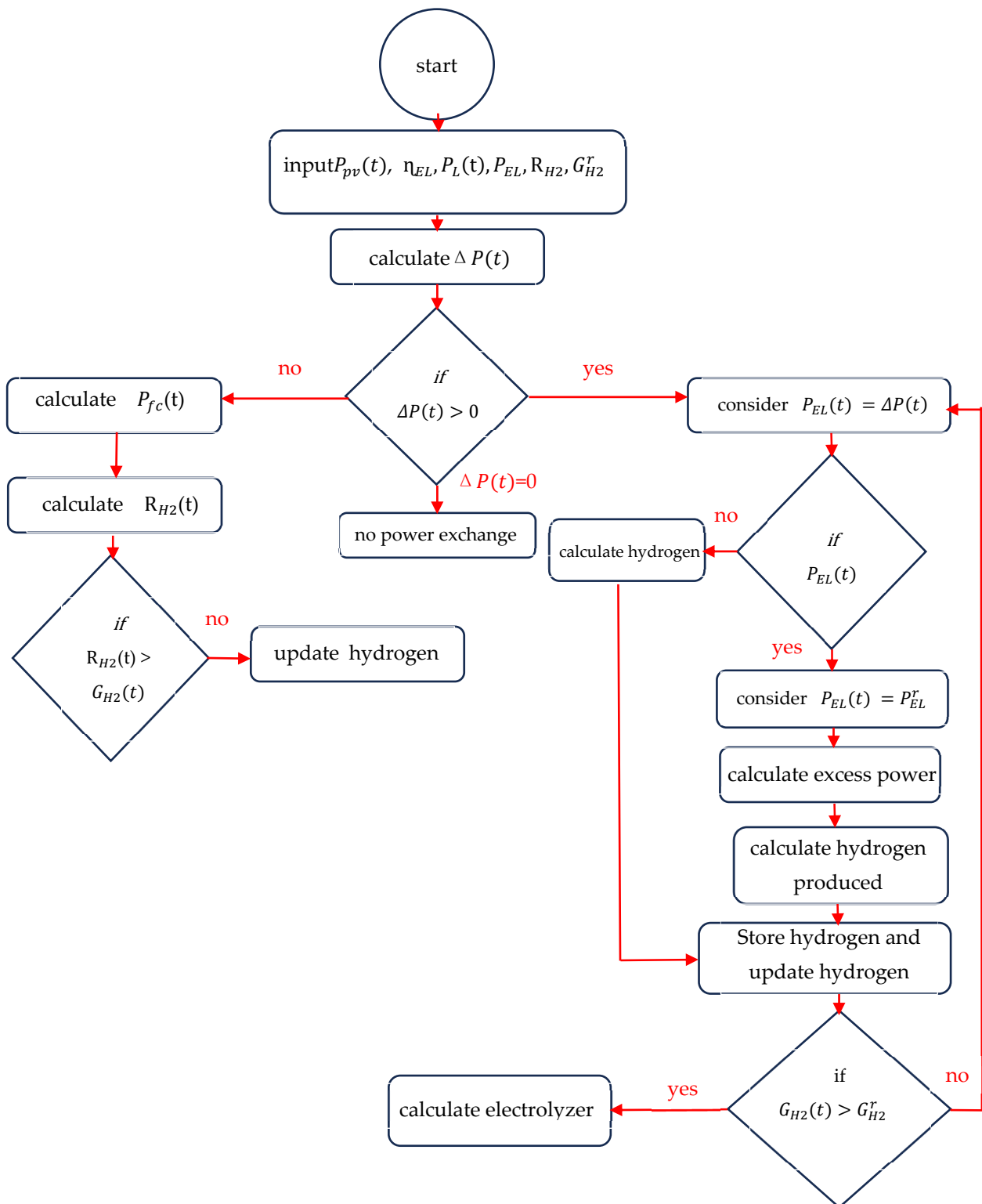


**Figure 6.** Flow chart for energy management of the proposed system.

The hydrogen tank begins the year with an initial capacity of 15 kg and reaches 19 kg by the end of the year for a constant load. For the night load, the tank starts at 11.5 kg and increases to 17.6 kg at the end of the year. The results show that the hydrogen production fluctuates across the four seasons, primarily influenced by the varying energy output of the PV system. This PV-generated energy plays a critical role in driving the electrolyzer

and determining the overall hydrogen yield, sufficient hydrogen to meet the load demand during the solar radiation period.

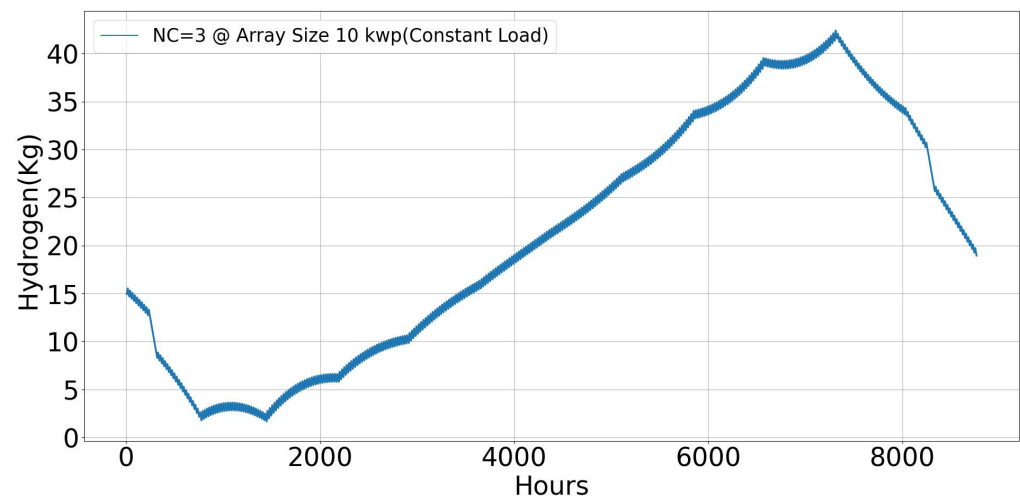


**Figure 7.** State of hydrogen entire year @ NC = 3, array size 10 kWp, tilted angle 30°.

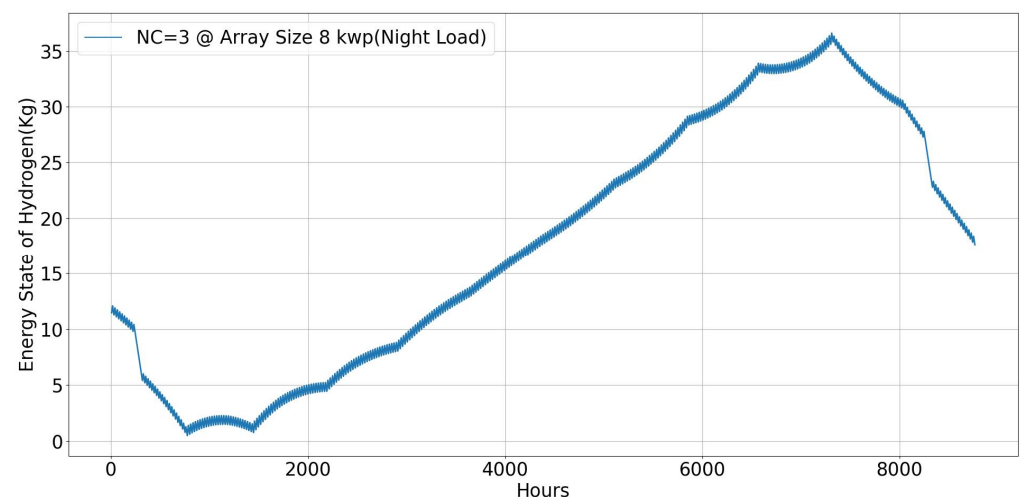
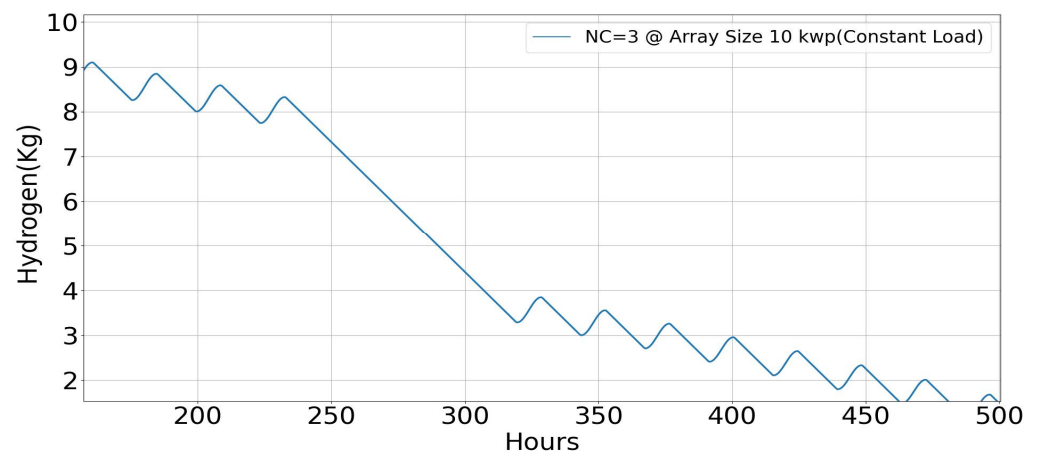


**Figure 8.** State of hydrogen entire year @ NC = 3, array Size 8 kWp night load, tilted angle 30°.

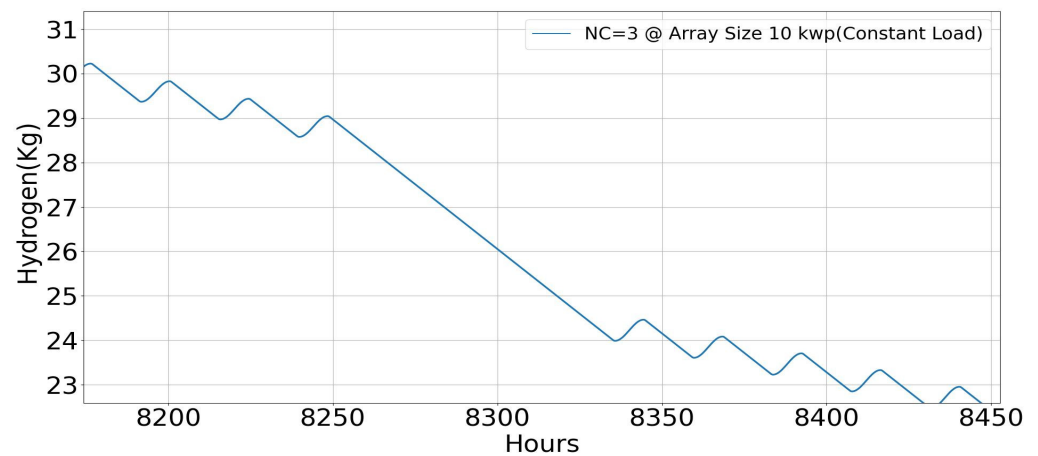
Figure 9a,b illustrates the accounts for three cloudy days in January (10th, 11th, and 12th) and three days in December (349th, 350th, and 351st), respectively; these figures highlight the impact of reduced solar irradiance on hydrogen production and storage. During these periods, solar energy generation drops significantly, leading to a complete halt in hydrogen production. Consequently, the system draws upon the existing hydrogen stored in the tank to supply the load through the fuel cell. This rapid decline in the hydrogen storage demonstrates the system's reliance on prior storage to maintain an uninterrupted energy supply under extended low-solar conditions. These periods represent the worst-case climatic scenarios considered in the system design to ensure reliability during prolonged cloudy days.

Figures 10 and 11 show the monthly hydrogen production under varying seasonal conditions, emphasizing the effect of cloudy days in winter. The hydrogen production drops significantly during the cloudy periods in January and December due to reduced solar input. However, the system's sizing ensures that enough hydrogen is stored in advance to handle these events. The design maintains a sufficient end-of-year hydrogen reserve to

guarantee the energy availability at the beginning of the following year, demonstrating resilience against Cairo's most adverse solar conditions.



(a)



(b)

**Figure 9.** (a) Three successive cloudy days in January. (b) Three successive cloudy days in December.

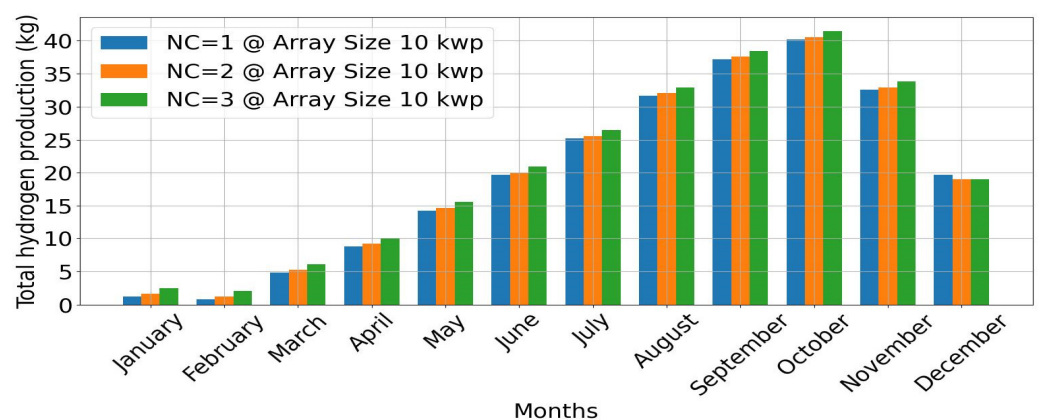


**Figure 10.** The hydrogen production during the solar radiation period by month through the year @ NC = 1&2&3, constant load 1 KW, array size 10 kWp, tilted angle 30°.

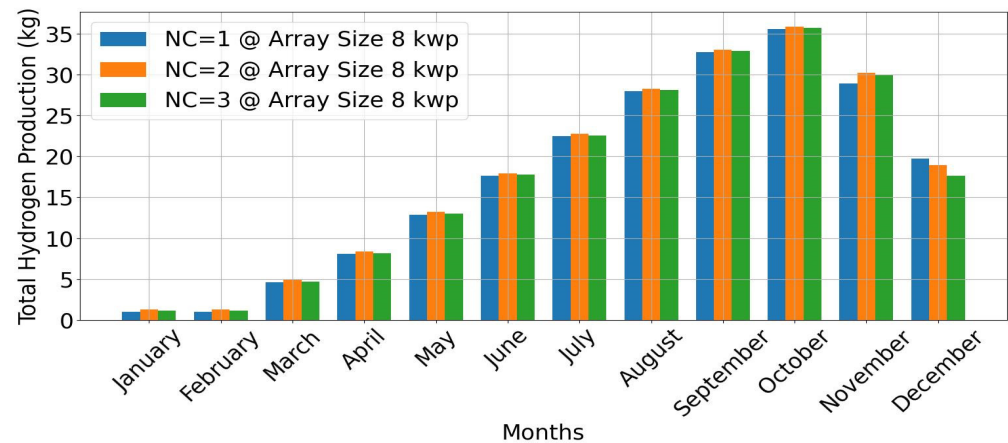


**Figure 11.** The hydrogen production during the solar radiation period by month through the year @ NC = 1&2&3, constant load 1 KW, array size 10 kWp night load, tilted angle 30°.

## 5. Economic Analysis

This section presents a cost-based comparison between the PV/H<sub>2</sub> and PV/Battery systems under constant and night load conditions. The reference system is designed to supply a 1 kW continuous load throughout the year, including worst-case weather conditions. All the initial costs include mounting and installation.

The total cost of each system includes the capital cost of the PV array and other major components such as batteries, Proton Exchange Membrane Fuel Cell (PEMFC), Proton Exchange Membrane Electrolyzer (PEMEZ), converters, and hydrogen tanks. Table 3 summarizes the initial costs and lifespans for all components. A 21-year project lifetime and an annual interest rate of 6% are assumed, with an operation and maintenance (O&M) cost of 5% of the component's initial cost as reported in [10].

**Table 3.** Initial cost and lifetime of both system components [18].

| Component           | Initial Cost | Lifetime (Years) |
|---------------------|--------------|------------------|
| PV                  | 312 USD/Kw   | 25               |
| PEMEZ               | 1000 USD/Kw  | 20               |
| PEMFC               | 1000 USD/Kw  | 10               |
| Converter           | 146 USD/Kw   | 10               |
| H <sub>2</sub> Tank | 570 USD/Kg   | 20               |
| Compressor          | 1800 USD/Kw  | 20               |
| Battery             | 100 USD/Kw   | 3                |

The component requiring a replacement in the PV/Hydrogen system is the fuel cell and DC/DC Converter. The FC operates based on hours rather than years. The configuration results in 50,000 h of fuel cell operation throughout the year, necessitating replacement at the end of the 10th year. The effective interest over each 10-year period is 0.8% for the FC and DC/DC Converter.

For the PV/Battery system, the batteries require replacement every three years, with an effective interest rate of 0.19% per replacement cycle. Replacement costs are determined according to established equations; all other components share the system's full 21-year lifetime and are not replaced.

To incorporate the effect of photovoltaic (PV) performance degradation over time, the Levelized Cost of Energy (LCOE) was calculated using a present worth factor that includes an annual degradation rate. This is represented by Equation (16)

$$P_0 = E_0 \times C_0 \times \left( \frac{1 - \left( \frac{1+g}{1+i} \right)^N}{i - g} \right) \quad (16)$$

where:

$P_0$  Total cost over 21 years

$E_0$  Average yearly generated energy (kWh)

$C_0$  Cost of Energy per kWh

$i$  Yearly interest rate

$g$  the annual degradation rate (assumed 2% for PV systems in Egypt)

This formula accounts for the typical 2% annual drop in the PV output, which is often caused by environmental factors such as dust accumulation and surface glass abrasion from sandstorms. If degradation is neglected (i.e.,  $g = 0$ ), the equation reduces to the conventional annuity factor used in Equation (17):

$$P_0 = E_0 \times C_0 \times \left( \frac{1 - (1+i)^{-N}}{i} \right) \quad (17)$$

Tables 4 and 5 present the impact of adding three cloudy days to the capital investments for each system configuration. The impact of system reliability was factored in when comparing the two loads and their effect on the cost of energy. The Levelized Cost of Electricity (LCOE) is used to estimate the cost of providing 1 kW of electricity. The results show that the PV/H<sub>2</sub> system is more cost-effective than the PV/Battery configuration for critical applications. For a constant load with several cloudy days, NC = 3, the LCOE values are 0.23 USD/kWh for the PV/H<sub>2</sub> system and 0.52 USD/kWh for the PV/Battery system. In the case of the night load, the LCOE increases to 0.36 USD/kWh for the PV/H<sub>2</sub> system and 0.67 USD/kWh for the PV/Battery system.

**Table 4.** A 1 kW constant load standalone PV/hydrogen system (NC = 3).

| Tank Size               | Array Size (kWp) | $T_{off}$ (h) | Reliability | Initial Cost USD/kWh | Cost USD/kWh |
|-------------------------|------------------|---------------|-------------|----------------------|--------------|
| 2                       | 10               | 219           | 97.5%       | 13,255.37            | 0.13         |
| 4                       | 10               | 148           | 98.3%       | 14,395.37            | 0.14         |
| 6                       | 10               | 132           | 98.5%       | 15,535.37            | 0.15         |
| 8                       | 10               | 74            | 99.16%      | 16,675.37            | 0.16         |
| 10                      | 10               | 68            | 99.22%      | 17,815.37            | 0.17         |
| 13                      | 10               | 7             | 99.99%      | 19,525.37            | 0.19         |
| 15                      | 10               | 0             | 100%        | 20,665.37            | 0.20         |
| 19                      |                  |               |             |                      |              |
| (End of The First Year) | 10               | 0             | 100%        | 22,945.37            | 0.23         |

**Table 5.** A 1 kW night load standalone PV/hydrogen system (NC = 3).

| Tank Size               | Array Size (kWp) | $T_{off}$ (h) | Reliability | Initial Cost USD/kWh | Cost USD/kWh |
|-------------------------|------------------|---------------|-------------|----------------------|--------------|
| 2                       | 8                | 164           | 96.6%       | 9630.37              | 0.19         |
| 4                       | 8                | 115           | 97.37%      | 10,770.37            | 0.21         |
| 6                       | 8                | 89            | 97.97%      | 11,910.37            | 0.23         |
| 8                       | 8                | 54            | 98.77%      | 13,050.37            | 0.25         |
| 10                      | 8                | 19            | 99.57%      | 14,190.37            | 0.28         |
| 11.5                    | 8                | 0             | 100%        | 15,045.37            | 0.29         |
| 17.6                    |                  |               |             |                      |              |
| (End of The First Year) | 8                | 0             | 100%        | 18,522.37            | 0.36         |

As a supplementary economic estimate, the performance of lithium-ion batteries was also considered. Using typical values from the recent literature, 400 USD/kWh capital cost, and a 13-year lifespan [20] calculated an approximate Levelized Cost of Electricity (LCOE), which was calculated using the same energy demand profiles as in the lead-acid simulation. The resulting LCOE was 0.41 USD/kWh for the constant load and 0.49 USD/kWh for the night load, representing a 21% and a 27% cost reduction, respectively, compared to lead-acid batteries.

Lithium-ion batteries offer clear advantages in terms of the energy density, longer life cycle, and reduced replacement frequency. However, they also require advanced thermal management, especially in hot climates, due to their sensitivity to high operating temperatures, which can reduce the performance and the safety over time [28,29]. While this estimate is not derived from a full simulation, it provides a realistic economic reference, reinforcing the potential of lithium-ion as an improved battery storage option, though hydrogen storage remains more cost-effective in this study's scenarios.

The total cost of the hydrogen-based system is primarily driven by the cost of the hydrogen storage tank, in addition to the costs of the electrolyzer, the fuel cell, and the photovoltaic (PV) components. The overall system cost can be expressed as the sum of these individual components. Among them, the tank cost increases linearly with the required storage size and tends to dominate the total cost, especially in scenarios with extended cloudy day requirements. Since the number of hydrogen tanks must be an integer, this introduces stepwise changes in the total cost, while the remaining cost variation is attributed to the continuous variation in the other system components.

The higher LCOE observed in the battery-based system is primarily due to the substantial number of batteries required to meet the energy demand, their relatively short operational lifespan, and the significant costs associated with battery replacement over the system's lifetime.

### 5.1. Payback Period

The Payback Period (PBP) reflects how quickly the system investment is recovered. It is calculated as:

$$P_0 = E_0 \times C_P \times \left( \frac{1 - (1 + i)^{-PBP}}{i} \right) \quad (18)$$

where:

$C_P$  Cost of Energy multiplied by the profit of the system.

$PBP$  Payback Period in years

### 5.2. Economic Sensitivity Analysis

A sensitivity analysis was conducted to assess how changes in solar irradiance, hydrogen storage capacity, and electricity costs affect the economic feasibility of the systems. This analysis revealed that the areas with lower solar irradiance may experience higher LCE values, suggesting the need for regional optimization and adaptation to local conditions. The criterion used to assess the economic feasibility of any system is the payback period. The shorter the payback period, assuming an annual interest rate of 6%, the better the investment.

Figures 12 and 13 show the constant load. The PBP is 7 years for the PV/H<sub>2</sub> system and 16 years for the PV/Battery system. In the case of the night load, the PBP increases to 7.2 years for the PV/H<sub>2</sub> system and 15 years for the PV/Battery system.

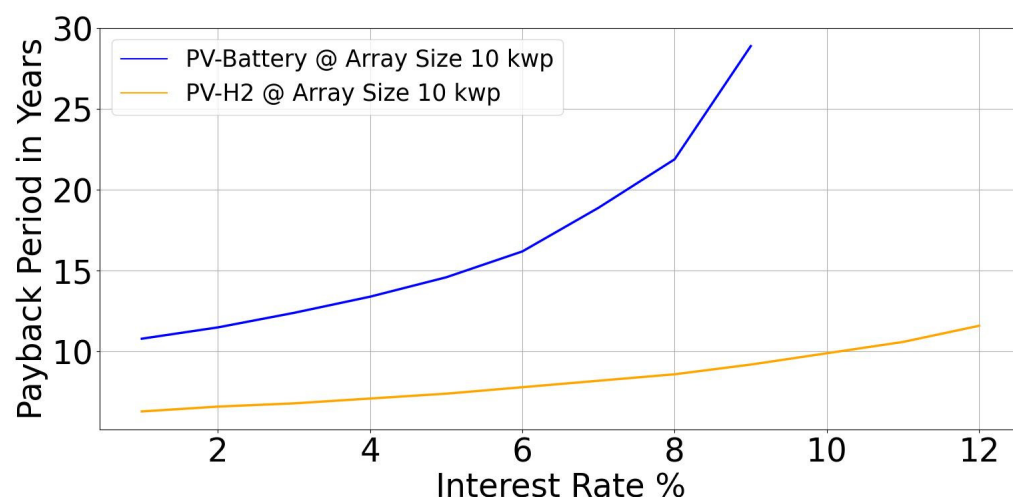


**Figure 12.** The payback period of the two considered systems for the constant load versus the interest rate.

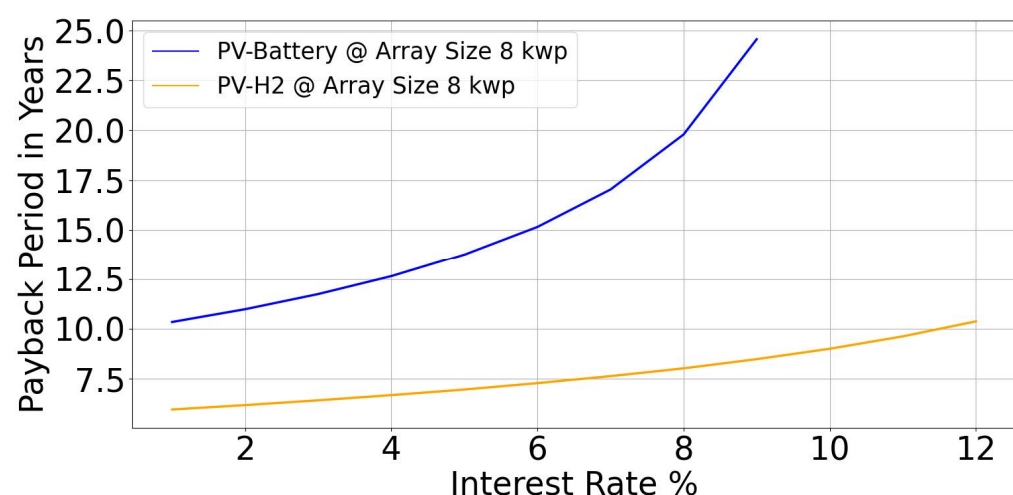


**Figure 13.** The payback period of the two considered systems for the night load versus the interest rate.

The payback period of the PV/Battery system is always longer than that of the PV/H<sub>2</sub> system. The main reason for this is the high cost and short lifetime of the batteries, as the battery cost is the dominant factor in the PV/Battery system. The short lifespan of the batteries requires their replacement every three years. On the other hand, in the PV/H<sub>2</sub> system, the hydrogen tanks are the primary cost, but the tank lifetime is much longer, with no need for replacement.

Figure 14 shows the effect of the selling price of one kWh on the payback period for both systems for a constant load. It is clear that as the selling price increases (i.e., an increase in profit), Figure 14 illustrates that the payback period (PBP) is a vital indicator of the project feasibility. The calculations were performed using established equations, with a profit of 20% selected to facilitate a comparison between the two systems under various load conditions. This percentage was chosen based on the highest observed LCOE, which corresponds to the battery-based configuration.

The results for the constant load are as follows: the PBP is 5.3 years for the PV/H<sub>2</sub> system and 9.7 years for the PV/Battery system. In the case of the night load, the PBP increases to 6.3 years for the PV/H<sub>2</sub> system and 12.2 years for the PV/Battery system.

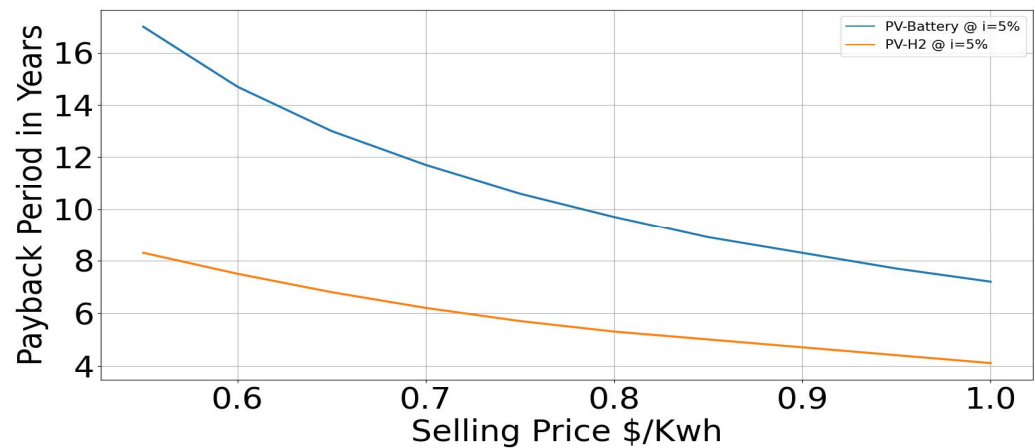


Figure 14. Payback period in years versus the selling price for the constant load @i = 5%.

As shown in Figure 15, the payback period the PV/H<sub>2</sub> is shorter than that of the PV/Batteries at different interest rates and different load profiles.

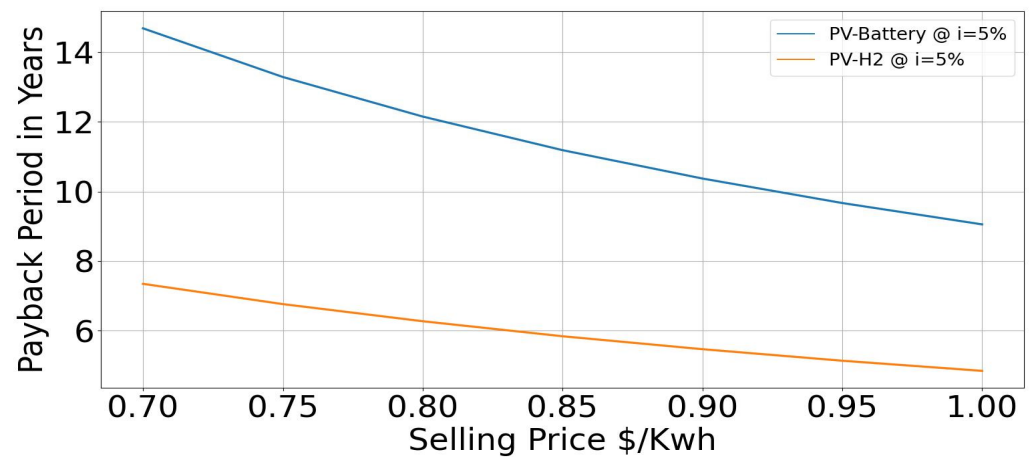


Figure 15. Payback period in years versus selling price for night load @i = 5%.

### 5.3. Inflation Causes

Inflation and interest rate changes affect the component replacement costs differently, depending on the system.

**PV/Battery system:** since the batteries are replaced multiple times, the cost increases with inflation. The energy cost rises to 0.30 USD/kWh (the constant load) and 0.40 USD/kWh (the night load) at an average battery replacement interest rate.

**PV/H<sub>2</sub> system:** the hydrogen tank, with its long lifetime, is less sensitive to inflation. Cost estimates are 0.37 USD/kWh (the constant load) and 0.60 USD/kWh (the night load), assuming a 6% interest rate and a 50 kg tank.

Figures 16 and 17 illustrate these economic sensitivities. The PV/Battery system cost is closely tied to battery inflation, while the PV/H<sub>2</sub> system is more capital-heavy upfront but less sensitive over time. While this study focuses on small-scale, low-pressure hydrogen storage suitable for standalone systems, the results offer an insight into how scaling affects economic performance. At the grid scale, the economies of scale would likely reduce the capital cost per unit of hydrogen storage, particularly in tank fabrication and system integration. As a result, the LCOE and the payback period could improve, especially for systems with large energy demand and long-duration storage needs. However, such systems introduce additional factors such as high-pressure storage and advanced safety

systems, which were not modeled in this study. Future work may expand the analysis to grid-scale applications, incorporating those considerations.

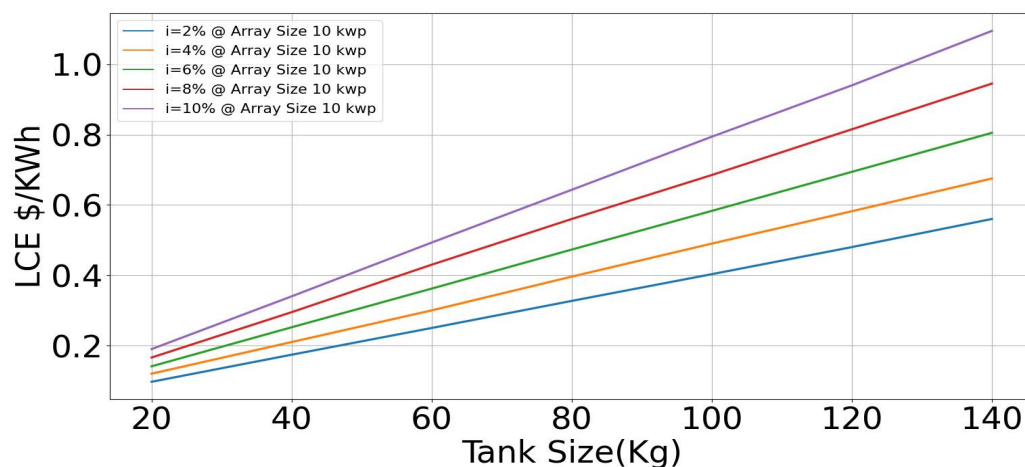


Figure 16. The Levelized Cost of Energy versus the tank size for the constant load.

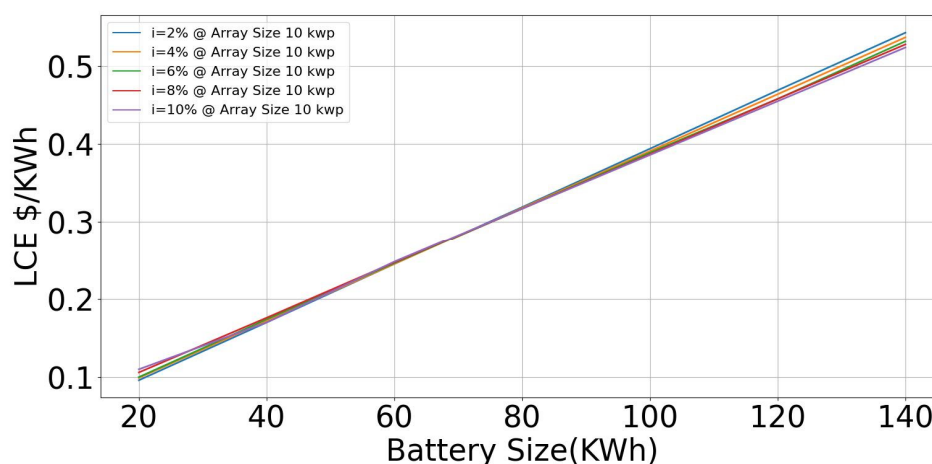


Figure 17. The Levelized Cost of Energy versus the battery size for the constant load.

## 6. Conclusions

This study presents a comparative techno-economic analysis of two standalone photovoltaic (PV) systems designed to supply critical loads, one using lead-acid batteries and the other using green hydrogen as storage. Both the systems were modeled and simulated under Cairo's climatic conditions, assuming worst-case scenarios of 3.5 consecutive cloudy days. The systems were evaluated for two load profiles: the constant load and the night load, to achieve 100% reliability and reduce energy loss.

The simulation results show that the PV/H<sub>2</sub> system consistently outperforms the PV/Battery system in both cost and performance. For the constant load, the Levelized Cost of Electricity (LCOE) is reduced from USD 0.52/kWh (Battery) to USD 0.23/kWh (Hydrogen). For the night load, the LCOE improves from 0.67 USD/kWh to 0.36 USD/kWh. This confirms that the night load is inherently more expensive to support due to its reliance on stored energy during solar-off hours.

Payback period analysis further supports the advantage of hydrogen. At a 6% interest rate, the PV/H<sub>2</sub> system achieves a payback period of 7 years for the constant load, compared to 16 years for the PV/Battery system. With a 20% profit margin included, this drops to 5.3 years for hydrogen, versus 9.7 years for batteries. Night load scenarios follow a similar trend, with hydrogen offering significantly shorter cost recovery times.

In terms of reliability–cost trade-offs, the analysis shows that small compromises in reliability can significantly reduce the system cost. For instance, increasing the tank size from 2 kg to 15 kg (the constant load) improves the reliability from 97.5% to 100%, but raises the initial cost by 55% and the LCOE by 0.13 USD/kWh. A similar pattern is observed in night load scenarios, emphasizing the need to balance the system cost with the criticality of the application.

The economic sensitivity analysis reveals that hydrogen systems are more resilient to inflation and interest rate changes. While battery systems suffer from frequent replacements and compounding costs, hydrogen systems front-load most expenses, benefiting from longer component lifespans, especially the hydrogen tank. Even under extended cloudy day conditions and variable inflation rates, the PV/H<sub>2</sub> system maintains a lower LCE than its battery-based counterpart.

In the current simulation, energy loss is defined as the duration or amount of unmet load ( $T_{off}$ ), which is set to zero in the final optimized scenarios. However, the real-world losses occur through system inefficiencies (e.g., inverter loss, DC-DC converter loss, electrolyzer/fuel cell conversion, and curtailment when hydrogen storage is full). These losses are embedded in the efficiency parameters of each component (e.g., 90% electrolyzer efficiency, 95% inverter, and 95% DC-DC converter), but excess PV energy that cannot be stored is not explicitly tracked as curtailed energy. Future work could quantify annual energy loss due to curtailment and other inefficiencies more explicitly.

This study compares hydrogen storage with traditional lead-acid batteries due to their lower initial cost and continued use in small-scale off-grid systems. In addition to the core comparison between hydrogen storage and lead-acid batteries, a supplementary economic estimate was conducted for lithium-ion batteries to provide a broader perspective on storage alternatives. The results showed that lithium-ion storage reduces the Levelized Cost of Electricity (LCOE) compared to lead-acid by approximately 21% for the constant load and 27% for night-only load scenarios. While lithium-ion offers improved the energy density, higher efficiency, and longer lifespan, it also introduces operational challenges, particularly in hot climates like Egypt, where thermal management becomes critical. These findings suggest that lithium-ion technology may offer a viable alternative for certain applications. Still, green hydrogen remains the most cost-effective and scalable solution across both load profiles in this study.

While this study focuses on the techno-economic performance of hydrogen and battery storage systems, we recognize the importance of assessing their environmental impacts. Battery manufacturing, particularly for Li-ion systems, involves the mining and processing of rare materials, which can result in significant environmental burdens. Hydrogen produced via electrolysis (green hydrogen) is cleaner during operation, but still requires energy and water input. A full life-cycle environmental analysis comparing hydrogen and battery systems is an important area for future research. Such analysis could complement the economic findings and provide a more comprehensive sustainability perspective.

The PV/H<sub>2</sub> system offers a more reliable, economically viable, and future-resilient solution for standalone critical-load applications. Its superior long-term performance under adverse weather and economic conditions makes it a strong candidate for off-grid, high-reliability energy systems.

**Author Contributions:** Conceptualization, A.L. and W.R.A.; methodology, A.L.; software, A.L.; validation, A.L., W.R.A. and S.M.M.; formal analysis, A.L.; investigation, A.L.; resources, S.M.M.; data curation, A.L.; writing—original draft preparation, A.L.; writing—review and editing, W.R.A.; visualization, F.N.; supervision, W.R.A.; project administration, A.L. and S.M.M. All authors have read and agreed to the published version of the manuscript.

**Funding:** This research received no external funding.

**Data Availability Statement:** The original contributions presented in the study are included in the article; further inquiries can be directed at the corresponding author.

**Conflicts of 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.

## References

1. Angelico, R.; Giametta, F.; Bianchi, B.; Catalano, P. Green Hydrogen for Energy Transition: A Critical Perspective. *Energies* **2025**, *18*, 404. [\[CrossRef\]](#)
2. Kumar, N.; Lee, S.Y.; Park, S.J. Advancements in hydrogen storage technologies: A comprehensive review of materials, methods, and economic policy. *Nano Today* **2024**, *56*, 102302. [\[CrossRef\]](#)
3. Alam, S.N.; Khalid, Z.; Singh, B.; Guldhe, A. Integration of government policies on the global level for green hydrogen production. In *Green Hydrogen Economy for Environmental Sustainability*; American Chemical Society: Washington, DC, USA, 2024; Volume 1: Fundamentals and Feedstocks, pp. 1–28.
4. Masters, G.M. *Renewable and Efficient Electric Power Systems*, 2nd ed.; John Wiley & Sons: Hoboken, NJ, USA, 2013.
5. Ozden, E.; Tari, I. Energy–exergy and economic analyses of a hybrid solar–hydrogen renewable energy system in Ankara, Turkey. *Appl. Therm. Eng.* **2016**, *99*, 169–178. [\[CrossRef\]](#)
6. Rakhshani, E.; Rouzbehi, K.; Sánchez, A.J.; Tobar, A.C.; Pouresmaeil, E. Integration of large-scale PV-based generation into power systems: A survey. *Energies* **2019**, *12*, 1425. [\[CrossRef\]](#)
7. Rahman, S.; Tam, K.S. A feasibility study of photovoltaic-fuel cell hybrid energy system. *IEEE Trans. Energy Convers.* **1988**, *3*, 50–55. [\[CrossRef\]](#) [\[PubMed\]](#)
8. Sun, L.; Jin, Y.; Pan, L.; Shen, J.; Lee, K.Y. Efficiency analysis and control of a grid-connected PEM fuel cell in distributed generation. *Energy Convers. Manag.* **2019**, *195*, 587–596. [\[CrossRef\]](#)
9. Hassan, Q.; Jaszczur, M.; Hafedh, S.A.; Abbas, M.K.; Abdulateef, A.M.; Hasan, A.; Abdulateef, J.; Mohamad, A. Optimizing a microgrid photovoltaic-fuel cell energy system at the highest renewable fraction. *Int. J. Hydrogen Energy* **2022**, *47*, 13710–13731. [\[CrossRef\]](#)
10. Nasser, M.; Hassan, H. Assessment of standalone streetlighting energy storage systems based on hydrogen of hybrid PV/electrolyzer/fuel cell/desalination and PV/batteries. *J. Energy Storage* **2023**, *63*, 10698. [\[CrossRef\]](#)
11. Nousir, S.E.; Anis, W.R.; Abouelatta, M.; Adly, G.S.; Abdelaal, M.A. Developing Techno-economic GUI-. based Software for On-grid, and Off-grid Photovoltaic Systems Sizing. *Ain Shams Eng. J.* **2024**, *15*, 102508. [\[CrossRef\]](#)
12. Miled, A.; Farhani, S.; Askri, F. Theoretical modeling and economic analysis of PV and fuel cell energy system for an off-grid green villa in Sidi Bouzid, Tunisia-A case study. *Int. J. Hydrogen Energy* **2025**, *105*, 932–945. [\[CrossRef\]](#)
13. Farhani, S.; Barhoumi, E.M.; Islam, Q.U.; Becha, F. Optimal design and economic analysis of a stand-alone integrated solar hydrogen water desalination system case study agriculture farm in Kairouan Tunisia. *Int. J. Hydrogen Energy* **2024**, *63*, 759–766. [\[CrossRef\]](#)
14. Farhani, S.; Grissa, H.; Ouda, M.; Bacha, F. A techno-economic feasibility study of electricity and hydrogen production in hybrid solar-wind energy park. The case study of Tunisian Sahel. *Eng. Technol. Appl. Sci. Res.* **2024**, *14*, 15154–15160. [\[CrossRef\]](#)
15. Barhoumi, E.M.; Okonkwo, P.C.; Ben Belgacem, I.; Zghaibeh, M.; Tlili, I. Optimal sizing of photovoltaic systems based green hydrogen refueling stations case study Oman. *Int. J. Hydrogen Energy* **2022**, *47*, 31964–31973. [\[CrossRef\]](#)
16. Stackhouse, P.W.; Whitlock, C.H.; Huang, D.; Mikovitz, J.C. *Surface Meteorology and Solar Energy, Version 6.0 Methodology*; NASA Technical Report NASA/TM—2008-215961; NASA Langley Research Center: Hampton, VA, USA, 2008. Available online: <https://ntrs.nasa.gov/citations/20080012200> (accessed on 25 June 2025).
17. Singh, S.; Chauhan, P.; Singh, N. Capacity optimization of grid connected solar/fuel cell energy system using hybrid ABC-PSO algorithm. *Int. J. Hydrogen Energy* **2020**, *45*, 10070–10088. [\[CrossRef\]](#)
18. Kazem, H.A.; Chaichan, M.T.; Al-Waeli, A.H.A.; Sopian, K.; Alnaser, W.E.; Kazmerski, L.; Alnaser, N.W. A review of photovoltaic/thermal (PV/T) incorporation in the hydrogen production process. *Glob. Energy Interconnect.* **2025**, *8*, 363–393. [\[CrossRef\]](#)
19. Duffie, J.A.; Beckman, W.A.; Blair, N. *Solar Engineering of Thermal Processes, Photovoltaics and Wind*; John Wiley & Sons: Hoboken, NJ, USA, 2020.
20. Han, X.; Garrison, J.; Hug, G. Techno-economic analysis of PV-battery systems in Switzerland. *Renew. Sustain. Energy Rev.* **2022**, *158*, 112028. [\[CrossRef\]](#)
21. Tebibel, H. Methodology for multi-objective optimization of wind turbine/battery/electrolyzer system for decentralized clean hydrogen production using an adapted power management strategy for low wind speed conditions. *Energy Conversion and strategy for low wind speed conditions. Energy Convers. Manag.* **2021**, *238*, 114125.

22. Nasser, M.; Megahed, T.F.; Ookawara, S.; Hassan, H. A review of water electrolysis-based systems for hydrogen production using hybrid/solar/wind energy systems. *Environ. Sci. Pollut. Res.* **2022**, *29*, 86994–87018. [[CrossRef](#)]
23. Ahmadi, M.H.; Mohammadi, A.; Pourfayaz, F.; Mehrpooya, M.; Bidi, M.; Valero, A.; Uson, S. Thermodynamic analysis and optimization of a waste heat recovery system for proton exchange membrane fuel cell using transcritical carbon dioxide cycle and cold energy of liquefied natural gas. *J. Nat. Gas Sci. Eng.* **2016**, *34*, 428–438. [[CrossRef](#)]
24. EG&G Technical Services, Inc. *Fuel Cell Handbook*, 7th ed.; U.S. Department of Energy Office of Fossil Energy National Energy Technology Laboratory: Morgantown, WV, USA, 2004.
25. Al-Orabi, A.M.; Osman, M.G.; Sedhom, B.E. Analysis of the economic and technological viability of producing green hydrogen with renewable energy sources in a variety of climates to reduce CO<sub>2</sub> emissions: A case study in Egypt. *Appl. Energy* **2023**, *338*, 120958. [[CrossRef](#)]
26. Magliano, A.; Perez Carrera, C.; Pappalardo, C.M.; Guida, D.; Berardi, V.P. A comprehensive literature review on hydrogen tanks: Storage, safety, and structural integrity. *Appl. Sci.* **2024**, *14*, 9348. [[CrossRef](#)]
27. Emma, D.; Ehrmann, A.; Schwenzfeier-Hellkamp, E. Safety of Hydrogen Storage Technologies. *Processes* **2024**, *12*, 2182. [[CrossRef](#)]
28. Liu, J.; Zhou, J.; Li, M.; Shao, W.; Cao, X.; Ding, J. Lithium-ion battery combustion with different state of charge and combustion prevention based on flame arrester. *Therm. Sci. Eng. Prog.* **2025**, *61*, 103550. [[CrossRef](#)]
29. Ortiz, Y.; Arévalo, P.; Peña, D.; Jurado, F. Recent advances in thermal management strategies for lithium-ion batteries: A comprehensive review. *Batteries* **2024**, *10*, 83. [[CrossRef](#)]

**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.