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Integrated Plant Design for Green Hydrogen Production and Power Generation in Photovoltaic Systems: Balancing Electrolyzer Sizing and Storage

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Abstract: This study evaluates the performance and feasibility of hybrid photovoltaic–hydrogen systems integrated with 4.2 MW PV installations, focusing on the interplay between electrolyzer capacity, energy storage, and hydrogen production. Key findings reveal that downsizing electrolyzers, such as using a 1 MW unit instead of a 2 MW model, increases operational efficiency by extending nominal power usage, though it reduces total hydrogen output by approximately 50%. Meanwhile, expanding energy storage systems show diminishing returns, with added capacity offering minimal gains in hydrogen production and raising economic concerns. The system's performance is highly weather-dependent, with daily hydrogen production ranging from 26 kg on cloudy winter days to 375 kg during sunny summer conditions. Surplus energy export to the grid peaks at 3300 kWh during periods of high solar generation but is minimal otherwise. For economic and operational viability, the system design must prioritize directing a majority of PV energy to hydrogen production while minimizing grid export, requiring a minimum of 50% PV energy allocation to the hydrogen value chain. Cost analysis estimates a Levelized Cost of Hydrogen (LCOH) as low as €6/kg with an optimized configuration of a 2 MW electrolyzer and 2 MWh battery. Although high production costs challenge economic sustainability, careful component optimization and supportive policies can enable competitive hydrogen pricing and a positive net present value (NPV) over the system's lifetime.

Keywords: hydrogen generation; PV–hydrogen integration; electrolysis; cost of hydrogen production; standardized energy solutions

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1. Introduction

The global energy transition is driving an urgent search for sustainable solutions to reduce greenhouse gas emissions and enhance energy resilience. A wide range of technologies, including wind energy, nuclear power, and advanced energy storage systems, offer promising pathways to achieve these goals. Among these solutions, renewable energy systems, particularly photovoltaic (PV) plants, have become a cornerstone due to their scalability and decreasing costs. However, the rapid deployment of large-scale PV installations has highlighted new challenges. Grid congestion, overproduction during peak sunlight hours, and the intermittent nature of solar power underline the need for integrated energy strategies that optimize the use of PV-generated electricity. One promising approach is coupling PV systems with hydrogen production infrastructure. Green hydrogen, produced via electrolysis powered by renewable energy, is increasingly recognized as a key player in decarbonizing hard-to-abate sectors, providing a versatile energy carrier and renewable energy storage solution. The integration of hydrogen production with PV plants offers several benefits, such as mitigating curtailment issues, enhancing energy storage capabilities, and diversifying the utilization of renewable energy. However, the feasibility of these systems is closely tied to their economic viability and technical performance, which remain under active investigation. Moreover, existing studies reveal both significant opportunities and persistent challenges, such as the high initial investment costs and the need for scalable solutions across different regions and energy markets.

In this context, the development of standardized methodologies and configurations for PV–hydrogen (PV-H_2) systems represents a critical step toward their broader adoption, enabling a more comprehensive evaluation of their performance and competitiveness in comparison to other energy systems. This study aims to contribute to this effort by examining the design, operation, and economic potential of such systems, focusing on a fully integrated PV-H_2 solution.

1.1. State of the Art

Research into PV-H_2 systems has evolved significantly over the last decade. Capurso et al. in [1] underscored hydrogen's pivotal role in sustainable energy systems, emphasizing its potential to provide both flexibility and long-term storage for renewable energy. Early studies, such as those by Boudries et al. [2], explored the technical feasibility of coupling PV systems with electrolyzers for industrial-scale hydrogen production, laying the groundwork for more complex hybrid configurations. Hinkley et al. in [3] introduced a financial perspective, analyzing the economic barriers and opportunities for PV-driven hydrogen production. As the field matured, studies began addressing the integration of PV systems with other renewable sources and storage solutions. Qolipour et al. in [4] demonstrated the viability of hybrid PV and wind configurations for hydrogen generation, while different authors provided insights into grid-connected systems and their environmental impacts through lifecycle assessments [5,6].

In more recent times, Maurer et al. in [7] and Gallardo et al. in [8] advanced the optimization of system designs, focusing on parameter studies and standalone configurations, respectively. Wei et al. in [9] introduced integrated energy storage models, highlighting the growing importance of storage in enhancing system performance. Despite these advancements, the field lacks a unified framework for standardizing PV-H_2 systems. Many studies are constrained by specific case studies or experimental setups, making it challenging to generalize findings or apply them across varied scenarios. Recent calls for standardization and replicable design methodologies reflect the need for a broader, more systematic approach to this promising technology.

1.2. Motivation for the Study

The present study investigates the potential for developing a standardized photovoltaic–hydrogen (PV-H_2) system that integrates photovoltaic generation and hydrogen production into a single, scalable solution. Drawing inspiration from the standardization of PV installations, which has accelerated solar energy deployment, this research extends the concept to PV-H_2 systems, aiming to enhance their adaptability and economic viability in the renewable energy landscape. The proposed approach not only seeks to optimize system performance by balancing hydrogen production and electricity export but also addresses the pressing need for renewable energy systems to support the thermal energy sector. In this context, hydrogen offers a particularly promising pathway, acting as a versatile energy carrier capable of bridging the gap between renewable electricity generation and thermal energy applications.

A key aspect of this framework is the prioritization of hydrogen generation, with system configurations designed to direct at least 50% of PV energy to the hydrogen value chain. This ensures operational flexibility while aligning with sustainability goals. The study also explores the interplay between electrolyzer sizing, energy storage, and overall system efficiency, presenting a framework for evaluating the scalability and replicability of such systems under diverse environmental and market conditions. One of the primary objectives of this study is to analyze the proposed system from an economic perspective, focusing on evaluating the cost of hydrogen production. To evaluate the economic feasibility of the proposed PV-H_2 system, several approaches can be considered. These include life cycle cost analysis (LCCA), payback period evaluations, and profitability assessments based on net present value (NPV). Each of these methods offers unique insights into different aspects of the system's economic performance [10]. In this study, we sought to apply the theory of the Levelized Cost of Hydrogen (LCOH). This approach allows us to comprehensively assess the cost competitiveness of hydrogen production by considering capital expenditures, operational costs, and the system's lifetime energy output.

By targeting a replicable "PV-H_2 package", the study offers a novel approach to integrating decentralized hydrogen hubs into complex energy systems. This research provides practical solutions that foster broader adoption of renewable energy technologies, extending their applications beyond electricity generation to include thermal energy systems. These insights bridge existing gaps in the literature and present a scalable, sustainable option for future energy systems.

2. System Configuration and Operational Constraints

The rationale behind the proposed work stems from the observation that photovoltaic energy, as highlighted in all major international reports, is the fastest-growing energy source. This growth is largely attributed to its achievement of highly competitive costs. Figure 1 illustrates the recent growth in global photovoltaic (PV) installations, showing both the energy generated (in TWh) and the installed capacity (in GW). By the end of 2023, according to GSR data [11], global PV installations reached approximately 1589 GW, producing just over 1600 TWh of energy. This implies an average of around 1000 equivalent operating hours per year for PV systems worldwide, a figure that has remained relatively stable over time with minor fluctuations. Given the proliferation of PV installations, relying solely on grid capacity is no longer a viable approach for integrating large amounts of solar power.

The rapid growth of photovoltaic installations, which increased from just over 180 GW to nearly 1600 GW between 2013 and 2023, reflects the impact of this technology's modularity, ease of deployment, and cost-effectiveness. Further expansion, however, cannot rely solely on grid management systems and must incorporate storage solutions to handle the energy generated more effectively.

Hydrogen offers a promising pathway: It complements electricity generation, supports increased renewable installations, and extends the application of renewables to thermal and mobility sectors. To ensure the system's effectiveness, prioritizing hydrogen generation over direct electricity production is crucial.

Innovative projects increasingly explore hydrogen as a storage solution, leveraging its ability to capture surplus energy and store it for use beyond peak solar production hours. A scalable and efficient plant design integrates hydrogen generation and distribution with electricity production. To enhance flexibility, the system incorporates appropriately sized energy storage. Figure 2 outlines the proposed system, centered on a 4.2 MW photovoltaic installation designed for hydrogen production and energy distribution. The plant is engineered to meet a critical technical and regulatory requirement: allocating at least 50% of its annual electricity output to hydrogen production, with the remaining energy directed to the electrical grid. The system comprises a 4.2 MW photovoltaic array powering a hybrid energy system that includes an electrolyzer and energy storage. The analysis focuses on two electrolyzer sizes, 1 MW and 2 MW, alongside options for energy storage configurations. Operational constraints emphasize directing at least half of the generated energy toward hydrogen production, evaluating how different setups impact overall system flexibility and performance.

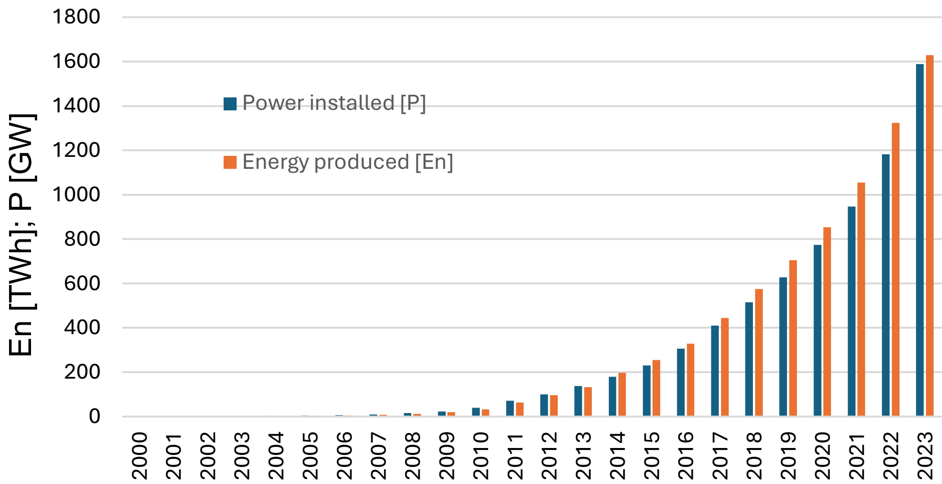

Figure 1. Global photovoltaic (PV) installations: trends in installed capacity (GW) and energy generation (TWh) in the current century.

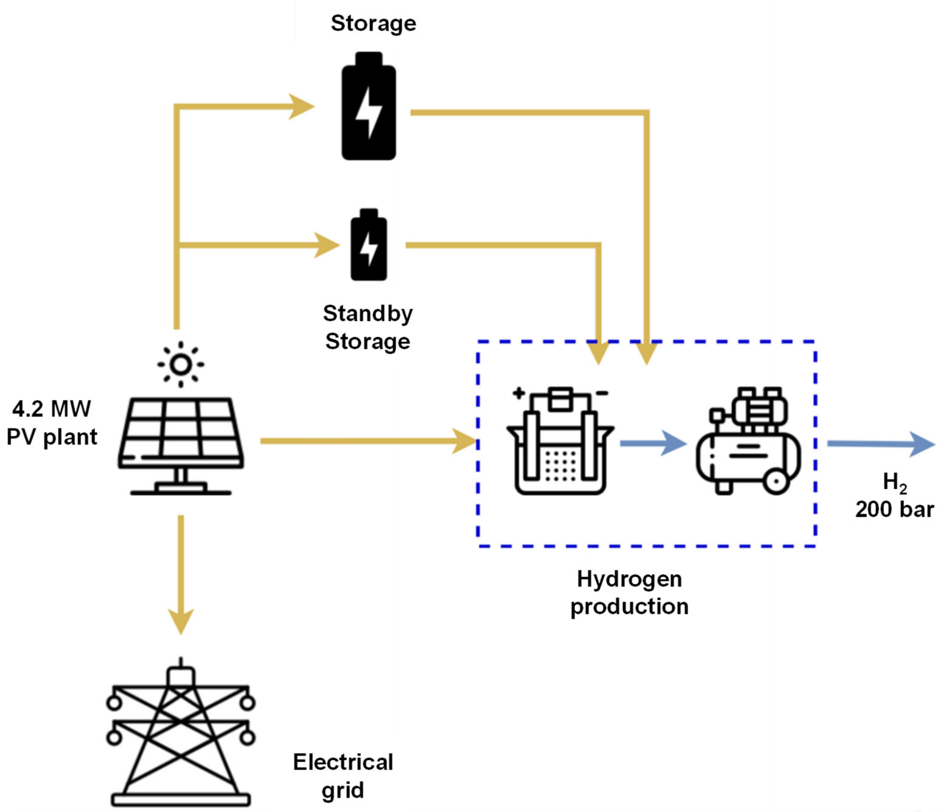

Figure 2. Schematic representation of a scalable and flexible plant configuration integrating hydrogen generation and compression, and electrical power generation.

3. Characteristics of the Components and Selected Subsystems

This section provides an overview of the plant's design and the specific components used, highlighting key technical specifications and sizing considerations. To ensure the system's practicality and alignment with real-world conditions, this study exclusively references commercially available components [12–14]. This approach not only strengthens the credibility of technical assumptions but also facilitates the creation of a realistic economic model for the plant.

By leveraging market-ready components, the study supports the development of scalable and replicable PV-H_2 systems that can be implemented using existing supply chains and infrastructure. This ensures the findings are grounded in current technologies while providing a foundation for future advancements.

3.1. PV Plant

The photovoltaic (PV) plant is designed using commercially available modules with nominal power ratings between 500 and 550 W and efficiencies in the range of 20–22%, commercially available today from different producers. To reach the target capacity, approximately 7836 to 8400 modules will be required. The system will be equipped with eight 500 kW inverters, providing a total inverter capacity of 4 MW, slightly undersized relative to the total PV capacity installed. This configuration allows for efficient energy conversion while minimizing potential overproduction losses.

The design incorporates standardized components to facilitate cost estimation and optimize overall system performance. The slight undersizing of inverter capacity relative to PV output helps reduce system costs without significantly impacting energy yield, as minor energy losses during peak production are balanced by a lower overall equipment investment. This configuration provides a cost-effective balance between production capacity and energy efficiency, establishing a solid foundation for integrating hydrogen production modules in a modular and scalable way.

3.2. Electrolyzer

In selecting and sizing electrolyzers for hydrogen production alongside the PV plant, we chose a low-temperature alkaline electrolyzer based on data from manufacturers' catalogs. These electrolyzers are available in 1 MW, 2 MW, and 4 MW models, corresponding to approximately 25%, 50%, and 100% of the nominal power of the PV installation, respectively. Table 1 summarizes general data for a commercially available electrolyzer; the data used for the analysis are partially derived from [12] and have been partially rearranged and adapted by the authors, following the analysis conducted in [13].

Table 1. Electrolyzer's specifications and assumptions of the authors based on commercial data [12].

	Type 1	**Type 2**	**Type 3**
Power class	1 MW	2 MW	4 MW
H_2 nominal flow rate	200 Nm^3/h	400 Nm^3/h	800 Nm^3/h
H_2 nominal flow rate	18 kg/h	36 kg/h	72 kg/h
H_2 delivery pressure	27–30 bar	27–30 bar	27–30 bar
Output temperature	80 °C	80 °C	80 °C
Energy consumption	5.1 kWh/Nm^3	5.0 kWh/Nm^3	5.0 kWh/Nm^3
Energy consumption	57 kWh/kg	56 kWh/kg	56 kWh/kg
Operational range	20–100%	20–100%	20–100%
Minimum power	0.2 MW	0.4 MW	0.8 MW
Hot standby power	15 kW	30 kW	60 kW
Water consumption	15 L/kg H_2	15 L/kg H_2	15 L/kg H_2

As the 4 MW model would seldom operate at full capacity in this configuration, it is not considered a cost-effective option. Consequently, our analysis focuses on the 1 MW and 2 MW models, evaluating their energy efficiency, compatibility with PV output, and cost-effectiveness within the overall system design.

3.3. Storage Systems

The storage system incorporates two types of batteries, each tailored to support hydrogen production. The first (backup battery) extends electrolyzer operation beyond sunlight hours, ensuring a continuous production cycle. The second (hot standby battery) maintains the electrolyzer in standby mode, ready to resume operation without delays.

This dual-storage approach optimizes the integration of PV plants with hydrogen production, enhancing system flexibility and aligning with the overall objective of maximizing energy utilization for hydrogen generation. A purely electrical energy storage system was excluded from the design due to its significant cost increase and limited impact on overall system performance. Instead, a short-duration storage solution was selected, aligning hydrogen production with periods of higher energy availability, such as the summer months.

3.3.1. Backup Battery

The backup battery plays a critical role in extending the operational hours of the electrolyzer beyond periods of direct solar energy availability. As an example, the backup battery can be sized to supply an additional hour of operation at the nominal power output of the electrolyzer. For a 2 MW electrolyzer, this configuration would require a minimum storage capacity of 2 MWh. This initial sizing ensures operational continuity and enhances system reliability, particularly during short periods of reduced energy input. However, the capacity can be fine-tuned based on specific operational requirements, cost constraints, or evolving system needs. For instance, a detailed cost–benefit analysis might reveal opportunities to optimize battery sizing by aligning it more closely with anticipated downtime or production goals, thereby reducing capital and maintenance expenses without compromising performance. This approach provides flexibility in the system design, enabling stakeholders to balance reliability, efficiency, and economic feasibility.

3.3.2. Hot Standby Battery

The standby battery ensures continuous and reliable electrolyzer operation, even during periods of reduced or no solar input. This can be designed to support a minimum period of standby power. According to the data available in the technical literature on electrolyzers [15], the energy requirement for the hot standby battery can be expressed as a percentage of the nominal capacity of electrolyzers. In this study, we have selected 1.5% of nominal power as a reference. The size of the standby battery is further determined based on the number of hours required to maintain the operation of the electrolyzer during standby conditions. The reference value for the energy capacity of the hot standby battery, E_{basic} can be defined as follows:

$$E_{basic} = 1.5\% \cdot P_{nom} \cdot n_{hours} \tag{1}$$

The sizing of a standby battery depends on the desired standby duration. For instance, to maintain 10 h of standby for the 2 MW electrolyzer, a preliminary estimate suggests a battery capacity of approximately 300 kWh. If the standby period increases to 16 h, the required capacity rises to around 480 kWh. For a maximum standby period of 20 h, the capacity would need to be scaled up to 600 kWh.

The storage batteries must be slightly oversized to account for the fact that they cannot be fully discharged without impacting performance and longevity. Assuming a discharge rate limit (*SC*) of 80%, the actual capacity of each battery needs to be increased accordingly to meet the required energy needs. This ensures that even with the discharge limit, the backup and standby batteries can reliably provide the necessary power for uninterrupted electrolyzer operation. If a maximum acceptable depth of discharge is considered—reasonably set at 80%—the battery capacity must be oversized accordingly. This can be estimated using the following formula, where SC = 0.8.

$$E_{stand\text{-}by} = \frac{E_{basic}}{SC} \tag{2}$$

Applying this adjustment, the required capacity increases to approximately 375 kWh in the first case (10 h standby) and about 750 kWh in the third case (20 h standby).

3.4. Compressor

As shown in Figure 2, the design includes a compression system capable of storing hydrogen at a pressure of approximately 200 bar, ensuring compatibility with standard industrial storage and distribution requirements. For the compressor, we have relied on data from real-world models documented in the literature to ensure that our analysis is grounded in practical and commercially viable technologies. Specifically, we referenced a typical efficiency of 60%, a value representative of modern compression systems. From this, we derived the specific energy required for the compression process, which plays a critical role in the overall energy balance of the system. The estimation of the energy required for compression was derived using manufacturer-provided data, considering the theoretical minimum work of compression [14]:

$$l_{c,id} = R \cdot T_1 \cdot ln\left(\frac{p_2}{p_1}\right) \tag{3}$$

The energy required to obtain a final pressure of 200 bar, starting from 353 K and 27 bar (Table 1), is about 2.94 MJ/kg_{H2}:

$$l_{c,id} = R \cdot T_1 \cdot ln\left(\frac{p_2}{p_1}\right) = 4.157 \cdot 353 \cdot ln\left(\frac{200}{27}\right) = 2938 \text{ kJ/kg} \tag{4}$$

So that the specific work really required is as follows:

$$l_{c,real} = \frac{l_{c,id}}{\eta} = \frac{2938}{0.6} = 4897 \frac{\text{kJ}}{\text{kg}} = 1.36 \text{ kWh/kg} \tag{5}$$

The relevant data of the compressor are summarized in Table 2.

Table 2. Compressor-specific data.

	Value
Output pressure	200 bar
Inlet pressure	27 bar
Inlet temperature	80 °C
H_2 mass flow rate	40 kg/h
Maximum power	150 kW
Specific consumption	1.36 kWh/kg
Efficiency	0.6

4. Economic Analysis and Economic Parameters

To assess the viability of a solution like the one proposed, it is essential to develop an economic analysis aimed at understanding the cost of hydrogen production relative to current standards and established benchmarks.

The concept of minimizing the cost of hydrogen production is a key principle that can greatly aid in optimizing any renewable energy generation system. This approach helps determine how resources and components, such as electrolyzers, can be configured to maximize efficiency and reduce the costs associated with hydrogen production, making the best use of available green energy [16].

To perform the economic analysis of the hybrid system considered, key costs include Capital Expenditures (CAPEX), the capital costs to build the plant, amortized over time, Operating Expenses (OPEX), or ongoing costs for operation, including energy use and maintenance, all the costs for Operations and Maintenance (O&M), including the costs for system management and preventive maintenance and in some cases the costs for the Balance of Plant (BoP), or the costs for non-energy-producing components, such as distribution and cooling systems. Understanding these costs is essential for assessing the system's economic viability and optimizing investment returns.

The variable identified for the analysis is first of all the Levelized Cost of Hydrogen (LCOH), a key metric that represents the per-unit cost of producing hydrogen over the lifecycle of a project, accounting for capital expenses, operational costs, and system efficiency. The topic of *LCOH* has been extensively addressed in a series of publications, highlighting its critical role in evaluating the economic viability of hydrogen production technologies [17,18]. The *LCOH* calculation excludes revenues from selling surplus electricity to the grid, in order to prevent the system from being oversized for the purpose of electricity sales. The formula for estimating *LCOH* (in €/kg_{H2}) is presented in Equation (6):

$$LCOH = \frac{\sum_k CAPEX_k + C_{proj} + \sum_{j=1}^{n} \frac{\sum_k OPEX_{k,j}}{(1+i)^j}}{\sum_{j=1}^{n} \frac{m_{H2,prod,j}}{(1+i)^j}} \quad (6)$$

where $m_{H2,prod,j}$ [kg] is the mass of hydrogen produced during j-th year, n is the lifetime of the project set at 20 years, i is the investment rate set at 5%, $CAPEX_k$ is the investment cost of the k-th component [€], $OPEX_{k,j}$ are the operation and maintenance costs for the k-th component during the j-th year, and C_{proj} are the project costs estimated at 12.5% of *CAPEX* excluding PV and battery. Another important economic parameter to monitor is the Net Present Value (*NPV*), which measures the difference between the present value of cash inflows and outflows over the lifecycle of a project, providing an indicator of its overall profitability. *NPV* is defined according to Equations (7) and (8):

$$NPV_j = NPV_{j-1} + CF_j/(1+i)^j \quad (7)$$

$$NPV_{20} = -\left(\sum_k CAPEX_k + C_{proj}\right) + \sum_{j=1}^{20} CF_j/(1+i)^j \quad (8)$$

where CF_n is the cash flow during the j-th year. The positive cash flows are associated with the sale of green hydrogen produced and the excess electricity generated by photovoltaics, whereas the negative cash flows are linked to the purchasing of demineralized water for the electrolyzer and the operation and maintenance of the technologies.

The main economic assumptions are reported in Tables 3 and 4.

Table 3. Economic model: cost of the various components.

Component	Voice	Value
PV plant	Investment cost (CAPEX) O&M (after 15 years) OPEX fixed	1060 €/kW [19] 30 €/kWp year 2% CAPEX/year [20]
Storage system	Investment cost (CAPEX) OPEX fixed	300 €/kWh [21] 2.5% CAPEX/year [21]
Electrolyzer	Investment cost (CAPEX) Balance of Plant (BoP) OPEX fixed	732 €/kW [22] 464 €/kW 5% CAPEX/year
Compressor	Investment cost (CAPEX) OPEX fixed	4577 €/kW [23] 2% CAPEX/year [24]

Table 4. Economic model: cost of the energy vectors [25,26].

Vector	Type	Value
Hydrogen	Grey H_2 Blue H_2 Green H_2	3 €/kg 4.5 €/kg 8 €/kg
Electricity	-	7 c€/kWh
Demineralized water	-	3.58 €/m^3

The *NPV* is very sensitive to the selling price of energy vectors, particularly that of hydrogen. Consequently, we have examined three distinct price scenarios to assess the impact of substituting hydrogen produced from natural gas with or without carbon capture (referred to as blue or grey hydrogen, respectively) or hydrogen from renewable plants (green hydrogen).

5. Energy Flow Management and Performance and Production Scenarios

It is important to emphasize that a plant like the one illustrated in Figure 2, which integrates photovoltaic generation with hydrogen production and the electric grid, is viable primarily if most of the energy generated by the PV system is dedicated to the hydrogen supply chain. Given the current market price of hydrogen, the plant conceptually makes sense only if hydrogen production is the dominant outcome, with minimal energy diversion to the grid. A definitive assessment, however, will require an economic analysis to validate the plant's feasibility under real-world conditions.

The operational logic of the proposed system is based on a simulation derived from a typical climatic profile for the region. In terms of system prioritization, hydrogen generation is always favored. Electricity distribution to the grid occurs only when the battery storage system is fully charged, ensuring that the maximum amount of energy is directed toward hydrogen production. This strategy aligns with the system's goal of maximizing hydrogen output and minimizing energy losses. For the purposes of this study, it is assumed that hydrogen utilization follows a daily consumption pattern, enabling a consistent operational framework for the system's design and performance evaluation.

In Section 3, we have discussed the main components of the whole system. Although the sizes of the photovoltaic plant and electrolyzers under consideration have been discretely defined, the system also includes storage solutions that can come in various capacities. Each storage capacity corresponds to a specific duration for which the energy generated by the photovoltaic plant can be stored. It is evident that significantly increasing the size of the storage system may not be economically viable. Nonetheless, multiple configurations remain possible, allowing flexibility in system design.

For preliminary evaluations, specific configurations with a production constraint on hydrogen generation were considered too. Specifically, we assumed that at least 50% of the PV plant's energy must be allocated to hydrogen production. This constraint ensures a reliable energy flow to the hydrogen system while keeping grid interaction at a reduced level. To enforce this 50% allocation, careful energy management between the photovoltaic array, the electrolyzer, and the storage system becomes critical. The energy flow needs to be dynamically distributed, accounting for solar irradiance fluctuations and storage demands to maintain continuous hydrogen production.

Our design approach focused on maximizing the plant's efficiency and reducing unnecessary energy diversion to the grid. With a nominal PV capacity of approximately 4 MW, it became clear that the system would produce above 2 MW for only a limited number of hours. Consequently, using a 4 MW electrolyzer was considered impractical. Instead, we opted to analyze electrolyzer configurations of 1 MW (about 25% of PV capacity) and 2 MW (almost 50% of PV capacity), allowing the system to operate directly with the PV plant's output during significant portions of the day. Surplus energy beyond the electrolyzer's capacity could then be routed to the grid or stored for later use to enhance hydrogen production. To explore these options further, we evaluated three scenarios: one without storage, one with a 1 MWh storage system, and one with a 2 MWh storage system. This approach enables us to prioritize hydrogen generation while optimizing plant flexibility and aligning with broader sustainability goals.

The operational logic of the system was implemented using MATLAB code to simulate the plant's performance across different days, with solar radiation at the location serving as the primary input. This approach enabled effective management of the interactions between all system components while adhering to the predefined operational rules. The simulation logic is structured as follows:

Photovoltaic Generation > Electrolyzer Nominal Power: If PV generation exceeds the electrolyzer's nominal power, the excess energy is first directed to charge the battery until it reaches full capacity. Once the battery is fully charged, the remaining power is exported to the electrical grid.

Photovoltaic Generation $\geq$ 25% of the Electrolyzer Power: When photovoltaic (PV) generation is available and exceeds at least 25% of the electrolyzer's nominal power, the electrolyzer operates either at nominal load or partial load, depending on the available power.

Photovoltaic Generation < 25% of the Electrolyzer Power: If PV generation is present but below 25% of the electrolyzer's total power capacity, the available PV power is still directed to the hydrogen production system. The electrolyzer can then supplement this power with energy stored in the battery.

No Photovoltaic Generation: In the absence of PV generation, the electrolyzer operates entirely using energy supplied by the battery.

This methodology ensures seamless integration and coordination among the plant's components while optimizing energy flow for hydrogen production based on real-time solar radiation inputs.

Based on the four configurations resulting from combining the two electrolyzer sizes and the two storage systems, this section presents an analysis of overall system performance. The plant is virtually located in a coastal area of central Italy. The reference climate data are reported in Table 5. This profile is built upon a detailed climate analysis conducted for the year 2023.

Table 5. Reference climatic data for the reference place in central Tuscany (Italy).

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec	Year
T_{avg} [°C]	7.3	7.4	10.7	12.9	17.9	20.6	22.9	23.1	19.8	15.6	11.7	7.6	14.8
H_d [kWh/(m^2 day)]	1.6	2.3	3.3	4.3	5.9	6.4	6.8	5.9	4.4	2.6	1.9	1.4	3.9
Outdoor RH [%]	85.0	74.8	79.8	78.9	74.4	74.2	71.5	76.6	81.5	86.2	78.3	85.8	79.0
Wind velocity [m/s]	1.8	1.5	1.3	1.6	1.9	1.6	1.7	1.3	1.0	1.4	1.6	2.1	1.6

Different production scenarios are explored to highlight how each configuration affects the amount of hydrogen produced and the system's overall efficiency. The results illustrate achievable hydrogen production levels and each scenario's impact on costs and system reliability. Considering the PV plant production, Figure 3 shows three realistic weeks, one in winter (a), one in spring (b), and one in summer (c), consisting of alternating beautiful days and worse days. As can be observed, on many days throughout the year, the power production of the plant exceeds the capacity of the electrolyzer. In different cases, corresponding to many winter days and certain days with unfavorable weather conditions during intermediate seasons, the power generated by the photovoltaic system is not sufficient for the direct activation of the electrolyzer.

To ensure efficient use of PV generation, the system prioritizes hydrogen production while minimizing energy export to the grid. Excess energy is captured by a storage system, which plays a critical role in enabling hydrogen production even during fluctuations in PV output. Once the storage battery reaches its maximum capacity, any additional power generated by the PV system is directed to the grid, maintaining system flexibility and ensuring full utilization of the available energy.

Different system configurations have been analyzed to evaluate the performance under various conditions. Two electrolyzer capacities were considered: one with 2 MW (50% of the nominal PV power) and one with 1 MW (25% of the nominal PV power), both coupled with the same storage capacity of 2 MWh.

Figure 4 provides the monthly production of the PV plant, while Figure 5 provides a specific production, considering the energy produced for each month for the unit value of the peak power installed (1 kW). From a conceptual standpoint, the trends shown in the following figures are similar, although they offer valuable insights into some quantitative details, providing a clear understanding of the plant's performance both in total and on a per-unit basis. The logic of the system operation prioritizes hydrogen production and sending energy to the grid only when there are production surpluses, and the electrolyzer operates at nominal power and storage is full. The electrolyzer operates at four discrete power levels: 25% of nominal power, 50% of nominal power, 75% nominal power, and full nominal power. No intermediate operating ranges are allowed.

The primary workflow is as follows:

Energy Allocation: The photovoltaic plant generates energy that is first directed towards the electrolyzer, which converts power into hydrogen through electrolysis. This hydrogen serves as an energy storage solution.

Battery Charging: If the electrolyzer is operating at its nominal capacity and still there is additional photovoltaic energy, it is stored in a battery. The battery serves as a secondary storage medium, enabling the system to manage fluctuations in PV generation.

Grid Export: Only when the electrolyzer is running at its full capacity and the battery reaches 100% charge does the system send any surplus energy to the grid. This typically occurs during periods of high PV production, such as sunny summer days, when the storage facilities reach their maximum capacity.

Energy Discharge: Once the PV system ceases production (for example, in the evening), the energy stored in the battery is then discharged to support the electrolyzer's needs for additional time.

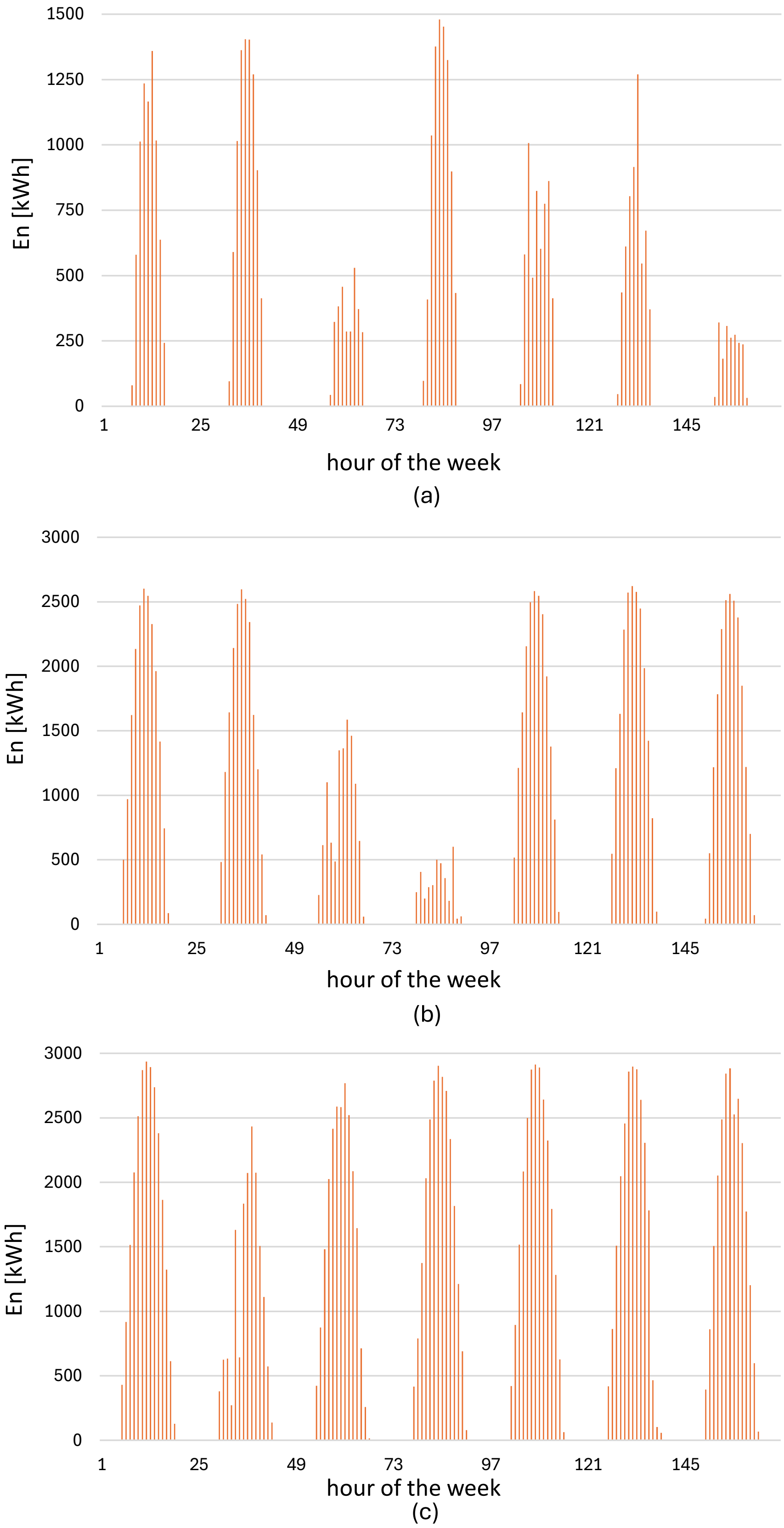

Figure 3. Energy generated by the PV plant in three weeks in January (**a**), April (**b**), and July (**c**).

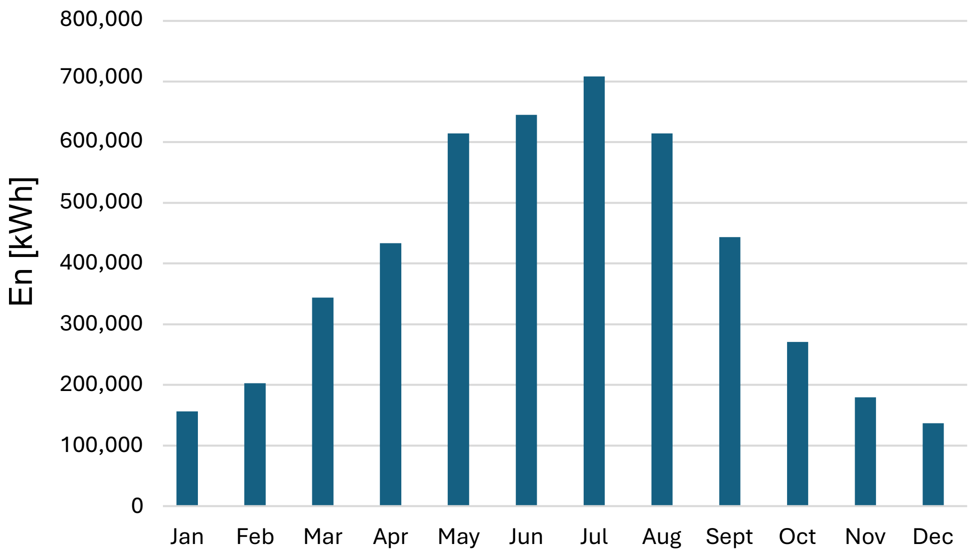

Figure 4. Energy generated by the PV plant for each month.

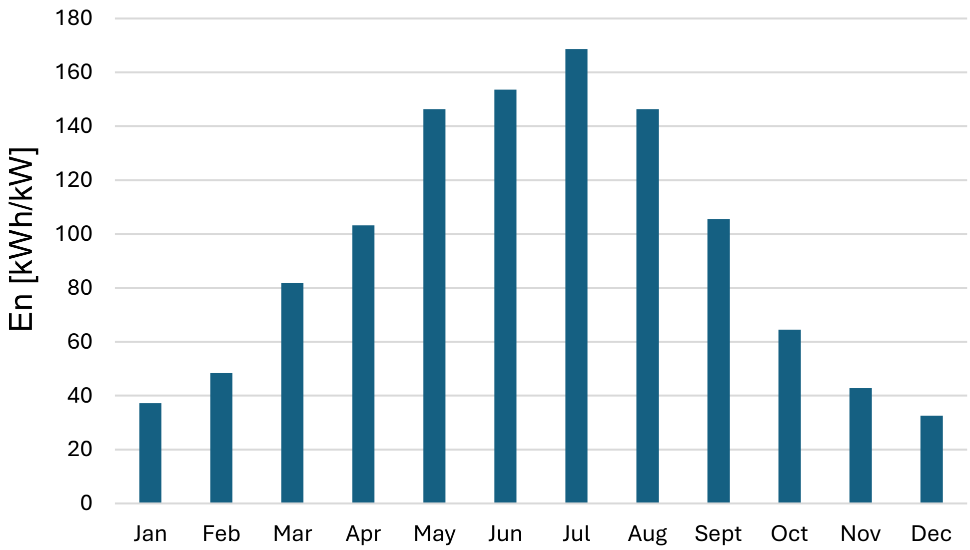

Figure 5. Specific energy produced monthly by the PV plant.

Considering as reference case of a 2 MW electrolyzer, and the results of the simulation, it can be observed that it operates at nominal power only briefly, remains inactive for more than 50% of the time, and functions at nominal power for about 10% of the time. Table 6 summarizes the operating mode of the component. Reducing the size of the electrolyzer at 1 MW while maintaining the same storage capacity increases the time the electrolyzer operates at nominal conditions and the overall hydrogen production time, as shown in Table 7. Naturally, given the two electrolyzers, the smaller one will run for a greater number of hours. Table 8 provides the operating hours for each of the two electrolyzers. Equivalent operating hours also increase by approximately 50%; this means that total hydrogen production decreases by 25%.

In the analysis, three different storage levels were examined: no storage, 1 MWh of storage, and 2 MWh of storage. Table 9 provides a general analysis of the various examined strategies. As shown by the data analysis in Table 9, the requirement that 50% of the energy production be allocated to the hydrogen supply chain is met in all six cases examined, including an electrolyzer sized at a quarter of the photovoltaic plant's power capacity. In the case of a 1 MW electrolyzer, it will operate for many more hours overall, both in total and at nominal power, ensuring that at least 50% (58%) of the generated energy is directed to the hydrogen chain. For an electrolyzer sized at half the peak power of the photovoltaic plant (2 MW), with a storage system of 2 MWh, approximately 93% of the generated energy will be destined for hydrogen production. Solutions incorporating larger components are, from an energy perspective, less effective. However, to determine which of the six solutions is the most cost-effective, an economic analysis is necessary.

Table 6. Operating hours of the 2 MW electrolyzer in various modes.

Electrolyzer Operation	Share	Operating Hours
Inactive	54.8%	4798
25%	17.1%	1496
50%	11.8%	1039
75%	6.2%	542
Nominal power	10.1%	885

Table 7. Operating hours of the 1 MW electrolyzer in various modes (without storage).

Electrolyzer Operation	Share	Operating Hours
Inactive	48.5%	4242
25%	9.4%	826
50%	14.3%	1257
75%	4.4%	384
Nominal power	23.4%	2050

Table 8. Operating hours of the two electrolyzers.

Electrolyzer Type	Equivalent Operating Hours at Nominal Power for the Electrolyzer
Electrolyzer (1 MW)	3173
Electrolyzer (2 MW)	2185

Table 9. General analysis of the examined strategies in all six scenarios.

Electrolyzer	Storage	Electricity for H_2 Production [kWh]	%	Electricity for Grid [kWh]	%	Energy Losses [kWh]	%
2 MW	2 MWh	4.51×10^6	90	3.96×10^5	7	1.49×10^5	3
	1 MWh	4.29×10^6	85	5.81×10^5	12	1.57×10^5	3
	0 MWh	3.80×10^6	76	1.05×10^6	21	1.79×10^5	4
1 MW	2 MWh	3.38×10^6	67	1.58×10^6	31	6.97×10^4	1
	1 MWh	3.26×10^6	65	1.70×10^6	34	7.14×10^4	1
	0 MWh	2.92×10^6	58	2.02×10^6	40	8.44×10^4	2

Increasing the size of the storage system does not appear to be particularly advantageous, even from an energetic perspective. As shown in Figure 6 for the 2 MW electrolyzer case, such an increase does not result in significant improvements in hydrogen production levels. Increasing the size of the storage system, even up to 4 MWh (a size that is equivalent to the maximum hourly photovoltaic energy production), does not yield any significant energetic benefits.

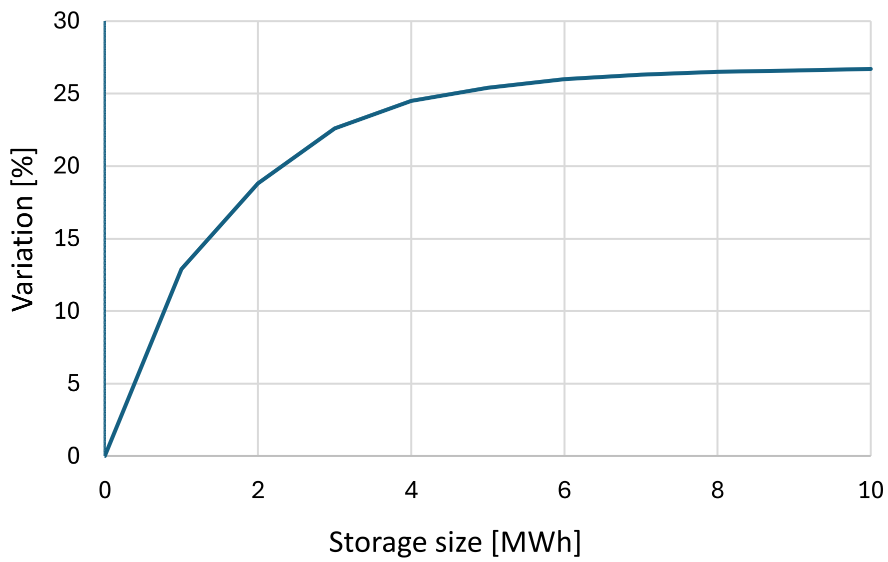

Figure 6. Increase in hydrogen production with the increase in the size of the storage.

Considering the case of the 2 MW electrolyze paired with a 2 MWh storage system, the following table provides an overview of the hydrogen produced and the energy exported to the electrical grid for selected typical days, offering a clear perspective on the orders of magnitude involved. Table 10 summarizes the main data. As shown in the table, the system's production varies significantly across different days, which can pose challenges for the hydrogen supply chain. Daily production ranges from approximately 26 kg on a typical cloudy winter day to a maximum of about 375 kg on a clear summer day. Similarly, the energy exported to the grid fluctuates considerably, becoming significant only during summer or mid-season days, with a peak of 3300 kWh. Despite these challenges, the proposed solution represents a technically viable approach that can be considered alongside other solutions, as those discussed in [27].

Table 10. Hydrogen production and energy export data for a 2 MW electrolyzer over typical days.

Day	Clear-Sky Day	Cloudy Day
July (Summer day)	Hydrogen produced: 375 kg Electricity to grid: 3300 kWh	Hydrogen produced: 275 kg Electricity to grid: 0 kWh
April (Mid-season day)	Hydrogen produced: 303 kg Electricity to grid: 1270 kWh	Hydrogen produced: 62 kg Electricity to grid: 0 kWh
January (Winter day)	Hydrogen produced: 116 kg Electricity to grid: 0 kWh	Hydrogen produced: 27 kg Electricity to grid: 0 kWh

6. Economic Viability and Cost Analysis

Currently, green hydrogen production costs pose a significant challenge to the economic viability of the system. This section provides an overview of production costs for each configuration and explores possible optimization strategies, considering the six different cases summarized in Table 7.

Cost-reduction opportunities are identified by optimizing the size of the electrolyzes and storage systems, pinpointing configurations that yield the best cost-efficiency results. Figure 7 illustrates the heat map of LCOH as a function of electrolyzer and battery storage size. It can be observed that when the electrolyze size is minimal, a larger battery can be a cost-effective solution.

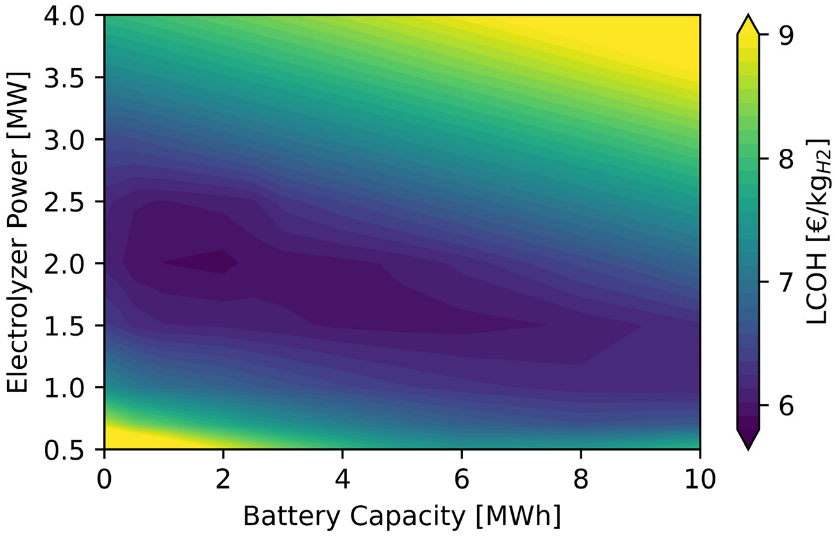

Figure 7. LCOH heatmap varying battery capacity and electrolyzer power.

Conversely, when the electrolyzer size is increased, the energy from PV is more fully exploited, and consequently, a smaller battery capacity optimizes the system. The minimum LCOH results are equal to 5.868 €/kg with an electrolyzer power of 2 MW and a battery capacity of 2 MWh. These findings broadly align with the technical evaluations discussed in the previous section, reinforcing the idea that system optimization in terms of electrolyzers, and storage size plays a critical role in achieving both energy efficiency and cost-effectiveness. The value we obtained is also consistent with recent international indicators, such as those reported in [28].

As visible in Figure 8, the requirement that at least 50% of the PV plant's energy must be allocated toward the hydrogen production system is not a constraint within the zone of the minimum LCOH.

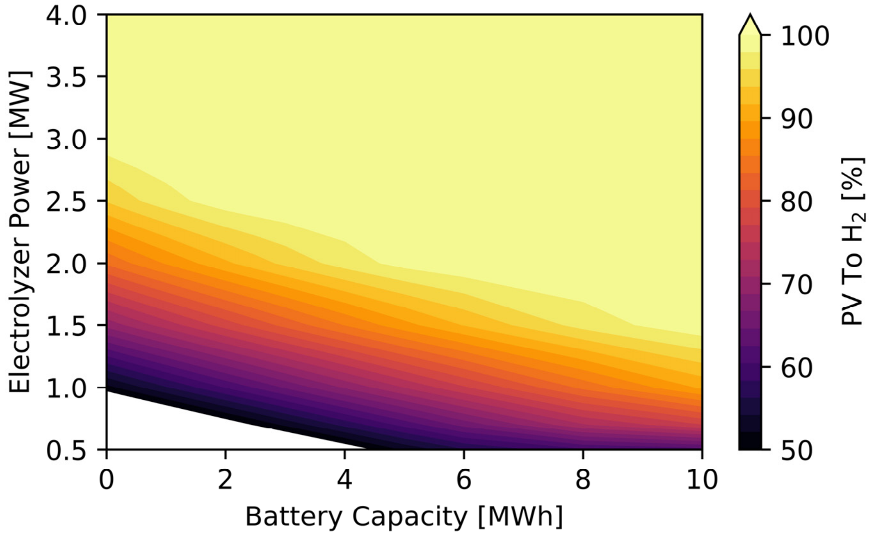

Figure 8. Percentage of PV energy to hydrogen production heatmap varying battery capacity and electrolyzer power.

Indeed, the percentage falls below 50% with electrolyzer power lower than 1 MW and with low battery capacities. As previously seen, with the optimal electrolyzer and battery size, 90% of the produced energy is directed toward the hydrogen production system, with an annual hydrogen production of about 104 tons.

Figure 9 represents the contributions of each component and technology to the composition of LCOH. It is evident that the PV system and the electrolyzer represent the primary contributors to the total cost. PV impact is about 45%, of which 30.4% is for CAPEX and 14.6% is for OPEX, while electrolyzer impact is 35.7%, of which 16.1% is for CAPEX and 19.7% is for OPEX.

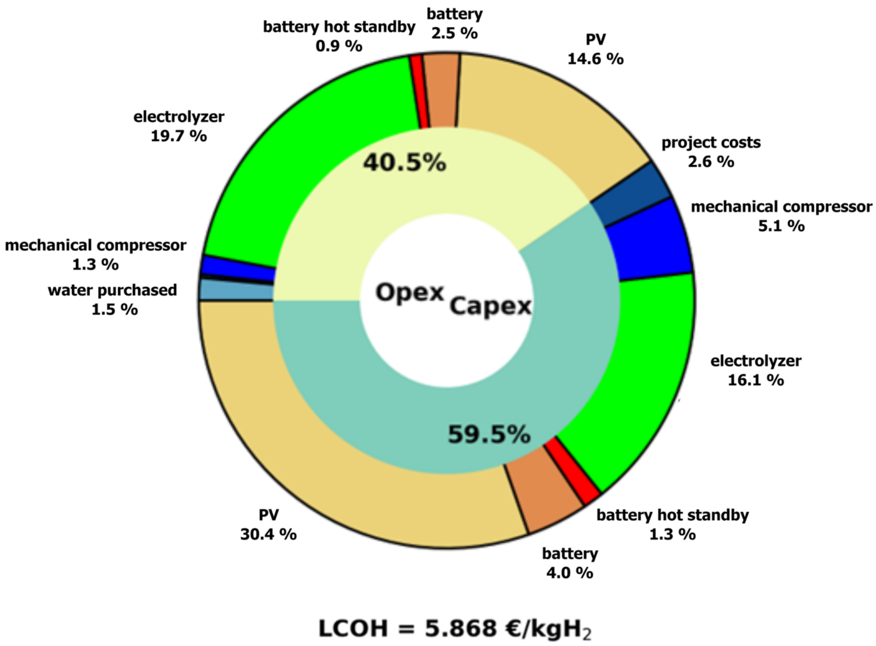

Figure 9. Technologies contributions to Levelized Cost of Hydrogen.

With regard to the NPV, a sensitivity analysis on the price of hydrogen is conducted with the objective of identifying the optimal system sizes. The hydrogen costs used for this analysis were derived from an international report on the subject, just exposed in Table 4 [24,25].

Figure 10 illustrates the results. It can be observed that the positive cash flow is insufficient to repay the investment in both the grey and blue hydrogen scenarios, as the hydrogen selling price is lower than the production price, which is the LCOH.

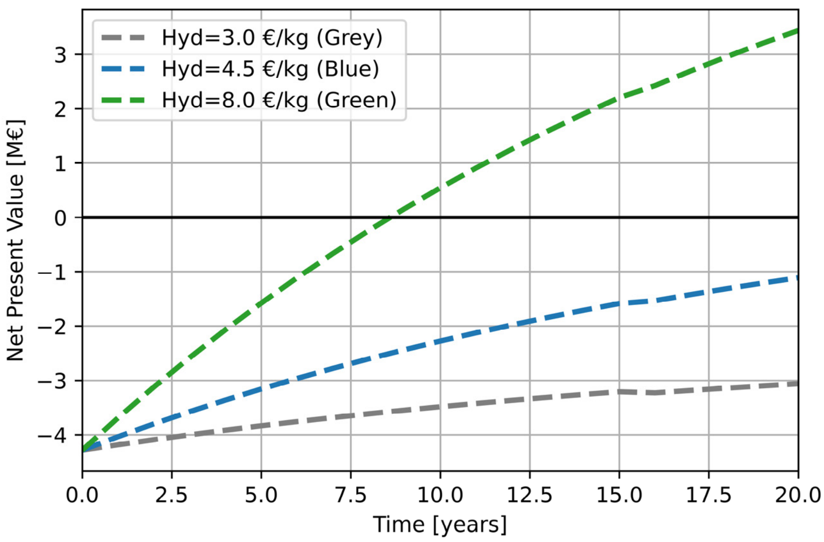

Figure 10. Net Present Value with different hydrogen prices.

However, if the hydrogen is sold at a price of 8 €/kg, the investment is paid back in less than 9 years, with an NPV of 3.5 M€ at the end of the system's lifetime. Nevertheless, it is important to note that a hydrogen price of 8 €/kg is still considered quite high, which raises questions about the economic competitiveness of green hydrogen compared to conventional hydrogen production methods and other energy sources.

From an economic perspective, the system's scalability is influenced by fixed costs associated with electrolyzers and storage systems. For smaller PV capacities or lower hydrogen demands, these fixed costs may outweigh the benefits, reducing the overall cost-effectiveness of the system. Conversely, beyond a certain scale, the cost of additional infrastructure (e.g., larger storage systems or grid reinforcements) might increase disproportionately, impacting the system's economic feasibility. One technical challenge in scaling up the system is the availability of electrolyzers with sufficiently large capacities to handle increased hydrogen production demands. Currently, the market for electrolyzers is dominated by medium-scale units, and while larger units are being developed, their commercial availability and performance under real-world conditions remain uncertain. This limitation may introduce bottlenecks in system design and increase costs due to the need for multiple units or custom solutions. Additionally, as PV capacity grows, energy storage systems must also scale proportionally.

7. Conclusions

This study analyzed the performance of a hybrid photovoltaic–hydrogen system, focusing on a specific configuration tied to a 4.2 MW photovoltaic plant. The primary focus was to maximize hydrogen production to achieve the lowest production cost. To ensure practicality, we based our analysis on commercially available components.

The results highlight two key electrolyzer sizing options: one corresponding to approximately 50% of the PV system power and another at 25%. A 2 MW electrolyzer paired with a 2 MWh storage system allows over 90% of the energy produced by the PV system to be directed toward hydrogen generation. Reducing the electrolyzer size inevitably decreases the percentage of energy allocated to hydrogen production. However, even in the absence of a storage system, the production levels remain significant. Ultimately, the choice of configuration depends on the goal of minimizing hydrogen production costs while balancing the system's scalability and efficiency. This analysis provides valuable insights into designing PV–hydrogen systems optimized for economic and operational performance.

The findings offer key insights for optimizing PV–hydrogen systems from both technical and economic perspectives:

- Electrolyzer Utilization: A larger electrolyzer (2 MW) is underutilized, working at nominal power only occasionally and remaining inactive nearly half the time. Downsizing improves efficiency and utilization but reduces total hydrogen.
- Energy Storage: Expanding storage capacity yields diminishing returns in hydrogen production, particularly for larger electrolyzers, highlighting the need for balanced storage sizing tailored to specific contexts.
- Production Variability: Hydrogen production varies widely, from 26 kg/day in winter to 375 kg/day in summer, with energy export peaking at 3300 kWh during high solar generation. Effective management of this variability is critical.
- Economic Viability: Minimizing grid energy export and prioritizing hydrogen production improve economic performance, with configurations ensuring at least 50% of PV energy supports hydrogen generation showing better results. From an economic perspective, optimizing electrolyzer and storage sizes significantly reduces the Levelized Cost of Hydrogen (LCOH), with the best configuration achieving a minimum LCOH of 5.868 €/kg. The cost analysis indicates that the photovoltaic system and electrolyzer

are the primary contributors to LCOH, accounting for 45% and 35.7%, respectively. A sensitivity analysis shows that with a hydrogen selling price of 8 €/kg, the system could achieve payback within 9 years and generate a positive NPV of 3.5 M€ over its lifetime.

Overall, the study underscores the importance of balancing PV generation, electrolyzer size, and storage capacity to enhance system efficiency and achieve operational goals.

While the analysis is centered on this particular scale, the proposed methodology and findings have a broader conceptual significance. The framework can be adapted to systems of different sizes without losing generality, offering flexibility for various applications and scaling requirements. While our current work focuses on technical and general economic feasibility, the inclusion of lifecycle environmental impact analysis is indeed a valuable addition. Environmental impacts of PV modules, batteries, and other components would provide a more general holistic perspective.

In conclusion, while reducing hydrogen production costs is technically feasible through system optimization, achieving economic sustainability depends on competitive hydrogen pricing and supportive policies. Future research should explore strategies to mitigate production variability, integrate other renewable sources, and analyze scalability for broader energy network integration.

From a more general perspective, systems like the one analyzed in this study could be adapted to integrate other renewable energy sources, such as wind or hydropower. These resources could complement photovoltaic generation by mitigating variability and enhancing overall system reliability. For instance, wind energy could provide a steady contribution during periods of low solar availability, while hydropower might offer dispatchable energy to stabilize operations. By enabling the integration of diverse renewable resources, hybrid systems like the one proposed hold significant promise for supporting the energy transition and achieving a more balanced and resilient renewable energy network.

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

Symbols and Abbreviations

The following abbreviations are used in this manuscript:

C_{proj}	Project costs [€]
CAPEX	Capital expenditure [€]
CF	Cash flow

E	Energy [kWh]
Hd	Irradiance [kWh/(m^2 day)]
Hyd	Reference cost of hydrogen [€/kg]
lc,id	Specific work for compression, ideal value [kJ/kg]
lc,real	Specific work for compression, real value [kJ/kg]
LCCA	Life cycle cost analysis
LCOH	Levelized cost of hydrogen [€/kg]
M	Mass [kg]
n_{hours}	Number of hours
NPV	Net present value [€]
O&M	Operation and management
OPEX	Operational expenditure [€]
p	Pressure [bar]
P	Power [kW]
PV	Photovoltaic
R	Constant of the gas [J/kg K]
RH	Relative humidity
SC	Discharge rate limit [%]
T	Temperature [K]
η	Efficiency

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