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Economic Analysis of a Hydrogen Power Plant in the Portuguese Electricity Market

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Abstract: Hydrogen is regarded as a flexible energy carrier with multiple applications across several sectors. For instance, it can be used in industrial processes, transports, heating, and electrical power generation. Green hydrogen, produced from renewable sources, can have a crucial role in the pathway towards global decarbonization. However, the success of green hydrogen production ultimately depends on its economic sustainability. In this context, this work evaluates the economic performance of a hydrogen power plant participating in the electricity market and supplying multiple hydrogen consumers. The analysis includes technical and economical details of the main components of the hydrogen power plant. Its operation is simulated using six different scenarios, which admit the production of either grey or green hydrogen. The scenarios used for the analysis include data from the Iberian electricity market for the Portuguese hub. An important conclusion is that the combination of multiple services in a hydrogen power plant has a positive effect on its economic performance. However, as of today, consumers who would wish to acquire green hydrogen would have to be willing to pay higher prices to compensate for the shorter periods of operation of hydrogen power plants and for their intrinsic losses. Nonetheless, an increase in green hydrogen demand based on a greater environmental awareness can lead to the need to not only build more of these facilities, but also to integrate more services into them. This could promote the investment in hydrogen-related technologies and result in changes in capital and operating costs of key components of these plants, which are necessary to bring down production costs.

Keywords: economic analysis; green hydrogen production; hydrogen power plant; power-to-gas; renewable energy

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1. Introduction

1.1. Motivation and Background

The production and consumption of green hydrogen (H_2) are expected to contribute to the decarbonization of multiple sectors and, as such, it is part of the European Commission's pathway to a more sustainable and self-reliant Europe [1].

Portugal, as a member state of the European Union, presented its National Strategy for Hydrogen (EN-H_2) in 2020, which intends to promote the gradual introduction of H_2 in multiple sectors of the economy and is regarded as a strategic opportunity for the country to diversify and increase its security of energy supply [2]. Among the goals set in EN-H_2 through 2030 is the creation of 50 to 100 hydrogen refueling stations (HRS) in the national territory, reaching 2 GW to 2.5 GW of installed capacity in electrolysers and achieving an admixture of 10% to 15% of H_2 to natural gas (NG) in the NG network by volume [3]. This H_2 roadmap is in line with pursued environmental goals and decarbonization strategy, which also assumes the decommissioning of several thermal power plants in Portugal and Spain [4].

Currently, one of the main challenges faced by green hydrogen is its high production cost, making it noncompetitive with H_2 produced from fossil fuels, commercialized at around 1.5 EUR/kg, even if highly dependent on the price of NG. At the same time, the costs of grey H_2 with carbon capture and storage (CCS), less polluting, are around 2 EUR/kg [1]. However, due to technological development and a continuous decrease in the cost of renewable energy sources (RES), the price of green H_2 is expected to keep dropping and reach cost parity with grey H_2 within the next decade [5].

In this context, the penetration of hydrogen power plants (H_2PP) in the energy system capable of producing green hydrogen is expected to grow in the coming years [6]. They may be able to participate in multi-energy services, for instance, in selling green H_2 to different industries and customers. In addition, they might be able to participate in the energy and ancillary services markets, when required by the network operator or profitable. Therefore, techno and economic analysis for the strategic participation of H_2PP in the electricity market must be pursued.

1.2. Literature Review

Numerous studies and initiatives are being conducted to assess the technical and economic viability of hydrogen-based solutions.

The authors in [7] studied the cost of H_2 production and its impact on the Iberian electricity market (MIBEL). Different scenarios, based on the Portuguese and Spanish energy and climate plans, were assessed. The CEVESA simulator was used, analysing pessimistic and optimistic scenarios under the MIBEL. It was concluded that H_2 production can contribute to reducing spillages by raising demand in periods of higher non-dispatchable generation.

Alternatively, the authors in [8] performed multiple Monte Carlo simulations to estimate the costs of producing green H_2 in Poland as part of the Polish Hydrogen Strategy. Using large-scale H_2 production systems powered by onshore wind turbines and solar photovoltaic (PV) panels, current production costs were estimated to be between 6.37 EUR/kg and 13.48 EUR/kg. H_2 production costs for the next 30 years were also projected, resulting in estimated costs for 2030 between 2.33 EUR/kg and 4.30 EUR/kg, and between 1.23 EUR/kg and 2.03 EUR/kg for 2050.

In Mexico, the viability of a power-to-gas-to-power solution in a rural microgrid to replace diesel generators was examined [9]. The system was modelled using the Homer software, aiming to analyse the hydrogen storage strategy on a seasonal basis. More precisely, the strategy was to produce H_2 through an electrolyser from excess distributed energy resources (DER) during winter months, supplying it back to the grid via a fuel cell when the demand grows in summer. For the economic sensitivity analysis, multiple capital expenditure (CAPEX) and operational expenditure (OPEX) values were considered for the electrolyser, storage tank, and fuel cell. However, the use of H_2 for end uses other than electricity generation was not considered.

In Slovenia, the possibility of producing green H_2 in a hydropower station was studied, comparing its price with that of other sources of H_2 production [10], adding the possibility for the H_2PP to provide ancillary services, which leads to a higher profit. In addition, the competitiveness of green hydrogen within different sectors (industry, heat generation, transport, and mobility) was also analysed.

The authors in [11] focused on the assessment of an H_2PP with multiple clients. The electrolyser was powered by a wind farm and/or a PV power plant, supplying a stationary fuel cell, an HRS for fuel cell electric vehicles (FCEV), a biological hydrogen methanation (BHM) process, and the injection in the natural gas grid. It was assumed that the owner of the HRS oversees the H_2 compression system needed to supply the station and, as such, it was not included in the analysis. The influence of the energy source (a wind farm or PV plant) was examined, and it was concluded that the replacement of the wind farm by the PV plant leads to a reduction in H_2 production and a reduction in the H_2 surplus. Moreover, the economic feasibility was analysed through the levelized cost of hydrogen (LCOH). Before the inclusion of the BHM process, an LCOH lower than 7 EUR/kg was accomplished, and, with the introduction of the BHM, the LCOH was reduced to 5 EUR/kg. Subsequently, the LCOH was assessed in [12] for a decentralized HRS, used by forklifts, with on-site production. A sensitivity analysis of several aspects, such as electricity costs, investment expenses, and electrolyser's stack replacement costs, was conducted. The main results pointed out that an LCOH of 10.3 EUR/kg can be accomplished over a 20 year lifetime. It was added that, if capital costs were reduced by 80%, the LCOH would drop to 6.7 EUR/kg.

A techno-economic analysis of green H_2 production across multiple Italian regions was performed in [13]. The electrolysers were powered by electricity bought from the grid or by RES (wind, solar, and geothermal) through a power purchase agreement (PPA), with a price ranging from 50 EUR/MWh to 100 EUR/MWh. The produced H_2 was used in the mobility sector or injected into the natural gas grid. It was concluded that, depending on electricity prices, the LCOH would range from 6.90 EUR/kg to 9.85 EUR/kg.

In northern Denmark, there is an H_2PP project that exploits wind power surpluses to produce H_2 and balance grid demand [14]. The produced H_2 is supplied to a nearby industrial complex by pipeline or, alternatively, it is delivered by tube trailers to other industries and for clean transportation.

Finally, in [15], a multi-state model for electrolysers was presented that considers three states of operation (production, hot standby, and idle) instead of just two (production and idle). The produced H_2 supplies an HRS, which includes a compression stage and a dispenser. The multi-state model was tested with data from an existing installation, being compared with the two states model. The assessed scenarios considered different H_2 demands, multiple H_2 prices, different wholesale market electricity prices, and distinct efficiencies for the electrolyser. The results show that the multi-state model leads to a reduction in H_2 production costs.

One of the common conclusions derived from these studies is that a reduction in the components' cost is still necessary for these plants to be competitive [12]. Table 1 presents an overview and comparison of the main characteristics and services provided by different H_2PP studies in the literature. It is noteworthy that most studies focus on providing a single service for the H_2 produced, which significantly constrains the flexibility of this energy vector in multi-energy systems.

Table 1. Summary of the services found in the literature review and in the present paper.

Reference	Production	Fuel Cell	Industrial Feedstock	NG Mix	HRS	Transport	BHM
[7]	✓			unspecified			
[8]	✓			unspecified			
[9]	✓	✓					
[10]	✓		✓	✓	✓		
[11]	✓	✓		✓	✓		✓
[12]	✓	✓			✓		
[13]	✓			✓	✓		
[14]	✓		✓		✓	✓	
[15]	✓				✓		
The proposed work	✓	✓		✓	✓	✓	

1.3. Main Contributions

The present work studies the economic feasibility of a megawatt-scale H_2PP participating in the MIBEL and supplying different H_2 customers, combining the main services described in the literature review. To the best of our knowledge, the present work is one of the most complete works regarding the multi-service criteria for the operation of an H_2PP.

To provide meaningful analysis, the economic operation of the H_2PP is simulated across multiple scenarios, considering the actual and futuristic (green) generation conditions of the power system. Furthermore, factors such as maintenance and operating costs, depreciation rate, and corporate taxes are included in the calculation of the financial indicators used. It was also assumed that the construction of the facility is financed by a loan with a certain interest rate. The main contributions of this paper are threefold:

- Propose a mathematical energy model for an H_2PP, including all the main components;
- Simulate the participation of an H_2PP in the Iberian electricity market—Portuguese pole—under different scenarios while selling H_2 to multiple customers;
- Analyse the economic viability of an investment in an H_2PP and the achieved H_2 prices in different scenarios.

1.4. Paper Organization

In addition to this introductory section, the paper is structured as follows. The H_2PP framework for multi-service provision is presented in Section 2, and its operating model is mathematically formulated in Section 3. Constraints related to customer demand are also included in the model. Next, in Section 4, the main technical characteristics of the plant are described, the customers are detailed, the simulation scenarios are presented, and the economic analysis for each case is performed. Finally, Section 5 assembles the main conclusions drawn from this work.

2. Hydrogen Power Plant Framework

2.1. Design of a Hydrogen Power Plant

Typically, an H_2PP is composed of several components, such as: (i) the electrolyser to extract H_2 from water, (ii) storage tanks to store the produced hydrogen, and (iii) stationary fuel cells to generate electricity from H_2. In addition to being used to produce electricity, hydrogen has other uses. For instance, it can be (i) mixed and burned with natural gas to decrease CO_2 emissions, (ii) consumed by vehicles (H_2 cars, buses, forklifts, etc.), or (iii) used in industrial processes [16].

In this perspective, the H_2PP envisioned for this study is equipped with an electrolyser, a storage tank, a fuel cell, and two different compressors, needed to supply specific customers, as depicted in Figure 1.

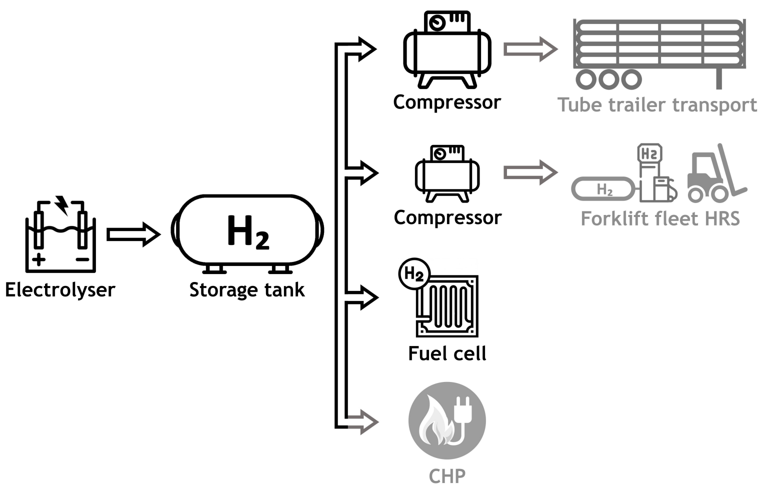

Figure 1. Diagram of a hydrogen power plant and its related provided services.

The expected customers are a nearby facility using a combined heat and power (CHP) microturbine fed with a mix of H_2 and natural gas, an HRS used by a forklift fleet, and a tube trailer that transports hydrogen to a customer farther away. The H_2 to be supplied to the forklift fleet and to the tube trailer is compressed using the two available compressors.

2.2. Operation and Management Modelling

The operation and management of the H_2PP consist of a day-ahead dispatch for assessing when the H_2PP is producing, storing, and selling H_2 to the different customers, according to the prices they are willing to pay for the different services. In this scope, the proposed H_2PP operation and management model, as well as the economic analysis, consists of three main steps, represented in Figure 2.

First, it starts by gathering the prices of the energy market and information related to renewable and non-renewable generation for each hour of the day, while the technical details of the H_2PP and the H_2 demand of its customers are also specified. Next, in the second step, the day-ahead optimization problem is solved, yielding the results regarding the energy consumed, stored, and produced by the H_2PP, the amount of H_2 sold to the customers, and the expected revenue for each day. In this step, the goal is to maximize the profit of the H_2PP, as described in Section 3. Finally, in the last step, the economic analysis is performed for the expected lifetime of the H_2PP, with several financial metrics being computed. An economic analysis is performed to assess the economic viability of the H_2PP.

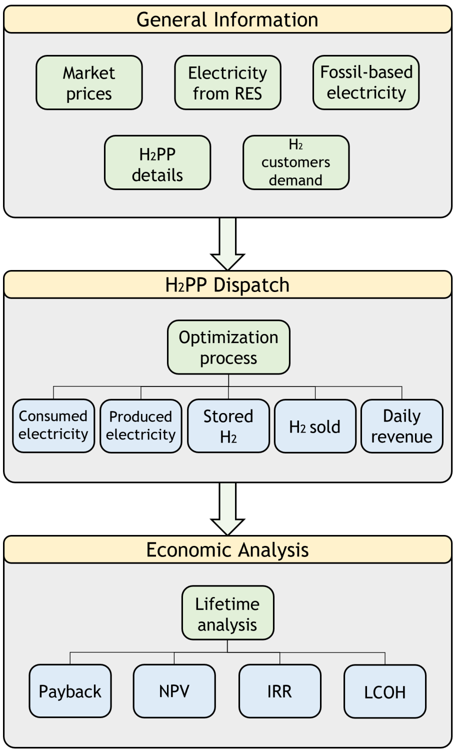

Figure 2. Overview of the H_2PP's technical and economic analysis.

3. Mathematical Formulation

The optimization model proposed aims to emulate the strategic operation of an H_2PP considering its participation in multi-services on a day-ahead basis. The problem aims to maximize the profit of the H_2PP operator under strategic participation in different services.

The H_2PP operation problem is modelled as a mixed-integer linear programming optimization problem. Objective function (1) includes:

$$max.\ f = \sum_{t=1}^{T} \Big[- P_{(t)}^{ELEC} \cdot \pi_{e(t)}^{B} + P_{(t)}^{FC} \cdot \pi_{e(t)}^{S} + m_{H_2(t)}^{CHP} \cdot \pi_{H_2}^{CHP} + m_{H_2(t)}^{FL} \cdot \pi_{H_2}^{FL} + m_{H_2(t)}^{TRSP} \cdot \pi_{H_2}^{TRSP} - P_{(t)}^{FL\,CP} \cdot \pi_{e(t)}^{B} - P_{(t)}^{TRSP\,CP} \cdot \pi_{e(t)}^{B} \Big] - m_{H_2(24)}^{+} \cdot \pi_{H_2}^{+} + m_{H_2(24)}^{-} \cdot \pi_{H_2}^{-} \quad (1)$$

where, for each interval $t \in T$, $P^{ELEC}_{(t)}$ is the electricity consumed by the electrolyser and $\pi^{B}_{e(t)}$ is the price at which the H_2PP buys electricity from the market, $P^{FC}_{(t)}$ is the electricity produced by the fuel cell and $\pi^{S}_{e(t)}$ is the price at which it sells electricity to the market, $m^{CHP}_{H_2(t)}$ is the mass of H_2 consumed by the CHP and $\pi^{CHP}_{H_2}$ is the price it pays per unit of H_2 to the H_2PP operator. In addition, $m^{FL}_{H_2(t)}$ is the mass of H_2 sold to the forklift fleet and $\pi^{FL}_{H_2}$ is the price the fleet pays per unit of H_2; $m^{TRSP}_{H_2(t)}$ is the mass of H_2 loaded into the tube trailer in each period and $\pi^{TRSP}_{H_2}$ is the price the trailer operator pays per unit of H_2; $P^{FL\ CP}_{(t)}$ is the electricity consumed by the forklift fleet compressor and $P^{FL\ TRSP}_{(t)}$ is the electricity consumed by the trailer compressor; $m^{+}_{H_2(24)}$ is the amount of H_2 in the tank above a pre-determined set point at the last interval and $\pi^{+}_{H_2}$ is the penalty factor for being above the set point; and $+m^{-}_{H_2(24)}$ is the amount of H_2 in the tank below the same set point at the last interval and $\pi^{-}_{H_2}$ is the penalty factor by being below it.

The H_2 produced by the electrolyser in each period [17], in kilograms, is given by (2):

$$m^{ELEC}_{H_2(t)} = \frac{P^{ELEC}_{(t)} \cdot \eta^{ELEC}}{HHV_{H_2}} \tag{2}$$

where $P^{ELEC}_{(t)}$ is the electricity it consumes, η^{ELEC} is its efficiency, and HHV_{H_2} is the higher heating value (HHV) of H_2 (39.4 kWh/kg [18]). The electrolyser has to operate between a minimum and maximum power, defined by:

$$P^{ELEC}_{(t)} \geq P^{ELEC}_{min} \cdot B^{ELEC}_{(t)} \tag{3}$$

$$P^{ELEC}_{(t)} \leq P^{ELEC}_{max} \cdot B^{ELEC}_{(t)} \tag{4}$$

where P^{ELEC}_{min} and P^{ELEC}_{max} are the minimum and maximum power and $B^{ELEC}_{(t)}$ is a binary variable that indicates whether it is turned on or off (on: $B^{ELEC}_{(t)}$=1, off: $B^{ELEC}_{(t)}$=0).

The H_2 consumed by the fuel cell, in kilograms, is given by [17]:

$$m^{FC}_{H_2(t)} = \frac{P^{FC}_{(t)}}{\eta^{FC} \cdot HHV_{H_2}} \tag{5}$$

where η^{FC} is the fuel cell efficiency. Similarly to the electrolyser, the fuel cell also has to operate between a minimum and maximum power:

$$P^{FC}_{(t)} \geq P^{FC}_{min} \cdot B^{FC}_{(t)} \tag{6}$$

$$P^{FC}_{(t)} \leq P^{FC}_{max} \cdot B^{FC}_{(t)} \tag{7}$$

where P^{FC}_{min} and P^{FC}_{max} are the minimum and maximum power and $B^{FC}_{(t)}$ is a binary variable that indicates whether the device is turned on or off. Equation (8) ensures the electrolyser and fuel cell are not turned on simultaneously:

$$B^{ELEC}_{(t)} + B^{FC}_{(t)} \leq 1 \tag{8}$$

Regarding the customers of the H_2PP, for each period, the CHP microturbine has a certain maximum H_2 demand, meaning it can be supplied with a H_2 mass between 0 and an upper limit:

$$0 \leq m^{CHP}_{H_2(t)} \leq m^{CHP}_{H_2\ req(t)} \tag{9}$$

where $m^{CHP}_{H_2\,req(t)}$ is the maximum H_2 required by the CHP. Likewise, the forklift fleet also has a certain maximum H_2 demand for each period t:

$$0 \leq m^{FL}_{H_2(t)} \leq m^{FL}_{H_2\,req(t)} \tag{10}$$

where $m^{FL}_{H_2\,req(t)}$ is the maximum H_2 required by the fleet.

Regarding the corresponding compressor, (11) specifies the amount of energy consumed by the device in each interval, and (12) restricts the gas flow rate:

$$P^{FL\,CP}_{(t)} = P^{FL\,CP} \cdot m^{FL}_{H_2(t)} \tag{11}$$

$$0 \leq m^{FL}_{H_2(t)} \leq m^{FL\,CP}_{H_2 max} \tag{12}$$

where $P^{FL\,CP}$ is the energy consumed by this compressor for each unit of mass of H_2 and $m^{FL\,CP}_{H_2 max}$ is its maximum compression rate.

The process of supplying H_2 to the tube trailer follows additional constraints. This happens because this trailer must either be completely filled or not filled at all. In addition, the filling procedure must take place in consecutive hours. Equation (13) is the trailer's balance equation, which ensures whether the trailer is filled up to its maximum capacity.

$$\sum_{t=1}^{T} m^{TRSP}_{H_2(t)} \cdot B^{TRSP}_{(t)} = m^{TT}_{H_2} \cdot B^{TT} \tag{13}$$

where $B^{TRSP}_{(t)}$ is a binary variable indicating whether H_2 is loaded to the tube trailer in that period or not, $m^{TT}_{H_2}$ is the total capacity of the trailer, and B^{TT} is a binary variable indicating whether it is to be completely refilled or not at all.

Equation (14) ensures the trailer refilling process does not exceed the acceptable time.

$$\sum_{t=1}^{T} B^{TRSP}_{(t)} \leq T_{Rfl} \tag{14}$$

where T_{Rfl} is the acceptable refilling time. Equations (15) and (16), adapted from [19], assure the refilling process is done across consecutive periods.

$$\begin{gathered} \sum_{n=t}^{k+T_{Rfl}-1} B^{TRSP}_{(n)} \geq T_{Rfl}\left[B^{TRSP}_{(t)} - B^{TRSP}_{(t-1)}\right], \\ \forall t = 1 \cdots T - T_{Rfl} + 1 \end{gathered} \tag{15}$$

$$\begin{gathered} \sum_{n=t}^{T} \left\{B^{TRSP}_{(n)} - \left[B^{TRSP}_{(t)} - B^{TRSP}_{(t-1)}\right]\right\} \geq 0, \\ \forall t = T - T_{Rfl} + 2 \cdots T \end{gathered} \tag{16}$$

Again, the compressor is modelled by two expressions given by

$$P^{TRSP\,CP}_{(t)} = P^{TRSP\,CP} \cdot m^{TRSP}_{H_2(t)} \tag{17}$$

$$0 \leq m^{TRSP}_{H_2(t)} \leq m^{TRSP\,CP}_{H_2 max} \tag{18}$$

where $P^{TRSP\,CP}$ is the energy consumed by this compressor for each unit of mass of H_2 and $m^{TRSP\,CP}_{H_2 max}$ is its maximum compression rate.

For each period of time, the H_2 mass inside the H_2PP storage tank is given by

$$\begin{gathered} m^{Tank}_{H_2(t)} = m^{Tank}_{H_2(t-1)} + m^{ELEC}_{H_2(t)} - m^{FC}_{H_2(t)} \\ - m^{CHP}_{H_2(t)} - m^{FL}_{H_2(t)} - m^{TRSP}_{H_2(t)} \end{gathered} \tag{19}$$

where $m_{H_2(t)}^{Tank}$ is the H_2 mass in the tank at the end of the interval t and $m_{H_2(t-1)}^{Tank}$ is the mass in the tank at the end of the previous interval.

In order to avoid an irrational depletion of the stored H_2 at the last period of each day (t = 24), another constraint is added:

$$m_{H_2\ (24)}^{Tank} - m_{H_2\ SP}^{Tank} = m_{H_2(24)}^{+} - m_{H_2(24)}^{-} \tag{20}$$

where $m_{H_2\ SP}^{Tank}$ is a predefined H_2 set point and $m_{H_2(24)}^{+}$ and $+m_{H_2(24)}^{-}$ are non-negative variables that represent, respectively, the amount of H_2 in the tank above and below that set point. The penalty factors $\pi_{H_2}^{+}$ and $\pi_{H_2}^{-}$ noted in (1) are calculated according to

$$\pi_{H_2}^{+} = \pi_{H_2}^{-} = \overline{\pi_{e(t)}^{B_{td}}} - \overline{\pi_{e(t)}^{B_{tmw}}} \tag{21}$$

where $\overline{\pi_{e(t)}^{B_{td}}}$ is the average of $\pi_{e(t)}^{B}$ on that day and $\overline{\pi_{e(t)}^{B_{tmw}}}$ is the expected average of $\pi_{e(t)}^{B}$ for the next day. Hence, the penalty factors are defined as the difference between today's and tomorrow's price of the electricity consumed by the electrolyser. Combined with these factors, constraint (20) acts upon the optimization process, ensuring the tank is either above the set point if the price of the electricity will rise the next day or below the set point if the price of electricity will drop. Note that the daily revenue is determined post-optimization using the objective function without penalties.

4. Case Study

This section presents a case study illustrating the application of the developed model for the multi-service participation of an H_2PP. The simulations were carried out with the programming environment MATLAB [20] and with the mathematical modelling system GAMS [21]. MATLAB was used as an interface for handling data with GAMS, while GAMS performed and solved the mixed integer non-linear programming model using the DICOPT (DIscrete and Continuous OPTimizer) solver [22].

4.1. Case Characterization

The H_2PP has a 1.5 MW electrolyser, a 65 m^3 tank, a 240 kW fuel cell, and two compressors. Their main technical and economic details are provided in Table 2 and Table 3, respectively.

Table 2. Technical characteristics of the H_2PP equipment.

Device	Parameter	Electrolyser
Electrolyser	Nominal power Power range Efficiency	1.5 MW 10–100% [23] 70% [17]
Fuel cell	Nominal power Power range Efficiency	240 kW 10–100% [17] 50% [23]
Tank	Volume Maximum capacity Minimum capacity Maximum pressure	65 m^3 [17] 170 kg [17] 17 kg [24] 30 bar [17]
Forklift compressor	Nominal power Suction pressure Discharge pressure Maximum flow rate Energy consumption	13.5 kW 30 bar 500 bar 5 kg/h 2.7 kWh/kg [23]

Table 2. *Cont.*

Device	Parameter	Electrolyser
Tube trailer compressor	Nominal power Suction pressure Discharge pressure Maximum flow rate Energy consumption	85 kW 30 bar 200 bar 50 kg/h 1.7 kWh/kg [23]

Table 3. Economic characteristics of the H_2PP equipment.

Device	Parameter	Electrolyser
Electrolyser	Full system lifespan Stack lifespan CAPEX OPEX Stack replacement	20 years [25] 85,000 h [25] EUR 900,000 [26] 45,000 EUR/year [27] EUR 315,000 [25]
Fuel cell	Lifespan CAPEX OPEX	20 years [23] EUR 480,000 [23] EUR 9600 [27]
Tank	Lifespan CAPEX OPEX	30–40 years [23] EUR 68,000 [27] EUR 1360 [27]
Forklift compressor	Lifespan CAPEX OPEX	30 years [28] EUR 125,000 [27] 2500 EUR/year [27]
Tube trailer compressor	Lifespan CAPEX OPEX	30 years [28] EUR 850,000 [27] 17,000 EUR/year [27]

This H_2PP is expected to be built over 2 years [29] and operate for 20 years, as in [11]. In addition, it is assumed that 80% of the initial necessary capital is borrowed. Investment details used in the economic analysis are provided in Table 4.

Because the project has a time horizon of 22 years, a payback period of 13 years is expected in the economic analysis, a value that is cited in other works involving hydrogen production and RES [30,31].

Table 4. Parameters used in the economic analysis.

Parameter	Value
Project lifetime Plant lifetime Construction time	22 years 20 years 2 years [29]
Inflation Depreciation rate Discount rate Corporate income tax	2% [32] 5% [29] 10% [33] 21% [34]
Own capital Borrowed capital Interest rate	20% 80% 2% [35]

Regarding the different services/customers that the H_2PP can provide, the following are detailed. The first H_2 customer has a 600 kW CHP microturbine, based on the one presented in [36]. This equipment, usually powered by natural gas, can operate on an H_2/NG mix, with a total H_2 volume of up to 10%. Its load curve (based on [37]) and maximum H_2 and natural gas demand are given in Table 5.

Table 5. CHP hourly electrical output and fuel intake for a H_2 volumetric percentage of 10%.

Time Range	Output	H_2 Intake		NG Intake	
[hh:mm]	[kWh]	[kg/h]	[kWh/h]	[kg/h]	[kWh/h]
00:00–04:59	90	0.257	8.547	20.17	264.2
05:00–05:59	300	0.856	28.49	67.22	880.6
06:00–16:59	600	1.711	56.98	134.4	1761
17:00–17:59	300	0.856	28.49	67.22	880.6
18:00–23:59	90	0.257	8.547	20.17	264.2
Total	8190	23.36	777.8	1835	24,040

The second H_2 customer owns a fleet of hydrogen-powered forklifts that operates in a large logistics centre. The H_2 is supplied to their refueling station using a pipeline and a 30/500 bar compressor. In this case, their maximum H_2 demand is 5 kg/h (120 kg/day), enough to power around 120 of these vehicles for a full working day [23].

Finally, the third H_2 customer is a distribution company, responsible for shipping fuel between producers and end users. Among other vehicles, this company operates a hydrogen tube trailer. It is assumed that the customer intends to buy 300 kg of H_2 each day to fill a 200 bar tube trailer, to be loaded in 6 h [38], meaning the compressor must have a flow rate of at least 50 kg/h.

The price at which H_2 is sold to these customers shall cover, at least, energy expenses related to production and compression. In this way, the minimum prices for each customer are given by

$$\pi^{CHP}_{H_2\,min} = \frac{\overline{\pi^B_e}}{\eta^{ELEC}} \cdot HHV_{H_2} \tag{22}$$

$$\pi^{FL}_{H_2\,min} = \frac{\overline{\pi^B_e}}{\eta^{ELEC}} \cdot HHV_{H_2} + \overline{\pi^B_e} \cdot P^{FL\,CP} \tag{23}$$

$$\pi^{TRSP}_{H_2\,min} = \frac{\overline{\pi^B_e}}{\eta^{ELEC}} \cdot HHV_{H_2} + \overline{\pi^B_e} \cdot P^{TRSP\,CP} \tag{24}$$

where $\overline{\pi^B_e}$ is the average price of electricity. However, to cover other expenses (cost of equipment, maintenance, depreciation, loan interest, etc.) and make the plant profitable, the prices obtained using (22)–(24) must be further increased, as shown below.

In this analysis, in each period, the fuel cell is set to sell energy to the grid at a price equal to MIBEL's price for the same hour, meaning that $\pi^S_{e(t)} = \pi^B_{e(t)}$.

For the economic analysis, the operation of the H_2PP is simulated using six different scenarios: Grey17–20, Green17–20, PPA17–20, Grey21, Green21, and PPA21. When the designation Grey is used, it is accepted to have the production of grey H_2. In the Green scenarios, the electrolyser can only be turned on when no fossil-fuel power plants are producing energy in the Portuguese system. Furthermore, for these scenarios, the H_2PP buys electricity from the Iberian energy market (MIBEL), paying the corresponding hourly market clearing price. Note that it is assumed that the H_2PP follows a price-taker behaviour. The PPA scenarios assume the H_2 power plant obtains its energy from a large wind farm, with which it signed a long-term PPA for a price of 86 EUR/MWh. As only wind energy is used, exclusively green H_2 is produced.

The scenarios are also split in accordance with time spans. When the suffix 17–20 is used, the operation of the H_2PP is simulated in the years between 2017 and 2020. The result of those 4 years is then combined, creating an "average year" to be replicated 20 times, covering the plant's lifetime.

Conversely, when the suffix 21 is used, the operation of the power plant is simulated for the year 2021, using the corresponding data regarding energy prices and usage of renewable and non-renewable sources (needed for the Green scenarios). To cover the project's lifetime this year is, as before, replicated twenty times.

There are two main reasons to separate the year 2021 from the others. First, due to the ongoing global energy crisis, the price of electricity in the MIBEL suffered a significant increase [39]. And second, with the decommissioning of a large coal-fired power plant in January 2021 in Portugal [40], the number of hours available to generate green H_2 has significantly increased in the Portuguese power system.

4.2. Results

The described scenarios were simulated, and an economic analysis was carried out for each one. The required prices to reach a payback period of 13 years are shown in Table 6.

Table 6. H_2 prices for each client, to reach a 13-year payback.

Scenarios	$\pi_{H_2}^{CHP}$ [EUR/kg]	$\pi_{H_2}^{FL}$ [EUR/kg]	$\pi_{H_2}^{TRSP}$ [EUR/kg]
Grey17–20	5.092	5.337	5.243
Green17–20	31.79	33.32	32.73
PPA17–20	7.357	7.711	7.575
Grey21	7.336	7.689	7.553
Green21	13.93	14.60	14.34
PPA21	7.349	7.703	7.567

Regarding the 17–20 scenarios, the most favourable is Grey17–20, with prices around 5.0 to 5.4 EUR/kg. This result was expected because, in this situation, energy costs are low (when compared to 2021), and the electrolyser is not just limited to hours of RES generation. However, in Green17–20, hydrogen prices are substantially higher, surpassing 30 EUR/kg, as the hours available for the plant to produce H_2 are quite limited. In PPA17–20, the prices are closer to those of Grey17–20, between 7 and 8 EUR/kg.

For the 2021 scenarios, as before, production of grey H_2 leads to lower prices in Grey21, between 7 and 8 EUR/kg, but higher than those of Grey17–20 due to the rise in electricity costs. In contrast, the RES scenario experienced a positive evolution due to the decrease in non-renewable sources, with Green21 presenting prices in the range of 13–15 EUR/kg. In the PPA scenario, production is not affected by energy costs, meaning that prices do not face major changes, remaining between 7 and 8 EUR/kg.

The variation of the payback period with the price of H_2 for each client, across these six different settings, is presented in Figures 3–5. It can be seen how, in all the given scenarios, as the prices increase, the payback period drops at a decreasing rate.

To complement the price analysis, the possibility of a more uncertain payback period is considered, varying between 11 and 15 years, that is, 13 ± 2 years. A situation such as this could arise from uncertain factors, such as sudden changes in a hypothetical hydrogen market, which would lead to a need to adjust H_2 prices to ensure this H_2PP remains competitive. The prices leading to a payback of 11 and 15 years are marked in Figures 3–5 and listed in Table 7.

Table 7. H_2 prices for each client to reach a payback period of 11 years and 15 years.

Scenarios	$\pi_{H_2}^{CHP}$ [EUR/kg]		$\pi_{H_2}^{FL}$ [EUR/kg]		$\pi_{H_2}^{TRSP}$ [EUR/kg]	
	11 Years	15 Years	11 Years	15 Years	11 Years	15 Years
Grey17–20	5.220	4.991	5.471	5.231	5.375	5.139
Green17–20	33.27	30.74	34.83	32.22	34.21	31.65
PPA17–20	7.479	7.259	7.838	7.606	7.701	7.474
Grey21	7.508	7.197	7.869	7.543	7.730	7.411
Green21	14.45	13.52	15.14	14.19	14.88	13.93
PPA21	7.469	7.249	7.828	7.598	7.692	7.464

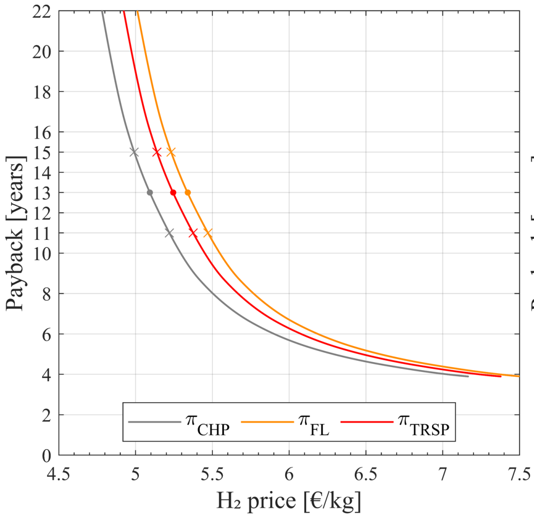

Figure 3. Grey scenarios—relation between payback period and H_2 price for each customer for scenario Grey17–20 (**left**) and Grey21 (**right**).

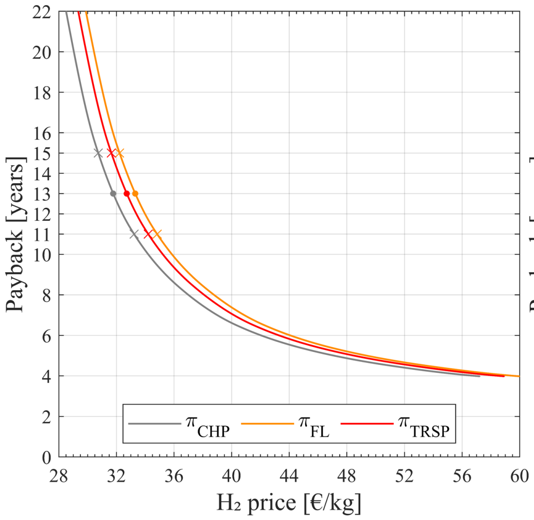

Figure 4. Green scenarios—relation between payback period and H_2 price for each customer for scenario Green17–20 (**left**) and Green21 (**right**).

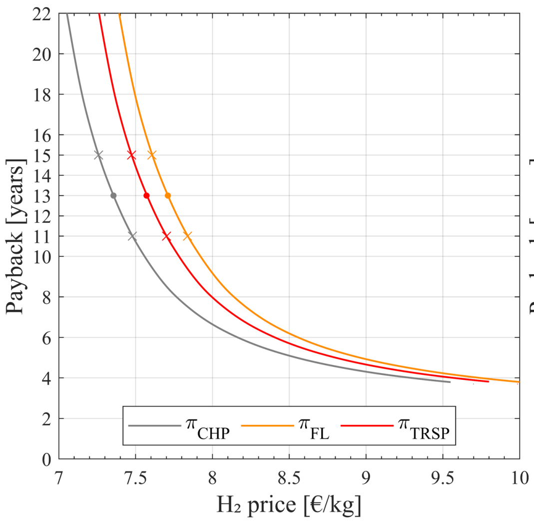

Figure 5. PPA scenarios—relation between payback period and H_2 price for each customer for scenario PPA17–20 (**left**) and PPA21 (**right**).

For the prices leading to a payback of 13 years, a set of economic metrics used to assess the performance of the investment were computed, namely: net present value (NPV), internal return rate (IRR), and levelised cost of hydrogen (LCOH). The LCOH is calculated following Equation (25), in EUR/kg [17]. It results from adding all energy expenses, capital expenses, and operational expenses, and dividing by the amount of H_2 produced.

$$LCOH = \frac{\sum_{i=0}^{2}\left[CAPEX_i \cdot \left(\frac{1}{1+d}\right)^i + OPEX_i \cdot \left(\frac{1+e}{1+d}\right)^i + Energy\,costs_i \cdot \left(\frac{1+e}{1+d}\right)^i\right]}{\sum_{i=1}^{2}\left[Produced\ H_2\ mass_i \cdot \left(\frac{1+e}{1+d}\right)^i\right]} \tag{25}$$

where i is the year, d is the discount rate, and e is the annual inflation rate.

The results, given in Table 8, line up with the aforesaid analysis. As before, Grey17–20 is the most beneficial setting and Green17–20 is the least promising. The main differences are in the LCOH, which varies substantially between scenarios. The NPV reaches similar values, close to 315,000 EUR in all scenarios but the Green ones, where it is lower. The difference in return rates is negligible.

Table 8. Economic metrics (NPV, IRR, and LCOH) corresponding to a 13-year payback.

Scenarios	NPV [EUR]	IRR [%]	LCOH [EUR/kg]
Grey17–20	315,075	15.99	4.72
Green17–20	253,426	15.29	21.7
PPA17–20	312,990	15.95	7.59
Grey21	313,611	15.96	6.88
Green21	252,662	15.28	10.6
PPA21	314,818	15.99	7.57

The average yearly values of hydrogen produced by the electrolyser and consumed by the fuel cell and the customers are provided in Table 9. The results show how the increase in energy prices from Grey17–20 to Grey21 led to a decrease in H_2 generation and commercialization. In addition, the lack of production in Green17–20 and its significant boost in Green21 are evidenced. The PPA scenarios show similar results, with the difference that, as the production costs do not change, but the price at which the fuel cell sells energy increases from PPA17–20 to PPA21, it injects more energy into the grid.

Table 9 shows how the fuel cell, which was set to sell energy to the grid at market price, is barely activated. This situation, worsened by its low efficiency (50%), can be solved by increasing the energy selling price. This solution, which was not implemented in this work, can be triggered by the H_2PP operator, who shall control this price to boost the competitiveness of the fuel cell in the energy market.

Table 9. Average yearly H_2 production and consumption, for a 13-year payback.

Scenarios	Electrolyser Production [kg]	Fuel Cell Consumption [kg]	CHP Consumption [kg]	Forklift Fleet Consumption [kg]	Tube Trailer Consumption [kg]
Grey17–20	156,259	0	6796	40,102	109,200
Green17–20	11,955	0	635	4606	6675
PPA17–20	157,575	0	7962	40,113	109,500
Grey21	111,313	245	5429	31,238	74,400
Green21	31,496	41.6	1646	11,208	186,00
PPA21	159,315	1820	7882	40,113	109,500

5. Conclusions

This work performed a techno-economic analysis of an H_2PP considering its participation in the electricity market, as well as the possibility of providing H_2 to different services/customers. The strategic operation on the use of the produced H_2 was also analysed.

The results show that the production of electrolytic grey H_2 is the most economic so far, resulting in an LCOH between 4.72 EUR/kg and 6.88 EUR/kg, for a payback of 13 years. However, those scenarios are not the most pertinent, as the hydrogen economy of the future must be centred on RES. Regarding the production of green H_2, when the renewable energy to power the H_2PP was purchased at market price, the LCOH varied from 10.6 EUR/kg to 21.7 EUR/kg. When the energy was obtained through a PPA, the LCOH was lower and more stable, ranging from 7.57 EUR/kg to 7.59 EUR/kg. Still, even in the most beneficial scenarios, the achieved prices for green H_2 are very high when compared to grey H_2. Furthermore, these prices are far too high when compared to the costs of grey H_2 obtained from fossil sources, with a price between 1.5 EUR/kg and 2 EUR/kg.

In line with the literature, it can be concluded that H_2PP based on RES is not yet cost-competitive, but its environmental benefits are clear. In addition, the fuel cell did not prove to be of significant use to the H_2PP. Nevertheless, it is clear that green H_2 has the potential to contribute to the decarbonization of power systems in the coming years.

Future work will focus on: (i) studying a more detailed model of the H_2PP capabilities, for instance, the electrolyser; (ii) assessing the impact of H_2PP in the power grid, and (iii) studying the strategic participation of the H_2PP in the energy and ancillary services market.

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Abbreviations

The following abbreviations are used in this manuscript.

BHM	Biological Hydrogen Methanation
CAPEX	Capital Expenditure
CCS	Carbon Capture and Storage
CHP	Combined Heat and Power
DER	Distributed Energy Resources
DICOPT	DIscrete and Continuous OPTimizer
FC	Fuel Cell
FCEV	Fuel Cell Electric Vehicles
GAMS	General Algebraic Modelling Language
H_2	Hydrogen
H_2PP	Hydrogen Power Plant
HRS	Hydrogen Refuelling Station
IRR	Internal Rate of Return

LCOH	Levelized Cost of Hydrogen
MDPI	Multidisciplinary Digital Publishing Institute
MIBEL	Mercado Ibérico de Eletricidade
NG	Natural Gas
NPV	Net Present Value
OPEX	Operational Expenditure
PPA	Power Purchase Agreement
PV	Photovoltaic
RES	Renewable Energy Source

Nomenclature

The main notation used in this paper is stated here for quick reference.

Sets	
T	Set of time periods
Indexes	
t	Index for time periods (e.g., 60 min (1.0))
Parameters	
η	Efficiency
π	Price
HHV	Higher Heating Value
Decision variables	
B	Binary Variable
m	Mass
P	Active Power
Subscripts and Superscripts	
Ch	Charge Process
CHP	Combined Heat and Power
CP	Compressor
Dch	Discharge Process
$ELEC$	Electrolyser
FC	Fuel Cell
FL	Forklift
H_2	Hydrogen
Max	Upper Bound Limit
Min	Lower Bound Limit
NG	Natural Gas
$TRSP$	Transport
TT	Tube Trailer

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