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Techno-economic model and feasibility assessment of green hydrogen projects based on electrolysis supplied by photovoltaic PPAs

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HIGHLIGHTS

- Technical and economic feasibility assessment of green hydrogen projects.
- An operational multi-state modeling of electrolyzers is proposed.
- PPAs facilitate the decarbonization of hydrogen production facilities.
- Sensitivity analysis to PPA prices, network tariffs exemption and public funding rates.

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ABSTRACT

The use of hydrogen produced from renewable energy enables the reduction of greenhouse gas (GHG) emissions pursued in different international strategies. The use of power-purchase agreements (PPAs) to supply renewable electricity to hydrogen production plants is an approach that can improve the feasibility of projects. This paper presents a model applicable to hydrogen projects regarding the technical and economic perspective and applies it to the Spanish case, where pioneering projects are taking place via photovoltaic PPAs. The results show that PPAs are an enabling mechanism for sustaining green hydrogen projects.

Introduction

In the last decade, climate change mitigation has become a priority at the international level. The Paris Agreement was a decisive milestone reached in 2015 at the Conference of Parties (COP) 21, where 196 countries endorsed a treaty committed to limiting global warming well below 2 Celsius degrees in comparison with pre-industrial levels [1]. This objective was recently updated at COP 26, with a target of maintaining the 1.5 Celsius degrees increase limit between 2030 and 2050 [2]. To tackle this problem, strategies and action

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Abbreviations

ATR	(Access Tariff Rate)
CAPEX	(Capital Expenditures)
CFADS	(Cashflows Available for Debt Service)
CFW	(Cashflows avaluable for promoters)
CNMC	(Spanish National Markets and Competition Commission)
CSUT	(Cold Start-up Time)
D	(Debt)
DA	(Depreciation and Amortization)
DS	(Debt Service)
DSCR	(Debt Service Coverage Ratio)
Econsmkt	(Electricity consumed from wholesale electricity market)
EPC	(Engineering, Procurement and Construction)
EprodPPA	(Electricity produced with the PPA)
Esold	(Energy sold to wholesale electricity market)
GHG	(Greenhouse Gases)
GR	(Gearing Ratio)
HPTW	(Hydrogen Production in Time Window)
IP	(Interest Payment)
IRR	(Rate of Return)
LCOH	(Levelized cost of Hydrogen)
MPL	(Minimum Partial Load)
NPV	(Net Present Value)
O&M	(Operation and Maintenance)
OPEX	(Operational Expenditures)
PPAs	(Power Purchase Agreements)
Psold	(hourly price of wholesale electricity market)
RE	(Renewable Energy)
PEM	(Polymer Electrolyte Membrane)
PH	(Hydrogen Produced)
PP	(Principal Payment)
PPPA	(Price of Power Purchase Agreement)
PWE	(Nominal Power of Electrolysis System)
SPH	(Selling Price of Hydrogen)
SPV	(Special Purpose Vehicle)
SL	(System Licetime)
SR	(Stack Replacement)
TR	(Tax Rate)
TW	(Time Window)
WCn	(Water Consumption)

plans have focused on increasing the renewable energy (RE) share, increasing energy efficiency, and/or limiting GHG emissions [3–5].

In this scenario, hydrogen appears as a promising energy vector that can accommodate the fluctuations and unpredictability of RE sources [6,7]. Particularly, hydrogen can be produced through electrolysis from RE electricity and then be stored and transported at a large scale with limited energy losses through a wide variety of alternatives. In addition, the potential end uses of hydrogen are also vast. This includes applications in industry, transport, and energy, which benefits the aggregation of demand in each project location [8]. Besides, significant technology improvements have taken place in recent years mainly regarding reductions in the capital expenditures (CAPEX) of critical equipment in hydrogen production facilities (particularly in the case of electrolysis systems). Another improvement is the possibility to upscale hydrogen production facilities and benefit from economies of scale [9,10]. Indeed, currently more than 30 countries have launched or are developing their national hydrogen strategies [11]. Most of these strategies include targets related to the deployment of a hydrogen production infrastructure based on electrolysis from RE.

Currently, one of the most promising approaches for producing hydrogen from RE is the use of power-purchase agreements (PPAs) [12–14]. This scheme allows for the use of renewable electricity without a physical connection, which alleviates issues related to the co-location of the electrolysis plant near RE sources. In particular, the direct physical connection of RE sources to electrolysis systems in off-grid configurations requires managing the unpredictability and fluctuating character of the electricity supply. This also involves the need to include electrochemical storage devices (batteries) to cover the unavailability of the RE supply, which will mean a higher project CAPEX. Furthermore, the impact of a direct connection of RE generation on electrolysis systems is unknown in terms of the possible accelerated degradation of the stack due to fluctuations in the electricity supply [15,16]. On the other hand, the use of self-consumption formulas to connect both the RE generation units and the electrolysis systems to the grid and establish a balance behind the meter implies a physical co-location of these assets. This implies the need for the end user to allocate space not only for the electrolyzer but also the RE plant, which may not be possible in many industry driven projects [17]. Moreover, setting a PPA with an RE plant means that the hydrogen production plant promoter can avoid the CAPEX of that investment, which both eliminates the risk related to the deployment of the renewable electricity facility and maintains long-term stability in the electricity prices. The latter is especially important in the current situation where wholesale electricity market prices are highly volatile, in such a way that the PPA becomes an instrument to provide security in the electricity supply prices. In addition, as PPAs are bilateral contracts between a supplier and a consumer, the conditions can be established in agreeable terms for both parties [18,19]. In particular, if appropriately modelled and sized, financial PPAs 'as produced' are interesting for electricity consumers (e.g., hydrogen production plants) to access low-cost green energy as compared with other PPA schemes.

Despite the benefits presented above, green hydrogen production projects with PPAs involve a certain complexity. Depending on the type of agreement, price set, energy volumes, and characteristics of the RE plant behind the electricity supply, the feasibility of the hydrogen project can vary considerably. In this context, this paper proposes a techno-economic model of hydrogen production plant projects when supplied with PPAs to be used for feasibility assessment. The paper is structured as follows: section 2 defines the techno-economic model of hydrogen production plant projects with PPAs. Section 3 provides a definition of the case study applied to a hydrogen production plant receiving electricity from a financial PPA 'as produced.' This section also lists the necessary scenarios to validate the model. Following this, section 4 presents the results obtained for each scenario, including a discussion on the findings obtained. Lastly, section 5 provides the main conclusions and contributions of the publication based on the information provided in sections 3 and 4.

Techno-economic model of green hydrogen production projects with PPAs

Definition and purpose of the model

The conceptual representation of the energy assets in an electrolysis plant supplied with a renewable PPA includes the elements, connections, and contractual relationships depicted in Fig. 1. This comprises the RE plant, which does not need to be close to the hydrogen production plant and will sell the electricity produced ($EprodPPA_h$) every hour h to the wholesale electricity market. This also includes the hydrogen production plant, which will consume electricity from the wholesale electricity market ($Econsmkt_h$). If there were not a PPA in place, this would be the standard connection of an electrolysis plant to the grid to purchase energy from the wholesale electricity market.

However, due to the settlement of a financial PPA between these two entities (see the green line in Fig. 1), the RE plant (producer) will sell the energy to the wholesale electricity market. In the same way, the hydrogen production facility (consumer) will purchase the electricity from the wholesale market at the hourly prices marked by the pool. Following this, the differences in price will be resolved (normally every month) between the agents to maintain the agreed price of the PPA ($PPPA$). This is done so that for every hour, every entity will need to issue or receive a payment to the other, which maintains the $PPPA$ value. In particular, for the case of a financial PPA 'as produced,' the consumer will be obliged to purchase an agreed percentage, or all energy produced in the RE plant at the fixed price $PPPA$ to the producer with hourly matching. Such obligation is normally imposed through a 'take or pay' clause in the contract and will typically lead to a lower priced PPA as compared with an 'as consumed' modality, which requires the delivery of green electricity to the consumer meeting the demand side schedule. Although the price set will tend to be lower, the RE plant benefits by securing the project cashflows: whenever there is electricity production, the consumer will purchase it. For the consumer, most of the annualized costs of the hydrogen production plant are relative to the electricity supply. Thus, the techno-economic model presented in this paper considers a financial 'as produced' PPA with 'take or pay' clause. Additionally, access to green hydrogen certificates may require real time matching of hydrogen production with a dedicated RE supply ('as produced' PPA), which will provide additional revenues. Finally, it is also important to consider that there will be moments when the electricity volume purchased from the PPA exceeds the demand from the electrolysis plant. In this case, the hydrogen production plant operator will be able to sell that electricity $Esold_h$ to the wholesale electricity market or other consumers. Conversely, as the PPA may not cover all the demand from the hydrogen production plant, so it will sometimes be required to purchase energy from the wholesale electricity market, $Econsmkt_h$, in addition to $EprodPPA_h$.

The PPA supply can be modelled as the RE plant production forecast for every hour $EprodPPA_h$ which in the case of photovoltaic (PV) energy can be predicted accurately within several days [20,21]. Thus, this paper builds on a PV PPA, where the volume of energy is delivered in central hours of the day when wholesale electricity market prices are high. However, the model can be also applied to other RE sources such as wind power.

However, the wholesale electricity market prices forecast must also be considered to resolve the balance of the PPA, accommodate the excess energy purchased ($Esold_h$), and provide additional electricity in case it is demanded in certain moments ($Econsmkt_h$). Today, most developed countries present liberalized wholesale electricity markets where prices are determined by the demand and supply bids. Normally, these bids are ordered and determine a marginal price that is equal for all consumers [22]. When considering historical data and seasonality as well as information from future markets and local RE and fossil fuel shares in the energy generation mix, it is possible to accurately predict the structure of these prices in time windows of several days [23,24].

The hydrogen production plant will be comprised of the electrolysis facility in addition to compression and storage equipment, as depicted in Fig. 2. The distribution chain, which normally belongs to another actor that usually handles this part, is left out of the scope of this model.

In relation to the electrolyzer, for the two most mature technologies (alkaline and polymer electrolyte membrane, PEM), it is supplied in a container that includes the stack (i.e.,

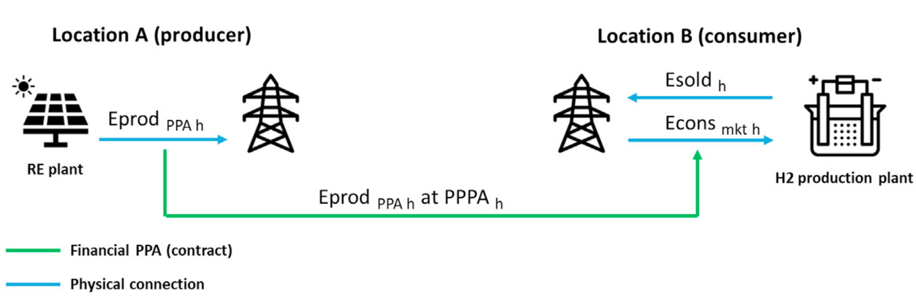

Fig. 1 – [Single fitting] Conceptual representation of the energy flows between the hydrogen production plant and the RE plant setting the PPA.

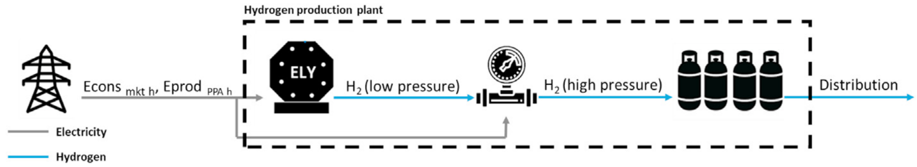

Fig. 2 – [Single fitting] Scope and energy flows in the hydrogen production plant.

core element producing hydrogen from a DC power supply), balance of the plant (i.e., assembly required to keep the stack at stable pressure and temperature values), and rectifier (i.e., the element required to convert the electricity supply from AC to DC) [25,26].

In terms of hydrogen production with the electrolyzer, the different states of operation and their limitations need to be considered [26–28]. Particularly, the electrolyzer will produce hydrogen when it is in 'generation' state between a minimum partial load (*MPL*) and its nominal power. For the operator to keep the electrolyzer warm and pressurized waiting for attractive price signals in the short term, it is also possible to use the 'hot-standby' state, which will demand a certain energy consumption but will reach 'generation' with a fast response. Finally, it may be attractive to turn off the unit if the hydrogen demand has been met or because it is not interesting to produce for several hours. This is possible through the 'off' state, which implies a neglectable energy consumption. However, there is a long response time to transition from 'off' to 'generation' since the unit is at an ambient temperature and depressurized. It is also required to consider that many transitions from 'off' to 'generation' (so-called 'cold starts') may imply an accelerated degradation of the stack.

Regarding the compressor, the most commonly used systems are hydraulic compresssors due to their capacity to manage high pressures (in relation to piston compressors) and maturity (as compared with membrane or metal hydrides compression) [29]. These systems require electricity to increase the pressure of the hydrogen and deliver it to the end users or storage devices. For some pressure increases, one may need to allocate several compressors in succession, while it is also possible to use several of them in parallel to increase the flow rate.

In relation to hydrogen storage, it can be made in the form a buffer wherein a fleet of hydrogen trailers are refilled and distributed to the end users depending on the location of the consumption point. Hydrogen storage tanks can be sized to match the prediction of the RE resource, the prices of electricity, and the unavailability periods of the electrolyzer, which might span several days.

In this way, the scope of the model is the hydrogen project, being the PPA contract supply and the electricity grid inputs for it, as presented above. Currently, hydrogen production projects with electrolysis are evolving from fully funded initiatives in the framework of R&D and innovation programs to bankable initiatives [30,31]. Due to the large scale of many of these projects and investment size, project finance approaches are already being used to manage the contributions of different actors within the initiative. In these cases, different actors intervene to fund the CAPEX, which may include sponsors or promoters (allocating equity to the project), banks and loaners (allocating debt to the project), or funding bodies (contributing to reducing the CAPEX of the EPC process). In order to build the project, a special purpose vehicle (SPV) can be created to aggregate the contributions from these actors [32], centralize the distribution of benefits from the project, and separate the financial part of the project from sponsors' accounting balances. In this scenario, the model will consider the elements assessed when evaluating the feasibility of these projects while also accounting for the optimal dispatch of the hydrogen production plant in terms of maximization of the net present value (*NPV*) of cashflows.

Mathematical formulation of the model

As introduced in the previous section, the main parameter used to assess the feasibility of the project is the *NPV* of cashflows, which needs to be higher than zero to produce a positive business case for the project promoters. The mathematical formulation is equal to the sum of the cashflows available for the promoters CFW_y reached at each year y in project lifetime L brought to the present moment through the discount rate d minus the CAPEX invested prior to start of operations (year 0):

$$\mathrm{NPV} = -CAPEX_0 + \sum_{y=0}^{L} \frac{CFW_y}{(1+d)^y} \tag{1}$$

For the discount rate calculation, the value will depend on the minimum rate of return demanded by the project promoters, and it is possible to estimate it via the weighted average cost of capital (WACC) or by comparing with similar investments done. The $CAPEX_0$ will be the sum of all costs relative to carrying out the engineering, procurement, and construction (EPC) of the hydrogen production plant prior to plant operation, including the commissioning in year 0. This CAPEX includes the electrolyzer, which may include the cost of replacement of stacks expected during project lifetime, if negotiated with the supplier or integrated into the maintenance contract ($CAPEX_{WE}$). It also includes the compressor ($CAPEX_{Comp}$), the hydrogen storage equipment ($CAPEX_{H2S}$), the civil works ($CAPEX_{CW}$), design and engineering works ($CAPEX_{DE}$), the global plant control station for automation and monitoring purposes ($CAPEX_{CS}$), and the cost associated with interconnection, integration, and commissioning prior to operation ($CAPEX_{IC}$). If there is public funding for the project, it will normally be provided as a grant with a certain funding rate *FR* covering the above-mentioned elements. This reduces the initial investment, which contributes to reducing CAPEX. Additionally, if there is debt supporting the payment, it will cover a percentage of the investment (gearing ratio, *GR*) that promoters will not fund in year 0, as it happens with public funding. This is represented in the following equation:

$$CAPEX_0 = (1-GR)\cdot(1-FR)\cdot(CAPEX_{WE} + CAPEX_{Comp} + CAPEX_{H2S} + CAPEX_{CW} + CAPEX_{CS} + CAPEX_{DE} + CAPEX_{IC}) \tag{2}$$

Regarding the CFW_y, it is equal to the revenues, R_y, minus the operational expenses, $OPEX_y$ (operating cashflow), the CAPEX (which will be zero as of the start of operations in a hydrogen project), the taxes, TAX_y and the payment of the debt service DS_y if there are lenders involved in the initiative. CFW_y apply as of starting year of operation of the plant:

$$CFW_y = R_y - OPEX_y - CAPEX_y - TAX_y - DS_y \tag{3}$$

The debt service yearly payment is composed of the interest and the principal, which are distributed along the tenor, dt, or period (in years) fixed by the lending institution to return the debt. A normal scheme is the 'annuity' modality, which will consist of a yearly fixed debt payment (usually paid every six months in practice). In this modality, DS is a constant amount calculated as per the following equation, where i is the interest rate:

$$DS = \frac{D}{\frac{1-(1+i)^{-dt}}{i}} \tag{4}$$

As can be observed, the numerator is the debt D paid by the lending entity at the beginning of the project:

$$D = GR\cdot(1-FR)\cdot(CAPEX_{WE} + CAPEX_{Comp} + CAPEX_{H2S} + CAPEX_{CW} + CAPEX_{CS} + CAPEX_{IC} + CAPEX_{DE}) \tag{5}$$

Following this, the principal payment PP_y is calculated as DS minus the interest payment IP_y. At the same time, IP_y is calculated as the remaining debt in each year multiplied per i, following the equations below. However, while the 'annuity' is the most common formula, there are other payment schemes as well as variations that can be included by the lending entity.

$$IP_1 = i\cdot D \tag{6}$$

$$IP_y = i\cdot\left(D - \sum_{y=1}^{y} PP_{y-1}\right) \tag{7}$$

$$PP_y = DS - IP_y \tag{8}$$

Returning to eq (3), TAX_y values are relative to the payable taxes associated with the project activities. They are calculated as revenues R_y minus operational expenses $OPEX_y$, interests IP_y, depreciation and amortization DA_y and multiplied per the applicable tax rate TR dependent on local conditions:

$$TAX_y = TR(R_y - OPEX_y - IP_y - DA_y \tag{9}$$

DA_y can be calculated following different accountancy practices, where the easiest possibility is to follow linear depreciation. This means a constant depreciation equal to the project CAPEX within the lifetime L of the project.

Continuing with eq (3), R_y is equal to the value streams captured within the project. In the case of the present model, these streams will come from selling the hydrogen produced every year PH_y plus the excess electricity from the PPA 'as produced' sold to the wholesale electricity market $PPAsold_y$:

$$R_y = PH_y + PPAsold_y \tag{10}$$

The $OPEX_y$, however, is equal to the aggregation of contracts relative to the operation phase. This includes the maintenance of the electrolyzer ($OPEXWE_y$), excluding the cost of stack replacements SR required in certain years during project lifetime. This cost can be added to the $CAPEX_{WE}$ in agreement with the manufacturer to avoid a high investment in the middle of the project duration. These contracts also include the maintenance of the compressor ($OPEXComp_y$) and hydrogen storage ($OPEXH2S_y$) as well as the cost of managing the facility ($OPEXFac_y$). In addition, it is required to consider the electricity supply costs ES_y and the water consumed for the generation of hydrogen in the electrolyzer, WC_y:

$$OPEX_y = OPEXWE_y + OPEXComp_y + OPEXH2S_y + OPEXFac_y + ES_y + WC_y + SR_y \tag{11}$$

If the overall objective is to maximize the NPV presented in eq (1), then the focus will be on reaching the highest possible CFW_y (as $CAPEX_0$ is constant and dependent on the project design, while the discount rate d is the target return rate desired by the promoters and is also a fixed parameter). Considering eqs (3)–(11) and eliminating the constant parameters that cannot be subject to optimization to maximize CFW_y (for example, constant OPEX), the following are variable concepts VC_y dependent on the operation of the electrolysis system:

$$VC_y = PH_y + PPAsold_y - ES_y - WC_y - SR_y \tag{12}$$

Then, the optimal dispatch of the plant will be obtained by minimizing the negative value of VC_y:

$$\min\left(-PH_y - PPAsold_y + ES_y + WC_y + SR_y\right) \tag{13}$$

As illustrated in section 2.1, it is possible to anticipate hourly price structures of wholesale electricity markets as well as RE production in a time window TW of several days. Moreover, it is possible to size the hydrogen storage with a capacity matching the full production of the electrolysis system within such a timeframe. At the same time, it is possible to know the hydrogen demand determining the required production of the electrolyzer for TW. In this way, it is possible to obtain the optimal dispatch of the electrolysis plant and the renewable PPA by decomposing the values in eq (13) in 1-h timescales and eliminating constant values. The selection of an hourly time step in the model is based on the fact that wholesale market electricity prices vary with this frequency, which is needed to establish the price balance between renewable producer and electrolysis facility (consumer). This hourly cost function is obtained as shown in eq (14), where the hourly variables to be calculated include the states of operation of the electrolyzer in each hour h (a_h, b_h, and c_h) and its load factor, r_h. As the energy consumed and sold from the wholesale market ($Econsmkt_h$ and $Esold_h$, respectively) for each hour influence also on the costs and revenues, those are also variables to be calculated, as it will be explained in the next paragraphs:

$$min \sum_{y=1}^{TW} (Cb \cdot r_h \cdot b_h) + SRC\ .\ b_h + (Cab \cdot r_h \cdot b_h \cdot a_{h-1}) + (Ccb \cdot b_h \cdot c_{h-1}) + Econs\ mkt_h \cdot (P\ mkt_h + ATR_h) \cdot b_h + Econs\ mkt_h \cdot (P\ mkt_h + ATR_h) \cdot c_h - (Esold_h \cdot Psold_h) \tag{14}$$

In this equation, the first term includes *Cb*, which is a constant equal to the hourly water consumption of the electrolyzer *WCn* (EUR) minus the remuneration for the gas produced in an hour *HPn* (kg/h), being both constant values calculated at nominal power of the electrolyzer:

$$Cb = WCn - HPn \cdot SPH \tag{15}$$

$$WCn = CW\ .WCR\ .\ \frac{PWE}{\eta} \tag{16}$$

$$HPn = \frac{PWE}{\eta} \tag{17}$$

Here, *SPH* is the selling price of the hydrogen produced (EUR/kg), *PWE* is the power of the machine (MW), η is the efficiency (electrolyzer plus compressor) in MWh/kg of gas generated, *WCR* is the water required in production (L/kg of gas), and *CW* is the cost of water (EUR/m^3). In eq (14), r represents the load factor of the electrolyzer in hour h (real variable between 0 and 1), and b is an integer variable taking a value of 1 if the machine is in production and 0 if not in hour h.

The second term in eq (14) considers the cost of degradation *SRC*, which occurs in the stack in production. Due to the current lack of available information, *SRC* can be expressed as the cost of stack replacement *SR* divided between the expected lifetime of this component *SL*, which will take place with the electrolyzer in production (b_h equal to 1). It is important to highlight that if the number of required stack replacements are calculated at the beginning of the project and included as part of CAPEX, then it is not required to consider this parameter.

$$SRC = \frac{SR}{SL} \tag{18}$$

In third place, *Cab* accounts for the lack of hydrogen production when the electrolyzer is in cold start, and it is required to transition towards hydrogen production in hour h. This is the reason why b_h multiplies a_{h-1} and r_h in eq (14). Specifically, a is a Boolean taking a value of 1 in case the electrolyzer is in 'off' state and r_h considers the hydrogen production in that hour. To calculate the remuneration for hydrogen lost due to cold start-up, it is possible to divide the production in 1 h at a nominal rate by the cold start-up time *CSUT* of the electrolyzer. *CSUT* is expressed as the percentage of hours required to carry out the cold start-up.

$$Cab = CSUT \cdot HPn \cdot SPH \tag{19}$$

The fourth term in eq (14) addresses the cost associated with the lack of hydrogen production when the electrolyzer is in 'hot-standby' to start producing hydrogen in hour h. This is the reason why b_h multiplies c_{h-1}, where c is a Boolean which takes a value of 1 in case the electrolyzer is in 'hot-standby' state. Here, Ccb is calculated through *HSUT*, or the time expressed as the percentage of hours required to perform hot start-up (standby to production):

$$Ccb = HSUT \cdot HPn \cdot SPH \tag{20}$$

In fifth and sixth place, eq (14) includes the additional electricity imported from the wholesale electricity market in hour h $Econsmkt_h$ for both production and hot stand-by states. The hourly energy cost is the sum of the market price $P\ mkt_h$ and the network access tariff rate ATR_h. . These terms are multiplied by b_h and c_h since the electrolyzer consumes energy in both cases.

Finally, the electricity sold to the electricity grid in case the PPA delivers more electricity than required is included in the last term in eq (14). Here, $Esold_h$ is a real variable including the electricity exports to the wholesale electricity market at each hourly price $Psold_h$.

In addition to the minimization function, the following equations need to be considered as restrictions to calculate the optimal dispatch of the plant:

$$\sum_{h=1}^{TW} HPn \cdot r_h \cdot b_h = HPTW \tag{21}$$

$$Icons_{mkt\ h} + Isold_h \leq 1 \forall h \tag{22}$$

$$EconsPPA_h + Econsmkt_h - PWE \cdot r_h - Esold_h - E_c \cdot c_h = 0 \forall h \tag{23}$$

$$a_h + b_h + c_h = 1 \forall h \tag{24}$$

$$\sum_{h=1}^{TW} b_h \cdot a_{h-1} \leq N \tag{25}$$

$$c_h \cdot a_{h-1} = 0 \forall h \tag{26}$$

$$a_h \cdot c_{h-1} = 0 \forall h \tag{27}$$

$$r_h - b_h \leq 0 \forall h \tag{28}$$

$$-r_h + MPL \cdot b_h \leq 0 \forall h \tag{29}$$

$$0 \leq r_h \leq 1 \forall h \tag{30}$$

$$Esold_h \leq Isold_h \cdot EconsPPA_h \forall h \tag{31}$$

$$Econsmkt_h \leq Icons_{mkt\ h} \cdot PWE \cdot r_h \forall h \tag{32}$$

Eq (21) imposes the hydrogen production desired for the established time window, *HPTW*.

The next equation includes $Icons_{mkt\ h}$, an integer variable that takes a value equal to 1 when there is electricity consumption from the wholesale market and 0 if not. This equation also considers $Isold_h$, an integer variable that takes a value equal to 1 if there is electricity sold to the wholesale market and 0 if not. Thus, in the same hour, it is possible to either consume or sell electricity to the wholesale market but not do both.

Furthermore, Eq (23) introduces the energy balance that needs to be maintained every hour. Since the PPA is 'take or pay', $EconsPPA_h$ is equal to the hourly RE production forecasted for hour h consumed from the PPA, and E_c is the energy consumption of the electrolyzer in a standby state. The remaining variables have been already presented.

Eq (24) establishes an hourly restriction for the electrolysis system to remain in only one operation state each hour. Eq (25) limits the number of possible cold start-ups during TW, while Eq (26) and (27) restrict transitions from 'off' to 'hot-standby.' Eqs (28)–(30) impose that r_h is between minimum partial and nominal power of the electrolyzer if it is in production, while it will assume a value of 0 if it is in 'off' or 'hot-standby.'

Finally, Eq (31) imposes that it is not possible to sell more electricity than the consumption from the PPA to the market. Similarly, as per Eq (32), if energy is purchased to the spot market, the volume is always equal or less than the demand from the electrolyzer.

Eqs (14)–(32) constitute a mixed integer non-linear problem (MINLP), which can be resolved for each TW in y (where N is the number of time windows in the year). As anticipated previously in this section, the variables to be calculated are the states of operation of the electrolyzer (a_h, b_h, and c_h) for each hour and its load factor, r_h. Other variables include the energy consumed and sold from the wholesale market ($Econsmkt_h$ and $Esold_h$, respectively) and the respective boolean indicators $Icons_{mkt\ h}$ and $Isold_h$, required for the formulation of the problem. Once it is solved, it is possible to calculate the values in Eq (13) following the equations below:

$$-PH_y + WC_y = \sum_{n=1}^{N}\left(\sum_{h=1}^{TW} Cb\cdot r_h\cdot b_h\right) \tag{33}$$

$$PPAsold_y = \sum_{n=1}^{N}\left(\sum_{h=1}^{TW} Esold_h\cdot Psold_h\right) \tag{34}$$

$$ES_y = \sum_{n=1}^{N}\sum_{h=1}^{TW}(Cab\cdot r_h\cdot b_h\cdot a_{h-1}) + (Ccb\cdot b_h\cdot c_{h-1}) + Econs\,mkt_h\cdot(P\,mkt_h + ATR_h)\cdot b_h + Econs\,mkt_h\cdot(P\,mkt_h + ATR_h)\cdot c_h \tag{35}$$

$$SR_y = \sum_{n=1}^{N}\left(\sum_{h=1}^{TW} SRC\cdot\ b_h\right) \tag{36}$$

Following this, these values in Eqs (33)–(36) can be integrated with Eqs (1)–(11) to obtain the NPV and other ratios used to assess the feasibility of the project. To validate the model and obtain the most common ratios in a hydrogen project, Section 3 applies it to a case study and a series of scenarios.

Definition of the case study for the application of the model

The case study for validation of the model includes an infrastructure scope including the PV plant supplying the PPA 'as produced' and the hydrogen production plant (electrolysis, compression, and hydrogen storage sufficient to cover a TW). The values used to build the base case are presented in Tables 1–3 below [10,25,33–40]:

As it can be observed, the proposed case study is located in Spain, where the settlement of financial PPAs is common after the liberalization of the electricity market activities (Law 54/1997 replaced by Law 24/2013). As in other EU member states, in Spain the wholesale market electricity hourly prices are marginal and determined by the most expensive generation bid which allows delivering the required energy to the consumers (after ordering all the bids from lower to higher price). This hourly wholesale electricity market price is the one at which renewable producer will sell electricity and the same at which the consumer (electrolysis plant) will purchase it; however, these agents will allocate compensation payments (in one direction or another, so-called contracts for differences, CfD) so that the PPA price is always 35 EUR/MWh as detailed in Table 1. For instance, if the wholesale market electricity price is 50 EUR/MWh, then the renewable producer will pay 15 EUR/MWh delivered to the consumer so that they are both settled in the agreed 35 EUR/MWh figure. In Spain, the Nominated Electricity Market Operator (OMIE) is in charge of managing the wholesale electricity market exchanges, while the System Operator, Red Eléctrica de España (REE) will resolve all technical issues so that the security of supply is guaranteed.

With these input parameters, the model will be applied to the base case presented above as well as in the reference scenarios depicted in Table 4. The base case is scenario 5 in Table 4, where the following variations will be introduced:

- Presence of the PPA – When the PPA is in place (scenarios 1 to 9), additional electricity will be purchased at merchant price if the PPA does not meet the entire hydrogen demand. If there is no PPA (scenarios 10 to 12), all the electricity will be acquired in the wholesale electricity market.
- Hydrogen demand – The values of this demand are 500 Tn/yr (scenarios 1 to 3 and 10), 600 Tn/yr (scenarios 4 to 6 and 11), and 700 Tn/yr (scenarios 7 to 9 and 12).
- PV plant size – The values of peak power for the PV plant supplying the PPA will be 5, 10, or 15 MW depending on the scenario.

In addition to these scenarios, the following variations will be introduced in the course of the assessment in section 4:

Table 1 – Technical and economic of the PV plant supplying the PPA.

PV plant supplying the PPA	
Parameter	Value/description
PPA agreement	Financial, 'as produced' with 'take or pay' clause, hourly dispatch matching with load, 20 yrs
PPA price	35 EUR/MWh
Peak power	10,000 kW
Technology	Monocrystalline
Location	Spain
Latitude	39.7028010
Longitude	2.8676490
Azimuth	0°
Inclination	30°

Table 2 – Technical and economic characterization of hydrogen infrastructure in the production plant.

Hydrogen production plant		
	Parameter	Value/description
	Grid access point	5 MW, MV grid
WE	Nominal power, *PWE*	5 MW
	Technology	Alkaline
	Components in the container	MV/LV transformer, rectifier, stack, BOP
	Overall system efficiency	50 kWh/kg
	Output pressure	30 bar
	Hot-standby consumption, E_C/PWE	2% of nominal power
	Minimum partial load, *MPL*	10%
	System CAPEX, $CAPEX_{WE}$	1,100 EUR/kW
	System OPEX, $OPEXWE_y$	3% of CAPEX/yr
	Cost of stack replacements, *SR*	30% of $CAPEX_{WE}$ if stack lifetime exceeded in project duration
	Lifetime for stack replacement cost, *SL*	80,000 h
	Cost of water, *WC*	3.8 EUR/m^3
	Consumption of water to produce H2, *WCR*	15 L/kg
	Cold start-up time	20 min.
	Hot start-up time	30 s
Mechanical compressor (hydraulic)	System CAPEX, $CAPEX_{Comp}$	500 kEUR
	System OPEX	3% of CAPEX/yr
	Inlet hydrogen flow	100 kg/h (WE system at nominal power)
	Input pressure	30 bar
	Output pressure	250 bar
	Electricity consumption	2 kWh/kg of H2 compressed
Storage tanks	System CAPEX, $CAPEX_{H2S}$	2,000 kEUR
	System OPEX	3% of CAPEX/yr
	Storage capacity	5,000 kg of H2
	Storage pressure	250 bar
Other EPC and O&M costs	Plant surface	500 m^2
	Civil works costs, $CAPEX_{CW}$	950 EUR/m^2
	Engineering costs, $CAPEX_{DE}$	5% of ($CAPEX_{WE}$ + $CAPEX_{Comp}$ + $CAPEX_{H2S}$)/yr
	Control station, $CAPEX_{CS}$	5% of ($CAPEX_{WE}$ + $CAPEX_{Comp}$ + $CAPEX_{H2S}$)/yr
	Interconnexion and commissioning, $CAPEX_{IC}$	10% of ($CAPEX_{WE}$ + $CAPEX_{Comp}$ + $CAPEX_{H2S}$)/yr
	Facility O&M, $OPEXFac_y$	3% of ($CAPEX_{CW}$ + $CAPEX_{IC}$ + $CAPEX_{DE}$ + $CAPEX_{CS}$)/yr

Table 3 – Boundary conditions relative to the project.

Project boundary conditions	
Parameter	Value/description
Hydrogen demand	600 tonnes/yr
Hydrogen selling price	6 EUR/kg (at storage interface with customer's trucks/portable racks)
Project lifetime	20 yrs
Public funding	30% (grant to CAPEX)
Debt coverage	80% of non-granted CAPEX
Debt tenor	10 yrs
Repayment type	Annuity
Loan interest rate	3%
Equity coverage	20% of non-granted CAPEX
Discount rate	8% (minimum return rate expected for promoters)
Time window (dispatch)	3 days (predictability of wholesale electricity market prices structure and PPA production within this period of time)
Electricity supply contract	Pass-through contract indexed to wholesale electricity market
Electricity sold	Excess electricity from PPA sold at hourly electricity market prices (detracting grid export tax)
Year	2018 (applicable to hourly electricity prices, ATR, power access rate, electricity tax, grid export tax, and other charges forming the hourly price of electricity supply contract)
Assets depreciation	Linear with lifetime
Inflation	2%/yr

Table 4 – Boundary conditions relative to the project.

No.	PPA (Yes/No)	PPA price (EUR/MWh)	H2 demand (Tn/yr)	PV plant (MWp)
1	Yes	35	500	5
2	Yes	35	500	10
3	Yes	35	500	15
4	Yes	35	600	5
5	Yes	35	600	10
6	Yes	35	600	15
7	Yes	35	700	5
8	Yes	35	700	10
9	Yes	35	700	15
10	No	N.A.	500	N.A.
11	No	N.A.	600	N.A.
12	No	N.A.	700	N.A.

- PPA price – Scenarios 1 to 9 will be modified by introducing different PPA prices of 30 EUR/MWh and 40 EUR/MWh.
- ATR exemption – Access tariff rates are regulated costs included in electricity supply contracts. Their exemption will be applied to scenarios 1 to 12.
- Funding rate – The intensity of funding for grants to the CAPEX will be iterated between 30% and 100% to observe the benefits produced for scenarios 1, 5, and 9 (lowest PV plant size and hydrogen demand, base case and highest PV plant size, and hydrogen demand, respectively).

Results and discussion

Assessment of scenarios 1 to 12

This section presents the results obtained after the application of the model to the scenarios in Table 4. In order to solve the mixed integer non-linear problem (MINLP) described in section 2.2 and required to calculate the optimal dispatch of the plant, GAMS (General Algebraic Modeling System) software has been used, applying a branch-and-cut method to break the non-linear problem (NLP) model into subproblems.

Prior to the analysis of results of the different scenarios, the energy dispatch of the model is shown in Fig. 3 below for 72 h within a year in scenario 5 with the purpose of illustrating how the electrolysis plant operator can either purchase electricity from the grid and/or the PPA as well as how the PPA production can be sold to the electrolysis plant or to the wholesale electricity market:

Table 5 – Feasibility indicators obtained for each scenario.

No.	Levered IRR (%)	NPV (kEUR)	LCOH (EUR/kg)	LCOH (excl. grant) (EUR/kg)	Min. DSCR (1×)
1	1.65%	−1816	3.60	3.96	0.58
2	4.42%	−1022	3.52	3.88	0.69
3	4.25%	−1069	3.52	3.88	0.68
4	7.60%	−114	3.42	3.72	0.81
5	11.04%	858	3.33	3.63	0.93
6	11.26%	921	3.32	3.62	0.94
7	12.61%	1297	3.31	3.56	0.98
8	16.83%	2435	3.22	3.48	1.12
9	17.38%	2577	3.21	3.47	1.14
10	−2.94%	−3094	3.74	4.10	0.41
11	2.90%	−1458	3.54	3.84	0.63
12	7.64%	−103	3.41	3.67	0.82

As it can be observed, in order to maintain the electrolysis consumption required to produce the demanded hydrogen amount within the 72 h time window, the consumption from PV power is prioritized while additional electricity is imported from the grid in moments when the wholesale market prices are low (typically, in night periods, hours 1 to 5, 24 to 27 and 50 to 53 in the figure). When the PV production exceeds the maximum electrolysis power, the excess electricity is sold to the wholesale electricity market.

Table 5 presents the indicators used to evaluate the feasibility of the project in each scenario, including the following:

- Return rate *IRR* – This is the value of the discount rate *d* for which NPV is equal to zero in eq (1). It expresses the profitability of the project. If it is higher than the desired *d* value, the project is profitable, and NPV will be higher than zero.
- NPV – This value is calculated as per eq (1). If NPV is higher than zero, the project is profitable, as the IRR will be higher than *d*.
- Levelized cost of hydrogen *LCOH* (EUR/kg) – This is NPV of all project costs, brought to the present moment by using the discount rate *d* including $CAPEX_0$ (eq (2)) and $OPEX_y$ (eq

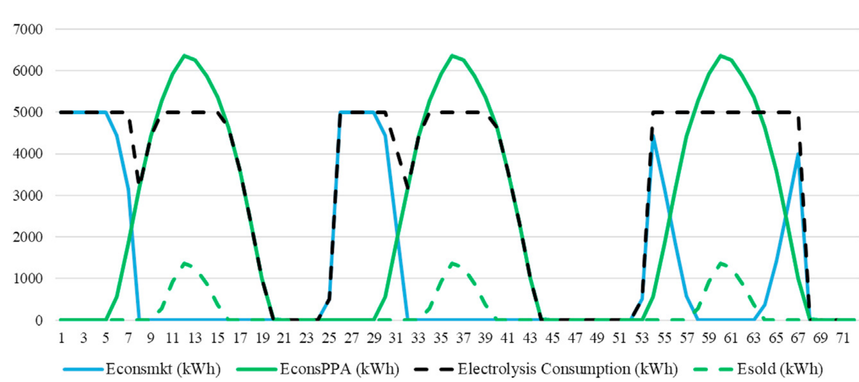

Fig. 3 – [Single fitting] 72 h sample of energy dispatch delivered by the model for scenario 5 including hourly values for *Econsmkt*, *EconsPPA*, Electrolysis Consumption and *Esold*, in kWh.

(11)) for the complete project duration, divided between the hydrogen produced yearly in project duration:

$$LCOH = \frac{-CAPEX_0 + \sum_{y=0}^{L} \frac{OPEX_y}{(1+d)^y}}{\sum_{y=0}^{L} (HP \cdot N)_y} \tag{37}$$

- *LCOH* excluding grant – This indicator considers the CAPEX in cases without funding for the project (only debt). It includes the $CAPEX_0$ considered in the standard LCOH calculation plus the grant (the rest will be debt).
- Minimum debt service coverage ratio *DSCR* – As explained before, it is required to pay for the debt service DS_y each year. To control this, the lending entity will measure that the cash flow available for the debt service $CFADS_y$ is higher than DS_y, as per Eqs (38) and (39). Normally, the lending entity will control that *DSCR* is higher than 1 for every year. Otherwise, the promoters will need to add equity or additional funds to cover DS_y, as shown below:

$$CFADS_y = R_y - OPEX_y - CAPEX_y - TAX_y \tag{38}$$

$$DSCR_y = \frac{CFADS_y}{DS_y} \tag{39}$$

It is important to highlight that all these indicators reflect feasibility for project promoters and are calculated against the equity invested in the project. Given that debt is provided by a lending entity and the grant is provided by a public institution, these elements are excluded from $CAPEX_0$, as eq (2) shows. Only the LCOH excluding grant is calculated to compare with the case where there was no public funding for the project, and the amount was instead covered with equity from the project promoters.

Table 5 shows that the presence of off takers willing to consume the hydrogen produced by the plant is a highly important factor, as scenarios 7 to 9 (700 tonnes/yr) reach higher IRR and lower LCOH values than scenarios 4 to 6 (600 tonnes/yr). However, scenarios 4 to 6 are more favorable than scenarios 1 to 3 (500 tonnes/yr demanded). Regarding the size of the PV plant to deliver the PPA 'as produced', in case it has the same size as the electrolysis system power (5 MW, scenarios 1, 4 and 7), then it is going to benefit the business case against the fully merchant case (scenario 10). In this way, a 5 MW PV plant is going to add less return than setting this agreement with a 10 MW plant (scenarios 2, 5 and 8). However, an agreement with a 15 MW plant is not going to produce sensible improvements in the return rate in relation to 10 MW. Particularly, case 9 is slightly more profitable than 8, as it occurs between scenarios 6 and 5 (with a lower increase). However, scenario 3 is less profitable than scenario 2. This is due to the fact that there is too much production from the PPA, exceeding the demand required from the electrolysis system. Then, due to the 'take or pay' condition of the contract, it is going to be required to sell the surplus energy to the grid. In many situations when this occurs, the price of the PPA is also higher than the hourly electricity market price, which results in the selling of excess electricity from the PPA for a price lower than the cost of its acquisition. This fact will impact the IRR more if the plant is under rather than overused (case 1 with 500 tonnes/yr required as compared with 4 and 7 with 600 and 700, respectively). Regarding the fully merchant scenarios where there is no PPA (scenarios 10 to 12), the results show that the incorporation of a solar PPA at 35 EUR/MWh always benefits the project. Here, scenarios 1 to 3 are more profitable than scenario 10, while 4 to 6 are more profitable than 11, and 7 to 9 are more profitable than 12. In addition to adding stability to the cashflows (as the energy cost is fixed against the volatility of wholesale electricity market hourly prices), the PPA means a higher return rate.

In terms of investment decisions, if the minimum discount rate to be reached by the project is 8%, it can be seen in Fig. 4 that the only positive cases are 5–9 (which have positive NPV and IRR higher than *d*). This means that the minimum hydrogen demand for a remuneration price of 6 EUR/kg needs to be at least around 600 tonnes/yr. Furthermore, if the PPA comes from a 5 MW PV plant, the hydrogen demand needs to be around 700 tonnes/yr.

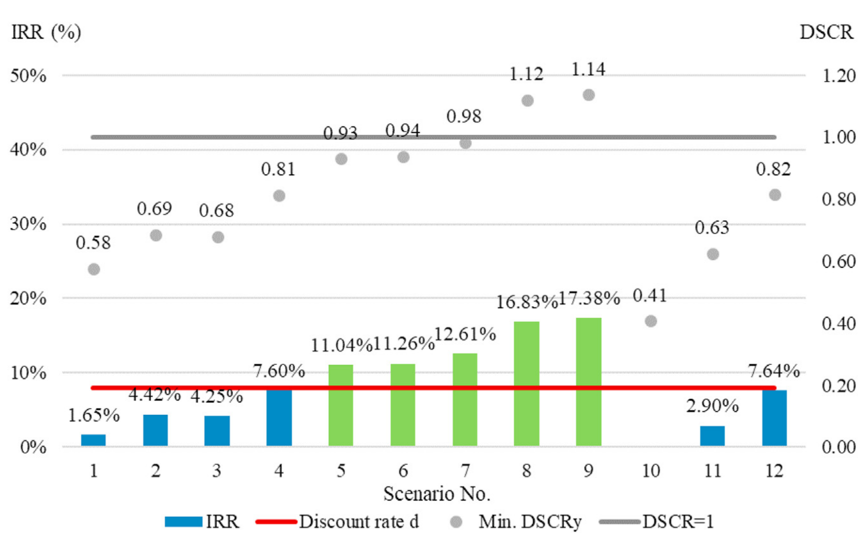

Fig. 4 – [Single fitting] IRR (%) in bars (left axis) and minimum $DSCR_y$ (grey dots, right axis) for scenarios 1 to 12.

Finally, regarding the LCOH, Fig. 5 highlights that the presence of funding is important to reduce it. Since CAPEX (which is the amount covered with a grant) has a higher impact in low demand cases (1–3), the reductions achieved through public funding range from 0.36 EUR/kg (scenarios 1 to 3 and 10) to 0.26 EUR/kg (scenarios 6 to 9 and 12). This aspect gives importance to the grants to CAPEX in early stage of hydrogen deployment projects. Particularly, the desired demand for the hydrogen production can be lower than expected when initiatives enter into operation, so such grant schemes compensate such risk. To conclude, DSCR values show that, in the beginning of project execution, the cash flows are sometimes not sufficient to cover the debt service. In such cases, it will be required to allocate more funds (temporarily) from the project shareholders. It is also possible that shareholders allocate debt to the project to solve this issue. Only cases 8 and 9 ensure that the *CFADS* cover the debt service to the lending institution, as represented in Fig. 4 below:

Building on scenarios 1 to 12, sections 4.2–4.4 present the sensitivity analysis regarding variations in the relevant input parameters.

Sensitivity to different public funding rates

As presented in the previous section, a 30% grant to CAPEX reduces LCOH sensibly and it is especially important when hydrogen demand is lower. This section assesses reference scenarios 1 (lowest demand and PV size), 5 (base case), and 9 (highest demand and PV size) against variations in the funding rate up to 70%. As higher values are normally attributed to laboratory prototypes, innovation projects in nearly market ready technology such as hydrogen equipment should receive an equal or lower percentage. Fig. 6 presents the results obtained when scenarios 1, 5, and 9 include a funding rate between 0% (no funding) to 70%, aggregated in 10% steps.

Since the IRR needs to be higher than 8% regardless of the PV plant size or hydrogen demand, all cases are positive for the promoters in case public funding rate is 60% of higher. With 50% or lower funding rates, scenario 1 is not profitable. However, scenario 5 will be profitable for a 20% funding rate but not below 10%. Scenario 9 is feasible (from the IRR point of view) even without public funding. This reflects the importance of compromising a high demand from the off-takers or an appropriate project sizing. It is also important to consider that the funding rate reductions impact exponentially on the return rate of the project, which means that funding programs will need to consider progressive decreases in parallel with technology improvements. This ensures that they do not disconnect their support to hydrogen technologies prematurely. In all cases, funding programs should target rates of 20% of CAPEX or higher for projects similar to the case study in this paper (at least for cases in line with scenarios 5 to 9). They should also ensure that the hydrogen demand, selling price, and PPA volumes are sustainable and guaranteed by the promoters.

Regarding the LCOH, it will increase linearly for the promoters with decreases in the funding rate, as they will need to add more equity to fund the same CAPEX. Conversely, the LCOH excluding the grant will be much higher than the standard LCOH for the promoters when the funding rate increases. However, with a decrease in the funding rate, both values will tend to align until there is no public funding for the project. In this situation, both values will be equal since promoters will cover all the CAPEX without public funding (excluding the debt).

Sensitivity to PPA prices

As presented in previous sections, the PPA will cover the risk from volatility of wholesale electricity markets and will reduce the LCOH and increase IRR for the same conditions (see section 4.1). However, electricity market prices are evolving towards an increase due to current inflationary scenarios in fossil fuels originated for different causes in recent years. For this reason, two variations are added over baseline scenarios 1 to 9 (while 10 to 12 remain similar): PPA prices of 30 EUR/MWh (A) and 40 EUR/MWh (B) for the same PV plant.

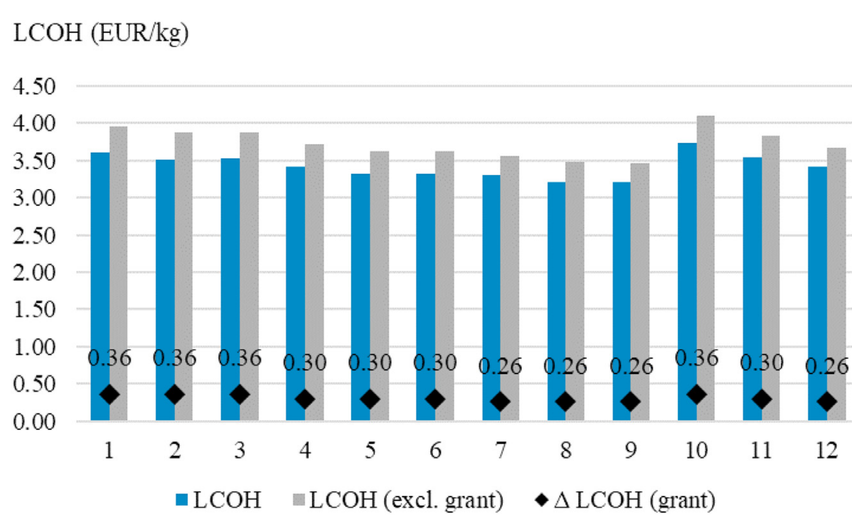

Fig. 5 – [Single fitting] LCOH (blue columns), LCOH excluding grant (grey columns), and LCOH difference introduced by the presence of the 30% grant to the CAPEX (black diamonds) in EUR/kg. (For interpretation of the references to colour in this figure legend, the reader is referred to the Web version of this article.)

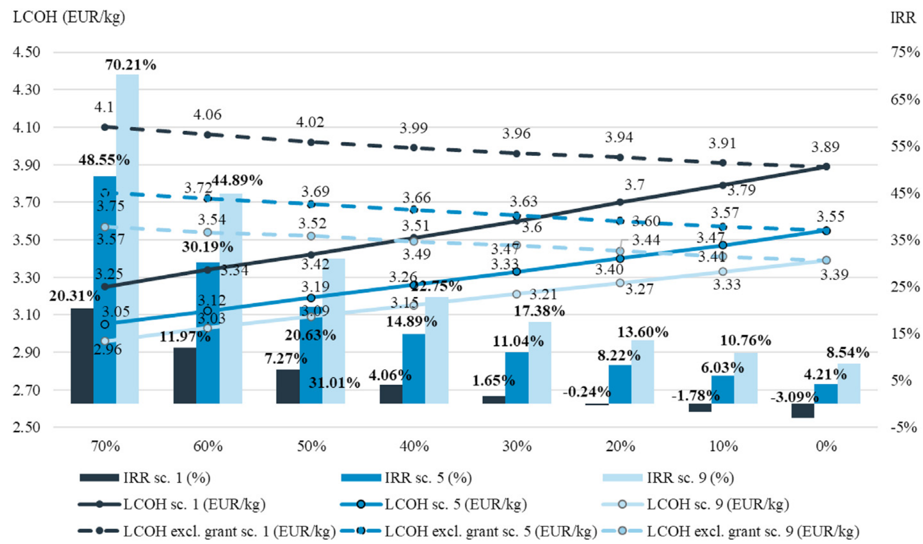

Fig. 6 – [Double fitting] LCOH (EUR/kg, left axis, continuous line), LCOH excluding grant (EUR/kg, left axis, discontinuous line), and IRR (%, right axis, columns) for scenarios 1 (dark blue), 5 (intermediate blue) and 9 (light blue) against different funding rates (horizontal axis, between rates of 70%–0%). (For interpretation of the references to colour in this figure legend, the reader is referred to the Web version of this article.)

Fig. 7 shows that A cases are viable for all situations except for scenarios 1 A and 2 A due to the low hydrogen demand and the PV size of 5 MW. In contrast, for the B cases, only 5 B, 7 B, 8 B, and 9 B are viable. In particular, due to the high price of the PPA, scenario 6 B is less profitable than 5 B since the PV plant is larger. In many times, electricity surplus exported to the grid will be sold at less competitive prices as compared with scenarios 6 and 6 A. The same happens with scenarios 3 B and 2 B and 9 B and 8 B, where a large PV plant increases the surplus electricity paid at a higher price to then be exported to the grid with lower remuneration. For this reason, a two times ratio between PV plant size (MWp) and the electrolyzer (PWE) is more attractive than a three times multiplier.

However, the LCOH values in Fig. 7 also demonstrate that as the PV plant size providing the PPA increases, the difference between A and B cases with the same baseline scenarios grows. This is due to the increased amount of energy that is acquired from the PPA, which explains why the difference in LCOH between cases 3 and 3 A is higher than that between 2 and 2 A or 1 and 1 A. The same happens with the differences between cases 3 B and 3, 2 B and 2 or 1 B and 1, and this

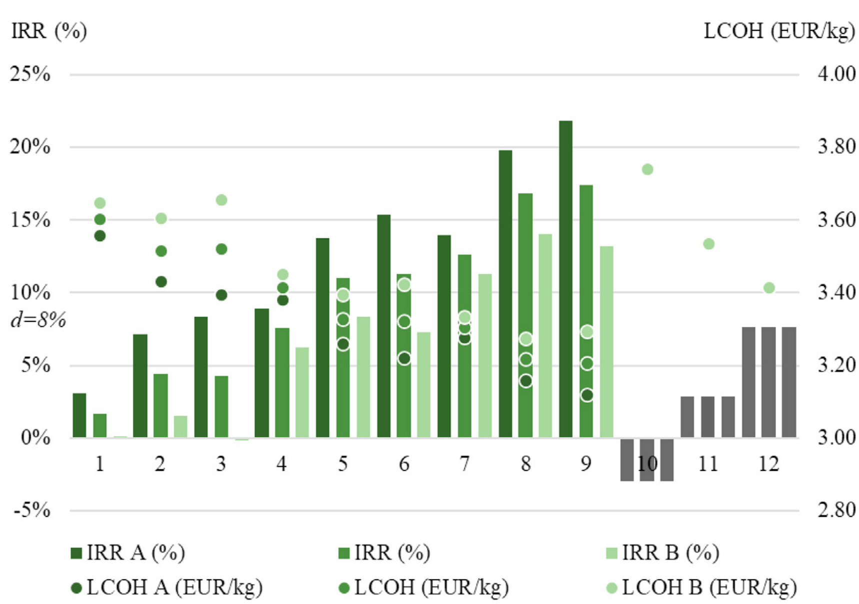

Fig. 7 – [Single fitting] IRR (%, left axis, vertical bars) and LCOH (EUR/kg, right axis, dots) for scenarios 1 to 12 (A cases with PPA at 30 EUR/MWh in dark green, Table 5 scenarios with PPA at 35 EUR/MWh in green, and B cases with PPA at 40 EUR/MWh in light green). (For interpretation of the references to colour in this figure legend, the reader is referred to the Web version of this article.)

propagates to scenarios 7 to 5 and 9 to 7. When the hydrogen demand increases, the LCOH decreases, as depicted in previous sections. Thus, increasing the hydrogen demand reduces the differences between A and B cases with the same baseline scenarios. In this case, both more energy from the PPA is purchased to generate more hydrogen and more excess of electricity is sold to the grid. Moreover, it is also required to import more additional electricity from the wholesale market in moments when the PV plant is not producing energy. For this reason, the differences between A and B cases with baseline scenarios 1 to 3 are higher than those in scenarios 4 to 6 as well as 7 to 9. In all cases, the 5 EUR/MWh variation in the PPA price is a significant factor that supposes a difference in LCOH between 0.029 EUR/kg (case 7, PV plant of 5 MW, 700 tonnes/yr demand) and 0.13 EUR/kg (case 3, PV plant of 15 MW, 500 tonnes/yr).

Finally, it is important to highlight that even a PPA price of 40 EUR/MWh (cases 1 B–9 B) does not produce a LCOH as high as that in merchant scenarios 10 to 12 (as per the values in Table 6).

Table 6 – IRR (%) and LCOH values for scenarios 1 to 12 considering A and B cases.

No.	IRR A (%)	IRR (%)	IRR B (%)	LCOH A (EUR/kg)	LCOH (EUR/kg)	LCOH B (EUR/kg)
1	3.10%	1.65%	0.15%	3.56	3.60	3.65
2	7.15%	4.42%	1.55%	3.43	3.52	3.61
3	8.31%	4.25%	−0.14%	3.40	3.52	3.66
4	8.92%	7.60%	6.27%	3.38	3.42	3.45
5	13.76%	11.04%	8.37%	3.26	3.33	3.40
6	15.38%	11.26%	7.27%	3.22	3.32	3.42
7	13.98%	12.61%	11.26%	3.28	3.31	3.33
8	19.76%	16.83%	14.02%	3.16	3.22	3.28
9	21.85%	17.38%	13.16%	3.12	3.21	3.29
10	−2.94%	−2.94%	−2.94%	3.74	3.74	3.74
11	2.90%	2.90%	2.90%	3.54	3.54	3.54
12	7.64%	7.64%	7.64%	3.41	3.41	3.41

Impact of access tariffs exemption

Another source of reduction in LCOH and increase in IRR comes from the review of network access tariffs (ATR) from the regulatory bodies. In Spain, there are proposals calling for exemptions from charges (set by the government) and tolls (established by the regulatory agency CNMC) in electrolysis projects. Both regulated terms form the network access tariff which is hourly added up to wholesale electricity market prices. The impact of this measure is presented in Fig. 8, which presents C cases (ATR exemption).

It can be observed that all ATR exempted cases with PPA are profitable except for scenario 1, which is the most unfavorable of those. Also, the merchant scenario 12 becomes profitable as the ATR is not applied to the wholesale market electricity purchased. Similarly to the previous scenario and since there is a financial PPA in place where ATR apply to the RE supply from the PV plant also, the larger the size of it is, the greater the difference between baseline scenarios and C cases are (scenarios 1 to 3, 4 to 6 and 7 to 9 show this trend). However, when the hydrogen demand increases, this impact of this exemption is diluted by the higher amount of gas produced. The difference with scenarios A and B is that ATR exemption benefits all cases in a more stable way (not being so dependent on the PV plant size or the demand) between 0.12 and 0.22 EUR/kg. Also, it benefits also scenarios 10 to 12 with 0.10–0.12 EUR/kg. Thus, this becomes an instrument to reduce a critical component in LCOH as cost of electricity supply is in all possible scenarios.

LCOH structure and environmental impact

This section first presents the LCOH composition from scenarios 1 (lowest demand and PV size), 5 (base case), and 9 (highest demand and PV size). This also includes variations A, B, and C (cases 10 to 12 are excluded since there is not a PPA and the structure is different). The results are shown in Fig. 9, which illustrates the predominance of electricity supply costs,

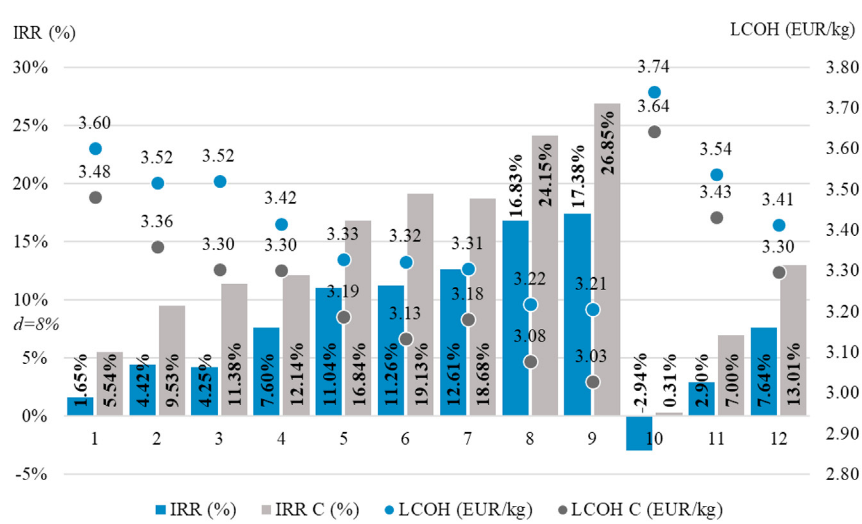

Fig. 8 – [Single fitting] IRR (%, left axis, vertical bars), LCOH (EUR/kg, right axis, dots), for scenarios 1 to 12 (C cases with ATR exemption in grey, baseline scenarios in blue). (For interpretation of the references to colour in this figure legend, the reader is referred to the Web version of this article.)

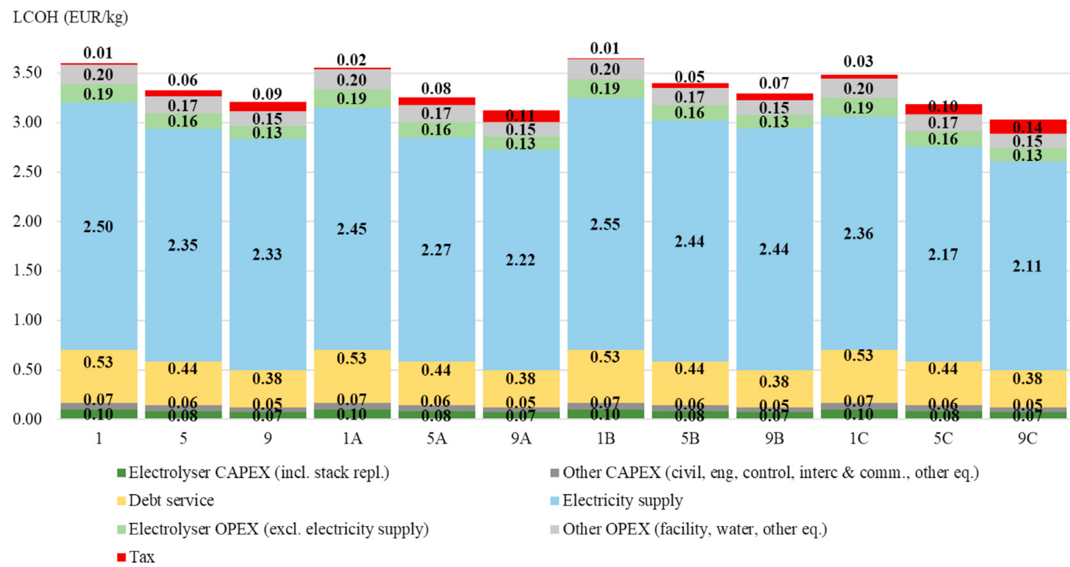

Fig. 9 – [Single fitting] LCOH decomposition (EUR/kg, stacked bars), for scenarios 1, 5 and 9 considering variations A, B and C presented in sections 4.3 and 4.4.

even when favorable situations such as A and C apply. In particular, electricity supply costs are between 67.81% of LCOH (scenario 1C) to 74.11% (scenario 9 B) for the promoters of the project. The second contributor to the share of costs is CAPEX (including the electrolysis system, peripherals, other costs, and the debt service that is paid to cover the loan delivered by the lending entity at project start) with a share between 15.17% of LCOH (scenario 9 B) to 20.10% (scenario 1C). The third element involves OPEX from the electrolyzer (excluding electricity), the other equipment, and the plant, which means between 8.67% (scenario 9 B) to 11.11% (scenario 1C). Finally, taxes will represent 0.23% of LCOH for scenario 1 B, where there is less taxable income due to less hydrogen production and a higher electricity cost given the 30 EUR/MWh PPA price. Taxes will represent 4.56% for scenario 9C, where the situation is the opposite to scenario 1 B.

To conclude, this section shows in Fig. 10 the environmental benefit added by the usage of the PPA in relation to the acquisition of electricity in the wholesale electricity market. As it can be observed, the RE electricity consumed in the electrolyzer grows with the hydrogen demand, as even if all the PV production is exploited, there is more energy purchased from the wholesale electricity market with a certain RE footprint. Thus, the RE consumed in scenarios 7 to 9 is higher than the equivalent situations in scenarios 4 to 6. The same occurs with scenarios 4 to 6 and their equivalents in scenarios

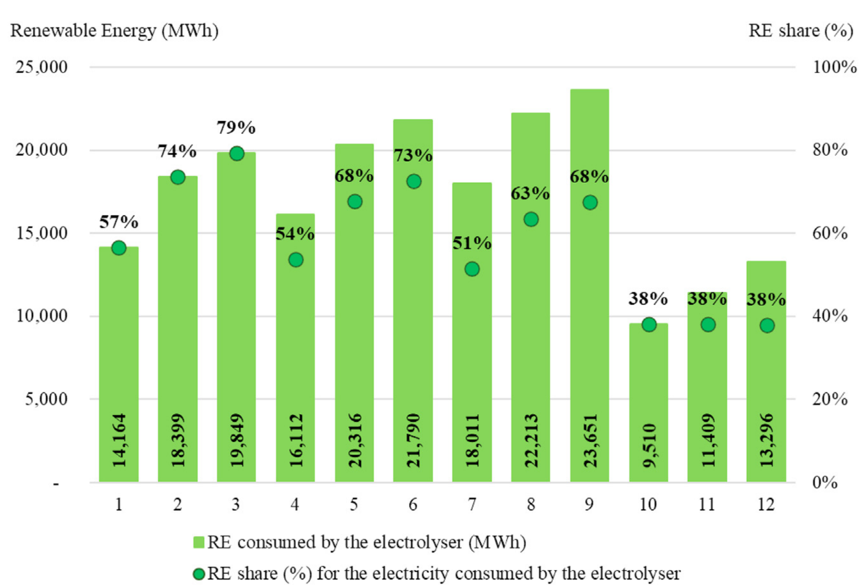

Fig. 10 – [Single fitting] RE consumed in the electrolyzer (MWh, light green bars) and RE share of the electricity used to produce hydrogen (%, dark green dots). (For interpretation of the references to colour in this figure legend, the reader is referred to the Web version of this article.)

Table 7 – Direct CO_2 savings (excluding PV exports) in scenarios 1–3, 4–6 and 7–9 in relation to the grid connected cases 10–12.

PPA scenarios	1	4	7	2	5	8	3	6	9
Grid conn. scenarios used for comparison	10			11			12		
CO_2 emmission savings (TPA)	698.10	990.30	1275.15	1048.50	1336.05	1620.60	982.95	1274.10	1553.25

1 to 3. Similarly, scenario 12 consumes more RE than scenario 11, with scenario 10 consuming less clean energy. However, the RE share of electricity supplied to the electrolyzer is higher in scenarios 1 to 3 than the equivalent scenarios 4 to 6. The same is replicated between scenarios 4 to 6 and scenarios 7 to 9. This is due to the fact that a higher hydrogen demand requires from increased use of the PPA but also, in many times when PV is not available, electricity from the wholesale market which includes a certain carbon footprint. This is the reason why, regardless the electricity consumption from the electrolyzer, the scenarios 10 to 12 have a similar RE share (percentage of clean energy in the electricity coming from the grid). In any case, the contribution from the PPA ranges from 51% to 57% in case of a 5 MW PV plant, 63%–74% for a 10 MW PV facility and 68%–79% for a 15 MW PV plant.

Assuming a carbon footprint of 150 kg of CO_2 per MWh of electricity from the grid [41], then the emissions savings of scenarios 1–3, 4–6 and 7–9 are calculated in the table below in relation to scenarios 10–12 in Table 7. As it can be observed, the carbon footprint direct savings (excluding electricity exports from the PPA) range between 698.10 and 1620.60 tons per annum (TPA).

Conclusions and contributions of the paper

This paper presents a techno-economic model applied to the assessment of the feasibility of green hydrogen projects supplied by renewable PPAs. It considers different funding structures, project stakeholders, and sources of CAPEX and OPEX. To validate the model, it is applied to a case with a photovoltaic financial PPA 'as produced' with 'take or pay' clause applied to a hydrogen production plant connected to the grid. The electricity is purchased via a 'pass-through' contract indexed to electricity prices, with a 5 MW electrolyzer, compression station, and hydrogen storage tank designed to accommodate three days of production.

The results show that the introduction of a PPA increases the return rate of the project. Signing an agreement with a PV plant with a peak power doubling the electrolysis system size increases the return rate significantly, while multiplying it by a three times factor does not add any critical benefit. The return rate in all cases improves the merchant case where all electricity is purchased from the wholesale electricity market. Furthermore, this model ensures the use of a hydrogen demand adjusted to the production potential of the plant at a stable price.

In early stages of deployment for hydrogen production plants, public funding rates to the CAPEX of the projects in the form of dedicated grants is important. In order to cover all possible situations when the initiative starts (hydrogen demand lower than expected, PPA signed with a PV plant smaller than the ideal case), an appropriate amount is 20% or higher for the case study presented.

Another important aspect is the negotiation of the PPA price, which is typically lower for 'as produced' contracts. For a project similar to the case study in this paper, a 5 EUR/MWh difference in the agreed PPA price may mean up to 0.13 EUR/kg.

However, a more effective measure than reduced PPA prices is the access to exemptions in network access tariff ATR, as this decisively impact electricity supply costs. These exemptions imply reductions between 0.12 and 0.22 EUR/kg. Such reductions become important when electricity supply dominates the LCOH, being between 67.81% and 74.11% in the simulated cases.

Thus, an initial measure for supporting green hydrogen project deployment with PPAs is to provide public funding in the form of grants to the CAPEX to cover the oversizing of the electrolysis plant in relation to the demand. However, once more and more projects are deployed, exemption of regulated terms of the electricity transmission (especially ATR costs) are an attractive measure to benefit all initiatives as a whole.

Finally, in addition to the benefits in the financial domain, PPAs facilitate the decarbonization of hydrogen production facilities. In relation to fully merchant cases (i.e., 38% of the RE share), the simulated PPA scenarios imply 51%–79% of zero emission electricity supplied to the electrolysis system.

Declaration of Competing Interest

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

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