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Optimal dispatch model for PV-electrolysis plants in self-consumption regime to produce green hydrogen: A Spanish case study

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HIGHLIGHTS

- A techno-economic model of electrolysis plants with PV sources is formulated.
- The model calculates the optimal hourly dispatch of the PV-electrolysis plant.
- Forecast of solar PV production and market electricity prices are considered.
- Environmental constraints are added to ensure solar PV is used to produce hydrogen.
- A case study based on real data is used to test the model in a series of scenarios.

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ABSTRACT

The production of green hydrogen from renewable energy by means of water electrolysis is a promising approach to support energy sector decarbonization. This paper presents a techno-economic model of plants with PV sources connected to electrolysis in self-consumption regime that considers the dynamics of electrolysis systems. The model calculates the optimal hourly dispatch of the electrolysis system including the operational states (production, standby, and idle), the load factor in production, and the energy imports and exports to the electricity grid. Results indicate that the model is a useful decision support tool to operate electrolysis plants connected to PV plants in self-consumption regimes with the target of reducing hydrogen production costs.

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Introduction

The importance of addressing climate change has been recognized in the last decades at an international level and was endorsed by the Paris Agreement signed by 190 countries in 2015 [1]. Since then, different roadmaps and targets have been established by countries to reduce greenhouse gas (GHG) emissions and to increase renewable energy (RE) and energy efficiency [2,3].

Hydrogen is a sustainable energy vector that can be produced, stored, and distributed in different forms and volumes with a wide range of possible end-uses [4–8]. One key benefit of hydrogen is that it can be produced at any moment using electricity with controlled energy losses via electrolysis, which decouples generation from consumption. This characteristic provides demand-side flexibility to electricity grids with increased shares of RE [9,10]. Due to this benefit and the rapid advances of hydrogen technologies in recent years, many countries have outlined specific targets for the deployment of electrolysis plants to supply this fuel for different end-uses. In particular, the size of hydrogen production plants with electrolysis has increased to the scale of multiple MWs, which reduces the capital expenditure (CAPEX) and benefits business cases via a centralized production of this fuel for a range of proximate end-uses [11,12]. For this reason, Australia, New Zealand, USA, Canada, China, Korea, Japan, South Africa, and several European countries (Spain, France, Germany, Netherlands, Norway, Portugal, UK, and Italy) have recently developed national strategies that include targets for the deployment of a certain installed capacity of electrolysis suiting local conditions [13].

However, while industry and research focus has been on reducing CAPEX and upscaling electrolysis plants to reduce the levelized cost of hydrogen (LCOH) [14,15], the greatest share of annualized costs in these projects still comes from electricity consumption [16,17]. Specifically, these costs range from 50% to 80% of all the annualized expenses in grid connected projects, depending on the electrolysis technology, size, hours of use, etcetera. Thus, in a scenario in which the priority is to incorporate RE as an energy source and the use of electrolysis has been identified as an enabler, these electricity sources could diminish the cost of operation of hydrogen production plants, which would benefit the global sustainability targets and national roadmaps previously mentioned.

Currently, the approaches for integrating RE with electrolysis rely on different methods. In a high level, the first one is the direct connection of RE sources (particularly photovoltaic plants, due to the better predictability and lower variability of solar compared to wind resources) to an electrolyzer in off-grid configurations [18–25]. Here, the challenge is in the dynamic operation of the electrolyzer, which must absorb variations in input power, and doing so will impact its lifetime and degradation. To solve this, it is possible to use electrochemical batteries hybridized with the electrolyzer, but this solution will increase the cost of the project [26]. Moreover, one must use some energy to support essential operations during the night in order to keep the electrolyzer in standby or start it in some periods, which reduces global efficiency and requires energy from a battery and/or a fuel cell. The second method employs a direct connection to the grid—and has consequent advantages related to the operation of the electrolyzer—but requires a power purchase agreement (PPA) with an RE plant. Since this agreement will generally cover part of the energy demanded by the electrolyzer, an optimal strategy is to approach the wholesale electricity market when prices are lower than the negotiated amount in the PPA. However, signing a PPA does not exclude the electrolyzer operator from paying grid access tariffs and fees [27,28]. Finally, an approach that combines the benefits of off-grid connection and the use of PPA contracts is self-consumption. Using this approach, the electrolyzer consumes power from the RE sources and/or the grid, depending on the occasion. Thus, additional energy storage devices need to be incorporated (as is the case with off-grid configurations) since the grid acts as a backup source. Moreover, with this approach there are no access tariffs and fees applicable to the RE power injected into the electrolyzer. Further, in a self-consumption facility, the end-use of the RE will be the production of green hydrogen throughout the whole project lifetime; the same is not true of a PPA, which will last no more than 10–15 years.

However, while the self-consumption approach presents many benefits, a key associated challenge is determining the optimal dispatch of the electrolyzer by considering both the variability and unpredictability of RE sources and the dynamics of electrolysis systems, including their multiple intermediate states of operation, with the objective of guaranteeing that hydrogen storage tanks remain filled to a certain level. Also, in order to guarantee that the PV production matches the electrolysis load, avoiding grid congestion and favoring green hydrogen production, it is required to impose environmental restrictions. Thus, this paper proposes a model of PV-electrolysis plants in self-consumption regime that determines the optimal dispatch of these facilities considering the variability of the RE source and the target of generating the hydrogen at the minimum operational cost for a given facility. In addition, in order to ensure the PV plant production is prioritized for the production of hydrogen (avoiding energy pricing speculation with wholesale electricity market prices) the model adds an environmental restriction meeting this target in order to foster the lowest possible carbon footprint in the hydrogen generation. To this end, the paper is structured as follows: Section 2 describes the mathematical formulation of the model for PV-electrolysis plants coupled in self-consumption regimes. Section 3 describes a case study applied to a plant located in Spain and presents different simulation scenarios with sensitivity to hydrogen demand, PV plant production, seasonality and the consideration or not of the environmental restriction. In Section 4, the results obtained for these scenarios are presented and discussed. Finally, Section 5 presents conclusions and recommendations based on the content of Sections 3 and 4.

Techno-economic model of PV-electrolysis plants in self-consumption regime

Assumptions and description of the model

The connection of a PV source to an electrolysis plant in a self-consumption regime includes the elements and energy flows represented in Fig. 1: the energy produced from the solar photovoltaic plant (EPV_h), the energy imported from the electricity grid ($EIMP_h$), the energy sold to the wholesale electricity market ($EEXP_h$), and the energy consumed by the electrolyzer every hour h ($EELY_hI$). This section presents the techno-economic model and how it serves the purpose of setting these flows in an optimal manner.

The first and preferred energy source for the electrolyzer is the PV plant, which comprises photovoltaic modules, a solar tracker, and inverters that deliver electricity in AC. For a given location (expressed through latitude and longitude), one can use the orientation of the plant (provided via azimuth and inclination), the datasheets of the selected PV panels and inverters, and radiation data collection campaigns to forecast accurate production data in 72-h windows with 1 h resolution [29,30]. Thus, the present model assume this degree of forecasting with 1-h resolution is possible.

The second energy source feeding the electrolyzer is the grid, which is used as a backup electricity source when the PV resource is unavailable. Intra-day wholesale electricity markets are currently liberalized in most countries, and prices are highly influenced by local conditions, including the share and type of RE sources and the availability of backup coal and/or gas power plants. In recent years, forecasting approaches to predict hourly profiles of prices in wholesale electricity markets have evolved towards accurate methods in time windows that have grown from several hours to days. Although several prediction models and statistical models have been widely used in different research, modern approaches incorporate computational intelligence models. Approaches based on machine learning and neural networks have yielded particularly promising results for 3-day time windows [31,32]. As a result, the model presented in this paper assumes it is possible to anticipate electricity prices within this time window.

Finally, the core element in the plant is the electrolysis system, which includes the rectifier, balance of plant (BOP), and stack. The most mature and widespread electrolysis technologies today are polymer electrolyte membrane (PEM) and alkaline, each of which has different performance and characteristics. In both cases, the rectifier converts the AC supply from the grid to DC at a voltage and current level suitable for the stack. The BOP is a set of peripheral equipment that keeps the stack at a suitable pressure and temperature in the different states of electrolyzer operation. Finally, the stack is the nuclear element of the electrolyzer and produces hydrogen when electricity is supplied to it in DC over a certain power level. Currently, to offer flexibility to electrolysis plant operators, a manufacturer's supply systems can operate in three different states. These states and the relevant transitions between them can be described as follows [33,34]:

- Idle. The electrolyzer is deenergized, depressurized and at ambient temperature in this state. The only energy consumption comes from the control and command system and some items in the BOP that may need to act to keep the electrolyzer operative (e.g., anti-freezing pumps). In this state, it is possible to transition to produce hydrogen (cold start), but this operation takes 5–20 min depending on whether the technology is PEM or alkaline. Currently, the impact of repeated cold starts on the lifetime of the stack is unknown, so some manufacturers advise against a repeated number of these transitions in day-to-day operation of the plant [35]. The opposite transition from production to idle deenergizes the system almost instantaneously, so it is not relevant for the model, which concerns the dispatch of PV energy to an electrolysis plant. Moreover, it is not sustainable to transition from idle to standby or vice-versa because, in an ideal scenario, the purpose of an idle state is to produce hydrogen. Conversely, it is not sustainable to stop producing hydrogen to go to standby, which consumes power, but then transition to idle.
- Standby. The electrolyzer consumes energy to remain pressurized and at service temperature, but hydrogen is not produced in this state of operation [36,37]. The added value of this state of operation is that it is possible to return to production (hot start) in 1–30 s depending on the technology, with PEM systems showing a faster response. The opposite case (transitioning from production to standby) can be neglected for the same reasons as transitions from production to idle.
- Production. In this state, the electrolyzer produces hydrogen, consuming electricity at levels between the minimum partial load and the nominal power according to the limits set by the manufacturer.

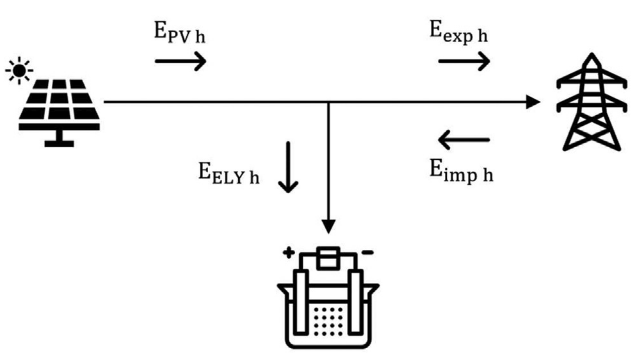

Fig. 1 – Simplified representation of a PV-source-to-electrolysis-plant connection in a self-consumption regime.

In addition to these assumptions related to modeling the critical elements in the plant, the model considers the following:

- It is possible to model and predict the demand of hydrogen by the end-user of the plant. In cases of mobility with fleets of fuel cell electric vehicles, one can normally anticipate the weekly consumption of fuel; the same is usually true for industries in which the purpose is to replace the production of hydrogen via methane reforming or similar methods with electrolysis. If natural gas is to be replaced by following price signals, the expected demand can be anticipated via predictions based on the prices of this gas, which can be elaborated similarly to the case of electricity.
- The plant designer has included a hydrogen storage infrastructure downstream from the electrolysis system to

maintain a buffer consistent with periods without solar radiation (avoiding excessive usage of electricity from the electricity grid), and this infrastructure considers the hydrogen demand to be met and its profile.

Mathematical formulation of the model

The objective of the model is to determine the optimal dispatch of PV energy to the electrolysis plant with the target of maximizing income while covering the hydrogen demand. In this way, the economic feasibility in a best-case scenario can be obtained, or the dispatch schedule of a plant can be calculated at a certain frequency determined by the operator.

Particularly, the optimal dispatch of the plant will determine, for every hour h, the distribution of the energy flows. For the forecasted electricity production from the PV plant, EPV_h, this dispatch will set, depending on the case, the energy purchased from the grid, $EIMP_h$, and the energy sold to the wholesale electricity market, $EEXP_h$. Both of these are real variables greater than or equal to zero. The model will also set the state of operation of the electrolyzer, which can be a_h for idle, b_h for production, or c_h for standby (as detailed in Section 2.1). These variables are binary and equal to 1 if the electrolyzer is in the specified state of operation and 0 otherwise. Moreover, in production, the model will determine the load factor, r_h, at which the electrolyzer is operating in production state. The load factor r_h is a real variable that ranges between the minimum partial load, MPL (expressed as a percentage of nominal power, P), and 1 when the electrolyzer is in a production state. Otherwise, in standby and idle, the load factor is 0.

To obtain the optimal dispatch for every hour h, the incomes, I_h, defined as the difference between revenues, R_h, and costs, C_h, need to be maximized:

$$I_h = R_h - C_h \tag{1}$$

In equation (1), R_h captures the revenues that include those relative to the hydrogen sold, RHS_h, and those relative to the electricity exported to the wholesale electricity market, REE_h:

$$R_h = RHS_h + REE_h \tag{2}$$

The amount of hydrogen produced every hour depends on the nominal power of the electrolyzer, P_{ELY}; the efficiency, η, defined as the energy required to produce 1 kg of hydrogen; and the load factor, $r_{h,}$. If RH is the remuneration captured per kilogram of hydrogen sold, then the following revenue is captured in production when b_h is equal to 1:

$$RHS_h = RH \cdot (P / \eta) \cdot r_h \cdot b_h \tag{3}$$

The revenues captured from the electricity exported to the wholesale electricity market will depend on $EEXP_h$ and the price of the wholesale electricity market forecasted for that hour, $PEXP_h$:

$$REE_h = EEXP_h \cdot PEXP_h \tag{4}$$

On the other hand, the cost, C_h, must include costs dependent on the variables presented above. This is because those costs are not dependent on variables such as CAPEX or fixed preventive maintenance OPEX (excluding stack replacements) but instead are fixed. These costs therefore do not vary if the dispatch of the plant changes. Equation (5) provides such costs relevant to the problem:

$$C_h = CEIMP_h + WC \cdot r_h \cdot b_h + SRC \cdot b_h + Ccb \cdot b_h \cdot c_{h-1} + Cab \cdot r_h \cdot b_h \cdot a_{h-1} \tag{5}$$

These costs include $CEIMP_h$, the hourly cost of the electricity imported from the electricity grid to sustain the production of hydrogen when PV power is not available or to maintain the electrolyzer in standby state. As in equation (4), $CEIMP_h$ are equal to $EIMP_h$ multiplied by the cost of electricity, which includes the wholesale market electricity price plus energy access tariffs (since power access tariffs are fixed) and fees expressed in an hourly basis, $PIMP_h$:

$$CEIMP_h = EIMP_h \cdot PIMP_h \cdot b_h + EIMP_h \cdot PIMP_h \cdot c_h \tag{6}$$

Returning to equation (5), the second term represents the water costs, WC_h, which apply when hydrogen is being generated in production state, b_h, and are proportional to the load factor r_h at which the electrolyzer is working. The third term reflects the stack replacement costs. Due to the lack of existing information on durability of electrolysis stacks today under dynamic regimes of operation, the lifetime value assumed is the one indicated by the manufacturer in the product specifications. Usually, the stack lifetime is indicated a value equal to the maximum hours of operation in production state (that is, whenever b_h, is equal to 1) for which the system efficiency value can be maintained [11,38–41]. After these hours of operation have expired, it is assumed that the plant operator will replace the stack in order to maintain the terms in the operation and maintenance contract valid. Finally, the model considers the negative impact of transitions to start the electrolyzer, including hot starts and cold starts. In particular, the revenue from hydrogen that would be produced if the electrolyzer was not transitioning to production is subtracted in the form of the constant values Cab and Ccb. Cab is a constant parameter equal to the revenue from hydrogen RH that would be produced at nominal power, P/η, over a period of time equal to the cold start time duration, CST, expressed in hours. In the same way, Ccb is a constant value equal to the revenue lost due to the hydrogen not generated at nominal power for a time period equal to the hot start time, HST, also expressed in hours. Equations (7) and (8) include these constant values, respectively:

$$Cab = RH \cdot (P / \eta) \cdot CST \tag{7}$$

$$Ccb = RH \cdot (P / \eta) \cdot HST \tag{8}$$

Thus, the objective function OF dependent on the variables of the problem to be minimized can be expressed as follows for a time window TW of several hours, which is equal to equation (2) expanded with items in equations (2)–(8):

$$\begin{aligned} OF = \sum_{h=1}^{TW} & EIMP_h \cdot PIMP_h \cdot b_h + EIMP_h \cdot PIMP_h \cdot c_h + WC \cdot r_h \cdot b_h \\ & + SRC \cdot b_h + Ccb \cdot r_h \cdot b_h \cdot c_{h-1} + Cab \cdot r_h \cdot b_h \cdot a_{h-1} \\ & - RH \cdot (P / \eta) \cdot r_h \cdot b_h - EEXP_h \cdot PEXP_h \end{aligned} \tag{9}$$

However, the constraints of the problem also need to be fixed. Equation (10) thus imposes the required demand of hydrogen RW to be produced in this predefined time window TW, assuming there is sufficient storage capacity at the output of the electrolyzer to accommodate the fuel produced in that period:

$$\sum_{h=1}^{TW} (P_{ELY} / \eta) \cdot r_h \cdot b_h = RW \tag{10}$$

In addition to fixing the demand of hydrogen, the model must also adjust the energy flows as per Fig. 1. In particular, the energy consumed by the electrolyzer (in production and standby states) needs to be served from the PV plant and/or electricity grid. In the case of surplus RE power, the production may be exported; this export is reflected by $IIEXP_h$, binary variable that assume a value of 0 or 1. On the contrary, $IIMP_h$ will reflect the required energy imports.

$$EPV_h + EIMP_h \cdot IIMP_h - EEXP_h \cdot IEXP_h - P_{ELY} \cdot r_h - E_c \cdot c_h = 0 \quad \forall h \tag{11}$$

In addition, equation (12) mandates that, every hour, net electricity is either purchased from or sold to the grid (i.e., both cannot occur within the same hour):

$$IIMP_h + IEXP_h \le 1 \ \forall h \tag{12}$$

Moreover, the restrictions in equations (13) and (14) define limits on the amount of electricity imported and exported, respectively. Specifically, the maximum amount of the electricity imported from the grid is the consumption of the electrolyzer at rated power, while the upper limit for the electricity exported to the grid is the available electricity production in the solar PV plant.

$$0 \le EIMP_h \le IIMP_h \cdot P_{ELY} \quad \forall h, \text{ with } IIMP_h \in \mathbb{Z} \text{ and } EIMP_h \in \mathbb{R} \tag{13}$$

$$0 \le EEXP_h \le IEXP_h \cdot EPV_h \quad \forall h, \text{ with } IEXP_h \in \mathbb{Z} \text{ and } EEXP_h \in \mathbb{R} \tag{14}$$

Because the model is designed to optimally dispatch the electrolyzer, it can be in one operational state each hour as per equation (15):

$$a_h + b_h + c_h = 1 \ \forall h \tag{15}$$

In keeping with the restrictions in Section 2.1, equation (16) restricts the number of cold starts as recommended by the electrolysis system provider:

$$\sum_{h=1}^{TW} b_h . a_{h-1} \le N \tag{16}$$

To allocate a sustainable control strategy for the electrolyzer, the transition from idle to standby and vice versa is restricted by equations (17) and (18). That is, if the electrolyzer leaves the idle state, it should be to produce hydrogen. This is, there is no benefit to starting the electrolyzer if it is to remain in standby in a high-level optimal dispatch strategy where electricity prices and PV production can be anticipated.

$$c_h . a_{h-1} = 0 \quad \forall h \tag{17}$$

$$a_h . c_{h-1} = 0 \quad \forall h \tag{18}$$

Another important restriction that needs to be added is the value of r_h, which must be zero when the electrolyzer is in standby or idle, but between MPL and 1 in production, as explained in the beginning of this section:

$$r_h - b_h \le 0 \ \forall h \tag{19}$$

$$-r_h + MPL . b_h \le 0 \ \forall h \tag{20}$$

$$0 \le r_h \le 1 \quad \forall h, \text{ with } r_h \in \mathbb{R} \tag{21}$$

The list of restrictions required to define the problem have been provided in equations (10)–(21). However, an economic optimization of the problem may result in energy from the PV plant that is not used to feed the electrolyzer but instead is sold to the wholesale electricity market. This situation may occur, for example, due to a pricing opportunity for which it is possible to produce hydrogen in periods without solar radiation because there are low import prices and this speculation is more profitable than using the renewable resource. Thus, to avoid this situation but also to compare the cost of matching energy from a PV plant and hydrogen production, the "environmental constraints" in equations (22)–(24) can be defined:

$$a_h \ge 1 - q \quad h \in \text{hours without solar resource} \tag{22}$$

$$q \le k . \sum_{h=1}^{TW} r_h \tag{23}$$

$$q \ge 1 - \frac{1}{k \, . \, \sum_{h=1}^{TW} r_h} \tag{24}$$

In particular, equation (22) prioritizes scheduling the electrolyzer operation during hours with available solar resources, even if other dispatch strategies would be more profitable, where q is a binary variable equal to 0 if there is enough PV production to meet the electrolyzer demand during the planned timeframe TW and equal to 1 otherwise. In equations (23) and (24), the constant parameter k appears, which is a ratio equal to the nominal power of the electrolyzer, P_{ELY}, divided by the sum of available energy from the solar PV plant which could be potentially used to produce the hydrogen demand in TW (sum of EPV_h with a cap equal to the nominal power of the electrolyzer).

Equations (9)–(21)—or (9) to (24), depending on whether the environmental constraints are included—constitute a mixed-integer nonlinear optimization problem (MINLP) that can be solved for a certain time window to determine the optimal dispatch of PV energy to an electrolysis plant in a self-consumption regime. Particularly, the model will provide the hourly values of the energy imported and exported from the electricity grid ($EIMP_h$, $EEXP_h$) as well as the operational states (a_h, b_h, and c_h), and the load factor r_h of the electrolyzer. To validate the proposed model, it is applied to several scenarios described in Section 3 using the General Algebraic Modeling System (GAMS) software. Specifically, a branch-and-cut method is used to break the nonlinear problem (NLP) model into a list of subproblems.

Definition of case study for application of the model

To test the model, a real Spanish case study of a PV connection to an electrolysis plant has been defined with application of realistic radiation values and applicable regulations, codes, and tariffs. The model has been applied to a project including a PV plant with 6 MW peak power connected in a self-consumption regime to the grid to supply energy to a PEM electrolyzer with techno-economic parameters [10–15,38–41] for a 2 MW system. The PEM technology has been proposed for this case study due to the better dynamics when following the PV production. Nevertheless, in case of selecting an alkaline electrolysis system, the variations in the values selected would be in system efficiency, cost of stack replacement, lifetime for stack replacement, minimum partial load, cold and hot start time (being the last three parameters more favorable for the PEM technology [39,40]). For the sizing of the case study (PV to electrolysis installed power), different current planned and operational projects have been considered [42–44].

The parameters characterizing the PV plant and the electrolyzer are provided in Tables 1 and 2, respectively:

In relation to other input parameters for the model and assumptions, the following considerations apply:

- For the electricity imports, the electricity contract is indexed to wholesale market electricity prices using 2019 data. The access tariffs and taxes of that year also apply.
- Exported electricity is sold at wholesale electricity market values.
- As per the self-consumption regulations in Spain, access tariffs and taxes do not apply to the energy consumed from the PV plant.
- The time window is set to 72 h, which allows the operator to meet hydrogen demands while maintenance tasks in the plant are completed. Using this time window, PV forecasts can be created on an hourly basis with sufficient accuracy. It is also possible to predict a hydrogen demand for 3 days (normally, projects have defined weekly demands, which can be scaled to use this time period).

Table 1 – Technical and economic parameters used to model the PV plant in the case study.

Parameters of the PV plant	
Parameter	**Value**
Peak power	6000 kW
Technology	Monocrystalline
Latitude	39.7028010
Longitude	2.8676490
Azimuth	0°
Inclination	30°

Table 2 – Technical and economic parameters used to model the electrolyzer in the case study.

Parameters for modeling of the electrolysis system	
Parameter	**Value**
Nominal power	2000 kW
Technology	PEM
Overall system efficiency	52 kWh/kg
Standby consumption (percentage of nominal power)	2%
Minimum partial load (percentage of nominal power)	10%
System CAPEX	1300 (EUR/kW)
Cost of stack replacements	35% of CAPEX
Lifetime for stack replacement cost	40,000 h
Cost of water	3.8 EUR/m^3
Consumption of water to produce hydrogen	15 L/kg
Cold start time (idle to production)	10 min.
Hot start time (standby to production)	5 s
Maximum number of cold starts	3 every 72 h

- It is possible to anticipate the solar PV production EPV_h for the 72-h time window based on available methods in the literature.
- Wholesale electricity market prices can be foreseen with sufficient accuracy in a 3-day time window.
- The hydrogen storage capacity at the output of the electrolyzer is not within the scope of the model. Thus, it is assumed there is a hydrogen storage buffer at the output of the electrolyzer with sufficient capacity to accommodate a 3-day demand.
- The hydrogen produced is valued at 5 EUR/kg at the output of the electrolyzer, which is a valid assumption when the fuel is used for mobility purposes. By adding CAPEX and the fixed preventive maintenance OPEX of this electrolyzer as well as other cost elements downstream from the plant (e.g., hydrogen storage), an analyst can complete a technoeconomic assessment of the plant.

With these input parameters, the model can be tested in different scenarios to observe the achieved behavior in 3-day time windows under different conditions. Table 3 provides a list of the assumptions in each of the scenarios proposed, where the following conditions vary:

- Radiation data. For the selected location, the radiation data on a sunny day differs seasonally: radiation is higher in summer than in winter, with spring and autumn data falling within average ranges. The same is true in most countries. Thus, scenarios have been built based on one average day in January (representative of winter period in North hemisphere), July (representative of summer) and April (representative of spring and autumn).
- Hydrogen demand. This parameter critically impacts dispatch, particularly when the solar resource cannot meet demand, as such a situation requires importing electricity from the grid.
- Environmental constraints. As discussed in Section 2.2, an optimal dispatch targeting cost minimization may lead to extra energy imports from the electricity grid while some solar resource is sold in the wholesale market. Then, all the

Table 3 – List of scenarios simulated in the case study.

Case No.	Month (radiation)	PV prod. (kWh) in time window	H_2 demand (kg)	Env. restriction
1	January	54,888	355	No
2			711	
3			1066	
4			1422	
5	April	90,048	355	
6			711	
7			1066	
8			1422	
9	July	102,180	355	
10			711	
11			1066	
12			1422	
13	January	54,888	355	Yes
14			711	
15			1066	
16			1422	
17	April	90,048	355	
18			711	
19			1066	
20			1422	
21	July	102,180	355	
22			711	
23			1066	
24			1422	

scenarios will be simulated with and without the environmental constraints designed in equations (22)–(24).

Results and discussion

This section presents the results from the application of the model to the case study described before including the scenarios in Table 3 as well as the fixed infrastructure data in Table 1 (PV plant) and Table 2 (electrolysis plant). Specifically, Table 4 presents the results obtained, including the time spent in each operational state by the electrolyzer to produce the hydrogen in compliance with problem restrictions, the amount of energy imported and exported to the grid, the electrolysis system consumption, as well as the number of hours required to import and export this electricity.

When considering the results, it is clear that for the scenarios including the environmental restriction (13–24), the objective function is higher than or equal to those that do not include it (1–12). As explained in the previous section, the optimization problem targets the maximization of variable-dependent incomes (which are equal to the negative value of). Only for scenarios 1 and 13 were these *OF* values equal; this outcome occurred because the optimal dispatch in economic terms matched the environmental one. However, the impact of the environmental restrictions was not very high in terms of values. If the difference in *OF* values is obtained for each scenario with and without restriction and it is divided by the hydrogen produced, it is possible to obtain the economic impact per kilogram of fuel of adding the environmental constraints. The highest value is 0.15 EUR/kg for scenarios 8 and 20 and the average value is 0.05 EUR/kg for all pairs of scenarios simulated, very low in comparison to the LCOH of hydrogen produced by means of electrolysis, which currently ranges between 3 and 5 EUR/kg. One must also consider that, on a yearly basis, not all days will have radiation, as is assumed in the scenarios simulated. When there is no radiation, electricity must be purchased from the electricity grid for several days, which would mitigate this cost. Moreover, in real conditions, the errors in forecasts for electricity grid prices would be on the same order of magnitude as the cost of environmental constraints. This is due to the very high volatility in current energy markets: it is easier to predict the solar PV production than market fluctuations. Thus, since the environmental restriction imposes the matching between PV and electrolyzer in hours with solar resource, this strategy offers a safer way to obtain low-cost energy to feed the electrolysis system than speculation with import and export prices.

Furthermore, the operation pattern and energy consumption of the electrolyzer vary between cases 1 to 12 and 13 to 24. In particular, the environmental restrictions require the system to follow the hourly averaged PV production curve, which slightly increases the hours in production of the electrolyzer at different load factors. However, the scenarios without the restriction present an equal or higher number of hours in a standby state. In this state, the system waits for price opportunities relative to electricity imports at low cost to limit the number of cold starts for each 3-day window to mitigate accelerated degradation. Thus, all the energy from the PV plant is fed to the electrolyzer when the environmental restrictions are in place, but also the energy consumed by the electrolyzer is lower. In particular, the difference reaches 1360 kWh between scenarios 6 and 18 (presented in Figs. 3 and 4, respectively). In scenario 6, the electrolyzer remains in standby status between hours 20 and 30 as well as 44 and 55 (night time without solar PV resource) to profit from opportunities to import electricity at a lower cost instead of benefitting from solar energy at the beginning of the second day (hours 32 to 36). However, in scenario 18 the electrolyzer remains in an idle state overnight, reducing the consumption and respecting the restriction of one cold start per day. In global terms, for all the pairs of scenarios (with and without environmental restrictions), the average in energy consumption increases for the electrolyzer is 397 kWh, as indicated in Fig. 5. This energy comes from either the PV plant or the electricity grid, but the optimal dispatch without the environmental constraints involves higher or equal energy imports due to price speculation in relation to the scenarios in which environmental restrictions are in place, with a consequent higher dependence on the grid. This difference reaches a maximum of 8830 kWh (16% of PV plant production) between scenarios 2 and 14, with an average for all the pairs of scenarios of 3592 kWh.

On the other hand, it is evident that the influence of PV seasonality impacts the need to import energy to produce the same amount of hydrogen. For all cases with environmental restrictions (13–24) where the hydrogen demand is the same, in January the system must import more energy than in April; the same pattern occurs between scenarios in April and July. Specifically, the need for energy imports decreases in scenarios in April by between 510 kWh (difference between

Table 4 – Summary of results obtained from the simulation of the scenarios.

No.	Electrolyzer operational state			Electrolyzer consumption (kWh)	Energy imported (kWh)	Energy exported (kWh)	Hours importing energy (h)	Hours exporting energy (h)	Objective Function (EUR)
	Idle (h)	Production (h)	Standby (h)						
	$\sum_{h=1}^{TW} a_h$	$\sum_{h=1}^{TW} b_h$	$\sum_{h=1}^{TW} c_h$	$\sum_{h=1}^{TW} r_h.b_h + c_h$	$\sum_{h=1}^{TW} EIMP_h$	$\sum_{h=1}^{TW} EEXP_h$	$\sum_{h=1}^{TW} IIMP_h$	$\sum_{h=1}^{TW} IEXP_h$	OF
1	61	11	0	18,461	510	36,937	3	25	−3457
2	44	21	7	37,253	10,922	28,557	15	22	−3988
3	35	31	6	55,674	15,424	14,638	16	21	−4469
4	19	40	13	74,467	33,047	13,468	37	20	−4885
5	43	10	19	19,221	4779	75,606	13	39	−3707
6	19	19	34	38,333	9348	61,062	25	37	−4725
7	13	29	30	56,634	11,079	44,493	24	36	−5705
8	13	38	21	74,787	19,842	35,103	29	32	−6614
9	62	10	0	18,461	0	83,719	1	45	−6758
10	51	20	1	37,013	0	65,167	9	44	−7121
11	40	30	2	55,514	0	46,666	1	43	−7483
12	31	40	1	73,987	7226	35,419	8	36	−7781
13	61	11	0	18,461	510	36,937	1	26	−3457
14	51	21	0	36,973	2092	20,006	2	24	−3965
15	40	32	0	55,434	12,858	12,311	11	17	−4393
16	18	43	11	74,387	31,299	11,800	31	21	−4837
17	61	11	0	18,461	0	71,587	0	42	−3694
18	51	21	0	36,973	631	53,705	3	39	−4695
19	41	30	1	55,474	3375	37,948	6	36	−5621
20	33	39	0	73,947	11,705	27,805	13	28	−6396
21	59	12	1	18,501	0	83,679	0	43	−6711
22	50	22	0	36,973	0	65,207	0	44	−7091
23	39	31	2	55,514	0	46,666	0	44	−7476
24	33	39	0	73,947	6605	34,838	6	39	−7753

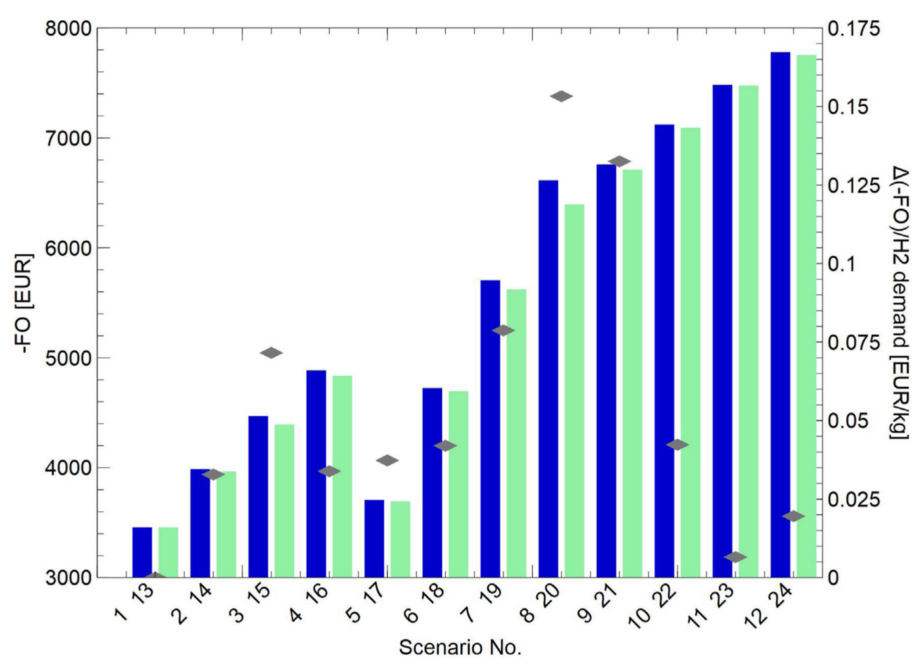

Fig. 2 – Representation of negative OF values for each scenario (vertical bars) and their divergence in terms of costs (EUR/kg of hydrogen, grey diamonds) between pairs of scenarios with (green vertical bars) and without (blue vertical bars) environmental constraints. (For interpretation of the references to colour in this figure legend, the reader is referred to the Web version of this article.)

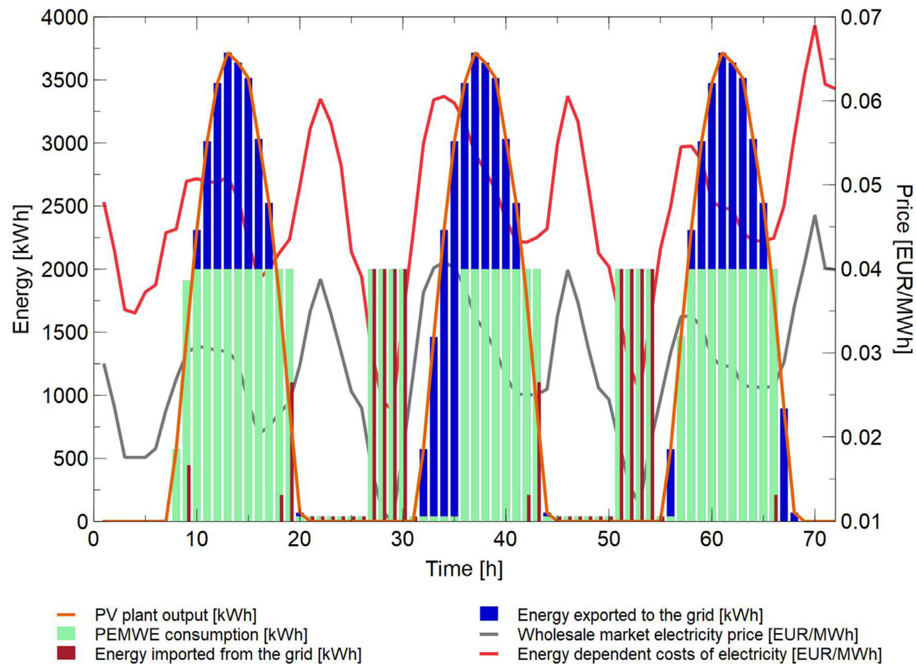

Fig. 3 – Representation of the optimal dispatch of scenario 8.

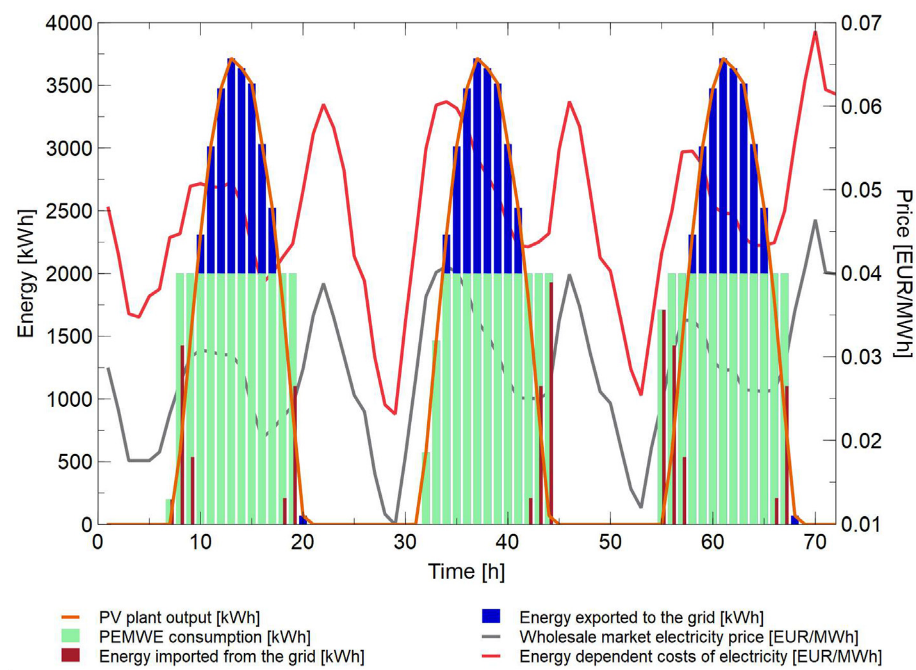

Fig. 4 – Representation of the optimal dispatch of scenario 20.

scenarios 13 and 17) and 19,594 kWh (scenarios 16 and 20) when compared to those in January. In the same way, the demand for energy imports decreases in the scenarios in July by up to 5100 kWh (difference between scenarios 20 and 24). This pattern also occurs for most cases without the environmental restrictions (1–12). Although in some scenario it may be attractive to consume more electricity from the grid, the PV resource (when available) tends to be more profitable in general. Moreover, in Figs. 2 and 5 it is evident that the same is true for *OF* values, which are better in July than in April and in April than January.

Finally, the influence of the hydrogen demand is also critical for the optimal dispatch strategy. Increasing this demand requires higher energy imports to compensate for the lack of solar PV plant availability in some periods and less energy exports, as depicted in Figs. 2 and 5. This need for higher energy imports happens when comparing cases with environmental restrictions and when comparing cases without these

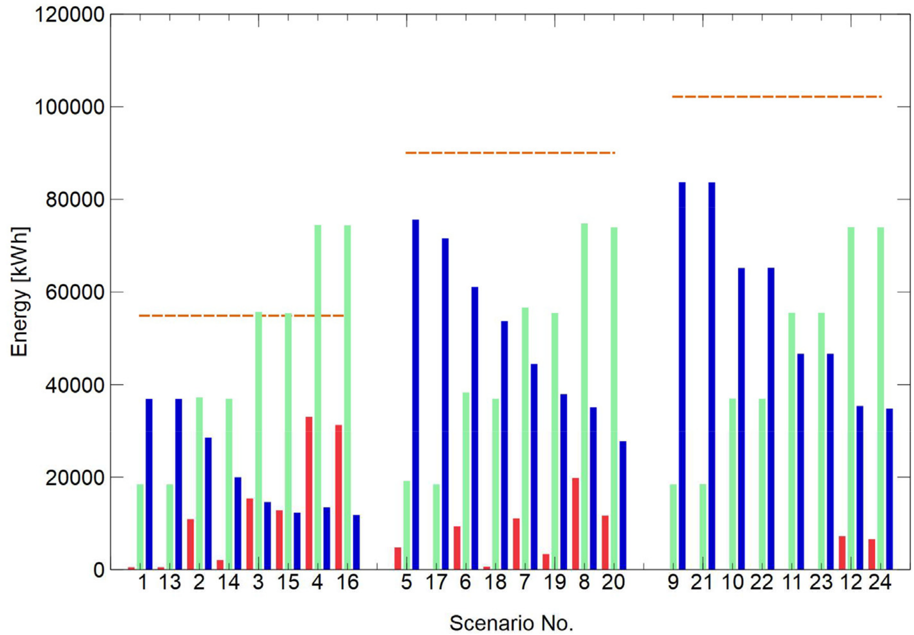

Fig. 5 – Representation of energy flows including PV plant production (dotted orange horizontal line), energy exports (blue vertical bars), and imports (red vertical bars) from the grid as well as electrolyzer consumption (green vertical bars) in the different scenarios. (For interpretation of the references to colour in this figure legend, the reader is referred to the Web version of this article.)

restrictions. However, although there are less energy exports and higher energy imports when the demand increases, the revenues for the hydrogen produced compensate for this fact due to the price attributed to the hydrogen produced (5 EUR/kg). Thus, the *OF* values improve with a higher demand for hydrogen.

Conclusions and recommendations

This paper presents a model for the optimal dispatch of PV to electrolysis plants operating in a self-consumption regime, which has been identified as a promising approach to reduce LCOH. Particularly, the model can be used to accurately calculate the plant dispatch and use it as an input in project feasibility stages, to optimally size the scale of the plant for a given location or to optimally schedule operations of hydrogen projects in execution with the purpose of maximizing incomes.

The model considers the predictability of solar PV production and wholesale market electricity prices in time windows of hours to several days, which is realistic considering current forecasting tools. Moreover, the proposed model considers the dynamics of the electrolysis systems and the possibility of adding environmental constraints to ensure RE is used to generate hydrogen. The outputs of the execution of the dispatch model include the optimal hourly values of operational states of the electrolyzer (production, standby, or idle), the load factor in production, as well as the energy imported and exported to the electricity grid for each hour in the selected time window.

To test the model, a case study based on real data has been used that includes a series of scenarios and considers time windows of 72 h. The results indicate that the environmental constraints guarantee that the solar PV energy is delivered to the electrolyzer with very low cost compared to usual LCOH figures that arise from economical optimal dispatch without this restriction. In addition, the practice of speculating the cost of energy imports and exports to the grid with the purpose of maximizing the economic incomes of the plant relies on accurately predicting wholesale electricity market prices every hour, and these values are currently much more volatile and unstable than PV production for the time window selected. Thus, the environmental constraints guarantee using all power from the PV plant to produce hydrogen when there is radiation, which is generally more profitable in the long term than relying on predictions of wholesale electricity market prices, as the latter include a higher risk of error. In addition, the maximization of the economic benefit supposes a higher usage of the standby state to comply with a restriction on the maximum number of cold starts, which results in higher energy consumption in relation to the dispatch obtained when the environmental constraints are in place. Furthermore, dependence on the electricity grid is higher if the environmental constraints are not applied, with more energy imports required, which limits the benefit of self-consumption as a measure to enable an increased share of RE in electricity grids in the next decades.

The seasonality of PV production was also studied in these scenarios, and it was concluded that winter days will require, on average, more energy imports than spring/autumn, which in turn require more imports than summer days. However, this conclusion may be distorted when the environmental constraints are not applied and there are price signals that justify importing more energy in months with more solar radiation. However, in most cases, the reduction in the need for energy imports is substantial depending on seasonality. Consequently, the plant designer should consider not only the average radiation profiles but also the seasonal differences to appropriately size the hydrogen storage downstream from the electrolyzer if energy imports are to be minimized. In addition, it has been also observed that the hydrogen demand is the main driver required from energy imports to feed the electrolysis system, but the greater it is, the higher the plant income.

To conclude, the optimal dispatch model presented in this paper serves to schedule the operation of PV-electrolysis plants in self-consumption regime. When combined with forecasting tools for estimating RE production and energy market prices, this model presents a useful decision support tool to operate hydrogen production facilities considering project profitability (lowest possible operational costs for the given restrictions) and sustainability (by prioritizing the matching of the RE source generation and the hydrogen production).

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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