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Multi-state techno-economic model for optimal dispatch of grid connected hydrogen electrolysis systems operating under dynamic conditions

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HIGHLIGHTS

- Multi-state model of electrolysis systems operating in dynamic conditions.
- Mathematical formulation of the multi-state model.
- Optimal hourly dispatch of grid connected electrolysis systems.
- Testing of the model with a real case study against a two states model.
- Sensitivity analysis for the case study including yearly results.

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ABSTRACT

The production of hydrogen through water electrolysis is a promising pathway to decarbonize the energy sector. This paper presents a techno-economic model of electrolysis plants based on multiple states of operation: production, hot standby and idle. The model enables the calculation of the optimal hourly dispatch of electrolyzers to produce hydrogen for different end uses. This model has been tested with real data from an existing installation and compared with a simpler electrolyzer model that is based on two states. The results indicate that an operational strategy that considers the multi-state model leads to a decrease in final hydrogen production costs. These reduced costs will benefit businesses, especially while electrolysis plants grow in size to accommodate further increases in demand.

Abbreviations: BOP, Balance Of Plant; CAPEX, Capital Expenditures; EU, European Union; FCEVs, Fuel cell electric vehicles; FCH, fuel cells and hydrogen; HRS, Hydrogen Refueling Station; MILP, Mixed Integer Linear Problem; NLP, Non-linear Problem; OPEX, Operational Expenditures; PEM, Polymer Electrolyte Membrane; PSU, Power Supply Unit; RE, Renewable Energy; RES, Renewable Energy Sources; WE, Water Electrolysis.

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Introduction

In the last decades, different initiatives worldwide have been fostering the introduction of fuel cells and hydrogen (FCH) technologies to address ambitious goals related to climate change [1–5]. In particular, the use of water electrolysis (WE) to produce hydrogen as an energy carrier is a promising approach to increase the penetration of renewable energy sources (RES) without overloading transmission and distribution electricity grids [6–12].

Today, electrolysis technologies still face critical challenges. These primarily include meeting the need for increased lifetime and energy efficiency of electrolysis systems, reaching stable and robust dynamic operation and reducing capital (CAPEX) and operational (OPEX) expenditures [13–17]. One of the main barriers to meeting these challenges is linked to electricity access costs, which increases annualized expenditures in electrolysis plants [18,19]. To overcome this obstacle, electrolysis plant operators can take advantage of low hourly electricity prices combined with grid balancing services. To this end, electrolysis plants must have the capacity for dynamic operation (which is currently being studied in several flagship demonstration projects [20]). This also mandates the application of optimal dispatch strategies based on sufficiently accurate techno-economic models of WE to obtain the operation states in which the electrolysis plants should operate. Currently, most models used to obtain the optimal dispatch and calculate the feasibility of electrolysis plants with techno-economic criteria are based on two states of operation [21–23].

In the early stages of this technology's deployment, electrolysis plant investors may expect progressive increases in hydrogen demand over time. This pattern holds true for most of the EU's existing hydrogen refueling stations (HRS) with on-site production that uses electrolysis; although these stations are currently oversized or underutilized based on the existing number of fuel cell electric vehicles (FCEVs), demand is projected to increase in the future [24–27]. This strategy has been selected to avoid further costly upgrades to the HRS when demand increases.

When the demand for hydrogen is lower than the capacity of the electrolyzer, the plant operator may benefit from keeping the electrolyzer in hot standby when electricity prices are high and producing hydrogen when prices are low. Maintaining this hot standby state avoids excessive cold starts during the stack lifetime and thus prevents degradation. However, it may also be desirable to turn off the unit once the hydrogen demand for a given period has been met to avoid the electricity consumption of hot standby.

To optimize electrolysis plant operation, this paper proposes a multi-state techno-economic model of electrolysis system that includes production, hot standby and idle states. This model can be used to determine the optimal dispatch strategy of electrolysis plants and to conduct realistic financial and technical feasibility studies. The paper is structured as follows: Section 2 describes the mathematical formulation of the multi-state model for water electrolyzers operating under dynamic conditions. In Section 3 the model is applied to a short-term case study, and the results are compared to those of a model based on two states. In Section 4, the multi-state model is applied to a one-year case study, and the results are discussed. Finally, Section 5 presents a series of conclusions and recommendations based on the results from Sections 3 and 4.

Multi-state techno-economic model for water electrolyzers operating in dynamic conditions

Description, scope and assumptions supporting the model

The aim of the techno-economic model proposed in this paper is to determine the optimal hourly dispatch strategy for electrolyzers that profits from the price volatility of the wholesale electricity market. This model applies to the most mature, state-of-the-art WE technologies, which includes low-temperature alkaline and polymer electrolyte membrane (PEM).

The scope of the model includes the electrolysis system, this is, the stack, the balance of plant (BOP) and the power supply unit (PSU). The latter typically includes a transformer and a rectifier to inject electricity in direct current to the stack under the required voltage and current conditions.

To achieve a sufficiently accurate dispatch calculation that considers technical and economic criteria, the model incorporates production, standby and idle states. These states are described below:

- Production: In this state, the input power to the WE system ranges from minimum partial operation (typically 10% of electrolyzer's rated power) to full load operation. In the production state, the electrolyzer produces hydrogen with a near-constant efficiency value; efficiency is slightly superior for partial loads. However, degradation of the stack takes place at the same time and affects the efficiency value, which decreases progressively. When the efficiency value falls below 90% of its initial value, the stack must be replaced. One or several replacements may be needed throughout the lifetime of the electrolysis plant.
- Standby: In this state there is no hydrogen production, but electricity consumption is required to maintain a specific temperature and pressure within the electrolyzer. Returning to a production state requires energy consumption but takes only in a matter of seconds.
- Idle: In this state the electrolyzer is turned off, that is, it is depressurized and cold. In this state, only low power consumption from control units and anti-freezing systems (if applicable given the location of the plant) is required; this consumption is much lower than that needed to keep the system in standby.

The system must be able to transition between these states. The transition times and implications for the model are depicted below:

- Standby to production (hot start): This transition takes place within seconds and is possible because the electrolyzer is warm and pressurized. The time required to reach the rated power of the system varies from 1 to 5 s for PEM technology to up to 30 s for alkaline electrolyzers.

- Production to standby: This transition takes place instantaneously because, in the production state, the electrolyzer is already warm and pressurized and in very similar conditions to those required to enter standby.
- Idle to production (cold start): The time required to pressurize and heat the unit to transition to production (the so-called cold start time) varies from 5 to 20 min depending on the technology (PEM or alkaline [13,23]). Notably, the impact of repeated cold starts on stack lifetime is currently unknown. Some manufacturers advise against exceeding several to five thousand cold starts during system lifetime [28,29].
- Production to idle: Although the time required to transition the unit into an idle state varies between the PEM and the alkaline technologies, it takes several minutes. However, as the electrolyzer stops producing hydrogen and the model follows an hourly basis, this time can be considered instantaneous for the purposes of the model.
- Idle to standby and standby to idle: These transitions are not profitable for the electrolysis plant operator, so the system should always move directly from production into idle or vice versa. Spending 1h in the standby state is unnecessary.

Given these definitions, the assumptions supporting the model are listed below:

- First, the model assumes that the operator of the electrolysis plant can purchase electricity through a contract indexed to wholesale market electricity prices. This assumption allows the model to obtain the optimal economic dispatch of the electrolyzer per hour.
- The demand and remuneration for the hydrogen output of the electrolyzer for injection into the hydrogen storage devices (portable or static) are unknown. The demand can be estimated based on final consumer use patterns, while the remuneration can be determined by using existing values in the literature [30] or by detracting the annualized costs of assets downstream the electrolyzer plant.
- It is possible to accurately estimate the wholesale market electricity prices three days in advance by analyzing seasonal and working patterns of electricity demand and by using information from the derivatives market.
- The hydrogen storage systems downstream from the electrolyzer are sized to accommodate the hydrogen production demand without adding restrictions to the model.

Mathematical formulation of the model

As the purpose of the model is to calculate the optimal dispatch of the electrolysis plant, the mathematical formulation includes consumption-dependent costs and revenues in order to maximize the economic benefit. Thus, once the model has been applied to a specific business case, it is possible to obtain the optimal dispatch of the electrolyzer and then apply other cost and revenue streams linked to the plant.

To calculate the optimal dispatch for each hour, h, in a year, the economic benefit, B_h, to be maximized is defined as the difference between revenues, R_h, and costs, C_h:

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

where R_h is the revenue for the hydrogen sold with the electrolyzer operating in production. As presented in equation (2), the efficiency η (kWh/kg), defined as the energy required to produce 1 kg of hydrogen, can be considered a constant parameter to perform economic optimization (due to the very low increase experienced when operating the electrolyzer at partial load). Then, if P is the rated power of the electrolyzer and RH is the remuneration for the hydrogen sold, R_h is proportional to the hourly load factor of the electrolyzer in production state r_h:

$$R_h = RH \cdot (P/\eta).r_h \tag{2}$$

As described in the previous section, R_h is equal to zero in standby and idle states because there is no hydrogen production.

The costs C_h also vary depending on the state of operation. As presented in equation (3), the costs in production, CP_h, are equal to the sum of:

- SRC_h: the hourly stack replacement costs, that is, the annual stack replacement cost divided by the number of hours in a year.
- $EPCP_h$: the hourly electricity purchase costs in production at rated power, which is equivalent to the sum of wholesale market cost plus network access tariff.
- WC_h: the water consumption per hour at rated power.

Both $EPCP_h$ and WC_h depend on r_h, while SRC_h assumes a constant value (degradation is assumed to be constant in production due to its unknown patterns [30]).

$$CP_h = (EPCP_h + WC_h) \cdot r_h + SRC_h \tag{3}$$

However, for the costs in standby, CS_h, the stack is not producing hydrogen, so SRC_h can be omitted. This is also true for WC_h, as the water demand is calculated per kilogram of hydrogen and considered in equation (2). Thus, the only costs in standby are the hourly electricity purchase costs $EPCS_h$, which have a constant value and are a percentage of the rated power of the electrolyzer system.

$$CS_h = EPCS_h \tag{4}$$

Finally, costs in idle CI_h can be considered in the model but have been omitted due to the very low energy demand of the electrolyzer in this state.

To calculate the hourly economic benefit, B_h, the following information is required: the load factor in production, r_h, and the electrolyzer's operating state. Consequently, following values must be calculated to obtain B_h:

- r_h: the load factor of the electrolyzer in production, which is a decimal value that lies between the minimum load factor (typically between 0.1 and 0.15) and 1. The load factor expresses the percentage of power demand in relation to the nominal power of the electrolyzer for each hour in the production state.

- a_h: an integer value that is equal to 1 in idle, 0 in standby and 0 in production.
- b_h: an integer value that is equal to 0 in idle, 0 in standby and 1 in production.
- c_h: an integer value that is equal to 0 in idle, 1 in standby and 0 in production.

The model also considers the costs related to the transition time between idle and production (cold start time) and between standby to production (hot start time). The implications of these transitions in terms of costs are that the electrolyzer is not producing hydrogen. The following values relate to transition times:

- CST_h: the percentage of an hour required for the electrolyzer to transition from idle to production.
- HST_h: the percentage of an hour required for the electrolyzer to transition from standby to production.

To maximize equation (1), the hourly equation for the objective function OF to be minimized every hour h is presented in equation (5):

$$OF_h = (-RH\cdot(P/\eta) + EPCP_h + SRC_h + WC_h)\cdot bh\cdot r_h + EPCS_h\cdot c_h + CI_h\cdot a_h + (CST_h\cdot RH\cdot(P/\eta))\cdot r_h\cdot b_h . a_{h-1} + (HST_h.RH.(P/\eta))\cdot b_h\cdot c_{h-1} \quad (5)$$

An additional restriction is the demand constraint, RW, which is the remuneration for selling the hydrogen produced within a certain time window TW to meet the expected demand for hydrogen. RW is defined in equation (6):

$$RW = \sum_{h=1}^{TW}(P/\eta)\cdot bh\cdot r_h \quad (6)$$

Thus, OF has the following form when the model is applied to a time frame TW:

$$OF = \sum_{h=1}^{TW} OF_h \quad (7)$$

Finally, other additional constraints are defined in the model to implement the previously defined operation states. These are summarized in equations (8–14).

$$a_h + b_h + c_h = 1\forall h \quad (8)$$

$$\sum_{h=1}^{TW} b_h\cdot a_{h-1} \le N \quad (9)$$

$$c_h.a_{h-1} = 0\ \forall h \quad (10)$$

$$a_h\cdot c_{h-1} = 0\ \forall h \quad (11)$$

$$r_h - b_h \le 0\ \forall h \quad (12)$$

$$-r_h + MPL\cdot b_h \le 0\forall h \quad (13)$$

$$0 \le r_h \le 1\ \forall h \quad (14)$$

Where N is the number of cold starts allowed within TW (to limit transitions from idle to production state) and MPL is the minimum partial load allowable for the electrolyzer, expressed as the percentage of power over the rated power. Equation (8) forces the electrolyzer to be in one of the three operation states each hour. Equation (9) imposes a maximum number of cold starts, and equations (10) and (11) restrict transitions from idle to standby. Finally, Equations (12–14) mandate that r_h be between the minimum partial and full load in production; r_h takes a value of 0 in the remaining states.

Equations (7–14) constitute a mixed-integer non-linear optimization problem (MINLP) that can be progressively solved within a certain time window to determine the optimal dispatch of an electrolysis plant. The solution of this linear system reflects the optimal operation strategy of the electrolyzer for each hour (r_h, a_h, b_h and c_h values). With the purpose of testing and applying the model to several scenarios in Sections 3 and 4, this MINLP problem has been solved using GAMS (General Algebraic Modeling System) by applying a branch-and-cut method to break the non-linear problem (NLP) model into a list of subproblems.

Definition of case study and application of the model

To test the model of electrolysis system formulated in section 2, a real case study of a Spanish grid-connected electrolyzer was defined using the framework of the EU project E-LAND [31]. This electrolyzer produces hydrogen to refuel a small fleet of FCEVs supplied by an HRS. The hydrogen production installation is depicted in Fig. 1:

The model is then applied to the electrolyzer system (which includes the stack, the BOP and the PSU). The scope of the model provides the flexibility to address other case studies in which there may be other pieces of equipment in the hydrogen production plant (for example, in the situation of a use case with injection into the gas grid where there will be required an injection skid and a pipeline). Thus, the analyst can either apply the techno-economic assessment to the electrolysis system (as it is the case in this paper with the purpose of testing the model formulated in section 2.2) or to expand it to the hydrogen production plant including the different elements required to produce the fuel as demanded by the end user. In the first case, it will be required to know the remuneration of the hydrogen at the output of the electrolyzer using prices in EUR/kg, where the value of the pieces of equipment downstream the plant have been removed (typically storage, compression, distribution and/or dispensing). In the second case, the analyst will work with the remuneration for the hydrogen at the output of the plant and will need to include the costs associated to the equipment downstream the electrolyzer as well as other elements of cost (for instance, if there is a compressor, the electricity consumption required to increase pressure per kilogram of hydrogen, expressed in kWh/kg, can be added to the global system efficiency value of the electrolyser, expressed in kWh/kg).

Even though the scope in this case study is the electrolysis system, a series of boundary conditions need to be considered

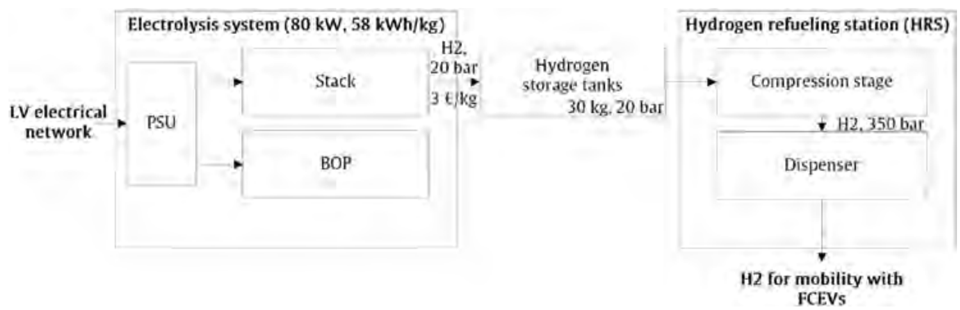

Fig. 1 – [2-column fitting] Representation of the hydrogen production installation used for the case study.

to assign values to the constant parameters in the model. This includes [31]:

- The electricity contract selected is one indexed to wholesale market electricity prices (2018 data).
- It is possible to anticipate wholesale market electricity prices several days in advance through existing forecasting techniques.
- The weekly demand for hydrogen to supply the HRS has been assumed constant since the usual routes from the captive fleet of FCEVs are known.
- The revenue for hydrogen delivered to hydrogen storage tanks (at the output of the electrolyzer) is 3 EUR/kg.
- Hydrogen storage capacity is 30 kg at 20 bar.

In addition, the technical parameters used to model the electrolyzer system are included in Table 1 [13,30].

With these input parameters, the model of electrolysis system can be tested over different short-term time frames (3 or 6 days). The input parameters, such as the hydrogen demand or the permissible number of cold starts, can also be modified to observe the impacts of these variations on the objective function value. Different time frames have also been selected for different months in 2018 (January and April) to observe the impact of wholesale market electricity price variation. The adjustments introduced to generate the different cases and an overview of the results are presented in Table 2 and Table 3, which use data from wholesale market electricity prices in January 2018 and April 2018, respectively.

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

Parameters for the electrolyzer system	
Parameter	Value
Nominal power	80 kW
System efficiency	58 kWh/kg
Standby consumption	5% of nominal power
Minimum partial load	15% of nominal power
Water consumption	15 L/kg
Lifetime for stack replacement cost	80,000 h
Lifetime of WE system	20 years
Lifetime of project	20 years
Maximum number of cold starts in system lifetime	3000–5000/year

Fig. 2 illustrates cases 1 (left) and 25 (right), each of which demonstrates different wholesale market electricity prices used to test the model and their influence on the operation pattern of the electrolyzer. For case 1, the best operation strategy is to profit from low electricity prices between hours 20 and 55 (using the standby state combined with minimum partial operation to avoid expensive energy costs) and between hours 120 and 144. Although there are some low-price peaks around hours 75 and 100, the best strategy is to avoid these hours due to the remaining high hourly prices throughout this time window, preventing the need for unnecessary cold starts. On the other hand, case 25 indicates an operational strategy that takes advance of the lower electricity prices in the first three days versus the remaining days. Minimal use of the standby state is also apparent in most of the cases. This result occurs because, for systems in the range of several to hundreds of kW, the ratio of standby consumption to system rated power (5% in this case study, as presented in Table 1) is higher than multi MW electrolysis plants (around 2% [23]). This difference is related to a need for larger BOP components in low power systems than in multi MW systems. However, in some cases in Tables 2 and 3, the standby state is used when hydrogen demand is low (e.g., case 1 with a production equivalent to 21.5% of the time generating hydrogen at full load). Taking advantage of low hourly electricity prices separated by a few hours is also desirable, and a standby state prevents exceeding the number of cold starts.

Furthermore, more accurately anticipating wholesale electricity prices enables the use of longer time horizons to better schedule the operation of the electrolyzer. In other words, with the same maximum permissible number of cold starts, it is possible to operate the electrolyzer more profitably (i.e., with a lower value for *OF*). As presented in Fig. 3, for cases 37, 40, 43 and 46 in April (within a six-day period), knowing electricity prices in advance enabled the system to first produce hydrogen and then to transition into idle. For example, cases 38 and 39 (three-day period each) both have an *OF* 36.8% higher (representing a savings of 0.16 EUR per kg of hydrogen produced) compared to case 37 (six-day period), while cases 14 and 15 have very similar results to case 13 (see Fig. 4) due to the different wholesale market prices structure in January and April. The monetary benefit arising from this anticipation strategy clearly decreases with hydrogen demand, as more hours in production are needed and cannot be limited to times with low wholesale electricity market prices.

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Table 2 – List of cases used to test the model with wholesale market electricity prices from January 2018.

Descriptions of cases					Results					
Case	Electricity market prices	Time frame (days)	Hydrogen demand (kg)	Maximum permissible cold starts	OF value (EUR)	Time (h) spent in production			Time (h) spent in standby	Time (h) spent in idle
						Full load ($r = 1$)	Minimum partial load ($r = 0.15$)	Partial load ($r > 0.15$)		
1	Jan. 15–20th	6	42.86	2	32.18	28	18	1	9	88
2	Jan. 15–17th	3	21.43	1	16.17	14	9	1	9	39
3	Jan. 18–20th	3	21.43	1	16.14	14	9	1	0	48
4	Jan. 15–20th	6	85.72	2	97.09	54	50	1	0	39
5	Jan. 15–17th	3	42.86	1	53.38	26	29	1	0	16
6	Jan. 18–20th	3	42.86	1	47.56	28	19	1	0	24
7	Jan. 15–20th	6	128.58	2	196.82	86	43	1	0	14
8	Jan. 15–17th	3	64.29	1	113.10	43	22	1	0	6
9	Jan. 18–20th	3	64.29	1	86.16	42	29	1	0	0
10	Jan. 15–20th	6	171.44	2	332.29	121	20	1	0	2
11	Jan. 15–17th	3	85.72	1	184.19	60	11	1	0	0
12	Jan. 18–20th	3	85.72	1	149.99	60	11	1	0	0
13	Jan. 15–20th	6	42.86	4	25.66	28	14	1	0	101
14	Jan. 15–17th	3	21.43	2	10.52	15	2	1	0	54
15	Jan. 18–20th	3	21.43	2	15.53	14	7	1	0	50
16	Jan. 15–20th	6	85.72	4	87.42	56	38	1	0	49
17	Jan. 15–17th	3	42.86	2	51.27	29	12	1	0	30
18	Jan. 18–20th	3	42.86	2	43.38	30	2	1	0	39
19	Jan. 15–20th	6	128.58	4	196.59	88	29	1	2	24
20	Jan. 15–17th	3	64.29	2	113.10	43	22	1	0	6
21	Jan. 18–20th	3	64.29	2	84.49	44	12	1	0	15
22	Jan. 15–20th	6	171.44	4	332.53	121	16	1	0	6
23	Jan. 15–17th	3	85.72	2	184.19	60	11	1	0	0
24	Jan. 18–20th	3	85.72	2	149.98	60	9	1	0	2

Table 3 – List of cases used to test the model with wholesale market electricity prices from April 2018.

Descriptions of cases					Results					
Case	Electricity market prices	Time frame (days)	Hydrogen demand (kg)	Maximum permissible cold starts	OF value (EUR)	Time (h) spent in production			Time (h) spent in standby	Time (h) spent in idle
						Full load ($r = 1$)	Minimum partial load ($r = 0.15$)	Partial load ($r > 0.15$)		
25	Apr. 2–7th	6	42.86	2	−18.27	27	22	1	0	94
26	Apr. 2–4th	3	21.43	1	−11.66	12	18	1	0	41
27	Apr. 5–7th	3	21.43	1	2.66	12	18	1	0	41
28	Apr. 2–7th	6	85.72	2	−15.02	58	26	1	0	59
29	Apr. 2–4th	3	42.86	1	−17.37	26	28	1	0	17
30	Apr. 5–7th	3	42.86	1	13.38	28	16	1	0	27
31	Apr. 2–7th	6	128.58	2	4.32	89	23	1	0	31
32	Apr. 2–4th	3	64.29	1	−17.50	42	24	1	0	5
33	Apr. 5–7th	3	64.29	1	32.03	45	9	1	0	17
34	Apr. 2–7th	6	171.44	2	42.46	122	12	1	0	9
35	Apr. 2–4th	3	85.72	1	−8.97	61	6	1	0	4
36	Apr. 5–7th	3	85.72	1	55.09	61	5	1	2	3
37	Apr. 2–7th	6	42.86	4	−18.87	29	10	1	0	104
38	Apr. 2–4th	3	21.43	2	−13.82	12	20	1	1	38
39	Apr. 5–7th	3	21.43	2	1.89	13	11	1	0	47
40	Apr. 2–7th	6	85.72	4	−16.29	58	24	1	0	61
41	Apr. 2–4th	3	42.86	2	−18.27	27	22	1	0	22
42	Apr. 5–7th	3	42.86	2	13.33	29	11	1	0	31
43	Apr. 2–7th	6	128.58	4	4.26	90	18	1	0	35
44	Apr. 2–4th	3	64.29	2	−17.86	44	16	1	0	11
45	Apr. 5–7th	3	64.29	2	32.06	45	5	1	0	21
46	Apr. 2–7th	6	171.44	4	42.48	122	12	1	0	9
47	Apr. 2–4th	3	85.72	2	−8.98	61	6	1	0	4
48	Apr. 5–7th	3	85.72	2	54.53	60	8	1	0	3

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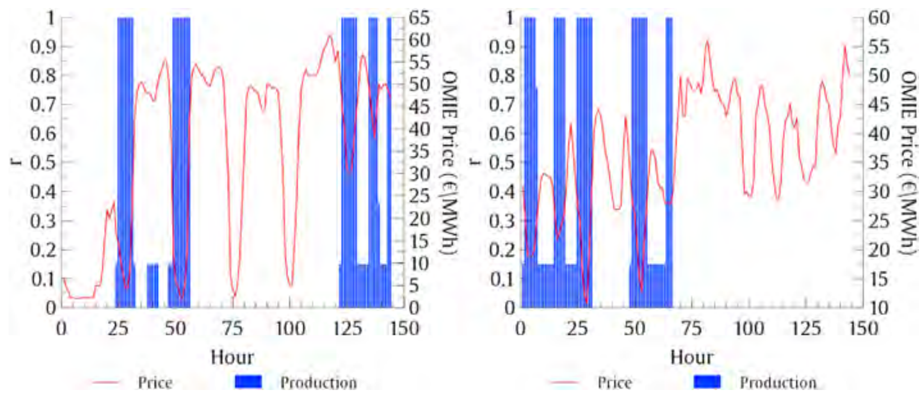

Fig. 2 – [2-column fitting] Wholesale market electricity prices (red-colored line) and load factor in production (blue bars) in cases 1 and 25. (For interpretation of the references to color/color in this figure legend, the reader is referred to the Web version of this article.)

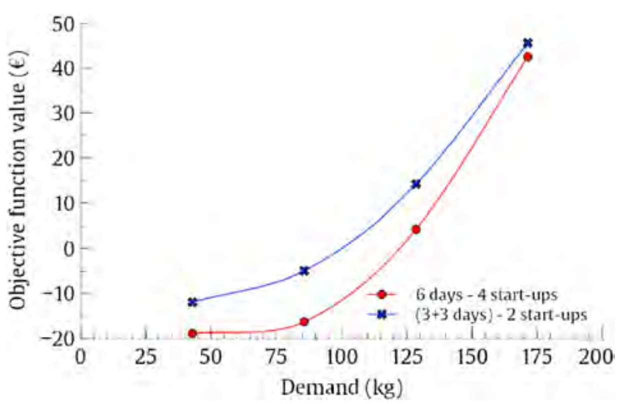

Fig. 3 – [Single fitting] OF values for cases 37, 40, 43 and 46 (red dots) and for cases 38–39, 41–42, 44–45 and 47–48 (blue dots). (For interpretation of the references to color/color in this figure legend, the reader is referred to the Web version of this article.)

Another result that can be inferred from the analysis of the data is the positive impact of increasing the number of cold starts from a maximum of two every six days to four (so as not to exceed the 5000 recommended by the manufacturer in Table 1). The importance of this change increases when the hydrogen demand is lower and also when there is a high frequency of peaks with low wholesale market electricity prices to profit from. For example, when cases 1 and 13 are compared, doubling the number of allowable cold starts to cover the same hydrogen demand increases the benefits by 20%. Fig. 5 illustrates this fact with cases 1, 4, 7, 10, 13, 16, 19 and 22.

Finally, it is also important to note the relevance of using the transition to idle to maximize the profit generated by the electrolysis plant when the demand for hydrogen is low. Figs. 6 and 7 present a comparison between the multi-state model of this paper and a two-state model. The latter is a variation of the model presented in this section, but it includes only standby and production states. These two-state models are

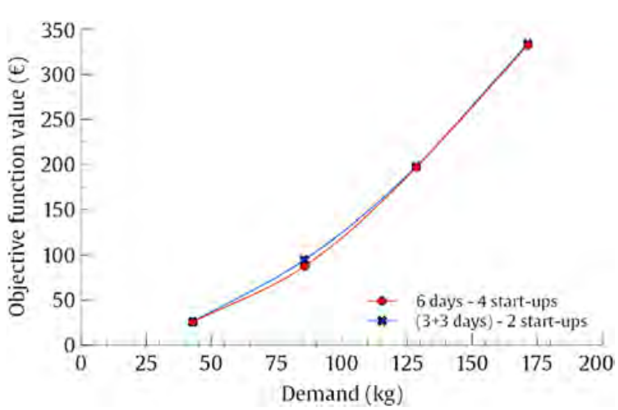

Fig. 4 – [Single fitting] OF values for cases 13, 16, 19 and 22 (red dots) and for combined cases 14–15, 17–18, 20–21 and 23–24 (blue dots). (For interpretation of the references to color/color in this figure legend, the reader is referred to the Web version of this article.)

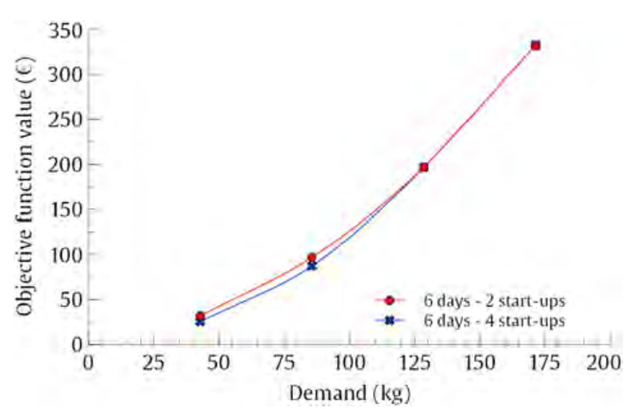

Fig. 5 – [Single column fitting] OF values for cases 1, 4, 7 and 10 (red dots) and for cases 13, 16, 19 and 22. (For interpretation of the references to color/color in this figure legend, the reader is referred to the Web version of this article.)

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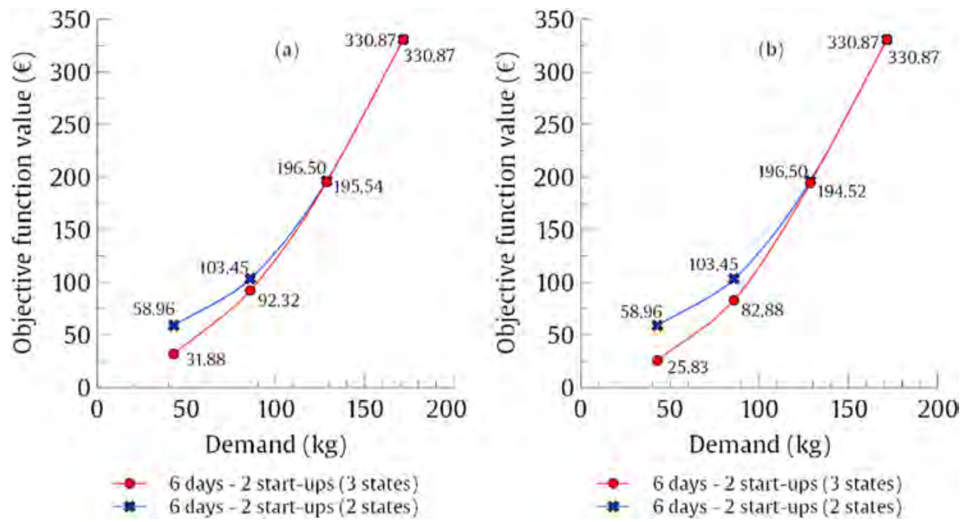

Fig. 6 – [2-column fitting] OF values for cases 1, 4, 7 and 10 when applying the multi-state model (red dots on the left), for cases 1, 4, 7 and 10 when applying the two state model (blue dots on the left), for cases 13, 16, 19 and 22 when applying the multi-state model (red dots on the right) and for cases 13, 16, 19 and 22 when applying the two-state model (blue dots on the right). (For interpretation of the references to color/color in this figure legend, the reader is referred to the Web version of this article.)

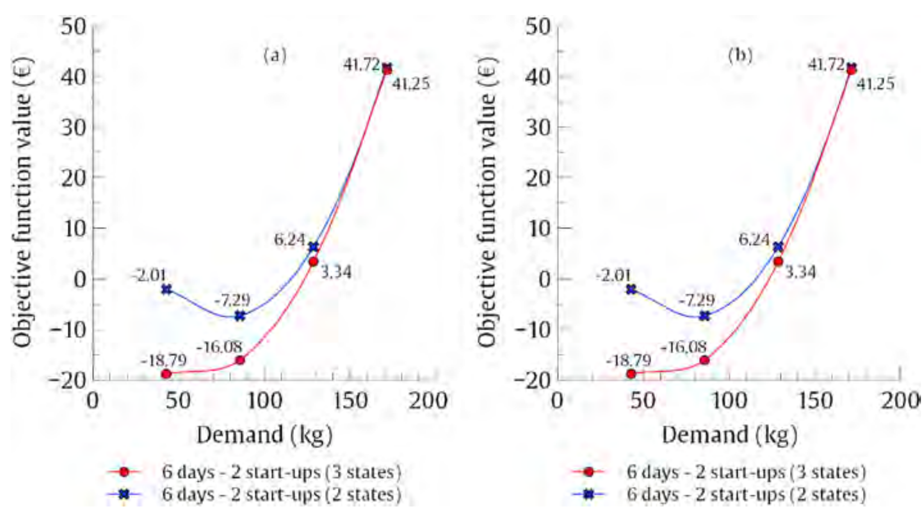

Fig. 7 – [2-column fitting] OF values for cases 25, 28, 31 and 34 when applying the multi-state model (red dots on the left), for cases 25, 28, 31 and 34 when applying the two state model (blue dots on the left), for cases 37, 40, 43 and 46 when applying the multi-state model (red dots on the right) and for cases 37, 40, 43 and 46 when applying the two state model (blue dots on the right). (For interpretation of the references to color/color in this figure legend, the reader is referred to the Web version of this article.)

used to study the feasibility of electrolysis plants that must respond to price minimization strategies. Such strategies avoid idle states to prevent an excessive number of cold-starts [18]. As observed, the lower the hydrogen demand, the higher the savings because the electrolysis plant operator can profit from optimal electricity prices and then go to idle. Without the option of switching to idle, the system would have to remain in standby, which would require energy consumption to keep the unit warm and pressurized. For example, in case 1, the use of the idle state saves 0.63 EUR/kg of hydrogen. In case 13, a standby state can be avoided when wholesale market electricity prices peak. As prices are more stable for case 13, the cost savings arising from entering an idle state are lower but still important (0.39 EUR/kg).

Results and discussion

The previous section discusses the application of the multi-state model to short-term time periods to observe specific

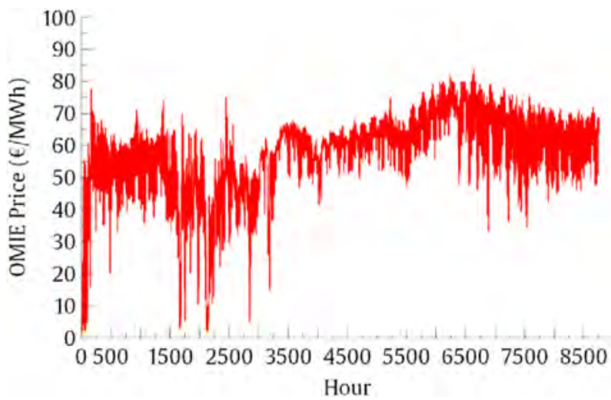

Fig. 8 – [Single column fitting]. Hourly wholesale market electricity prices in Spain in 2018 used for the scenarios of this section.

represent the historical maximum and minimum values in Spain (12% increase and 35% decrease, respectively). On the other hand, the variations in revenue for hydrogen sold in the electrolysis plant (3–5 EUR/kg) allow reaching profitable cases for mobility applications (final fuel price to end users between 7 and 9 EUR/kg). Finally, the 58 kWh/kg efficiency value used in scenarios 1 to 18 is based on Table 4, which characterizes a system manufactured several years ago. In scenarios 19 to 24, a value of 50 kWh/kg was used; this update reflects 2020 trends for alkaline technology [13]. Considering future trends allows one to assess the profitability of results at present. In all cases, the maximum permissible number of cold starts in the time window used for simulations (three days) is equal to one.

The impact of the variation of wholesale market electricity prices is illustrated in Figs. 9 and 10. As presented, a 12% increase in 2018 prices implies that scenario 15 generates a

Table 4 – Description of the scenarios assessed.

Description of scenarios					OF value
No.	Weekly hydrogen demand (kg)	Revenue for hydrogen sold (EUR/kg)	Wholesale market electricity prices	System efficiency (kWh/kg)	
1	50	3	2018 values	58	2644.03
2	50	3	35% decrease in 2018 values	58	−270.94
3	50	3	12% increase in 2018 values	58	3642.96
4	200	3	2018 values	58	18,069.89
5	200	3	35% decrease in 2018 values	58	4491.14
6	200	3	12% increase in 2018 values	58	22,722.90
7	50	4	2018 values	58	46.57
8	50	4	35% decrease in 2018 values	58	−2865.94
9	50	4	12% increase in 2018 values	58	1044.74
10	200	4	2018 values	58	7658.45
11	200	4	35% decrease in 2018 values	58	−5931.08
12	200	4	12% increase in 2018 values	58	12,312.15
13	50	5	2018 values	58	−2548.91
14	50	5	35% decrease in 2018 values	58	−5462.01
15	50	5	12% increase in 2018 values	58	−1551.64
16	200	5	2018 values	58	−2771.59
17	200	5	35% decrease in 2018 values	58	−16,320.76
18	200	5	12% increase in 2018 values	58	1889.45
19	50	3	2018	50	1397.24
20	50	4	2018	50	−1614.67
21	50	5	2018	50	−4624.54
22	200	3	2018	50	13,072.60
23	200	4	2018	50	985.76
24	200	5	2018	50	−11,093.20

impacts of the variation of different input parameters. To provide annual results, in this section the model is applied to the case study described in Section 3 and to a series of mobility-based scenarios with FCEVs to perform different sensitivity analyses and to provide additional insights. Wholesale market electricity prices of Spanish market operator OMIE from 2018 have been applied (see Fig. 8).

These scenarios and the *OF* value obtained are described in the rightmost column of Table 4. The weekly hydrogen demands of 50 kg and 200 kg are equivalent to the demand of around 5 and 20 commercial fuel-cell-powered business cars, respectively, fully refueling their 5 kg on-board tanks twice per week. The variations in wholesale market electricity prices

limited profit (negative *OF*) because the 5 EUR/kg remuneration for hydrogen contributes to cover the production costs. The strategy profits from low electricity prices but requires a certain amount of power consumption during some periods at minimum partial load operation or standby (between high wholesale electricity market price peaks). In fact, to avoid excessive transitions to idle (and subsequently, cold starts) when electricity prices are high, an increased hydrogen demand also leads to increased energy costs because these periods are longer. Also, when the demand is higher, hydrogen eventually has to be produced at higher electricity prices. Due to these factors, although scenarios 3, 9 and 15 have the same input parameters (a weekly demand of 50 kg of hydrogen),

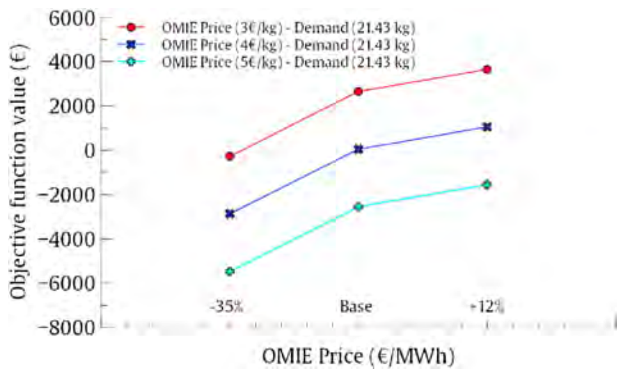

Fig. 9 – [Single-column fitting]. OF values for scenarios 1, 2 and 3 (red dots); 7, 8 and 9 (dark blue dots); and 13, 14 and 15 (light blue dots). (For interpretation of the references to color/color in this figure legend, the reader is referred to the Web version of this article.)

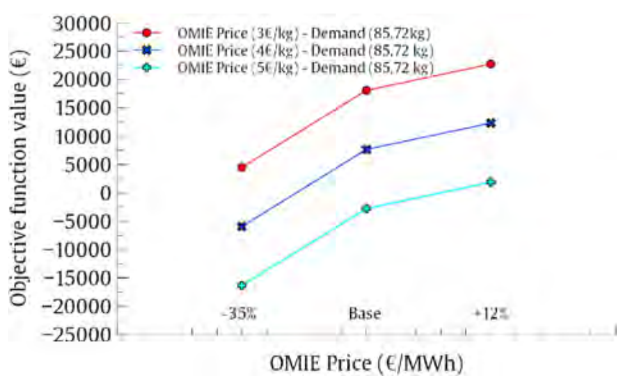

Fig. 10 – [Single-column fitting]. OF values for scenarios 4, 5 and 6 (red dots); 10, 11 and 12 (dark blue dots); and 16, 17 and 18 (light blue dots). (For interpretation of the references to color/color in this figure legend, the reader is referred to the Web version of this article.)

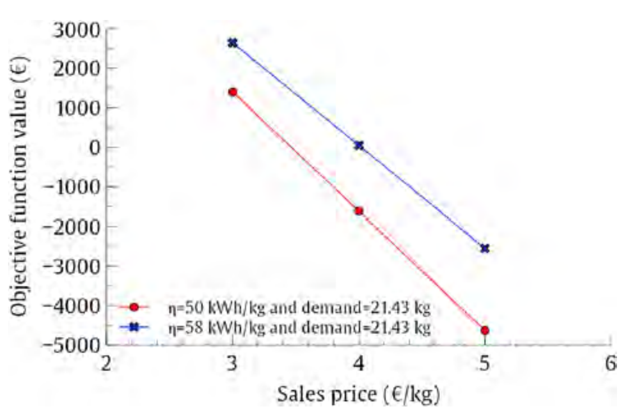

Fig. 11 – [Single-column fitting]. OF values for scenarios 19, 20 and 21 (red dots) and 1, 7 and 13 (blue dots). (For interpretation of the references to color/color in this figure legend, the reader is referred to the Web version of this article.)

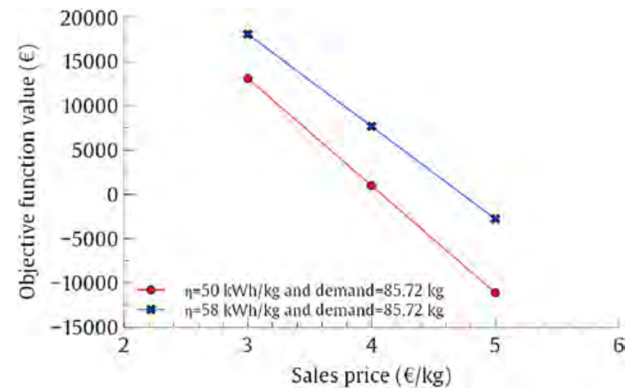

Fig. 12 – [Single-column fitting]. OF values for scenarios 22, 23 and 24 (red dots) and 4, 10 and 16 (blue dots). (For interpretation of the references to color/color in this figure legend, the reader is referred to the Web version of this article.)

they are more profitable than scenarios 6, 12 and 18 (a weekly demand of 200 kg of hydrogen). In the opposite case of minimum historical values of wholesale market electricity prices, scenarios 11 and 17 are more attractive than scenarios 8 and 14. This difference occurs because the hydrogen prices of 4 and 5 EUR/kg reduce the impact of longer periods at minimum partial load or standby when the demand is also high (scenarios 11 and 17). The hydrogen price also offsets the more expensive electricity required to produce the additional demand for this fuel. However, although electricity prices are low and the input parameters are the same, scenario 2 (weekly demand of 50 kg) is more attractive than scenario 5 (hydrogen demand of 200 kg). This is because the revenues from the hydrogen production (3 EUR/kg) do not compensate for the power consumption of the electrolyzer in a production state at higher electricity prices combined with the periods when the system is at standby or minimum partial load operation. For the baseline 2018 electricity prices, scenarios 1 and 7 are more profitable than scenarios 4 and 10. Only scenario 13 is more attractive than scenario 16 due to the 5 EUR/kg hydrogen price and the reasons explained above.

To address the volatility of wholesale market electricity prices, which can move between the thresholds simulated in these scenarios, different strategies can be used to lower hydrogen production costs. These strategies include benefiting from payments in exchange for the provision of grid services or discounts given for using curtailed electricity from RES, for example. On the other hand, the exact payment received by the operator of the electrolysis plant depends on the final price of hydrogen supplied at the HRS.

For the scenarios above, a negative *OF* value may not be sufficient to overcome the remaining costs linked to the plant, including system CAPEX, OPEX, stack replacements and other fixed terms related to electricity tariffs or other financial costs. This shortcoming is partly due to the efficiency value selected for the case study. To reflect current technology trends, scenarios 19 to 24 provide the results obtained using the efficiency expected for alkaline technology in 2020, 50 kWh/kg

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[13]. Fig. 11 indicates that scenarios 19, 20 and 21 offer an extra benefit of between 0.48, 0.64 and 0,80 EUR/kg of hydrogen compared to scenarios 1, 7 and 13. These benefits are considerable when compared with the hydrogen prices of 3, 4 and 5 EUR/kg for scenarios 1, 7 and 13, respectively. Fig. 12 also presents the similar benefits per kilogram of hydrogen obtained in scenarios 22 to 24 versus scenarios 4, 10 and 16. However, higher net amounts are obtained because production increases, ranging from 4997 EUR (scenario 4 vs. scenario 22) to 8321 EUR (scenario 6 vs. scenario 24).

Conclusions and recommendations

This paper presents a multi-state model of electrolysis systems that considers the production, standby and idle states as well as the related transitions, allowing one to determine the optimal dispatch of hydrogen production plants when using price minimization strategies.

The model has been tested using data from a real case study. The results indicate that anticipating hourly wholesale market electricity prices and applying the model allows a plant to transition to standby or idle (without exceeding a maximum permissible number of cold starts to prevent damage) to avoid high expenses relative to energy costs. Currently, two-state models, which consider production and standby states, are commonly used to keep an electrolyzer warm and pressurized in order to rapidly respond to different electricity market setpoints. However, an operation strategy that considers forecasted hourly electricity prices enables one to reduce plant costs by assuming an idle state when the hydrogen demand has been met. This practice avoids extra costs from standby operation, resulting in higher margins for the operator of hydrogen production plants.

The application of the model to different year-long scenarios has also demonstrated the considerable impact of varying some input parameters in a precise manner. In particular, wholesale market electricity prices may determine whether scenarios become profitable, but the selling price of hydrogen remains an essential aspect to maximize the system's benefits. The influence of both aspects varies with the demand for hydrogen: if more hydrogen needs to be produced, the levelized cost of hydrogen grows because the average electricity price used to supply the electrolyzer increases, so higher remuneration for this fuel is required to reach a profitable outcome. The application of the model has also illustrated how improvements in efficiency are critical to improve the profitability of this technology. However, the operator of the plant has limited influence on these factors, so additional cost reduction strategies need to be applied on the operational side to maximize profits. These may include profiting from providing grid services or from using bilateral contracts with RE producers. The economic profit from such strategies can be translated into final hourly prices for the electricity supplied to the electrolyzer. The multi-state model in this paper can be applied to ultimately determine the optimal dispatch of the hydrogen production plant. Thus, the application of the multi-state model presented in this paper, combined with different energy markets price forecasting strategies, comprises a decision support tool to operate hydrogen production plants in a more profitable way.

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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