INTERNATIONAL JOURNAL OF HYDROGEN ENERGY 44 (2019) 17431–17442

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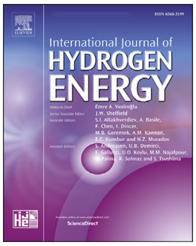

Techno-economic modelling of water electrolysers in the range of several MW to provide grid services while generating hydrogen for different applications: A case study in Spain applied to mobility with FCEVs

G. Matute [a], J.M. Yusta [b,*], L.C. Correas [c]

[a] Instrumentación y Componentes S.A., Alaún, 8, 50197, Zaragoza, Spain
[b] Department of Electrical Engineering, University of Zaragoza, María de Luna, 3, 50018, Zaragoza, Spain
[c] Universidad San Jorge, 50830, Villanueva de Gállego Zaragoza, Spain

ARTICLE INFO

Article history:
Received 30 January 2019
Received in revised form
9 May 2019
Accepted 10 May 2019
Available online 5 June 2019

Keywords:
Electrolyser
Fuel cell electric vehicle
Electricity market
Grid services
Frequency adjustment
Hydrogen markets

ABSTRACT

The use of hydrogen as energy carrier is a promising option to decarbonize both energy and transport sectors. This paper presents an advanced techno-economic model for calculation of optimal dispatch of large-scale multi MW electrolysis plants in order to obtain a more accurate evaluation of the feasibility of business cases related to the supply of this fuel for different end uses combined with grid services' provision. The model is applied to the Spanish case using different scenarios to determine the minimum demand required from the FCEV market so that electrolysis facilities featuring several MW result in profitable business cases. The results show that grid services contribute to the profitability of hydrogen production for mobility, given a minimum but considerable demand from FCEV fleets.

Introduction

The European Union (EU) aims to reduce greenhouse gas emissions by 40%, increase the share of renewable energy in the Member States' energy mix to 27%, and reach the 27% energy efficiency target by 2030 [1]. To accommodate this share of renewable energy sources (RES) without overloading transmission and distribution grids, a techno-economically viable solution is to convert the surplus renewable energy into hydrogen. The hydrogen generated by means of water electrolysis (WE) may be applied to different end uses, covering the following ones [2,3].

- chemical industry, refineries, or steel manufacturing to generate other by-products;
- refuelling of fuel cell electric vehicles (FCEVs);

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* *Corresponding author.*
E-mail address: jmyusta@unizar.es (J.M. Yusta).

https://doi.org/10.1016/j.ijhydene.2019.05.092

List of acronyms:

AWE	Alkaline Water Electrolysis
BEVs	Battery Electric Vehicles
BOP	Balance of Plant
CAPEX	Capital Expenditures
EU	European Union
FCEVs	Fuel Cell Electric Vehicles
HRS	Hydrogen Refueling Station
ICE	Internal Combustion Engine;
MO	Maintenance Operator
OMIP	Operador del Mercado Ibérico de Energía - Polo Portugués
OPEX	Operational Expenditures
PEM	Polymer Electrolyte Membrane
PSU	Power Supply Unit
RES	Renewable Energy Sources
SO	System Operator
TCO	Total Cost Of Ownership;
WE	Water Electrolysis
WACC	Weighted Average Capital Costs

- injection into the natural gas grid and use of gas networks as storage system for electric grids; and
- re-electrification via stationary fuel cells for cogeneration to inject electricity in weak grids or isolated microgrids.

Currently, FCEVs market seems to be one of the most promising for the hydrogen sector because of the following:

- The electricity grid has limited capacity to accommodate a full replacement of all the existing internal combustion engine (ICE) vehicles by battery electric vehicles (BEVs) without expensive infrastructure upgrades or advanced integration strategies [4,5]. Thus, other sustainable mobility concepts are expected to coexist with BEVs.
- The competition with fossil fuel prices results in hydrogen prices to final customers in the range of 8–10 EUR/kg.
- FCEVs are similar in performance to conventional vehicles in relation to refuelling times (around 2 min) and range (superior to 100 km per kg of hydrogen stored on board).
- The mobility sector is a large market that allows making profit from economies of scale. This may be achieved by upscaling hydrogen refuelling infrastructures or aggregating fleet operators to decrease cost of vehicles through large-scale contracts with manufacturers.

However, electrolysis technologies still face critical challenges that primarily include the need for reaching higher durability and efficiency, allowing dynamic operation with robust and stable performance, and reducing capital expenditures (CAPEX) and operational expenditures (OPEX). One possibility for operators and investors to overcome these challenges is to obtain revenues from the sale of hydrogen but also from the provision of grid services by operating electrolysers as flexible loads and responding to power setpoints within seconds. In fact, the potential of water electrolysis (WE) to provide different services to electricity grids has been widely assessed [6–9] as well as initially demonstrated in pilot projects in the EU, as in the Fuel Cells and Hydrogen 2 Joint Undertaking (FCH 2 JU) on-going projects DEMO4GRID and H2FUTURE for alkaline and polymer electrolyte membrane (PEM) technologies, respectively.

Thus, flexibility is defined in this context as the modification of generation and/or consumption patterns in reaction to an external signal (price signal or activation) to provide a service within the energy system [10].

According to Ref. [11], the higher the rates of RES in the European electricity grids, the more flexibility in the demand side should be implemented. The benefits of flexibility on the demand side may lead to key achievements such as the following:

- being able to accommodate and even increase the amount of RES in the system;
- avoiding or delaying network reinforcement; and
- system operators being able to match generation with demand.

In this scenario, hydrogen generation by WE could act as a dynamic load able to contribute to the flexibility of the electricity grid. Besides, while electrolysis is not very competitive today against other technologies that can bring flexibility to the grid in the range of several to hundreds of kW (due to competition with mature, proven, and fast response technologies such as different types of electrochemical batteries), it is in the range of several to hundreds of MW, where WE presents much more reduced CAPEX and OPEX values per unit of power due to economies of scale. In this range of power, it is possible for electrolysers to participate in the provision of grid services related to frequency adjustment for transmission system operators (TSO). Current regulations in most EU countries already allow not only generators but also consumers over a certain threshold (typically 1 MW or 5 MW, depending on the country). This concept is known as demand side flexibility, referring to the possibility of loads providing flexibility to the grid.

Thus, this paper proposes an accurate techno-economic model of multi MW electrolysis units to provide grid services and implement price minimization strategies, which should help FCEV and hydrogen refuelling stations (HRS) operators to conduct realistic financial and technical feasibility analysis and ease the search of profitable business. The paper is structured as follows: section 2 presents a multi MW WE model applied to the case of dynamic operation for grid services provision. Section 3 presents the methodology for optimal dispatch using the model presented in section 2. Then, section 4 describes the context in Spain which serves to apply the model and the optimal dispatch methodology as well as the case study and related future scenarios. With that framework defined, section 5 presents a discussion on the results obtained of the revenue optimization under various scenarios. Finally, section 6 elaborates on a series of conclusions and recommendations based on the results.

State of the art characterization and modelling of water electrolysers for the case study

For the two WE feasible technologies, namely alkaline and PEM, differences arise from the type of electrolyte used: liquid (potassium hydroxide) in the case of alkaline technology and a solid membrane in the case of PEM electrolysers.

From a high-level perspective, the advantages and disadvantages linked to each technology are listed in Table 1 [3,12].

Nonetheless, both technologies keep on developing with focus on achieving safe and robust operation under dynamic conditions required when units are coupled to RES or are used to provide grid services. For the first case, pilot activities are testing improvements on PEM [13] and alkaline [14] units towards operation with direct and partial coupling to RES. In parallel, considerable progress is being done to optimize the sizing, boundary and input parameters for such installations considering control, cost or durability criteria integrating PEM [15] and alkaline electrolysers [16–18]. For the second case, the potential of PEM and alkaline technologies to provide grid services as flexible loads connected to electricity networks in terms of dynamic response is well known from the point of view of fast response requirements [19,20]. However, a relevant number of demonstration activities are still required (as those introduced in the previous section) to gain knowledge and extract reliable results related to long term operation.

In this scenario, some reliable techno-economic values and targets for the potential development of both PEM and alkaline technologies have been set (and updated in a regular basis) by the FCH 2 JU in the EU. It is worth remembering that this EU initiative gathers all public and private actors relevant in hydrogen technology including electrolysis manufacturers. The parameters used to model the PEM and alkaline electrolysers in this paper are provided in Table 2 for 5 MW systems in 2017 and 2025 considering reference EU studies [3,12,21] as well as experiences from on-going EU projects to provide grid services with electrolysers.

It is assumed that repetitive cold starts and dynamic operation of WE may negatively impact stack lifetime. But WE operation to provide grid services requires partial load, fast response within seconds and even operate in "standby mode" (this is, there is not production of hydrogen, but the stack is kept under operating temperature/pressure as well as all equipment within the balance of plant, BOP). This mode requires an estimated average 2% of nominal power at the stack in the case of multi-MW electrolysers and continuous energy consumption at the BOP equipment. Nevertheless, in multi-MW stacks, BOP consumption should weight a lower percentage of nominal power when compared to the typical 10% or 20% in the case of smaller electrolysers, in the range of several to hundreds of kW. This is another reason why large electrolysis units seem more suitable in providing grid services.

Given the hourly wholesale electricity market price evolution, the use of the standby mode together with partial load operation enables cost optimization strategies combining revenues from the hydrogen supply to FCEVs and from the provision of grid services. Following this approach, electrolysers can be modelled using two high-level states: production and standby. In the latter case, the machine is always ready with a fast response to start hydrogen production when electricity prices are low again or when the grid operator demands grid services, as explained below.

Table 1 – High-level vision of advantages and disadvantages of alkaline and PEM technologies.

	Alkaline	PEM
Advantages	• Lower CAPEX/OPEX • Mature and proven technology in multi-MW size for stationary operation • High lifetime of stack	• Short response time in dynamic operation • Stable solid electrolyte • Good performance in partial operation • High purity level of hydrogen
Disadvantages	• Less stable liquid electrolyte • Need for hydrogen purification for end uses • Longer time response • Long cold start time	• Higher CAPEX/OPEX • Lower lifetime of stack • Presence of platinum group metals • Less mature and proven technology for multi-MW uses

Table 2 – Parameters to model alkaline and PEM electrolysers.

Parameter	Alkaline		PEM	
	2017	2025	2017	2025
CAPEX of the system including stack, balance of plant, and power supply unit (EUR/kW)	830	600	1300	900
OPEX % of CAPEX/year)	3	3	3	3
OPEX due to stack replacement (EUR/kW)	380	270	470	250
Lifetime (h) of stack	80,000	90,000	40,000	50,000
System lifetime (years)	20	20	20	20
Water consumption (L/kg of hydrogen produced)	15	15	15	15
System efficiency (kWhe/kg hydrogen)	52	50	61	53
Output pressure intervals (bar)	1–15	15–30	15–30	30–60
Minimum input power for partial operation (% of full load power)	10%	10%	10%	10%
Minimum response time (from hot standby to full load or vice-versa, seconds)	5	5	1	1
Cold start time (minutes)	<10	<10	<5	<5

- Production. This state corresponds to partial and full load operation, with the possibility to generate hydrogen when the input power ranges from 10% to 100% of the electrolyser's rated power. In this state, as the only available end of life information from multi MW electrolysers is related to continuous operation in the chemical industry [3], degradation of the stack is modelled as linear throughout lifetime due to lack of experimental data on how this phenomenon occurs with dynamic operation. Electrolyser's efficiency during production is a constant value, as provided in Table 2. Replacement of the stack occurs when efficiency falls below 90% of the initial value. Although it is known that stacks perform more efficiently at partial load [3], efficiency variations across the load curve have been neglected. In addition, there is a lack of data from manufacturers at multi MW level and also system efficiency depends on each BOP configuration (see values in Table 2).
- Standby. In this state there is no hydrogen production but electricity consumption to keep the electrolyser warm and pressurized (assumed as 2% of the electrolyser system's rated power when running at full load), with the ability to ramp up into production within seconds.

As electrolysers show an availability of at least 98% [12] and BOP equipment is sufficiently mature, it is assumed, for the purpose of this analysis, that it is not necessary to save a certain shut-down time for maintenance. Besides, grid services provision generally allows up to 5% of unavailability for maintenance. Other transitory states to bring the electrolyser from one to another can also be excluded from this analysis due to their low duration (seconds).

On the other hand, it is possible to keep electrolysers depressurized and at low temperature in the state previous to standby (generally known as cold standby or idle) with nearly zero energy consumption. However, this situation is not acceptable, as the time response to transition to production is in the range of several minutes. Moreover, cold starts should be avoided as their long-term effects on the stack lifetime are still unknown in alkaline and PEM technologies [14]. Current research projects intend to decrease cold start time to below 3 min [22] and to verify its effects on lifetime, which could in the end allow operation in cold standby, hence reducing the energy bill. However, at this moment, initiatives and research focused on grid services provision agree on the need to keep the electrolyser pressurized and warm in a low consumption standby state to ensure fast response.

For this reason, this paper considers only production (at different loads) and standby mode for modelling the electrolyser to provide grid services under dynamic operation (see Fig. 1).

Finally, the modelling in this study considers an electrolyser system including stack, balance of plant, and power supply unit (PSU) as represented in Fig. 1. The PSU in an electrolyser system typically includes a transformer and a rectifier to feed direct current power into the stack under the required conditions (low voltage, high current).

Methodology

The methodology proposed in this paper is based on optimal economic dispatch of an electrolysis plant by calculating the optimal hourly operation under the standby or production mode (partial to full load). The scope considers the electrolyser system, filling centres, and hydrogen storage devices, excluding the hydrogen refuelling station (HRS).

Then, for each hour h in a year, the economic benefit B_h to be maximized is defined as the difference between incomes I_h and costs C_h. I_h and C_h are obtained as the sum of components in equations (2)–(5) annualized and put in an hourly basis.

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

where I_h can be broken down into the remuneration for selling the hydrogen generated with the electrolyser operating at nominal power to FCEVs market (IHM_h) and that captured from the provision of the grid service (IGS_h):

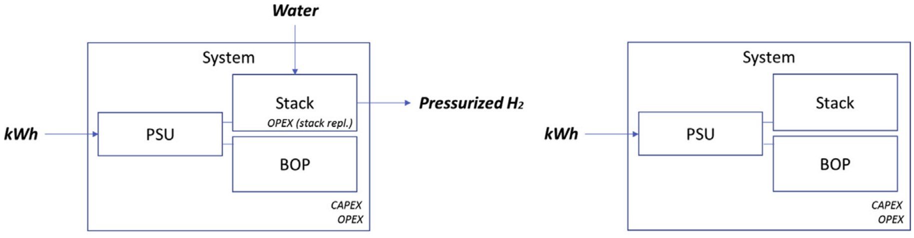
$$I_h = IHM_h + IGS_h \tag{2}$$

As explained in section 2, the model considers linear efficiency for the purpose of techno-economic feasibility assessments so IHM_h is proportional to the load factor of the electrolyser in production mode r_h.

On the other hand, C_h can be expressed as the sum of equipment costs EC_h and electricity purchase costs EPC_h

$$C_h = EC_h + EPC_h \tag{3}$$

where EC_h includes the CAPEX (CWE_h) and the OPEX (OWE_h) of the electrolyser, the stack replacement costs (SRC_h) and the water consumption (WC_h). It also includes the CAPEX from filling centres (CFC_h), storage trucks (CST_h) and other costs such as civil and engineering works or land permits (COT_h) as well as their relative OPEX (OFC_h, OST_h and OOT_h, respectively), as presented in equation (4):



Production (WE partial/full load)

Standby (WE hot, pressurized)

Fig. 1 – [Single fitting] Representation of the production mode (left) and standby mode (right) of the model.

$$EC_h = CWE_h + OWE_h + SRC_h + WC_h + CFC_h + CST_h + COT_h + OFC_h + OST_h + OOT_h \quad (4)$$

In the context of demand side flexibility, an electricity contract indexed to wholesale market electricity prices allows large consumers to benefit from changing hourly electricity prices. A common option offered by retail electricity providers are the so called “pass-through contracts” indexed to wholesale market electricity prices. Considering this option for a large consumer in Spain, equation (5) shows the breakdown of the hourly electricity costs EPC_h:

$$EPC_h = WM_h + CP_h + PMOSO_h + ATE_h + ATP_h + ET_h + MT_h + OC_h + FF_h \quad (5)$$

The variables in equation (5) are explained below:

WM_h: wholesale market electricity prices.

CP_h: capacity payments which are assigned to generators for availability to cover the demand.

$PMOSO_h$: payments to the market operator (MO) OMIE and the system operator (SO) REE.

ATE_h:access tariffs for the energy purchased.

ATP_h: access tariffs for the contracted power.

ET_h: electricity taxes.

MT_h: municipality taxes.

OC_h: retailer operation costs for accessing energy markets.

FF_h:retailer financing fees.

The items in equations (4) and (5) which depend on the energy consumed (partial to full load in production as well as standby consumption) are WC_h, WM_h, CP_h, $PMOSO_h$, ATE_h, ET_h, MT_h, OC_h and FF_h. Besides, their variation is proportional to the energy consumption of the electrolyser; this is, to r_h.

Then, consumption dependent costs CDC_h are:

$$CDC_h = WM_h + WC_h + PMOSO_h + ATE_h + ET_h + MT_h + OC_h + FF_h \quad (6)$$

Besides, degradation of the stack takes place in production mode only, so SRC_h related costs are then considered. This degradation is linked to stack operation, so it is independent from the load factor value r_h.

As presented, IHM_h depends on the energy consumed in the electrolyser to produce hydrogen while IGS_h is constant as it is relative to hourly availability payments to provide secondary frequency regulation. Thus, the following variables have to be calculated to maximize the benefit B_h:

- r_h: the load factor of the electrolyser which is a real variable between 0.1 and 1 expressing the percentage of power demand in relation to nominal power within each hour.
- y_h: the integer variable which is equal to 1 in production, and 0 in standby.
- z_h: the integer variable which is equal to 0 in production, and 1 in standby.

If the consumption of the electrolyser in standby in relation to the nominal power CS is known, the objective function to be maximized hourly is:

$$max(IHM_h - CDC_h) \cdot r_h - SRC_h \cdot y_h - CDC_h \cdot z_h \cdot CS \quad (7)$$

In the optimization problem, some constraints related to operation modes of the electrolyser should be also considered, as shown in equations (8)–(11). This includes RW, the remuneration for selling the hydrogen produced within a three days period (time window to obtain accurate estimations of wholesale market electricity prices) to cover the demand from a certain number of FCEVs.

$$\sum (r_h \cdot IHM_h) = RW \quad (8)$$

$$r_h - y_h \leq 0 \quad (9)$$

$$-r_h + 0.1 \cdot y_h \leq 0 \quad (10)$$

$$y_h + z_h = 1 \quad (11)$$

Equations (7)–(11) constitute a mixed integer linear optimization problem, which is solved through a simplex algorithm for all hours in a year (in this case, year 2016 following the assumptions listed in Section 4 in terms of wholesale market electricity prices and hydrogen demand). This allows obtaining the operation pattern of the electrolyser for each hour in the year (hourly values of r_h, y_h, z_h) and then calculating the economic benefit through equations (1)–(6) for a certain hydrogen demand affecting the constant value RW. This process is iterated until the minimum number of FCEVs to make equation (1) greater than zero is found by modifying the RW value in each iteration.

Context in Spain and definition of scenarios for the case study

Situation in Spain

In Spain, the only possibility to provide grid services using loads [23] is called ‘interruptibility grid service’. The service requires decreasing consumption in either 5 MW or 90 MW steps. However, due to the service availability of more than 95% required by the TSO, this scenario is not feasible for the participation of multi-MW electrolysers, as the OPEX would be dramatically affected (95% of the year, electrolysers should be operating over 5 MW load). This scenario does not match well with the expected near future deployment of FCEVs, which would eventually generate smaller demands.

A more attractive option would be the participation in the secondary regulation market managed by the Spanish transmission system operator Red Eléctrica de España, which contributes to adjust frequency in the transmission grid. The provision of this service is remunerated for both decreasing and increasing loads in 10 MW steps within maximum 5 min. Currently, only electricity generators are allowed to participate in the provision of the service. However, based on the trends in other EU countries [24], where grid services are already in place providing remuneration to increasing or decreasing loads in 1 MW–5 MW steps to regulate frequency, Spain should soon require a similar approach to avoid substantial grid reinforcement.

Besides, Spain is still lagging other EU initiatives in terms of hydrogen refuelling infrastructure, which is concentrated in central and northern Europe. Table 3 shows the expected number of HRSs in the EU in 2020, 2025 and 2030 in pioneering countries [25–29].

Spain is trying to join these initiatives within this framework. Currently, six HRSs are available in Spain for refuelling, and four new ones are foreseen by 2020 to link the north of the country with the south of France through the H2PiyR project [30]. These initiatives aim at tackling the ambitious expectations set out by the Spanish government in 2016 of 20 HRSs by 2020 [31]. The main barrier to the introduction of hydrogen mobility in Spain, as in other countries, is the high total cost of ownership (TCO) for the FCEVs and, especially, for the refuelling infrastructure. FCEVs are already available with a similar performance compared to conventional ICE vehicles, where the still higher CAPEX and OPEX are mainly due to the content in platinum group metals and limited lifetime of fuel cell stacks.

In the case of refuelling infrastructure with on-site green hydrogen production from water electrolysis, CAPEX includes the electrolyser itself, the hydrogen storage, compression and HRS. As regard to the electrolyser, costs per MW exceed 800 kEUR if alkaline WE (AWE) or 1300 kEUR if PEM WE (see Table 2). For the HRS, in case of supply at 700 bar, the costs should account for 1000 kEUR for a supply of around 200 kg of hydrogen per day [12]. Considering that an average car in the EU travels 12,000 km/year [32] and fuel use of 1 kg per 100 km, this means 2.3 kg of hydrogen demand per week and per car. The smaller the HRS, the higher the unit costs, due to economies of scale.

Thus, the case study developed to test the model and the optimal dispatch methodology explained before assesses the minimum demand of hydrogen required from a potential fleet of FCEVs in Spain, so that the implementation of 5 MW electrolysers supplying this fuel while participating in the secondary regulation market is economically feasible. For this purpose, a base case and different scenarios to evaluate sensitivity against different parameters are detailed in Section 4.2.

Scope and definition of scenarios in the case study

The hydrogen production facility considered for the case study includes the electrolysis system as defined in Fig. 1, the filling centre (compression skids as well as piping and filling equipment to inject the hydrogen into vessels such as tube trailers or cylinders), and logistics for the transport of hydrogen. Literature usually provides both the expected selling price charged by HRS operators to end users (FCEVs) and the price to be paid by HRS operators to gas suppliers. The expected hydrogen price intervals for mobility competitive with fossil fuels while providing revenues to HRS operators and sustaining the supply chain are provided in Table 4 [2,12,21].

Table 4 – Expected intervals of the price of hydrogen from 2017 to 2025 in EU countries.

Acceptable hydrogen fuel price to end-users	**9–10 EUR/kg H_2**
Acceptable hydrogen fuel price delivered to HRS	**5–7 EUR/kg H_2**

Table 5 – Technical and economic data about filling centres and tube trailers.

Filling centers			
Input and output pressure	Power consumption	Maximum hydrogen flow	CAPEX (EUR)
Patm to 200 bar	5 kWhe/kg	20 kg/h	687
		100 kg/h	1986
		400 kg/h	4959
15 bar–200 bar	2.4 kWhe/kg	20 kg/h	498
		100 kg/h	1441
		400 kg/h	3597
30 bar–200 bar	1.7 kWhe/kg	20 kg/h	467
		100 kg/h	1351
		400 kg/h	3373
60 bar–200 bar	1.1 kWhe/kg	20 kg/h	441
		100 kg/h	1276
		400 kg/h	3185
Tube trailers			
Pressure (bar)			CAPEX (EUR/kg)
200 bar			500

Thus, the case study considers a 5 MW electrolyser to supply hydrogen to tube trailers for distribution to the HRS. Specifically, 12 trailers with a capacity of 200 kg at 200 bar are considered. It is expected that 500 bar, Type 4, composite-based cylinders could equip commercial trailers by 2025 which would deliver up to 1000 kg per truck [12]. Moreover, in the long term, an infrastructure of hydrogen pipelines should support massive FCEV deployment. These trailers could serve a minimum of six HRS located several kilometres around the electrolyser by using two of them for each supply point —one would be charged at the generation point with hydrogen while the other one would be used as mobile storage in the station— along with a cabin to exchange them. Some technical and economic data about compression equipment to reach 200 bar and tube trailers to store 200 kg of hydrogen at 200 bar are provided in Table 5 [12].

Regarding electricity tariffs for large consumers, the most appropriate formulas in Spain to put in place price minimization strategies (i.e., operating when the wholesale market prices are low) are the contracts indexed to hourly electricity

Table 3 – Perspectives for the cumulated number of HRSs deployed in EU countries.

	Belgium	Germany	UK	Netherlands	Denmark	Sweden	Norway	France	Italy	Total (EU)
2020	25	100	65	20	15	15	25	29	20	**314**
2025	75	400	300	80	185	185	308	355	197	**2085**
2030	150	900	1100	200	500	500	833	600	442	**5225**

prices. In this study, as proposed in section 3, a pass-through contract indexed to spot market prices is considered [33,34]. It includes transmission power loss coefficients [35], which are applied to capacity payments, payments to MO/SO, and operation costs included in equation (5) in Section 3.

About the provision of grid services, as explained in Section 4.1, participation in secondary regulation is suggested assuming that electricity consumers are allowed to participate in this regulation by increasing or decreasing their consumption. The provision of this grid service is rewarded through two concepts [36]:

- availability payment, in EUR per MW offered either to increase or decrease, and assigned automatically each hour to the units participating in the service provision that have bid below the marginal price the day before for each hour in the day; and
- activation, in EUR per MWh offered either to increase or decrease and calculated as the marginal price of the tertiary regulation that would have been required to cover the secondary regulation.

A reasonable approach for a 5 MW electrolyser could be the provision of the service integrated in a pool with other generation units and/or loads to offer 1 MW steps of increase or decrease. In this way, for example, if the electrolyser works at full load (e.g., because electricity prices are low) and it is demanded to increase power consumption, other units within the pool will provide the service. The same would happen if the requirement is to decrease power and the unit is in standby mode. Then, the electrolyser would be used to capture the availability payment and support provision of the service to an operator that participates in secondary regulation.

Another possibility could be to participate individually in the provision of the service, but it would require operation at an intermediate load which allows increasing or decreasing the power as bid. The drawback is that this strategy limits taking full advantage of price minimization strategies. Although more power would be available to be captured in secondary regulation (i.e., around 2 MW to be increased or decreased if the electrolyser is operating at 2.5 MW when electricity prices are low), the operation at an intermediate point means more hours at higher electricity prices and more degradation of the stack (as the machine spends more time in the generation state). This is not compensated by the reward for availability to provide the grid service.

An additional strategy could be to operate the electrolyser at full load power (5 MW), waiting to provide the service by decreasing in a single 5 MW step (interruptibility service). However, in this case the hydrogen produced must be aligned with the reasonable demand from the FCEVs fleet available. If, on the contrary, the electrolyser is kept in standby to increase power when demanded by secondary regulation requests, the amount of hydrogen produced could not reach the demand ensuring profitability. Besides, if secondary regulation is allowed to electricity consumers in the short term in Spain, the requisite of a minimum of 10 MW steps would be expected to be maintained until the service is prepared to accommodate smaller steps (as in other EU countries).

These facts as well as the currently unknown capabilities of electrolysis in dynamic operation (which could involve additional maintenance needs, etc.) make it more realistic to group several units, which guarantee a response to the requests from secondary regulation. Thus, the case study in this paper focuses on a 5 MW electrolyser prioritizing price minimization strategies while offering 1 MW steps in secondary regulation, either increasing or decreasing. This electrolyser could then be integrated with other generation units and/or loads to capture the availability payment linked to this grid service.

Finally, the following assumptions are made to build the case study:

- It is possible to anticipate with sufficient accuracy the wholesale market electricity prices three days in advance to design the electrolyser's operation patterns through the market operator (*Operador del Mercado Ibérico de Energía - Polo Portugués*, OMIP). OMIP manages the power derivatives market in Spain and Portugal, including futures.
- The demand from each FCEV follows a weekly pattern and is estimated at 2.3 kg per week, as detailed in Section 4.1.
- The selling price of hydrogen when delivered to an HRS is 7 EUR/kg, which is still competitive with fossil fuels.
- Financial costs to acquire all the equipment in the scope of the case study with external funding are assumed to be 5% of the weighted average capital costs (WACC).
- The electrolysis unit and project are designed for a lifetime of 20 years.

In addition, the base case in this study will be varied to assess the scenarios resulting from modifications of some

Table 6 – Description of the scenarios assessed.

Scenario	*Description*	
1	• 5 MW AWE with key performance indicators (KPIs) for 2017 for the equipment involved • The year 2016 as the basis for values of prices, taxes, and tariffs • Contract indexed to wholesale electricity market and provision of secondary regulation grid service • Hydrogen generated at atmospheric pressure to refuel FCEVs and sold at 7 EUR/kg to HRS operators	
2	Variations on scenario 1:	5 MW, 30 bar AWE with 2025 KPIs for the equipment involved
3		5 MW, 30 bar PEM WE with 2017 KPIs for the equipment involved
4		5 MW, 60 bar PEM WE with 2025 KPIs for the equipment involved
5		10% decrease in wholesale electricity market prices over 2016 values
6		10% increase in wholesale electricity market prices over 2016 values
7		Hydrogen sold at 5 EUR/kg to HRS operators
8		Hydrogen sold at 6 EUR/kg to HRS operators

Table 7 – Annualized costs and incomes obtained as well as results after simulating each scenario to refuel a minimum FCEV fleet for each case to reach a minimum positive benefit.

		Scenario							
		1	2	3	4	5	6	7	8
Results	Hours of operation (h) per year	2316	1723	3820	2056	2435	2656	5470	1849
	Yearly hydrogen production (kg)	203,157	166,634	304,625	190,018	213,596	232,982	479,824	266,052
	Minimum FCEV fleet	**1404**	**1093**	**2040**	**1311**	**1339**	**1478**	**3275**	**1849**
Costs (EUR)	Electrolyser system CAPEX	207,500	150,000	325,000	225,000	207,500	207,500	207,500	207,500
	Electrolyser system OPEX	6225	4500	9750	6750	6225	6225	6225	6225
	Stack replacement costs	–	–	117,500	–	–	–	95,000	–
	Water consumption	11,580	9498	17,364	10,831	12,175	13,280	27,350	15,165
	Wholesale market energy cost	413,579	297,301	664,563	368,119	362,280	469,006	999,368	544,223
	Energy cost (energy access tariff cost + wholesale market cost)	428,959	309,074	689,412	382,095	377,072	485,044	1,044,838	563,926
	Demand access tariff cost	306,476	306,476	306,476	306,476	306,476	306,476	306,476	306,476
	Electricity tax	37,601	31,471	50,917	35,205	34,948	40,468	69,089	44,501
	Municipal tax	6204	4460	9968	5522	5434	7035	14,991	8163
	Operation costs	15,414	11,258	23,819	13,811	14,721	16,125	34,191	19,880
	Financial costs	2206	1847	2988	2066	2051	2375	4054	2611
	Filling center CAPEX	99,300	67,550	67,550	63,800	99,300	99,300	99,300	99,300
	Mobile storage CAPEX	48,000	48,000	48,000	48,000	48,000	48,000	48,000	48,000
	Other costs (CAPEX)	141,920	106,220	176,220	134,720	141,920	141,920	141,920	141,920
	Mobile storage OPEX	1920	1920	1920	1920	1920	1920	1920	1920
	Other costs (OPEX)	5677	4249	7049	5389	5677	5677	5677	5677
	Financial costs (WACC 5%)	24,836	18,589	30,839	23,576	24,836	24,836	24,836	24,836
Incomes (EUR)	Incomes for selling hydrogen	1,182,530	920,635	1,717,402	1,104,257	1,127,289	1,244,921	1,970,384	1,334,559
	Secondary regulation service provision	136,688	136,688	136,688	136,688	136,688	136,688	136,688	136,688
	Total annualized incomes	1,319,217	1,057,323	1,854,089	1,240,945	1,263,977	1,381,609	2,107,071	1,471,247

input parameters and data, as presented in Table 6, in a sensitivity analysis.

Results and discussion

To implement the methodology described in Section 3, MATLAB has been applied to solve the mixed integer linear optimization problems linked to every scenario in Table 6. The results, which include the minimum demand expressed as a minimum number of FCEVs, are provided in Table 7.

Scenarios 1 and 3 present the results obtained for alkaline and PEM technologies with current performance indicators, respectively. As observed, CAPEX from PEM WE is considerably higher than that of AWE. Besides, durability of the stack is also more reduced in PEM WE. For this reason, within the 20-year lifetime of the project, a stack replacement is needed in scenario 3 but not in scenario 1. This is because, in scenario 3, there is a need to feed more FCEVs to reach profitability. In addition, as presented in Fig. 2, superior efficiency ensures that a minimum fleet of 1404 FCEVs would be needed in scenario 1, whereas scenario 3 would need 2040 FCEVs (45% more).

Thus, although PEM WE has been suggested for dynamic operation, the fact that secondary regulation requires a response within 5 min makes AWE capable of providing the service while presenting a more favourable business case. Another advantage of PEM WE technology is that it delivers hydrogen at higher pressure. In scenario 3, it is assumed that while the AWE generates hydrogen at atmospheric pressure, the PEM WE delivers hydrogen at 30 bars, which leads to reduced costs in filling centres to inject the gas in the trailers and increased overall efficiency, as less energy is needed for compression (see Table 5).

On the other hand, scenarios 2 and 4 present the impact of introducing improvements in electrolysis equipment for each technology over scenarios 1 and 3, respectively. The improvements introduced in performance indicators are expected by 2025 as a consequence of research and innovation projects in place in the field of electrolysis, but not for the gas handling equipment, as filling centres based on electromechanical compression and tube trailers are already mature technology. Specifically, 500 bar trucks are expected to be still more expensive per kg of hydrogen than 200 bar ones by 2025 [12], so this pressure level has not been considered. As observed, in the case of AWE technology (scenario 2), these improvements in performance indicators yield a decrease in the required FCEV demand by 22.15% in relation to scenario 1 to obtain a profitable case. Besides, operation pressure has been set to 30 bar, which reduces the costs of filling centres and increases efficiency.

In the case of PEM WE technology (scenario 4), improvements in capabilities enable a positive case with 35.73% reduction (see Fig. 3) in demand with respect to scenario 3, with an impact that is considerably greater than that in the AWE's case. This is because PEM WE technology is less mature, and considerable improvements are expected in the following years. A clear sample is that the work towards increasing the durability of PEM WE stacks foreseen for the next decade allows covering the demand in scenario 4 without stack replacement, which was needed in scenario 2. Besides, the delivery of hydrogen at 60 bar in scenario 4 leads to reduced CAPEX from filling centres and improves global efficiency of the facility.

In parallel, scenarios 5 and 6 show respectively the impact of an increase and decrease of 10% in wholesale market electricity prices over those in 2016. A price increase over levels in 2016 is reasonable, as the average wholesale market electricity price in that year was 39.67 EUR/MWh, lower than the price in 2015 (50.31 EUR/MWh) or 2014 (42.14 EUR/MWh). Specifically, wholesale market electricity prices in 2017 were particularly high with an average of 52.24 EUR/MWh in Spain.

On the other hand, a decrease over 2016 prices can be expected in the short to medium term if more renewable energy is added to the energy mix to comply with the EU targets by 2030. Nevertheless, the impact of these changes on prices is not very relevant for the minimum demand of FCEVs required. Scenario 5 means a decrease in the demand by 4.63%, while scenario 6 leads to an increase in the demand for FCEVs by 5.27%. This is because, in Spain, the impact of wholesale market electricity prices in relation to other regulated concepts (e.g., tariffs or taxes) is low in comparison to that in EU member states, and this does not have a considerable weight on final energy bills. In fact, the cost of energy in the wholesale market in relation to the final figure in the energy bill is 48.91% in scenario 5 and 54.69% in scenario 6 (see Fig. 3). As a result, critical reductions in wholesale market prices would have to

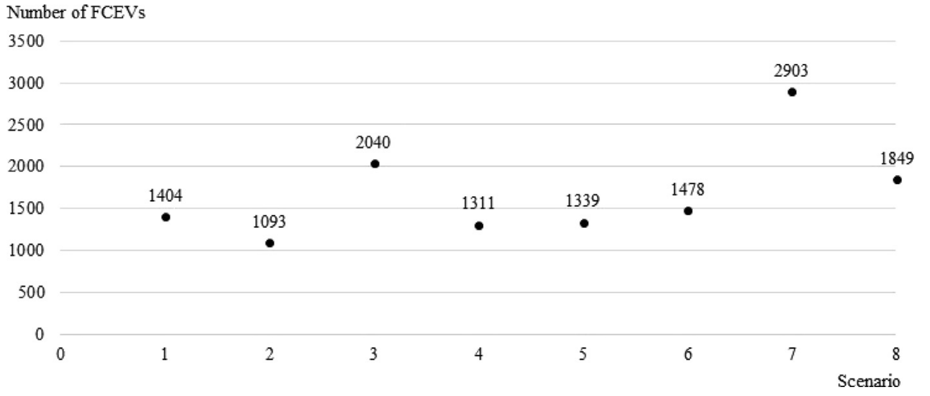


Fig. 2 – [2-column fitting] Minimum required number of FCEVs so that scenarios 1 to 8 are profitable.

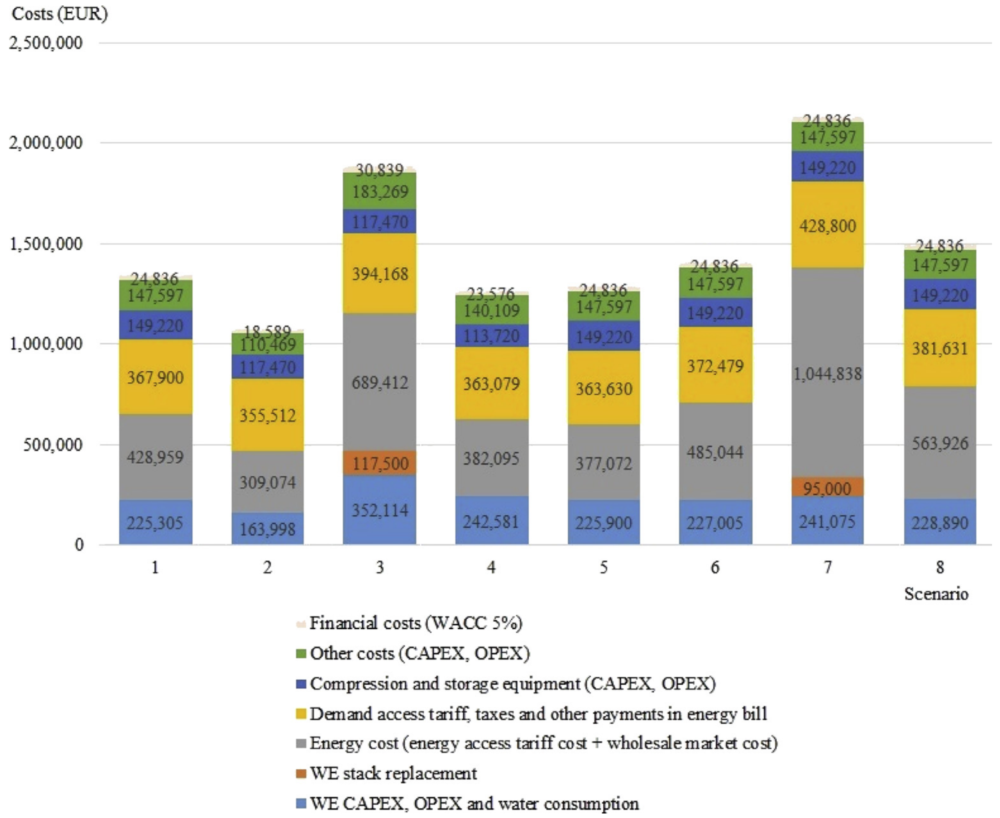


Fig. 3 – [2-column fitting] Breakdown of costs in scenarios 1 to 8.

take place so that this has a visible impact on the feasibility of the case study.

Finally, scenarios 7 and 8 show the consequence of modifications in the hydrogen fuel price at the point of delivery to HRS to 5 EUR/kg and 6 EUR/kg, respectively. As presented in Fig. 2, the impact is quite considerable on the initial situation with a remuneration of 7 EUR/kg (scenario 1), increasing the minimum fleet of FCEVs to 1849 vehicles in scenario 8 and 3275 in scenario 7. These figures come from the fact that the range of 5–7 EUR/kg is linked to the final price to consumers of 8–10 EUR/kg. If a conventional FCEV refuels 5 kg of hydrogen (which allows driving for around 500 km), then the cost of fully refuelling the vehicle for end users is around 40 to 50 EUR, which is designed to be competitive with diesel and allow HRS operation to fully support investment and operation of the infrastructure and obtain a reasonable margin. Thus, it is expected that this remuneration is indexed to fossil fuel prices in the following years, and at least scenario 8 may possibly occur. As presented, in scenario 7, there is a need to replace the stack during the project's lifetime even with AWE technology, which leads to the need for a higher demand of FCEVs to refuel.

As observed in Fig. 2, in all scenarios, the minimum required number of FCEVs is over 1000 vehicles, which is far from the country's market perspectives despite the ambitious plans for these vehicles' deployment set for the year 2020. The contribution to the income from participation in secondary regulation is important (ranging from 6.48% in scenario 7–12.92% in scenario 2). However, the critical factor is to receive sufficient remuneration for hydrogen, which should be between 6 and 7 EUR/kg at the point of delivery. These costs are linked to electricity costs despite CAPEX and OPEX of electrolysis equipment still being considerably high (ranging from 10% of total annualized costs in scenario 7–18.32% in scenario 4, as their impact is reduced with increasing operational hours per year).

Conclusions and recommendations

This paper has presented a novel model of multi MW electrolyser considering different modes of operation and an optimal dispatch methodology to assess the techno-economic feasibility of hydrogen production plants designed to provide grid services while delivering this fuel for different applications. To validate the model, it has been applied to the Spanish case of FCEV based mobility considering the possibility to participate in the provision of secondary regulation service for multi MW loads.

Multi-MW electrolysis combined with the provision of grid services in Spain appears as a promising option to obtain cost-competitive hydrogen for different applications, including mobility. However, a sufficient hydrogen demand from FCEVs is necessary for the profitability of a HRS network, which is not in place today. The results in this paper show that the contribution from the provision of secondary regulation for a 5 MW electrolysis unit is around 10%, and the minimum demand to obtain non-negative business cases should be over 1000 FCEVs. To obtain a better return on investment, which is needed for companies to bet on multi-MW electrolysis facilities, the number of FCEVs around the production plants should be even higher.

Thus, incremental and progressive efforts are required to boost such demand to create a growing mass of FCEVs to refuel. The options include positioning distributed HRS with on-site production and smaller electrolysers (with the consequent negative business cases occurring only in the beginning) or production of hydrogen with cheaper but non-environmentally sustainable methods (e.g., steam methane reforming) during a previous phase to stimulate demand. This should be accompanied by incentives for deployment of HRS and FCEVs (e.g. via partially funded demonstration projects or support instruments to reduce GHG emissions such as feed-in-tariffs, contracts for difference or other) especially in the north of Spain to connect with French initiatives and users.

Besides, regulatory steps could be taken in parallel to this previous phase of demand consolidation to allow the deployment of multi-MW electrolysers by allowing their use to provide grid services. Specially, it is important to allow the participation of large consumers in balancing services provision. This implies not only their involvement in the interruptibility grid service as it is done today, but also in balancing markets such as secondary frequency regulation. This implies amending or replacing current regulations [36] to allow positive or negative packages of several MW to correct grid frequency with a similar remuneration to that assigned today to generation units.

Acknowledgement

This work is supported by the ELYntegration and DEMO4GRID projects of the Fuel Cells and Hydrogen Joint Undertaking and the Industrial Doctoral Programme of the University of Zaragoza under the 2017 call.

The ELYntegration and DEMO4GRID projects have received funding from the Fuel Cells and Hydrogen 2 Joint Undertaking, (https://www.fch.europa.eu) under grant agreement numbers 671458 and 736351, respectively. This joint undertaking receives support from the European Union's Horizon 2020 research and innovation program. These projects are also supported by the Swiss State Secretariat for Education, Research and Innovation (SERI) under contract number 15.0252 and 17.00002, respectively.

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