Feasibility of Hydrogen Production

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Abstract

Portugal has been one of the pioneering countries in Europe in incorporating renewable energy into the electricity system, reaching a share of renewable energy in electricity production of 61New vectors such as hydrogen have been the focus of attention, as possible substitutes for non-electrifiable sources, among other purposes. On August 14, 2020, in Portugal, the ENH2 was approved, which foresees the installation of 2 to 2.5 GW of electrolyzers by 2030 for hydrogen production. However, this technology needs research and improvement in several areas, among them production costs. In this context, this thesis focuses on the production of H2, focusing on the Alkaline and PEM technologies. Three possible production scenarios were simulated in three locations in Portugal, with the objective of analysing the levelized costs of hydrogen production. The first scenario assumes the production of H2 by electrolysis with direct connection to the public grid (RESP). The second considers a power purchase agreement with local renewable power plants, through "*Power Purchase Agreements*" (PPA's) contracts. The third assumes renewable self-consumption. Six different models were considered with the objective of comparing the final levelized cost and its relationship with some key indicators. **Keywords:** Renewable Energy, Hydrogen, PEM and Alkaline electrolysis, LCOH

1. Introduction

Nowadays, we have several sources of energy, fossil fuels, such as coal, petroleum, and natural gas. These sources of energy have been used for over 20 decades, resulting in excessive energy consumption, unrestrained exploitation, and considerable waste. The challenge for the energy sector in both developed and developing countries is not just energy production and consumption, but also to reduce carbon emissions. The energy transition must reduce emissions, while ensuring that sufficient energy is available for economic growth. Portugal had 40.43 Mt of CO2 Emissions in 2020. Energy transition urgency is also due to the accelerating climate change in the recent years. The average global temperature has been increasing, surpassing the value of the pre-industrial baseline by 1.04 $\circ$C [13]. In the next decade, the energy sector will be the one that will make the greatest contribution to decarbonization.

In this light, it is worth highlighting the role that renewable gases, in particular **hydrogen**, can play in the decarbonization of the various sectors of the economy (industry and transport) for reasons as: electric energy can not replace some sectors, for example burning gases like natural gas; and also will allow reaching higher levels of incorporation of renewable energy sources in the energy consumption. [17].

Portugal is sensitive to this issue, becoming one of the best counties in incorporation of renewable power pants in the electric sector. On the 14th of August 2020 the National Hydrogen Strategy (EN-H2) was approved in the Council of Ministers.This year, 2022, was also launched in Portugal by LNEG [2], the Hydrogen map (allocating the best geographical places for hydrogen production, with several layers included).

2. Hydrogen

Hydrogen is a non-poisonous, tasteless, colourless, and odourless gas and it is a material that has been known for more than 200 years. The main properties are presented in Table 1

2.1. Hydrogen Production

To frame the implementation of this "new energy" present in this molecule, it is important first of all to define the configurations considered as priorities in the hydrogen value chain. The assessment of its sustainability is considered complex, as it includes multiple and influencing factors that at different stages of the chain are also interrelated. In practice, the hydrogen value chain includes five stages, production/conversion from feedstocks, conditioning (compression or liquefaction), storage, distribution/transport and supply the end use. The end

Table 1: Hydrogen Properties

Properties	SI Units	References
Molecular weight	1.0079	[16]
Vapor pressure at [-252.8 ℃].	101.283 kPa.	[16]
Density of the gas at boiling point and 1 atm	1.331 kg/m3	[16]
Density of the liquid at boiling point and 1 atm	67.76 kg/m3	[16]
Density (at 25 ℃ and 1 bar)	0.0813 g/L	[4]
Freezing/Melting point at (101.283 kPa)	-259.2 ℃	[8]
Boiling point at (101.283 kPa)	-252.8 ℃	[16]
Critical temperature	-239.9 ℃	[4]
Critical pressure	1296.212 kPa, abs	[8, 4]
Critical density	30.12 kg/m3	[16, 11]
Triple Point	-259.3 ℃ at 7.042 kPa, abs	[8, 4]
Lower heating value, [weight/volume at 1 atm]	120 MJ/kg / 11 MJ/m3 or 3 kwh/m3	[16, 4]
Higher heating value, [weight/volume at 1 atm]	141.8 MJ/kg / 13 MJ/m3	[16]
Explosive (detonability) limits	18.2 to 58.9 vol% in air	[16]
Auto-ignition temperature/in air	400 ℃/571 ℃	[16]
Specific heat at constant pressure Cp	14.34 kJ/(kg) (℃)	[16, 8]
Specific heat at constant pressure Cv	10.12 kJ/(kg) (℃)	[16]

user can be identified in following strategic configurations: Power-to-Power, Power-to-Fuel, Power-to-Mobility, Power-to-Gas and Power-to-Industry.

The first stage of the hydrogen value chain comprises hydrogen production, with different pathways, processes and associated technologies. Depending on the scale required a distinction is made between large scale (centralised) and small scale (decentralised) production. This stage, as is the main theme of this work.

Presently, the entire worldwide hydrogen production is around 500 billion cubic meters per year. As shows Figure 1, it can can be produced from a variety of processes and the definition of the hydrogen depends of the source of production.

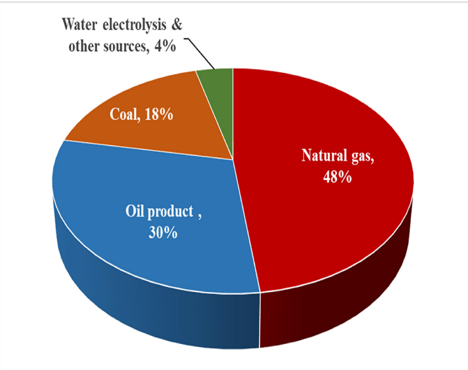

Figure 1: Current hydrogen gas product sources , from [14]

Green hydrogen or clean hydrogen, has low a production rate, International Energy Agency (IEA) estimates that less than 0.4% of hydrogen is produced by the electrolysis of water powered by renewable electricity [5]. It can be produce from one or more renewable power plants (hybrid system).

In the electrolysis process, water molecule is the reactant it is dissociated into hydrogen (H2) and oxygen (O2) under the influence of electricity.

Like fuel cells, a water electrolysis cell consist of an anode and a cathode, also called electrodes, placed front-to-front and separated by a thin layer of an ion-conducting material which is called electrolyte. They could be made of an aqueous solution containing ions, a proton exchange membrane (PEM) or an oxygen ion exchange ceramic membrane. Electrolysis of water is not a spontaneous phenomenon, it needs an external intervention (power source), so a direct current (DC) is applied from the negative terminal of the DC source (from the anode) to the cathode (seat of the reduction reaction), where the hydrogen is produced. The reactions vary with the technologies used.

Water electrolysis can be classified in to the four types based on their electrolyte, cell design, operating conditions, and ionic agents (OH-,H+,O2-), however operating principles are both the cases same. The four kinds of electrolysis methods are: [13].

- Alkaline water electrolysis (AWE) ,
- Solid oxide electrolysis (SOE),
- Proton Exchange Membrane (PEM) water electrolysis
- Microbial electrolysis cells (MEC)

Microbial electrolysis, is under development, being a recent technology (invented in 1931 by Barnett Cohen) and also because there is less data and information available, this study is gonna be focused on the first three. Solid Oxide (SOE) is also under development, although already with some data available.

The overall formula of the water electrolysis, gives the water splitting in hydrogen and oxygen:

Overall cell:

$$H_2O \rightleftharpoons H_2 + 1/2O_2$$

2.2. Alkaline Electrolysis

Hydrogen production by alkaline water electrolysis is a already well established technology and is a simple and suitable technology for hydrogen production.

It is a technology up to the megawatt range for commercial level in worldwide and the phenomenon first introduced by Troostwijk and Diemann in 1789.

The two electrodes are separated by a diaphragm (ZrO_2) that must also be permeable to the hydroxide ions and water molecules. The electrolyte is Potassium hydroxide (KOH) in liquid state. In the cathode hydrogen and the charge carrier OH^- are produced, and in the anode the water and oxygen are produced together with 2 electrons.

2.3. Proton Exchange Membrane Water Electrolysis (PEM)

After the alkaline water electrolysis, in the 1960s, it was invented a new and revolutionary electrolysis by the General Electric, the first water electrolyzer based on a solid polymer electrolyte concept. This concept was idealized by Grubb where a solid sulfonated polystyrene membrane was used as an electrolyte.Also referred to as proton exchange membrane or polymer electrolyte membrane water electrolysis, both with the acronym PEM. In this technology is used an acidic membrane as solid electrolyte, usually made of Nafion, Fumapem, Flemion, or Aciplex [16], more or less between 20 and 300 µm in thickness. This membrane is used instead of a liquid electrolyte, that conducts H^+ ions from anode to cathode, and separates hydrogen and oxygen that are produced in the reactions. It is responsible for providing high proton conductivity (0.1 +- 0.02 S cm^{-1}) as the electrolyte in the alkaline electrolysis, but also provides low gas crossover, compact system design and high-pressure operation [8].

Together, the membrane and the electrodes,constitute the membrane electrode assembly (MEA). The low membrane thickness, is in part the reason for many of the advantages of the solid polymer electrolyte. It also provides high current density (above $2Acm^{-2}$), good efficiency, fast response, operates under lower temperatures 20 to 80 degrees.

2.4. Solid oxide electrolysis (SOE)

Dönitz and Erdle were the first to report, results from a solid oxide electrolyzer (SOECs) from within the HotElly project at Dornier System GmbH using a supported tubular electrolyte in the 1980s.In therms of operation has the particularity of operation at really high pressure and high temperatures 500–850 ℃ and utilizes the water in the form of steam. It has the potential to produce hydrogen from steam with higher electrical efficiency than alkaline or PEM technologies, taking advantage of the energy in the steam to split water into hydrogen and oxygen.

This technology has a good potential for the future mass production of hydrogen, but for that, the issues related to the durability of the ceramic materials at high temperature and long-term operation have to be solved before going to commercialization on a large scale.

Besides these three technologies, there are also some others under development, like the Microbial electrolysis cell (MEC) technology or the Anion exchange membrane electrolysis.

2.5. Key Performance Indicators

Alkaline is the most mature technology, well established and constitutes the most extended electrolytic technology at a commercial level worldwide.Thyssenkrupp is one of the most relevant vendors in water alkaline electrolysers, has pre-engineered 20 MW modules. In therms of durability, Alkaline is the one that processes long term, as well as stability, also because has much more maturity. The CAPEX prices are in order of 450–1260 (€/kW).[12]

PEM technology is a more recent technology. The most remarkable scale-up design is the one developed by Siemens. The largest module is 17.5 MW that consists of 24 stacks and several separators with an approximate hydrogen production capacity of 3,650 Nm^3/h. The CAPEX prices are in order of 90–1620 (€/kW) [12].

In terms of flexibility of operation, both PEM and Alkaline present good performances, both can adapt well to the intermittency of renewables. Although PEM have a quicker response to power supply changes as it has the ability to ramp up and down very quickly and also can deliver peak shaving frequency regulation and continency services.

Due to being at lab-scale level, the values of Solid Oxide Electrolysis are estimations with high level of uncertainty. A summary is presented in the following table 2.

3. Methodology

This work considers the production of hydrogen at three sites and under three possible scenarios, with the objective of analyze the possible quantity of hydrogen produced, and levelized cost of hydrogen production (LCOH).

3.1. Geographic Locations

The geographic locations, were chosen based on a license auction system that was implemented in Portugal launched last year (2021) for the production of energy from renewable sources, with a focus on floating solar. A total of 7 lots, each one equivalent to one dam in Portugal. Each dam was located in the Arcgis software as well as renewable power plants, and each one or dam evaluated in terms of: Solar Auction power capacity; Renewable Powe plants near by the dams, either wind or

Table 2: Hydrogen Properties

KPI	Alkaline [12]	PEM [8, 12]	SOEC [12]
Technology status	Mature	New / Mature for small scale	lab-scale
Current density (mA/cm2)	200 - 500	800 - 2500	250-500
Cell voltage (V)	1.8–2.4	1.8–2.2	0.7–1.5
Energy consumption (kW h / N m3)	4.6-4.8	4.9-5.2	3.7-4.1
Energy consumption (kW h / Kg h2)	40-60	40-60	20-40
Production Rate (m3 H2/ h)	≤ 760	≤ 40	≤ 40
Temperature range (℃)	ambient - 120	70-90	500-850
Hydrogen purity (vol%)	99.3–9.99	99.9999	99.9
Efficiency	63–70%	56–60%	74–81%
System lifetime (year)	20-30	10-20	-
Annual Degradation (%/year)	20-30	20-30	-
Cold start up time (min)	15	5–10	> 60
Warm start up time (min)	1-5	0,2	-
Flexibility of Operation	High	Very High	Low
Water Consumption (ton H2O/ton H2)	Approx. 18	Approx.18	Approx.18
Oxygen production (ton O2/ton H2)	8	8	-
Plant footprint (m2/kWe)	0.095	0.048	-
Largest Project (Power,Location, Application)	25 MW, Malaysia, Silicon	10 MW, Germany, Refinery	kW Range, Testing

solar or solar floating and using the Hydrogen map from LNEG criteria, launched by LNEG [2].

The locations chosen were:

- Alqueva, mainly due to the PV renewable around and the high potential of PV installation;

- Castelo de Bode, because has high levels of power available from floating solar plant, and because has the natural gas grid passing by (in Pego) as can be a good option for hydrogen injection;

- Alto Rabagao and Paradela, two dams merged in one single site, because are close from one another, and have the same substation of energy reception. It is assumed the name North site for this merger.

3.2. Three sites configuration

The three sites have different combinations of renewable power plants, so the capacity will vary with the locations as well as the PV and wind incidence in each region.The values of average efficiency and hours of production of the power plants, are based in a work made in Portugal by LNEG [10], that studied the potential of a wind and a solar power plant installation (with a nominal power of 10MW).

Table 3 defines Alqueva, Pego and North´s Renewable power profiles according with the study described as well as the assumed Power input in the electrolysers for the purpose of hydrogen production.

As an example, applying for the hybrid case in north site, in Figure 2 is presented the daily profile for the several zones in Portugal, in the case of North is zone/WPP 6. The solar profile is not presented, it is assumed that full fills the missing power that wind power do not, between 6 to 18h to maintain a constant power input (in the 10MW example plant considered in LNEG study, between the 3,2 and 4 MW). But for the Power available in North, is converted to 40MW of constant Power input.

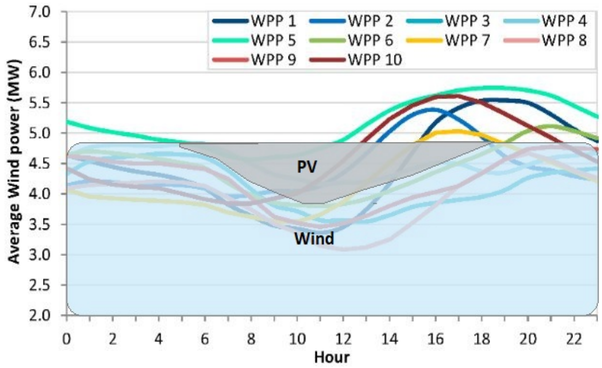

Figure 2: Daily Wind + PV Profile, from [10]

The electrolysers used for the calculations, were chosen from some of the most commercialized companies in the market. These companies have a wide range of electrolysers, PEM or Alkaline. The models chosen were for large scale installations.

For alkaline technology, McPhy (McLyzer 800-30), Thyssenkrupp 20 MW and Nel (A2000). For PEM technology, the Siemens electrolyser silyser 300, and Cummins (Hylyzer 1000-30 and the 4000-30).

The electrolyser system receives AC electricity, which is converted via transformer and rectifier subsystems into DC electricity for use by the electrolyser stack. The transformer subsystem is an oil-immersed, ambient air-cooled unit, manufactured to IEC-76. The rectifier subsystem converts the AC voltage to DC voltage using thyristors. Water is supplied in the cathode side, pumped to ensure the cooling temperature in the stack. Usually after the stack, a buffer for hydrogen storage shall be installed to guarantee higher hydrogen purity and a constant hydrogen flow. For the same purpose, purity, a deoxidizer and dryer should be installed after the buffer. It is assumed the public grid water.

Table 3: Three sites Definition based on LNEG study

Site	Technology	$Power_{available}$ (MW)	Zone	Hours per day (h)	Efficiency (%)	Power input (MW)
Alqueva	PV	160	5	9	20	30
Pego	PV	50	1	8	20	10
North	PV	55	3	10	10	40
	Wind PP	75	6	15,5	50	

After hydrogen production, compression and storage are considered. In therms of compression, it depends of the hydrogen end user. For example for the mobility sector the pressure needed in the hydrogen produced is 700 bar (example in the Toyota Mirai). In this case, is assumed that there is a regular demand and the plant needs a short therm storage. A mature solution, is to compress at 200 bar in tanks of type I, from the literature [7], due to the fact of being a mature solutions, and is one of the best options of tanks, since they have the best cost performance and the weight of the tank is not a significant decision factor.

After compressed, it must be transported to demand centers either though pipelines or tanker truck/train. These post-production steps add additional costs that are not captured in this work.

3.3. Scenarios of study

For each site, it is considered three different scenarios that attempt to capture different ways that an electrolyser could be physically connected to a renewable electricity generator. This type of analysis, using possible scenarios of hydrogen production, was also made in the "Assessment of Hydrogen Production Costs from Electrolysis: United States and Europe by the International Council on Clean Transportation. [9].

The three scenarios are:

Scenario 1 – "Direct Grid Connect": It is assumed assume that the electrolyser is grid connected and therefore can produce hydrogen gas at full capacity factor for 8760 hours per year, $LoadFactor = 1$. A contract with a reseller entity (energy company) from the retail market is signed, and the energy supplied is green, because guarantees of origin are bought, and the seller entity does the management of all of the energy. The prices vary with the market and time of contract and the energy company. In this scenario taxes and grid fees are taking into account. It is assumed the grid fees from 2021 published by ERSE [1].

Scenario 2 – "Direct Renewable Connect": It is assumed that the electricity comes through long-term Power Purchase Agreements (PPA) to procure only renewable electricity. The contract is made with the locals renewable power plants (Located in Arcgis). Under this scenario, the intermittency of the renewable electricity generator means that the electrolyser's capacity factor is equal to the generator's capacity factor. In this scenario taxes and grid fees are also taking into account, from ERSE [1]. The electricity prices vary with the contract made and time of contract.

Scenario 3 – "Auto-consumption" In this scenario it is assumed that the electrolyser is only connected to the on site renewable power plant. It is assumed that the renewable power plants are the same technologies, capacity and number of plants as the ones of scenario 2. The excess of energy produced can be sold to the grid, being residual, is not considered in this study. Taxes and grid fees are not taking into account.

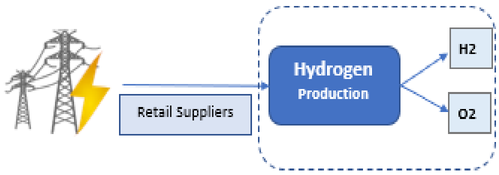

Figure 3: Scheme Scenario 1

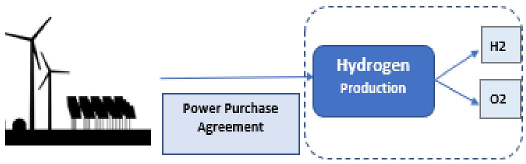

Figure 4: Scheme Scenario 2

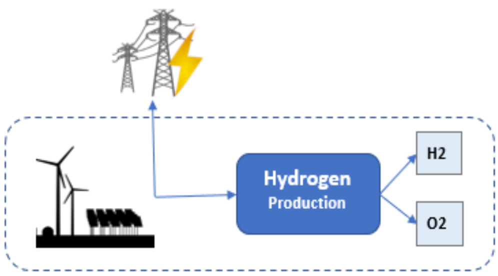

Figure 5: Scheme Scenario 3

In Table 4, it's stated the three scenarios resume as well as the electricity payment model, and grid fees. Besides grid fees, there are other taxes that, being residual, are not included in this study, also because the lack of data.

Table 4: Three Scenarios overview

	Parameters	Scenario 1	Scenario 2	Scenario 3
Alqueva	Hours of production	8760	3285	3285
	LF	1	0.375	0.375
Pego	Hours of production [10]	8760	2920	2920
	LF	1	0.33	0.33
North	Hours of production	8760	7000	7000
	LF	1	0.79	0.79
	Electricity fees	Retail Market	Power Purchase Agreement	0€/KWh
	Grid fees from [1]	yes	yes	no

4. Data

Capital and operation costs for the specific **electrolysers** models chosen are not available. Using investment cost data for 1MW taken from the literature review from Franco et al. [12], and the OPEX values represent 1.5% of the CAPEX.

The CAPEX is calculated using a scale factor (logarithmic relationship as a method of estimating costs by scaling) for Alkaline and PEM are calculated using:

$$C_b = Ca * \left(\frac{Sb}{Sa}\right)^f \tag{1}$$

Where C_b stands for the unknown equipment costs at the appropriate scale S_b (size, capacity, nominal power) and the components, C_a and S_a represent the cost sand scale of the known reference component, respectively. In this case 1MW reference from Franc et al.[12]. f is the scale factor applied to the technology .

To find the CAPEX for the **compression** station, the National Research Council [6] developed the relationships in equation 2.

To calculate the power needed to compress an idealized gas, a relationship is used from Christensen [9], as presented in equation 3.

Where, Q is the flow rate (kg/day), the subtraction for 24 times 3600 is a factor that converts day units into seconds, Pin is the inlet pressure of the compressor, $Pout$ is the outlet pressure of the compressor, Z the hydrogen compressibility factor equal to 1.03198, N is the number of compressor stages (assumed to be 2 for this work), T is the inlet temperature of the compressor (310.95 K), γ is the ratio of specific heats (1.4), M_{H2} is the molecular mass of hydrogen ($2.15g/mol$), η is the compressor efficiency ratio (taken as 75%), the universal constant of ideal gas $R = 8.314J/molK$.

On-site short therm storage is assumed 0.6 €/Kg [9].

About some other costs associated, from literature [15], the CAPEX of Balance of Plant components, construction and assembly costs with the quantity of hydrogen produced, is 200 000 €/MW.

$$CAPEX_{COMPRESSOR} = 2545P[KW] \tag{2}$$

$$P(KW) = Q\left(\frac{1}{24*3600}\right)\frac{ZTR}{M_{H2}\eta}\frac{N\gamma}{\gamma-1}\left(\left(\frac{Pout}{Pin}\right)^{\frac{\gamma-1}{N\gamma}} - 1\right) \tag{3}$$

The calculation of the hydrogen cost of production, $c_{H2/kg}$ in [€/kg_{H2}], based in the calculations made by Jovan et al. [15], it is made in 4 parcels, in order: the price of electricity consumption of the electroyzer C_{elect}, the capital and operational costs $p_{CAPEX+OPEX}$, the price of electricity consumption of the compressor C_{comp}, the price of the tap water p_{water} in [€/kgH2] and the price of grid fees $p_{gridfees}$. Stated in Equation 4.

$$c_{H2/kg} = (C_{elect} * p_{elec}) + (C_{elect} * p_{(CAPEX+OPEX)stack}) \\ (C_{comp} * P_{elec}) + p_{water} + +(C_{elect} * p_{gridfees}) \tag{4}$$

Where C_{elect} stands for the specific electrolyzer energy consumption [$kWh/kgH2$] which varies with the electrolyzers models,; p_{elec} the electricity cost [€/kWh] , varies with the scenarios stated in table 4. The calculation of the price per kilogram fom the capital and operational costs, is presented below in Eq. 5:

$$p_{(CAPEX+OPEX)stack} = \\ \left(\frac{CAPEX_{electrolyser+compressor+storage+BoP} + OPEX_{total}}{h * LF * n * P}\right) \tag{5}$$

For the purpose of scenario 3, an approximation of how much would cost the installation of the equivalent renewable power plants was made. The values of IRENA [13], are presented in Table 5, for 30 years of lifetime:

Table 5: Auto-consumption Renewable CAPEX

Site	**Technology**	**CAPEX M€/y**	**OPEX €/y**
Alqueva	PV	6.539	3.05
Pego	PV	2.211	1.034
North	PV and Wind	8.44	4.283

To better understand the feasibility of a H2 production project, and to compare with other technologies of H2 production, LCOH must be calculated since it represents the average net present cost of the hydrogen generation for a generating plant over its lifetime. Its formula is presented in Eq.6 in €/kgH2:

$$LCOH = \frac{I_0 + OPEX * K_a}{P_{H2} * Ka} \tag{6}$$

Where,

$$K_a = \frac{(1+r)^n - 1}{r * (1+r)^n} \tag{7}$$

Where P_{H2} stands for yearly H2 production [kg]; n the lifetime of the project [years]; and r the discount rate.

Discount rate corresponds to the minimum rate of return on an investment project, i.e. the return that an investor requires to develop a project. This rate is used to update the future cash-flows generated as of today and it consists of three components/rate. For the LCOH is assumed a discount rate 10%, a typical return required by private investors.

5. Results & discussion

5.1. Hydrogen Production

The total amount of hydrogen produced in each site, is directly proportional to the Power Input, the load factor and the maximum capacity of production of each electrolyzer. In Figure 6, and fixing an Alkaline model (McLyzer), it can be noticed that in scenario 1 the energy is full load, and consequently it has the best performance of production.

For example, a total of 2 models of Thyssenkrupp are needed in North site, because has a net production rate of $4000Nm3/h$ ($1kg/h = 11.12Nm3/h$ of hydrogen), giving an equivalent power of $20MW$. So for an input of 40MW, 2 units cover the power input. Comparing with the McLyzer 800-30, for example, has net production rate of $800Nm3/h$, an equivalent Power of $4MW$, a total of 10 units in North are needed.

Scenario 2 and 3 have the same production, due to the same load factor (hours of production). Comparing with Scenario 1, Scenarios 2 and 3 have H2 productions 20% lower in North, 70% in Pego and 60% in Alqueva. The difference is smaller in North than in Pego and Alqueva, due to the fact of having more hours of production, a total of 7000h, due to the hybrid system installed.

5.2. Costs of H2 and LCOH

In Table 6, is resumed the results of hydrogen costs of production, and LCOH for today and for 2030. The results are for all scenarios and sites, and assuming an electricity price of 50€/MWh. From the 6 models, only three are presented, NEL, McLyzer and Siemens silyzer 300, were chosen due to both being the most costly compatible term cost.

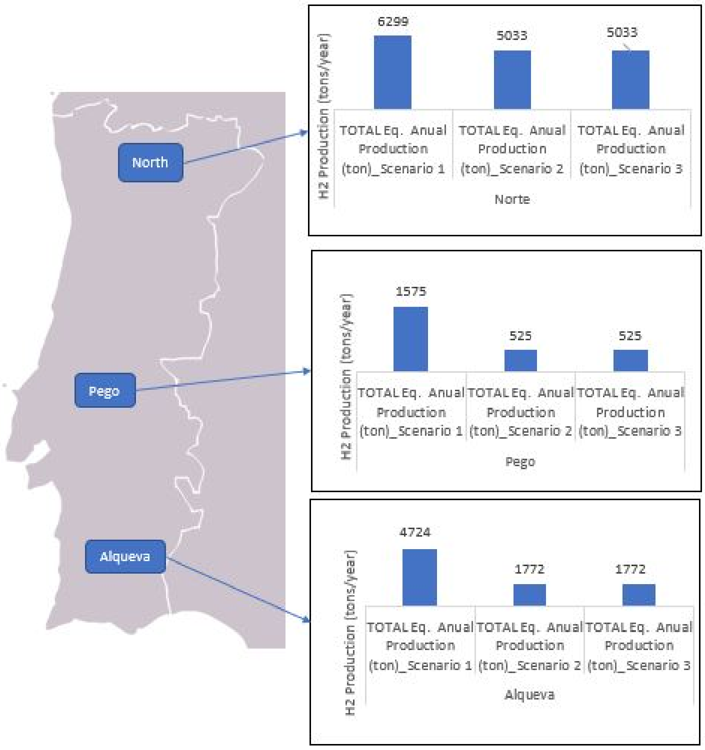

Figure 6: Three Sites - Hydrogen Production

Scenario 1 considers full load in every sites/locations, plus, has a clear advantage of being risk free of interruptibility of power input. On the other hand, is highly dependant of the electricity costs, which has high weight in the final hydrogen production cost. Alqueva and Pego have similar costs, in North are higher mainly due to the higher grid fees, stated in ERSE [1]. In general, for 50€/MWh, and when comparing with an average cost of hydrogen production from fossil fuel 2€/kgH2, the three sites are far from a competitive cost of production. For lower electricity prices, can reach better LCOH, for example for 20€/MWh, a cost of 2.5€/kgH2.

Scenario 2, can be a good option if the accorded price are lower than scenario 1. Obviously, for a similar price for both scenarios 1 and 2, is not worth it, because having less hours of production, as in Table 6 it is more expensive, an so, a scenario to refuse. The electricity cost for Scenario 2 has to be 22.25 €/MWh lower in Alqueva, 30€/MWh in Pego and 3,4€/MWh in North to have he same LCOH as Scenario 1. The results are inconclusive because the price accorded in the PPA is unknown.

Scenario 3,Scenario 3, the auto consumption case, achieves very competitive costs in North site. Mainly because there is no grid fees associates to the costs. the hybridization of wind and solar increases the time of production. LCOH of NEL, McLyzer and Siemens, offer prices of 3.03€/kgH2 (17% more expensive than LCOGH, costs of grey

Table 6: Results Overview

		Scenario 1			Scenario 2			Scenario 3		
		NEL	McLyzer	Siemens	NEL	McLyzer	Siemens	NEL	McLyzer	Siemens
Alqueva	Hours		8760			3285			3285	
	Production (tons)	5368,29	4724,09	5028,05	2013,11	1771,53	1885,52	2013,11	1771,53	1885,52
	Cost (€/KgH2)	3,61	3,92	4,14	3,86	4,19	4,58	3,75	4,43	4,45
	LCOH(€/KgH2)	4,28	4,71	5,01	5,05	5,65	6,24	7,56	9,11	9,05
	LCOH_2030(€/KgH2)	4,11	4,51	4,90	4,77	5,29	6,14	7,12	8,57	8,77
Pego	Hours		8760			2920			2920	
	Production (tons)	1789,43	1574,70	1676,02	596,48	524,90	558,67	596,48	524,90	558,67
	Cost (€/KgH2)	3,64	3,95	4,17	4,04	4,38	4,81	4,35	5,14	5,16
	LCOH(€/KgH2)	4,35	4,79	5,08	5,45	6,14	6,77	10,16	12,25	12,04
	LCOH_2030(€/KgH2)	4,15	4,56	4,96	5,03	5,60	6,59	9,58	11,55	6,59
North	Hours		8760			7000			7000	
	Production (tons)	7157,72	6298,79	6704,07	5719,64	5033,28	5357,14	5719,64	5033,28	5357,14
	Cost (€/KgH2)	4,32	4,69	4,93	4,22	4,58	4,84	1,73	2,04	2,05
	LCOH(€/KgH2)	4,67	5,13	5,44	4,65	5,12	5,48	3,03	3,63	3,66
	LCOH_2030(€/KgH2)	4,50	4,93	5,34	4,60	5,05	5,52	2,82	3,38	3,53

hydrogen), 3.63 €/KgH2 and 3.66€/kgH2. In 2030 is expected that the pirce would be 2.82 €/kgH2, only 13% higher than the LCOGH.

Alqueva and Pego have worst costs, because is just one renewable technology installed, in this case solar floating PV. Giving less time of production.

Being Scenario 3 the only one with competitive costs, in Figure 7 is presented the results of the present costs of production, and for 2030 for Scenario 3, fixing the McLyzer electrolyzer model.

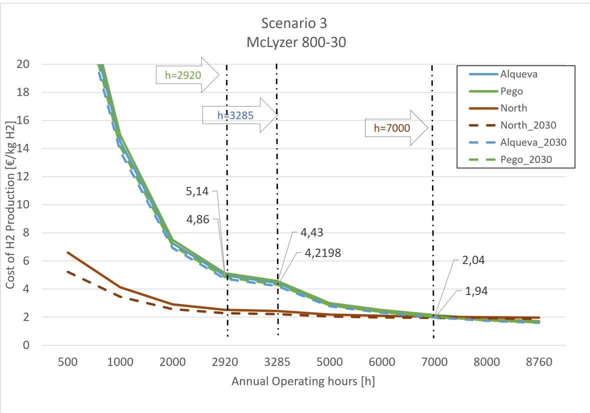

Figure 7: Scenario 3 - H2 production cost for different number of operating hours

Being the North site the best performance, now it is considering just the LCOH using McLyzer electrolyzer for North site. Starting at the highest electricity price (300 €/MWh) and finishing at the lowest (20 €/MWh) where hydrogen is still produced, in Figure 8 and in Figure 9, is provided a cumulative production for North Site. Due to the fact of Scenario 2 be similar to scenario 1, and due to low data available, the cumulative perspective is done for scenarios 1 and 3. Scenario 2 is just presented the total cost. Is also presented an average cost of hydrogen from fossil fuels (2 €/kgH2).

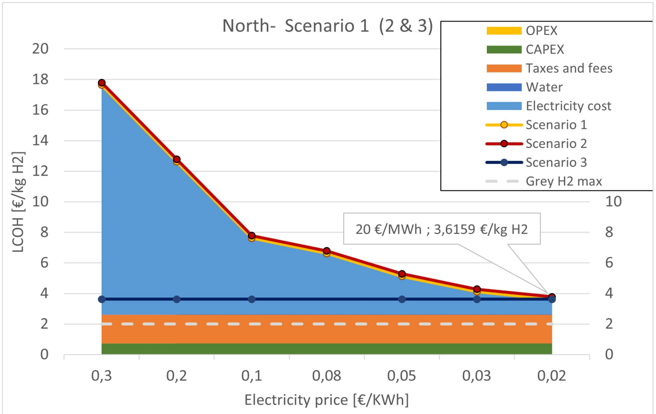

Figure 8: LCOH North- Cumulative in Scenario 1; Total of Scenarios 2 and 3

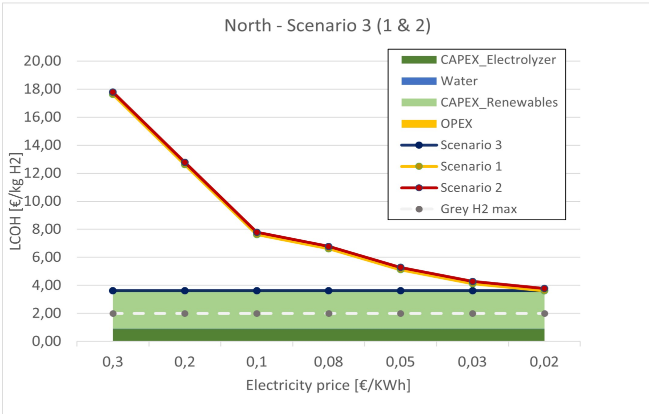

Figure 9: LCOH North- Cumulative in Scenario 3; Total of Scenarios 1 and 2

In general, all the sites and scenarios, even in lower electricity prices, present levelized costs higher than the reference price of grey hydrogen, 2 €/kgH2. Although most of them are in the expected range of values mentioned in IEA [3].

5.3. Electrolyzer's models comparison

After the sites and scenarios analysis, the same calculations were made, but taking into account the others five electrolyzers models. For simplicity,

Scenario 1 in Alqueva with a price of 50 €/MWh is taken as example. The difference in the costs of production have several factors to take into account. One of them, is the CAPEX and OPEX of each technology, being the alkaline technology the best cost competitive. In Figure 10 is presented the overall LCOH and just the levelized costs of CAPEX.

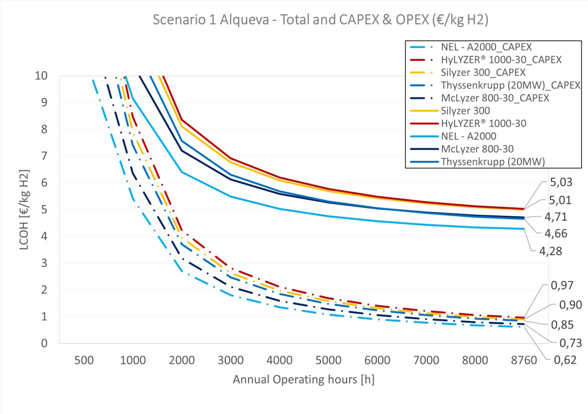

Figure 10: CAPEX comparinson between models

NEL elecrolyzer model has he lowest total LCOH (4.28 €/kgH2), followed by the others alkalines Mclyzers and thyssenkrupp around (4.65 €/kgH2 and 4.7 €/kgH2), followed by the PEM technologies, with very similar prices the siemens and both Hylyzers (around 5 €/kgH2 and 5.03 €/kgH2). A lower LCOH in NEL model, is reached using the values for 2030, of 4.1145 €/kgH2. The levelized cost of CAPEX of Alkaline NEL, presents the lowest values with (0.62 €/kgH2), and the PEM Hylyzers the highest prices (0.97 €/kgH2).

Other parameter to take into account is the power consumption, that varies with the models 51 KWh/Kg to 46KWh/Kg. With a similar power consumption, the variation comparing the alkaline NEL and the PEM siemens, consuming 46 KW/kg, is only 7%. The lifetime of each technology is also important, in Alkaline can go from 20 to 30 years and PEM, due to be a more recent technology have less lifetimes than Alkaline, from 10 to 20 from [12]. In this work was considered the same lifetime (20 years) for all the models. Nevertheless, a sensitive analysis of different lifetime is presented in Figure 11.

It can be noticed, that for the alkalines models, the levelized cost of hydrogen can go from 4.2€/kgH2 to 4.7€/kgH2 and for the PEM models, from 5€/kgH2 to 5.4€/kgH2.

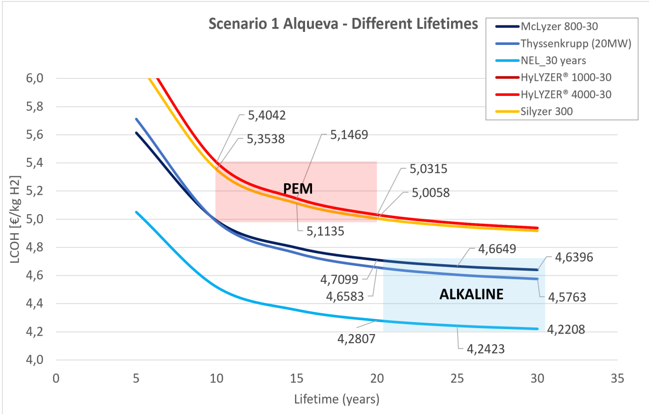

Figure 11: Levelized Cost of Hydrogen North for different Lifetimes

6. Conclusions

- The costs results in Alqueva, Pego and North, are in general, according with the literature, in the range of 2€/kgH2 to 7€/kgH2.

- If the hydrogen production plant is connected to the grid, a low electricity price is the major priority. Installations connected to low grid densities results in high grid priced, associated to the processes of transportation of electricity, as is the case of North (using the Silyzer PEM model, around 20% higher than Alqueva and Pego).

- In general, for Scenario 1, Alqueva, Pego and North is far from being competitive. Even paying a low electricity price of 35 €/MWh, the cost has to low 46% to reach the reference fossil fuels hydrogen reference cost (2€/kgH2).

- Scenario 2 has lower quality results comparing with scenario 1, because of the low load Factor. Also, has high levels of uncertainty due to the electricity price differences unknown from scenario 1. To have the same cost as scenario 1, the electricity cost for Scenario 2 has to be 22.25 €/MWh lower.

- Scenario 3 shows the best performance in North site. Being an auto consumption scenario, combined with an hybrid renewable system, rices will tend to go down, due to a bigger load factor. The best case representative is the case of North Site. When comparing with the reference fossil fuels hydrogen reference cost (2€/kgH2), prices in North are 14% lower to 3% higher, depending of the electrolyzer model in usage.

- Alqueva and Pego present high costs due to the not hybridization, only having a solar floating plant. Renewable installation costs are the major cost. In this case, some possible solutions would be: To add batteries to the systems in a way that the surplus of energy produced could be stored and used in off pick times, to integrate other renewable technologies for example Wind turbines to hybridize with the solar floating installed; and the surplus can be also be sold to the grid, or to local consumers.

- North has the best performance, reaching a LCOH of 3.08€/kgH2 for today's electrolyzer CAPEX prices, and a value of 2.82€/kgH2 for 2030's prices. It will need to low 40% to reach the reference cost from fossil fuels.
- Currently, there are three main technologies of electrolysers: alkaline, proton exchange membrane (PEM) and solid oxide electrolyzer (SOEC). Alkaline and PEM were used in calculations for three sites in Portugal, mainly due to the maturity and already having commercial models in the market.
- Electrolysers price counts as stated, around 20% of the final costs. In this case, for example in scenario 1, grid connected, NEL presents 0.62 €/kgH2 around 15% of the total costs, Hylyzer 0.92€/kgH2 around 18%. Taking NEl's levelized cost of CAPEX as reference, Siemens CAPEX is 48% more expensive.
- PEM Silyzer and Hylyzer, both reach the highest prices, due to the higher capex but also due to the high power consumption. If the PEM's power consumption is equal do the NEL's (46 KW/kg) the LCOH will lower 9% (around 0.44€/kgH2).
- Another important factor analyzed, is the variability of lifetime. Alkalines have higher lifetimes in years around [20-30] and PEM electrolyzers [10-20]. For a middle term, 25 year for NEL reaches 4.24€/kgH2 and 15 years for Hylyzer 21% higher (5.149€/kgH2).
- The effect of scale is noticed. For scenario 1, using the Alkaline McLyzer model, Pego's site present a LCOH 13% higher than Alqueva's.

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