Technical and Economic Feasibility of Hydrogen Production Integrated into Waste-to-Energy Plants: the CTRSU case-study

Diansambo Zola Miguel Masembo
diansambo.masembo@tecnico.ulisboa.pt
Instituto Superior Técnico, Universidade de Lisboa, Portugal

September 2022

***Abstract*—Waste management, apart from being an essential element in the sustainable development of any location in the world, also contributes significantly to the global renewable energy production levels when it is integrated with energy recovery. However, with the changes in demand levels, plants without energy storage technologies tend to be in a disadvantageous position as surplus power can be often wasted when the demand is lower than the supply. Since hydrogen is currently regarded as one of the main alternatives to tackle the problem of energy storage to support the energy transition into renewable sources, in this thesis, two scenarios of hydrogen production in a waste-to-energy plant are studied. Scenario 1 considers the conversion of the total energy produced at the plant into hydrogen, while scenario 2 considers only one-third of the total energy. In both scenarios, two water electrolysis technologies are assessed, namely alkaline electrolysis and SOEC. From the study, it is suggested that producing hydrogen with one-third of total electricity is always more profitable than selling all electricity to the grid. Moreover, producing hydrogen in scenario 1 is more profitable than selling all the electricity to the grid when the electricity price is lower than 90 €/MWh and more profitable than in scenario 2 when the electricity price is lower than 80 €/MWh, therefore, from this price onwards, scenario 2 becomes the most profitable one. In both situations, SOEC technology is the most profitable one in scenario 1 and alkaline electrolysis in scenario 2.**

***Keywords*—green hydrogen, water electrolysis, alkaline, SOEC, waste-to-energy**

I. INTRODUCTION

Waste-to-energy (WtE) process, as a renewable energy source, is estimated to contribute significantly to the sustainable management of MSW globally. It is expected that a reduction of around 10–15% in the global GHG emissions can be achieved through improved solid waste management (recycling, waste diversion from landfill and energy recovery from waste) [1].

The European Union (EU) has enacted comprehensive legislation with goals and targets to improve waste management while also lowering GHG emissions and negative health and environmental impacts. The concept of a hierarchy of waste management options, which includes a legally binding prioritisation of waste management activities, has been developed in the EU. Essentially, waste prevention is the most desirable option, followed by material recovery and recycling (metal, glass, paper recycling, or organic waste composting), energy recovery from waste (through incineration, or digestion of biodegradable wastes), and finally disposal (landfilling), with no material or energy recovery as the least desirable option [2].

Europe is estimated to have 582 WtE plants, with Germany, France and UK being at the leading front [3], while Portugal has three plants distributed along the country [4].

About 41% of the total Municipal Solid Waste (MSW) generated in 2020, in the Portugal mainland, was sent to landfill and 19% was directed for energy recovery and other fractions for different types of waste treatments [6].

According to the data from IEA (International Energy Agency) presented in Fig. 1, in 2020, around 325 GWh of electricity was produced from the conversion of MSW into energy in Portugal, with significant growth in production level in 2020 compared to the past 20 years.

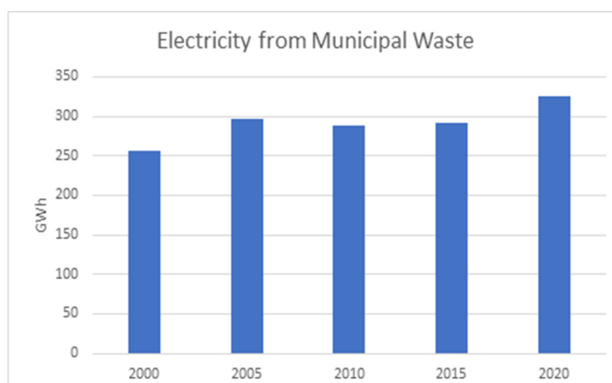

Figure 1. Electricity produced from MSW in Portugal [7]

Nevertheless, electricity prices can be volatile to several factors, such as the rise or fall of fossil fuels prices, CO_2 prices, or even natural events such as lack of rain that may affect hydroelectricity production as well as political conflicts that affect the global or regional trading of energy commodities.

Towards the end of the year 2021, the average daily prices of electricity in The Iberian Electricity Market, also known as

MIBEL, increased drastically due to the situation of conflict between Russia and Ukraine, as the supply of natural gas and other energy resources to the EU market were directly affected.

Figure 2. Electricity produced from MSW in Portugal [8]

Because of the frequent fluctuations of electricity prices, energy producers such as WtE plants ought to look at energy storage alternatives to ensure the technical and economical sustainability of their businesses, considering scenarios when the prices are low and/or high in the market.

In this thesis work, a technical and economic analysis is carried out to assess the feasibility of producing hydrogen gas from electricity at the WtE plant of Valorsul (CTRSU) in Lisbon, Portugal.

II. Characteristics of the CTRSU Plant

The CTRSU (Municipal Solid Waste Treatment Centre) is a WtE plant with energy recovery for electricity production, operated by the company Valorsul, located in the metropolitan area of Lisbon, Portugal. It consists of an incineration plant for mass burning of solid waste with 3 installed incineration lines, each with a capacity of processing 28 t/h of MSW [9].

CTRSU is equipped with 3 boilers, each producing around 66 t/h of steam (420°C, 52.8 bar) [10]. The boilers are connected to a turbogenerator with a condensing turbine with a rated power of 50 MW to produce electricity. The annual electricity production is approximately 350 GWh, and a small fraction is used for internal consumption of the plant, while most of it is injected into the Portuguese national electricity grid [11].

The CTRSU is the main unit of the Valorsul in terms of energy production and economic revenues. In 2019, 316 GWh of the 361 GWh of electricity produced was exported to the national grid. While in 2020, the revenues from the CTRSU electricity sales represented about 41% of the total revenues of the company [12].

Similar to many other WtE incineration systems with energy recovery, CTRSU follows 5 main operation stages: Reception of the unsorted MSW, combustion, electrical energy production, flue gas treatment, and ash residue treatment [10].

A. Electricity Production

The heat produced in the combustion is used in the boilers to generate steam at a high temperature that is then applied to the turbogenerator for electrical energy production. Natural gas is utilised to start up the combustion and on occasions when the minimum temperature of 850 °C needs to be maintained inside the combustion chamber.

The water circulated in the boilers unit is previously demineralised to avoid corrosions in the walls of the unit. Despite the water circulation system being a closed loop, there are still some losses that occur through purging and other loss factors; therefore, some water is injected according to the necessity into the water storage tank that feeds into the boiler to replenish for losses, around 6 to 7 m^3/h [9].

Because of the proximity of the plant installations to the Tagus River, water for cooling down the condenser is obtained directly from the river with an open circuit. Filters are used to avoid the entrance of undesired particles into the engine unit.

The system of electricity production from CTRSU uses a steam flowrate of about 198 t/h for the turbogenerator. The gross power production is estimated at 587 kWh/t of MSW, from which 89 kWh/t is for internal consumption [10].

III. Scenarios for Hydrogen Production

The alkaline and the SOEC electrolysis technologies were targeted as the most desirable candidates for hydrogen production in CTRSU since the alkaline is currently the most established and mature technology for water electrolysis in the market and the SOEC would seem to be well fitting as the WtE plant already produces both electricity and high-temperature steam. Hence, to evaluate the feasibility of Hydrogen production, two scenarios were defined and both technologies will be assessed inside each scenario.

- Scenario 1 (S1): Alkaline or SOEC hydrogen production using the total energy from the plant.
- Scenario 2 (S2): Alkaline or SOEC hydrogen production using one-third of the total energy from the plant.

To execute the analysis of hydrogen production in both scenarios, some initial values were acquired from the company Valorsul based on numbers from the year 2019. The data from the year 2019 was preferred instead of the year 2020, because the production data for 2020 was rather atypical due to the pandemic situation that affected the regular consumption trend of citizens in the region of operation of the CTRSU, resulting in a lower level of energy production [12].

In both scenarios, it is assumed an injection of the gas into the grid with regular demand, however, a 24h buffer storage is considered necessary to maintain a regular supply.

The costs related to power supply, installation, the general balance of the plant and others are assumed to be included in the CAPEX for the electrolyser system as indicated in [13].

Table I
ENERGY PRODUCTION DATA AT CTRSU, YEAR 2019 [12].

Parameter	Scenario 1	Scenario 2
Power Produced	316,375 MWh	105,458.3 MWh
Steam Produced	1,710,959 $tonnes$	570,319.6 $tonnes$
Annual Plant Availability (h_a)	8,410 $hours$	

A. S1: Alkaline Electrolysis Case

The A series of electrolysers from NEL are amongst the most energy efficient in the world [14], hence the NEL electrolyser A3880 was chosen as reference for the calculations, considering the large scale of production to be considered in this case.

Table II
KEY SPECIFICATIONS OF THE A3880 [14].

Specifications	A3880
Capacity Range per Unit	2,400 - 3,880 Nm^3/h
DC Power Consumption at Stack Level	3.8-4.4 kWh/Nm^3
H_2 Purity	99.9 ± 0.1%
O_2 Purity	99.5 ± 0.5%
Delivery Pressure	1–200 $bar(g)$
Electrolyte	25% KOH Aqueous Solution
Ambient Temperature	5-35°C

The AC power consumption at the system level is assumed to be 4.7 kWh/Nm^3, based on other electrolysers with similar parameters, such as the SUNFIRE-HYLINK ALKALINE.

The size of the electrolysis system required for the case scenario is determined by (1), which estimates the H_2 production capacity rate $Nm^3(H_2/h)$.

$$H_2(Nm^3/h) = \frac{Available\ Power}{AC\ Consumption\ Rate \times h_a} \tag{1}$$

The O_2 production in the electrolysis system can also be estimated by the stoichiometric equation of H_2O (2). For each 2 mol of H_2 produced during the splitting of water one mol of O_2 is produced. And for 1kg of H_2, there is 8kg of O_2.

$$2H_2(g) + O_2(g) \rightarrow H_2O(l) \tag{2}$$

It is assumed that the electrolysis plant includes a water treatment system with reverse osmosis that requires 1.2 to 2 L/Nm^3 [13 to 17 L/kg of H_2] (varies depending on potable water quality) to produce approximately 0.8 L/Nm^3 of demineralised water for the electrolysis process [15]. Therefore, the potable water consumption rate is taken as 2 $L/Nm^3(H_2)$, considering the worst scenario possible of potable water quality.

Having the demineralised water consumption rate, it is possible to estimate the Potassium Hydroxide consumption (KOH) rate per H_2 used during alkaline electrolysis, considering the density of KOH to be 2040 kg/m^3 [16], and the density of H_2 at NTP (0.0837 kg/m^3).

Table III
PRODUCTION AND CONSUMPTION RATES FOR S1: ALKALINE CASE.

H_2 Production	8,000 Nm^3/h 670.35 kg/h
O_2 Production	4,000 Nm^3/h 5326.68 kg/h
Potable Water Consumption	2 $L/Nm^3(H_2)$ 0.02388 $m^3/kg(H_2)$
KOH Consumption	4.87 $kg(KOH)/kg(H_2)$

Since each stack of the A3880 is rated 485 Nm^3/h and 2.2 MW, the A3880 would be scaled up to a 17 stacks modular system to cover the H_2 production rate at CTRSU. Therefore, the system capacity range per unit will be 8245 Nm^3/h, 37.4 MW.

CAPEX and OPEX for the A3880 are not available. Hence, values were estimated based on literature references, such as [17] and [18]. CAPEX and OPEX data were obtained from [18], which presents comprehensive report about a 20 MW alkaline system. Subsequently, the value of the electrolyser CAPEX was scaled for a 37.4 MW system using data from [17]. Furthermore, the CAPEX for compression of H_2 before storage had to be calculated separately using (3).

$$CAPEX_{\text{comp}}(€) = 0.84 \times 15,000 \times \left(\frac{P(kW)}{10kW}\right)^{0.9} \tag{3}$$

While the power $P(kW)$ required to compress H_2 from $p_{in} = 1\ bar$, the atmospheric pressure at electrolysis delivery, to $p_{out} = 200\ bar$ is computed with (4), taken from [19].

$$P(kW) = \frac{Q \times ZTR}{M_{H_2} \times \eta_{comp}} \times \frac{N\gamma}{\gamma - 1} \times \left[\left(\frac{p_{out}}{p_{in}}\right)^{\frac{\gamma-1}{N\gamma}} - 1\right] \tag{4}$$

Where Q is the flow rate in kg/s, Z the compressibility factor (set at 1 as an approximation), T the temperature at the inlet (293.15 K), R the ideal gas constant (8.314 $J/K.mol$), M_{H_2} the hydrogen molecular mass, η_{comp} the compressor efficiency (set at 75%), N the number of compressor stages and γ the isentropic coefficient (1.4).

The correspondent values of CAPEX and OPEX are described in IV.

Table IV
CAPEX AND OPEX RATES FOR SCENARIO 1: ALKALINE CASE.

Equipment	Cost
Electrolyser system	
CAPEX [€/kW]	550
OPEX [% of electrolyser CAPEX/YEAR]	2 [13]
CAPEX stack replacement [€/kW]	340 [13]
Potable Water [€/m^3]	3.26 [20]
KOH [€/kg]	0.475 [21]
H_2 **Compressor**	
CAPEX [€/kW]	694.45
OPEX [% of compressor CAPEX/YEAR]	3 [19]
H_2 **Storage**	
CAPEX [€/kg]	225 [19]
OPEX [% of storage CAPEX/YEAR]	0.5 [19]

B. S1: SOEC Case

For the high temperature of water electrolysis case, a Topsoe electrolyser system (SOEC 100 MW SOEC 32,000 Nm^3/h) [22] is considered as reference. The key specifications of the Topsoe SOEC system electrolysis system can be found in Table V.

Based on the same reason as in III-A, the AC power consumption at the system level is estimated to be 3.4

Table V
KEY SPECIFICATIONS OF TOPSOE SOEC ELECTROLYSER [22].

Specifications	Topsoe
Capacity Range per Unit	32,000 Nm^3/h
Power consumption rating	100 MW
DC Power Consumption at Stack Level	3.1 kWh/Nm^3
H_2O (Steam) consumption	27,000 kg/h
H_2 Purity	Up to 99.999% [a]
Delivery Pressure	2 $bar(g)$
Delivery temperature	Ambient

[a] Dry basis after gas cleaning

kWh/Nm^3. The SOEC system is scaled down by a factor of 3, which gives the characteristics in VI.

Table VI
TOPSOE SIZED ACCORDING TO CTRSU SPECIFICATIONS.

Specifications	Topsoe
Capacity Range per Unit	10,666.66 Nm^3/h
Power consumption rating	33.3 MW
AC Consumption at System Level	3.4 kWh/Nm^3
H_2O (Steam) consumption	9,000 kg/h

The steam required per year is then computed as a percentage of the total amount of steam available in the year 2019, as represented in (5), and the power input is then deduced from the remained percentage of steam not used as direct input for electrolysis which is converted into electricity. See (6).

$$\textit{SteamInput}(\%) = \frac{\textit{Steam Flowrate (kg/h)} \times h_a}{\textit{Steam Produced (kg)}} \tag{5}$$

$$\textit{PowerInput}(\%) = [100\% - \textit{SteamInput(\%)}] \times Power_{(2019)} \tag{6}$$

The production rates of hydrogen and oxygen are, therefore, estimated using both the power consumption rate and steam flow rate of the SOEC system, based on the amounts of electrical power and steam available for input.

Table VII
STEAM ENERGY USAGE AND PRODUCTION RATES FOR S1: SOEC CASE.

Steam to SOEC	4.42%	75,690 $tonnes$
Steam to Electricity	95.58%	302.4 GWh
Electricity/Steam Ratio	4 $kWh/kg(H_20)$	
H_2 Production	10,574.91 Nm^3/h	885.67 kg/h
O_2 Production	5,287.46 Nm^3/h	7,037.60 kg/h

CAPEX and OPEX for the Topsoe electrolysis are obtained from academic literature and reports. While the power $P(kW)$ required to compress H_2 from p_{in} = 2 bar, delivery pressure from the Topsoe electrolyser unit to p_{out} = 200 bar is computed using (4). And the compressor CAPEX is similarly obtained from (3).

Table VIII
CAPEX AND OPEX RATES FOR SCENARIO 1: SOEC CASE.

Equipment	Cost
Electrolyser system	
CAPEX [€/kW]	2,500 [23]
OPEX [% of electrolyser CAPEX/YEAR]	3 [24]
CAPEX stack replacement [€/kW]	340 [13]
H_2 **Compressor**	
CAPEX [€/kW]	693.58
OPEX [% of compressor CAPEX/YEAR]	3 [19]
H_2 **Storage**	
CAPEX [€/kg]	225 [19]
OPEX [% of storage CAPEX/YEAR]	0.5 [19]

C. S2: Alkaline Electrolysis Case

For this case, the A3880 is chosen once more, although the capacity of the electrolysis plant unit is adjusted to meet the energy production values of this scenario (see I). The production rates are calculated based on (1), while the consumption rates remain the same as in III-A.

Table IX
PRODUCTION AND CONSUMPTION RATES FOR S2: ALKALINE CASE.

H_2 Production	2,668 Nm^3/h 223.45 kg/h
O_2 Production	1,334 Nm^3/h 1,775.56 kg/h
Potable Water Consumption	2 $L/Nm^3(H_2)$ 0.02388 $m^3/kg(H_2)$
KOH Consumption	4.87 $kg(KOH)/kg(H_2)$

Judging from production rates in IX, the A3880 is scaled to a 6 stacks modular system to cover the necessary H_2 production rate at the plant. Since each stack is rated at 485 Nm^3/h, 2.2 MW, the system capacity range per unit is 2910 Nm^3/h, 13.2 MW.

CAPEX and OPEX are estimated based on the rates presented in IV, with two exceptions:

- Since the size of the electrolyser system is now smaller (13.2 MW) than in III-A, the value of CAPEX per unit of power is estimated to be 575 €/kW.
- The compressor CAPEX per unit had to be recalculated since the hydrogen flowrate, Q, takes a smaller value compared to scenario 1.

D. S2: SOEC Case

For the high-temperature water electrolysis case in this scenario, a SUNFIRE-HYLINK SOEC [25] is considered reference. The electrolyser follows a modular system design, in which, one system produces 750 Nm^3/h hydrogen with an AC power consumption of 3.6 kWh/Nm^3.

The production rate in this current scenario is expected to be much lower compared to scenario 1, hence, since the technical data available for the SUNFIRE-HYLINK SOEC is estimated for relatively small production capacity rates, it is assumed that scaling up the SUNFIRE-HYLINK SOEC by a factor of 5 will provide more accurate estimations in terms

Table X
KEY SPECIFICATIONS OF SUNFIRE-HYLINK SOEC ELECTROLYSER [22].

Specifications	SUNFIRE-HYLINK
Capacity Range per Unit	750 Nm^3/h
Power consumption rating	2.68 MW
DC Power Consumption at Stack Level	3.3 kWh/Nm^3
H_2O (Steam) consumption	860 kg/h
H_2 Purity	Up to 99.99%
Delivery Pressure	0 $bar(g)$
Delivery temperature	Ambient

of power consumption and steam flowrate requirements than scaling down the Topsoe unit.

Table XI
SUNFIRE-HYLINK SOEC SIZED ACCORDING TO CTRSU SPECIFICATIONS.

Specifications	SUNFIRE-HYLINK
Capacity Range per Unit	3,750 Nm^3/h
Power consumption rating	13.4 MW
AC Power consumption at System Level	3.6 kWh/Nm^3
H_2O (Steam) consumption	4,300 kg/h

The steam and power input percentages for the high-temperature electrolysis with SUNFIRE-HYLINK SOEC were estimated using (5) and (6). production rates of hydrogen and oxygen can be estimated using both the power consumption rate and steam flow rate of the SOEC system, combined with the amounts of electrical power and steam available for input.

Table XII
STEAM ENERGY USAGE AND PRODUCTION RATES FOR S2: SOEC CASE.

Steam to SOEC	6.34%	36,163 $tonnes$
Steam to Electricity	93.66%	98.8 GWh
Electricity/Steam Ratio	2.73 $kWh/kg(H_20)$	
H_2 Production	3,262.37 Nm^3/h	273.2 kg/h
O_2 Production	1631.18 Nm^3/h	2,171.10 kg/h

CAPEX and OPEX are estimated based on the rates presented in VIII. Considering the two exceptions mentioned previously in III-C, the CAPEX for the electrolyser system is now estimated at 2750 €/kW.

E. Oxygen Selling Option

Oxygen capture is considered in both cases (alkaline and SOEC) for scenario 1 and 2. A 24h buffer storage approach is considered as in the hydrogen production scenarios with a pipeline system for direct injection. Liquefaction and storage in tanks are assumed because of the large production rates, with the possibility to sell to local industry or for medical applications (high purity).

The assumption that 65,280 $kg_{(O_2)} \approx 57\ m^3$ of liquid O_2 [19], [26] was applied for the liquefaction of O_2 calculations throughout this study.

Table XIII
CAPEX AND OPEX RATES FOR O_2 LIQUEFACTION AND STORAGE.

Equipment	Cost
O_2 liquefaction	
CAPEX [$€/kW_{electrolyser}$]	125 [19]
OPEX [% of liquefaction CAPEX/YEAR]	3 [19]
O_2 Storage	
CAPEX [$€/m^3_{liquidO_2}$]	453 [27]
OPEX [% of storage CAPEX/YEAR]	3 [19]

IV. HYDROGEN PRODUCTION COST

The specific cost of hydrogen production (C_{H_2}) is calculated for all scenarios and cases, as a function of the variation of the electricity prices. The equation for C_{H_2} is adapted from [19].

$$C_{H_2} = \epsilon_{electrol} \times \left(p_{elect} + \frac{OPEX_{H_2}}{P \times h_a} \right) + \epsilon_{comp} \cdot p_{elect} + \epsilon_{H_2O} + \epsilon_{KOH} \tag{7}$$

Where $\varepsilon_{electrolyzer}$ represents the power consumption of the electrolyser at the system level $[kWh/kg_{H2}]$; p_{elect} the electricity price [$€/kWh$]; $OPEX_{H_2}$ the electrolyser system, compressor and H_2 storage OPEX [€/year]; P the electrolyser system power rating $[kW]$; h_a the annual plant availability hours $[h]$; ε_{comp} the specific power consumption of the compressor kWh/kg_{H_2} (0.93 [19]); ε_{H_2O} the water cost per kg of produced H_2 [$€/kg_{H_2}$]; ε_{KOH} the KOH cost per kg of produced H_2.

For the SOEC case ε_{H_2O} and ε_{KOH} are considered zero, as water is replaced by the steam already existent at the WtE plant and KOH is not needed.

When oxygen selling is introduced, the specific cost of oxygen production (C_{O_2}) is also calculated considering the OPEX of O_2 liquefier and storage [$€/year$] ($OPEX_{O_2}$), ε_{liq} the liquefier power consumption $[kWh/kg_{O_2}]$ ($\varepsilon_{liq} = 0.52$ [19]), and p_{O_2} the selling price of oxygen - considered as 100 $€/tonne$ [19] (for industrial applications).

$$C_{O_2} = \epsilon_{electrol} \times \left(p_{elect} + \frac{OPEX_{O_2}}{P \times h_a} \right) + 8 \times \epsilon_{liq} \cdot p_{elect} - 8 \times p_{O_2} \tag{8}$$

Therefore, the total specific cost of hydrogen with the impact of oxygen C_{H_2/O_2} is estimated in (9).

$$C_{H_2/O_2} = C_{H_2} + C_{O_2} \tag{9}$$

However, in S2, since hydrogen is being produced with one-third of total energy and the remaining two-thirds are being directly exported to the grid, the revenue of the electricity selling from the latter is deducted from the total specific cost of hydrogen (see (10)). Where $\lambda[kWh/kg_{H_2}]$ is the ratio of exported electricity per kg of produced H_2, estimated in (11)

$$C_{H_2/O_2}(scenario2) = [C_{H_2} - (\lambda \times p_{elect})] + C_{O_2} \tag{10}$$

$$\lambda = \frac{\frac{2}{3} \times \textit{total produced power } (kWh)}{H_2 \textit{ production rate}(kg/h) \times h_a} \quad (11)$$

V. SELLING PROFITS

Three different contexts are considered to analyse the profits:

- Sale of hydrogen and oxygen.

$$Profit = Q_{H_2}[p_{H_2} + 8 \times p_{O_2} - C_{H_2/O_2}] \quad (12)$$

- Sale of hydrogen only. Oxygen is released into the atmosphere.

$$Profit = Q_{H_2}[p_{H_2} - C_{H_2}] \quad (13)$$

- Sale of all electricity to the grid. Without H_2 and O_2 production.

$$Profit = \textit{total produced power } (kWh) \times p_{elect} \quad (14)$$

The selling price for green hydrogen may vary between 3 to 8 €/kg [28]. In this study, hydrogen selling price (p_{H_2}) is taken to be 8 $€/kg$.

VI. ECONOMIC FEASIBILITY OF THE PROJECT

To Analyse the economic feasibility of the H_2 production at CTRSU, the following economic and financial indicators are considered: Levelised cost of H_2 (LCOH), Net Present Value (NPV), and the Internal Rate of Return (IRR).

A. LCOH

LCOH measures the average net present cost of hydrogen production over the lifetime of the generating plant. It can be estimated with the formula in (15).

$$LCOH[€/kg] = \frac{\alpha \times CAPEX_{Total} + OPEX_{Total}}{H_2\ rate \times h_a} + C_{H_2} \quad (15)$$

Where,

$$\alpha = \frac{r(1+r)^n}{(1+r)^n - 1} \quad (16)$$

For calculating the LCOH, H_2 rate is the hydrogen production rate of the electrolyser system $[kg/h]$ While r stands for the discount rate [%], and n the estimated hydrogen plant lifetime $[years]$, taken to be 10% and 20 years respectively for all calculations.

The project is considered economically feasible when $LCOH \geq p_{H_2}$.

B. NPV

NPV is used to analyse the profitability of a project. Being defined as the difference between the discounted incomes and the discounted outcomes, called the cash flow over the lifetime of the project.

$$NPV = \frac{CF}{\alpha} - CAPEX_{Total} \quad (17)$$

CF stands for cash-flow, and $CAPEX_{Total}$ is the total investment in year zero.

In Portugal, the corporate tax, called IRC (Imposto sobre o Rendimento de Pessoas Coletivas) is 21% [19]. This tax is imposed on companies over their profits. This deduction is applied over the cash-flow when NPV is estimated.

When $NPV > 0$, the project is considered economically profitable, the investment is recovered, the minimum rate of return of capital is achieved and a surplus is achieved.

When $NPV = 0$, the project is feasible, the investment is recovered and the minimum rate of return of capital is achieved.

When $NPV < 0$, the project is not economically profitable.

C. IRR

IRR is the discount rate that turns the NPV equal to zero. It also shows the real rate of return of the project.

$$IRR^{(k+1)} = \frac{CF}{CAPEX_{Total}} \times \frac{(1 + IRR^{(k)})^n - 1}{(1 + IRR^{(k)})^n} \quad (18)$$

A project is considered profitable if IRR is higher than the discount of the initial rate, r.

VII. RESULTS AND DISCUSSION

A. Production Costs

In S1, the costs increase together with the electricity prices, and H_2 cost with Oxygen selling is lower than H_2, however, the latter tends to become cheaper when as electricity prices are become higher. Additionally, in the SOEC case, H_2 cost with oxygen selling starts negative at very low prices of electricity because the oxygen selling revenue is higher than the cost of hydrogen production. This does not happen in the alkaline case because the cost of hydrogen production is higher than SOEC since additional feedstocks are required (potable water and KOH).

In S2, SOEC is initially the cheapest technology at low electricity prices but alkaline seems to take over at high prices. This happens because λ is greater for the alkaline case as the plant has a lower H_2 production rate compared to the SOEC case which causes the alkaline case to have more direct electricity selling revenues than the SOEC case. Essentially, SOEC remains the cheaper technology in S1, and in S2 when the electricity prices are low (close to zero).

Overall, S1 with alkaline electrolysis is generally the most expensive option. S2 with SOEC is the cheapest, but when electricity prices are higher than 100 €/MWh S2 with alkaline technology becomes the cheapest.

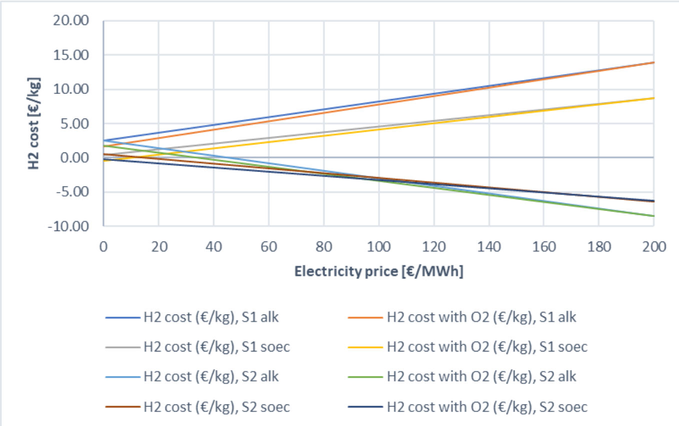

Figure 3. Specific hydrogen production costs.

B. Selling Profits

The graphs in Fig. 4 point that S2 leads to the most profitable revenues. In this scenario, selling $H_2\&O_2$ from SOEC is most profitable when the electricity price is below 100 €/MWh; beyond this price, it is more profitable to sell $H_2\&O_2$ from alkaline electrolysis. Selling H_2 only in S2 is also more profitable than in S1.

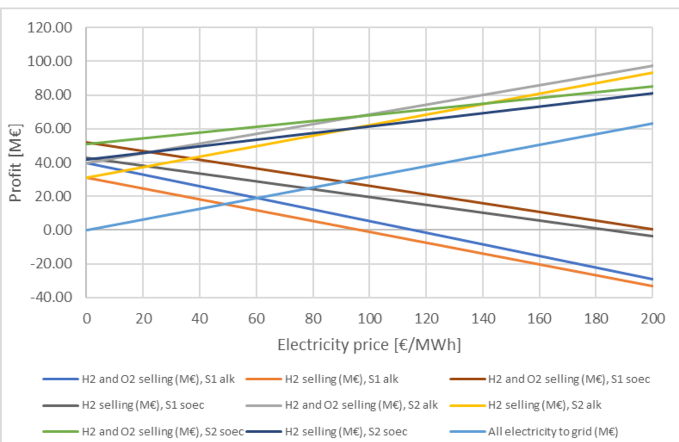

Figure 4. Profits from hydrogen and electricity selling.

Nonetheless, when the electricity price is absolutely zero, selling $H_2\&O_2$ from SOEC in either scenario is equally the most profitable, however, profitability in S1 will have a decreasing trend as electricity prices increase up to the point that when electricity price is higher than 90 €/MWh, it becomes more profitable to sell the electricity directly to the grid without any gas production. Applying the S1 would be considered a feasible option if the intention is to generate hydrogen solely when the electricity prices are down in the market.

C. Economic Feasibility of the Project

The LCOH analysis demonstrates that S2 has the cheapest options, as they are all below the selling price of hydrogen. This implies that the average cost of producing hydrogen can be recovered, meaning that the project would always be feasible. On the other side, in S1, for alkaline technology, the project would be feasible only when the electricity price is lower than 80 €/MWh, while SOEC remains feasible up to roughly 135 €/MWh.

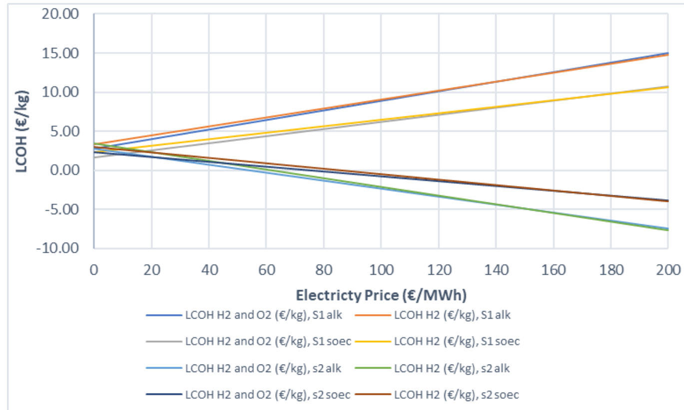

Figure 5. LCOH curves from all scenarios and cases.

In any case, the LCOH for $H_2\&O_2$ is always slightly cheaper than producing producing H_2 only.

As estimated by the LCOH, the NPV graphs also indicate that all cases in S2 are always economically profitable since their curves remain increasingly positive along all electricity prices. Alkaline technology is the most profitable in S2.

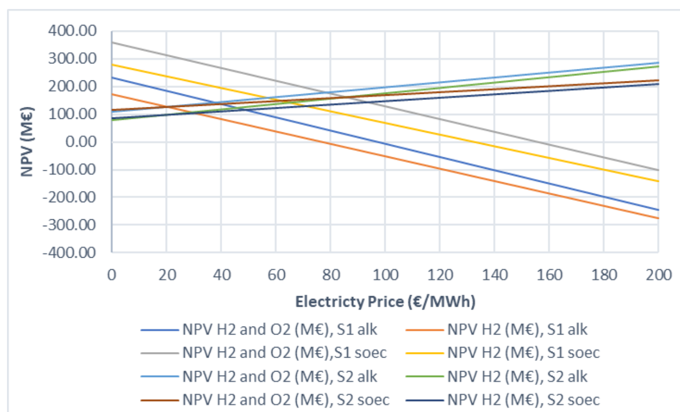

Figure 6. NPV from all scenarios and cases.

However, S1 is the most profitable option when the electricity price is no greater than 20 €/MWh. Up to this point, selling H_2 only, despite being the least profitable in S1, remains more profitable than all cases from S2. Selling $H_2\&O_2$ from alkaline of S1 will be profitable until the electricity price is below 40 €/MWh, after this price, both SOEC and alkaline cases from S2 become more profitable.

Utilising SOEC for producing and selling H_2 only in S1 is more profitable than S2 until the electricity price remains approximately below 60 €/MWh, beyond this point, all cases in scenario 2 become more profitable. While producing and selling $H_2\&O_2$ with SOEC in S1 is the most profitable as long as the electricity price is below 80 €/MWh. Conclusively, NPV curves show that, in all individual cases from both scenarios, producing and selling $H_2\&O_2$ is always more profitable than H_2 only.

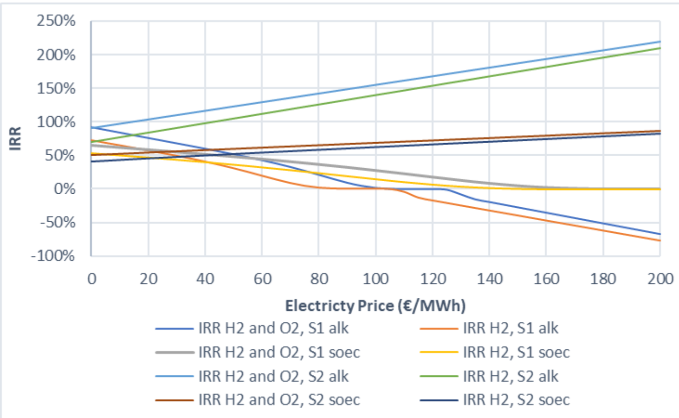

Figure 7. IRR in all scenarios and cases.

Finally, the IRR shows that alkaline electrolysis technology in S2 gives the two the highest internal return rates, in which selling $H_2\&O_2$ gives a marginally higher return rate than producing and selling only H_2. Likewise, the SOEC technology case from S2 gives the two second-highest IRR.

As expected, in scenario 2, all IRRs are always higher than the initial discount rate, r, ensuring the profitability of the options. Meanwhile, S1 cases still show different degrees of positive profitability at up certain electricity prices.

VIII. Conclusion

In face of the fluctuation of electricity prices in the MIBEL, the analysis in this work is done taking into account the variation of prices from 0 to 200 €/MWh for two scenarios. In scenario 1, the entire energy produced from the WtE at CTRSU is applied for electrolysis (316.4 GWh and 1,710,959 tonnes of steam) meanwhile in scenario 2, only one-third of the energy produced (105.5 GWh and 570,316,6 tonnes of steam) is used for electrolysis, as the remaining two-thirds is injected into the national grid. Both scenarios are assessed with the alkaline and SOEC technologies. The energy production values for the year 2019 from CTRSU are considered for the calculations since the values of MSW and energy production are regular and unaffected by the pandemic situation. Additionally, oxygen capturing and sales are also introduced into the analysis of hydrogen production.

Producing hydrogen in scenario 1 is more profitable than selling all the electricity to the grid when the electricity price is lower than 90 €/MWh. However, producing hydrogen in scenario 2 is always more profitable than selling all electricity to the grid. Furthermore, applying the LCOH calculations, it is perceived that scenario 2 is generally the cheapest in average cost and is always feasible despite the electricity prices, assuming a hydrogen selling price of 8 €/kg. On the other hand, NPV curves point out that scenario 1 is the most profitable option when the electricity price is at least below 20 €/MWh. SOEC for hydrogen with oxygen capture in scenario 1 can be the most profitable option when the electricity price is zero, but the profit level drop rather quickly as the electricity price rises, becoming less profitable than alkaline for hydrogen with oxygen capture in scenario 2 at 80 €/MWh. From 90 €/MWh onwards is more profitable to apply any case of scenario 2 than any case from scenario 1.

In the IRR analysis, it is evident that scenario 2 has a higher rate of return than the discount rate (r=10%) along all electricity prices. In this scenario, alkaline technology always has a higher return rate than SOEC. Scenario 1 produces a decreasing rate of return, making the project only when electricity prices are considerably low.

Overall, the results indicate that converting one-third of the total electricity into hydrogen gives the lowest production costs since these costs are reduced and profits per kg of hydrogen are increased through the selling of the remaining fraction of the electricity. Alternatively, when the electricity price is below 20 €/MWh, it is more convenient to convert all the energy into hydrogen.

Finally, it was observed that in all cases and scenarios, the LCOH decreases and NPV for hydrogen is increased as an oxygen capturing option is included. However, this fact may not be entirely realistic if the oxygen end-use application site is out of reach of the plant location since other economic factors would need to be considered, such as bigger storage capacity, transportation and/or distribution systems.

Acknowledgment

This research work was supported by Valorsul - Valorização e Tratamento de Resíduos Sólidos das Regiões de Lisboa e do Oeste, S.A.

References

[1] UNEP, Global Waste Management Outlook, 2015.
[2] European Parliament, "DIRECTIVE 2010/75/EU OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL of 24 November 2010 on industrial emissions (integrated pollution prevention and control)," Council of the European Union, Brussels, 2010.
[3] N. Scarlat, F. Fahl and J.-F. Dallemand, "Status and Opportunities for Energy Recovery from Municipal Solid Waste in Europe," Waste and Biomass Valorization, vol. 10, p. 2425–2444, 2019.
[4] M. Margallo, R. Aldaco, A. Irabien, V. Carrillo, M. Fischer, B. A. and F. P., "Life cycle assessment modelling of waste-to-energy incineration in Spain and Portugal," Waste Management & Research, vol. 32, no. 6, pp. 492-499, 2014.
[5] S. Xará, M. F. Almeida and C. Costa," Energy from waste in Portugal: the state of the art," 2008.
[6] APA, "WASTE: MUNICIPAL WASTE PRODUCTION AND MANAGEMENT," 2021. [Online]. Available: https://rea.apambiente.pt/content/municipal-waste-production-andmanagement?language=en. [Accessed 17 July 2020].
[7] IEA, "Renewables," International Energy Agency, 2021. [Online]. Available:https://www.iea.org/fuels-and-technologies/renewables. [Accessed 17 July 2020].
[8] MIBEL, "Market today," 2022. [Online]. Available: https://www.omip.pt/en/plazo-hoy. [Accessed 17 July 2022].
[9] S. G. Furtado, F. J. M.-H. dos Santos and R. J. R. Laia, "Análise do sistema de tratamento de efluentes gasosos de uma central de valorização energética de resíduos sólidos urbanos," ISEL, Lisbon, 2014.

[10] Valorsul, “A Combustao,” Valorsul, 2022. [Online]. Available: http://www.valorsul.pt/pt/seccao/areas-de-negocio/valorizacao-energetica/a-combustao. [Accessed 20 July 2022].
[11] V. S. R. Tavares, J. M. D. J. de Melo and M. d. G. M. Martinho, “Analise de Ciclo de Vida dos RU em Destino Final. Caso de Estudo: Aterros e Incineradoras de Portugal,” 2013.
[12] Valorsul, “Relatório e contas 2020,” 2021.
[13] IRENA, “Hydrogen from Renewable Power: Technology Outlook for the Energy Transition,” 2018.
[14] NEL, “Atmospheric Alkaline Electrolyser,” NEL. [Online]. Available: https://nelhydrogen.com/product/atmospheric-alkaline-electrolyser-a-series/. [Accessed 21 July 2022].
[15] Cummins, “HySTAT®: ALKALINE ELECTROLYZERS,” 2021.
[16] National Center for Biotechnology Information, “PubChem Compound Summary for CID 14797, Potassium hydroxide,” 2022.
[17] J. Proost, “State-of-the art CAPEX data for water electrolysers, and their impact on renewable hydrogen price settings,” International Journal of Hydrogen Energy, vol. 44, no.9, pp. 4406-4413, 2019.
[18] IRENA, “Hydrogen from Renewable Power: Technology Outlook for the Energy Transition,” 2018.
[19] T. R. Lucas, A. F. Ferreira, B. S. Pereira and M. Alves, “Hydrogen production from the WindFloat Atlantic offshore wind farm: A techno-economic analysis,” Applied Energy, vol. 310, p. 118481, 2022.
[20] EPAL, “www.epal.pt,” EPAL, 2022. [Online]. Available: https://www.epal.pt/EPAL/menu/clientes/tarif%C3%A1rio/%C3%A1gua. [Accessed 23 July 2022].
[21] PHARMACOMPASS, “Potassium Hydroxide,” 2016. [Online]. Available: https://www.pharmacompass.com/price/potassium-hydroxide. [Accessed 22 July 2022].
[22] TOPSOE, 2021. [Online]. Available: https://www.topsoe.com/processes/green-hydrogen. [Accessed 23 July 2022].
[23] L. Wang, M. Chen, R. Küngas, T.-E. Lin, S. Diethelm, F. Maréchal and J. Van herle, “Power-tofuels via solid-oxide electrolyzer: Operating window and techno-economics,” Renewable and Sustainable Energy Reviews, vol. 110, pp. 174-187, 2019.
[24] EU, “FUEL CELLS AND HYDROGEN JOINT UNDERTAKING (FCH JU): Multi - Annual Work Plan 2014 - 2020,” 2014.
[25] Sunfire GmbH, “RENEWABLE HYDROGEN FOR INDUSTRIAL APPLICATIONS: SUNFIRE-HYLINK SOEC,” 2021.
[26] “Universal Industrial Gases, Inc,” [Online]. Available: http://www.uigi.com/o2_conv.html. [Accessed 09 July 2022].
[27] [Online]. Available: https://www.alibaba.com/product-detail/30m3-liquid-oxygen-hold-upvessel_62517830815.html. [Accessed 09 July 2022].
[28] PwC, “The green hydrogen economy: Predicting the decarbonisation agenda of tomorrow,” [Online]. Available: https://www.pwc.com/gx/en/industries/energy-utilities-resources/futureenergy/green-hydrogen-cost.html. [Accessed 27 July 2022].