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Towards the introduction of green hydrogen in the energy mix of Mediterranean islands through the integration of wind and solar power: a techno-economic case study

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Abstract:

Mediterranean islands have always struggled with power supply, with the high cost of electrical submarine cables prompting the pursuing of energy self-sufficiency with renewable energy sources (RES). Despite being clean and sustainable, RES are intermittent and unpredictable, hence the integration of a storage system is crucial to match load with production. Modern batteries are a valuable solution for short term storage, but they are unsuitable for long term storage for both technical and economic reasons. Green hydrogen is among the most promising options to enable a year-long autonomous operation, but it is still an expensive option, with many technical issues that still need to be addressed. One of the key factors hampering a reduction of the levelized cost of green hydrogen (LCOH) is the low number of working hours that an electrolyzer can exploit when connected to low-capacity factor RES. Starting with real production data of a wind turbine and a PV farm in a Mediterranean island, this study aims to assess the optimal combination of wind and solar power to decrease the LCOH (intended as its production cost only) and thus the cost of storage.

The study is made of three steps. First, a comprehensive parametric optimization is carried out to determine the optimal combination of electrolyzer and PV field size to minimize the LCOH produced from the surplus power generated on the island. Secondly, an additional analysis is performed to calculate the minimum PV field expansion required to achieve a complete energy self-sufficiency and to estimate the resulting LCOH in such case. Lastly, the implementation of a fleet of hydrogen buses is proposed to both reduce the carbon footprint of the island transportation system, and further lower the cost of hydrogen production.

Keywords:

Green Hydrogen; Island; Wind; Photovoltaics; Techno-economics; LCOH.

1. Introduction

The focus of the present study is the estimation of the cost of producing green hydrogen on the island of Tilos, as a potential upgrade of the hybrid energy system (HES) currently in use. Nowadays, the system involves a 800-kW wind turbine, a 160-kWp PV field, and a 2.88 MWh battery in proximity of two villages. These villages experience a peak demand of 960 kW during the summer season.

More specifically, the objective is to assess the potential for hydrogen production using the excess power generated by the HES due to the mismatch between intermittent renewable energy production and demand. This excess power is harnessed for water splitting using an alkaline electrolyzer.

The analysis first evaluates the energy deficit and surplus of the HES, initially considering only the RES production and then assessing the storage potentiality. An electrolyzer model is then used to analyze the H_2 production potential from the power excess profiles generated by different scenarios resulting from the upgrade of the PV field. For each simulated couple of increased PV power and electrolyzer sizes, the levelized cost of hydrogen (LCOH) is calculated. Next, the annual hydrogen generation is compared with a preliminary estimation of the amount of hydrogen required to achieve 100% self-sufficiency by reconverting it back to electricity using a fuel cell. The aim is to identify the configuration that produces the cheapest hydrogen in the case a form of seasonal storage is needed. Additionally, this study explores the possibility of using hydrogen excess to power a fleet of buses, which would help in the decarbonization of public transport during the summer

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season without imposing an additional strain on the electrical grid. Moreover, it is demonstrated how an increase in the amount of produced hydrogen could further lower the LCOH.

This preliminary assessment aims to evaluate the green hydrogen production potential in remote islands. Those communities may largely benefit from a suitable mean of seasonal storage, due to their highly variable energy demand during the year.

1.1. Tilos project

Tilos belongs to the Greek Non-Interconnected Islands (NIIs) group, i.e., remote communities in the Aegean sea whose electricity requirements have been almost entirely supplied by a local generation based on outdated thermal power stations that rely on diesel and heavy oil [1]. Due to the high solar radiation and pretty high wind speeds that characterize the region, the energy production of the area could be shifted towards a more sustainable generation based on renewable sources. Funded by the European Horizon 2020 project, the hybrid energy system (HES) of Tilos was completed in 2019 and comprises of an Enercon E-53 800-kW wind turbine and a 160-kWp photovoltaic field. In addition, a 2.88-MWh high temperature battery was selected as the storage medium to manage the intermittent energy fluxes from renewable generators [2]. Today, the HES is owned and managed by Eunice Energy Group (EEG), which kindly provided real operational data used for the analyses.

1.2. Green hydrogen production in islands

As a complement to the introduction of RES, green hydrogen and power-to-gas technologies are seen as promising for a variety of applications for the island of Tilos and other similar communities. Due to the significant variation of the electrical energy demand resulting from the seasonal variation of the population, green hydrogen tanks could be in fact a suitable option to store the energy generated in the winter season, when the population is minimum. Then, H_2 can be converted back to electricity during summer when tourists make the population triple.

Several studies have already proven that green hydrogen can be used for seasonal storage. H_2 produced by means of water electrolysis driven by renewable power produced by PV and wind generators can be stored in tanks and, when needed, reconverted into electricity via fuel cells or thermal machines. Lubello et al. [3] assessed the feasibility to utilize hydrogen for long-term storage in energy systems. Despite being inconvenient in normal scenarios, an island could be a suitable candidate for this kind of applications because of its remote location and thus high costs of connection with the main grid. Another viable and promising option is the export of clean fuels. Vilbergsson et al. [4] investigated the potential of producing green hydrogen in remote locations with abundant renewable resources. If electrolysis is utilized to exploit the energy surplus of those communities, a suitable option could also be to export the fuel towards the mainland. Even considering transport, authors proved that hydrogen produced in this way could have a lower environmental impact than yellow hydrogen produced using grid electricity in some European countries.

The possibility of producing hydrogen in a Greek island has been previously investigated by Lykas et al. [5]. The authors performed a dynamic investigation and optimization of a solar-based unit for green hydrogen production by means of a PEM electrolyzer and found that their system can meet the variable demand of an island. The present work builds upon the same main concept and considers a similar location, but different RES generators and another, yet similar, electrolyzer technology, while additional scenarios for hydrogen use are introduced. One factor that may hinder the introduction of this energy vector in islands is the high production cost. To this end, the correct sizing of the hydrogen production plant for an optimal exploitation of all components is key to minimizing the expense. The levelized cost of hydrogen (LCOH) of generating hydrogen from a mix of solar and wind power in different locations with different capacity factors was computed by Tang et al. [6]. In the study, authors calculated the price difference of producing hydrogen in locations with a different availability of renewable sources and proved that LCOH may vary from 7.2 €/kg in low windy areas to 3.5 €/kg if the plant has a high availability of the renewable resource. This result reinforces the interest in investigating the hydrogen production potential of islands, due to their high-RES potential.

1.3. Aims of the study

This study assesses the green hydrogen production potential of the hybrid energy system (HES) of the island of Tilos and the resulting cost for producing it. Figure 1 represents the layout of the considered plant and schematizes how clean power produced by renewable generators, supported by the battery energy storage, satisfy the island load. In addition, the power excess is considered as the input for an alkaline electrolyzer that splits water molecules in oxygen and hydrogen. The hydrogen can then be utilized by users or stored in high pressure tanks for further applications. A first sensitivity analysis on a wide range of electrolyzer sizes and possible PV upgrades was used to assess which configuration can produce hydrogen in Tilos at the lowest cost exploiting the power production excess of the island.

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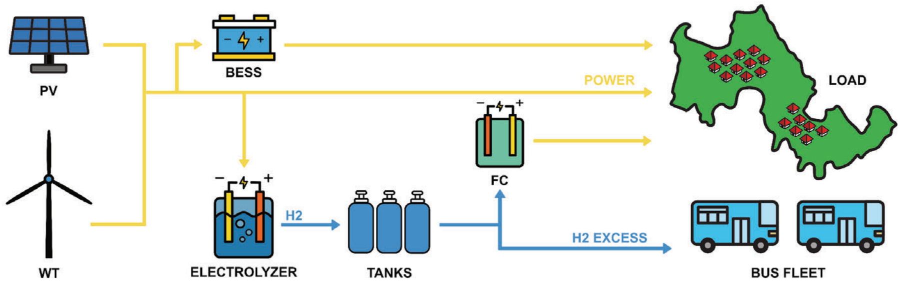

Figure. 1. Tilos HES layout paired with green hydrogen production from power excess and an example of its possible utilization

Then, the possibility of using such hydrogen as seasonal storage is presented, which is supposed to be achieved by means of a fuel cell that converts the gas back to electricity. The hydrogen production capability of different configurations is compared to their hydrogen demand to reach 100% self-sufficiency. The scope is to assess the minimum required upgrade of the PV field to reach total energy independence and to figure out what would be the LCOH in that case. Finally, the LCOH of the hydrogen excess produced by those systems is quantified and a possible exploitation of that excess is proposed. Hydrogen can indeed represent a clean fuel for the decarbonization of the public transport system of the island, and a reduction in the cost of the production excess can make it a competitive fuel with respect to current fossil alternatives.

2. Materials and methods

2.1. Available data

Historical production data of the HES have been made available by EEG, the owner and manager of the system. These data cover eleven months of operation, from November 29th, 2020, to October 29th, 2021, and contain solar production and wind speed measurements sampled with a 1-minute time resolution, directly harvested by the energy management system (EMS). During the first phase of the work available data have been analyzed to produce a consistent input for the hydrogen production model and missing data have been filled. In addition, to carry out relevant production estimations and compare results with literature, a year of operation is required. To address this, PV and wind production datasets were further filled and extended as described in the following section.

2.1.1 Reconstruction of missing data

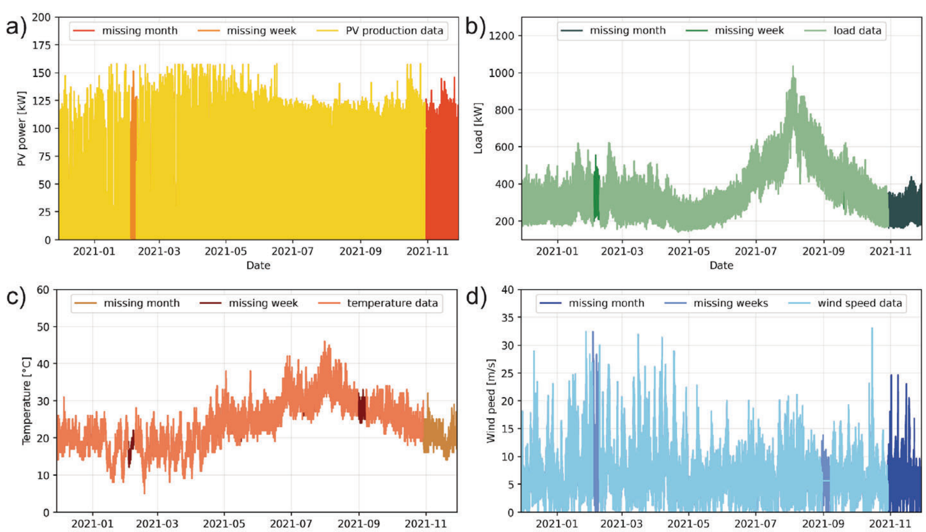

Figure. 2. Time trend during the considered period operation and highlight on reconstructed data related to missing weeks and missing month for a) PV production, b) load, c) ambient temperature, and d) wind speed.

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PV power – Regarding the PV production dataset, a linear interpolation was first carried out to fill missing production for hourly periods. This simple yet effective method produced satisfying results for short time intervals. Production data filled using linear interpolation are represented in yellow in Figure 2 (a). The analysis showed that, for each quantity, the period between Feb 2nd and 8th 2021 is missing. To fill this missing spot, a support vector regression (SVR) was applied to find the correlation between the missing data and the value recorded one, two, three and four weeks before. This reconstruction is visible, in orange, in Figure 2 (a). SVR was also applied to reconstruct the missing month from 29th October to 29th November 2021, finding correlations with the previous month and two months prior. The filled month is again visible in Figure 2 (a), in red.

Load and temperature - Load and temperature datasets were cleaned and filled in a similar way. The load dataset was cleaned by abnormal data points. Outliers too far from the moving average of the load time series were removed, as well as isolated missing values given by measurement errors. Then, gaps shorter than 5 hours were again filled by a linear interpolation with satisfying results. After that, short missing periods in the order of days to one week were filled using again SVR trained on the autocorrelation of the series with its own past values. In Figure 2 (b), the resulting reconstructed periods are highlighted in green. Finally, the missing month was reconstructed by means of a multi-layer perceptron regression. Because of the shape of the series, the method was trained on the first 3 months of data. Figure 2 (b) shows the final obtained load trend. The temperature dataset was pre-processed, cleaned, and filled as well. Using the same methods described for the load dataset, missing periods were reconstructed. The whole year temperature time trend is presented in Figure 2 (c).

Wind speed - The wind speed dataset was lacking the same week of February and the final month of November 2021. Due to the small length of the period and low autocorrelation of the wind series, it was chosen to copy measures from previous days to fill the gaps. In this case, an abnormal measure characterized the period between August 31st and September 8th, 2021, for which a constant value was reported for the wind speed, due to a malfunctioning of the acquisition system. Those data were rejected and substituted using the same procedure utilized for the missing week. Then, for the missing month, winter days were sampled from the dataset at random to reconstruct the missing data. Figure 2 (d) reports the wind speed related to the eleven months in light blue, the reconstructed missing weeks in blue, and the reconstructed missing month in dark blue. Finally, via the ideal power curve of the Enercon E-53 800kW wind turbine, the power production was estimated from the obtained wind speed data for the entire year.

2.2. Resource assessment

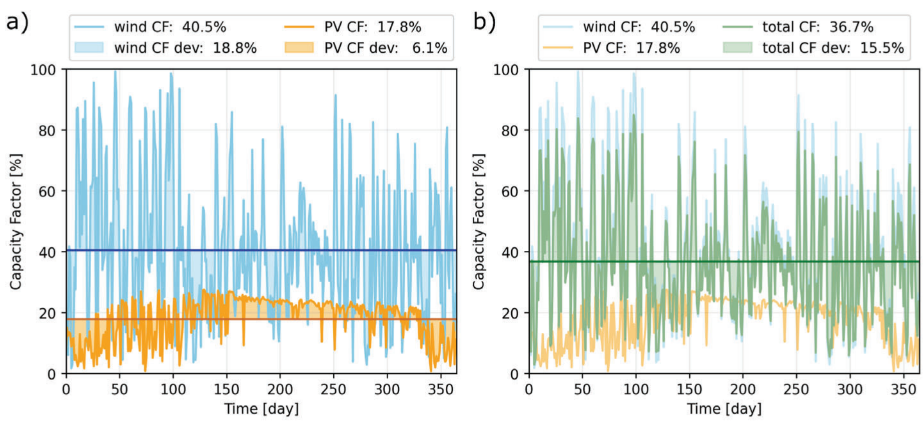

Figure. 3. Daily variation of average capacity factor (CF) and yearly mean value for: a) wind turbine (in blue) and PV field (in orange) and b) hybrid energy system composed by the previous two.

In Figure 3, power production data have been reorganized from January to December, moving the first month of the original dataset to the end, in order to appreciate the seasonal variation of the two resources. Instead of the power production itself from each generator, the energy assessment was based on the generator capacity factor (CF), i.e., the ratio between the actual energy production in each time frame and the energy that the same generator would have produced during the same interval if working at rated power. Figure 3 (a) shows the daily average CF of the wind turbine (in light blue) and PV field (in orange). The CF of the wind turbine is normalized with respect to its nominal power, 800 kW, while the one of the PV is normalized to its peak power of 160 kWp. The dark blue and dark orange flat lines represent the average CF of generators, 40.5% for the WT and 17.8% for the PV. This remarkably high wind capacity factor would in practice be much lower due to the frequent curtailments made by the grid operator to avoid instability problems [7], again proving the need for a suitable energy storage system. It is apparent how the capacity factor of the PV is higher during the summer season than in the winter season, due to the higher solar radiation and light hours. On the other hand, the wind turbine tends to produce slightly more during winter and spring season. In general, as expected the two resources show a certain degree of complementarity, and their combination may lead to steadier energy productions during the year. Figure 3 (b) shows in green the total CF of the system, given by the sum of power generated by the two resources. Its average value (36.7%) is lower than the one related to the single turbine, but its deviation is lower: 15.5% vs 18.8% of the WT because of the lower variation of the PV (6.1%).

2.2.1 Power surplus and deficit during the year

Figure 4 (a) illustrates the match between the weekly average power production (in black) and the average island demand (in red). As discussed, the weekly average power production shows how the synergy between wind and solar energy makes the power production average almost constant during the year. On the other hand, the island demand is characterized by a clear peak during the summer season, primarily due to the presence of tourists that greatly increase the population of the island and thus its energy needs. Therefore, a considerable power deficit of around 1046 MWh affects summer months. During the rest of the year, especially in the first part, the decrease in the island population creates a power excess of around 1125 MWh.

2.2.2 Battery supported operation

A 2.88 MWh lithium-ion battery is considered to simulate how an electrochemical storage device, close to the actual one installed in the island of Tilos, would shift the power profile. Because of the strong seasonal variation of the island load, the current storage size cannot shift the entire power excess towards the power deficit. In our preliminary estimation, the 2.88 MWh BESS still creates an energy deficit of 755 MWh during summer, and the system reaches 74.9% of self-sufficiency. In that scenario, the power excess of more than 781 MWh created in winter months, when the load is covered by the current RES generation and the battery is already full, has the potential to be converted to hydrogen for seasonal storage. Figure 4 (b) clearly shows how the BESS could fill the gap between surplus and deficit energy, although the daily averaged profile of the delivered power slightly differs from the original one. Thus, a seasonal storage device seems the perfect candidate for meeting this residual requirement.

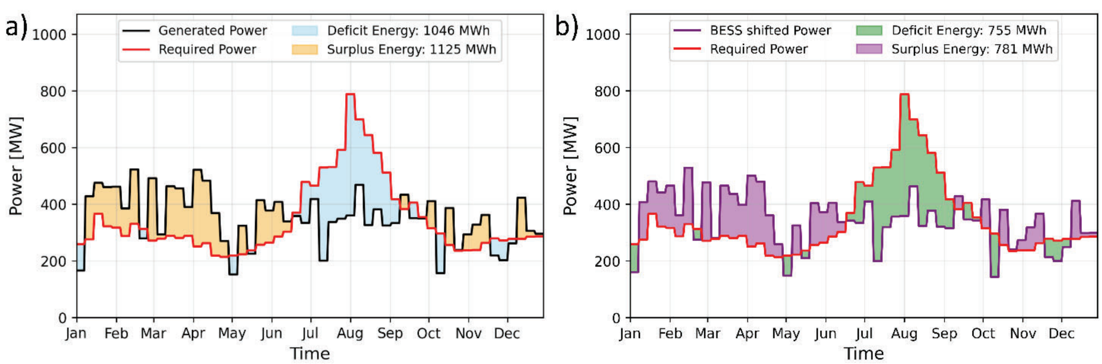

Figure. 4. Match between the daily averaged power production (black line) and the island demand (red line). Highlight on energy surplus (orange/purple areas) and energy deficit (light blue/green areas) for a) RES production and b) BESS-shifted production.

2.3. Green hydrogen production

An in-house alkaline electrolyzer model was developed by some of the authors and was already applied to some other case studies for the green hydrogen production from wind farms [8]. The model was based on the 1MW commercial electrolyzer produced by McPhy, a leading alkaline electrolyzer manufacturer. Since the current Tilos HES has a nominal power of 960 kW, the electrolyzer stack had to be resized to meet the power excess magnitude of the system. Power absorbed by a cell is given by the product of its current and voltage (Eq. 1) and, in this case, corresponds to roughly 9.45 kW. The stack of the commercial 1MW electrolyzer is thus composed of roughly 106 cells connected in series. In this work, customized stacks made by the series connection of a variable number of cells were considered to reach various power levels between 200 kW (22 cells) to 1.5 MW (150 cells), to match the total nominal power level of the HES composed by the wind farm and the PV field.

The operating voltage of the electrolyzer varies due to the performance degradation in time and cool down effect when the H_2 production stops. This time, the main component responsible for the thermal loss, the gas-liquid separator, is scaled according to the considered number of cells to maintain the proper mass flow rate of hydrogen. At each timestep, the conversion factor of the stack is updated according to Eq. 1.

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$$\varphi = \frac{H_{2,id}}{I_{id} \cdot n_{cells} \cdot (V_{ideal} + \Delta V_{time,deg} \cdot h_{work} + \Delta V_{Thermal,deg} \cdot (T_{rated} - T_{el}))} \tag{1}$$

To analyze the H_2 exploitation, a fuel cell with a fixed conversion efficiency was considered for the conversion of gas back to electricity. According to IRENA [9], the efficiency of this technology typically ranges between 50 to 68%, thus an average value of 60% was considered for this analysis.

2.5. LCOH

$$LCOH = \frac{\sum_{t=0}^{20} \frac{(CAPEX_t + OPEX_t)}{(1+i)^t}}{\sum_{t=0}^{20} \frac{H_{prod}}{(1+i)^t}} \tag{2}$$

The levelized cost of hydrogen (LCOH) was selected as the main techno-economic metric for comparing different plant layouts. It represents the cost of producing a unit of hydrogen over a selected period of time (20 years in this case) by means of a certain configuration. The LCOH can be computed, according to Eq. 2, as the ratio between the actualized sum of capital (CAPEX) and operating (OPEX) costs and the actualized hydrogen yield of the plant (H_{prod}), considering in this case a discount rate *i* of 6%.

Capital costs (CAPEX) consider the investment cost for the electrolyzer. According to IRENA [9], a 1MW electrolyzer stack has a specific cost of 270 €/kW and accounts for 45% of the total price of the device. Consequently, the electrolyzer price cost was scaled when smaller or bigger stacks were considered, while the balance of plant (BOP) cost was kept constant. CAPEX also includes the substitution costs that must be faced when a part or a whole component must be substituted. The electrolyzer stack has an expected lifetime of 10 years, thus a replacement is expected halfway the plant life.

Operational costs (OPEX) consider instead the necessary maintenance to keep the electrolysis in proper operating conditions, in this case assumed equal to 2.75% of its initial investment. OPEX also accounts for the cost of energy generated by the wind turbine and the PV panels. Since generators first aim to feed the load of the island, only the cost of the consumed energy by the electrolyzer is considered here for the preliminary LCOH calculation, and it was assumed equal to the LCOE of RES. According to IRENA [10], the LCOE was 33 €/MWh for offshore wind and 48 €/MWh for PV in 2021. For this study, because of the energy mix of Tilos HES, such cost was considered equal to 40 €/MWh. Because of the uncertainty and variability of this cost, the present analysis assumed a constant LCOE even when the PV share in the energy mix increases.

Storage, distribution, and utilization costs of the hydrogen have been excluded from the calculation since the scope of the current work is to evaluate the theoretical production cost of H_2 in the island. Possible utilizations of the gas presented in section 3 are studied mainly to assess the required H_2 annual yield, functional to correctly estimate the size of components and key for the LCOH calculation.

3. Results

This section presents the main results related to the hydrogen production potential of several configurations involving different sizes of the photovoltaic field and electrolyzer power levels, assessed by means of the previously described framework. Electrolyzers are fed by the excess power of the HES, after that the wind turbine and the augmented PV field have satisfied the load of the island with BESS support. For each of those configurations, a year of operation was simulated and, together with the amount of hydrogen that each of those can provide, the LCOH and the annual yield were assessed to compare their performance.

3.1. LEVELIZED COST OF HYDROGEN

To provide a general overview of the optimal combination of PV and electrolyzer power to reach the minimum LCOH on the island of Tilos, Figure 5 displays the LCOH for every computed combination of electrolyzer power ranging between 200 and 1400 kW fed by PV power ranging between 0 and 1600 kW, in addition to the fixed 800-kW wind turbine. Inefficient combinations of high PV power and small electrolyzer modules, as well as low PV powers and high electrolyzer power combinations, can be observed in yellow areas. As previously mentioned, it is essential to maintain a right balance between the two to correctly exploit the system.

The area in which combinations lead to the cheapest green hydrogen is characterized by intermediate electrolyzer sizes, between 400 and 800 kW, paired with high PV powers (dark blue region). Overall, increasing the PV size makes the energy surplus high enough to enhance the electrolyzer exploitation and recover the initial investment cost. To optimally utilize the energy surplus of current Tilos HES, a 475-kW electrolyzer should be installed. The analysis shows that a kilogram of hydrogen produced in that way would cost 6.46 €. If the upgrade of the PV field peak capacity is allowed so as to reach the nominal power of the wind turbine of 800 kW, a 520-kW electrolyzer would bring down the price to 5.04 €/kg.

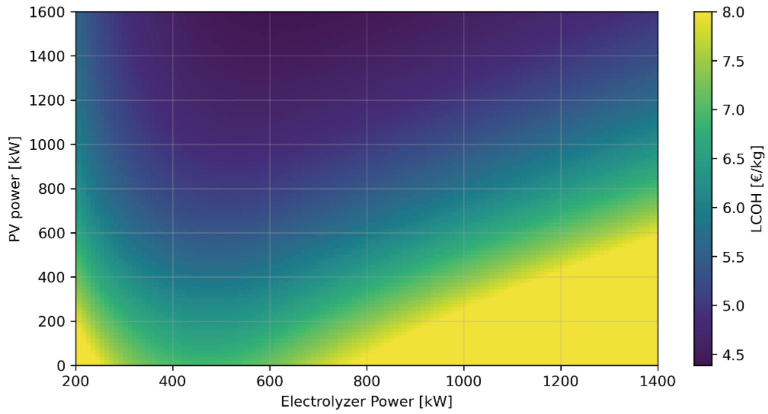

Figure. 5. Colormap showing the levelized cost of hydrogen (LCOH) for each considered combination of electrolyzer and PV power. High LCOH in yellow and low LCOH in dark blue.

It is worth mentioning that the lowest price achieved by the simulation is 4.38 €/kg and given by the combination of a 615-kW electrolyzer with 1600-kWp PV field. However, such a high installed capacity cannot be easily installed in the island. Depending on the hydrogen production requirements that could arise if green gas must be utilized for seasonal storage or other applications, a higher production cost may be acceptable to increase the annual yield. To put those numbers in perspective, the next subsections consider possible uses of green hydrogen.

3.2. HYDROGEN AS SEASONAL STORAGE

This section presents the results of a scenario in which green hydrogen is used as seasonal storage. Hydrogen generated during winter is converted back to electricity during summer to reach 100% energy independence. Figure 6 (a) displays the mass of hydrogen required to reach 100% self-sufficiency (in light blue), varying the installed PV power. Increasing the installed PV capacity generates more renewable power in the summer season, when the demand peaks, leading to an increase of self-consumption. As a result, the required hydrogen curve shows a decreasing trend. The same figure also shows the hydrogen amount that electrolyzers of different sizes (ranging between 0.5 to 1 MW) can produce by exploiting the power excess of the system, always varying the PV capacity.

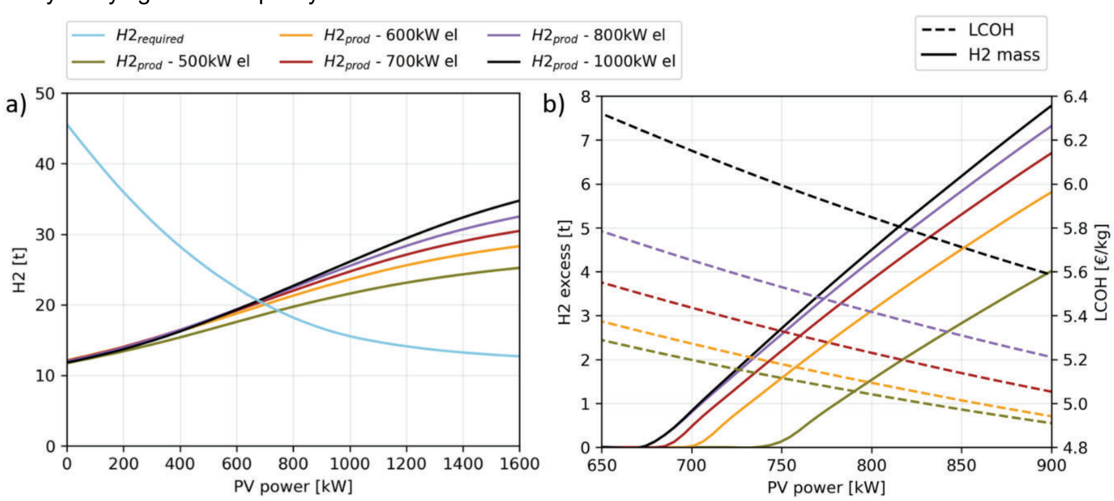

Figure. 6. a) Hydrogen mass required to reach 100 % self-sufficiency (light blue curve) and H_2 production capability from different electrolyzer power varying the PV installed power (line in different colors); b) magnitude (continuous lines) and LCOH (dashed lines) of the hydrogen excess.

With the current HES of Tilos, 37.8 tons of hydrogen would be required to satisfy the energy deficit in summer. However, only 13.6 tons of H_2 can be produced by exploiting the production surplus in winter. This means that, even if hydrogen is employed as a seasonal storage, the system could reach a maximum self-consumption rate of 82.6%, hence requiring a PV field upgrade for full energy independence. The intersection points

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between the hydrogen demand and the hydrogen production curves occur at a PV power between 650 and 750 kWp. This is the bare minimum PV power to both increase the self-consumption of the system (up to around 87% without H_2 reconversion) and produce enough hydrogen for the seasonal storage.

After having assessed the required PV upgrade to reach self-sufficiency, Figure 6 (b) focuses on PV capacities ranging from this value up to 900 kWp, slightly higher than the nominal capacity of the wind turbine. In Figure 6 (b), continuous lines show the hydrogen excess that would be produced if the PV capacity is increased, while dashed lines show the resulting costs of hydrogen. Upon examination of the results, an 800-kW electrolyzer is required to achieve total self-sufficiency with the smallest possible PV upgrade. The purple line shows that, coupled with a 675-kWp PV field, this configuration reaches energy independence with an LCOH of 5.66 €/kg.

On the other hand, the green line shows that the configuration that allows reaching 100% self-sufficiency with a lower hydrogen cost (5.11 €/kg) only requires an additional PV upgrade to 750 kWp, since it better exploits a 500kW-only electrolyzer. Dashed lines in Figure 6(b) also show that the increase of the PV power allows for a reduction of the hydrogen cost for all considered electrolyzer levels in addition to the benefit of producing additional hydrogen for other purposes. If the PV power is increased up to 900 kW, a 600-kW electrolyzer can produce almost 6 tons of extra hydrogen at a competitive price of 4.92 €/kg. In the following section, one example of possible use of this extra-production is proposed in the context of a new fleet of buses for a carbon neutral public transport for the island. It is worth remembering that the aim behind the following analysis is to estimate what could be done with extra H_2 that, if correctly justified, may bring to a further reduction in the LCOH.

3.2. HYDROGEN FOR TRANSPORTS

Even today, locally produced green hydrogen may be a cost-competitive fuel in remote islands. Focus of the following calculation is only put on the potential fuel cost, thus excluding the cost of substitution of the current transport fleet, which will represent the topic for future analyses. To calculate the number of hydrogen-fed buses that can be used during the summer season, the existing Solbus was taken as a reference. This bus, with a capacity of 63 passengers, is able of driving 16.39 km on 1 kg of hydrogen [11]. A 7% energy loss was assumed when compressing the hydrogen from 30 to 350 bar, which is the required pressure in the storage tank of the bus. This loss was based on the needed compressor power of a multistage compressor [12]. It is estimated that a bus can drive the whole route on the island 7 times per day. The route was based on the actual bus stops on Tilos. When the bus is only used in the summer season (corresponding to approximately 90 days) the total amount of kilometers driven per year, and thus the required kilograms of hydrogen per year, can be calculated. Figure 7 shows that the number of buses that can drive on the island increases from 0 with a PV power of 700 kW, to 3 or 7 (depending on the electrolyzer size) with a PV power of 900 kW.

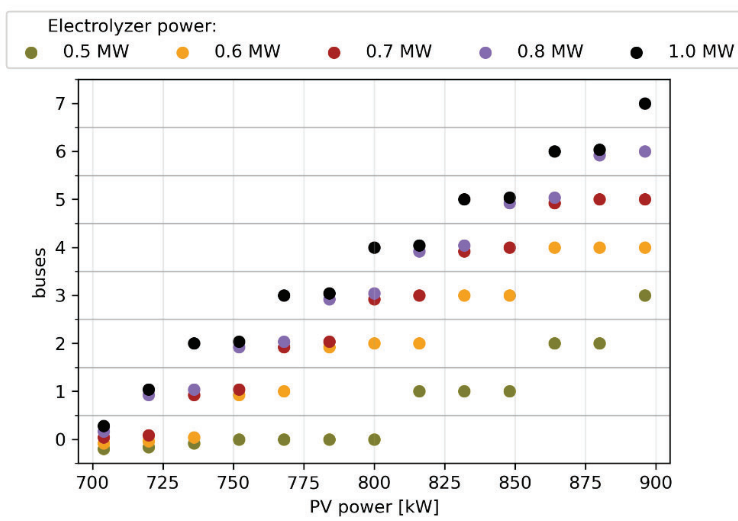

Figure. 7. Number of hydrogen buses that can be powered by the hydrogen surplus coming from different electrolyzer sizes paired with an increasing PV installed power.

Currently, most buses worldwide (including the Greek bus company KTEL) use diesel as a fuel. Assuming a consumption of 24 liters diesel per 100 km [13] would already make the hydrogen competitive with diesel with an average diesel price of €1.81 per liter in Greece [14]. The diesel prices do, however, vary across Greece. On a remote island the price for one liter of diesel is higher than on the mainland. This difference can partially be explained by the extra transportation costs from the Greek mainland to the island. On average petrol prices are 3-4 cents higher on islands compared to the mainland, or even more for particularly remote islands. The prices for fuel and electricity should probably be higher, but the costs are subsidized and shared by all mainland consumers through a levy on electricity bills [15][16][17]. When hydrogen is produced locally, no transportation costs are required. A rough estimation shows that the cost for hydrogen with an LCOH of 6 €/kg will be around € 37 per 100 kilometers versus € 43.20 for diesel with a cost of € 1.80 per liter. Another advantage of hydrogen over diesel is the fact that a hydrogen bus emits no carbon dioxide or other air pollutant during operation. Different studies show that diesel buses emit over 1.5 kg CO2 per kilometer, which would result in 26.5 tons emission when running 90 days on Tilos. This does not include the transportation from the refinery to the fuel station which might be responsible for an even bigger share of emission [18][19].

Another option to decrease pollution would be to electrify the buses. Hydrogen has however the advantage over electricity that it is produced in winter when there is an electricity surplus. Using electricity would mean that the consumption peak in summer will increase even more. Furthermore, a hydrogen bus does not need to refuel during a day while an electric bus might have to recharge.

4. Discussion and conclusions

The high capacity factors of both the wind turbine and PV field demonstrate the abundance of renewable resources on the island of Tilos. This significantly impacts the competitive LCOH results and highlights the areas' clear potential for H_2 production.

The resulting LCOH was calculated for different scenarios considering both the current system and foreseeable upgrades that could lead to 100% self-sustained operation, and to the decarbonization of the public transport fleet. Table 1 summarizes results of the most remarkable configurations analyzed in the present study.

Table 1. Results from most significant plant configurations: 1) current Tilos' HES, 2) smallest PV upgrade for 100% self-sufficiency, 3) smallest electrolyzer for 100% self-sufficiency, 4) PV upgrade for LCOH abatement and H_2 excess for buses and 5) global lowest LCOH.

Config n°	PV power [kWp]	El. Power [kW]	LCOH [€/kg]	H_2 request [t/y]	H_2 prod. [t/y]	Self-suff. [%]	H_2 excess [t/y]
1	160	475	6.46	37.8	12.7	82	-
2	675	800	5.66	20.3	20.3	100	-
3	750	500	5.11	19.1	19.1	100	-
4	900	600	4.92	16.5	22.5	100	6
5	1600	615	4.38	12.7	28.5	100	15.8

Tilos' HES is equipped with an 800-kW wind turbine and a small 160-kW PV field (Configuration 1). The seasonal variation of the local demand creates a considerable energy deficit during summer, the tourist season. Considering a fuel cell with a conversion efficiency of 60%, it was estimated that more than 37.8 tons of hydrogen are required to achieve 100% self-sufficiency. However, results have shown that an alkaline electrolyzer fed by the power excess of the current HES is able to produce only 12.7 tons of H_2. It is thus evident that there is a need of upgrading the PV field to achieve energy independence. The analysis pointed out that a minimum installed PV power of 675 kWp (Configuration 2) is required to produce the same amount of hydrogen that the island needs. To generate enough hydrogen with this power capacity, an oversized stack of 800 kW must be installed, but this results in a LCOH higher than 5.66 €/kg.

To size the stack correctly, one must consider an additional upgrade of the PV field to 750 kWp (Configuration 3). When paired with a 500-kW electrolyzer, this system achieves 100% self-sufficiency at an LCOH of 5.11 €/kg. Configuration 4 moreover shows that, if it is possible to expand the photovoltaic generator further, excess hydrogen production means a better utilization of the installed electrolyzer and a further reduce the LCOH. A 900-kWp PV field paired with a 600-kW electrolyzer would produce an additional 6 tons of hydrogen at a competitive price of 4.92 €/kg. Without strict limitations on the photovoltaic field expansion, Configuration 5 shows that a high capacity PV field (1600 kWp) could optimally utilize a 615-kW stack and achieve an LCOH of 4.38 €/kg. Results thus show that scaling up components is a suitable strategy to lower the LCOH.

Hydrogen buses have been proposed as a possible use for the excess of hydrogen. Such a fleet could decarbonize the public transport during the touristic season without the introduction of an additional burden to the electric grid, as an electric bus fleet would do. Since their introduction would justify an increase in the hydrogen yield, this technology could contribute to a further decrease of the LCOH. Further developments of the study could include a better assessment of the energy required for hydrogen compression, as well as an estimation of the footprint of the required PV expansion and hydrogen tanks. Furthermore, a variable efficiency fuel cell model, similar to the one employed for the electrolyzer, would produce more accurate results regarding the actual electrical energy coming from the gas-to-power conversion.

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Nomenclature

$CAPEX$ capital expenditures

CF capacity factor

$LCOH$ levelized cost of hydrogen, €/kg

M mass, kg

P power

PV photovoltaics

WT wind turbine

$OPEX$ operational expenditures

Greek symbols

η efficiency

φ conversion factor, kg/kWh

Subscripts and superscripts

a air

el electrolyzer

id ideal

op operational

PV photovoltaics

WT wind turbine

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