Hydrogen revamping of a hard-to-abate industrial plant: a techno-economic feasibility case study

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Abstract: Replace traditional fossil fuels with renewable gases is one of the European Commission's targets to counteract climate change and future energy shortages. However, this goal is highly challenging since the techno-economic feasibility of decarbonization still needs to be determined. Despite being responsible for the highest greenhouse gas emissions, hard-to-abate industrial companies are still discouraged from introducing renewable gases in their processes due to the potential negative impact on economic competitiveness. The paper investigates the economic competitiveness of grey and green hydrogen produced by a Power to Hydrogen plant partially substituting the natural gas feed in a chemical industry in the South of Italy. Specifically, the plant's capacity is optimized through a linear optimization model called Optiplant, minimizing the levelized cost of hydrogen. The results show that grey hydrogen is more competitive than green hydrogen even if higher CO2eq. gas emissions occur. Lastly, possible solutions to attract investments of industrial investors in similar processes are discussed.

Keywords: Green hydrogen, Power-to-X, Electrolysis, Renewable energy sources, Techno-economic analysis.

I. INTRODUCTION

Sustainable and green energy is becoming a central topic in addressing the problems of climate change and the energy crisis. Against this background, hydrogen is considered as a key element in the energy transition to gradually replace fossil fuels with the aim of reducing greenhouse gases. The main objective of the Hydrogen Europe strategy is to achieve at least 40 gigawatts of electrolyser capacity, with an expected annual production of 10 million tonnes of green hydrogen [1]. One of the most sustainable modes for hydrogen production is the electrolysis of water, a chemical process in which the water (H_2O) molecule is decomposed through the application of electricity Power to Gas (P2G) or Power to Hydrogen (P2H) plants [2,3]. While the industrial communities together with policy makers are working to overcome the existing techno-economic, normative and social barriers that slow-down the market penetration [4], several implementation projects are under investigations. The purpose of the present study is to evaluate the feasibility of a partial substitution of methane gas with a percentage of hydrogen, analyzing technical and economic factors in three different ways of powering an alkaline electrolyser. The analysis is set in a real production plant operating in the hard-to-abate sector where emissions still account for about 30% of global emissions [5]. Of these, the largest share is covered by heavy industry, which accounts for about 23% on a global scale and 18% in the European Union [6]. Green hydrogen can become a central element for emission abatement in heavy industry [7], however the use of renewable technologies for its production is still a critical issue due to the still high cost compared to traditional production methods such as Steam Methane Reforming. Minutillo et al. calculated an LCOH for hydrogen produced with electricity from PV plant and grid of 9.3 to 12.5 Eur/kg [8]. Berrada et al. reported a cost of 3.49-5.96 Eur/kg using a solar plant installed in Morocco [9]. Moreover, in most cases, industries operating in hard-to-abate sectors need constant production, which clashes with the intermittency of renewable resources creating an imbalance between supply and demand. Therefore, the use of green hydrogen in these sectors requires storage solutions that further increase its cost. In addition, the implementation of green hydrogen affects numerous actors in the supply chain such as green electricity suppliers, electrolysers, distribution, facilities, and consumers that makes implementation even more complex. Azadnia et al. [20] conducted a study on the risk factors existing in the implementation of this technology in the hard to abate identifying the high initial investment for production and distribution as the main risk factor out of a list of 43 risks analyzed overall, followed by the insufficient capacity of electrolysers installed or scheduled to be installed compared to the set production targets for future years and the lack of policy and regulation. Although there are not many studies addressing the issue of replacing fossil sources with non-climate-changing fuels such as hydrogen in the heavy industry sector, Superchi et al. conducted a study on the use of hydrogen in the steel production sector, produced by electrolysis powered by a hybrid configuration of wind farm and power grid, providing batteries and hydrogen tanks as storage methods, resulting in a final production cost of 4.95 €/kg corresponding to about 0.15 €/kWh [10]. Hydrogen can be a key element in decarbonizing heavy industry, but the only way to make its implementation competitive is to use major incentives on the policy side [22]. However, to the authors' knowledge, there is no work in the literature directly analyzing the impact of substituting methane with hydrogen percentage in technical, environmental, and economic terms in a case study related to a plant operating in the hard to abate. In addition, a comparison is introduced between the case where hydrogen demand is fixed and constant (plant operates continuously using a fixed percentage of hydrogen), and the possibility of introducing an annual demand target without production constraints. This case in fact may be of interest because, the hydrogen demand analyzed, not representing the entire energy demand, can be met with hydrogen produced at times of greatest convenience (reducing the required storage). In this way, in case of non-availability/convenience in hydrogen production, the use of methane gas for carrying out production processes can still be used. The initial target examined in this study to begin the decarbonization process is 10% of the plant's energy requirements.

II. Methods and materials

This section describes the methodology on which this paper is based. There is a description of the plant and the processes that regulate its operation, introducing all the inputs that allow to carry out the technical-economic analysis.

A. *Model description*

Optiplant is a linear optimization tool whose purpose is the minimization of the objective function reported in Eq. (1) that includes all cost items related to the adopted plant configuration [12]. All investment costs should be annualized according to the Au factor reported in Eq. (2).

$$T_C = \min \sum_{u,t} P_{u,t} \times X_{u,t} + \sum_{u} (I_u \times A_u + F_u) \times C_u + \sum_{u,t} V_u \times X_{u,t} \qquad (1$$

$$A_u = \frac{d(1+d)^n}{(1+d)^n - 1} \qquad (2$$

Where:

- T_C is the minimum total cost of the plant.
- $X_{u,t}$ is the hourly mass or energy flow from the unit 'u' at time 't'.
- C_u are the capacities of unit 'u'.
- P_u is the hourly price of the output from unit 'u' at time 't'.
- F_u is the fixed operation and maintenance costs of unit 'u'.
- V_u is the variable operation and maintenance costs of unit 'u'.
- I_u is the total investment expenditure of unit 'u'.
- d is the discount rate assumed to be equal to 8%.
- n is the technical lifetime of the unit 'u'.

The objective function must be solved considering the set of boundary conditions imposed. First, an annual or an hourly based hydrogen demand can be imposed to the model. In the first case, hydrogen is produced when it is more economical. Therefore, the units that need to fulfil an annual demand D_u withstand to the conditions that the sum of all the hourly productions is equal to the annual value as indicated in Eq. (3):

$$\sum_{t} X_{u,t} = D_u \qquad \forall\, u \in \text{MinD} \qquad (3$$

In the second case, hydrogen demand is a demand vector with values for each hour of the year.

The instantaneous load of each unit must be between the nominal and the minimum as defined in Eq. (4). The minimum load (L_u^{min}) may be different from 0. For example, a minimum working load of the electrolyser (20%) is considered as a percentage of the maximum capacity for safety reasons related to the flammability of the oxygen-hydrogen mixture. Similarly, a minimum load of electrical energy storage in the battery is used to avoid full charge/discharge cycles that lead to damage of lithium batteries.

$$C_u \times L_u^{min} \le X_{u,t} \le C_u \qquad \forall\, u, t \qquad (4$$

The renewable energy generation at time 't' is calculated multiplying the nominal plant's capacity with the hourly technological power profile $PP_{u,t}$ as shown in Eq. (5):

$$X_{u,t} = PP_{u,t} \times C_u \quad \forall u \in \varphi, t \tag{5}$$

Where φ is the subset of renewable plants intermittent power units. The formula shown in Eq. (6) regulates the energy storage of hydrogen in pressurized tanks and electricity in batteries.

$$X_{u\in Tj,t} - X_{u\in Tj,t-1} - \zeta^{in}_{v\in Inj} \times X_{v\in Inj,t} + \xi^{out}_{w\in Outj} \times X_{w\in Outj,t} = 0 \quad \forall j, t > 1 \tag{6}$$

Where:

- T_j is the subset of units acting as energy storages e.g., the hydrogen tank and the battery (considered empty at time t=0).
- In_j are the units with charging/discharging.
- ξ indicates charge and discharge efficiencies.

B. *Plant description*

The Power to Hydrogen (P2H) plant investigated is composed of the following sections: a desalinization unit, an electrolysis, gas compression and storage sections. Based on the configuration, also PV panels and battery storage are present as schematically shown in Figure 1. The electrolysis process requires pure water (10 ppm of dissolved salt) to produce hydrogen preventing electrolyzer's damages. Since the analyzed plant is close to the sea, seawater can be used for the process, after a desalination process saving pure water for other uses. Once produced, hydrogen is supplied to the end-user or store in gas pressurized tanks (Type II tanks have been considered) after being compressed at a storage pressure of 700 bar through piston or diaphragm compressors.

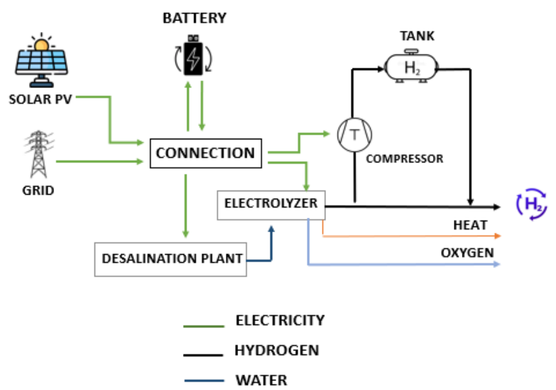

Figure 1: Energy hub configuration.

For the present study three different scenarios have been analyzed and compared in order to determine which is the least cost production pathway and what is the amount of CO_2 that can be saved using different configurations. In the simulated plant configurations electricity supply can come from the national electric grid or onsite solar PV panels. However, due to the intermittency of solar source, storage solutions may be necessary in mixed and island cases. In cases where electricity production exceeds that required, on the other hand, storage in lithium batteries may be used. A brief description of the three different scenarios analyzed follows:

1. **Grid**: Totally grid connected scenario, all the plant components are powered only by 100% electricity from the grid.
2. **Mixed**: In this case a mixture of grid and renewable (from solar PV) electricity is considered.
3. **Island**: In this case the plant is considered as a stand-alone system and the electricity comes entirely from renewable sources (solar PV).

The three proposed scenarios were analyzed with two different types of demand, free annual (42000 kg/year) and constant hourly (4.7 kg/h). This amount of hydrogen corresponds to 10 % of the plant's current energy needs, the remaining part would still be covered using methane gas. In the first case, demand must be met on an annual basis with the goal of economic optimization (according to the availability of renewable resources), while with the second type the model is constrained to production on a constant hourly basis. The plant configurations that meet the two different types of demand were analyzed because the hydrogen produced would be used as a substitute energy source for methane and not for a production process, this also allows a certain degree of flexibility in its use to be implemented. The possibility of sizing a plant to meet only a target annual demand is therefore a choice to be considered because at times when it is not convenient to produce hydrogen, methane gas can still be used. In reference to Opex costs such as electricity used by the grid, to the hourly profiles of power obtainable from the photovoltaic system and for the CO2 emission profile for the electricity production for the grid, the year 2019 was considered as the reference year because it predates the Covid-19 pandemic and the energy crisis due to the war in Ukraine, which altered prices and consumption and consequently the production mode. Despite waste heat and oxygen are produced by the P2H plants, their use is not considered in the case study.

C. *Plant's techno-economic input data*

Capex investment cost andfixed operating costs for different years are reported in the Table I and are taken from [14] and [19] for ion-lithium batteries.

Regarding variable OPEX only electricity consumption for the grid is assumed. Specifically, a fixed tariff of 0.19/kWh is considered according to the data reported by ARERA for the year 2019 for the consumption range 500 - 2000 MWh/year, which represents the final cost to the consumer that includes PUN and fixed costs for management, distribution and dispatching [13].

TABLE I. ECONOMIC PARAMETERS

Component	Unit	CAPEX [€/unity]	Fixed OPEX [€/unity/y]
Desalination	$\frac{kgH2O}{h}$	26.2	-
Electrolyser	kW	750	220
Compressor	$\frac{kgH2}{h}$	11000	220
Tank	kgH2	900	18
PV plant	kW	870	10.6
Battery	kWh	320	5.1

TABLE II. ECONOMIC PARAMETERS FOR SENSITIVITY

Component	CAPEX [€/unity] 2030/2040/2050	Fixed OPEX [€/unity/y] 2030/2040/2050
Electrolyser	570/450/350	29/23/18
PV plant	570/460/410	8.9/8/7.5
Battery	190/150/120	3.8/3/2.4

Regarding electricity consumption and other energy losses, the following specific assumptions were made. For the electrolysis section, an average power consumption of 51.2 kWh/kg_{H2} (corresponding to an efficiency of 65% based on the hydrogen Lower Heating Value) is implemented in the model to produce hydrogen at atmospheric pressure while an electricity consumption of up to 2.53 kWh/kg_{H2} has been calculated to compress hydrogen up to 700 bar assuming typical values for isentropic, mechanical, electric, and auxiliary efficiency equal respectively to 0.8, 0.95, 0.95 and 0.96. While different configurations of compression including intercooling between compression stages could reduce the amount of energy consumption, the worst value has been considered. In addition to energy consumption, battery energy losses are considered in the model. As reported by the Danish Energy Agency [14], a charging efficiency of 98% and a discharging efficiency of 97% is considered. To these values it is then added 2% for AC/DC conversions resulting in a total loss for charging and discharging respectively of 0.04 kWh/$kWh_{charged}$ and 0.05 kWh/ $kWh_{charged}$.

D. *2.8 Solar PV power profile*

In the area under consideration, it is possible to obtain almost 1600 peak equivalent hours. The hourly power profile obtainable for electricity production from photovoltaic panels was derived by the "Renewable Ninja" tool from actual solar irradiance data for the year 2019 [15,16]. The input data for obtaining the final power output are listed below:

- Geographic coordinates of the examined area that are not disclosed for confidentiality reasons.
- Tilt angle: 35°
- Azimuth angle: 180°

E. *Economic and environmental comparison criteria*

To evaluate the economic competitiveness of hydrogen respect to methane, the levelized cost of hydrogen production LCOH expresses the ratio between the sum of costs related to the plant (annualised Capex and Opex) and the total annual hydrogen production has been calculated. In the case of hourly demand, the sum of all production per hour is considered; in the case of annual demand, the denominator represents the value of the annual target demand as in Eq. (8):

$$\mathrm{LCOH} = \frac{\mathrm{T_C}}{\sum_{i=1}^{8760} \mathrm{H2\ hourly\ production}} \qquad (8$$

The cost of mitigation is the cost of avoiding 1 kg of carbon dioxide through the three scenarios involving electrolysis, compared to what would be emitted by the combustion of methane gas. The annual production of hydrogen corresponding to 10% of the energy needs of the plant is 42 tons, corresponding to about 1400 MWh of energy. Using the lower calorific value of methane gas (35880 kJ/Smc) the avoided methane quantity corresponding to the same energy quantity of about 140468 Smc (94000 kg) is determined. Using the emission factor for methane gas combustion of 2.75 kg CO2/kg, the annual emission from methane combustion of approximately 259 tons is determined. The mitigation cost is then calculated with the following formula:

$$\mathrm{C_{CO2}} = \frac{\mathrm{T_C}}{\mathrm{CO_{2,CH4}} - \mathrm{CO_{2,GRID/ISLAND/MIXED}}} \qquad (8$$

Where:

- $CO_{2,CH4}$ is the total CO_2 emission saving avoiding the combustion of methane.
- $CO_{2,GRID/ISLAND,MIXED}$ is the total CO_2 emission for the production of hydrogen in the three scenarios.

To conclude, a sensitivity analysis was carried out by varying the CAPEX of the main plant components: electrolyzer, photovoltaic panels, and storage battery, which are believed to be the candidates that will experience the greatest price reduction because of technological innovation and production scalability. The only scenario considered for the sensitivity analysis is the Island scenario since, as also shown in Figure 4 it appears to be the one most affected by the CAPEX of the plant components. From the reported values, it is observed that from 2020 to 2050 to have the greatest price reduction are batteries with a reduction of about 70%, while for electrolyzers and PV a reduction of about 50% is estimated. In each case the largest decrease occurs in the first decade 20-30.

III. Results and Discussion

The CO2 emission profile for power generation for the national grid according to the Italian energy mix referring to the year 2019 [17] is shown in the figure. To verify the procedure used, the profile created is compared with the energy production in GWh from renewable sources reported by Terna [18]. It is observed that, as could be expected, as the production from renewable increases, there is a decrease in CO2 emission.

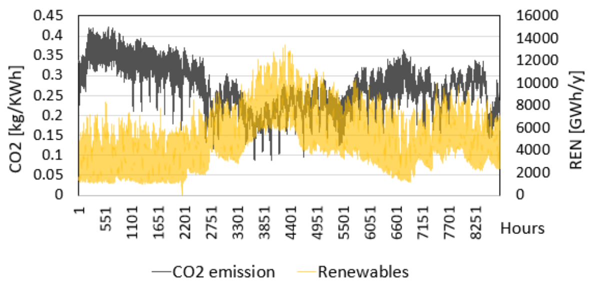

Figure 2: CO2 hourly profile for grid electricity generation and renewables production.

CAPEX cost represents the sum of all costs of the plant components considered, appropriately sized. TOTAL OPEX cost considers fixed and variable operating costs such as maintenance costs and the cost of purchasing power from the grid where applicable.

TABLE 2. CAPEX AND OPEX WITH HOURLY AND YEARLY DEMAND

Scenario	CAPEX [M€] [HOURLY/YERLY]	TOTAL OPEX [M€/year] [HOURLY/YEARLY]
GRID	0.2	0.4
MIXED	2.1	0.1/0.05
ISLAND	4.7/2.9	0.076/0.05

As shown in Table 2, a reduction of investment is achievable changing the demand profile even if it is not always easily to be implemented in real cases due to the industrial production constraints to be satisfied. The Figure 3 shows the installed storage capacity expressed in MWh for pressurized hydrogen tanks and lithium batteries for hydrogen and electricity storage, respectively. No storage is provided in the Grid scenario as there is no grid access constraint. In the Island scenario, on the other hand, in the case of constant hourly demand, hydrogen storage (17 MWh) and electricity storage (4 MWh) are planned, while only electricity storage is planned for the annual target.Thus, without special constraints, for the purpose of energy storage, electricity storage is convenient compared to hydrogen production and storage. In the Mixed scenario, on the other hand, the projected storage capacities are significantly lower.

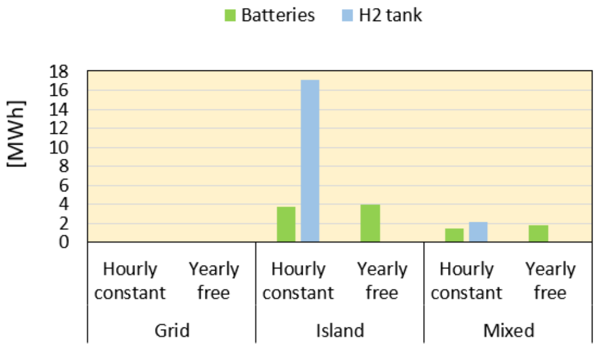

Figure 3: Hydrogen and electricity storage installed capacities.

The Figure 4 depicts the cost of hydrogen production expressed in €/kWh by dividing all contributions that added together lead to the final value. The Opex costs of O&M are inclusive of all plant components. For the Grid scenario, the cost is around 0.3 €/kWh with the largest contribution being the Opex cost of electricity absorbed from the grid. For the Island scenario, the highest costs are due to the PV system and battery storage, which also lead to high O&M costs. Compared to the demand type with annual target, the hourly profile requires more installed PV capacity and consequent storage in batteries, leading to a final cost of production that exceeds 0.36 €/kWh versus 0.22 €/kWh in the case of annual demand. Finally, the Mixed scenario that represents the one with the lowest production cost stands at 0.21 €/kWh with hourly constant demand and 0.17 €/kWh in the case of annual demand target.

This is due to no need to oversize the renewable plant to cope with times of low solar resource availability.

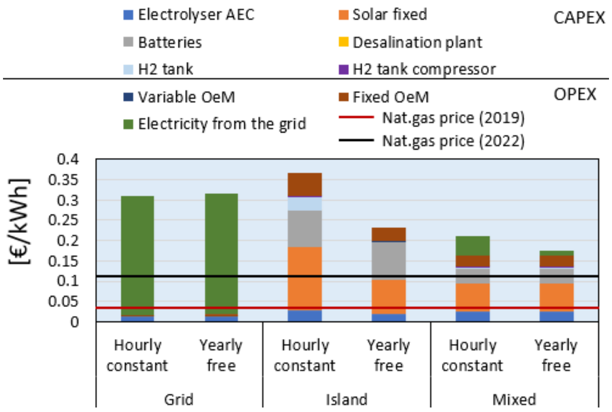

Figure 4: LCOH Levelized cost of hydrogen.

The different costs obtained for the various scenarios were compared with the price of natural gas obtained from [21] with reference to the year 2019 and 2022 considered a year with record increases for gas prices due to the war in Ukraine. The comparison shows that the use of hydrogen produced by electrolysis cannot be considered competitive with methane gas since even considering the gas price reached in 2022, the cheapest scenario with annual demand is still 54 % more expensive than the use of methane gas. On the other hand, wanting to achieve a 100% green scenario (Island scenario), the cost to be incurred would be 227% higher in the case of meeting hourly demand and 109% higher with meeting the annual demand target. Finally, the mitigation cost is shown in Figure 5, which is the cost of avoiding 1 kg of carbon dioxide with the three different scenarios involving electrolysis. Emissions avoided compared to burning 100% methane are considered for the analysis. The annual emissions of the three scenarios are also calculated. While the current energy mix results in greater emission in the Grid scenario, i.e., 570 tons, for the Mixed scenario the emission level varies depending on the type of demand analyzed (99 tons for constant demand and 23 tons for the annual demand target), while the Island scenario is considered completely Green supporting the path towards industrial production decarbonization. As shown in Figure 5, the highest value for the mitigation cost is found in the Island scenario with constant hourly demand touching 2 €/kg CO2, while the lowest in the Mixed scenario with annual demand target with a value of about 1 €/kg CO2. There are no great differences between the Mixed and Island scenarios as the reduction in emissions to 0 in the Island case is balanced by the increase in the total investment costs of the plant.

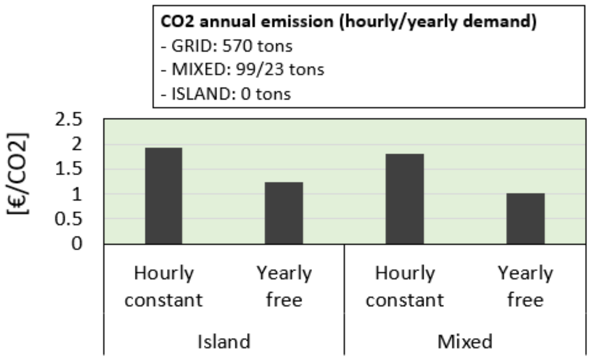

Figure 5: Economic impact of substituting production with green methods vs production with emissions. Annualized investments for each scenario are divided by the amount of CO2 saved.

Finally, it is noted that with the estimated investment costs for the year 2030, the cost of hydrogen production remains higher even than the purchase price of methane gas referred to the year 2022 (worst case scenario). While with the estimated investment costs to the year 2040, in the case of fully green annual hydrogen demand target, this results in a lower cost than that of methane at the year 2022. Should methane prices remain over the years similar to those prior to the pandemic and war in Ukraine, economically producing hydrogen as a substitute for methane is economically disadvantageous.

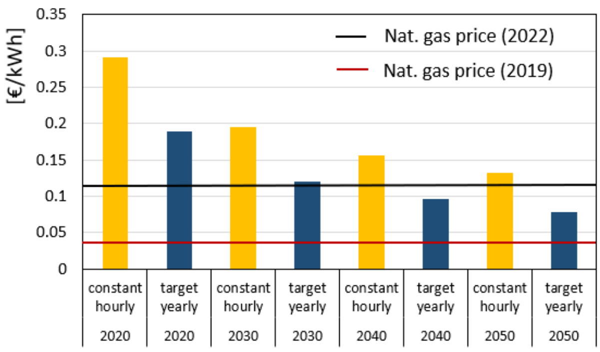

Figure 6: Sensitivity analysis on the production cost.

IV. Conclusions

The paper analyzes and compares different scenarios of power to hydrogen (P2H) plant's configurations to be implemented in a hard-to-abate industry. Two demand profiles are investigated aiming to minimize the investment and maximize the reduction of carbon dioxide emissions: constant hourly and annual free. The comparison concerns three different types of supply of the alkaline electrolyser: 100% grid, 100% solar PV and a hybrid configuration between the two previous. The results show that in both types of demand the Mixed scenario represents the cheapest with a production cost of 0.21 €/kWh (constant hourly demand) and

0.17 €/kWh (free yearly demand). In the case of hourly demand, the least economic scenario is Island with a production cost of 0.36 €/kWh, while with annual demand the use of the grid alone (Grid scenario) is the most disadvantageous solution. From the environmental point of view, instead, the Grid scenario represents the most impacting with 570 tons emitted in a year, followed by the Mixed with 99 tons emitted (hourly demand) and 23 tons (annual demand), while the Island scenario is considered 100% green. Wanting to replace 10% of the plant's methane energy consumption with hydrogen produced through a share or entirely from renewable energy the calculated cost varies between 1-2 €, depending on the scenarios and the type of demand, to avoid 1 kg of carbon dioxide produced and the cost of production never turns out to be competitive with the purchase price of methane even considering the price reached in 2022 as a result of the energy crisis. Therefore, it can be concluded that using hydrogen as a blending solution to replace methane as a fuel turns out to be environmentally convenient only if a high percentage of renewable is present, as using only energy from the grid turns out to be more polluting than burning methane in the current energy mix. From an economic point of view, the optimal solution among those considered is the hybrid configuration (renewables plus grid), while at present the use of 100% renewables is not economically viable without incentives or other supporting mechanism even considering a significant decrease in investment costs over the years.

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