

Power to Methane technologies through renewable H₂ and CO₂ from biogas: the case of Sardinia

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Abstract. A Power-to-Methane system based on a Biological Hydrogen Methanation (BHM) process using the CO₂ produced by a biogas upgrading process and the H₂ produced by an alkaline electrolyser was analysed in this work. The electrolyser can be fed by the electrical energy produced by a dedicated PV plant or supplied by the electrical grid. The analysis of the energy production from the PV plant and the consumption of the electrolyser was carried out on an hourly basis considering different sizes for the PV plant and four different scenarios for the operating time of the electrolyser. Also, a preliminary economic analysis was carried out to estimate the levelized cost of biomethane (LCOBM) and the costs of biomethane transport with a dedicated pipeline and in form of LNG by trucks. Finally, the paper investigated the availability of biomass and biogas in Sardinia that can be converted into biomethane, and the contribution of BHM plants to supply the forecast demand of CH₄. The availability of biogas in Sardinia, together with the production of biomethane through BHM systems, can supply up to 44% of the forecast demand of CH₄.

1 Introduction

Energy conversion technologies based on Renewable Energy Sources (RES), such as solar photovoltaic (PV) and wind turbines (WT), are characterised by intermittent and fluctuating electricity production, due to variable weather conditions. Therefore, suitable energy storage systems are required to support and improve the efficiency of electrical grids by uncoupling the energy production and consumption phases. In particular, Power-to-Gas (PtG) technologies are currently proposed to produce “green” fuels from RES and reduce the carbon footprint of the so-called hard-to-abate sectors (mainly industry and transport) by the gradual substitution of conventional fossil fuels. Power-to-Hydrogen (PtH₂) and Power-to-Methane (PtM), two specific applications of PtG, use electricity generated by RES systems to produce hydrogen and methane, respectively. The latter is synthesised from hydrogen, previously produced by electrolysis, and carbon dioxide [1]. The resulting methane can be injected into an existing natural gas distribution grid to substitute the fossil fuel or directly used in all the well-established natural gas applications.

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Power-to-Methane technologies are based on the conversion of H_2 and CO_2 into methane via catalytic (or chemical) methanation or Biological Hydrogen Methanation (BHM) processes. Methane production from renewable hydrogen is a complex and expensive task. Therefore, research on CO_2 methanation has intensified over the last decades in order to improve the efficiency and reduce the costs of the process [2–4].

An overview of the Power-to-Methane plants in Europe, both installed and under construction, was carried out in [5], distinguishing plants based on biological methanation from those based on chemical processes. The majority of the facilities is located in Central Europe and a few examples are reported in the following (when reported, the power output of the plant refers to the electrical capacity of the electrolyser). In operation since 2013, the Audi E-Gas [6] plant in Germany (13 MW_{el} of power-to-methane installed considering only those facilities of known capacity [5]) is the biggest Power-to-Gas plant worldwide. Hydrogen is produced by three alkaline electrolysers with an overall electrical power of 6 MW_{el} , while the CO_2 is provided by a biogas plant. The BioCatProject [7], successfully completed in December 2016, aims to use the biological methanation solutions developed by Electrochaeta [8] as part of a Power-to-Methane process chain. The plant, located in Denmark (where there is a total of 28 MW_{el} of Power-to-Methane installed, the largest in Europe [5]), is based on an alkaline electrolyser with an electrical power input of 1 MW_{el} .

Owing to the requirement of CO_2 , Power-to-Methane processes can be usefully integrated with biogas upgrading processes. As well known, biogas is a mixture, mainly composed of CH_4 and CO_2 (up to 50%) produced by anaerobic digestion processes, widely used to recover the energy content of agricultural residues, agro-industrial by-products, organic urban wastes, wastewater, etc. Other than for power generation, anaerobic digestion processes can be used to produce biomethane by splitting up the CO_2 through suitable biogas upgrading processes. Therefore, recycling the available CO_2 in Power-to-Methane projects allows to further increase the production of biomethane [9]. Obviously, Power-to-Methane concepts integrated with anaerobic digestion plants are of special interest especially if the H_2 is produced by renewable energy sources (in particular wind and solar energy). For this reason, because the availability of wind and solar energy resources, as well as a significant amount of biomass residues and by-products, the energy system of the island of Sardinia (Italy) could benefit from the diffusion of biomethane technologies and the development of the PtM concept based on Biological Hydrogen Methanation processes.

The aim of this paper is to analyse the capabilities of a BHM process integrated with anaerobic digesters and biogas upgrading processes in a regional context such as that of Sardinia. Therefore, a Power-to-Methane system based on an anaerobic digestion plant with a biogas production of about $8600 \text{ Nm}^3/\text{d}$ and a water electrolyser fed by a PV plant was analysed through dedicated models developed in MATLAB. Starting from the availability of biomass residues in Sardinia, the results of the PtM system have been used to evaluate the potential contribution of residual biomass and H_2 from RES to the natural gas demand of the island. In addition, the levelized cost of biomethane (LCOBM) was evaluated by a preliminary economic analysis considering production and transport costs of biomethane.

2 System configuration

Figure 1 shows the conceptual scheme of the Power-to-Methane plant analysed in this paper. The PtM plant is based on a biological hydrogen methanation process integrated with an anaerobic digestion plant and an electrolyser fed by RES electricity. Typically, the size of a PtM plant is related to the power input of the electrolyser, that represents the greatest energy consumption of the overall system. The BHM process recovers the CO_2 produced by the biogas upgrading section of the anaerobic digester that splits the biogas into CO_2 and CH_4 . The H_2 is produced by an alkaline electrolyser mainly fed by the electricity generated by a

dedicated PV power plant. When the PV power is not available, the electrolyser is still fed by green energy supplied by the electrical grid. In fact, by means of a proper Power Purchase Agreement (PPA) with a Third-party commercial supplier, the energy purchased from the grid could be covered by other RES plants located in Sardinia, assuring the production of 100% green hydrogen. The hydrogen can be directly injected into the bioreactor or stored in a dedicated tank to decouple the production of H₂ and CH₄. The pressure of the H₂ storage is set equal to the electrolyser operating pressure and therefore a compression section is not required. Finally, the CH₄ can be injected in a dedicated pipeline or transported as LNG by trucks.

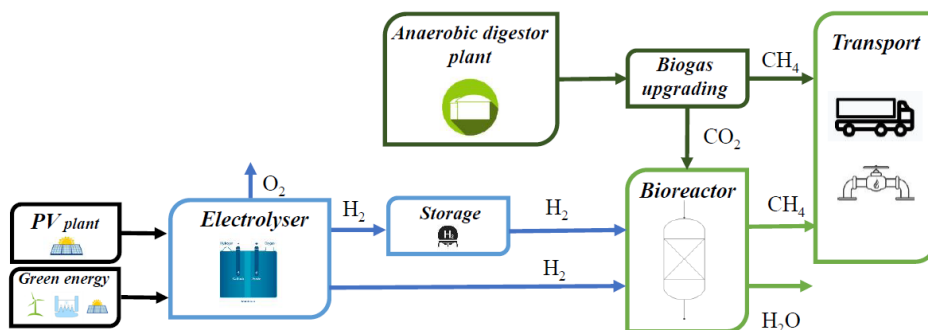


Figure 1. Conceptual scheme of the Power-to-Methane energy system.

2.1 Biogas production section

The biogas production section considered in this paper has been designed according to the performance of an industrial anaerobic digestion plant (Olmeo Company) operating in the North of Sardinia and currently used to feed an internal combustion engine with a power output of 1 MW_{el} [10]. The performance of this plant are representative of many other industrial scale anaerobic digesters currently operating in Sardinia. In particular, the anaerobic digester includes two reactors with an overall volume of 6400 m³, and it is fed with about 80 t/y of a mixture composed by 36% of dedicated crops and 64% of residual biomass. The anaerobic digestion plant produces about 8650 Nm³/d of biogas with a CH₄ concentration of 54% (the CO₂ concentration is about 45%, while the residual fraction is typically N₂, H₂, H₂S, and O₂). The anaerobic digester considered in this study is similar to that of the Olmeo Company plant and it was assumed a biogas production of 360 Nm³/h for 7500 h/y with and a CH₄ concentration of 54%. In this case, anaerobic digester is integrated with a biogas upgrading section aimed at producing biomethane composed by CH₄ (95–99%) and CO₂ (1–5%) [11]. Currently, six physical/chemical upgrading technologies are available at commercial level, i.e., water scrubbing, pressure swing adsorption, organic scrubbing, chemical scrubbing, cryogenic separation, and membrane separation. The performance of physical and chemical upgrading technologies depends on different parameters: gas pre-cleaning requirements, working pressure, CH₄ loss and CH₄ recovery, specific energy consumption, quality of upgraded gas, etc. In this paper, an upgrading process based on a physical water scrubbing process with a final CH₄ purity of 96–98% and CH₄ losses of about 2% has been considered. Physical scrubbing is a relatively a simple process, with low operation and maintenance costs, and achieves high methane purity and less methane losses compared to other technologies [12].

Table 1 summarises the main performance of the anaerobic digestion plant, the annual production of biogas, as well as CO₂ and CH₄ after the biogas upgrading section.

Table 1. Anaerobic digestion plant performance.

Parameter	Value
U [h/y]	7500
n [d/y]	312
Biogas [Nm ³ /y]	2,700,000
CH ₄ purity [%]	97
Net CO ₂ [Nm ³ /y]	1,178,550
Net CH ₄ [Nm ³ /y]	1,414,260

2.2 Hydrogen production, use, and storage

To produce the hydrogen required by the BHM process, the alkaline water electrolysis (AEL) technology was considered. In fact, among the three available water electrolysis technologies (i.e., alkaline, PEM, and solid oxide), alkaline and solid oxide electrolyzers are more appropriate for stationary applications with a stable and constant power load, while PEMEL technology is the most suitable for following a RES load [13]. Indeed, PEMEL are characterised by a response time, a load range, and a start-up and shutdown time more suitable for transient operation [13,14]. The electrolysis process was simulated through a specifically model developed in the Aspen Plus environment, adapting an electrochemical model developed by Ursua and Sanchis [15]. The functional scheme of the Aspen model developed for the simulation of the electrolysis process is shown in Figure 2.

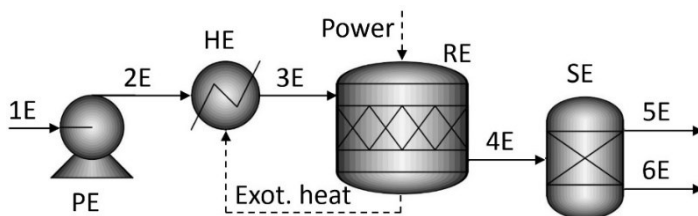


Figure 2. Flowsheet diagram of the electrolysis process.

The water entering the electrolysis section is compressed to the operating pressure (25 bar) of the electrolyser by a pump (PE) and heated to the operating temperature (65°C) by recovering the heat produced by the same electrochemical process (simulated with a heater block, HE). The water splitting reaction is carried out in an RStoic reactor (RE) with a conversion ratio of 1. Then, hydrogen (5E) and oxygen (6E) are split by a separator (SE).

The AEL electrochemical model was based on a stack composed by 22 cells in series, with a rated stack current of 120 A, a rated stack voltage of 37.3 V, and a nominal power of about 4.5 kW at the nominal conditions of 65 °C and 25 bar [15]. The number of total stacks was varied to match the desired size of the electrolyser and the consequent production of hydrogen. The power consumptions of pumps and auxiliaries are taken into account to calculate the overall power required by the electrolyser system. In addition, an AC/DC conversion efficiency equal to 0.97 to convert the AC grid RES power into the DC electrolyser power was also considered.

Four different scenarios for the operating time (24, 12, 8, and 6 hours a day) and therefore for the size of the H₂ production section, were analysed. Depending on the scenario, hydrogen is immediately and completely sent to the BHM (24-hour scenario) or it is either sent to the BHM and stored in a storage tank to be used later (12, 8, and 6-hour scenarios). Consequently,

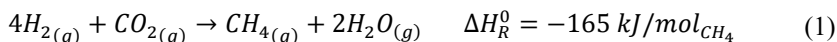
depending on the scenario, the volume of the storage system varies accordingly. The electrolyser was assumed to be powered by a PV plant and by the grid when RES electricity production is not enough to satisfy its power demand. The PV power plant was based on a given number of strings with a peak power of 9.9 kW. Table 2 summarises the PV plant characteristics. The analysis of the energy production from the PV plant and the consumption of the electrolyser was carried out on an hourly basis, considering the sunlight availability in a location near Cagliari, South Sardinia.

Table 2. PV plant characteristics.

Parameter	Value
P_{module} [W] [16]	330
NOCT [°C] [16]	45
Temperature Coefficient of Power [%/°C] [16]	-0.353
$\eta_{\text{reference module}}$ [16]	0.195
η_{BOP} (inverter and others) [17]	0.96*0.93
Location	Cagliari, Italy 39.2° N, 9.1° E
Azimuth and tilt	South, 30°
Solar irradiation [kWh/(m ² •year)]	1898.2
Number of modules per string	30
P_{string} [kW]	9.9

2.3 Methanation process

The methanation process can be based on the chemical or biological conversion of carbon dioxide and hydrogen into methane and water, according to the Sabatier reaction (1):



The methane yield of the process strongly depends on the operating pressure and temperature. At ambient temperature, the reaction is exothermic, with a decreasing enthalpy (ΔH) and an increasing Gibbs free energy (ΔG) with the temperature. Above 500 °C the reverse reaction (steam methane reforming) begins to predominate. Thus, 500 °C is the maximum temperature allowed for the Sabatier reaction. While plants that produce methane catalytically have been in operation for a long time, biological methanation has just reached industrial pilot scale experience and near-term commercial application.

In particular, the catalytic methanation process is typically carried out at temperatures between 200 and 550 °C and pressures ranging from 1 to 100 bar, depending on the used catalyst. Several metals may be employed as catalyst, such as Ni, Ru, Rh, and Co. The potential interest of a catalyst is mainly related to both its activity and product selectivity. Despite requiring high purity of the feed gas, nickel-based catalysts are considered to be the optimum choice in most of methanation plants, according to its relatively high activity, good CH₄ selectivity, and low price [18].

The Biological Hydrogen Methanation (BHM) process exploits the Sabatier reaction to convert H₂ and CO₂ into CH₄ with water as a by-product, by means of autotrophic hydrogenotrophic methanogens that play the role of an autocatalyst. The temperature and pressure depend on the range of activity of methanogens, lying between 0 and 120 °C and 1 and 10 bar. Nevertheless, the most common operating conditions for these systems are 20–70 °C and atmospheric pressure [5]. The BHM can be carried out through in-situ and ex-situ

processes, depending on how the reagents (H₂ and CO₂) are provided to the reactor. During in-situ processes both the anaerobic digestion and the methanation reactions are carried out in the same reactor: the H₂ is externally supplied, while the CO₂ is generated inside the same digester. On the contrary, in ex-situ processes BHM takes place inside a specific reactor fed by CO₂ (or biogas, composed of both CO₂ and CH₄) and H₂. While in the former the H₂ flow must be continuously adapted to the production of carbon dioxide in the anaerobic digester, leading to high costs associated with the control of the process, in the latter a constant ratio of H₂/CO₂ equal to 4:1 can be easily maintained [19].

Biological methanation has a reaction rate lower than chemical methanation due to a lower operating temperature. On the other hand, BHM has a high tolerance to impurities of the incoming gas and a simple process setup [20]. Indeed, the microbiota of the biological reactor can be adapted to the presence of impurities, without significant effects on the overall performance. In addition, another advantage of the BHM is its synergy with conventional anaerobic digestion process, whose upgrading section can be the CO₂ source to improve the overall production of biomethane [19]. Thus, an ex-situ BHM process was considered in this work.

Different parameters can be used for a punctual description of a BHM process [21]. However, for the sake of brevity, only two parameters are considered here: the Retention Time (RT) and the Methane Formation Rate (MFR) or Methane Production Rate (MPR). The retention time provides information on the average time the reactant gases remain in the reactor:

$$RT = \frac{V_R}{(\dot{V}_{G,in} + \dot{V}_{G,out})/2} [h] \quad (2)$$

where $\dot{V}_{G,in}$ is the total gas flow rate (hydrogen, carbon dioxide, and other gases if present) entering in the system, while $\dot{V}_{G,out}$ is the total output gas flow rate and V_R is the reactor volume.

The Methane Formation Rate is the methane production rate per unit of reactor volume. It is defined by the difference between the CH₄ output and input flow (when the injected gas is biogas), related the reactor volume:

$$MFR = \frac{\dot{V}_{CH_4,out} - \dot{V}_{CH_4,in}}{V_R} [(m^3/d)/m_R^3] \quad (3)$$

The performance of the bioreactor have been assumed according to the available data of an ex-situ lab experimental configuration [22]. Table 3 summarises the input data of the BHM plant and the performance of the studied bioreactor.

2.4 Preliminary economic analysis

A preliminary economic analysis was carried out to investigate the cost-effectiveness of the proposed Power-to-Methane energy system by evaluating the levelized cost of biomethane (LCOBM), according to the equation (4):

$$LCOBM = \frac{TCI + \sum_{k=1}^N (AC_k + EC_k) \cdot (1 + i)^{-k}}{\sum_{k=1}^N m_{CH_4,k} \cdot (1 + i)^{-k}} \quad (4)$$

where TCI is the total capital investment; AC and EC are the annual costs of operation and maintenance and electricity purchasing, respectively, m_{CH_4} is the annual biomethane production (biomethane from biogas upgrading production excluded), i is the annual interest

rate, and N is the operating lifetime. TCI includes the direct costs of electrolyser (stack and balance of plant), bioreactor, storage, together with overall indirect costs (site preparation costs, contingency costs, engineering costs). For simplicity, TCI was determined at the beginning of the operating lifetime period and the investment costs in the following years were neglected. Annual operating and maintenance costs were assumed as a percentage of the investment cost for the electrolyser, the H₂ storage, and the bioreactor. Table 4 summarises the cost assumptions and the cost of methane from a biogas plant.

Table 3. Bioreactor parameters and performance.

Parameter	Value
T (°C)	55
P (bar)	1
MFR [(m ³ /d)/m _R ³]	3.7
RT [h]	24
% _{vol} H _{2,in}	80
% _{vol} CO _{2,in}	20
H _{2,in} [Nm ³ /y]	4,713,109
CO _{2,in} [Nm ³ /y]	1,178,300
$\dot{V}_{G,in}$ [Nm ³ /day]	18,852
% _{vol} H _{2,out}	0
% _{vol} CO _{2,out}	4
% _{vol} CH _{4,out}	96

Table 4. Main assumptions for the economic analysis.

Parameter	Value
Electrolyser specific direct costs [€/kW] [23]	$C_{EL;D} = 800 \left(\frac{P_{EL}}{1000 kW}\right)^{-0.2}$
Electrolyser specific indirect costs [€/kW] [24]	$C_{EL;IND} = 25\% C_{EL;D} + 650$
Bioreactor direct cost [€] [25]	$C_R = 492.8 * (PCI_{CH_4} * \dot{m}_{CH_4})$
H ₂ storage direct costs [€] [26]	$C_s = 5800 + 1600 * V_s^{0.7}$
O&M annual costs (Electrolyser and Storage) [€] [27]	5% of TCI
O&M annual costs (Bioreactor) [€] [25]	8% of TCI
Electricity cost from PV plant [€/MWh]	50
Electricity cost from grid [€/MWh]	180
Annual interest rate [27]	5%
Operating lifetime [years] [27]	20
Methane from biogas plant [€/kg] [28]	0.33-0.86

2.5 Biomethane transport

Methane might be transported to the final users in form of compressed natural gas (CNG) by employing an existing natural gas pipeline or as liquefied natural gas (LNG) by using cryogenic trucks (when biomethane is liquefied, at a temperature of $-160\text{ }^{\circ}\text{C}$, it is called bioLNG or Liquefied Biogas). In this study, the costs of biomethane transport by pipeline and by cryogenic trucks were compared. Table 5 reports the capital (CAPEX) and operating (OPEX) expenditures related to the transport of CNG and LNG via pipeline and trucks, respectively.

Table 5. Economic indices for methane transport.

CAPEX & OPEX		
CAPEX LNG liquefaction [37,38] [$\text{€}/\text{Nm}^3$]		0.145
OPEX LNG liquefaction [30] [$\text{€}/\text{Nm}^3$]		0.026
CAPEX CNG compression [31] [$\text{€}/\text{Nm}^3$]		0.018
OPEX CNG compression [31] [$\text{€}/\text{Nm}^3$]		0.012
OPEX (transport)		
Distance [km]	CNG [$\text{€}/\text{Nm}^3$] [32]	LNG [$\text{€}/\text{Nm}^3$] [33]
100	0.0041	0.0206
200	0.0081	0.0276
400	0.0161	0.0416

3 Results and discussion

3.1 Power-to-Methane energy system

While the electrolyser was simulated in Aspen Plus, the BHM process model was separately developed in MATLAB. The calculation code is based on the performance of the ex-situ reactor of the experimental configuration [22], the inlet mass flow ($\text{CO}_{2,\text{in}}+\text{H}_{2,\text{in}}$), manually imported in MATLAB, is the first input data and all the process results have been calculated through the Sabatier equation, RT, MFR, and the volumetric composition percentages of the outgoing gas. The BHM reaction is carried out at $55\text{ }^{\circ}\text{C}$ and 1 bar, with a retention time of 24 h. According to reference data, the outlet gas is composed by $4\%_{\text{vol}}$ of CO_2 and $96\%_{\text{vol}}$ of CH_4 , with a complete conversion of the injected H_2 . Biomethane is produced at a daily rate higher than 3000 Nm^3 along with a daily water production of about 9050 m^3 , in a reactor with a volume of about 1200 m^3 . Table 6 summarises the main results of the BHM process.

Table 6. BHM process results.

Parameter	Value
CO _{2,in} [Nm ³ /y]	1.178,550
H _{2,in} [Nm ³ /y]	4,714,200
$\dot{V}_{G,in}$ [Nm ³ /day]	18,857
CO _{2,out} [Nm ³ /y]	47,142
H _{2,out} [Nm ³ /y]	0
CH _{4,out} [Nm ³ /y]	1,131,408
H ₂ O _{,out} [Nm ³ /y]	2,357,100
V _R [m ³]	1,200

Based on the stoichiometric ratio of the Sabatier reaction the studied BHM process requires a total of about 425 t/y of hydrogen. Table 7 summarises the main characteristics and results of the electrolysis system, providing the operating temperature and pressure, and the nominal efficiency. Also, the number of stacks, the power absorbed to produce the required hydrogen hourly flow, the hydrogen production, and the storage volume for the four scenarios are reported.

The size of the electrolyser reported in Table 7 was chosen to guarantee the hydrogen required to match the CO₂ production of the biogas section.

Table 7. Performance of the alkaline electrolyser.

Parameter	Value			
Operating temperature [°C]	65			
Operating pressure [bar]	25			
Efficiency	0.7078			
Case scenario				
	24 h	12 h	8 h	6 h
Stacks	572	1144	1716	2288
Power [MW]	2.673	5.346	8.019	10.692
Hydrogen production [kg/h]	56.8	113.6	170.4	227.2
Storage volume (25 bar) [m ³]	0	338	451	507

As reported in Table 7 and shown in Figure 3, by reducing the daily hours of operation, i.e., from 24 to 6 hours, a larger amount of hydrogen must be produced to guarantee a continuous 24-hour feeding to the BHM reactor.

Therefore, the utilisation factor of the electrolyser reduces, the required power increases and so does the required H₂ storage volume.

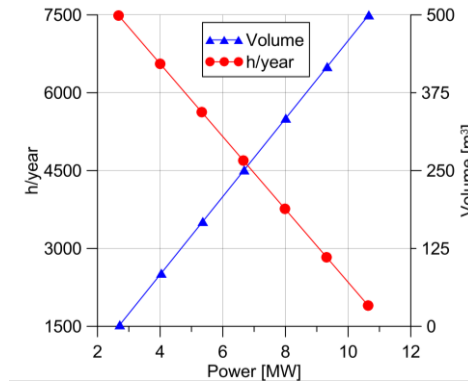


Figure 3. Electrolyser hours of operation (left) and H₂ storage volume (right) as a function of the electrolyser power input.

The yearly energy required by the electrolyzers can be supplied directly by a PV plant or by the grid during periods of low solar radiation. The PV power plant is scaled assuming different arrangements of multiple 10 kW PV stacks, each one composed by 30 PV modules with a 330 W rated power [16]. Thus, in this analysis the PV power output ranges between about 2 and 20 MW. Figure 4 shows the electrical energy absorbed by the electrolyser in the 4 cases (6, 8, 12, 24 operating hours a day) from the PV plant (self-consumed, Self) and from the grid (left graph), and the electrical energy overproduction of the PV plant and the total PV production (right graph), as a function of the installed PV power. For all scenarios, the energy consumptions of the electrolyser do not change with its operating hours and the size of the PV plant, while the share of energy self-consumption always increases with the PV plant size. However, by increasing the size of the PV plant, the improvement of the energy self-consumption becomes less and less significant, while greatly increases the amount of energy over-production. For this reason, a maximum PV power equal to 20 MW was assumed.

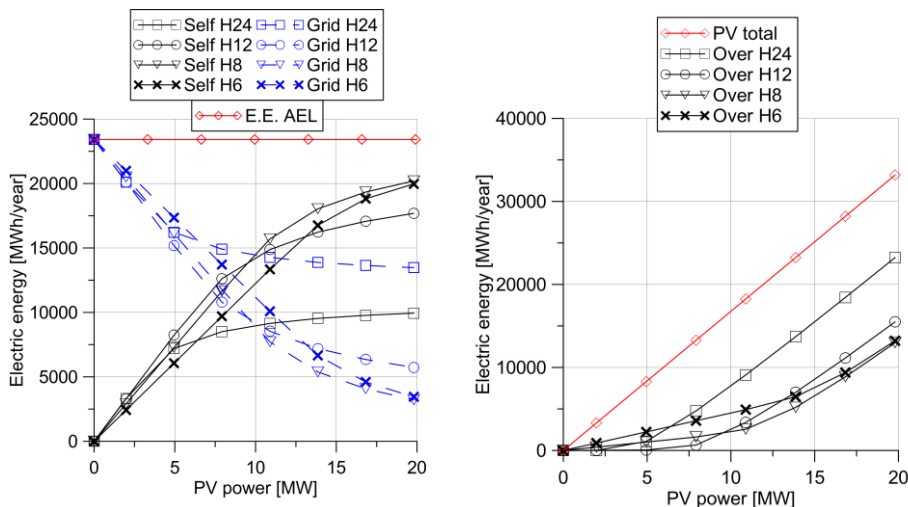


Figure 4. Electrical energy self-consumed and supplied by the grid (left) and PV overall and over-production (right) as a function of the PV size for the 4 case scenarios.

Considering the H24 scenario, the energy supplied by the grid is always higher than that self-consumed, and the PV overproduction greatly increases with the size of the PV plant (the over-production exceeds the energy self-consumption for a PV power over 11 MW). The share of energy self-consumption increases by reducing the operating hours of the electrolyser due to a better matching with the production profile of the PV plant. Up to a PV power of about 9 MW, the H12 scenario might be the best solution from an energetic point of view, because the hours of operation of the electrolyser virtually overlap the PV production. For a PV power higher than 9 MW, the highest self-consumption belongs to the H8 scenario. For the H12 and H8 scenarios, with a PV power higher than 7-8 MW, the amount of energy self-consumption becomes higher than that supplied by the grid, even if the overproduction begins to increase. In comparison to the H12 and H8 scenarios, the H6 scenario always shows a lower energy self-consumption and a higher over-production.

Figure 5 (left) shows the levelized cost of biomethane (LCOBM) as a function of the PV power for all four studied scenarios.

The levelized cost decreases with the increase in the PV power, since the RES energy is characterised by a cost (50 €/MWh) lower than that of the grid (180 €/MWh). The minimum value of LCOBM is reached for the 12H scenario and for high values of the PV power plant as best tradeoff between a high share of energy self-consumption (and therefore low electrical energy costs) and low capital costs for the electrolyser. In particular, the LCOBM is lower than 3.0 €/Nm³ for a PV power plant higher than about 14 MW. Obviously, the cost of biomethane produced by the biogas plant is much lower (0.24-0.62 €/Nm³) and more competitive than that of the biomethane produced by the Power-to-Methane plant. Nevertheless, the future costs reduction related to the further development and deployment of the electrolyser and BHM technologies will lead to a reduction in the LCOBM in the next years, making this process competitive with traditional ones.

Finally, Figure 5 (right) shows the CNG and LNG transport costs, considering both CAPEX and OPEX costs for the compression and liquefaction system. The CNG transport, along with a dedicate pipeline, if available, is a more economical option compared to the LNG transport by trucks. Moreover, the LNG option requires a more complex distribution system.

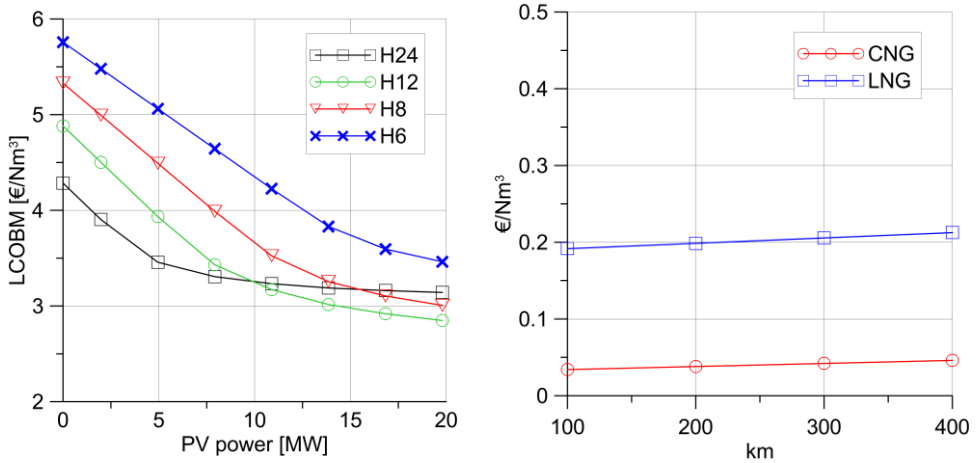


Figure 5. LCOBM as a function of the PV power (left) and CNG and LNG transport costs as a function of covered distance (right).

3.2 Biomethane contribution in Sardinia

The results of the PtM system analysed in the previous section were applied to the biomethane context of Sardinia. There are currently 25 anaerobic digestions plants integrated with power generation units in Sardinia, with a total power output of 21.4 MW and a total production of about 50 million Nm³/y of biogas [34]. The regional energy and environmental plan of Sardinia reports a methane consumption forecast of about 560 million Nm³/y [35]. Thus, it is clear the importance of providing a sustainable source of biomethane to match the forecast consumption.

Table 8 gives the residual biomass availability in Sardinia and the corresponding potential biogas production, as well as the biomethane and CO₂ production from the upgrading processes. Table 8 demonstrates a potential production larger than 263 million Nm³ of biogas and over 137 million Nm³ of biomethane [36]. The biomass availability and the potential production of biomethane from both upgrading and BHM allow defining the possible contribution as natural gas substitute.

To exploit such a biogas potential production, with reference to the average plant size considered in this work, at least 100 biogas plants should be employed. In addition to the biomethane production deriving from the biogas plants, almost 115 million Nm³/y of CO₂ are available downstream the biogas upgrading section to be further converted into more than 110 million Nm³/y of biomethane by BHM processes. Table 9 summarises the potential biomethane production that is achievable from the net residual CO₂ released by the biogas plants sited in Sardinia (Table 8). The availability of biomass can provide a contribution of about 25% to the forecast natural gas consumption, with an increase to 44% when BHM plants are employed to convert the CO₂ emitted by the biogas plants.

Along with the 100 biogas plants needed to exploit the biogas potential of Sardinia, the same number of BHM plants should be installed. The required hydrogen to sustain such a biomethane production would be produced by an overall electrolysis installed power of 515 MW and 643 MW from alkaline and PEM electrolyzers, respectively.

Table 8. Biomass and biogas potential in Sardinia.

Biomass	Available residues	Biogas production [Nm ³ /y]	Net CH ₄ production [Nm ³ /y]	Net residual CO ₂ [Nm ³ /y]
Animal manure [m ³ /y]	4,174,321	148,136,218	79,993,558	66,661,298
Sorghum [t/y]	443,980	53,277,655	28,769,934	23,974,945
Dedicated crops [t/y]	234,858	28,183,200	15,218,928	12,682,440
Artichoke residues [t/y]	180,671	18,699,397	10,097,674	8,414,729
Municipal solid waste organic fraction (MSWOF) [t/y]	79,289	6,660,242	3,596,531	2,997,109
Tomato residues [t/y]	56,910	5,890,185	3,180,700	2,650,583
Serum waste [t/y]	123,269	1,899,122	1,025,526	854,605
Slaughtering waste [t/y]	7,492	487,002	262,981	219,151
Total	-	263,233,021	137,881,456	114,901,214

Table 9. Biomethane production in the BHM from biogas-derived CO₂.

Parameter	Value
Net residual CO ₂ from biogas plants [Nm ³ /y]	114,901,214
Required H ₂ [Nm ³ /y]	459,604,855
Produced biomethane [Nm ³ /y]	110,305,165
Overall methane and biomethane [Nm ³ /y]	248,186,621
Forecast methane consumption covered	44,32%

Figure 6 shows the production of methane as a function of the number of installed plants (lower x axis), with a plant size considered in this work, and the corresponding biogas production (upper x axis) for the cases of simple upgrading and upgrading and biomethanation.

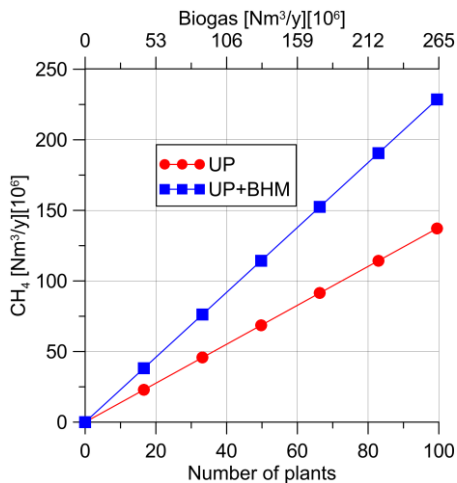


Figure 6. Methane production function of the number of installed plants and biogas production.

Conclusion

A biological hydrogen methanation (BHM) system was analysed in this work. Green H₂, produced by an alkaline electrolyser fed by a PV plant and by green energy from the grid, is injected in a bioreactor with CO₂, recovered from an anaerobic digester integrated with a biogas upgrading section, to synthesise biomethane. According to the electrolyser operating time, the produced H₂ can be directly injected into the bioreactor or stored in a dedicated tank. With a total recovered CO₂ of 1.2 million Nm³/y and 4.7 million Nm³/y of H₂, a biomethane production higher than 1 million Nm³/y was achieved in the studied BHM system. The energy analysis shows that the H12 scenario is the best solution because the hours of operation of the electrolyser virtually overlap the PV production and the highest amount of self-consumed energy can be reached. The preliminary economic analysis shows that with the H12 scenario, an LCBOM value lower than 3.0 €/Nm³ for a PV power plant higher than about 14 MW can be achieved. In addition, the CNG transport employing a dedicated pipeline, if available, is a more economical option of transport compared to the LNG transport by trucks, due to the higher CAPEX and OPEX costs related to the liquefaction plant. The analysis of the availability of biomass, and so of the production of biomethane by means of anaerobic digestion plants integrated with BHM systems, demonstrated that this solution could satisfy 44% of the forecast Sardinia demand of natural gas.

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