Journal of Physics: Conference Series

PAPER • OPEN ACCESS

Techno-economic assessment of enhanced Biogas&Power-to-SNG processes with high-temperature electrolysis integration

To cite this article: P Colbertaldo and G Guandalini 2022 *J. Phys.: Conf. Ser.* **2385** 012045

Journal of Physics: Conference Series **2385** (2022) 012045 doi:10.1088/1742-6596/2385/1/012045

Techno-economic assessment of enhanced Biogas&Power-to-SNG processes with high-temperature electrolysis integration

P Colbertaldo*, G Guandalini

Group of Energy Conversion Systems (GECoS), Department of Energy, Politecnico di Milano – Via Lambruschini, 4A, 20156 Milan, Italy

Abstract. Biogenic energy sources are essential elements of the decarbonization pathways, but are strongly constrained by the limited availability. In this context, Biogas&Power-to-X technologies are strongly supported as a promising solution to foster renewable power generation and drive sector coupling opportunities. This work investigates enhanced Synthetic Natural Gas (SNG) production processes for the repurposing of biogas plants. As an alternative to combined heat and power applications via internal combustion engines, the Italian legislation is supporting biogas-to-biomethane upgrading, focusing on the transport market. The proposed integrated plant scheme is a flexible solution based on Power-to-Hydrogen and methanation, able to exploit both electric and gas grid connections, enhancing biomethane production. Advanced process schemes are studied combining solid oxide electrolysers that exploit the methanation waste heat as input thermal energy and flexible PEM electrolysers that improve the part-load operation. The calculated efficiency at max load is about 55% for the Power-to-Methane block and nearly 75% for the overall integrated plant. Results show limited sensitivity of efficiency to input power variations, making the system suitable for the recovery of surplus renewable power generation.

1. Introduction

Recently, large attention has emerged on Power-to-X (P2X) technologies as solutions capable to recover surplus renewable electricity generation [1], thus favouring the increase of intermittent RES penetration in the power sector. The building block of all P2X options is electrolysis (alone referred to as Power-to-Hydrogen, P2H), because hydrogen is an essential element in any pathway. In a sector coupling perspective, aiming to exploit the existing infrastructures, such electrolysis-based hydrogen can be directed to a methanation system where it recombines with CO_2 to obtain CH_4 as final product. The advantage is to have an energy vector with perfect admixing characteristics for direct injection into the natural gas grid, without restrictions. In presence of a biogas plant comprising a purification system to obtain biomethane (pure CH_4), the combination of electrolysis and methanation can exploit the by-product stream of pure CO_2 from the upgrading process, generating additional synthetic natural gas (SNG) that can be blended with the pure CH_4 stream from the same upgrading.

A schematic of the system is presented in Figure 1. The large operational temperature and the exothermic nature of the methanation reaction provide waste heat that can be recovered, enabling the use of high-temperature electrolysis. The biogas upgrading unit typically operates continuously at nominal conditions, whereas the hydrogen production depends upon the availability of clean and/or inexpensive electricity. When the power feed limits the hydrogen output, the extra CO_2 may be simply

* Corresponding author: paolo.colbertaldo@polimi.it

vented, as it would happen if the biogas upgrading was not combined with a methanation system, or temporarily stored for later use.

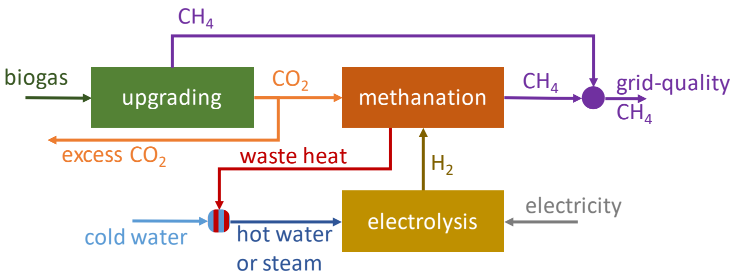

Figure 1. Overall system scheme.

In this work, this complex plant layout is investigated, aiming at designing a flexible system capable to comply with the variable load that expected by the fluctuations in electricity availability. Hence, operation at part-load of the methanation unit is studied and the combined presence of high-efficiency high-temperature electrolysis and flexible low-temperature electrolysis is proposed. Thus, the operation at nominal and off-design conditions is assessed, focusing in particular on the heat integration aspects.

2. State of the art

Biogas is a gaseous mixture of CH_4, CO_2, and few minor traces of other compounds, typically with a CH_4 fraction in the range 55-60%$_{vol}$. Such mixture is obtained via digestion of solid and liquid biomass in aerobic or anaerobic conditions, with the aid of heat provision and bacteria. The obtained mixture can be directly used as a fuel, since CO_2 acts as an inert in combustion processes, or further conditioned, e.g., removing partially or totally the CO_2. In the latter case, the fuel becomes pure CH_4, which is then called biomethane.

The deployment of biogas plants has been driven by the aim of recovering biomass residues that are difficult to be used directly (e.g., animal pasture), accelerating the decomposition process and collecting the methane that is generated. In particular, the Italian regulation since 2007 has favoured the local use of biogas in combined heat and power (CHP) devices, so that many agricultural and animal husbandry facilities have installed internal combustion engines within the allowed rating (below 1 MW_e), exploiting the thermal generation for space heating and for biodigester supply, whereas most of the electric generation has been directed to the power grid. Indeed, the regulation provided significant subsidies on the electricity flows injected into the national grid [2], as these constitute an additional share of renewable generation to comply with the national targets.

In more recent years, given the good trend in renewable power generation and aiming at supporting the decarbonization process in other sectors, such as mobility, the new regulations have shifted towards supporting the upgrade of biogas into biomethane and its injection into the natural gas grid [2]. A ‘guarantee of origin’ scheme was introduced to track the biogenic origin of that amount when sold to the final user [3]. Indeed, Italy features a significant share of natural gas-fuelled vehicles, historically in the passenger car sector (nearly 1 million vehicles [4]) and recently also in the heavy duty sector thanks to the advancements in liquified natural gas (LNG) solutions [5]. The primary impact of the regulation is to foster the use of a cleaner vehicle option compared to conventional gasoline or diesel engines and to enable an even further climate advantage thanks to the use of biogenic, hence CO_2-neutral, fuels. The secondary impact is the role of the gas grid in the decarbonization process and, looking forward at integrated systems such as that proposed in Figure 1, an additional interaction between the electric and the gas grids, yielding novel opportunities as well as challenges.

When talking about 'Power-to-X' applications, the key element is the electrolysis device. The technology of water splitting has been known since the 1960s for hydrogen production at small and stable quantities, but its development has strongly accelerated in the latest decade due to the potential use in surplus renewable power recovery [6]. The two main categories are low-temperature devices operating a (<100°C with liquid water feed and high-temperature units fed with steam (600-900°C). The main differences are the achievable electric efficiency and the flexibility in terms of minimum load and ramp rate. On the one hand, the balance of plant for operation at high temperature introduces additional complexity due to regenerative heat exchangers and external heat provision; on the other hand, the possibility to provide part of the required reaction energy in the form of heat reduces the electric demand and thus benefits the electric efficiency. Low-temperature technologies include alkaline and proton-exchange membrane electrolysis, which are available at commercial or early-commercial status [7], and anion-exchange membrane electrolysis, which is currently at lab/demo level [8]. High-temperature options feature a lower readiness level, and are mainly represented by solid oxide electrolysis cell (SOEC) that use materials and conditions similar to the corresponding fuel cell (SOFC) [6].

With respect to the methanation process, two groups of technologies are currently available, with different technology readiness level (TRL): catalytic reactor-based systems and biological solutions. In this work, the study focuses on the first option, being more technologically developed and leaving to further investigation the biological option. Nickel-based catalysts are the most widely used thanks to their high reactivity and selectivity towards CH_4, while fixed bed reactors are the conventional solution [9]–[11]. Since the reaction is strongly exothermic, intercooled systems and other heat management solutions have been developed, including recirculation of reactants, staged feeding, dilution, and integrated heat exchangers. Moreover, the limited conversion per pass requires recirculation loops to obtain almost complete conversions. Other options available are fluidized bed reactors and micro-channels reactors, with improved general performances, but higher complexity and costs [9]–[11].

3. System configuration and operation

This work focuses on the integration between the electrolyser and the methanation system as support for increasing the production of a biogas plant with upgrading. The biogas considered has a composition of 40%vol CO_2 and 60%vol CH_4, resulting in a LHV of 17.65 MJ/kg.

A chemical methanation scheme is considered, based on the TREMP technology, which is based on a series of three catalytic reactors where temperature is controlled to guarantee catalyst activation and flow recirculation allows to obtain the required output composition [11], [12]. Regarding hydrogen production, the proposed system configuration takes advantage of two technologies: a solid-oxide electrolysis (SOEC) system is sized to provide up to half of the nominal hydrogen request, whereas the remaining demand is satisfied by a PEM electrolyser (PEMEC). This combination allows to exploit the high electric efficiency of SOEC and the high flexibility of PEMEC, while respecting SOEC constraints on part-load operation, which is limited to a 60-100% range [13]. Figure 2 depicts the integration of streams in the proposed layout.

The system is modelled and simulated using Aspen Plus®. The SOEC performance variations are represented through an i-V polarization curve, experimentally obtained in [14] and rescaled to the nominal capacity, coupled with mass and energy balances accounting for internal heat integration. The thermal management of the cell maintains a constant inlet temperature of 800 °C avoiding thermal stresses [15]. The biogas upgrading plant is assumed to operate continuously with a 98% recovery and a 98% purity in the CH_4 output stream. The methanation system operates with a stoichiometric feed (4 mol_{H2}/mol_{CO2}) and is controlled by varying the input and output temperature of the reactors in order to guarantee that the final SNG stream after the blending of upgrading and methanation products respects the grid constraints: HHV in the range 34.95-45.28 MJ/Sm^3, Wobbe Index in the range 47.31-52.33 MJ/Sm^3, H_2 content below 0.5%vol, CO_2 content below 3%vol. Preliminary simulations showed that the H_2 limit is the most stringent one. Finally, the PEMEC system operates as a balancing component to guarantee the required hydrogen production, avoiding the use of hydrogen storage units. Up to 50% of the load, the PEMEC is shut off and the variation is managed by the SOEC, which follows thermal power availability from the methanation system and integrates the remaining thermal energy needs (for inlet stream heating) via electric boilers/evaporators.

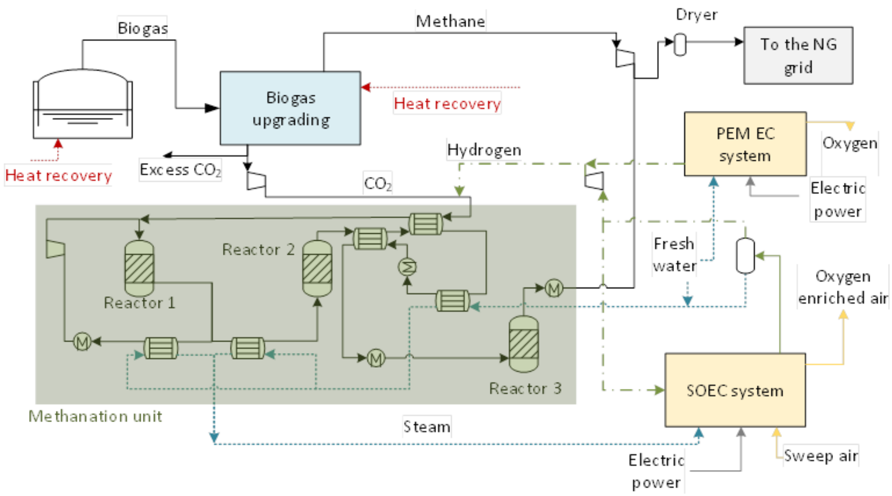

Figure 2. Mass and energy flows in the integrated electrolysis-methanation module.

4. Results and discussion

The system described above is analysed from both the technical and the economic point of views. In practice, the flexibility given by the presence of the P2G systems reduces the energy efficiency and increases the investment costs while proving the possibility to increase the production in favourable conditions. Hence, the system always introduces losses from the energy point of view and an economic comparison is required.

Table 1 lists the nominal capacities of all system components, resulting from the previous assumptions. The system is sized as a retrofit of an existing biogas plant, now aimed at electricity generation through an internal combustion engine (ICE). Due to the past structure of incentive regulation, most of the biogas plant are sized for cogeneration of heat and electricity, with a threshold of 1 MW_e, corresponding to about 500 kg/h of biogas. The methanation unit is sized in order to be able to convert 100% of the available CO_2 separated by the upgrading, resulting in a nominal CO_2 flow of 316 kg/h. As mentioned before, the hydrogen demand at nominal load is equally split between the two electrolysis units, resulting in 1.0 MW_e for the PEMEC (nominal efficiency of 62.1%) and 1.6 MW_e for the SOEC (nominal efficiency of 95.0% as cell and 85.1% as system).

Table 1. Nominal capacities of main system components.

	Biogas upgrading	**Methanation system**	**SOEC system**	**PEMEC**
Nominal capacity	500 kg_{biogas}/h (2.4 MW_{LHV})	316 kg_{CO2}/h	28.6 kg_{H2}/h (1.17 MW_{el})	28.6 kg_{H2}/h (1.6 MW_{el})

4.1. *Technical assessment*

The steady-state system operation is simulated, assuming a maximum variability range between 30% and 100% of the methanation rated capacity. The main issues related to lower loads are thermal gradients in the catalyst section and in compression units' management. The electricity consumption (i.e., the absorption of surplus power from renewable plants) varies approximately linearly, ranging from 0.8 MW_{el} to nearly 3.0 MW_{el}. When the available electricity is below 0.8 MW_{el}, the P2G is not active, and the upgrading unit operates alone. In Figure 3, the operating strategy is depicted, in terms of energy content of the produced gas and of CO_2 utilization fraction. Below 0.8 MW_e of available renewable electricity, the upgrading unit operates, purifying to grid standard up to 2.4 MW of biomethane (183 kg/h). This quantity is always injected into the grid, with additional contribution from the methanation unit if electricity is available. The hydrogen from the SOEC provides additional 0.8 MW of SNG, reaching 3.2 MW (243.5 kg/h), further increased to 4.02 MW (303.8 kg/h) when both electrolysis units operate at full power. The biological CO_2 separated by the upgrading is converted with an almost linear trend.

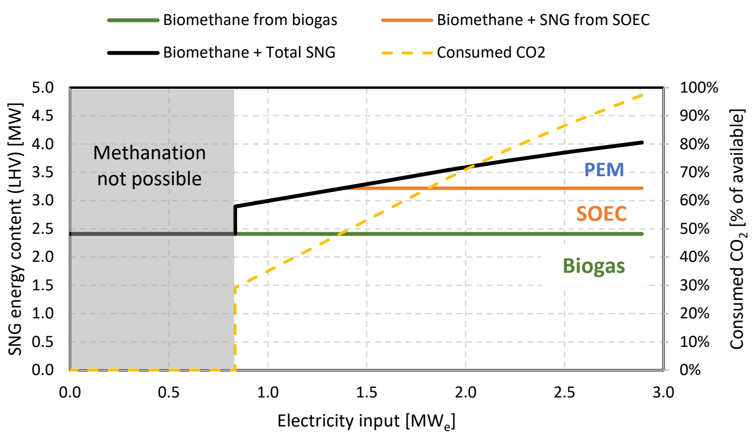

Figure 3. Gas injection in the grid as a function of the electricity input. The contribution of biogas upgrading, of SNG from SOEC-based hydrogen and of SNG from PEMEC-based hydrogen are evidenced, as well as the fraction of converted CO_2.

The additional gas production is linked with the electricity consumption, that is required by different components in the system, as displayed in Figure 4. The PEMEC and SOEC system are the strongest contributions, while upgrading and compression are almost negligible. The additional consumption for heating, due to the missing heat from methanation unit thermal integration, impacts for about 150-200 kW_e that are relevant for the global balance. Focusing on the heat recovery integration, the SOEC system is able to exploit about 24% of the available thermal power, but this leads to a larger reliance on externally-provided power (electrical resistance) when the methanation operates at low partial load. The remaining fraction is required by the upgrading unit for regeneration purposes or by the anaerobic digester.

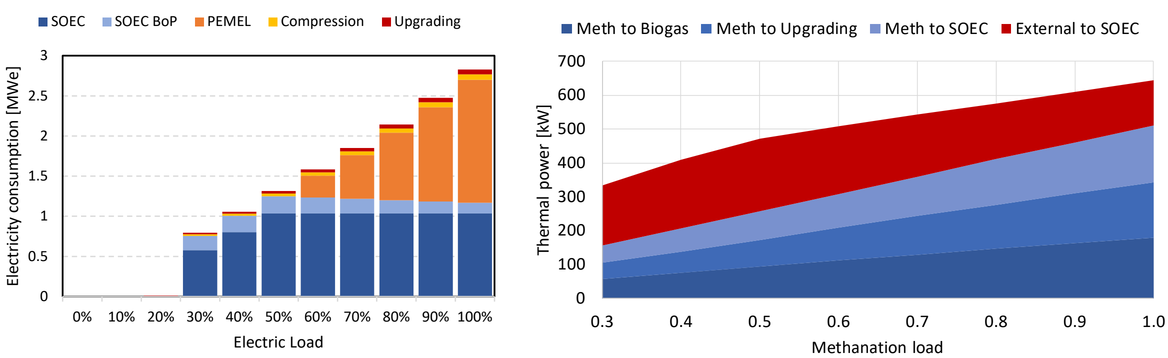

Figure 4. Left: Share of electricity use, as function of its availability. Right: Thermal power exchanged in the system as a function of the methanation system load.

The above-described mass and energy balances result in the system efficiencies depicted in Figure 5. Electrochemical devices are known to offer improved performance at partial load, thanks to reduced electrical losses: the P2G efficiency (i.e., electricity-to-SNG) is maximized when the system operates at about 70% of the methanation system nominal capacity (2.0 MW_e of electricity input). Nevertheless, the value is rather stable, showing very limited fluctuations with the load, due to the required electric input to the SOEC to compensate for missing heat from methanation. With respect to the global system, the energy efficiency (i.e., the total energy content of the gas with respect to all the energy inputs), always decreases at increasing electricity consumption because of the P2G losses:

$$\eta_{sys} = \frac{E_{HHV,biom} + E_{HHV,SNG}}{E_{HHV,biogas} + E_{el}} = \frac{E_{HHV,biom} + E_{el} \cdot \eta_{P2G}}{E_{HHV,biogas} + E_{el}}$$

since the upgrading unit operates continuously with minor losses, with a constant biomethane-to-biogas ratio.

Because of the opposite trend between energy efficiency and useful product amount, the system cannot be evaluated only on energy basis, but the system has to be scored also on economic basis.

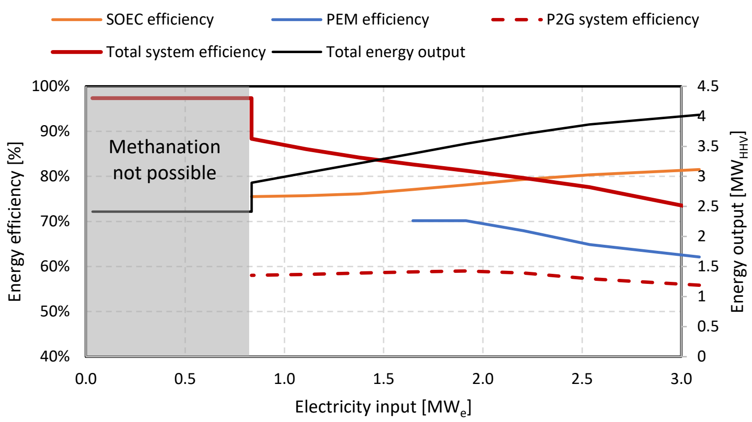

Figure 5. First-principle energy efficiencies and total energy output (biomethane+SNG HHV) at different loads.

4.2. Economic analysis

The system described in the previous paragraph includes three main sections: upgrading, methanation, and electrolysis. In Table 2, the size parameter and investment cost of the components are reported as lumped values. For the upgrading section, a specific cost of 2500 €/(Nm^3/h) for the scrubber unit is assumed, while the compressors cost is calculated using literature correlations. The methanation reactor cost is calculated with a reference cost of 82.5 M€ for a 1770 kW_{HHV} unit and using a scale factor of 0.65 [16]. Heat exchanger costs are a function of surfaces, fluids, and operating conditions, calculated according to [17]. The SOEC unit has a specific cost of 2200 €/kW_e, while for the PEMEC a lower cost equal to 1000 €/kW_e is assumed [18]. The cost of heat rejection unit and electric converters are from [19] and [16] respectively. Under these assumptions, the electrolysis systems represent more than 50% of the capital investment (see Figure 6), reaching 78% as complete P2G unit. Since the anaerobic digestor is already in operation, and represent the base case, its investment is not considered here. The fixed O&M costs are generally assumed as 1%/y of the initial investment. In addition to the installed equipment cost, instrumentation and control (10%), general services (10%) and engineering cost (7%) are added [16], considering also 50% additional cost for contingencies, due to the risk of these low TRL system.

Table 2. Investment and O&M fixed costs.

	Component	***Size***	***Investment cost [k€]***	***O&M fixed cost [k€/y]***
Upgrading section	Upgrading unit	411 Nm^3/h	1027.5	15.6
	CO_2 compressor	26.78 kW_e	14.0	
	CH_4 compressor	40.85 kW_e	18.9	
Methanation section	Methanation reactors	1.79 MW_{SNG}	933.1	10.2
	Heat exchangers	-	20.4	
	Dryer	19.0 Nm^3/h	3.05	
Electrolysis systems	SOEC	1.13 MW_e	2476.3	39.9
	PEMEC	1.51 MW_e	1507.9	
Other BOP	Heat rejection	0.21 MW_{th}	10.5	3.0
	AC/DC converters	2.64 MW_e (2 units)	263.3	
	H_2 compressor	62.0 kW_e	28.7	
Total	**Components**		**6303.7**	**68.7**
	With contingencies		**11282.5**	

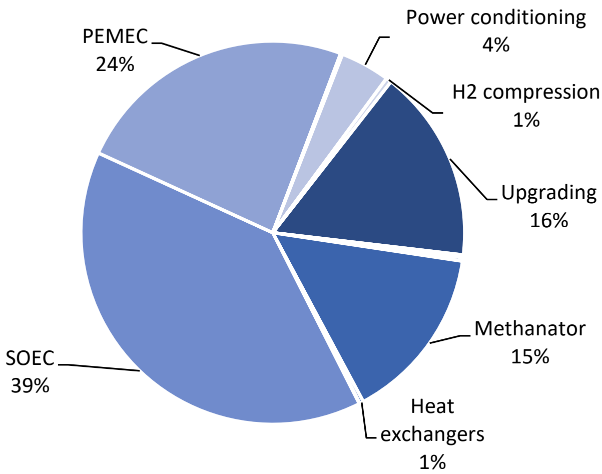

Figure 6. Share of investment costs over the total.

Since the system operation strategy is defined by the electricity price, in this work the analysis is performed assuming a constant price for gas market and looking for the electricity price making the system profitable. This price can be than compared with the actual market to understand the economic feasibility of the upgrading + P2G solution. The electricity market used as reference in this work is the Italian one, for which a reference price is PUN (weighted average of regional prices), that is depicted in Figure 7 for 2016 and 2019. As it can be observed, the variability of the price is quite small, with a difference in the average values of about 10 €/MWh and most of the hours with prices between 30 and 60 €/MWh. In the further calculations, 2019 prices are used since the most recent time series include contingencies that make them not suitable for a general analysis: 2020 has much lower average prices due to the pandemic impact, 2021 suffered a steep increase of prices (up to 5 times) in the last months, while 2022 is still ongoing. Due to the flexibility of the system, the electricity is assumed to be purchased for a different number of hours at the lowest possible price, according to the results of economic evaluations. Consequently, also the cumulative average price (i.e., the average of the first *n* hours with the lowest prices) is reported in the graph and will be useful in the following.

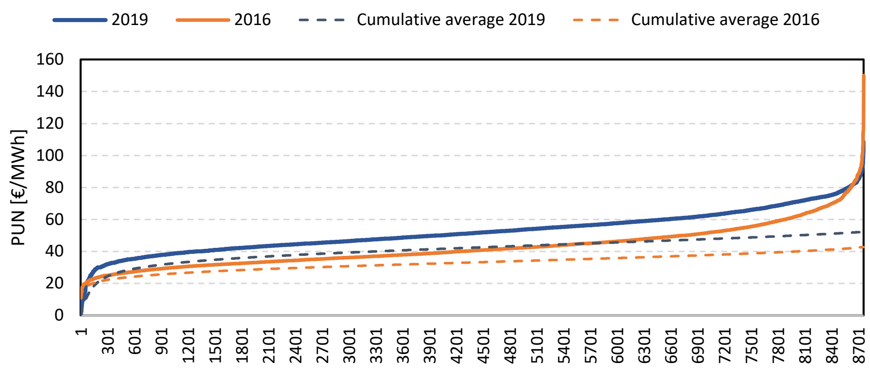

Figure 7. Example of sorted national electricity price for Italy (PUN) in 2016 and 2019: actual values and cumulated average values.

In this work, two main indicators are considered: the Net Present Value (NPV) and the Willingness-to-Pay (WtP). The first is a conventional economic index that provides the present value of an investment, considering all the actualized cash flows during lifetime. In this case, it can be calculated as:

$$NPV = -I_0 + \sum_{t=1}^{LT} \frac{CF_t}{(1+d)^t} = -I_0 + \alpha\left[-OPEX - p_e \cdot E_e + p_{gas} \cdot (E_{biom} + E_{SNG}) - p_{biog} \cdot E_{biog}\right]$$

where CF_t are constant in each year and consequently an actualization factor α can be used, which results equal to 9.82 considering a lifetime LT of 20 years and a discount rate d of 8%. The main contributions to the costs are the initial investment I_0, the fixed OPEX, the purchased electricity quantity E_e at average price p_e, the sold gas at average price p_{gas} that consider both the upgrading quantity E_{biom} and the methanation amount E_{SNG}. Since the anaerobic digester is assumed already existing, the biogas has a purchase cost p_{biog} that can be seen either as an actual purchase price or the cost of biogas production. For this contribution, a value of 0.2 €/kg$_{\text{biogas}}$ (about 40 €/MWh) is assumed; for comparison, also a case in which this contribution is negligible will be investigated.

On the other hand, the Willingness-to-Pay represents the maximum electricity price for which it is economically profitable to turn on the P2G section. It does not consider investment costs and only evaluates if revenues from additional production are higher than additional operating costs:

$$WtP = \frac{p_{gas} \cdot E_{SNG} - OPEX_{var}}{E_e}$$

where $OPEX_{var}$ are variable O&M costs related to P2G operation. In Figure 8a, the WtP calculated according to the previous energy balance is plotted against the gas sale price p_{gas}. As it can be observed, the relation is almost linear and provided as a range, since it is influenced by the actual P2G efficiency ($\eta_{P2G} = E_{SNG}/E_e$) that depends on the instantaneous availability of electricity at that price. The WtP can be seen as the maximum market price or the maximum cost of electricity production from a dedicated RES plant, for which P2G is turned on. The value is compared with the PUN 2019 (see Figure 7), giving the number of actual operating hours of the methanation section (see Figure 8a). As can be observed, up to 50 €/MWh of gas prices, the system is not profitable and pure upgrading is the best solution. On the other hand, the operating hours steeply increase between 70 and 140 €/MWh, fully saturating the production potential. In this region, the operation of the system is decided hour by hour according to the WtP. Above these prices, it is convenient to always operate the methanation unit.

A sensitivity analysis is performed considering different electricity price profiles, and the results for doubled prices are also reported in Figure 8, miming the actual strong increase of energy market prices. Already in this condition, the presence of the P2G unit becomes convenient at much higher gas prices (above 100 €/MWh) resulting in a reduced number of operating hours. This approach is simplified, since it neglects the dynamic of the system that can be relevant if the number of operation hours are small. Anyway, the general trends can be assumed as correct and the resulting values as upper bound for system profitability. It has also to be considered that intermittent operation and a low number of total hours results anyway in a non-feasible condition that is already excluded.

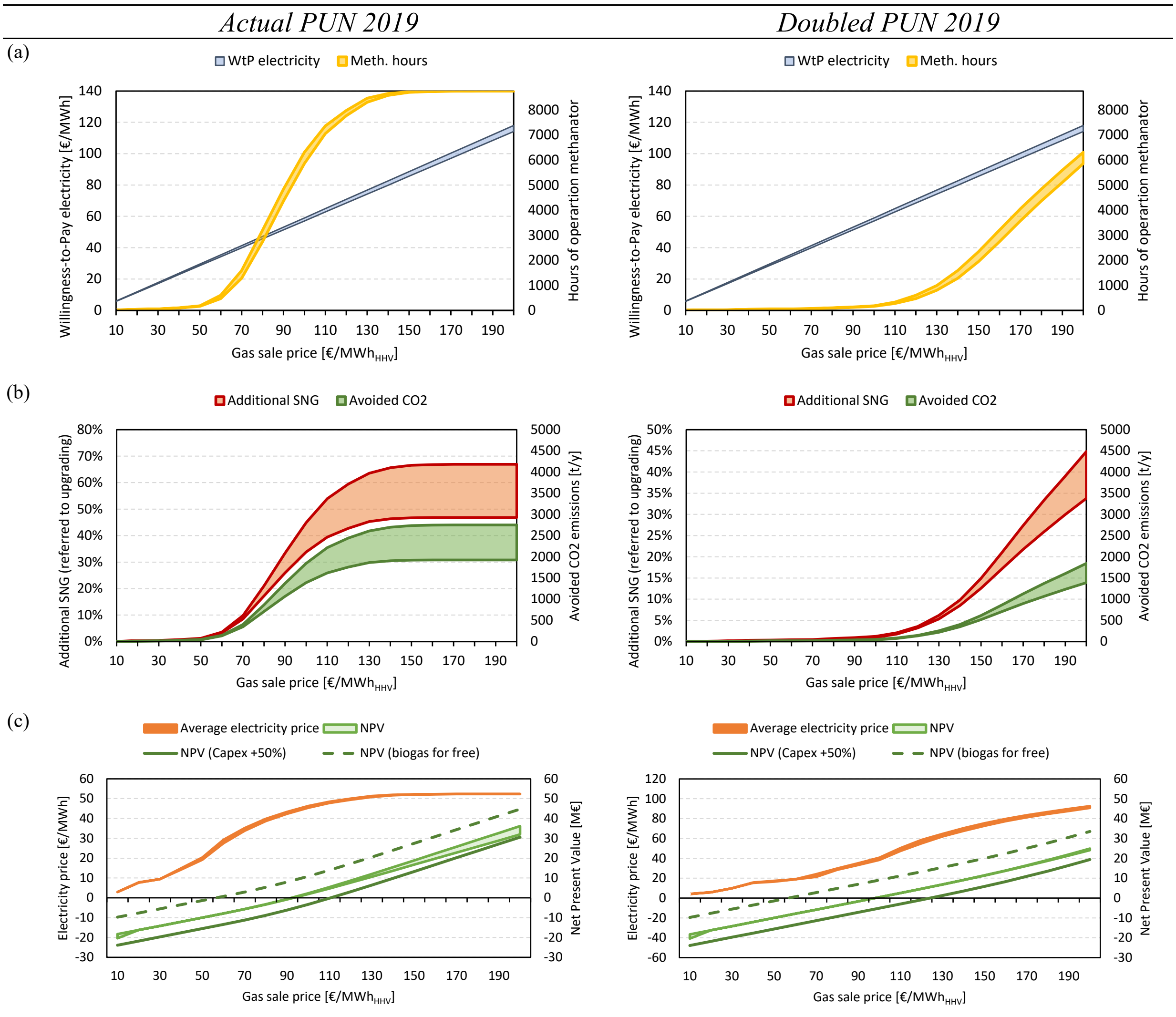

Figure 8. Economic evaluation of the upgrading + methanation system as a function of the gas sale price: (a) maximum electricity price (WtP) to operate methanation and resulting operation hours, (b) additional SNG production and avoided CO_2 emissions and (c) NPV of the system (lifetime 20 y, discount rate 8%) and actual average purchased electricity price. Ranges consider possible variations of system efficiency.

In Figure 8b, the corresponding additional SNG production with respect to the base upgraded biomethane and the avoided CO_2 (i.e., avoided emission from substituted natural gas) are depicted. As it can be observed, the trend is similar to the operating hours, with a stronger influence of system efficiency and a saturation of the system above 140 €/MWh. In the case of high energy market prices, the system is operated for a reduced number of hours and never saturates its production possibilities.

In addition to the analysis of the operation, the revenues from the plant have to pay back also the initial investment and the fixed costs. In Figure 8c, the average electricity price during the relevant hours (i.e., P2G in operation) and the resulting NPV are depicted. The NPV is positive when the gas price is above 90 €/MWh with 2019 electricity prices, which is in general a high cost for this commodity, but anyway comparable with actual prices in 2022. The impact of efficiency is limited. If the increased PUN is considered, the break-even point is almost the same. This is due to the small change of operating hours below 90 €/MWh that have negligible impact on the global economics. On the other hand, the strong reduction in additional gas production leads to a lower slope of the NPV curve for higher gas prices, with a 30% NPV reduction at 200 €/MWh.

Two other cases are reported in Figure 8c: NPV assuming an increase of investment cost of 50% with respect to the first estimate (Table 2) and a null cost of biogas. The first condition relates to the strong uncertainty in the purchase cost of some pieces of equipment, leading to an increase of about 20 €/MWh in break-even gas cost. Keeping the investment cost as low as possible is hence mandatory in this kind of applications, in particular if the actual operating hours remain low. The impact of the biogas cost is stronger, with a reduction of 40 €/MWh in the break-even gas cost, evidencing that this kind of solutions are economically more feasible for retrofitting (i.e., installation cost of the digester already written off) or for system with low biogas production costs (e.g., if the plant receives a fee to dispose of the inlet biomass).

5. Conclusions

This work analysed a Power-to-X application to enhance the production of SNG from biogas, converting the CO_2 content by means of a methanation system fed with green H_2 from electrolysis. The integration of high- and low-temperature electrolysis with the methanation plant allows to improve flexibility and leads to high overall efficiencies of the process with respect to the use of a single electrolysis technology. The calculated efficiency values are about 55% for the Power-to-Gas block and nearly 75% for the overall biogas and power conversion to SNG, with very limited variations in response to changes in the input power, thus appearing suitable for accommodating surplus renewable power generation.

The energy performance of the global system depends, anyway, on the actual operation and this requires an economic evaluation. Comparing the WtP with the recent-past electricity prices, the P2G system is operated when gas prices are greater than 90 €/MWh, but for a limited number of hours per year if the price remains below 140 €/MWh. On the opposite, above 140 €/MWh it is possible to operate the system steadily with a positive operational margin. If doubled electricity prices are considered with the same profile, the profitability range shrinks and gas prices above 100 €/MWh are required. From the investment profitability point of view, in the same range of operational margin (gas price above 90 €/MWh) also the installation costs are paid back (NPV>0).

In general, such integrated solution offers flexibility and high efficiency, but it requires favourable market conditions for profitability, as low-price or abundant electricity, high-price or scarce gas availability, and inexpensive biogas supply. This does not correspond with the current scenario, but it might occur in the coming years. Further assessments will investigate different system configurations, flexibility elements, and market conditions.

References

[1] B. Rego de Vasconcelos and J. M. Lavoie, “Recent advances in power-to-X technology for the production of fuels and chemicals,” *Frontiers in Chemistry*, vol. 7, p. 392, 2019, doi: 10.3389/fchem.2019.00392.

[2] Gestore Servizi Energetici (GSE), “Incentivi - Biometano.” https://www.gse.it/servizi-per-te/rinnovabili-per-i-trasporti/biometano/incentivi (accessed May 18, 2022).

[3] Gestore Servizi Energetici (GSE), “Garanzia d’origine.” https://www.gse.it/servizi-per-te/fonti-rinnovabili/garanzia-dorigine (accessed May 18, 2022).

[4] Automobile Club d’Italia (ACI), “Annuario statistico.” http://www.aci.it/laci/studi-e-ricerche/dati-e-statistiche/annuario-statistico.html (accessed Aug. 13, 2018).

[5] P. Tratzi *et al.*, "Liquefied biomethane for heavy-duty transport in Italy: A well-to-wheels approach," *Transportation Research Part D: Transport and Environment*, vol. 107, p. 103288, 2022, doi: 10.1016/j.trd.2022.103288.

[6] A. Buttler and H. Spliethoff, "Current status of water electrolysis for energy storage, grid balancing and sector coupling via power-to-gas and power-to-liquids: A review," *Renewable and Sustainable Energy Reviews*, vol. 82, no. September 2017, pp. 2440–2454, 2018, doi: 10.1016/j.rser.2017.09.003.

[7] J. Mergel, M. Carmo, and D. Fritz, "Status on Technologies for Hydrogen Production by Water Electrolysis," in *Transition to Renewable Energy Systems*, D. Stolten and V. Scherer, Eds. Weinheim, Germany: Wiley-VCH Verlag GmbH & Co. KGaA, 2013, pp. 425–450.

[8] I. Vincent and D. Bessarabov, "Low cost hydrogen production by anion exchange membrane electrolysis: A review," *Renewable and Sustainable Energy Reviews*, vol. 81, no. 2, pp. 1690–1704, 2018, doi: 10.1016/j.rser.2017.05.258.

[9] K. Ghaib and F. Z. Ben-Fares, "Power-to-Methane: A state-of-the-art review," *Renewable and Sustainable Energy Reviews*, vol. 81, pp. 433–446, Jan. 2018, doi: 10.1016/J.RSER.2017.08.004.

[10] S. Rönsch *et al.*, "Review on methanation – From fundamentals to current projects," *Fuel*, vol. 166, pp. 276–296, Feb. 2016, doi: 10.1016/J.FUEL.2015.10.111.

[11] M. Thema, F. Bauer, and M. Sterner, "Power-to-Gas: Electrolysis and methanation status review," *Renewable and Sustainable Energy Reviews*, vol. 112. Elsevier Ltd, pp. 775–787, Sep. 2019, doi: 10.1016/j.rser.2019.06.030.

[12] M. Sudiro and A. Bertucco, "Synthetic Natural Gas (SNG) from Coal and Biomass: a Survey of Existing Process Technologies, Open Issues and Perspectives," *Natural Gas*, Aug. 2010, doi: 10.5772/9835.

[13] L. Barelli, G. Bidini, and G. Cinti, "Steam vs. dry reformer: Experimental study on a solid oxide fuel cell short stack," *Catalysts*, vol. 8, no. 12, pp. 1–12, 2018, doi: 10.3390/catal8120599.

[14] P. Kazempoor and R. J. Braun, "Model validation and performance analysis of regenerative solid oxide cells for energy storage applications: Reversible operation," *International Journal of Hydrogen Energy*, vol. 39, no. 11, pp. 5955–5971, Apr. 2014, doi: 10.1016/J.IJHYDENE.2014.01.186.

[15] F. Petipas, A. Brisse, and C. Bouallou, "Model-based behaviour of a high temperature electrolyser system operated at various loads," *Journal of Power Sources*, vol. 239, pp. 584–595, Oct. 2013, doi: 10.1016/J.JPOWSOUR.2013.03.027.

[16] M. De Saint Jean, P. Baurens, C. Bouallou, and K. Couturier, "Economic assessment of a power-to-substitute-natural-gas process including high-temperature steam electrolysis," *International Journal of Hydrogen Energy*, vol. 40, no. 20, pp. 6487–6500, Jun. 2015, doi: 10.1016/J.IJHYDENE.2015.03.066.

[17] G. F. Hewitt and S. J. Pugh, "Approximate Design and Costing Methods for Heat Exchangers," *http://dx.doi.org/10.1080/01457630601023229*, vol. 28, no. 2, pp. 76–86, Feb. 2011, doi: 10.1080/01457630601023229.

[18] A. T. Mayyas, M. F. Ruth, B. S. Pivovar, G. Bender, and K. B. Wipke, "Manufacturing Cost Analysis for Proton Exchange Membrane Water Electrolyzers," Aug. 2019, doi: 10.2172/1557965.

[19] M. Usman, M. Imran, Y. Yang, D. H. Lee, and B. S. Park, "Thermo-economic comparison of air-cooled and cooling tower based Organic Rankine Cycle (ORC) with R245fa and R1233zde as candidate working fluids for different geographical climate conditions," *Energy*, vol. 123, pp. 353–366, 2017, doi: 10.1016/J.ENERGY.2017.01.134.