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A techno-economic feasibility analysis of solutions to cover the thermal and electrical demands of anaerobic digesters

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ABSTRACT

The use of biogas from anaerobic digestion (AD) has been switching in recent years from electricity to biomethane (BM) production. This choice leads to a higher energy efficiency compared to the use of biogas for combined heat and power (CHP) production, but results in a higher electricity demand for the upgrading and in the necessity of a heat supply for the digesters. This study analyses possible technical solutions, such as heat pumps or wood chip boilers to cover the thermal needs of the digester and photovoltaic panels (PV) to supply electricity. Three feedstocks were considered with high (organic waste), low (livestock manure), and intermediate (sewage sludge) biochemical methane potential (BMP), resulting in different electricity and heating needs. Results show that heat pumps (HP) are an economically viable solution for medium/low BMP feedstocks, for which relative payback times are in the range 1.5–5.4 years; in these cases, a reduction of 47–83 % of greenhouse gases (GHG) emissions and of 59–68 % of non-renewable primary energy is also achieved. For high BMP feedstocks, economic benefits are possible only with low electricity cost (below 130€/MWh_{el}), and a reduction of GHG emissions is possible only using low-carbon electrical energy (below 202 $kgCO_{2eq}$/kWh).

1. Introduction

The climate change crisis requires the abandonment of fossil fuels and the transition towards a low-carbon scenario powered by renewable energy. In this context, the anaerobic digestion (AD) of organic matter deriving from agricultural waste, livestock manure, organic fraction of the municipal solid waste or wastewater sludge allows to reduce the waste volume, to mitigate the impact of greenhouse gases (GHG) emissions and to produce biogas, a clean renewable energy source that can replace conventional fuels [1,2]. The average composition of biogas is 50–70 % methane (CH_4) and 30–50 % carbon dioxide (CO_2) [3], with minor amounts of other compounds regarded as impurities to be removed through a cleaning process [4]. Today, biogas is mainly used directly in combined heat and power (CHP) plants, upgraded into biomethane after the CO_2 removal or, to a lesser extent, as an energy source for cooking and heating [5]. The AD process requires high temperatures (∼ 37 °C in the mesophilic regime, ∼ 55 °C in the thermophilic regime) to enhance the growth of the microorganisms that are responsible for the substrate degradation and biogas production. Studies have demonstrated that increasing the digester temperature from 25 °C to 37 °C can triple the biogas production [6–8]. Thus, a good digester insulation must be provided [9], and thermal energy must be supplied to keep the biodigester at this temperature, heating the incoming feedstock and constantly compensating for the thermal dispersions towards the environment [3,10]. The thermal energy is usually generated in a cogeneration unit burning part of the biogas and distributed as hot water that is either delivered directly to the biomass or circulated into a serpentine embedded in the digester [11]. Other options are the placement of the digester underground, or the use of solar thermal technologies [12–14]. Calise et al. (2021, [15]) analysed the possible use of concentration photovoltaic/thermal collectors to provide electricity and heat to an AD plant, estimating a payback time of only 3 years. On the other hand, Lombardi et al. (2020, [16]) studied the effect of different factors (climate, collectors area and thermal storage size) on the cost-effectiveness of a solar-integrated OFMSW (Organic Fraction of Municipal Solid Waste) biomethane production plant in Italy, finding that only the cheapest technology (evacuated tubular collector) ensures the achievement of a payback time below 10 years.

When 100 % of the biogas is used to produce electricity with a CHP system, the waste heat production largely exceeds the heating demand of the digesters. However, the current incentives policies are now favouring biomethane production for injection into the national gas grid

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or application in the transport sector [17] over biogas use in CHP. For example, the recent REPower EU policy plan has set a nonbinding target of 34 Gm^3/y of biomethane by 2030. Budzianowski and Budzianowska (2015, [18]) analysed the biogas use for electricity and for biomethane production, concluding that the latter is much more energy efficient and lower incentives are needed to ensure its economic sustainability. However, according to Hakawati et al. (2017, [19]), the poorer performance of CHP from biogas is mainly related to the scarce in-situ use of waste heat, which should be better exploited as it can reach temperatures up to 180 °C and hence has several potential uses in the industry. Pöschl et al. (2010, [20]) concluded that cogeneration is profitable only if the final user is located close to the plant. This result is confirmed by a study conducted on northern Italy by Patrizio et al. (2015, [21]), which highlighted the relevant limitation of AD plants generally being in remote locations. Analogously, Bywater and Kusch-Brandt (2022, [22]) stated that it is vital to balance seasonal demands, finding year-round heat uses, and to consider alternative thermal production systems such as solar thermal or biomass. The recent shift of biogas use from CHP to upgrading into biomethane implies the issue of covering the heating demand of the digester and the electricity demand of the biogas upgrading system. In addition, strategies are investigated to increase the biomethane production, such as methanation, i.e. the production of additional CH_4 through the reaction between CO_2 and H_2. The reaction can be performed on the CO_2 separated after the biogas upgrading (Ghaib and Ben-Fares, 2018 [23]) or directly in the digester (Calbry-Muzika and Schildhauer, 2020 [24]). However, methanation is hardly financially sustainable in real-scale biomethane production plants so far [25–27]. Nazari et al. (2021, [28]) analysed the possible use of waste heat from the condenser of a geothermal power plant, concluding that this would lead to a 25 % higher biomethane production in an OFMSW anaerobic digestion plant.

Different combinations have therefore been investigated so far to identify the most convenient solution in terms of costs, as the economic efficiency of a biogas plant strongly depends on the heat and electricity generation systems employed [29]. Specifically, the cost of sustainable heating techniques can be a limiting factor [10] and the heat pump (HP) integration in AD plants is addressed only in a few studies, despite its great potentialities in covering such a low-temperature heating demand [30–32]. In their review on industrial HPs in China, Zhang et al. (2016, [33]) report examples of the use of wastewater-source HPs providing heat to the wastewater sludge anaerobic digester of a wastewater treatment plant (WWTP). Aridi and Yehya (2024, [34]) analysed different heat sources for anaerobic digesters, concluding that ground source HPs are more convenient in cold climates, whereas solar thermal panels should be considered in warm climates.

The aim of this study is to provide a quantitative model to estimate the thermal and electrical needs of three AD plants, characterized by different feedstocks and equipped with a biomethane upgrading section, and to examine the different opportunities to supply the required thermal energy (cogeneration, heat pump, biogas boiler, woodchip boiler) and electrical energy (cogeneration, photovoltaic plant, electricity from grid). The paper is structured as follows. Section 2 outlines the methodology for the scenarios analysis in terms of energy demand and supply, cost-effectiveness and environmental impact, while Section 3 presents the results of the calculations and their discussion. Finally, the conclusions of the study are outdrawn in Section 4.

2. Methodology

This work presents a comparative analysis between four different scenarios for thermal and electrical energy supply in biomethane production plants and a reference scenario. Assuming that the only difference in components between one configuration and the other are the thermal and electrical energy production systems to supply the plant and the size of the upgrading unit, whereas the other plant components (anaerobic digester, feedstock pretreatment unit and auxiliaries) and several operational costs (insurance, human resources, chemicals, auxiliary energy costs [35]) are the same, the objective of this analysis is to assess the relative difference of capital expenditure (CAPEX), of operational expenditure (OPEX), and of revenues for each solution, with respect to the reference case.

Table 1
Feedstocks characteristics. Data source(s): OFMSW [42], livestock effluents [43] and wastewater sludge [44].

Feedstock	Input (t/y)	TSS (% wt.)	VS (%)	VS (% wt.)	BMP (Nm^3/t_{VS})	BMP (Nm^3/t)	CH_4 (%)
OFSMW	35,000	23.0	81.6	18.8	403.0	75.6	60.6
Livestock effluents	42,340	6.9	74.9	5.2	270.5	14.0	65.5
Wastewater sludge	167,900	10.5	70.5	7.4	352.0	26.0	67.7

Section 2.1 presents the case studies hypothesized for the analysis, i.e., three AD plants processing feedstocks with high (OFMSW), low (livestock manure), and intermediate (wastewater sludge) biomethane production potential (BMP). The livestock manure is rarely processed alone, but generally with additional feedstocks to increase biogas production such as corn and triticale. However, example of manure-only AD plants can be found in remote areas, and the phase-out of energy crops for biogas production is highly desirable to reduce the land use conflict between food and energy production [36–39].

Section 2.2 presents the calculation of the thermal demand of the plants for keeping the anaerobic digesters in mesophile conditions (37 °C) and of the electrical demand for the biogas upgrading system and, when present, for the HP. The analysis is performed on a monthly basis to account for variable climatic conditions that influence the thermal dispersions and, when considered, the photovoltaic (PV) production.

Section 2.3 introduces the reference scenario and the four alternative scenarios characterized by different energy production systems, which are described in detail in Section 2.4. In Sections 2.5 and 2.6, the methodologies for economic and environmental analysis are explained. The spreadsheets with data and calculations are available as supplementary material.

2.1. AD plant configurations and basic sizing

The organic substrates used as feedstocks are characterized by various physical and chemical characteristics, which play a crucial role in determining the AD process efficiency and yield. In particular, the BMP, i.e. the volume of biomethane (BM) per unit mass of feedstock (Nm^3/t) or of volatile solids (Nm^3/t_{VS}) [40], plays a crucial role in determining the economic profitability of the plant. Three feedstocks were considered, namely.

A. Organic Fraction of Municipal Solid Waste (OFMSW): organic residues including food waste, kitchen waste, leaves, grass clippings and yard waste. The total input is 35,000 t/y;
B. Livestock effluents: pig slurry and cattle manure. The total input is 42,340 t/y;
C. Wastewater sludge: thickened sludge from wastewater treatment plants (WWTPs). The total input is 167,900 t/y.

The characteristics of feedstocks are reported in Table 1. The OFMSW has the highest BMP, whereas the livestock effluents exhibit the lowest value, as the energetic potential of manure is reduced after early hydrolysis in the animals digestive tract [41]. The wastewater sludge considered is a thickened primary sludge and its BMP is intermediate, both considering the production per unit mass and per unit mass of volatile solids. As shown in next sections, the use of these three feedstocks leads to very different values of heating and electricity demand

Table 2
Net daily biogas ($v_{BG,eff}$) and biomethane ($v_{BM,eff}$) production for each AD plant.

Feedstock	$v_{BG,eff}$ (Nm^3/d)	$v_{BM,eff}$ (Nm^3/d)
OFSMW	11,932	7,130
Livestock effluents	2,574	1,662
Wastewater sludge	17,647	11,780

Table 3
Number and design of biodigesters for each AD plant.

Feedstock	HRT (d)	N° of digesters (−)	Volume of each biodigester (m^3)	Digester diameter (m)	Feedstock depth (m)
OFSMW	50	2	4,546	26	4.5
Livestock	30	2	3,650	24	3.8
WW sludge	25	6	3,650	24	4.2

per unit of biomethane produced. Indeed, low BMP feedstocks require more heat to keep mesophilic conditions (37 °C) in the digester.

The effective biogas production $v_{BG,eff}$ (Nm^3/y) from a mass flowrate of feedstock $\dot{m}_{fs}$ (t/y) with a biochemical methane potential BMP (Nm^3/t) and a methane content $CH_4\%$ (dimensionless) is described by Eq. (1):

$$v_{BG,eff} = v_{BG,th} \bullet \eta_{ad} = \dot{m}_{fs} \cdot \frac{BMP}{CH_4\%} \bullet \eta_{ad} \quad \text{Eq. 1}$$

Where $v_{BG,th}$ (Nm^3/y) is the theoretical biogas production and the coefficient $\eta_{ad} = 0.997$ is introduced to consider the biogas losses occurring in the digester, quantified as 0.3 % [43,45].

Further losses occur in the upgrading, so that the effective biomethane production $v_{BM,eff}$ (Nm^3/y) is computed through Eq. (2):

$$v_{BM,eff} = v_{BG,eff} \bullet CH_4\% \bullet \eta_{up} \quad \text{Eq. 2}$$

where $\eta_{up} = 0.986$ is the efficiency of the upgrading stage (i.e., 1.4 % of biomethane lost in the upgrading phase based on References [43,45,46]).

The effective biomethane production reported in Eq. (2) is calculated assuming all the biogas is upgraded into biomethane and not partially burnt in the CHP.

The resulting net daily biogas and biomethane productions are shown in Table 2.

A key parameter to determine the heating demand of the anaerobic digesters is the sizing of their volume. The digesters were hypothesized as cylindrical with a dome, with the feedstock to be stored in the cylinder and the biogas in the dome. The cylindrical parts of the digesters were therefore sized according to different values of hydraulic retention time (HRT) recommended for the feedstocks [41], and the number of digesters was constrained to be even and was calculated to have a digester volume of 3,000–5,000 m^3. The resulting volumes V_{cyl} (m^3) were calculated with the formula reported in Eq. (3):

$$V_{cyl} = v_{fs} \bullet HRT \bullet SF \quad \text{Eq. 3}$$

where v_{fs} (m^3/d) is the total daily input of feedstock and HRT (d) is the hydraulic retention time, and SF = 1.3 (−) is the safety factor [47]. The gasometer dome volume V_{dome} (m^3) is computed as the volume of a spherical sector. The total volume splits into different vessels to obtain a standard size, and results are shown in Table 3. The geometrical characteristics of the cylindrical tank and gasometer dome are required to calculate the lateral wall surface, the floor and the dome areas, responsible for the heat losses towards the outside.

2.2. Energy demand

2.2.1. Heat demand

The thermal energy Q_{tot} (MWh_{th}/y) required to keep the digester at constant temperature is the sum along a year of the heat for the feedstock pre-heating Q_{ph} (MWh_{th}/month), and the heat for compensating the thermal losses through the digester surface Q_{loss} (MWh_{th}/month), computed for each month [48]. The heat needed for preheating the feedstock was calculated with Eq. (4):

$$Q_{ph} = 10^{-6} \bullet \dot{m}_{f,month} \bullet c_p \bullet \left(T_{dig} - T_f\right) \quad \text{Eq. 4}$$

where $\dot{m}_{f,m}$ (kg/month) is the feedstock mass flowrate per month, c_p (J/kg/K) is the specific heat of the feedstock, T_{dig} (K) is the digester mesophilic operational temperature, equal to 37 °C, and T_f (K) is the temperature at which the feedstock is encountered, which was considered as an average temperature of 15 °C. The specific heat of the feedstocks was approximated as equal to the value of water (c_p = 4,186 J/kg/K) due to their elevated water content.

The heat needed to compensate the thermal losses from the digester was calculated with Eq. (5):

$$Q_{loss} = h_{month} \bullet 10^{-6} \bullet \left[\left(A_{floor} \bullet U_{floor}\right) + \left(A_{walls} \bullet U_{walls}\right) + \left(A_{dome} \bullet U_{dome}\right)\right] \bullet \left(T_{dig} - T_{air}\right) \quad \text{Eq. 5}$$

where h_{month} (h) are the number of hours in the month, A_{floor}, A_{walls} and A_{dome} are the areas of biodigester floor, walls and dome, $U_{floor} = 0.465$ $W/m^2/K$, $U_{walls} = 0.320$ $W/m^2/K$ and $U_{dome} = 1$ $W/m^2/K$ are the transmittances of the floor, the lateral surface and the roof of the digester, and T_{air} (K) is the monthly average external temperature [43]. The heating requirement does not depend on the biogas utilization in subsequent stages. On the other hand, the thermal power to be installed depends on the operational hours hypothesized for the different components.

2.2.2. Electricity demand

The electricity demand is composed of three main items that are hereby described, namely biogas upgrading, substrate mixing and the HP, if any.

The electricity demand for biogas upgrading $E_{el,upgrading}$ (MWh_{el}/y) was calculated with Eq. (6).

$$E_{el,upgrading} = 10^{-3} \bullet v_{BG,up} \bullet E_{el,specific} \quad \text{Eq. 6}$$

where $E_{el,specific}$ (kWh_{el}/Nm^3_{BG}) is the specific electrical energy consumption for biogas upgrading to biomethane, equal to 0.3 kWh_{el}/Nm^3_{BG} [43,45], whereas $v_{BG,up}$ (Nm^3_{BG}/y) is the volumetric flow rate of biogas sent to upgrading. The electrical power absorbed by the upgrading system depends on the operational hours, which were set to 8,160 h/a. The electrical demand for mixing was neglected in the comparative analysis as it is the same for all the scenarios. If the digester heating is provided by a groundwater HP, its electricity demand $E_{el,HP}$ (MWh_{el}/y) is calculated with Eq. (7):

$$E_{el,HP} = \frac{Q_{th,HP}}{COP_{real}} \quad \text{Eq. 7}$$

where $Q_{th,HP}$ (kWh_{th}/y) is the thermal demand covered by the HP and the effective coefficient of performance (COP_{real}) is calculated as 50 % of the theoretical reverse Carnot cycle value (Eq. (8), see Refs. [49,50]):

$$COP_{real} = 0.5 \cdot COP_{Carnot} = 0.5 \cdot \frac{273.15 + T_{dig}}{T_{dig} - T_{gw}} \quad \text{Eq. 8}$$

where T_{gw} (K) is the groundwater temperature, which is considered as constant along the year. Considering T_{gw} = 15 °C, the resulting COP value is 7.05.

2.3. Scenarios for heat and electricity supply

Biogas can either be used for biomethane production or be burnt in the cogeneration plant. The proposed analysis compares for each plant a reference case (0) with four possible scenarios (1–4) of thermal and electrical energy on-site generation (or purchase) from an economic, energetic and environmental point of view.

(1) all the electricity is produced by the cogeneration plant, sized to provide 100 % of the electricity demand. The possible thermal needs not covered by the cogeneration plant are covered by a biogas boiler.
(2) all the heat is produced by a groundwater heat pump and the total electricity required is purchased from the electrical national grid.
(3) all the heat is produced by a groundwater heat pump and the total electricity required is partly provided by self-consumption from the photovoltaic plant and partly purchased from the electrical national grid.
(4) all the electrical energy demand is covered by the cogeneration plant, sized to provide 100 % of the electricity demand. If thermal needs exceed the waste heat production of the cogeneration unit, the remainder is covered by a groundwater heat pump supplied by electricity produced by the cogeneration plant.
(5) all the electrical energy is produced by the cogeneration plant, sized to provide 100 % of the electricity demand. If thermal needs exceed the waste heat production of the cogeneration unit, the remainder is covered by a biomass boiler fed by wood chips.

In scenarios 1 and 2, all the biogas is upgraded into biomethane instead of being partially used by a CHP unit, as the heat demand is entirely covered by the heat pump. This configuration, which is not foreseen in existing plants, was included on purpose in the analysis to evaluate its economic feasibility and energetic and environmental benefits.

2.4. Energy supply

2.4.1. Heat supply

The heat pump of scenarios 1 and 2 is supposed to provide the whole thermal request, with a capacity factor of 93 %, i.e., working 8,160 h per year. The cogeneration plant in scenarios 0, 3 and 4 covers part of the heating demand with its waste heat (assumed as 50 % of the energy provided by biogas) and the remainder is covered by a biogas boiler (base scenario, 0), a heat pump (scenario 3) or a woodchip boiler (scenario 4). The biogas boiler and the woodchip boiler used respectively in scenarios 0 and 4 have both a capacity factor of 92 % and a thermal efficiency of 95 %.

2.4.2. Electricity supply

Electricity is either bought from the national electrical grid, assuming a typical cost of 200 €/MWh$_{el}$ for non-household consumers in Italy, or partially produced by a photovoltaic plant, or completely supplied by the cogeneration plant. In scenario 2, which includes solar PV production, the PV systems of each configuration were sized equal to the peak power absorbed by the upgrading system, thus avoiding the delivery of excess electricity production to the grid. Therefore, the power of PV systems was set equal to the sum of the nominal power absorbed by the upgrading system and the share of the heat pump power used to preheat the feedstock: this choice is motivated by the fact that these two loads are constant, whereas heat losses vary through seasons. Assuming an electrical efficiency of 40 %, the cogenerator is sized to cover 100 % of the electrical energy consumption burning a share of the produced biogas. As the biomethane output is reduced, the electricity consumption for the upgrading phase is lower: in scenarios 0 and 3, therefore, an iterative process was performed to compute the share of biogas consumed by the CHP unit.

Table 4
Unit costs assumed to calculate CAPEX and OPEX of the biomethane production plants.

	CAPEX	OPEX
Upgrading unit	$\frac{C_{membrane} \bullet v_{BG,up}}{h_{upgrading}}$ (€) $C_{membrane} = 4800$ (€ $/m^3_{BG}/h$) [51]	0.02·$CAPEX$ [43]
CHP	$C_{CHP} \bullet P_{el,CHP}$ (€) $C_{CHP} = 1800$ (€ $/kW_{el}$) [52]	0.1277·$CAPEX$ [52]
Biogas boiler	$C_{boiler} \bullet P_{th,boiler}$ (€) $C_{boiler} = 270$ (€ $/kW$)	0.063·$CAPEX$ [53]
HP	$(2982 \bullet P_{th,HP}{}^{0.6094}) + C_{wells}$ (€) [54] $C_{wells} = 50000$ €	$(0.01 \cdot CAPEX) + 3€/MWh_{th}$ [54]
PV plant	1200 €$/kW_{el}$ [55]	0.00833·$CAPEX$ [56]
Grid electricity	–	200 €$/MWh_{el}$ [57]
Woodchip boiler	$C_{boiler} \bullet P_{th,boiler}$ (€) $C_{boiler} = 300$ (€ $/kW$) [58]	0.02·$CAPEX$ [58] 146 €$/t_{woodchip}$

2.5. Economic analysis

The investment costs related to the energy infrastructure comprise the upgrading plant, the biogas boiler, the heat pump, the photovoltaic plant, the cogeneration unit, and the woodchip boiler. The operational expenditure includes maintenance costs for each installed equipment, and purchase cost of electricity from the national grid (scenario 1 and 2) and woodchips (scenario 4). The unit costs assumed for the economic assessment, mostly dependent on the equipment installed power P (kW), are shown in Table 4.

Biogas production plants can be incentivized with feed-in tariffs for the electricity and the biomethane delivered to the grid, with different incentive schemes. In this study, the Interministerial Decree of March 2, 2018 for biomethane production was considered [59] and, summing the incentive (375€ per CIC - Certificate of Injection in Consumption, where 1 CIC = 583 Nm^3) and a cautious estimate of the market price, a total sale price of 0.70 €/Nm^3 can be assumed. The tool used for quantifying the convenience of a scenario with respect to the reference case consists in the calculation of a relative payback time, PBT$_{rel}$ (y), as expressed in Eq. (9).

$$PBT_{rel} = \frac{CAPEX_n - CAPEX_0}{Profit_n - Profit_0} \qquad \text{Eq. 9}$$

where CAPEX$_n$ (€) is the capital investment for scenario n, with n = 1, … 4, CAPEX$_0$ (€) is the capital investment of the reference scenario, Profit$_n$ (€/y) is the annual profit of scenario n and Profit$_0$ (€/y) is the annual profit of the reference scenario. The cost items considered in the analysis are listed in Table 4.

2.6. Assessment of energetic and environmental benefits

The energetic and environmental impact of the investigated choices for heat and electricity supply of biomethane production plants was assessed, in terms of primary energy (PE) consumption and greenhouse gas (GHG) emissions, in comparison to the standard option (scenario 0).

2.6.1. Primary energy consumption

Renewable and non-renewable PE consumption is used as a metric for comparing scenarios supplied by different energy sources, as it gives a comprehensive measure of the total energy extracted from natural sources and exploited within a given system after the conversion into a useable form through different energy carriers [60]. The Primary Energy Factor (PEF) determines how much PE is consumed to produce a unit of electricity or a unit of heat and it is split into the non-renewable share factor $f_{P,nren}$ and the renewable share factor $f_{P,ren}$. As the plants hypothesized have different sizes, the metric used for comparison is the

Table 5
Non-renewable and renewable PEFs for thermal and electrical energy production.

	$f_{P,nren}$	$f_{P,ren}$	PEF
Electricity from CHP	0.198	0.494	0.691
Heat from CHP	0.247	0.617	0.864
Heat from biogas boiler [61]	0.400	1.000	1.400
Electricity from grid [62]	1.390	0.300	1.690
Electricity from PV [63]	0.230	1.020	1.250
Heat from woodchip boiler [61]	0.200	1.000	1.200

specific energy consumption (kWh/Nm^3_{bioCH4}) attributable to electricity and heat production in CHP unit, heat production in biogas and biomass boiler, electricity absorption from the grid and production by the PV modules, calculated for each AD plant and each scenario. The values obtained were multiplied for the PEFs found in the literature for each energy source (Table 5) and summed to obtain the total specific PE consumption of each scenario, focusing on the share of non-renewable PE. The PEF related to the CHP was computed considering that 1 kWh of biogas can release 0.9 kWh of energy (0.5 kWh of electricity and 0.4 kWh of heat), and that 1 kWh of biogas accounts for 0.4 kWh of non-renewable PE and 1 kWh of renewable PE [61].

2.6.2. GHG emissions

In reference to the GHG emissions, the alternative solutions envisaged in scenarios 1–4 result in a variation compared to scenario 0, which is due to the use of electricity from the grid (scenarios 1 and 2), life cycle GHG emissions for photovoltaic panels (scenario 2), and to the use of wood chips (scenario 4). All scenarios imply an increase in biomethane production, which results in avoided emissions (fossil gas replacement) and increased emissions (methane leakage in the upgrading). The balance between avoided and additional emissions provides an evaluation of environmental benefits of each scenario.

For the replacement of fossil gas, an emission factor of 201.96 $kgCO_{2,eq}/MWh_{th}$ was used [64]. Considering a lower heating value of biomethane equal to LHV = 9.64 kWh_{th}/Nm^3 [5], this leads to an avoided emission of 1.95 $kgCO_{2,eq}$ per every Nm^3 of additional biomethane production. On the other hand, processing more biogas to produce biomethane results in additional methane losses. A cautious estimate of such leaks was made, i.e., 1.4 % of biogas processed. This means that a loss of 0.0142 Nm^3 of methane occurs per every Nm^3 of biomethane produced. Considering the density of biomethane (0.715 kg/Nm^3) and its global warming potential (GWP = 82.5 over a time horizon of 20 years [65]), it turns out that the emissions due to methane leaks are equal to 0.84 $kgCO_{2,eq}/Nm^3$.

The electricity produced in Italy has an emission factor of 297 $kgCO_{2,eq}/MWh_{el}$ according to the European Environment Agency [66]. The production of PV panels in China has a carbon footprint of 810 $kgCO_{2,eq}/kW$ according to Reichel et al. (2022, [67]). Therefore, with the load factor hypothesized (1,200 h/y) and cautiously considering a 20 years lifetime [22], the emission factor of electricity from PV panels is of 34 $kgCO_{2,eq}/MWh_{el}$, i.e., one order of magnitude lower than the electricity from the grid.

Finally, the GHG emission factor of a wood chip boiler was assumed to be 31.23 $kgCO_{2,eq}/MWh_{th}$ (Casasso et al., 2019, [58]).

3. Results and discussion

This chapter reports the numerical and graphical results for the energy demand and supply (Section 3.1), for the economic analysis (Section 3.2) and for the environmental benefits assessment (Section 3.3) of the three biomethane plants in the reference scenario and in the four analysed scenarios.

3.1. Energy demand and supply of the biomethane plants

The heat demand for feedstock preheating and digester losses compensation is the same in each scenario and equal to 1337.7 MWh_{th}/y, 1462.4 MWh_{th}/y and 5543.7 MWh_{th}/y for feedstocks (a), (b) and (c), respectively. Electricity demand is constant for scenarios 1 and 2, where all the biogas is upgraded to biomethane, while it changes in the other scenarios according to the share of biogas burnt into the CHP, and it is reported in Table 6. With respect to the reference scenario, the electricity demand in the scenarios 1 and 2 grows by 30 %, 162 % and 79 % for OFMSW, livestock effluents and wastewater sludge treatment plants, respectively.

The heat and electricity supply strategy for the three plants are reported in Table 7, showing the allocation of energy production among the foreseen components in every scenario. Not surprisingly it turns out that, for high-BMP feedstocks, the CHP designed to cover the electrical need provides for most of the heat demand; on the other hand, for low-BMP feedstocks, there is a considerable share of heat demand not covered by the CHP that requires a significant auxiliary installed power (either HP or boilers).

The evidence from these results implies that the convenience of a scenario compared to others depends on several factors, amongst which the thermal and electrical needs of the feedstocks (which, in turn, depend on its BMP) and the investment and operational costs for the components of the different plants set-ups. Considering the biomethane production, the OFMSW plant requires 0.514 kWh_{th}/Nm^3_{BM}, the livestock effluents plant requires 2.411 kWh_{th}/Nm^3_{BM} and the wastewater sludge plant requires 1.289 kWh_{th}/Nm^3_{BM}. These results confirm that higher BMP feedstock have lower heat requirements per unit of biomethane produced.

In the conventional configurations of biomethane plants including a cogenerator, an analysis can be performed on the optimal share of heating and electrical needs to be covered by CHP. For example, Caposciutti et al. (2020, [68]) found that using 36 % of biogas for CHP was the optimal solution for a wastewater sludge AD plant. This value minimized the overall CO_2 emissions compared to lower shares of biogas burnt in the CHP because, despite a higher biomethane production, a higher need for energy from the grid would have been reported. However, our study assumes that the share of biogas burnt in scenarios including CHP is set to cover 100 % of the electricity demand, and contextually scenarios relying on the HP consider that 100 % of biogas is upgraded. Biogas use in the biomethane production plants across scenarios 0–4 is reported in Table 8.

3.2. Economic analysis

3.2.1. Payback times of scenarios 1-4

The relative payback time (PBT_{rel}) of each alternative scenario was computed for the three biomethane production plants. To understand the meaning of this indicator expressed by Eq. (9), it is necessary to

Table 6
Electricity demand for OFMSW (a), livestock effluents (b) and wastewater sludge (c) treatment plants in scenarios 0–4 (MWhel/y).

	Scenario (0)			Scenarios (1) and (2)			Scenario (3)			Scenario (4)		
	(a)	(b)	(c)	(a)	(b)	(c)	(a)	(b)	(c)	(a)	(b)	(c)
Electricity demand	1,016.1	172.5	1,377.2	1,322.1	451.7	2,461.1	1,026.0	352.8	1,927.4	1,019.0	221.5	1,523.0

Table 7
Heat and electricity supply for OFMSW (a), livestock effluents (b) and wastewater sludge (c) treatment plants in scenarios 0–4 (MWh/y).

	Scenario (0)			Scenario (1)			Scenario (2)			Scenario (3)			Scenario (4)		
	(a)	(b)	(c)	(a)	(b)	(c)	(a)	(b)	(c)	(a)	(b)	(c)	(a)	(b)	(c)
Heat from CHP	1,270.2	215.6	1,721.5	–	–	–	–	–	–	1,282.5	441.1	2,409.2	1,273.7	276.8	1,903.7
Electricity from CHP	1,016.1	172.5	1,377.2	–	–	–	–	–	–	1,026.0	352.8	1,927.4	1,019.0	221.5	1,523.0
Heat from BG boiler	67.5	1,246.9	3,822.2	–	–	–	–	–	–	–	–	–	–	–	–
Heat from HP	–	–	–	1,337.7	1,462.4	5,543.7	1,337.7	1,462.4	5,543.7	55.2	1,021.4	3,134.5	–	–	–
Electricity from PV	–	–	–	–	–	–	371.2	242.7	1,092.6	–	–	–	–	–	–
Heat from woodchip boiler	–	–	–	–	–	–	–	–	–	–	–	–	64.0	1,185.6	3,640.0

highlight how for scenarios 1 to 4, the capital expenditure is always higher than in scenario 0. Therefore, if the alternative solution proposed results in a reduction of profits instead of the expected increment, Eq. (9) returns a negative PBT value, and the investment is never paid back. On the contrary, when the PBT calculated with Eq. (9) is positive, its value must be compared with the plant life.

Based on results reported in Table 9, general considerations can be made linking the type of feedstock processed by the plant and the suitability of new scenarios. With reference to the plant treating OFMSW, scenario 1 has a negative PBT and hence the extra investment is never paid back, whereas scenarios 2 and 3 have unviable (yet positive) PBT values. Scenario 4, on the contrary, is viable: the relatively small additional expense for a woodchip boiler ensures a slightly higher biomethane production since biogas is no more burnt in the backup boiler. Alternative configurations are always feasible for the plant treating animal manure: in fact, the main issue of the conventional solution of scenario 0 is that a noticeable share (22.1 %) of biogas is burnt by the auxiliary boiler to cover the heating needs, plus another 7.3 % used by the CHP system, with a strong impact on the final biomethane production. Replacing the biogas boiler with a heat pump (possibly coupled with PV) or a woodchip boiler leads to a much higher biomethane production. Similar results are observed, to a lesser extent, for the wastewater sludge AD plant, which has an intermediate BMP value.

3.2.2. Impact of grid electricity cost (scenarios 1–2)

A sensitivity analysis was performed to evaluate how the grid electricity cost impacts the comparison between scenarios including electricity purchase from the grid, namely scenarios 1 and 2. According to data referred to the first semester of 2023 as provided by Eurostat [69], the electricity price in European countries varies significantly depending on the energy production mix and on the internal market dynamics. The average electricity price for non-household consumers in Italy is 200 €/MWh, while it is lower in countries showing a large deployment of hydropower, and higher in countries where gas-fired plants are predominant. A range of electricity prices between 95 €/MWh_{el} and 300 €/MWh_{el}, corresponding to typical tariffs in Finland and Hungary respectively, was considered for the sensitivity analysis. Looking at the OFMSW plant, scenarios 1 and 2 become profitable for an electricity cost up to ~130 €/MWh_{el} and ~145 €/MWh_{el}, respectively. Analysing outcomes for the livestock effluents and for the wastewater sludge treatment plants, scenario 1 is viable until the electricity cost reaches a value of ~250 €/MWh_{el} and ~200 €/MWh_{el}, respectively, while scenario 2 appears always feasible for both plants. Scenarios 3 and 4 remain unaltered as the electricity demand is totally self-produced by the CHP. Fig. 1 shows results for scenario 1 and Fig. 2 for scenario 2.

3.2.3. Impact of woodchip cost (scenario 4)

Another sensitivity analysis was performed to evaluate how the unit cost of woodchips impacts the profitability of scenario 4. As a default cost, a precautionary value of 146 €/t was considered, although prices as low as 63 €/t were found performing a market survey. Therefore, a range of prices between 63 €/t and 300 €/t was considered. A very high upper limit for woodchip cost was chosen in this analysis to understand if a sudden price increase of this commodity can jeopardize the economic sustainability of this technical solution. Results show in Fig. 3 highlight that, for a woodchip cost exceeding 220 €/t, a steep increase in PBT is observed and this solution proves not economically convenient compared to the default configuration of scenario 0.

3.3. Energetic and environmental benefits

3.3.1. Primary energy consumption

As shown in Fig. 4, the analysis on the specific primary energy consumption reveals that scenarios including the heat pump are the most convenient solutions with respect to the reference scenario for the low and medium BMP feedstocks: indeed, for scenarios 1, 2 and 3 there

Table 8
Biogas uses in the biomethane production plants in scenarios 0–4 (%) for OFMSW (a), livestock effluents (b), and wastewater sludge (c).

	Scenario (0)			Scenarios (1) and (2)			Scenario (3)			Scenario (4)		
	(a)	(b)	(c)	(a)	(b)	(c)	(a)	(b)	(c)	(a)	(b)	(c)
CHP	10.0	7.3	8.2	0	0	0	10.1	14.9	11.5	10.0	9.3	9.1
Biogas boiler	0.3	22.1	9.6	0	0	0	–	–	–	–	–	–
Upgrading unit	89.7	70.6	82.2	100	100	100	89.9	85.1	88.5	90.0	90.7	90.9

Table 9
Relative PBT for each plant in the alternative scenarios (1–4) with respect to the reference case (0).

PBT_{rel} (y)	OFMSW	Livestock Effluents	Wastewater sludge
Scenario 1	−2.7 (no payback)	3.6	5.4
Scenario 2	245.9 (unviable)	4.2	4.8
Scenario 3	25.9 (unviable)	1.7	1.5
Scenario 4	4.0	3.6	3.5

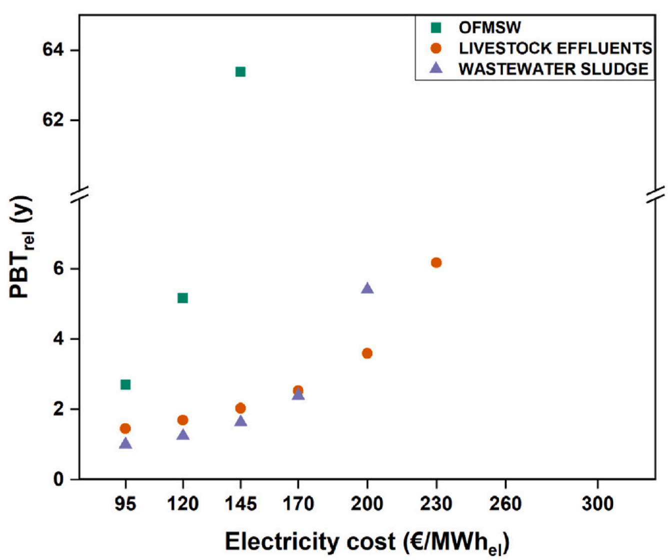

Fig. 1. Relative PBT with variable electricity cost in scenario 1 (HP), with respect to scenario 0, for the three plants.

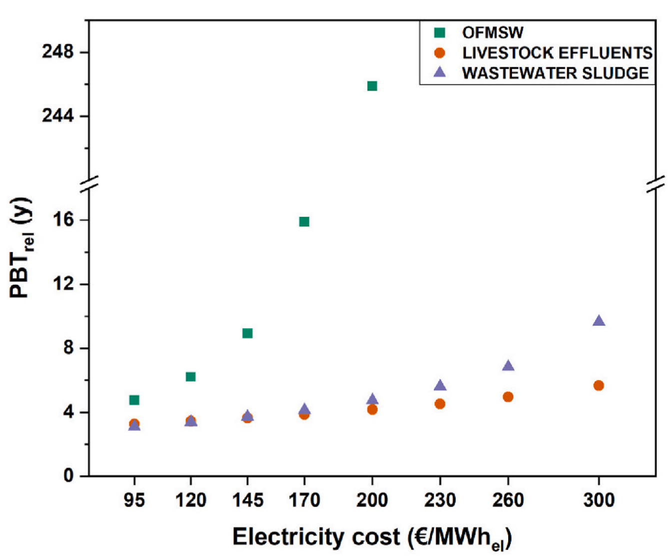

Fig. 2. Relative PBT with variable electricity cost in scenario 2 (HP + PV), with respect to scenario 0, for the three plants.

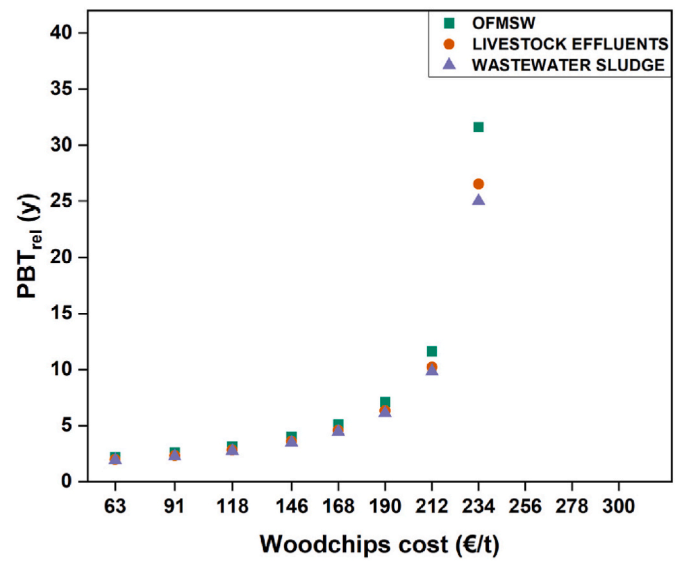

Fig. 3. Relative PBT with variable woodchips cost in scenario 4 (CHP + woodchip boiler), with respect to scenario 0, for the three plants.

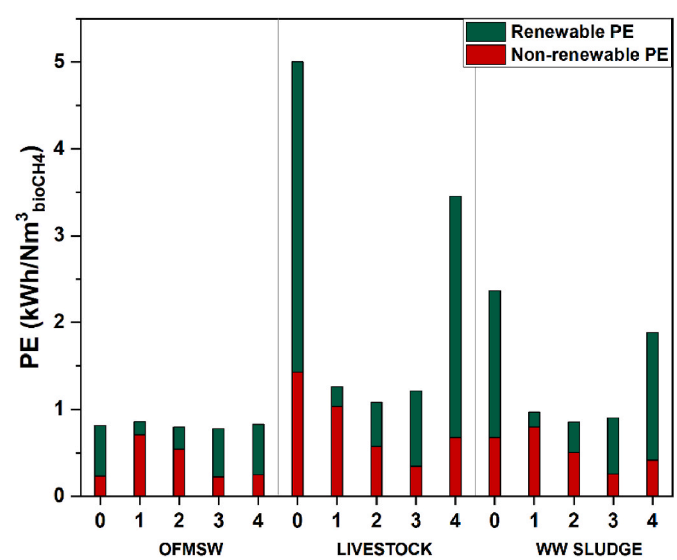

Fig. 4. Specific PE consumption (renewable and non-renewable) in every scenario (0–4) for each one of the three plants.

is a respective reduction in PE consumption of 75 %, 78 % and 76 % for livestock effluents and of 59 %, 64 % and 62 % for wastewater sludge. Scenario 4 leads to a more moderate reduction, equal to 31 % and 21 % for the two feedstocks. On the other hand, for high-BMP feedstock such as OFMSW, there is an increase of 6 % in PE consumption in scenario 1, and a reduction of 2 %, 5 % and 1 % in scenarios 2, 3 and 4, respectively.

Focusing on non-renewable primary energy (red columns in Fig. 4) it turns out that, for the OFMSW treatment plant, scenarios 1 and 2 lead to

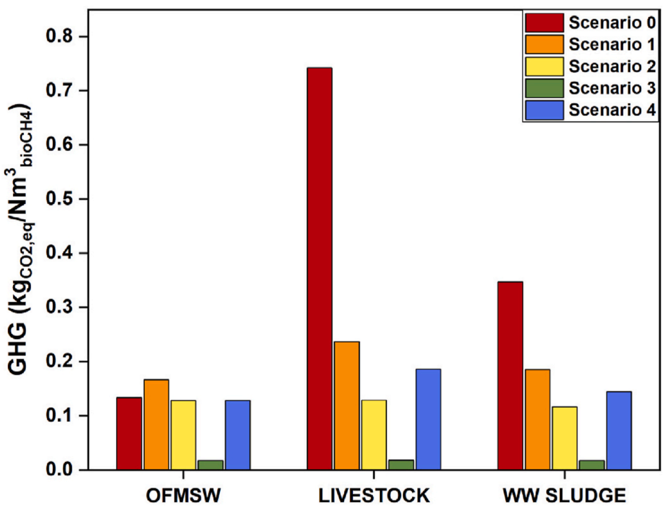

Fig. 5. GHG emissions in every scenario (0–4) for each one of the three plants.

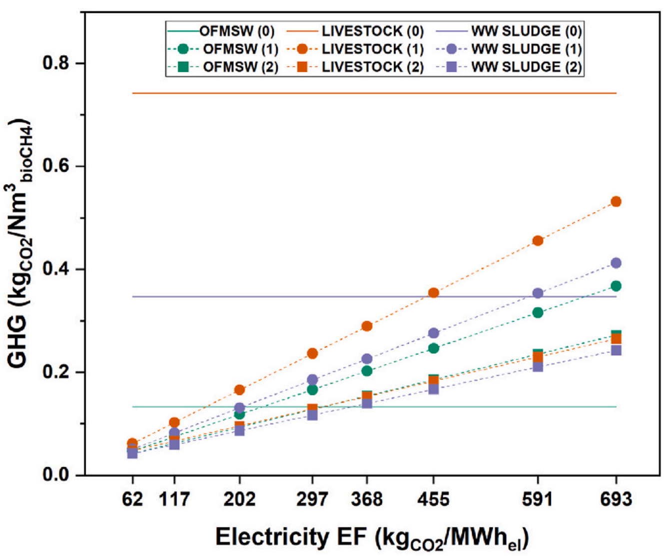

Fig. 6. Comparison of GHG emissions for scenarios 0, 1 and 2 with variable electricity EF.

an increase of consumption of 204 % and 133 % respectively, whereas slight variations are observed for scenario 3 (−5%) and scenario 4 (+6 %). On the other hand, for the animal manure treatment plant, configurations 1 to 4 lead to a reduction equal to 28 %, 60 %, 76 % and 53 %, respectively. Intermediate results are observed for the sewage sludge treatment plant, for which scenario 1 leads to +18 % non-renewable primary energy consumed, while the other scenarios produce a decrease of 26 % (scenario 2), 62 % (scenario 3) and 39 % (scenario 4). Broadly speaking, scenario 1 (HP without PV) shows a minor benefit in non-renewable primary energy savings compared to scenario 2 (HP with PV), due to the fossil share of grid electricity.

3.3.2. GHG emissions

Results on the climate-altering gases emissions, illustrated in Fig. 5, revealed that scenario 1 shows lower GHG emissions only for plants supplied with livestock effluents (−68 %) or wastewater sludge (−47 %), while higher values are recorded for the OFMSW plants (+25 %) where heating is provided by a heat pump supplied with grid electricity. On the other hand, scenario 2 reduces GHG emissions for every plant since a share of the electricity needs is covered by a PV plant (−4% for OFMSW, −83 % for livestock, −66 % for sludge); scenario 3 has the lowest GHG emissions (compared to scenario 0: 87 % for OFMSW, −98 % for livestock, −95 % for sludge) thanks to the use of both CHP and HP, with no electricity absorbed from the grid; scenario 4 provides benefits similar to scenario 2 (−4% for OFMSW, −75 % for livestock, −58 % for sludge), as the use of woodchip instead of biogas as a fuel for the auxiliary boiler leads to lower overall GHG emissions [70].

3.3.3. Impact of the electricity grid GHG emission factor

Since the reason for high GHG emissions in scenarios 1 and 2 is the electricity emission factor of the grid, a sensitivity analysis was performed considering typical electricity emission factors for European countries in 2022, in a range from 62 kg$_{CO2}$/MWh$_{el}$ (Finland) to 693 kg$_{CO2}$/MWh$_{el}$ (Estonia) [66]. Results are reported in Fig. 6 and show how alternative scenarios are more environmentally sustainable for the livestock plant for any electricity EF, while for the wastewater sludge plant for electricity EFs up to ~591 kg$_{CO2,eq}$/MWh$_{el}$ in scenario 1 and for any electricity EF in scenario 2. In the case of the OFMSW plant, scenario 1 is environmentally beneficial only for electricity EFs below ~230 kg$_{CO2,eq}$/MWh$_{el}$, scenario 2 only for EFs below ~310 kg$_{CO2,eq}$/MWh$_{el}$.

The results of the analyses on GHG emissions and primary energy demand are similar to the findings of Ardolino et al. (2018, [71]), who performed an LCA on different possible uses of biogas from OFMSW. Indeed, they found that converting biogas into biomethane has a strong benefit both in terms of GHG emissions (up to 79 % reduction) and of non-renewable energy demand (up to −36 %) compared to the use for electricity production with a CHP system. Other studies reveal that the use of PV systems can significantly reduce the GHG emissions in livestock farms (Jahangir et al., 2022, [72]) and in wastewater treatment plants (Milani and Nabi Bidhendi, 2024, [73]).

4. Conclusions

The process of anaerobic digestion to produce biogas followed by the upgrading to biomethane requires high amounts of thermal energy for the fulfilment of the mesophilic conditions and of electrical energy for the upgrading phase. The shift towards the incentivization of biomethane rather than electricity production generates a considerable interest in the evaluation of new scenarios to provide heat and electricity to the anaerobic digestion plant and the biogas upgrading system. Four supply scenarios are explored in this paper to understand the economic profitability and environmental impact of diversified combinations of energy generation systems, with respect to a base configuration (biogas CHP coupled with auxiliary biogas boiler), applied to three biomethane production plants fed by feedstocks characterized by low, medium and high biochemical methane potential. Scenarios 1 and 2 include a HP to satisfy the heat demand of the plant, while electricity is entirely purchased from the grid or partially produced by a PV plant. Scenarios 3 and 4 include a biogas CHP to cover the electricity requirements of the plant, while the possibly extra heat demand is supplied by an auxiliary HP or woodchip boiler, respectively. It is straightforward that scenarios including the CHP (3 and 4) show a lower biomethane production compared to the others, but they benefit from internal production of electricity and heat. On the other hand, HP-based scenarios (1 and 2) have a higher biomethane production (+10.3 % for OFMSW, +29.4 % for livestock effluents, +17.8 % for sludge), though entailing higher electricity consumption (+30 % for OFMSW, +162 % for livestock effluents, +79 % for sludge). Results of this study show that heat pumps are a viable and sustainable solution in contexts exhibiting low and medium BMP feedstock, low electricity cost and, considering GHG emissions, low CO_2-emission factor of the electricity grid.

Examining the environmental impact, the specific primary energy consumption does not change significantly for the OFMSW processing plant (−1% to +6 %), while it is noticeably reduced in every alternative scenario for livestock effluents (−31 % to −78 %) and wastewater sludge treatment plants (−21 % to −64 %). The GHG emissions are always reduced in a relevant measure in scenario 3 (−87 % to −98 %), whereas scenario 1 is the least beneficial from this point of view and, for OFMSW, it even results in higher GHG emissions (+25 %). Scenarios 2 and 4 provide a negligible benefit for OFMSW and a noticeable benefit for livestock manure (−83 % and −75 %) and, to a lesser extent, for wastewater sludge (−66 % and −58 %).

Although none of the investigated scenarios results in a remarkably higher profitability with respect to the reference case, some of them turned out to be financially feasible. In particular, it emerges how the combination of HP and PV is more profitable on the long run, as the main issue with the electrification is the electricity purchase from the grid at high costs. We can conclude that the shift towards the biomethane production opens opportunities for the deployment of heat pumps in the biomethane production plants, also considering the trends towards lower costs of this equipment and to the decarbonisation of the grid electricity, which will lead to increasingly relevant environmental and energy efficiency benefits.

CRediT authorship contribution statement

Maria Adele Taramasso: Writing – review & editing, Writing – original draft, Methodology, Data curation, Conceptualization. **Milad Motaghi:** Writing – original draft, Methodology, Data curation, Conceptualization. **Alessandro Casasso:** Writing – review & editing, Writing – original draft, Supervision, Methodology, Data curation, Conceptualization.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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Appendix A. Supplementary data

Supplementary data to this article can be found online at https://doi.org/10.1016/j.renene.2024.121485.

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List of abbreviations and symbols

AD: Anaerobic digester (or digestion)
BM: Biomethane
BMP: Biochemical Methane Potential
CAPEX: CAPital EXpenditure
CH_4: Methane
CO_2: Carbon dioxide
CHP: Combined heat and power
CIC: Certificate of Injection in Consumption
COP_{real}, COP_{Carnot}: Real and Theoretical Heat pump Coefficient Of Performance
EEA: European Environment Agency
EU: European Union
GHG: Greenhouse gas
GWP: Global Warming Potential
H_2: Hydrogen
HP: Heat Pump
HRT: Hydraulic Retention Time
IPCC: Intergovernmental Panel on Climate Change
LHV: Lower Heating Value
OFMSW: Organic Fraction of Municipal Solid Waste
OPEX: OPerational EXpenditure
PBT: Payback Time
PE: Primary Energy
PEF: Primary Energy Factor
PV: Photovoltaic
SF: Safety Factor for digester design
WWTP: Wastewater treatment plant

Nomenclature

A_{floor}, A_{dome}, A_{walls}: Areas of digester floor, dome and walls, m^2
C_{boiler}: Boiler investment cost, €/kW_{th}
C_{CHP}: CHP investment cost, €/kW_{el}
$C_{membrane}$: Membrane investment cost, €/m^3_{BG}/h
c_p: Specific heat of water, J/kg/K
C_{wells}: Geothermal wells investment cost, €
$E_{el,HP}$: Heat pump electricity consumption, MWh_{el}/y
$E_{el,specific}$: Specific electricity for upgrading, KWh_{el}/ Nm^3_{BG}
$E_{el,upgrading}$: Upgrading electricity consumption, MWh_{el}/y
$f_{P,nren}$: Non-renewable primary energy factor
$f_{P,ren}$: Renewable primary energy factor
h_{month}: Hours in a month
$h_{upgrading}$: Upgrading operational hours
$\dot{m}_{f,month}$: Feedstock monthly mass flowrate, t/y
$\dot{m}_{fs}$: Feedstock yearly mass flowrate, t/y
P: Equipment installed power, kW
$P_{el,CHP}$: CHP electrical power, kW_{el}
$P_{th,boiler}$: Boiler thermal power, kW_{th}
$P_{th,HP}$: Heat pump thermal power, kW_{th}
Q_{loss}: Thermal energy for feedstock preheating, MWh_{th}/y
Q_{ph}: Thermal energy for losses compensation, MWh_{th}/y
$Q_{th,HP}$: Heat pump thermal energy production, MWh_{th}/y
Q_{tot}: Thermal energy, MWh_{th}/y
T_{air}: Ambient air temperature, K
T_{dig}: Digester mesophilic temperature, K
T_f: Feedstock temperature, K
T_{gw}: Groundwater temperature, K
U_{floor}, U_{dome}, U_{walls}: Transmittances of digester floor, dome and walls, W/m^2/K
$v_{BG,eff}$: Effective biogas yearly production, Nm^3/y
$v_{BG,th}$: Theoretical biogas yearly production, Nm^3/y
$v_{BG,up}$: Biogas to upgrading, Nm^3/y
$v_{BM,eff}$: Effective biomethane yearly production, Nm^3/y
V_{cyl}: Volume of digester cylindrical tank, m^3
V_{dome}: Volume of digester dome for biogas storage, m^3
v_{fs}: Feedstock daily volumetric flowrate into digester, m^3/d
η_{ad}: Coefficient for biogas losses from digester
η_{up}: Efficiency of the upgrading phase