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# Life-cycle sustainability of thermochemical biogas upgrading via $CO_2$ methanation with green hydrogen

G. Sacchi [a], D. Ferrario [a], A. Agostini [b,*], C. Carbone [b], J. Bindi [b], C. Bassano [b], A. Lanzini [a]

[a] Department of Energy, Politecnico di Torino, Corso Duca degli Abruzzi 24, 10129 Turin, Italy
[b] Italian National Agency for New Technologies, Energy and the Environment, ENEA, Via Anguillarese 301, 00123 Rome, Italy

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ABSTRACT

Biomethane is expected to play an increasingly important role in the decarbonization of energy systems and the integration of renewable gases into existing infrastructures. This study investigates an innovative thermochemical pathway for biogas upgrading based on $CO_2$ methanation with renewable hydrogen, developed within the BIOMETHAVERSE project. Unlike conventional upgrading technologies based on $CO_2$ separation, the proposed approach directly converts the $CO_2$ in the biogas into biomethane, increasing biomethane yield while avoiding the energy intensive upgrading process and potential methane slip. A comprehensive assessment combining process modelling, techno-economic analysis, and environmental and social life cycle assessment is performed for three representative feedstocks: manure, biowaste, and maize. Process simulations show a $CO_2$ conversion of 98.6 % and a 67 % increase in biomethane output compared to conventional upgrading. Under current conditions, the levelized cost of biomethane (180–240 €/MWh) remains dominated by hydrogen production, which accounts for more than 50 % of total costs. Sensitivity analysis identifies a break-even electricity price of 14, 28 and 83 €/$MWh_{el}$ for manure, biowaste and maize respectively, while electrolyzer cost reductions can further decrease production costs by 10–25 %. Environmental results highlight the critical role of feedstock selection: manure and biowaste exhibit significantly lower impacts than maize, with manure achieving net negative GHG emissions. Methanation outperforms conventional upgrading when renewable electricity is used, while grid-based scenarios remain penalized by hydrogen-related emissions. Social LCA indicates that impacts are largely driven by feedstock supply chains, with additional risks associated with electricity-intensive hydrogen production. Overall, thermochemical methanation represents a promising pathway to enhance biomethane production and integrate renewable hydrogen, although its sustainability strongly depends on electricity decarbonization and feedstock choice.

## 1. Introduction

Climate change mitigation, fossil resources depletion, and increasing concerns over energy security have intensified the need to expand renewable energy systems and reduced reliance on fossil fuels [1,2]. Among renewable energy options, bioenergy from organic feedstocks represents a flexible pathway for producing renewable fuels and supporting the transition toward low-carbon energy systems [3]. Biomethane, obtained by upgrading biogas produced through anaerobic digestion (AD), is particularly relevant because its composition and properties are compatible with existing natural gas infrastructure. As a result, it can be used in established end-use sectors, including heat production, power generation, and transport [4]. In addition to energy production, biomethane systems can contribute to organic waste management, nutrient recycling, greenhouse gas emissions reduction, and, the valorisation of agricultural residues and organic wastes. These features make biomethane a relevant option within circular bioeconomy strategies and renewable gas integration pathways [5].

The policy relevance of biomethane is also reflected in the European Union's REPowerEU plan, which sets a production target of 35 billion cubic meters (bcm) per year by 2030. This target highlights the expected contribution of biomethane to renewable gas deployment, fossil fuel substitution, supply diversification, and the valorisation of domestic organic feedstock [6]. By early 2025, the installed production capacity reached approximately 7 bcm per year, distributed across 1,678

* Corresponding author.
*E-mail address:* alessandro.agostini@enea.it (A. Agostini).

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## Nomenclature

*Acronym and abbreviations*

| | |
|---|---|
| AD | Anaerobic Digestion |
| BEC | Bare Erected Cost |
| CAPEX | Capital Expenditures |
| CEPCI | Chemical Engineering Plant Cost Index |
| CHP | Combined Heat and Power |
| ETM | Ex-situ Thermochemical Methanation |
| FISIM | Financial Intermediation Services Indirectly Measured |
| GHG | Greenhouse Gas |
| GHSV | Gas Hourly Space Velocity |
| IEA | International Energy Agency |
| ILUC | Indirect Land Use Change |
| IRENA | International Renewable Energy Agency |
| LCA | Life Cycle Assessment |
| LCI | Life Cycle Inventory |
| LCOB | Levelized Cost of Biomethane |
| LHV | Lower Heating Value |
| OPEX | Operational Expenditures |
| PEMEC | Proton Exchange Membrane Electrolyzer Cell |
| TEA | Techno-Economic Analysis |
| VS | Volatile Solids |

operational plants [7]. At the global level, the technical potential for biomethane production by 2040 has been estimated to exceed 700 Mtoe, with the major contributions expected from the United States, Europe, China, Brazil, and India [8]. These estimates indicate that biomethane could represent a relevant component of future low-carbon energy systems, particularly in regions with abundant organic residues, established waste management infrastructures and increasing demand for renewable gaseous fuels [8].

Currently, biomethane is mainly produced by upgrading raw biogas which is primarily composed of $CH_4$ and $CO_2$. Conventional biogas upgrading technologies are based on the selective removal of $CO_2$ through processes such as chemical or physical scrubbing, membrane separation and cryogenic techniques [9]. As an alternative to $CO_2$ separation, methanation-based pathways exploit the Sabatier reaction, in which $CO_2$ reacts with $H_2$ to produce $CH_4$ and $H_2O$ [10–12]. Methanation can be applied to difference carbon-containing gas streams, including pure $CO_2$ from industrial sources [13], $CO_2$ separated from biogas [14], raw biogas from AD [15], or biomass-derived syngas [10–12,16,17].

Among these options, direct biogas methanation allows the $CO_2$ fraction of biogas to be converted into additional biomethane without a prior separation step. This approach can increase the biomethane yield and potentially reduce the energy demand, and methane losses associated with conventional upgrading processes [18]. However, the presence of methane in the feed affects the reaction equilibrium, and may lead to slightly lower conversion compared with pure $CO_2$ methanation. Under typical methanation pressures of 10–20 bar, this effect this effect is reported to become less pronounced [19]. Moreover, because methanation is strongly exothermic, reactor thermal management represents a critical design issue. In biogas-fed systems, the lower concentration of reactive species compared with pure $CO_2/H_2$ mixtures can

**Table 1**
Selected literature.

| Reference | | METHANATION UNIT Methodology | Catalyst | Cooling Medium | Feedstock | LCA | TEA (LCOB) |
|---|---|---|---|---|---|---|---|
| Jürgensen et al. | [19] | Kinetic Model | 0.5 % RuAl | Dowterm T | Biogas | No | No |
| Dannesboe et al. | [20] | Thermodynamic equilibrium | Ni – Al2O3 | Boiling water | Biogas | No | No |
| Aragüés-Aldea et al. | [21] | Kinetic model | Ni-Zr | Isothermal 250–400 °C | Biogas | No | No |
| Miguel et al. | [22] | Thermodynamic equilibrium | N/A | Isothermal 100–400 °C | $CO_2$ | No | No |
| Torcida et al. | [23] | Kinetic Model | Ni/Mg Al2O4 | Boiling water | Biogas | No | No |
| Hillestad et al. | [24] | Kinetic model | Ni – Al2O3 | Boiling water | Biogas | No | No |
| Canu et al. | [25] | Thermodynamic equilibrium | N/A | Isothermal ambient-800 °C | Biogas | No | No |
| Piso et al. | [27] | Kinetic Model | Ni-Al2O3 | Isothermal 300 °C | Biogas | No | *0.55 €/MWh |
| Witte et al. 2019 | [28] | Kinetic Model | Ni-Al2O3 | Isothermal 320–380 °C | Biogas | No | No |
| Witte at al. Part I Witte et al. Part II | [15,29] | Kinetic Model | Ni-Al2O3 | Thermo-oilMolten Salt | Biogas | No | 107 €/MWh |
| Giglio et al. | [30] | Kinetic Model | Ni – Al2O3 | Boiling water | Biogas from OFMSW | No | *104–398 €/MWh |
| Sanz-Monreal et al. | [31] | Kinetic Model | NiFe – Al2O3 | Boiling water | Biogas from MSW | No | 91.75 €/MWh |
| Gutiérrez-Martín et al. | [32] | Kinetic Model | 0.5 % RuAl | Boiling water | Biogas | | *51–55 €/MWh |
| Skorek-Osikowska et al. | [33] | Thermodynamic equilibrium Adiabatic | Ni – Al2O3 | Adiabatic | ManureWood Chips | Environmental | **69–93 €/MWh |
| Collet et al. | [34] | Stoichiometric | Ni – Al2O3 | N/A | Sewage Sludge | Environmental | 96–104 €/MWh |
| Silva et al. | [44] | Kinetic Model | Ni – Al2O3 | Boiling water | Biogas from WWTP | No | 50–52 €/MWh |
| Goffart De Roeck et al. | [45] | Stoichiometric | Ni – Al2O3 | Isothermal 270 °C | Biogas from Wastes | Environmental | No |
| Bidart et al. | [46] | Thermodynamic equilibrium | Not Specified | Not Specified | Biogas from manure | Environmental | No |
| Gaikward et al. | [47] | Thermodynamic equilibrium | Ni Based | XCELTHEM SST Oil | Biogas | No | No |
| Guilera et al. 2020 Guilera et al. 2021 | [48,49] | Stoichiometric | Ni Based | Boiling waterCompressed Air | Biogas from sewage sludge | Environmental | No |
| This work | | Kinetic Model | 0.5 % RuAl | Biogas | Manure MaizeBiowaste | EnvironmentalSocial | Yes |

*Conversion factor from €/$Sm^3$ to €/MWh = 94.78.
***Conversion factor from €/GJ to €/MWh = 3.6.*

moderate the heat release rate and facilitate temperature control within the catalytic bed. To date, the available literature has primarily focused on process modelling and thermodynamic analyses, typically considering adiabatic or water-cooled reactor configurations (see Table 1). [19–26]. In contrast, economic analyses of direct biogas methanation remain relatively limited. Existing studies can be broadly grouped into analyses focuses on net present value and overall financial performance [26] and studies aimed at estimating the Levelized Cost of Biomethane (LCOB), which is the main economic indicator considered in the present work. Among these, Piso et al. [27] compared LCOB between conventional upgrading and direct biogas methanation, showing that the latter generally results in higher LCOB mainly due to the costs associated with hydrogen production. Witte et al. [28] experimentally demonstrated the process in a single-stage fluidized bed, which, although it did not achieve gas grid quality, was subsequently developed into a two-stage configuration to achieve methane concentrations above 95 %.mol, resulting in production costs as low as 107 €/$MWh_{BM}$ [15,29]. Giglio et al. [30] performed a simulation of a direct biogas methanation unit integrated with a photovoltaic (PV) system, assessing the potential for surplus electricity storage and reporting LCOB values ranging from 1.1 to 4.02 €/$Sm^3$, depending on the underlying assumption. Similarly, Sanz-Monreal et al. [31] analysed a municipal solid waste biogas plant employing direct thermochemical methanation, estimating a profitability threshold for biomethane production of 91.75 €/$MWh_{BM}$. Gutierrez et al. [32] investigated the influence of biogas composition in adiabatic and water cooled reactors, reporting production costs between 0.54 and 0.58 €/$Sm^3$. Skorek-Osikowska et al. [33] and Collel et al. [34] included environmental impact assessments of direct catalytic methanation using manure and sewage sludge as feedstocks, respectively.

Life Cycle Assessment (LCA) studies, generally indicated that biofuels and biomethane can reduce greenhouse gas (GHG) emissions by 60–90 % compared to fossil fuels, depending on feedstock and process design [35,36]. Furthermore, AD of biomass may provide further environmental benefits, including lower resources and water consumption, as well as reduced eutrophication potential. However, the environmental sustainability of biogas and biomethane systems is highly dependent on feedstock selection and process design. For instance, AD of energy crops, combined with inefficient technologies and significant methane leakage may result in higher environmental impacts than fossil natural gas for some environmental impact categories [37–39].

The social dimension remains the least developed component of bioenergy sustainability assessment compared with environmental and economic analyses. Although the application of social LCA has increased in recent years, challenges persist regarding data availability, indicator selection, and result interpretation. Murphy et al. [40] recently reviewed the literature on social LCA in bioenergy, identifying 17 studies published between 2009 and 2024 that explicitly applied social LCA methodologies. The most frequently considered indicators were related to employment, working conditions, and health and safety, whereas structured stakeholder involvement was included only in a limited number of studies. However, only two studies addressed biogas or biomethane systems, and neither investigated the biomethane upgrading phase through a social LCA framework. To the best of the authors' knowledge, no peer-reviewed study has yet compared different biogas upgrading technologies in terms of life-cycle social impacts using a dedicated social LCA approach.

In addition to thermochemical methanation, biological methanation has attracted increasing interest as a low-carbon pathway for $CO_2$ conversion and biomethane production. In biological methanation, hydrogenotrophic microorganisms convert $CO_2$ and $H_2$ into $CH_4$ under mild temperature and pressure conditions, reducing the need for high-temperature reactors and metal-based catalysts. Biological systems may therefore offer advantages in terms of operating conditions, catalyst replacement, and integration with anaerobic digestion plants. However, their performance is often limited by slower reaction kinetics, gas–liquid mass transfer constraints, larger reactor volumes, and sensitivity to operating conditions such as pH, temperature, nutrient availability, and $H_2$ supply fluctuations [41,42].

While biological methanation and other power-to-gas routes represent relevant low-carbon alternatives, they are not modelled in detail in this work, which specifically aims to assess the technical, economic, environmental, and social implications of a direct thermochemical biogas methanation configuration. The proposed system is based on an innovative plant configuration consisting of three biogas-cooled fixed-bed methanation reactors for biomethane production and subsequent injection into the natural gas grid. The configuration is designed to simplify the process layout while preserving a high level of energy integration by exploiting both the exothermic nature of the Sabatier reaction and the relatively low concentration of reactive species in the biogas stream. This allows the biogas itself to be used as a cooling medium while simultaneously preheating the feed gas. A 60 kW pilot plant implementing this concept is currently under construction in Kolchiko, Lagadas, Greece [43]. This demonstrator is expected to provide experimental evidence on the technical feasibility of the proposed process configuration, thereby addressing the main limitations of the present simulation-based assessment.

The analysis covers the full biomethane production chain, considering three representative feedstocks, namely maize, biowaste, and manure, from biogas generation to methanation, gas cleaning, compression, and grid injection. For comparison, a conventional membrane-based upgrading route is also modelled as a reference case. Process modelling is complemented by a techno-economic analysis aimed at assessing economic feasibility and identifying the main cost drivers affecting biomethane production. In parallel, the environmental assessment compares the proposed pathway with conventional upgrading across key impact categories, including climate change, primary energy demand, water use, particulate matter formation, acidification, and eutrophication. Finally, a social life cycle assessment is performed to identify potential social hotspots along the supply chain across regions and social indicators.

Overall, this integrated approach contributes to the current literature by jointly assessing process performance, economic feasibility, and environmental and social sustainability, thereby clarifying the potential and limitations of direct biogas methanation as an alternative to conventional upgrading technologies.

## 2. Methods

The entire production chain, from feedstock input to biomethane output (Fig. 1), was modelled to assess its technical, economic, environmental, and social performance. The process consists of four subprocesses: (i) the biogas production unit; (ii) the hydrogen production unit; (iii) the methanation unit; iv) the cleaning and compression unit. Detailed modelling of these units was performed to evaluate process performance, costs, and life-cycle sustainability impacts. Three reference feedstocks, consistent with the Renewable Energy Directive [50] were considered: (i) maize; (ii) biowaste; and (iii) manure. These feedstocks were selected to represent a broad range of potential biomethane production pathways and differ significantly in terms of environmental profile. Manure was treated as a waste stream, with no upstream emissions allocated prior to collection and with potential credits associated with avoided methane emissions from storage. Biowaste was also modelled as a waste feedstock, but without associated credits, whereas maize was considered a conventional energy crop requiring significant agricultural inputs.

An anaerobic digester with a biogas production capacity of 535 kg/h was considered, consistent with a 1 MWe combined heat and power (CHP) plant, which represents a typical configuration for biogas valorisation [37]. A biogas composition of 60 vol% $CH_4$ and 40 vol% $CO_2$ was assumed for all feedstocks, after removal of $H_2S$ and other impurities. Hydrogen produced by a Proton Exchange Membrane Electrolyzer Cell (PEMEC) was fed to the methanation unit together with the biogas at $H_2$:

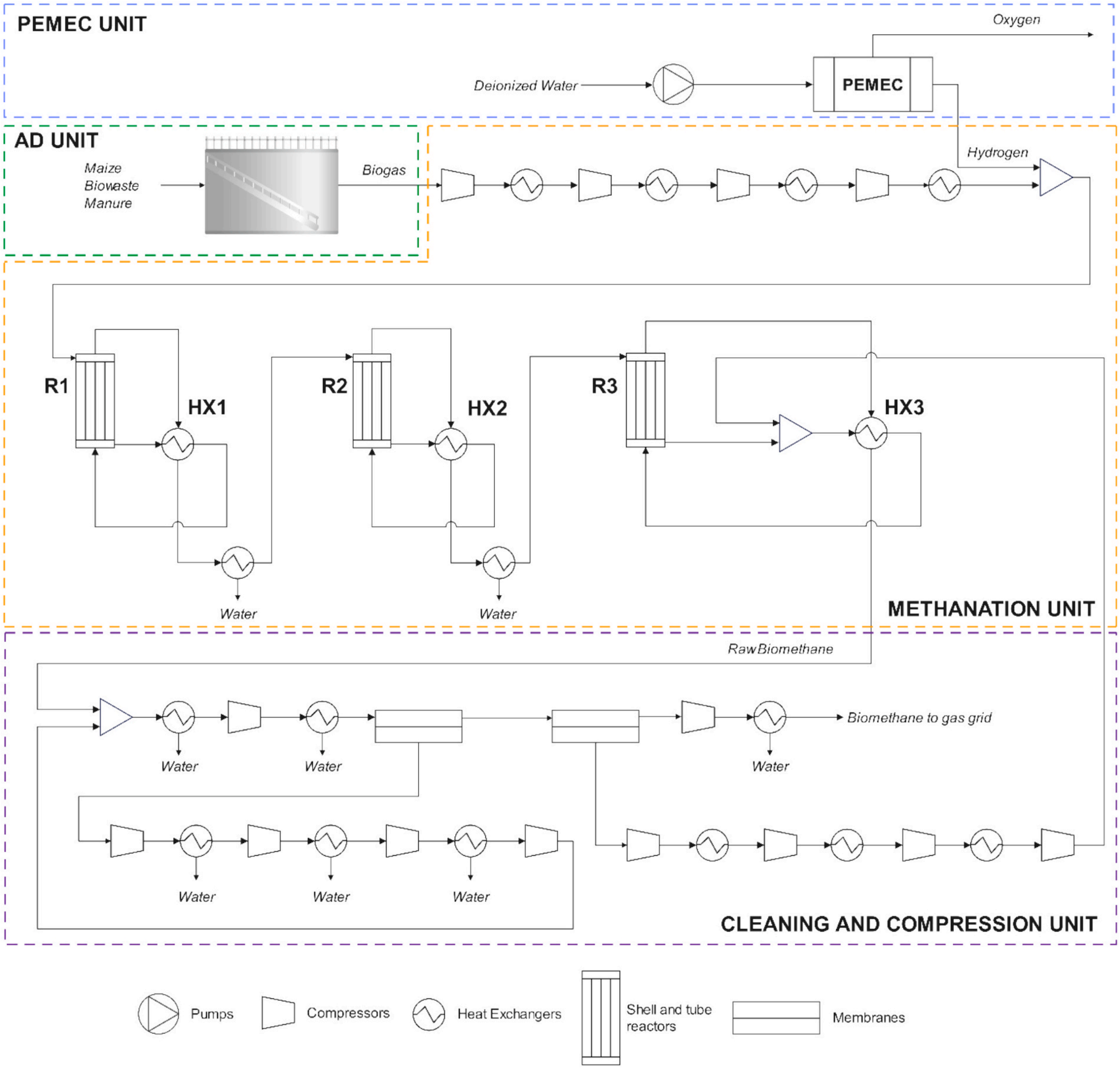


**Fig. 1.** Direct biogas methanation process.

$CO_2$ molar ratio of 4:1. A gas cleaning and compression unit was included for gas quality polishing and grid injection. The anaerobic digester was simulated using a black box approach, based on typical energy consumption and biogas productivities value from the literature [51]. In contrast, the methanation unit, PEMEC, cleaning and compression section, and membrane separation unit were modelled in Aspen Plus V14, which was used to perform detailed mass and energy balance calculations, thermodynamic equilibrium evaluation, reactor simulations, and preliminary equipment sizing. The Peng–Robinson equation of state was selected to estimate the thermodynamic properties of the process streams. The methanation reactors were modelled as kinetically driven plug-flow reactors (RPlug) in order to capture temperature and composition variations along the reactor axis. This approach was selected because the methanation process occurs in fixed-bed catalytic reactors under significant temperature gradients and reaction-rate limitations, making a kinetic plug-flow representation more suitable than equilibrium-based reactor models. Equipment sizing results obtained from Aspen Plus simulations were subsequently used as input for the techno-economic analysis and for the environmental and social LCA, which were carried out externally using dedicated methodologies and databases.

Environmental LCA was conducted using the LCA for Experts, developed by Sphera Solutions GmbH [52], combining Ecoinvent and Sphera datasets for background data. Techno-Economic Analysis (TEA) was carried out following the NETL methodology for energy systems plants, which is associated with an estimated uncertainty of ± 25 % [53]. Social LCA was performed using the PSILCA database in OpenLCA. The assessment was conducted using two feedstock categories: agricultural products for maize and manure, and waste collection and treatment products for biowaste. This choice was necessary because the available social LCA datasets did not allow a more detailed feedstock-specific representation. PEMEC data were obtained from the literature [40].

### 2.1. Process modelling

#### 2.1.1. AD and biogas production

The AD unit was modelled using a black box approach based on literature data [37,51] rather than through a detailed biochemical or kinetic digestion model. This choice is consistent with the objective of the study, which is not to optimize the AD performance, but to compare alternative downstream biogas upgrading pathways under harmonized feedstock and biogas production assumptions.

The digester was assumed to operate under mesophilic conditions, with a biogas outlet temperature of 35° [54]. A biogas production capacity of 535 kg/h was considered. This capacity is consistent with a typical 1 $MW_e$ CHP-based biogas plant; therefore, biogas productivity was calculated based on representative electricity generation efficiencies [37] and a biogas LHV of 17.7 MJ/kg. A total annual operating time of 8000 h/y was assumed for the digester [51]. After contaminant removal The biogas, was compressed to the methanation operating pressure of 15 bar using four intercooled compression stages. After each stage, the gas was cooled down to 25 °C to reduce compression electricity demand [13].

### 2.1.2. Hydrogen production

The PEMEC produces hydrogen through water electrolysis, using a solid polymer membrane as both the electrolyte and separator. PEMEC systems are characterized by compact design, high current density, rapid dynamic response, and ability to operate at high pressure, making them particularly suitable for integration with intermittent renewable energy sources [55]. The hydrogen production unit was modelled in AspenPlus V14 using the Electrolyzer block. The PEMEC operating temperature was set at 60 °C [55] and the unit was fed with deionized water at an operative pressure of 15 bar. The excess heat produced by the electrolyzer was assumed to fully satisfy the heat demand of the AD unit. The PEMEC performance parameters were defined by the voltage and faraday efficiency, set at 76 % and 97 % respectively [56] while the current density was assumed to be 18,000 $A/m^2$ [55].

### 2.1.3. Methanation unit

The methanation unit consists of three intercooled catalytic reactors, with a shell-and-tube configuration, arranged in series. In the innovative design reported in Fig. 1, each reactor is cooled down by the biogas, which circulates through the shell side, before being fed to the tubes where the reaction occurs. This configuration enables simultaneous feed gas preheating and temperature control within the catalytic bed. After preheating, the biogas is heated to the reactor inlet temperature of 250 °C [57], using the heat recovered from the reactor outlet stream. This temperature was selected as a compromise between reaction kinetics, thermodynamic equilibrium limitations, and catalyst stability. Lower temperatures favour methane formation from an equilibrium perspective but result in slower reaction rates, whereas excessively high temperatures may promote catalyst deactivation, hotspot formation, and carbon deposition within the catalytic bed. For this reason, the maximum temperature within each reactor was limited to 550 °C [25,57,58]. After each methanation stage, the products are cooled to 25 °C [13], allowing water condensation and shifting the chemical equilibrium towards methane formation in the subsequent stage.

The main design parameters of each reactor include: tube length, number of tubes, tube diameter, and bed voidage. The catalyst selected in this work is a 0.5 wt% $Ru/Al_2O_3$ commercial material (Aldrich, 206199, CAS = 1344–28–1, MDL = MFCD00011207), cylindrical pellets with a characteristic length of 3.2 mm [32]. The kinetics for the Sabatier reaction with this type of catalyst is provided by Falbo et al. [59].

### 2.1.4. Cleaning and compression

At the outlet of the third reactor stage, the biomethane composition does not yet meet the specifications required for gas grid injection. Therefore, an additional upgrading step is necessary to reach a methane concentration of 95 vol%, while allowing approximately 2 vol% $H_2$ in the final stream [60]. The feed gas mixture is compressed to 26 bar, enabling the removal of approximately 90 % of the water in a single membrane stage, with a water-rich permeate stream obtained at 1 bar. The water-rich stream is then processed through a series of compressors and condensers to further reduce its water content, yielding a recovered gas mixture that is recycled to the separation membrane. Similarly, excess hydrogen is separated in a downstream gas upgrading step after the dehydration membrane, compressed to the operating pressure, and recycled to the third reactor stage.

The resulting biomethane stream is subsequently delivered to the natural gas grid, which typically operates at pressures ranging from 4 to 70 bar [61]. In this study, the biomethane was delivered at 50 bar using a multistage compression system with an interstage cooling temperature of 25 °C, reaching a final $CH_4$ concentration of 97 vol%.

The membrane area was estimated using the standard permeation relationship reported in Eq. *1*, which relates the molar flow rate of the permeating species to its permeance and partial-pressure difference across the membrane. Counter-flow membranes were considered and, to account for the variation in driving force along the membrane axis, a one-dimensional model discretizing the membrane into 40 elements was employed.

$$A_{membrane} = \frac{\dot{n}_{permeate}}{Q_i \times (p_{if} - p_{ip})}$$

Where $\dot{n}_{permeate}$ is the molar flow rate of the permeate in mol/s, $Q_i$ is the permeance of species I, with $1GPU = 3.35 \bullet 10^{-10} mol/m^2 \bullet s \bullet Pa$ and $p_{if}$ and $p_{ip}$ the partial pressure of the given component $H_2O$ or $H_2$ in the feed and the permeate, respectively [13].

### 2.1.5. Biogas membrane upgrading unit

To enable a direct comparison between conventional upgrading and direct biogas methanation, a simplified model of a membrane-based biogas upgrading process was developed. A fraction of the raw biogas was first diverted to a boiler to meet the heat demand of the AD unit, while the remaining stream was processed in a two-stage membrane separation system with permeate recirculation (Fig. S2). The biogas was compressed to 15 bar using four intercooled compression stages before being fed to a two-stage commercial polymeric membrane unit. The first stage produced a retentate with a methane concentration of approximately 90 vol%, which was further upgraded in the second stage to meet product specifications. The permeate from the second stage was recycled to the inlet of the first stage to enhance overall methane recovery. The permeate pressure in both stages was maintained at 1 bar. The overall membrane area was evaluated using Eq. *1* assuming a $CO_2$ permeance of 62 GPU over a $CO_2/CH_4$ selectivity of 31 [62]. Table 2 summarize the modelling parameters adopted in the present work.

## 2.2. Economic analysis

The economic analysis was conducted to assess the feasibility of the process and to determine the LCOB, enabling comparison with alternative biomethane production pathways and fossil natural gas. Capital expenditures (CAPEX) were estimated starting from the Bare Erected Cost (BEC) of the main plant components. Equipment costs (EC) were calculated using cost functions from the literature, reported in Table S2 and bare module factors taken from Turton et al. [65]. The resulting EC values were updated using the 2025 CEPCI index (CEPCI2025 = 806.06) and converted into euros using a USD-to-EUR exchange rate of 0.85 [66]. The Total Overnight Cost (TOC) of the plant was then estimated following the NETL guidelines [42] (Eq. *(3)*, Eq. *(4)*, Eq. *(5)* accounting for the multiplying factors reported in Eq. *(6)*.

$$BEC = \sum EC_i \bullet F_{BM} \tag{2}$$

$$EPCC = BEC \bullet (1 + f_{EPC}) \tag{3}$$

$$TPC = \left(EPCC + f_{process} \bullet BEC\right) \bullet (1 + f_{project}) \tag{4}$$

$$TOC = TPC \bullet (1 + f_{OC}) \tag{5}$$

$$f_{OC} = f_{PPC} \bullet f_{IC} \bullet f_{FC} \bullet f_{OOC} \tag{6}$$

**Table 2**
Assumptions used for process modelling.

| PARAMETER | VALUE | U.M. |
|---|---|---|
| **AD UNIT** | | |
| LHV Biogas [51] | 17.7 | MJ/kg |
| Biogas composition ($CH_4$/$CO_2$) | 60/40 | %.vol |
| Cleaned Biogas Flow | 535 | kg/h |
| Biogas temperature [54] | 35 | °C |
| Biogas plant heat consumption (maize/biowaste/manure) [51] | 0.098/0.098/0.091 | $MJ/MJ_{BG}$ |
| Biogas plant electricity consumption (maize/biowaste/manure) [51] | 0.024/0.029/0.018 | $MJ/MJ_{BG}$ |
| Biogas Yield (maize/biowaste/manure) [51] | 12.4/15.7/7.2 | $MJ/kg_{VS}$ |
| Volatile Solids (maize/biowaste/manure) [51] | 0.336/0.217/0.07 | $kg_{VS}/kg_{total}$ |
| Total Solids (maize/biowaste/manure) [51] | 0.35/0.237/0.1 | $kg_{dry}/kg_{total}$ |
| $LHV_{Feed}$ (maize/biowaste/manure) [51] | 16.9/20.7/12 | $MJ/kg_{dry}$ |
| **PEMEC UNIT** | | |
| Voltage efficiency [56] | 76 % | – |
| Faraday Efficiency [56] | 97 % | – |
| Electrolyzer operating temperature [55] | 60 | °C |
| Electrolyzer current density [55] | 18,000 | $A/m^2$ |
| **ETM UNIT** | | |
| Operating inlet temperature [57] | 250 | °C |
| Maximum allowed temperature inside reactors [57] | 550 | °C |
| Interstage cooling temperature [13] | 25 | °C |
| Operating pressure [25] | 15 | bar |
| Pressure drop at each reactor [55] | 0.6 | bar |
| Catalyst particle dimension [32] | 3.2 | mm |
| Tube to particle ratio [57] | 10 | mm |
| Bed voidage [13] | 0.44 | – |
| Heat transfer coefficient [63] | 5 | $W/m^2K$ |
| **CLEANING AND COMPRESSION UNIT** | | |
| Permeability of water membrane [13] | 1000 | GPU |
| Permeability of hydrogen membrane [13] | 100 | GPU |
| Permeate pressure | 26 | bar |
| Retentate pressure | 1 | bar |
| Biomethane injection pressure [61] | 50 | bar |
| Compressors and Pump mechanical efficiency [64] | 94 % | – |
| Compressors and Pump isentropic efficiency [64] | 75 % | – |
| Compressors intercooling temperature [13] | 25 | °C |
| **MEMBRANE UPGRADING UNIT** | | |
| Permeability of $CO_2$ membrane [62] | 62 | GPU |
| $CO_2$/$CH_4$ selectivity [62] | 31 | – |
| Feed pressure [62] | 15 | bar |
| Permeate pressure | 1 | bar |

Investment expenditures are assumed to occur entirely in year 0. Replacement costs were accounted for the electrolyzer stack, membranes, and methanation catalyst. The electrolyzed stack was assumed to be replace every 10 years at a cost corresponding to 40 % of the CAPEX [14], consistently with projected PEMEC stack lifetimes of approximately 80,000 operating hours by 2030 [67]. Membranes, were assumed to be replaced every 5 years for the sole cost of the module [62], and the catalyst inside the reactor was assumed to be entirely replaced every 5 years. Given the limited amount of Ruthenium, and its absence from the Ecoinvent database, we applied a cut-off rule considering that the impact related to about 1.6 kg of Ruthenium along the full life cycle of the plant would be negligible. Fuel expenditures include only the electricity required to operate the electrolyzer, compressors, and AD unit. The heat demand for the AD unit was for assumed to be fully satisfied by excess heat recovered from the electrolyzer. Any remaining low-temperature heat was considered unrecovered and dissipated to the environment by means of a cooling tower. For the energy crop feedstock, an additional annual operational cost of €1,257,512 was included to account for harvesting and transportation activities [68]. All other operating expenditures (OPEX) are reported in Table 3.

A sensitivity analysis was conducted to compare the LCOB of direct biogas methanation and membrane upgrading, with the aim of identifying the conditions under which the methanation pathway becomes

**Table 3**
OPEX.

| PARAMETER | VALUE | U.M. |
|---|---|---|
| Engineering, procurement and contractor services – $f_{EPC}$ [53] | 20 | % |
| Process contingencies – $f_{process}$ [53] | 10 | % |
| Project contingencies – $f_{project}$ [53] | 20 | % |
| Pre-production cost – $f_{PPC}$ [53] | 2 | % |
| Inventory capital – $f_{IC}$ [53] | 0.5 | % |
| Financing cost – $f_{FC}$ [53] | 2.7 | % |
| Other owner's cost – $f_{OOC}$ [53] | 15 | % |
| Lifetime of plant (N) [30] | 30 | years |
| Discount rate (r) [30] | 10 | % |
| Cost of feedstock –Maize [68] | 1,257,512 | €/y |
| Equivalent Labour Shift [30] | 6 | – |
| Work Salary per Shift [30] | 40,000 | €/y |
| Insurance [68] | 50 | €/kW/y |
| Electricity Cost (Average EU 2025 S1 – Non Household consumer Band IE) [70] | 132 | $€/MWh_{el}$ |
| Deionized Water [30] | 1.5 | €/tonne |
| Oxygen selling price [30] | 25 | €/tonne |
| Catalyst cost [32] | 200 | €/kg |
| Membrane replacement [62] | 5 | years |
| PEMEC replacement (40 % CAPEX) [14] | 10 | years |
| Catalyst replacement | 5 | years |
| AD Maintenance [30] | 3 | $\%_{CAPEX}$ |
| PEMEC Maintenance [30] | 2 | $\%_{CAPEX}$ |
| General machinery Maintenance (Compressors, condensers, Membranes) [30] | 3.5 | $\%_{CAPEX}$ |
| ETM Reactor Maintenance [30] | 2.5 | $\%_{CAPEX}$ |

economically competitive with state-of-the-art upgrading technologies. Given the high energy intensity of the process, primarily associated with hydrogen production (Fig. 4), and the significant contribution of PEMEC to overall CAPEX, electricity price and PEMEC capital cost were selected as key sensitivity variables. PEMEC costs were varied according to different market maturity and technology penetration scenarios based on projections from the International Renewable Energy Agency (IRENA), which estimate substantial cost reductions by 2050 due to technological improvements and economies of scale [69].

## 2.3. Life cycle assessment

### 2.3.1. Environmental analysis

The environmental LCA adopted in this study complies with the ISO 14040 and ISO 14044 standards. The goal of the assessment is to evaluate the environmental performances of an innovative biogas upgrading process based on direct thermochemical methanation. Three representative feedstocks for biomethane production via AD were considered: maize, biowaste, and manure. The environmental impacts of the proposed pathway were compared with those of commercial biogas upgrading technologies, including membrane separation, scrubbing and PSA [71,72], as well as with fossil natural gas, which was used as the reference scenario. Biogas production pathways were modelled as described in Agostini et al. [37]. The system boundaries include raw materials acquisition, infrastructures, maintenance and operation, therefore, a cradle-to-gate approach was adopted (Fig. 2). The functional unit was defined as 1 MJ of biomethane injected into the gas grid.

The inventory data and assumptions for the modelled systems are reported in Table S5 of the Supplementary Materials. The Life Cycle Inventory (LCI) was compiled by combining process simulations outputs including mass and energy balances, with representative technology, process, and material datasets from the commercial background databases Ecoinvent (2025) [73] and Sphera (GaBi, 2025) [74]. In the absence of process-specific quantitative data for methane slip in the upgrading unit, methane slip was assumed to be negligible in the baseline model. This assumption is consistent with the very low upgrading losses reported in the Sphera database, typically in the range of 0.1–0.2 %, and with the RED II approach, according to which methane

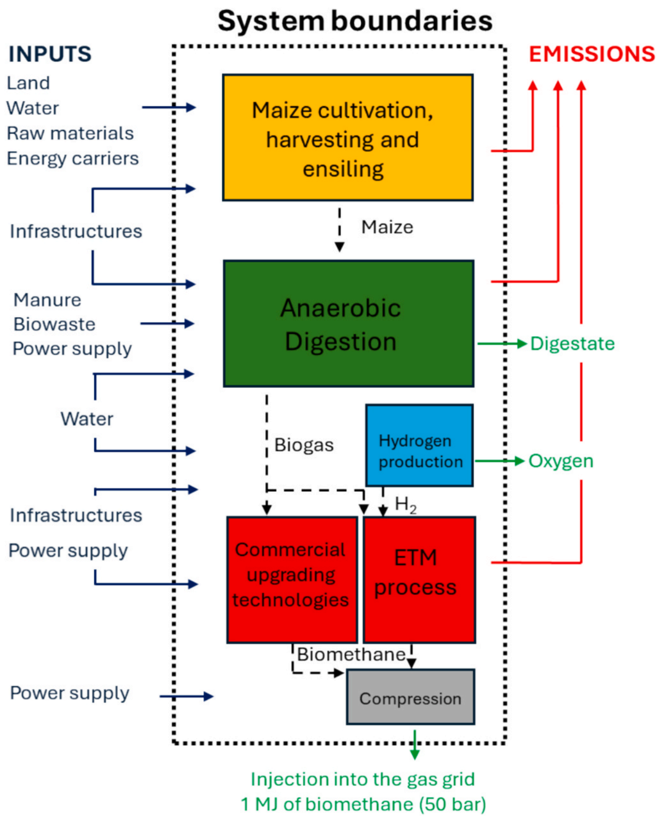


**Fig. 2.** Diagram of the system boundaries adopted for the LCA analysis.

emissions from biogas production can be considered negligible when closed storage and off-gas combustion systems are implemented [50]. To assess the influence of electricity supply, two scenarios were considered: (1) EU grid mix electricity production; and (2) a renewable power supply composed of a 50:50 mix of photovoltaic and wind energy. The feedstocks for biogas production were modelled as described in [72]. For maize, all emissions associated with energy crop cultivation were considered, including indirect land use change (ILUC). This additional factor was because the occupation of arable land by bioenergy crops may displace food and feed production, leading to market-mediated effects and additional GHG emissions from the expansion of agricultural land into forests or grasslands.. Although ILUC is difficult to quantify and remains highly uncertain an emission factor of 28 $gCO2_{eq}$/MJ of maize was adopted for bioenergy crop-based technologies [75]. Biowaste was treated as a waste feedstock, therefore, no emissions were allocated to its production, and only emissions associated with AD were considered. Manure was modelled similarly to biowaste but emission credits were also included for avoided emissions associated to its alternative management, such as open storage or field spreading resulting in negative net emissions.

Once the LCI was compiled, the most relevant environmental impact categories were identified following the Environmental Footprint (EF) methodology (European Commission, 2021, Annex 1 [76]). The EF procedure comprises four steps: classification, characterization, normalization, and weighting. Results were aggregated into a single score using normalization and weighting factors for the sixteen impact categories listed in Table S6. Impact categories contributing at least 80 % of the total single score were retained as the most relevant for this study, namely climate change, water use, primary fossil energy demand, particulate matter formation, terrestrial eutrophication, and acidification.

### 2.3.2. Social analysis

Social LCA has increasingly been applied in recent years as a framework for assessing potential social impacts across supply chains. Its methodological development builds on the ISO 14040 framework originally established for environmental LCA. The United Nations Environment Programme updated the dedicated social LCA guidelines in 2020 to improve the consistency and standardization of potential social impact assessment [77]. More recently, ISO 14075 was published to provide specific guidance for social LCA applications [78].

A comparative analysis of social risks was conducted for biomethane production through AD followed by thermochemical methanation. Two feedstock categories were considered. The “agricultural products” sector was used to represent maize and manure, with different economic values assigned to the corresponding supply chains, while the “waste collection and treatment products” sector was used to represent biowaste. Consistently with the environmental LCA, two electricity supply scenarios were analysed: (i) electricity supplied by the grid mix; and (ii) renewable electricity supplied by a 50:50 mix of photovoltaic and wind power. As in the environmental LCA, the functional unit was defined as 1 MJ of gas injected into the grid. The LCI used for the social LCA was based on mass, energy, and labour flows derived from the TEA. These foreground flows were linked to background processes using the PSILCA commercial database, which represents the global economy through monetary flows between economic sectors.

The limitations of the social LCA approach should be explicitly acknowledged. In particular, social LCA relies on qualitative and semi-quantitative indicators, and the underlying datasets are often affected by incompleteness, aggregation, and geographical representativeness issues. Therefore, although results are expressed quantitatively in terms of medium risk hours, they should be interpreted as indicative metrics for the identification of potential social hotspots rather than as precise quantitative measures of social performance. Consequently, strict quantitative comparisons among scenarios should be avoided, and the results should be discussed primarily in terms of relative trends and hotspot identification.

## 2.4. Key performance indicators

To ensure consistency across the different assessment dimensions, system performance was evaluated using a set of technical, economic, environmental, and social indicators. Technical and economic indicators are explicitly calculated in this section, while the environmental and social indicators are defined according to the LCA and S-LCA frameworks described in sections 2.3.1 and 2.3.2 respectively.

The following technical indicators were used to quantify process productivity, energy requirements, and the increase in biomethane production achieved through methanation relative to feedstock and biogas input. They also quantify the main electricity and hydrogen requirements of the process:

- Specific electric consumption – $en_{el}$ [$kWh_{el}/kWh_{LHV,BM}$]: total electric consumption of the system per kWh of biomethane produced.

$$en_{el} = \frac{P_{el,H2} + P_{el,aux} + P_{el,AD}}{G_{BM} \bullet LHV_{BM}} \tag{7}$$

where $P_{el}$ [kW] represents the total electric power consumption of the system, including the electrolyzer, the AD process, and auxiliary equipment such as compressors and pumps. $G_{BM}$ [kg/h] is the mass flow rate of the produced biomethane and $LHV_{BM}$ [MJ/kg] is the lower heating value of biomethane.

- Biomethane yield – $Y_{BM}$ [$kWh_{BM}/kg_{Feed}$]: overall biomethane production expressed as chemical energy per unit of feedstock.

$$Y_{BM} = \frac{G_{BM} \bullet LHV_{BM}}{G_{Feed}} \tag{8}$$

Where $G_{Feed}$ [kg/hr] is the biomass flow rate at the inlet of the process.

- Energy efficiency of plant – $\eta$ [%]: overall energy efficiency of plant, calculated as the ratio between biomethane energy output and the total energy input, including feedstock energy content and electricity consumption for hydrogen production, auxiliary equipment, and the AD process.

$$\eta = \frac{G_{BM} \bullet LHV_{BM}}{G_{feedstock} \bullet LHV_{feedstock} + P_{el,H2} + P_{el,aux} + P_{el,AD}} \tag{9}$$

Economic performance was assessed using the LCOB, which enables comparison between the proposed pathway and conventional upgrading routes. The LCOB represents the unit cost of biomethane for which the net present value of the system equals zero over the plant lifetime. It can be expressed in €/kWh or €/Nm$^3$, depending on the selected reference unit. In this work, the biomethane energy output was selected as the reference basis, and the LCOB was calculated according to Eq. *(10)*

$$LCOB = \frac{\sum_{t=1}^{N} \frac{I_t + M_t + F_t}{(1+r)^t}}{\sum_{t=1}^{N} \frac{E_t}{(1+r)^t}} \tag{10}$$

Where $I_t$ is the investment expenditures in the time interval $t$, $M_t$ and $F_t$ are the operational and maintenance expenditures and fuel/electricity costs associated to the process, respectively. $E_t$ [kWh] is the energy produced, in form of biomethane while $r$ and $N$ are the discount rate and the expected lifetime of the system, respectively.

Environmental performance was assessed through attributional LCA, considering the following impact categories, which are used as KPI:

- Climate change – $GHG_{eq}$ [$gCO_{2eq}/MJ_{BM}$]: total greenhouse gas emissions associated with the full life cycle of biomethane production, expressed as $CO_2$-equivalent per unit of energy output, accounting for contributions from feedstock supply, process operations, and energy use.
- Primary energy demand, fossils – $PED_f$ [$MJ/MJ_{BM}$]: cumulative consumption of fossil-based primary energy resources throughout the life cycle, normalized to the biomethane energy produced.
- Water footprint – WF [$m^3/MJ_{BM}$]: total freshwater consumption associated with the process, including direct and indirect water use along the supply chain, per unit of biomethane energy output.
- Particulate matter – PM [disease incidences/$MJ_{BM}$]: impact of particulate matter emissions on human health, expressed as the estimated number of disease incidences per unit of biomethane produced.
- Acidification potential – AP [mol $H^+_{eq}/MJ_{BM}$]: potential contribution to soil and water acidification caused by emissions of acidifying substances, normalized to the biomethane energy output.
- Eutrophication potential – EP [mol $N_{eq}/ MJ_{BM}$]: potential contribution to nutrient enrichment in aquatic and terrestrial ecosystems, mainly due to nitrogen-containing emissions, expressed per unit of biomethane energy output.

Social performance was assessed through social LCA (S-LCA), with the following indicators defined as key performance indicators.

- Child labour – CL [Medium risk hours]: indicator representing potential exposure to child labour risks along the life cycle
- Fair salary – FS [Medium risk hours]: indicator reflecting the risk of inadequate wages within the supply chain.
- Health expenditure – HE [Medium risk hours]: indicator representing risk related to insufficient access to healthcare services.

## 3. Results and discussion

This section presents the results of the process modelling, techno-economic analysis, and environmental and social life cycle assessment, and discusses the performance of the proposed methanation pathway in comparison with conventional upgrading. The analysis focuses on the main trade-offs between enhanced biomethane production, hydrogen requirements, economic feasibility, and life-cycle sustainability across the different feedstocks.

### 3.1. Mass and energy balances

Reactor design was carried out by fixing two of the four main parameters. Considering a tube-to-particle ratio of 10 [57], the tube diameter was set to 32 mm, while the bed voidage was assumed to be 0.44 [13]. Tube length and number of tubes were then optimized through a parametric analysis to maximize $CO_2$ conversion while respecting the maximum allowable reactor temperature. Table 4 summarizes the main characteristics of the reactors. In the first and second stages, the extent of reaction must be limited to prevent excessive temperature rise. At the same time, sufficient methane enrichment of the gas stream is required to enable completion of the conversion in the third reactor. In the final stage, the lower concentration of reactants allows improved thermal control and more effective heat management.

The proposed reactor configuration does not exhibit the typical bell-shaped temperature profile commonly reported in the literature for water cooled reactor [21]. Instead, temperature generally increases along the reactor axis, which limits the maximum allowable reactor length. Therefore, careful reactor design is required to ensure high $CO_2$ conversion while avoiding excessive temperature peaks. Fig. 3 shows the temperature profiles obtained for the selected optimal design configuration (Table 4).

The first and second reactors represent the most critical stages, with temperature peaks exceeding 500 °C at the end of the catalytic bed due to the high concentrations of reactants, namely $CO_2$ and $H_2$. In these reactors, 39.5 % and 51.5 % of the incoming $CO_2$ are converted into methane, respectively. In contrast, the third reactor operates as a polishing stage, enabling further methane enrichment while maintaining the reactor bed temperature below 500 °C. In this stage, $CO_2$ conversion reaches 95.2 %, resulting in an overall $CO_2$ conversion of 98.6 % across the entire methanation unit.

Fig. 4 shows the energy balance of the ETM pathway, including the PEMEC unit, the methanation unit, and the cleaning and compression section. An overall electricity input of approximately 4 MW is required to produce an additional biomethane output of about 1.8 MW. Most of the energy losses are associated with hydrogen production in the PEMEC, whereas the methanation section shows comparatively high conversion efficiency.

Table 6 reports the process KPIs, comparing direct biogas methanation with conventional membrane upgrading for all considered feedstocks. Overall, maize and biowaste exhibit similar plant efficiencies in both configurations, whereas manure shows lower efficiencies due to the lower conversion performance of the AD unit. Despite the significantly higher specific electricity consumption of the methanation pathway, 0.93 $MW_{el}/MW_{BM}$ compared with 0.05–0.07 $MW_{el}/MW_{BM}$ for membrane upgrading, overall plant efficiency increases when shifting from membrane upgrading to methanation. This improvement is particularly

**Table 4**
Reactors dimensions and catalyst loading.

| | N° TUBES | TUBE LENGTH [m] | GHSV [$h^{-1}$] | CATALYST LOAD [kg] | BED VOIDAGE |
|---|---|---|---|---|---|
| REACTOR-1 | 47 | 1.45 | 6169 | 77.2 | 0.44 |
| REACTOR-2 | 49 | 1.6 | 4230 | 88.8 | 0.44 |
| REACTOR-3 | 55 | 2.5 | 2212 | 155.7 | 0.44 |

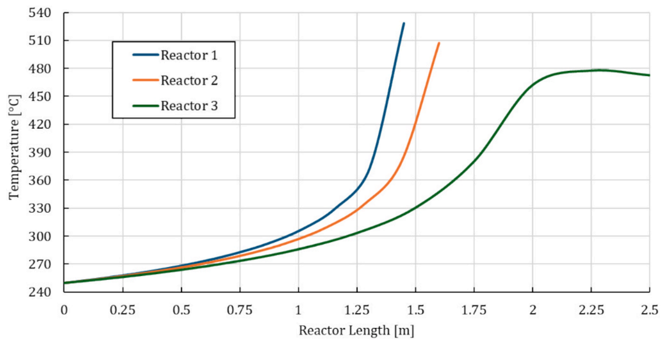


**Fig. 3.** Temperature profiles inside methanation reactors.

pronounced for manure, with an increase of 34.4 %, compared with 7.5 % for maize and 8.5 % for biowaste. This result is mainly related to the lower intrinsic energy demand of biogas production from manure. In all cases, the biomethane-to-biogas energy ratio more than doubles when methanation is adopted, increasing from 0.77 to 1.67 $MW_{BM}$/MWBG (Table 5). This increase is also due to the avoided need to divert part of the biogas to satisfy the plant thermal demand. In the integrated configuration considered in this work, the heat released by methanation is recovered and used to satisfy the thermal demand of the anaerobic digester, thereby preserving more biogas for biomethane production. Similarly, the specific biomethane yield per unit of feedstock increases substantially, from 0.11 to 0.23 $kWh_{BM}$/kg for manure, and from 0.89 and 0.73 to 1.93 and 1.58 $kWh_{BM}$/kg for maize and biowaste, respectively. These results indicate that, although the methanation pathway is more electricity-intensive, it significantly enhances overall energy recovery from the feedstock.

### 3.2. Economic analysis

This section examines the economic performance of direct biogas methanation in comparison with conventional membrane upgrading across the three selected feedstocks. The analysis focuses on capital cost distribution, the main contributors to the LCOB, and the influence of electricity price and electrolyzer cost on overall competitiveness. This allows the key economic constraints and the conditions required for competitive deployment to be identified.

Under the baseline assumptions, namely an electricity price of 132 €/MWh and a PEMEC cost of 1061 €/kW, the LCOB of direct biogas methanation remains higher than that of membrane upgrading for all feedstocks (Fig. 5). However, the cost gap is less pronounced in the case of maize. Specifically, manure and biowaste exhibit comparable LCOB values of 188 and 195 €/$MWh_{BM}$, respectively, while maize reaches the highest value, equal to 234 €/$MWh_{BM}$.

The cost breakdown shows that hydrogen production is the dominant cost driver, with electricity consumption in the PEM electrolyzer accounting for more than 50 % of the total LCOB in all cases. The contribution of the biogas production chain is feedstock-dependent. It is

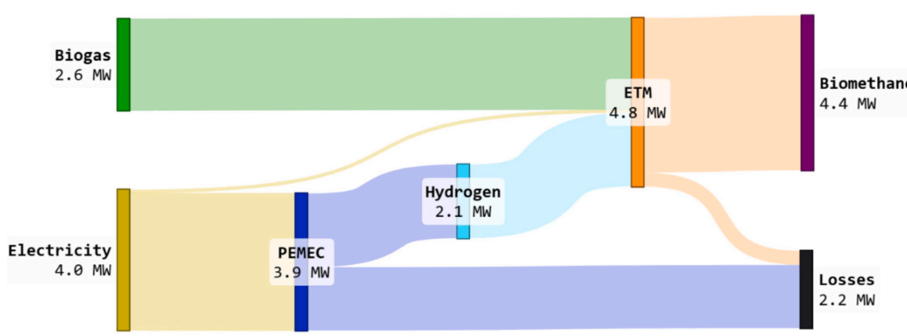


**Fig. 4.** Sankey of energy flows in the ETM process.

**Table 5**
Mass and energy balances and economic performance of the plant.

| PARAMETER | MAIZE | | BIOWASTE | | MANURE | | U.M. |
|---|---|---|---|---|---|---|---|
| Upgrading technology | Reference | Direct methanation | Reference | Direct methanation | Reference | Direct methanation | – |
| Feedstock consumption | 18,168 | 18,168 | 150,187 | 150,187 | 22,218 | 22,218 | tonne/y |
| Electric consumption | 981 | 29,749 | 1,086 | 29,854 | 855 | 29,623 | $MWh_{el}$/y |
| Digester | 504 | 504 | 609 | 609 | 378 | 378 | $MWh_{el}$/y |
| PEMEC | 0 | 28.393 | 0 | 28.393 | 0 | 28.393 | $MWh_{el}$/y |
| Upgrading | 477 | 852 | 477 | 852 | 477 | 852 | $MWh_{el}$/y |
| Hydrogen consumption | 0 | 506 | 0 | 506 | 0 | 506 | tonne/y |
| Biogas consumption | 21,026 | 21,026 | 21,026 | 21,026 | 21,026 | 21,026 | $MWh_{BG}$/y |
| Biomethane production | 16,109 | 35,083 | 16,109 | 35,083 | 16,109 | 35,083 | $MWh_{BM}$/y |
| Biomethane/biogas ratio | 0.77 | 1.67 | 0.77 | 1.67 | 0.77 | 1.67 | $MW_{BM}/MW_{BG}$ |
| Specific hydrogen consumption | 0 | 14.45 | 0 | 14.45 | 0 | 14.45 | $kg_{H2}/MWh_{BM}$ |
| Cooling duty | 0 | 11,343 | 0 | 11,343 | 0 | 11,343 | MWh/y |
| CAPEX | 10.43 | 23.39 | 11.60 | 24.57 | 7.10 | 20.06 | M€ |
| CAPEX specific | 5.18 | 5.33 | 5.76 | 5.60 | 3.53 | 4.57 | M€/$MW_{BM}$ |
| Labour cost | 240,000 | 240,000 | 240,000 | 240,000 | 240,000 | 240,000 | €/y |
| Insurance | 50,000 | 50,000 | 50,000 | 50,000 | 50,000 | 50,000 | €/y |
| Feedstock harvesting and collection | 1,257,512 | 1,257,512 | 0 | 0 | 0 | 0 | €/y |
| Deionized Water | 0 | 6,864 | 0 | 6,864 | 0 | 6,864 | €/y |
| Electricity consumption | 135,611 | 4,111,372 | 150,141 | 4,125,901 | 118,176 | 4,093,937 | €/y |
| Digester [a] | 69,740 | 69,740 | 52,305 | 52,305 | 84,269 | 84,269 | €/y |
| PEMEC [a] | 0 | 3,923,940 | 0 | 3,923,940 | 0 | 3,923,940 | €/y |
| Upgrading [a] | 65,872 | 117,692 | 65,872 | 117,692 | 65,872 | 117,692 | €/y |

[a] *Electricity price of 0.1382 €/$kWh_{el}$.*

**Table 6**
KPIs.

| PARAMETER<br>Upgrading technology | Symbol<br>– | MAIZE<br>Reference | <br>Direct methanation | BIOWASTE<br>Reference | <br>Direct methanation | MANURE<br>Reference | <br>Direct methanation | U.M.<br>– |
|---|---|---|---|---|---|---|---|---|
| **MASS AND ENERGY** | | | | | | | | |
| Specific electric consumption | $en_{el}$ | 0.061 | 0.929 | 0.067 | 0.932 | 0.053 | 0.925 | $kWh_{el}/kWh_{LHV,BM}$ |
| Biomethane yield | $Y_{BM}$ | 0.89 | 1.93 | 0.73 | 1.58 | 0.11 | 0.23 | $kWh_{BM}/kg_{Feed}$ |
| Energy efficiency of plant | $\eta$ | 52.2 | 56.2 | 51.3 | 55.7 | 31.6 | 42.5 | % |
| **ECONOMIC ANALYSIS** | | | | | | | | |
| Levelized cost of biomethane[a,b] | LCOB | 188.6 | 243.6 | 84.5 | 195.8 | 69.1 | 188.7 | €/$MW_{BM}$ |
| **ENVIRONMENTAL LCA** | | | | | | | | |
| Climate change (grid/RES)[c] | $GHG_{eq}$ | 6.2/5.3 | 11.0/3.0 | 45.2/44.3 | 34.3/26.4 | −15.7/-16.1 | −15.17/-16.9 | $gCO2_{eq}/MJ_{BM}$ |
| Primary energy demand, fossils (grid/RES)[c] | $PED_f$ | 90.2/70.9 | 167.6/43.4 | 211.3/192 | 240.0/116 | 90.1/70.9 | 167.6/43.4 | $MJ/MJ_{BM}$ |
| Water footprint (grid/RES)[c] | WF | 141.7/141.5 | 87.9/86.3 | 846.3/846.1 | 510.1/508.5 | 141.7/141.5 | 87.9/86.3 | $m^3 \bullet 10^{-3}/MJ_{BM}$ |
| Particulate matter (grid/RES)[c] | PM | 0.18/0.17 | 0.5/0.2 | 6.5/6.5 | 4.3/4.0 | −0.08/-0.09 | 0.4/0.04 | disease incidences • $10^{-9}/MJ_{BM}$ |
| Acidification potential (grid/RES)[c] | AP | 16.6/14.9 | 37.5/14.9 | 915.2/913.5 | 576.0/553.4 | −21.1/−22.1 | 14.9/-7.7 | mol $H^+_{eq} \bullet 10^{-6}/MJ_{BM}$ |
| Eutrophication potential (grid/RES)[c] | EP | 0.04/0.03 | 0.09/0.03 | 4.04/4.03 | 2.48/2.42 | −0.13/-0.14 | −0.02/-0.08 | mol $N_{eq} \bullet 10^{-3}/ MJ_{BM}$ |
| **SOCIAL LCA** | | | | | | | | |
| Child labour (grid/RES)[c] | CL | 1.48/2.11 | 2.36/5.56 | 1.78/2.4 | 2.52/5.72 | 0.51/1.11 | 2.4/5.56 | Medium risk hours • $10^{-5}$ |
| Fair salary (grid/RES)[c] | FS | 0.13/0.13 | 0.09/0.09 | 0.17/0.17 | 0.11/0.11 | 0.02/0.02 | 0.02/0.03 | Medium risk hours • $10^{-3}$ |
| Health expenditure (grid/RES)[c] | HE | 3.29/3.38 | 2.49/2.91 | 2.65/2.75 | 2.16/2.58 | 0.54/0.62 | 1.02/1.49 | Medium risk hours • $10^{-3}$ |

[a] *PEMEC cost of 1,061 €/kW.*
[b] *Electricity price of 0.1382 €/$kWh_{el}$.*
[c] *Grid: European electricity mix; RES: 50 %PV-50 %Wind.*

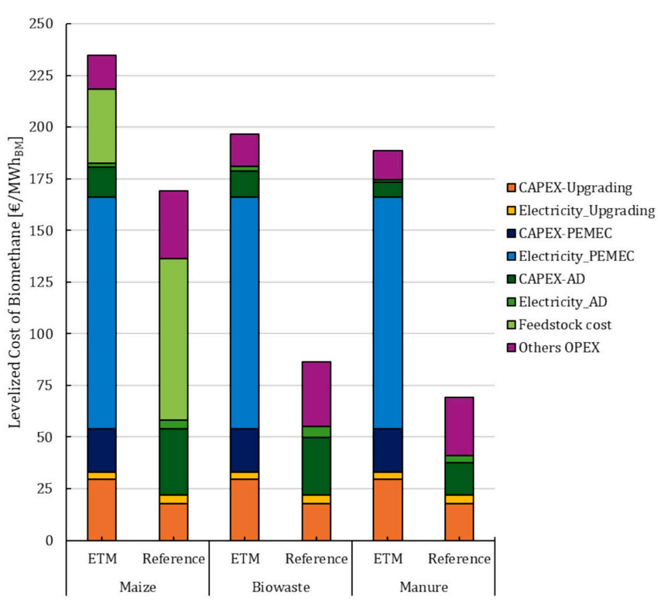


**Fig. 5.** LCOB breakdown.

relatively small for manure and biowaste, accounting for approximately 10 % and 13 % of the total LCOB, respectively, but becomes substantial for maize, where it accounts for around 31 %, mainly due to harvesting and feedstock logistics. Capital costs associated with the methanation unit and the PEMEC account for a smaller share of the total LCOB. However, PEMEC-related costs are expected to decline in the future through technological learning and economies of scale [69]. By contrast, operation and maintenance costs, together with electricity consumption for methanation auxiliaries, contribute only marginally to the final LCOB.

Manure exhibits the lowest specific investment cost, equal to 4.57 M€/$MW_{BM}$, followed by biowaste and maize, with 5.33 and 5.60 M€/$MW_{BM}$, respectively (Table 5). For maize and biowaste, the AD unit represents the largest share of the total investment, accounting for approximately 38 % and 35 % of total CAPEX, respectively. Its contribution is lower in the manure case, at around 26 %. In contrast, the PEMEC dominates the manure-based configuration, contributing approximately 40 % of the total investment, while still representing a significant share, around 30 %, in the maize and biowaste cases. The methanation unit contributes more uniformly across all feedstocks, accounting for approximately 25 % of total CAPEX. Finally, the gas cleaning and compression units have a comparatively minor impact, accounting for less than 15 % of the overall investment in all scenarios (Table S4).

The LCOB breakdown highlights the need to identifying the conditions under which direct biogas methanation may become economically competitive with membrane upgrading. To this end, Fig. 6 presents the results of a sensitivity analysis on electricity price and PEMEC cost, compared with the reference case and the fossil natural gas cost (46.4 €/MWh [70]). Electricity prices was varied according to representative values observed across European countries. The analysis considers high-price contexts, such as Italy, where electricity prices can reach approximately 166 €/$MWh_{el}$ [70] as well as lower-price contexts, such as Scandinavian countries, where values around 50–60 €/$MWh_{el}$ have been reported [70]. The sensitivity range was extended down to 0 €/$MWh_{el}$ to provide a broader assessment of the theoretical lower bound of the LCOB. This scenario should not be interpreted as a steady-state electricity price, but rather as a limiting case representative of periods with very low or even negative electricity prices, which may occur when renewable electricity production exceeds demand and no adequate storage or flexibility strategy is available [79–82]. Therefore, the sensitivity analysis does not aim to define a constant operating condition for the plant. Instead, it highlights that the economic feasibility of direct biogas methanation requires appropriate operational strategies to exploit periods of low-cost renewable electricity. In this context, future

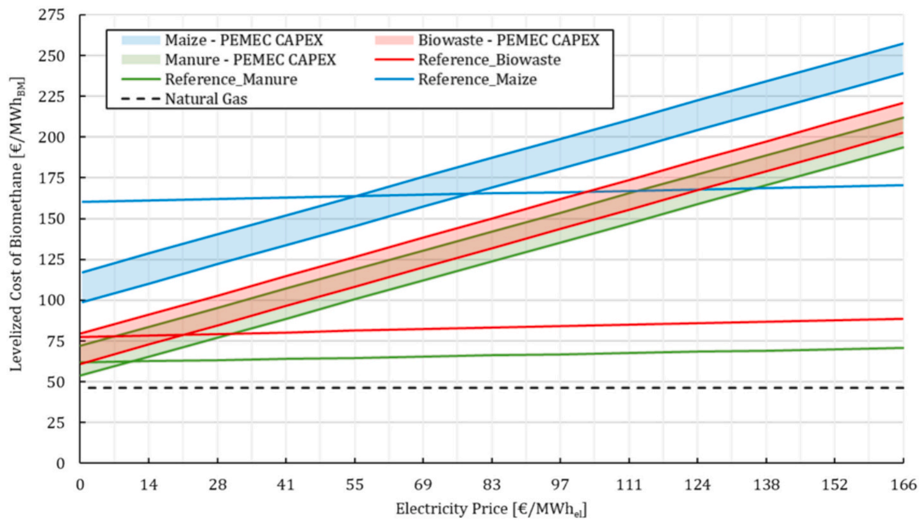


**Fig. 6.** LCOB varying the electricity prices varying the PEMEC capital cost.

studies should model the system at a higher energy-system level, considering the integration of renewable hybrid systems, hydrogen and/or electricity storage solutions [30,83], and dynamic operation of the biomethane production process. Such analyses would allow the productivity and economic performance of the plant to be assessed under variable load conditions.

The trends reported in Fig. 6 are mainly governed by the high electricity demand of the PEMEC unit. Since hydrogen production represents the dominant energy input of the direct methanation pathway, variations in electricity price are directly transferred to the LCOB, leading to an almost linear decrease in biomethane production cost as electricity price decreases. This explains why electricity price has a stronger influence than PEMEC capital cost reduction. The effect of PEMEC CAPEX is comparatively smaller because electrolyzer investment is distributed over the plant lifetime, whereas electricity consumption affects annual operating costs continuously. Therefore, even substantial reductions in PEMEC capital cost cannot fully compensate for high electricity prices. This result indicates that the economic feasibility of direct biogas methanation is primarily constrained by access to low-cost renewable electricity rather than by equipment cost reduction alone. Feedstock-related differences also affect the relative competitiveness of the pathway. For manure and biowaste, upstream feedstock-related costs are relatively low; therefore, hydrogen production dominates the total LCOB. In contrast, maize-based biomethane remains more expensive because the biogas production chain includes additional agricultural, harvesting, and transport-related costs. However, the higher biomethane output obtained through methanation partially dilutes these upstream costs over a larger product flow, explaining why the cost gap with conventional upgrading becomes less pronounced under favourable electricity price conditions.

In absolute terms, manure is the most cost-effective option for direct biogas methanation, reaching the lowest LCOB values under favourable conditions, in the range of 65–95 €/MWh$_{BM}$. Nevertheless, membrane upgrading is also highly competitive in the manure case. Therefore, full cost parity requires not only low electricity prices but also a substantial reduction in PEMEC capital cost. Under the high market penetration scenario, the LCOB of direct methanation decreases to approximately 65 €/MWh$_{BM}$, compared with about 63 €/MWh$_{BM}$ for membrane upgrading at an electricity price of 14 €/MWh$_{el}$. Biowaste shows a similar trend, although with slightly higher costs, reaching 72–100 €/MWh$_{BM}$ at electricity prices of 14–28 €/MWh$_{el}$, compared with approximately 79 €/MWh$_{BM}$ for membrane upgrading. Maize remains the least favourable feedstock in terms of absolute cost, but it also shows the widest margin for improvement. In particular, direct biogas methanation can approach or achieve cost competitiveness with membrane upgrading at comparatively higher electricity prices. Depending on the PEMEC cost scenario, LCOB values in the range of 160–200 €/MWh$_{BM}$ are obtained when electricity prices decrease to approximately 70–95 €/MWh$_{el}$.

To compare the effect of renewable electricity supply on the proposed pathway, three representative electricity costs from IRENA could be considered for green hydrogen production: offshore wind, 67 €/MWh$_{el}$; solar PV, 36 €/MWh$_{el}$; and onshore wind, 28 €/MWh$_{el}$ [84]. Under these assumptions, manure remains the most favourable feedstock for direct biogas methanation in absolute terms. However, full cost parity with membrane upgrading is generally not achieved unless very low electricity prices are combined with substantial PEMEC cost reductions. Biowaste shows a similar but slightly less favourable trend, with competitiveness approached only under the most advantageous combinations of renewable electricity cost and PEMEC market penetration. Maize, despite exhibiting the highest absolute costs, can reach cost competitiveness under less restrictive electricity price conditions because the higher biomethane productivity of the methanation pathway partly offsets the higher costs associated with the upstream biogas production chain.

Overall, direct biogas methanation appears less economically favourable than conventional membrane upgrading under the scenarios considered. At the same time, it delivers a substantial increase in biomethane production, enabling more complete valorisation of the carbon content of biogas and significantly enhancing product output compared with conventional upgrading. This added value is particularly relevant when biomethane maximization, domestic renewable gas production, energy security, power-to-gas integration, and the storage of excess renewable electricity are considered strategic objectives.

However, under the assumptions adopted in this study, the additional electricity demand, capital requirements, and process complexity are not yet fully compensated by the higher biomethane yield, even under favourable conditions such as low electricity prices and reduced electrolyzer costs. Conventional upgrading therefore remains the more mature and economically attractive option from a short-term perspective. Nevertheless, a purely economic comparison is not sufficient to fully capture the potential of the methanation pathway. A broader assessment, including environmental and social life cycle aspects, is therefore required to determine whether the increased production, improved carbon valorisation, contribution to domestic energy supply, and wider system integration benefits may justify the added complexity of the process.

### 3.3. Environmental impacts

The LCA was performed over the entire process chain, from the feedstock supply to the final product, biomethane. For each impact category, contributions associated with biogas and hydrogen production were mainly derived from literature sources [37,72], while the infrastructure of the methanation unit and the electricity supply were modelled using data from the Sphera and Ecoinvent databases. The primary objective of the analysis was to compare methanation-based upgrading technologies with conventional biogas upgrading routes, and to assess the influence of electricity supply from either renewable sources or the grid. Fossil natural gas extraction, compression, and transportation are included as a benchmark system. Since the functional output of the study is biomethane or fossil natural gas, the fuel use phase was excluded from the system boundaries.

The environmental trends shown in Fig. 7 are mainly driven by two factors: the type of feedstock used for biogas production and the electricity supply adopted for hydrogen generation. Feedstock selection strongly affects the upstream environmental burden. Maize-based pathways show the highest impacts because crop cultivation requires agricultural inputs, land occupation, fertilizer use, and harvesting operations. These contributions remain relevant even when renewable electricity is used for hydrogen production. In contrast, manure and biowaste exhibit substantially lower impacts because they are modelled as waste-derived feedstocks. In the manure case, the environmental profile is further improved by credits associated with avoided emissions from conventional manure management. This explains the negative climate change values observed for manure-based biomethane production. The role of electricity supply becomes particularly important for the methanation pathway because hydrogen production through electrolysis is highly electricity-intensive. When grid electricity is used, the additional electricity demand associated with PEMEC operation can offset part of the environmental benefit of $CO_2$ conversion. Conversely, when renewable electricity is used, the environmental burden of hydrogen production decreases significantly, allowing direct methanation to outperform conventional upgrading in selected impact categories, particularly climate change and fossil primary energy demand.

Regarding the climate change impact category, maize-based pathways exhibit emissions exceeding those of fossil natural gas, even when renewable electricity is employed. However, the maize-based biogas methanation pathway reduces this impact when renewable electricity is used, reaching 26 $gCO_{2eq}/MJ_{BM}$ compared with 44 $gCO_{2eq}/MJ_{BM}$ for conventional upgrading. This reduction occurs because the increased biomethane production enabled by methanation partially offsets the emissions associated with the biogas production chain. Biowaste and manure show similar trends. When renewable electricity is used, direct

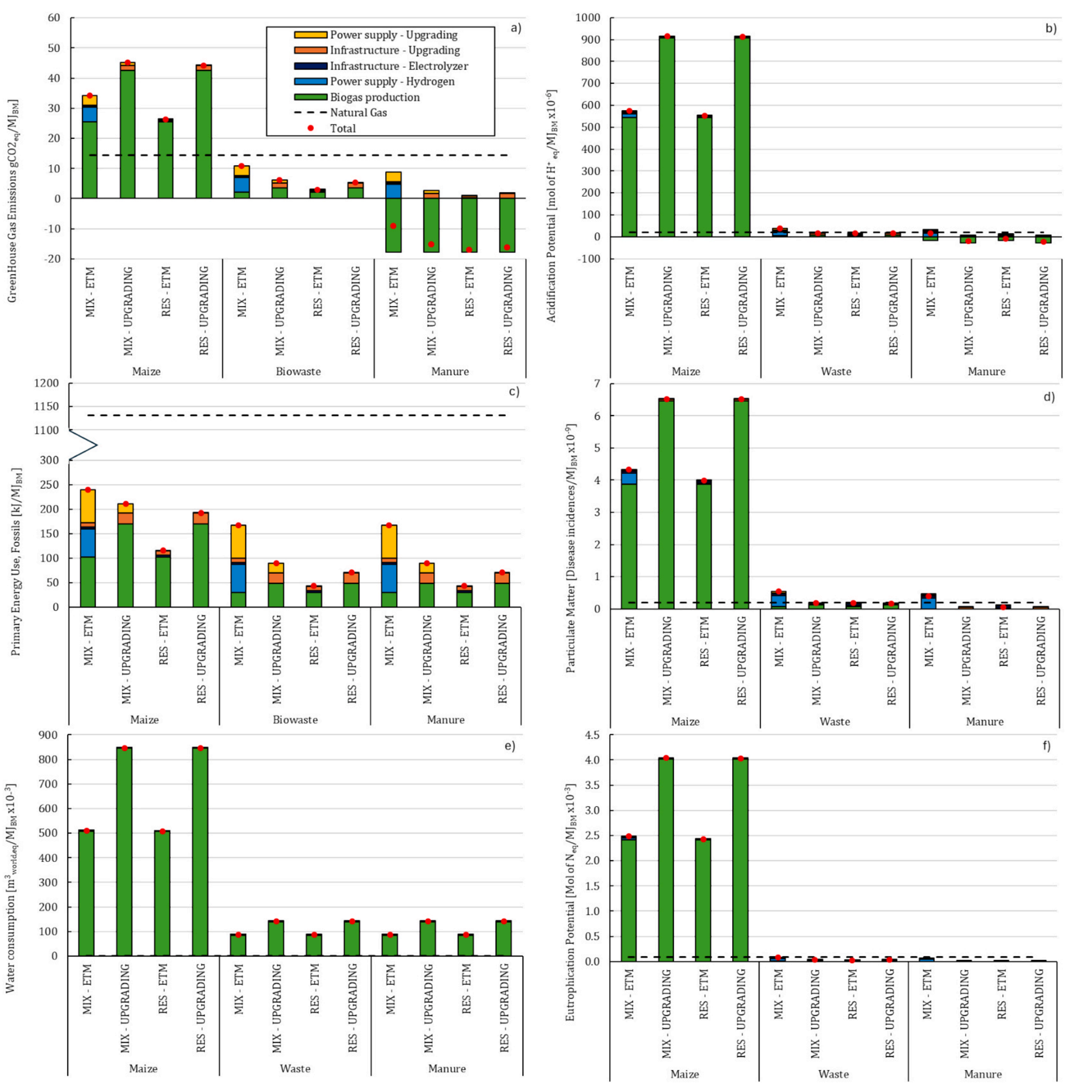


**Fig. 7.** Environmental LCA results a) climate change; b) acidification potential; c) primary energy use, fossils; d) particulate matter; e) water consumption; f) eutrophication potential.

biogas methanation has lower climate change impacts than conventional upgrading. For example, in the biowaste case, direct methanation reaches 3 $gCO_{2eq}/MJ_{BM}$, compared with 5 $gCO_{2eq}/MJ_{BM}$ for upgrading. However, when grid electricity is used, the methanation pathway becomes more impactful due to the high electricity demand of hydrogen production. In the biowaste case, emissions increase to 11 $gCO_{2eq}/MJ_{BM}$ for methanation, compared with 6 $gCO_{2eq}/MJ_{BM}$ for upgrading. In the manure case, negative emissions are still achieved even when grid electricity is used, reaching − 9 $gCO_{2eq}/MJ_{BM}$, because avoided emissions from conventional manure management counterbalance the emissions associated with hydrogen production.

The use of fossil resources for biomethane production is significantly lower than that associated with fossil natural gas extraction and transportation. All feedstocks exhibit a similar trend: methanation-based upgrading results in the lowest impacts when renewable electricity is used, whereas conventional upgrading performs better when electricity is supplied from the grid. Manure and biowaste exhibit comparable impacts, both substantially lower than those of maize. For these waste-based feedstocks, fossil resource use ranges from approximately 43 $kJ/MJ_{BM}$ when renewable electricity is coupled with methanation-based upgrading to about 170 $kJ/MJ_{BM}$ when electricity is supplied from the grid. In these cases, the main contributors shift toward electricity demand for hydrogen production, upgrading, and gas compression.

A similar feedstock-driven pattern is observed across the other impact categories. Water consumption in maize-based pathways is approximately five times higher than that of manure- and biowaste-based pathways, mainly due to upstream agricultural inputs. A detailed contribution breakdown is provided in the Supplementary Material. Similar trends are observed for acidification, particulate matter formation, and eutrophication, with maize exhibiting the highest impacts, while manure and biowaste show significantly lower values, in some cases comparable to fossil natural gas. For manure and biowaste, the relatively low impact intensity of the biogas production process increases the relative contribution of hydrogen production. In these cases, hydrogen production accounts for more than 40 % of the total impact in the biowaste case and more than 80 % in the manure case. The use of renewable electricity substantially reduces these impacts, although the methanation pathway does not always reach the same impact levels as conventional upgrading.

Across all categories, maize-based pathways present significant environmental challenges, exhibiting higher impacts than manure and biowaste and, in some cases, even exceeding those associated with fossil natural gas. This behaviour is mainly attributable to the biogas production chain, which remains a dominant contributor due to agricultural inputs and harvesting activities. In contrast, biowaste and manure show more favourable environmental performance, with manure in particular achieving net negative climate change impacts when the alternative fate of the feedstock is considered. Regarding technology choice and electricity supply, several impact categories are not directly energy-related; therefore, no substantial variation is observed when shifting from grid electricity to renewable electricity. However, when renewable electricity is employed, methanation-based upgrading outperforms conventional upgrading in selected categories, namely climate change, fossil resource use, and water consumption. This highlights the potential of direct methanation to improve the environmental performance of biomethane production systems under low-carbon electricity supply conditions.

### 3.4. Social impacts

The social LCA was conducted over the entire supply chain, from feed supply to biomethane production, following a cradle-to-gate approach. Biogas production and upgrading, together with hydrogen production, were modelled as foreground processes based on TEA and environmental LCA data. The electrolyzer, equipment, feedstock supply, and electricity production were represented as background using the PSILCA database. The primary objective of the analysis was to compare the social risks associated with methanation-based and conventional biogas upgrading routes. In addition, the influence of electricity supply, whether from renewable sources or the grid, was assessed. The PSILCA database contains a total of 70 qualitative and quantitative indicators [85], based on the UNEP Guidelines [77]. Therefore, the analysis was focused on the indicators considered most relevant for bioenergy systems according to the social LCA literature [40]. The selected indicators were fair salary, related to worker stakeholder category; health expenditure, related to society, and child labour, related to the children stakeholder category. These indicators are also consistent with relevant social LCA studies on hydrogen technologies [86–88].

A comprehensive evaluation of the two production pathways indicates that ETM generally results in lower specific social risk values than conventional upgrading for the selected indicators (Fig. 8). This outcome is mainly related to the higher biomethane output achieved through methanation, which distributes part of the feedstock-related social risks over a larger amount of final product. However, the results should be interpreted as indicative hotspot information rather than as definitive quantitative evidence of superior social performance. Across most indicators, biogas production represents the dominant

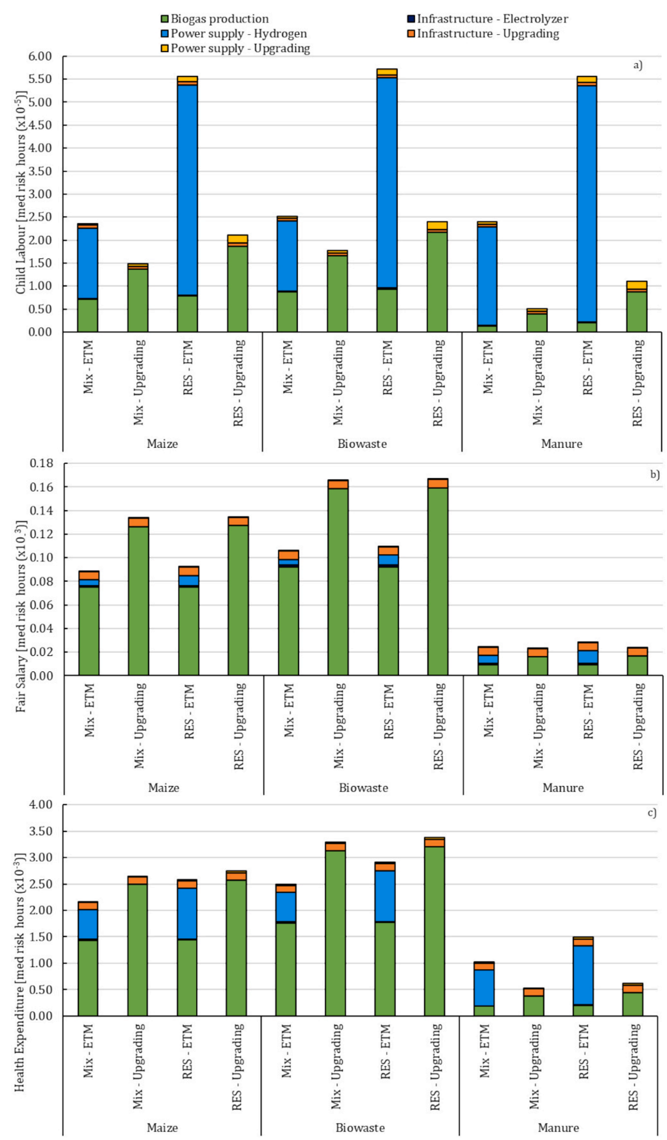


**Fig. 8.** Social LCA analysis: a) Child labour; b) Fair salary; c) Health expenditure.

contribution in both the conventional upgrading and ETM pathways, for both biowaste and energy crop feedstocks and under both grid electricity and renewable electricity scenarios. This contribution is mainly associated with feedstock supply. The only exception is observed for the child labour indicator, where the renewable electricity scenario shows a relevant contribution from electricity supply for electrolysis.

For the fair salary indicator, the main contribution again originates from biogas production in both the conventional upgrading and ETM pathways. This result is mainly driven by feedstock supply chains, since both the agricultural and waste management sectors in Italy present potential social risks related to wage levels. Similar considerations apply to the health expenditure indicator, although this indicator is defined at the country level rather than at the level of individual economic sectors. In this case, a minor additional contribution is associated with electricity supply for electrolysis. For the child labour indicator, ETM shows higher specific social risk values than conventional upgrading in some scenarios. This is mainly due to the higher electricity demand associated with electrolysis, particularly when renewable electricity is used. This result is consistent with previous social LCA studies on hydrogen production, which identified potential child labour risks in upstream supply chains related to the production of photovoltaic panels, solar cells, and power conditioning components for wind turbines [86]. These manufacturing activities are often located in East Asia, with China representing a relevant example [89].

However, a detailed contribution analysis shows that the FISIM sector plays a significant role in this result. This does not imply the presence of child labour within the methanation process or the FISIM sector itself. Rather, it reflects the structure of the PSILCA database, which is based on monetary flows between economic sectors [85,90,91]. Therefore, this result should be interpreted as an indication of potential upstream social hotspots rather than as direct evidence of child labour in the foreground process.

Several limitations of the social LCA approach should be acknowledged. First, PSILCA is based on the EORA multi-regional input–output database, where data are aggregated by economic sector. This aggregation may include a wide range of activities within the same sector, reducing the granularity of the assessment and affecting the estimation of social risks [90–93]. Second, in PSILCA, the Italian electricity-related process available for this study was too aggregated to distinguish the supply chains of different electricity generation technologies. Since the S-LCA aimed to compare a grid electricity scenario with a renewable electricity scenario based on photovoltaic and wind electricity, UK electricity datasets were used as technology-specific proxies for PV and wind. This modelling choice was introduced to preserve technological differentiation in the electricity supply chain, not to assume that UK social conditions are representative of Italy. The assumption was applied consistently across scenarios, but it limits the geographical representativeness of absolute results. Therefore, S-LCA outcomes should be interpreted as screening-level hotspot indications rather than site-specific social impact estimates. Third, additional uncertainty arises from the use of working hours as an activity variable, particularly for social indicators that are not directly related to workers [91,94].

Overall, the social LCA results provide two main insights. First, the social risks associated with biomethane production are largely influenced by feedstock supply, regardless of the upgrading technology adopted. In this respect, ETM can reduce specific social risk values by increasing biomethane production from the same biogas input. However, some social risks are linked to the structure of economic sectors and supply chains and are not necessarily proportional to the amount of material or energy required. Therefore, technology improvements alone cannot eliminate these risks, and targeted policy and supply-chain measures remain necessary. Second, the increased complexity of ETM may introduce additional upstream social hotspots due to the larger number of components and the higher electricity demand associated with hydrogen production. This is particularly relevant for renewable electricity supply chains, where environmental benefits may be accompanied by social risks related to technology manufacturing. These results confirm the importance of evaluating biomethane pathways through an integrated sustainability perspective, considering economic, environmental, and social dimensions together.

Overall, the analysis highlight the existence of a clear trade-off among the economic, environmental, and social dimensions of direct biogas methanation. From an economic perspective, the process is mainly constrained by the cost of renewable hydrogen, which depends strongly on electricity price. From an environmental perspective, the same electricity supply determines whether methanation provides benefits over conventional upgrading, especially in terms of climate change and fossil resource use. From a social perspective, the increased reliance on electricity and renewable technology supply chains may introduce additional upstream hotspots. Therefore, the most favourable configuration is not defined by a single indicator, but by the combination of waste-based feedstocks, low-carbon electricity, and reduced hydrogen production costs. Under these conditions, direct methanation can increase biomethane output and improve carbon utilization, although its current economic competitiveness remains limited compared with mature upgrading technologies.

## 4. Conclusions

Despite the comprehensive scope of the present assessment, several limitations should be acknowledged. First, the process modelling is based on literature data and steady-state simulations and does not account for transient operation, dynamic reactor behaviour, or fluctuations associated with renewable electricity supply. As a consequence, the operational variability and scale-up dynamics of commercial-scale plants may not be fully captured. Second, although the reactor modelling approach was based on literature kinetics and compared with published studies, no direct experimental validation of the proposed reactor configuration was performed within the scope of this work. Third, the techno-economic analysis relies on current and projected assumptions for electricity prices and electrolyzer technologies, which may evolve significantly depending on future market and technological developments. In addition, the adopted cost estimation methodology is associated with an intrinsic uncertainty of $\pm$ 25 %. The environmental assessment was conducted using an attributional LCA framework, which is appropriate for comparative technology assessment but does not capture broader system-level or market-mediated effects. Moreover, the social LCA is constrained by the use of input–output databases, which may limit the level of detail in representing specific supply chains and geographical contexts.

Future research should focus on the experimental validation of the proposed reactor configuration and on the integration of methanation with dynamic renewable electricity supply. Further work should also refine techno-economic assumptions under real market conditions, extend the environmental assessment through consequential LCA approaches, and improve the robustness of social impact evaluation using more detailed and site-specific data.

This study provides a comprehensive assessment of thermochemical biogas upgrading via direct $CO_2$ methanation with green hydrogen, integrating process modelling, techno-economic analysis, and environmental and social LCA. From a technical perspective, the proposed multi-stage methanation configuration enables high $CO_2$ conversion (up to 98.6 %) and a significant increase in biomethane yield (+67 %), demonstrating the potential of process intensification compared to conventional upgrading routes. The techno-economic analysis identifies hydrogen production as the dominant cost driver, accounting for more than 50 % of the levelized cost of biomethane under current conditions. As a result, the process is not yet economically competitive with conventional upgrading when grid electricity is used. However, sensitivity analysis highlights that competitiveness can be achieved under low-cost renewable electricity scenarios and reduced electrolyzer costs, identifying clear break-even conditions across different feedstocks.

Environmental results confirm that feedstock choice is a key determinant of sustainability. Waste-based feedstocks, such as manure and biowaste, exhibit substantially lower impacts than maize, with manure achieving net negative greenhouse gas emissions due to avoided emissions. Methanation can outperform conventional upgrading when coupled with low-carbon electricity, while its performance is penalized under carbon-intensive electricity mixes. The social LCA indicates that impacts are largely driven by feedstock production, with additional contributions from electricity supply chains associated with hydrogen production. While methanation may improve selected indicators, it can also introduce additional risks related to increased system complexity and extended supply chains.

Overall, thermochemical methanation should be regarded as a promising but still emerging pathway for enhancing biomethane production and integrating renewable hydrogen into the energy system. Under current techno-economic conditions, the process is not yet generally competitive with conventional upgrading, mainly due to the high electricity demand and cost associated with hydrogen production. Its future viability will depend on access to low-cost low-carbon electricity, further reductions in electrolyser costs, the use of waste-based feedstocks, and experimental validation at relevant scale. Therefore, the results should be interpreted as an assessment of potential future deployment conditions rather than as evidence of immediate commercial or policy readiness.

## CRediT authorship contribution statement

**G. Sacchi:** Writing – original draft, Visualization, Methodology, Investigation, Formal analysis, Data curation, Conceptualization. **D. Ferrario:** Writing – review & editing, Supervision, Methodology, Formal analysis, Data curation. **A. Agostini:** Writing – review & editing, Validation, Supervision, Software, Resources, Project administration, Methodology, Funding acquisition, Conceptualization. **C. Carbone:** Writing – review & editing, Writing – original draft, Validation, Methodology, Investigation, Formal analysis, Data curation. **J. Bindi:** Writing – original draft, Validation, Methodology, Investigation, Formal analysis, Data curation, Conceptualization. **C. Bassano:** Writing – review & editing, Validation, Supervision, Formal analysis. **A. Lanzini:** Writing – review & editing, Validation, Supervision, Methodology, Funding acquisition, 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

Additional reactor design, process modelling, cost and life-cycle assessment data supporting the study on thermochemical $CO_2$ methanation of biogas with green hydrogen. Supplementary data to this article can be found online at https://doi.org/10.1016/j.ecmx.2026.102112.

## Data availability

Data will be made available on request.

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