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Research paper

The role of solid oxide fuel cells in repowering agricultural biogas plants: A techno-economic assessment of electricity and biomethane pathways

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ABSTRACT

Biogas plays a well-established role in the European energy system, particularly in countries with strong agricultural supply chains. Biogas can be valorised either through electricity generation via Internal Combustion Engines (ICEs) or through upgrading to biomethane for grid injection. Solid Oxide Fuel Cells (SOFCs) are emerging as a promising alternative to ICEs, owing to their higher electrical efficiency and reduced pollutant emissions. This study evaluates the energy and economic feasibility of integrating SOFCs into existing agricultural biogas plants in northern Italy approaching the end of their incentive period. Four representative facilities were analysed under four operating configurations: electricity generation via ICE or SOFC, and biomethane production with auxiliary power supplied by either technology. Results indicate that SOFCs offer significant advantages for electricity generation in small-scale plants (100–300 kW_{el}), where their high efficiency, combined with capital incentives, makes them economically preferable to ICE repowering. In contrast, for large-scale plants (~1 MW_{el}), biomethane upgrading achieves the highest profitability. Medium-sized facilities represent a transition case, where the preferred strategy depends strongly on gas-grid distance and injection pressure requirements. Overall, the study demonstrates that SOFC integration can enhance the performance of existing biogas infrastructures. The optimal valorisation route ultimately depends on plant size, site-specific conditions, and the applicable incentive framework.

1. Introduction

Biogas is a high-energy-density renewable resource that plays an essential role in the global energy transition given its versatility and sustainable nature. It is obtained through the anaerobic digestion of biomass, a process that converts organic materials such as agricultural waste, manure, and food residues into energy. Europe currently leads biogas production worldwide, with a combined biogas and biomethane output of 22 billion cubic meters (bcm) in 2023 (European Biogas Association, 2024a). This volume is equivalent to Belgium's total natural gas consumption and represents about 4–5% of the European Union's overall gas demand (SandP Global, 2024).

After appropriate treatment, biogas can be used to generate electricity and heat or upgraded to biomethane, which can be injected into the natural gas grid (Minardi et al., 2023). This latter option offers a strategic advantage for decarbonising hard-to-electrify sectors such as transport and industry. In Europe, the United States and Canada, biogas is primarily used to generate electricity and heat or upgraded to biomethane for injection into the gas grid. Conversely, in China, India and several other regions, biogas is still predominantly used for domestic-scale applications, reflecting different historical adoption patterns, infrastructure development, and energy access priorities (IEA International Energy Agency, 2023).

In Europe, overall biogas production has remained relatively stable over the past decade, while the share of biomethane output has steadily expanded. In recent years, a marked shift has occurred from electricity production toward biomethane generation. Between 2020 and 2021, European biomethane output increased by 20%, rising from 31 TWh (2.9 bcm) to 37 TWh (3.5 bcm) (European Biogas Association, 2022). Germany remains the largest producer, contributing 50.4% of total European production, followed by Italy (13.9%) and France (9.4%) (European Commission, 2023). This transition towards biomethane is primarily driven by both economic and policy factors. On the economic side, the decreasing cost of wind and solar power have reduced the competitiveness of electricity generation from biogas (IEA International Energy Agency, 2020). On the policy side, many governments have

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actively promoted biomethane as a strategic pathway for decarbonising the transport and industry. Furthermore, the geopolitical crisis following the Russia-Ukraine conflict has reinforced the urgency of diversifying energy supplies, positioning biomethane as a crucial resource for enhancing Europe's energy security. This trend is reflected in the rapid expansion of biomethane infrastructure. Between 2011 and 2022, production increased from 0.5 bcm to 4.2 bcm. By mid-2024, Europe had reached 1548 biomethane production facilities (European Biogas Association, 2024b). This represents a sharp rise compared with previous years: 483 plants in 2018, 729 in 2020, 1023 in 2021, and 1322 in 2022–2023

In both pathways – direct electricity generation and biomethane upgrading – a cogeneration system (combined heat and power, CHP) is typically installed within the plant. When biogas is used for electricity production, the CHP unit represents the core component of the facility, generating electricity and heat as the main outputs. In biomethane configurations, a smaller CHP unit is generally installed and fuelled by biogas to supply the auxiliary energy demand of the anaerobic digestion and upgrading processes (e.g., compressors, gas treatment units, and control systems).

Currently, the most widely adopted CHP technology for biogas applications is the Internal Combustion Engine (ICE). An alternative approach involves the use of Solid Oxide Fuel Cells (SOFCs). A key advantage of SOFCs is their high electrical conversion efficiency, which can reach 50–60% (Langnickel et al., 2020). This is significantly higher than the 28–43% typically achieved by conventional ICE systems. SOFCs also offer near-zero emissions of local pollutants such as NOx, SOx, and particulate matter. Despite their promising performance, SOFCs are currently employed in only a few experimental biogas facilities. A notable example is the DEMOSOFC plant (Gandiglio et al., 2020), the first industrial-scale SOFC installation in Europe, operating with sewage biogas from a wastewater treatment facility in Collegno (Turin area, Italy).

The integration of SOFCs in biogas systems for electricity production has been extensively investigated in recent years, particularly regarding system performance (Langnickel et al., 2020), fuel flexibility, and degradation phenomena (Yu et al., 2025). Several studies have demonstrated the technical feasibility of operating SOFC systems with biogas or biomethane, reporting electrical efficiencies above 50% and highlighting the potential for improved environmental performance compared to conventional ICEs (Langnickel et al., 2020; Aguilar et al., 2025). Parallel research has focused on the impact of trace contaminants (including sulphur compounds, siloxanes and halogenated hydrocarbons) on SOFC degradation mechanisms (Pera et al., 2024). These studies have shown that fuel impurities can significantly affect electrochemical stability and long-term performance. Advanced biogas cleaning strategies and pre-treatment solutions are therefore required (Gandiglio, 2022; Santoni et al., 2024). In this context, enhanced gas-cleaning layouts tailored for fuel cell applications have been proposed to ensure stable operation and extend stack lifetime (Rozzi et al., 2025). From a techno-economic perspective, several authors have assessed the competitiveness of biogas-fed SOFC systems under different fuel and market scenarios (Ma et al., 2024; Tamburrano et al., 2024). Nevertheless, most of this research remains confined to theoretical analyses or laboratory-scale experiments.

A substantial body of literature has also compared electricity generation and biomethane upgrading pathways. Negro et al. (2025) evaluated a 1 MW biogas plant fed by the organic fraction of municipal solid waste, calculating the annual CO_2 savings for both biomethane and electricity (via ICE) operation modes. They found that, while electricity currently represents the most convenient solution from an environmental perspective, biomethane is expected to outperform it by 2030 as grid emission intensity decreases. Furthermore, heat recovery in the electricity-based system remains a critical factor that can significantly shift the environmentally optimal solution. Different electricity, biomethane, and hybrid layouts have also been assessed by Volpi et al. (2023) who concluded that the optimal scenario depends on local energy contexts and fluctuates based on specific demand for fuel or power. This scenario-dependency was confirmed through a SWOT (Strengths, Weaknesses, Opportunities, Threats) analysis by Fernández-González et al. (2020), while hybrid biomethane-electricity configurations were further proposed by O'Shea et al. (2016). Techno-economic analyses have identified plant size, substrate mix, and proximity to the gas grid as key determinants in selecting the optimal energy vector (Alao et al., 2024; Porto et al., 2025). However, most existing studies focus on ICE-based cogeneration as the benchmark electricity technology. Integrated comparisons that simultaneously consider advanced fuel cell technologies and upgrading pathways remain limited. Moreover, current analyses are frequently restricted to single case studies, failing to address the broader representativeness of different plant scales within a national context.

To the best of the authors' knowledge, no previous study has provided a comprehensive techno-economic comparison between ICE- and SOFC-based electricity generation and biomethane upgrading while also explicitly accounting for the existing regulatory and incentive frameworks. Furthermore, the potential role of SOFC systems as high-efficiency auxiliary units in biomethane plants has not been systematically assessed. This gap is particularly relevant in countries such as Italy, where a large number of agricultural biogas plants are approaching the end of their incentive period and must evaluate alternative repowering strategies.

1.1. Aim and novelty of the study

To address the aforementioned gaps, the present work evaluates the practical integration of SOFCs within the strategic decision-making framework of existing biogas facilities. The primary novelties of this research are:

- Systematic comparison of pathways: A holistic evaluation of four operating configurations for each plant scale: (i) electricity via ICE, (ii) electricity via SOFC, (iii) biomethane with ICE as auxiliary unit, and (iv) biomethane with SOFC as auxiliary unit.
- National-scale representativeness: Instead of a single case study, the analysis covers four representative agricultural biogas plants (100, 300, 600, and 999 kW_{el}) to capture the diversity of the Italian (and broader European) biogas sector.
- Methodological consistency: The derivation of original cost-size correlations for SOFC systems, refurbished/new ICEs, and biomethane upgrading units, based on current market quotations and operating plant data.

Particular attention is paid to the actual characteristics of the sites under study, such as biogas production profiles, supported by robust operational data provided in collaboration with the Consorzio Monviso Agroenergia (2024). In doing so, this work provides a holistic and application-oriented perspective on the role that SOFCs could play in the sustainable transformation of existing biogas infrastructures.

The remainder of this paper is organised as follows. Section 2 outlines the methodological framework and key assumptions adopted in the analysis. Section 3 presents the main results from both energy and economic perspectives, supported by detailed case studies. Finally, Section 4 summarises the key conclusions and offers recommendations for future developments.

2. Methodology

2.1. Case studies and plant configurations

This study evaluates the energy and economic performance of different technological pathways for existing agricultural biogas plants operating in Italy, particularly those approaching the end of their

incentive period. At the national level, Italy hosts approximately 1350 agricultural biogas plants with a total installed capacity of about 1.3 GW (Gestore Servizi Energetici, 2022). Among these, nearly 1050 plants will reach the end of their incentive period between 2023 and 2027. These plants represent around 78% of the total number and 75% of the installed power. Most of these installations are located in northern regions, where the agricultural and livestock sectors provide a stable feedstock base and well-developed biogas infrastructure. This context highlights the strategic relevance of assessing new operational pathways for post-incentive biogas plants, especially in terms of repowering or conversion to biomethane production.

To clarify the overall logic of the analysis, Fig. 1 illustrates the conceptual scheme of the four technological pathways investigated. The diagram shows how the biogas produced through anaerobic digestion can be directed toward two main routes:

- Electricity generation (EE), using either ICEs or SOFCs;
- Biomethane production (BM), where the raw biogas is upgraded and injected into the gas grid, with auxiliary electricity needs covered by either ICE or SOFC units.

The schematic view in Fig. 1 defines the four reference configurations (EE_ICE, EE_FC, BM_ICE, and BM_FC) and illustrates the system boundaries adopted in the comparative analysis.

To ensure that the analysis reflects the specific characteristics of the Italian biogas sector, four representative case studies were selected, based on real operational data provided by plant operators in northern Italy. The selected case studies were chosen according to their installed electrical capacity, as all four plants are currently configured for electricity generation using ICEs. The selected facilities cover a range of nominal electrical capacities – 100 kW_{el}, 300 kW_{el}, 600 kW_{el}, and 999 kW_{el} – that are representative of the most common plant sizes across the Italian agricultural biogas sector. The main features of each case study are summarised in Fig. 2 (with additional details in the Supplementary Material) and discussed below. These include feedstock composition, current technology, and possible reconfiguration options:

- The 100 kW_{el} plant, located in Scalenghe, is operated by an agricultural company and primarily utilises livestock effluent from cattle farming, with a minor contribution from plant-based biomass. Due to the limited biogas production at this scale, the biomethane conversion case was excluded from the analysis, as the associated investment cost would not be economically viable.
- The 300 kW_{el} pant, situated in Cavour, is owned by a cooperative. It reflects the typical features of small-scale biogas installations in Italy, relying on livestock waste as the main substrate, complemented by selected energy crops to achieve the required methane yield.
- The 600 kW_{el} facility, located in Piossasco, is characterised by the use of livestock manure collected from a nearby farm. Specifically, animal-derived biomass accounts for 72% of the total feedstock mass, while the remainder primarily consists of maize and ryegrass silage. These two substrates contribute to 38% and 62% of the total methane output, respectively. The use of high-moisture feedstock, especially manure, leads to a lower methane yield. As a result, the plant exhibits a higher thermal demand per unit of methane produced. This case is particularly relevant for exploring the feasibility of SOFC-based cogeneration systems, which offer a lower thermal power output than conventional Combined Heat and Power (CHP) units.
- The 999 kW_{el} plant, located in the municipality of Venaria Reale, represents the largest scale considered in the study. Its feedstock mix consists of dedicated energy crops, poultry manure from a nearby farm and coffee waste from a food processing industry.

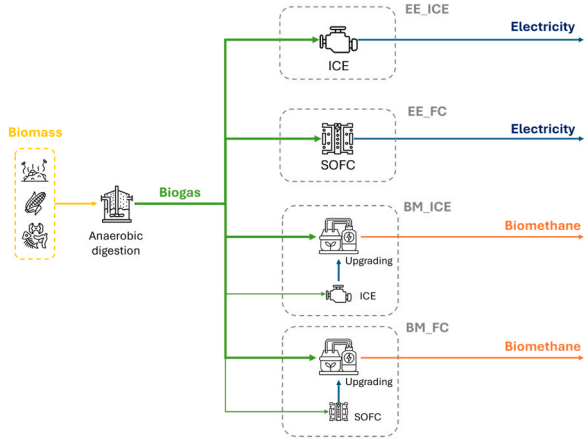

Fig. 1. Conceptual representation of the four technological pathways considered.

Each configuration is identified by a standardised nomenclature combining the final energy vector (EE or BM), the conversion technology (ICE or SOFC), and the nominal plant capacity. For biomethane plants, the nomenclature also specifies the distance and operating pressure of the gas grid (e.g., 1k24 = 1 km distance, 24 bar pressure; 3k54 = 3.3 km distance, 54 bar pressure). For example, EE_ICE_300 refers to electricity generation using an internal combustion engine in a 300 kW_{el} plant. BM_FC_999_1k24 denotes biomethane production supported by a fuel cell in a 999 kW_{el} facility located 1 km from the gas grid operating at 24 bar.

Not all combinations are feasible at every scale; in particular, biomethane production was excluded from the 100 kW_{el} plant due to limited gas flow and unfavourable economics. All configurations assume connection to the national electricity grid and include the presence of an auxiliary boiler for emergency heat supply.

The four case studies are identified according to the current installed electrical capacity of the internal combustion engines (i.e., 100, 300, 600 and 999 kW_{el}). However, when transitioning to the alternative configurations analysed in this work, the assessment is carried out by maintaining the same biogas flow rate currently available at each plant.

In EE configurations, the CHP unit is either a refurbished ICE, selected among the closest commercial sizes to the currently installed engine, or a new SOFC module. In BM configurations, instead, a new upgrading section is installed to convert most of the biogas into biomethane for grid injection. A minor fraction of the biogas produced on site is supplied to a smaller CHP unit, based either on ICE or SOFC technology, which is used exclusively to cover the internal auxiliary energy demand of the biomethane plant. This includes the electricity required by the upgrading section and the thermal energy required for digester operation. Therefore, BM configurations always require a new, smaller CHP unit, independent of the size of the existing ICE.

Moreover, regarding EE configurations, the rated electrical power of the CHP systems implemented in the simulated configurations does not necessarily match the nominal size of the existing ICEs. For instance, refurbished ICEs are selected among the closest commercial sizes, whereas SOFC-based systems may result in higher electrical capacities due to their superior efficiency and the modularity constraints imposed by available units. A complete overview of the resulting CHP capacities (nominal electrical power) is reported in the Supplementary Material.

2.2. Economic analysis

Based on the configurations described in Section 2.1, a detailed techno-economic assessment was performed for each case study. The analysis incorporates plant-specific data on energy production and consumption, capital and operational expenditures, and applicable incentive schemes, which vary depending on plant size and technology.

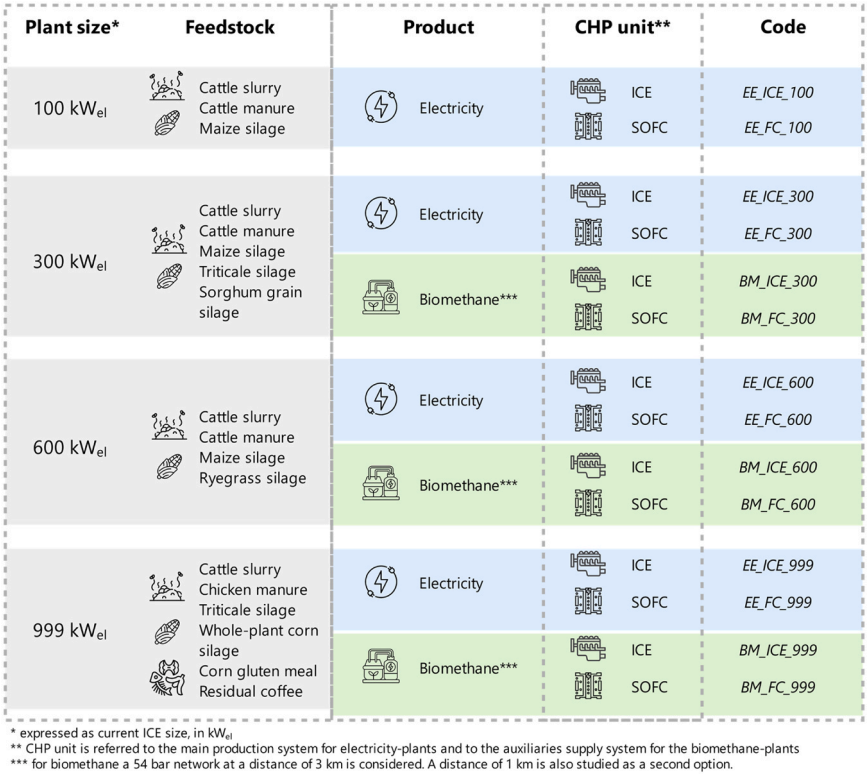

Fig. 2. Overview of the analysed configurations for the four representative biogas plants. The plant sizes of 100, 300, 600 and 999 kW_{el} refer to the currently installed ICE units, while the specific CHP sizes used in the analysed configurations are reported in the Supplementary Material.

The main objective is to evaluate the financial viability of each configuration over the plant's lifetime under realistic boundary conditions.

As a general assumption, excess thermal energy generated in electricity-only configurations is not valorised externally. Therefore, revenues are limited to electricity sales in EE configurations and to biomethane injection into the national gas grid in BM configurations.

For plants continuing electricity generation through ICEs (EE_ICE), extraordinary maintenance operations are required, including major interventions on both the digesters and the engines. In particular, the engine is assumed to be sent back to the manufacturer for refurbishment. These costs are treated as part of the initial investment, as they are essential for extending the plant's operational life.

Economic performance indicators are derived from the estimation of investment costs, operational costs, and revenue streams over the full lifetime of each plant.

2.2.1. Investment costs

The total investment cost (C_{INV}) is considered as a one-time expenditure incurred in the year preceding the start of operation and is calculated as:

$$C_{INV} = C_{ADR} + C_{BGC} + C_{CHP} + C_{UPG} + C_{GGR} + C_{PSU} + C_{CW} + C_{TC} \quad (1)$$

where:

- C_{ADR} is the cost of anaerobic digestion revamping.
- C_{BGC} is the cost of the biogas cleaning section.
- C_{CHP} is the cost of the cogeneration unit (ICE or SOFC). In the electricity-based configurations, this corresponds either to the purchase of a new SOFC system or to the refurbishment of the existing ICE, since all plants considered are already equipped with engines currently operating for electricity generation. In biomethane configurations, both the smaller SOFC and the ICE units used to cover auxiliary demands are instead considered as new equipment.
- C_{UPG} is the cost of the upgrading system for biogas to biomethane, including the post-combustor for off-gases, compressor and pressure regulation, metering, and odorization unit (REMI station).
- C_{GGR} represents the cost of connection to the gas grid and the construction of the REMI station building. The reference case (3k54) assumes a distance of 3.3 km from the plant to the gas transmission network, operating at 54 bar, in line with typical values observed for CMA plants. In addition, a best-case scenario (1k24) was analysed, considering a shorter connection distance of 1 km and a lower operating pressure of 24 bar, in order to assess the sensitivity of the overall investment profitability to these boundary conditions.
- C_{PSU} is the cost of the biomass required for initial plant start-up.
- C_{CW} is the cost of civil works (flooring, aggregates, site construction).
- C_{TC} are the technical cost (engineering, integration, project design, etc).

Plants adopting high-efficiency cogeneration technologies, specifically those that install SOFC in place of ICE, are eligible for an investment incentive of up to 65% on a maximum of €600,000, as provided by the Green Practices Decree (MASE, 2024). Additionally, plants that have participated in the auction procedures to access incentives under the Ministerial Decree of 15/09/2022 (Ministero della Transizione Ecologica, 2022) are entitled to a capital contribution based on specific investment categories and plant typologies, as detailed in the Supplementary Material.

For each configuration, the total investment cost was adjusted by subtracting all eligible capital incentives and grants, resulting in the net investment after incentives. This value represents the actual expenditure borne by the plant owner and was used in all subsequent economic evaluations.

2.2.2. Operational costs

For each year y, the operational costs ($C_{OP,y}$) include all expenditures associated with plant operation, from biomass procurement to mainte-

nance of system components, and are computed as:

$$C_{OP,y} = C_{BMS,y} + C_{BP,O\&M,y} + C_{CHP,O\&M,y} + C_{UCR,O\&M,y} + C_{EE,y} + C_{Tax,y} \quad (2)$$

where:

- $C_{BMS,y}$ is the cost of the biomass required for continuous plant operation. The biomass costs were defined according to representative Northern Italian market values for the specific feedstock mix of each case study, based on official price data from the Mantua and Bologna Chambers of Commerce;
- $C_{BP,O\&M,y}$ includes all expenses related to the biogas production section, the auxiliary boiler operation, digestate treatment, biomass and manure handling, personnel, consulting and digestate analysis.
- $C_{CHP,O\&M,y}$ consists of the maintenance and service costs of the cogeneration unit and catalyst.
- $C_{UCR,O\&M,y}$ represents the O&M costs of the upgrading unit, compressor and REMI station.
- $C_{EE,y}$ is the cost of electricity purchased from the grid during periods of cogeneration unit maintenance or insufficient self-production.
- $C_{Tax,y}$ are the taxes based on the taxable income.

Inflation effects were incorporated directly into the yearly projections of both operating costs and revenues.

Regarding SOFC operational costs, it is important to clarify the contractual arrangement assumed in this study. SOFC systems are typically supplied under a full-service performance contract. Under this arrangement, the plant owner pays an initial capital cost for the system and subsequently a fixed service tariff to the SOFC supplier, included in the CHP O&M cost term. This tariff covers ordinary maintenance, system monitoring, and all interventions required to maintain the guaranteed performance level, including stack replacement when needed. The plant owner has no role in decisions regarding cell management or replacement scheduling. As a consequence, stack replacement does not appear as a discrete cost item in the cash flow analysis presented in this study. Its cost is instead implicitly embedded within the constant CHP O&M cost, which is applied uniformly across all years of the 15-year evaluation period. Since the adopted SOFC efficiency corresponds to the guaranteed long-term performance level provided by the supplier, the effect of degradation is already reflected in the service-based cost model rather than treated as an additional efficiency decay scenario.

2.2.3. Revenues

For configurations focused exclusively on electricity production, revenues are calculated based on the Guaranteed Minimum Prices (GMP) (ARERA, 2024), as detailed in the Supplementary Material. As a reference, in 2024 the GMP applicable to a 600 kW_{el} plan injecting electricity into the national grid was 244.60 €/MWh. This value depends primarily on the plant's nominal electrical capacity and the average market price of corn, which influences the tariff adjustment mechanism.

For configurations producing biomethane for grid injection, the applicable incentive framework is defined by the Ministerial Decree of 15/09/2022 (see the Supplementary Material) (Ministero della Transizione Ecologica, 2022). In 2024, the reference tariff for a plant producing more than 100 Sm^3/h was 122.81 €/MWh, expressed on a biogas lower heating value (LHV) basis.

Any surplus electricity not covered by incentive mechanisms was valued at the average wholesale market price recorded between January and June 2024, corresponding to 93.14 €/MWh (GME, 2025). It should be noted that this value is applied only to residual surplus electricity not covered by incentive schemes and does not represent the main revenue driver for electricity-oriented configurations, which are remunerated through the Guaranteed Minimum Prices mechanism. Therefore, its influence on the overall economic results is marginal.

2.2.4. Input data

The technological components considered in the energy and economic analysis are commercially available on the market. The operating parameters of ICE-based cogeneration units, such as nominal power, efficiency and emission levels, are based on the datasheets of leading manufacturers. The SOFC system was modelled as a 50 kW_{el} modular unit, with load modulation capability down to 60% and a guaranteed electrical efficiency of 54% (LHV). This value was derived from commercial supplier data and represents a conservative long-term performance level guaranteed to the plant owner, rather than the maximum achievable efficiency of the technology. Techno-economic data, including investment and service costs, were obtained from product specifications and market quotations provided by existing commercial suppliers.

In the agricultural biogas plants, the feedstock supply can be typically planned and controlled throughout the year, since the biomass mix includes storable substrates such as energy crops and dry biomass, together with livestock effluents. This operating practice is commonly adopted in agricultural biogas facilities to maximise continuous CHP operation and incentive-based revenues. As a result, the biogas flow rate supplied to the SOFC is assumed to be nearly constant over the year, with only minor fluctuations due to seasonal temperature variations or changes in feedstock composition. Accordingly, the SOFC is assumed to operate continuously at its nominal working point (full load); partial-load operation and load-following effects are therefore not considered in the analysis.

The investment and operational costs associated with each configuration are reported in the Supplementary Material. Specifically, costs are grouped into macro-categories to highlight the contribution of the main plant sections (e.g., civil works, biogas cleaning, CHP unit, upgrading system, gas-grid connection), depending on the configuration under analysis. More detailed cost breakdowns are not provided due to confidentiality constraints. All financial calculations were performed assuming a discount rate of 4% and an annual inflation rate of 1.5%. The discount rate was selected in consultation with sectoral operators to represent realistic investment conditions for agricultural biogas plant owners.

Capital investment costs were estimated from recent market quotations and cost data made available through CMA, which has access to updated technical and economic information from a network including 224 agricultural biogas plants operating in Italy and 422 associated biogas suppliers. All cost data used in the analysis refer to 2024 values. For new ICE and SOFC units, quotations refer to complete CHP systems, including the main conversion unit and the auxiliary equipment required for plant integration. The estimation approach differs according to the configuration considered. In EE_ICE configurations, the plant continues electricity generation using the existing ICE after extraordinary maintenance and refurbishment; therefore, the CHP investment corresponds to the refurbishment of the existing unit rather than to the purchase of a new engine. In EE_FC configurations, the existing ICE is replaced by a new SOFC system. In biomethane configurations, the existing electricity-oriented CHP unit is not retained as the main conversion unit; instead, a new smaller CHP unit, based either on ICE or SOFC technology, is installed and sized only to supply the internal electricity demand of the upgrading section and the thermal demand of the digester. Biomethane upgrading and gas-grid connection costs were derived from recent quotations for real biomethane projects.

Based on the total investment costs reported in Appendix A and in the Supplementary Material, cost-size relationships were derived for both CHP technologies and biomethane upgrading systems. Fig. 3 illustrates these correlations. Specifically, panel (a) reports the specific capital cost of refurbished ICEs, new ICEs and SOFC systems as a function of installed electrical capacity, highlighting the different cost trajectories and the economies of scale associated with larger CHP units. Panel (b) presents the specific investment cost of biomethane upgrading and gas grid connection as a function of annual biomethane output, similarly

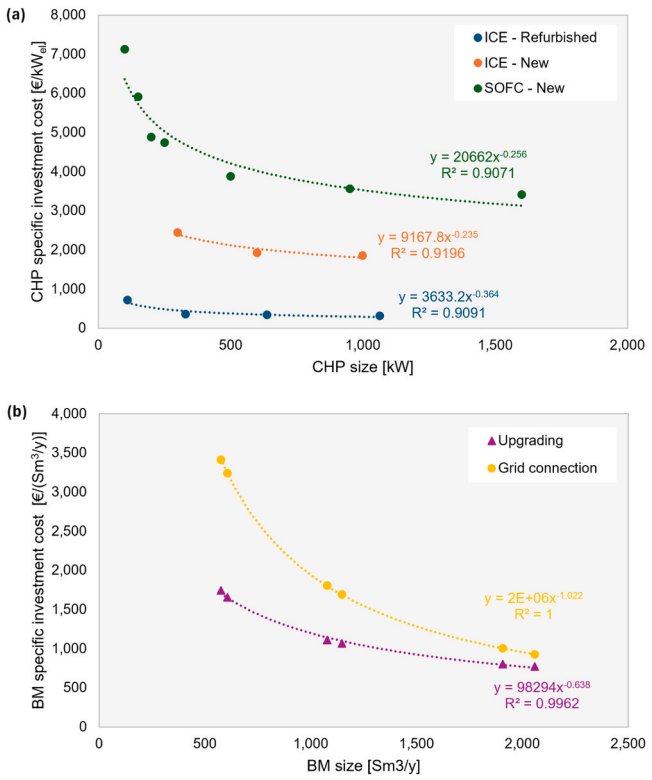

Fig. 3. (a) Specific capital cost of CHP technologies (refurbished ICE, new ICE and new SOFC) as a function of installed electrical capacity. (b) Specific capital cost of biomethane production systems (upgrading unit and gas grid connection) as a function of the annual biomethane production capacity. Dotted lines represent the fitted cost–size correlations derived from the investment data reported in Appendix A and in the Supplementary Material.

showing a marked decrease in unit cost with increasing plant size.

2.2.5. Energy and economic indicators

To enable a consistent comparison between the electricity sold to the grid and the biomethane produced, it was assumed that the entire amount of biomethane is converted into electricity in natural gas power plants.

According to the ISPRA Ambiente report (ISPRA, 2020), the average electrical efficiency of Italian natural-gas-fired plants (including both cogeneration and non-cogeneration units) was 56.4% in 2018. This efficiency value was therefore adopted to convert the energy content of biomethane into an equivalent amount of electrical energy (EE Equivalent). This value was used only as a reference conversion factor for the energy comparison between electricity and biomethane pathways. It does not affect the economic revenues of biomethane configurations, which are calculated according to the dedicated biomethane tariff and incentive framework. Such an approach provides a simple yet effective common metric for comparing two fundamentally different energy vectors. It should be noted that this is a simplified assumption that does not account for alternative uses of biomethane – such as in transport or industry – which could yield even greater decarbonisation benefits. Nevertheless, given that over 30% of natural gas consumption in Italy is currently allocated to power generation, this assumption represents a realistic and practical basis for comparisons (ARERA, 2023; SNAM, 2025; MASE, 2025).

The performance indicators, listed below, were calculated from the annual energy balance of each configuration. In particular, the EE equivalent indicator was introduced to compare electricity and biomethane pathways through a common energy metric.

- **Energy BG**: energy exiting from the biodigester calculated using the lower heating value (LHV) of biogas;
- **BM produced**: energy content of the biomethane produced in configurations focused on biomethane production;
- **EE equivalent**: annual net electrical energy generated by the plants operating in electricity production mode (EE configurations), after internal auxiliary consumption. For biomethane configurations (BM), it is a conventional electrical-equivalent value calculated by multiplying the lower-heating-value energy content of the biomethane injected into the grid by the reference electrical efficiency of Italian natural-gas-fired power plants (56.4%). This indicator is used only for energy comparison and does not affect the economic revenues of BM configurations, which are calculated according to the dedicated biomethane tariff scheme;
- **Electrical efficiency**: overall electrical efficiency, calculated as the ratio between the equivalent electrical energy (EE equivalent) and the input energy of biogas exiting the biodigester (Energy BG).

The main economic indicators are defined as:

- **INV TOT**: total investment cost, as described in the previous Section 2.2.1;
- **INV after incentive**: adjusted investment after applying the relevant incentive schemes;
- **NPV$_{15}$ (Net Present Value at 15 years)**: discounted net balance between revenues and costs over the first 15 years of operation.

$$NPV_{15} = C_{INV,inc} + \sum_{y=1}^{15} \frac{C_{OP,y} - C_{REV,y}}{(1+i)^y} \quad (3)$$

where $C_{INV,inc}$ is the total investment cost after incentive, $C_{OP,y}$ are the operation costs at year y, $C_{REV,y}$ are the revenues at year y and i is the discount rate.

- **ROI (Return on Investment)**: ratio between the net present value at the fifteenth year (NPV_{15}) and the initial investment cost after incentives (INV after incentive).

$$ROI = \frac{NPV_{15}}{C_{INV,inc}} \quad (4)$$

- **PBT (Payback Time)**: time required to recover the initial investment through generated cash flows, i.e. the year y at which NPV_y is equal to zero.

Since the analysed configurations produce different final energy vectors, namely electricity in the EE pathways and biomethane in the BM pathways, a unit electricity generation cost was not adopted as the main economic indicator. Although biomethane production was converted into an EE equivalent indicator for energy comparison, this conversion relies on the hypothetical use of biomethane for electricity generation in a natural-gas-fired power plant. This assumption was therefore not extended to the economic analysis. The economic comparison was instead based on NPV, ROI and payback time, which allow different energy products and incentive schemes to be evaluated within a common financial framework.

3. Results

In the following section, the energy and economic analyses of all possible configurations for the four plants are presented. Table 1 provides a summary of the results obtained for the different configurations investigated in this study across the four plant sizes (100, 300, 600, and 999 kW$_{el}$).

When assessing the equivalent energy output of electrical plants and biomethane plants (EE equivalent), it is essential to recall that, as discussed in Section 2.2.5, biomethane values are expressed as electrical equivalents, assuming that all the produced methane is converted to

Table 1
Comparative analysis of plant configurations: energy and economic indicators.

Configuration	Energy BG (LHV)	BM produced (LHV)	EE Equivalent	Electrical efficiency (LHV)	INV TOT	INV after incentive	PBT	NPV_{15}	ROI
	MWh/y	MWh/y	MWh/y		k€	k€	Years	k€	
EE_ICE_100	2465	-	836	34%	242	242	8.1	170	70%
EE_FC_100	2465	-	1283	52%	1223	623	7.1	587	94%
EE_ICE_300	7420	-	2563	35%	470	470	5.7	628	134%
EE_FC_300	7420	-	3859	52%	2429	1829	8.3	1223	67%
BM_ICE_300_3k54	7420	5726	3229	44%	3813	3299	-	-1709	-52%
BM_FC_300_3k54	7420	6035	3404	46%	4291	3778	-	-1805	-48%
EE_ICE_600	14,024	-	5109	36%	881	881	4.5	1677	190%
EE_FC_600	14,024	-	7243	52%	4262	3662	8.9	2055	56%
BM_ICE_600_3k54	14,024	10,729	6051	43%	4532	3619	-	-474	-13%
BM_ICE_600_1k24	14,024	11,008	6209	44%	3118	2204	7.2	1327	60%
BM_FC_600_3k54	14,024	11,428	6445	46%	5091	4121	-	-289	-7%
BM_FC_600_1k24	14,024	11,620	6554	47%	3670	2698	7.8	1459	54%
EE_ICE_999	24,391	-	8509	35%	1474	1474	5.9	1859	126%
EE_FC_999	24,391	-	12,629	52%	6930	6330	9.4	3082	49%
BM_ICE_999_3k54	24,391	18,988	10,709	44%	5529	3931	7.2	2356	60%
BM_ICE_999_1k24	24,391	19,527	11,013	45%	4110	2630	3.9	4442	169%
BM_FC_999_3k54	24,391	20,497	11,560	47%	6383	4670	7.1	3112	67%
BM_FC_999_1k24	24,391	20,911	11,794	48%	4946	3233	4.2	5180	160%

electricity in a natural gas power plant. Therefore, changes in this conversion factor would affect only the energy-normalised comparison, not the discounted cash-flow indicators. Consequently, the energy potential of biomethane in other end-uses (e.g., transport or industry) is not captured by this metric.

The findings highlight a significant efficiency improvement achieved by replacing conventional internal combustion engines with solid oxide fuel cells, with electrical conversion efficiency rising from approximately 35% to more than 50% (on an LHV basis). This gain, however, comes at the expense of higher capital costs (INV TOT indicator), particularly evident for the 600 kW_{el} and 999 kW_{el} plants, where total investment increases by a factor of three to five compared with ICE-based configurations.

From an economic standpoint, small-scale systems (100 kW_{el}) show markedly different behaviour: although SOFCs require higher upfront costs, their improved efficiency shortens the payback time and leads to higher ROI, confirming their suitability for decentralised electricity production. For medium-sized plants (600 kW_{el}), both the electric and biomethane routes display comparable profitability, depending on grid distance and the magnitude of available incentives. Finally, at large scale (999 kW_{el}), biomethane conversion clearly outperforms electricity generation, reflecting the combined effect of economies of scale and favourable support mechanisms.

3.1. Energy analysis

This section analyses the energy performance of the investigated configurations. The comparison is carried out at plant level, using Sankey diagrams that illustrate the flow of energy through the main subsystems – from biogas production to electricity, heat, and biomethane

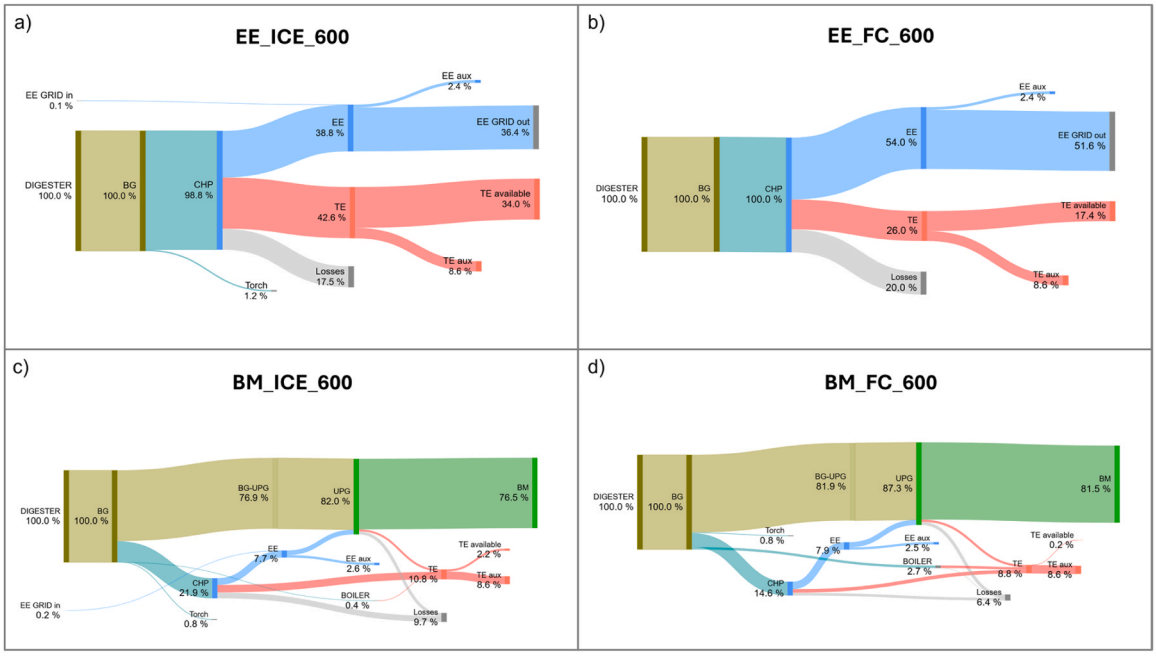

Fig. 4. Energy flow distribution for a) EE_ICE_600 configuration, b) EE_FC_600 configuration, c) BM_ICE_600 configuration, and d) BM_FC_600 configuration. All BM configurations refer to the 3k54 case.

outputs.

Fig. 4 shows the detailed distribution of energy flows for the 600 kW_{el} plant under both electricity (EE) and biomethane (BM) operating modes, comparing the ICE and SOFC configurations. The Sankey diagrams represent the annual energy fluxes within the plant, taking as 100% the energy content of biogas from the biodigester (i.e., its lower heating value multiplied by the flow rate). For biomethane configurations, the outputs refer exclusively to the energy content of the produced biomethane (based on its LHV), without conversion into electrical equivalents.

The output flows from the CHP consist of electrical energy (EE), thermal energy (TE), and losses. These outputs are further subdivided into electricity used by the plant auxiliaries (EE_aux), electricity exported to the grid (EE_grid_out), thermal energy supplied to external users (TE_available), and thermal energy used by the biodigester (TE_aux). A complete quantitative breakdown of these electrical and thermal flows for all configurations is reported in the Supplementary Material, including total CHP electricity production, auxiliary electricity demand, grid export, total thermal energy production, digester heat demand, and potentially available excess heat.

From an energy point of view, the adoption of SOFC offers significant advantages in all applications, particularly in electric-only configurations. In fact, the overall electrical efficiency increases from 36% to 52%. This improvement is especially noteworthy given that biogas plants supply a constant power output to the electricity grid. The significance of this aspect becomes even greater when considering that, in 2021, the total installed capacity of the Italian biogas-based electricity sector amounted to 1025 MW_{el}, almost entirely relying on ICEs (Terna, 2022). Enhancing conversion efficiency at the national scale could therefore represent a significant opportunity to improve the sector's overall energy performance and reduce its environmental footprint.

As regards biomethane plants, the use of SOFC technology enables a biomethane production that is about 4–6 %age points higher, even in smaller plants where the SOFC system cannot fully satisfy the auxiliary heat demand during the coldest months, thus requiring the use of a backup boiler. In particular, Fig. 4c and Fig. 4d show the energy flow distributions for the 600 kW_{el} biomethane plant in both ICE and SOFC configurations.

Only a limited number of plants are currently able to effectively valorise the excess thermal energy produced (TE _available), for instance by supplying heat to nearby industrial facilities or district heating networks. For these cases, the replacement of an ICE with a SOFC should be carefully assessed, since SOFCs generate a higher share of electricity but a lower amount of recoverable heat. Therefore, their adoption is justified only when local heat demand is limited or when electricity revenues dominate the plant's economic balance. Conversely, for biomethane configurations, the available excess thermal energy is typically negligible. As a result, reconversion from electricity-based operation to biomethane production generally leads to the loss of heat recovery opportunities and is therefore less attractive in contexts where thermal valorisation is relevant. Although TE_available is quantified for completeness, it is not monetised in the economic analysis because its valorisation depends on the presence of stable external heat users, which is highly site-specific and generally limited for agricultural biogas plants.

Fig. 5 compares the equivalent energy outputs (EE equivalent indicator) of all configurations, normalised to the reference ICE-based layout (EE_ICE), in order to highlight the relative performance of electricity and biomethane pathways across the four plant sizes.

It can be observed that, across all electrical plants, the adoption of SOFCs yields a significant improvement in efficiency (between 42% and 54% increase depending on the configurations). In contrast, for biomethane plants, the efficiency gain associated with SOFC integration is comparatively more limited.

3.2. Economic analysis

This section presents the main economic performance indicators of the investigated configurations. The analysis focuses on the cumulative cash flow trends over the 15-year lifetime of the plants, from which two key metrics are derived: the Payback Time (PBT), defined as the number of years required to recover the initial investment, and the Net Present Value at year 15 (NPV_{15}), which represents the discounted balance between revenues and expenditures.

Fig. 6 illustrates the evolution of cumulative cash flows for the 300, 600 and 999 kW_{el} plants. As shown in Fig. 6a, for small-scale plants (around 300 kW_{el} or below), biomethane configurations (green lines) never reach payback and display the weakest performance, both in terms of initial investment and the slope of the cash flow curve, indicating lower overall profitability. In particular, the adoption of SOFCs to supply auxiliary power (BM_FC_300) proves less convenient than the ICE-based alternative, as the substantial increase in capital expenditure is not offset by the modest efficiency improvement. Consequently, conversion to biomethane production is economically unattractive for this plant size range. Even under the most favourable network conditions (BM_ICE_300_1k24), the investment remains unprofitable. For configurations focused on electricity generation, the SOFC system, despite its higher initial investment, ensures better long-term

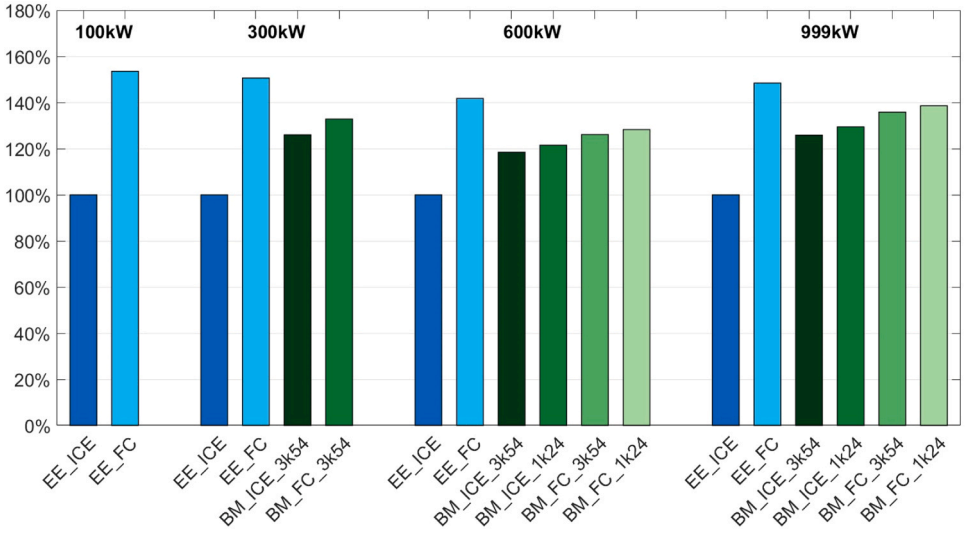

Fig. 5. Electrical Energy equivalent (EE equivalent) for all configurations, normalised to EE_ICE configuration.

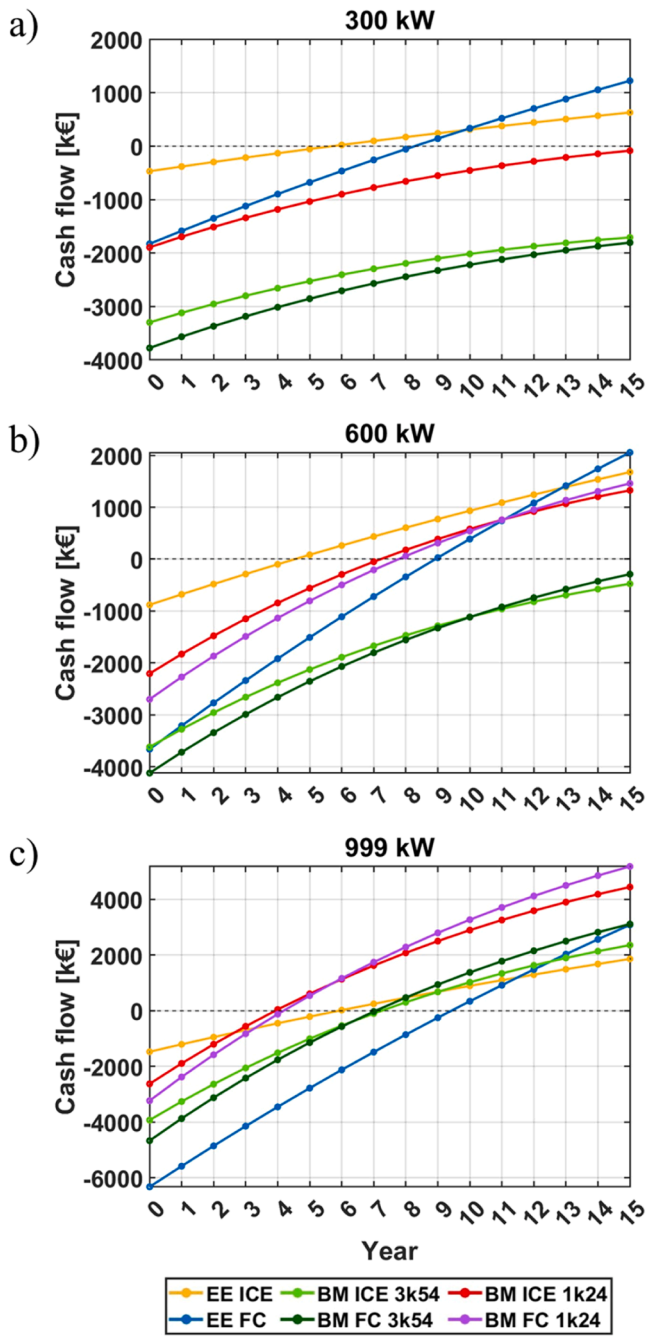

Fig. 6. Cumulative cash flows for all plant configurations.

profitability, as shown by the steeper slope of the cash flow curve and the higher NPV at the end of the project lifetime. The ICE configuration, on the other hand, achieves a shorter payback time (approximately 2.5 years less than SOFC), but yields an NPV_{15} roughly 50% lower. Overall, for small-scale biogas plants ($\leq$300 kW_{el}), continuing electricity generation – whether through SOFCs or ICEs – remains the most economically favourable strategy, while conversion to biomethane production does not offer competitive returns under current market and incentive conditions.

Fig. 6b shows the cash flows associated with the different configurations of the medium-sized 600 kW_{el} plant, where the performance gap between technologies narrows. Both ICE and SOFC electricity configurations achieve positive returns, with the SOFC yielding higher revenues but also requiring a substantially greater investment. Specifically, although the SOFC option (EE_FC_600) generates significantly more electricity (and therefore higher revenues) than the ICE version (EE_ICE_600), its investment cost is more than three times greater. As a result, the NPV at year 15 is only slightly higher than that of the ICE configuration, while the payback time is almost twice as long. When compared with the biomethane configurations, the investment required for the SOFC electricity configuration is similar to that needed for plant reconversion to biomethane, but the associated revenues are considerably higher. The feasibility of reconversion to biomethane production strongly depends on the distance from the gas grid and the operating pressure. If the network is 3300 m away (BM_ICE_600_3k54), the investment is not recovered within the plant's operating lifetime, while in cases where the network is at shorter distances (BM_ICE_600_1k24), the reconversion becomes competitive compared to the electric continuation. The power required to satisfy auxiliary consumption is relatively low, reaching 126 kW_{el} for the BM_FC_600_3k54 configuration. Therefore, the SOFC investment has a limited impact on the total investment and leads to a slight NPV advantage at the end of the lifetime.

For configurations focused on electricity generation, the SOFC system, despite its higher initial investment, ensures better long-term profitability, as shown by the steeper slope of the cash flow curve and the higher NPV at the end of the project lifetime (see the blue curve in Fig. 6a and Fig. 6b). It should be noted, however, that these results are strongly influenced by the investment incentives available for SOFC installations, which significantly reduce the effective capital burden. Under the Ecological Practices Decree (see Supplementary Material), SOFC-based cogeneration units benefit from a capital contribution of up to 65% of eligible costs (maximum €600,000), a support mechanism that is not available for conventional ICEs. The detailed investment costs and the corresponding incentive amounts applied in each configuration are reported in the Supplementary Material, where both the gross CHP cost and the incentive-adjusted value are presented for full transparency. A similar approach is adopted for biomethane configurations, for which capital contributions are also included in the reported values. The maximum eligible incentive of €600,000 introduces a scale-dependent effect. For small and medium-sized plants, the SOFC incentive covers a substantial share of the total CHP cost. For larger installations, the cap becomes binding and reduces the relative impact of the subsidy on the overall investment. This asymmetry contributes to the strong competitiveness of SOFC-based electricity generation in plants up to approximately 300–600 kW_{el}, while its economic advantage progressively diminishes as plant size increases.

For larger-scale plants, such as the 999 kW_{el} case study shown in Fig. 6c, conversion to biomethane production generally show stronger profitability than electricity generation. This is particularly evident under favourable 1k24 grid conditions (red and purple lines). Although the SOFC-based electricity configuration (EE_FC_999) achieves a significantly higher electrical output (up to 1.5 MW_{el} for the same biogas input, compared to 999 kW_{el} for the ICE), this efficiency advantage does not translate into superior economic performance. The SOFC option is characterised by the highest investment cost among all configurations, which results in the longest payback time and substantially increases the financial risk of the project. Among the biomethane options, only the ICE-based 3k54 configuration underperforms the SOFC electricity pathway, due to both the higher grid-connection cost and the lower operational efficiency. The EE_ICE_999 configuration presents the lowest investment cost overall but also the lowest operational profitability, resulting in a reduced final NPV. Consequently, for large-scale plants, reconversion to biomethane production emerges as the most cost-effective solution, particularly when the plant is located close to the gas grid (1k24 case). This advantage is also supported by the substantial incentive framework established by the Ministerial Decree of 15/09/2022 (Ministero della Transizione Ecologica, 2022), which strongly promotes the transition of existing biogas plants towards biomethane production (see the Supplementary Material).

It is also worth noting that, in the 600 and 999 kW_{el} case studies, SOFC-based electricity generation remains economically competitive

relative to refurbished ICE configurations, even when the capital incentive covers only a small fraction of the total CHP cost. For large SOFC units, the €600,000 incentive cap corresponds to a considerably lower percentage of the total investment. Nonetheless, SOFC configurations still outperform ICE-based electricity production due to their favourable scaling behaviour: the specific capital cost decreases substantially with increasing power size, as indicated by the CHP cost functions in Fig. 3. This result suggests that, for certain plant sizes, SOFC adoption is not only incentive-driven but structurally competitive.

Fig. 7 shows the NPV at year 15 for all configurations, normalised to that of the reference case (EE_ICE). This comparison provides a clear overview of the relative profitability of the different technological and operational pathways, highlighting how plant scale and grid connection distance strongly influence the preferred strategy. It should be noted that values are normalised to the EE_ICE configuration of each individual plant (100%). Therefore, the trend should not be interpreted as a continuous function of plant size, but as the outcome of four representative real case studies with different ICE efficiencies and cost structures. The relative advantage of EE_FC depends on the efficiency gap between the SOFC and the reference ICE, as well as on the specific investment cost of the SOFC. This explains why the relative NPV gain decreases for the 600 kW_{el} case, where the reference ICE is comparatively efficient, and increases again at larger scale, where SOFC specific costs decrease.

For small plants (100–300 kW_{el}), SOFC-based electricity generation (EE_FC) delivers the highest relative NPV, exceeding 200–300% of the reference, which underscores the economic advantage of efficiency improvements where grid connection for biomethane is prohibitively expensive. In medium-sized systems (600 kW_{el}), the results converge, revealing that both electric and biomethane routes can be financially competitive depending on local conditions, particularly the distance to the gas grid. For large-scale facilities (999 kW_{el}), biomethane configurations – especially BM_FC_1k24 – achieve the highest relative NPV, approaching 150–250% of the reference case. This confirms that the combination of economies of scale and incentive mechanisms decisively shifts profitability in favour of biomethane upgrading. Overall, Fig. 7 suggests the existence of a scale threshold around 600 kW_{el}, marking the transition between the economic predominance of electricity-based strategies and that of biomethane reconversion.

The effect of the discount rate on the economic performance of the configurations was further analysed in the Supplementary Material. As expected, absolute NPV_{15} values decrease as the discount rate increases, since future cash flows are given lower present value. Higher discount rates tend to favour configurations with lower initial investment and higher operating costs, such as ICE-based solutions, because future operating expenditures are discounted more strongly. Conversely, lower discount rates favour more capital-intensive but more efficient configurations, such as SOFC-based systems, since future operating savings have a greater weight in the NPV calculation. Despite these variations in absolute NPV_{15} values, the main scale-dependent trends identified in the manuscript remain unchanged.

The comparison between energy and economic indicators highlights a trade-off between efficiency maximisation and investment profitability. SOFC-based configurations generally provide the highest energy performance, as reflected by the EE equivalent indicator, due to their higher electrical efficiency. However, the most energy-efficient configuration is not always the most profitable one. Economic performance depends also on capital expenditure, operating costs, incentive mechanisms, plant size and gas-grid connection conditions. Therefore, the preferred configuration results from a balance between energy efficiency and economic viability rather than from energy performance alone.

4. Conclusions

This study investigated the technical and economic performance of ICEs and SOFCs when applied to agricultural biogas plants approaching the end of their incentive period in Italy. Four representative case studies, covering capacities from 100 to 999 kW_{el}, were analysed to evaluate two alternative valorisation routes – electricity generation and biomethane upgrading – under realistic operational and financial boundary conditions. The methodology combined detailed energy balance simulations with an economic assessment that included investment costs, operating expenditures, and incentive mechanisms defined by current Italian regulations.

The comparative analysis demonstrates that SOFC-based systems offer clear advantages in terms of electrical efficiency, which increases from approximately 35% to more than 50%. This improvement translates into a substantial reduction in biogas consumption and greenhouse gas emissions for the same power output. Main findings can be summarised as follows:

- For small-scale installations (100–300 kW_{el}), the continuation of electricity generation using SOFCs represents the most advantageous solution from both energy and economic perspectives. In these cases, the high electrical efficiency of SOFCs compensates for their greater investment costs, particularly when capital incentives – such as those established under the Ecological Practices Decree – are applied. These incentives play a decisive role in making SOFC-based

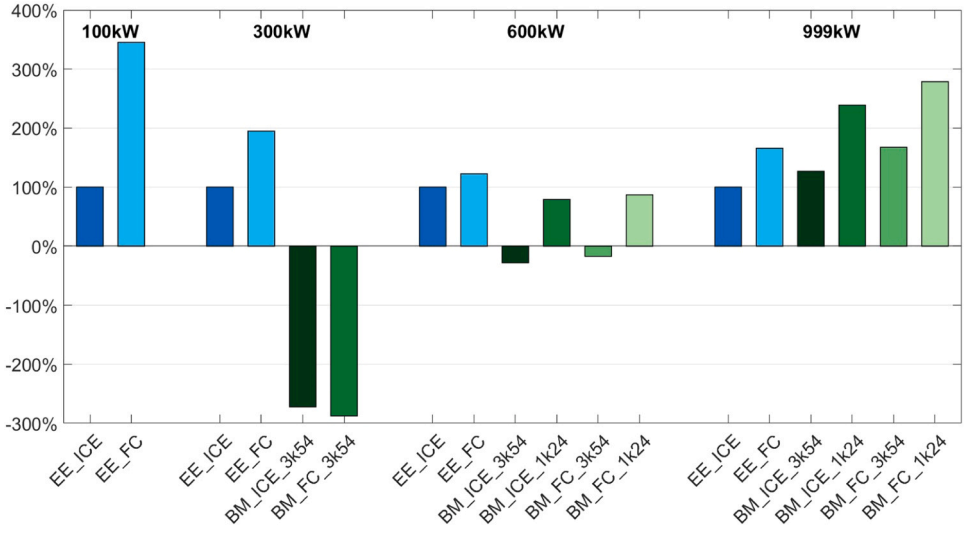

Fig. 7. NPV_{15} for all plant configurations with respect to NPV_{15} of EE_ICE configuration.

repowering financially attractive, whereas without them, ICE-based configurations would remain economically preferable.

- For medium-sized plants (600 kW_{el}), the economic comparison indicates that both SOFC-based electricity generation and biomethane production are technically feasible. However, the profitability of the biomethane option is strongly influenced by the distance to the gas grid and the pressure level required for injection. When these parameters are unfavourable, the SOFC-based electric configuration remains the most competitive choice. Importantly, within biomethane pathways, the integration of SOFCs as auxiliary power units improves biomethane output by only a few percentage points compared with ICE-based alternatives, while entailing higher capital costs. This limited impact is mainly due to the fact that auxiliary energy demand represents only a small share of the overall biomethane plant balance, whose investment cost is largely driven by upgrading, compression and gas-grid connection infrastructure. Therefore, SOFC adoption in biomethane configurations is not systematically economically justified under the analysed conditions and should be assessed on a case-by-case basis.
- For large-scale plants (about 1 MW_{el}), reconversion to biomethane is the preferred strategy, particularly when supported by the incentives provided by the Italian Ministerial Decree of 15/09/2022. In such cases, the use of SOFCs as auxiliary power sources can further enhance the plant's overall efficiency and sustainability.

The results underline the importance of adopting a site-specific, incentive-aware approach when planning the repowering of existing biogas plants. The integration of SOFCs can significantly improve system performance, but its feasibility depends on economic boundary conditions, incentive schemes, and proximity to gas infrastructure.

Acronyms

bcm	Billion cubic meter
BM	Biomethane
CAPEX	Capital Expenditures
CHP	Combined Heat and Power
CMA	Consorzio Monviso Agroenergia
FC	Fuel cell
GSE	Gestore dei Servizi Energetici, the Italian energy services operator
ICE	Internal Combustion Engine
INV	Initial Investment Cost
LHV	Lower Heating Value
NPV	Net Present Value
O&M	Operation and Maintenance
OPEX	Operational Expenditures
REMI	Pressure regulation, metering, and odorization unit
ROI	Return on Investment
SOFC	Solid Oxide Fuel Cell
UPG	Upgrading
VAT	Value-Added Tax

CRediT authorship contribution statement

Lucia Pera: Writing – review & editing, Visualization, Supervision, Methodology, Investigation, Data curation, Conceptualization. **Paolo Marocco:** Writing – review & editing, Visualization, Supervision, Methodology, Investigation, Conceptualization. **Andrea Chiabrando:** Resources, Project administration, Methodology, Data curation, Conceptualization. **Gabriele Novaira:** Writing – original draft, Visualization, Software, Methodology, Investigation, Formal analysis, Data curation. **Marta Gandiglio:** Writing – review & editing, Visualization, Supervision, Project administration, Methodology, 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

This appendix provides an overview of the cost assumptions and sizing logic adopted in the economic assessment, with the aim of clarifying how investment and operational costs are structured and how CHP capacities are defined across the analysed configurations. The full set of numerical cost data supporting the analysis is reported in the Supplementary Material.

The economic evaluation is based on a detailed breakdown of investment (CAPEX) and operational (OPEX) costs, grouped into macro-categories representing the main plant sections, such as civil works, anaerobic digestion revamping, biogas cleaning, CHP units, biomethane upgrading systems, grid connection infrastructure, and auxiliary systems. These cost items are consistently applied to all configurations analysed in the study, including electricity generation with ICE or SOFC and biomethane production with ICE- or SOFC-based auxiliary units.

Cost data originate from a combination of real operational information provided by Consorzio Monviso Agroenergia (CMA) and techno-economic analyses carried out jointly with the authors' affiliated university. This collaboration, ongoing for more than a decade, has focused on the assessment of SOFC integration in agricultural biogas plants and enables the use of realistic cost values reflecting both existing installations and consolidated practical experience. For all configurations, the economic assessment considers complete and fully functional systems. In particular, SOFC-related costs include the entire balance-of-plant required for reliable operation, such as enhanced biogas cleaning units, thermal management systems, power electronics, and control components, rather than only the electrochemical stack.

For biomethane configurations, new upgrading units are installed, and auxiliary electricity demand is supplied by newly installed, small-scale CHP units (ICE or SOFC), sized exclusively to cover internal consumption. In all cases, CHP sizing reflects market-available technologies rather than nominal reference values.

Figure A.1 summarises the resulting CHP sizes for all configurations, together with the corresponding specific investment costs expressed in €/kW. This representation enables a consistent comparison between ICE and SOFC technologies under equal biogas availability, independently of the nominal size labels used to identify the reference plants. The complete numerical datasets supporting Figure A.1, including detailed CAPEX, OPEX and incentive contributions, are provided in the Supplementary Material.

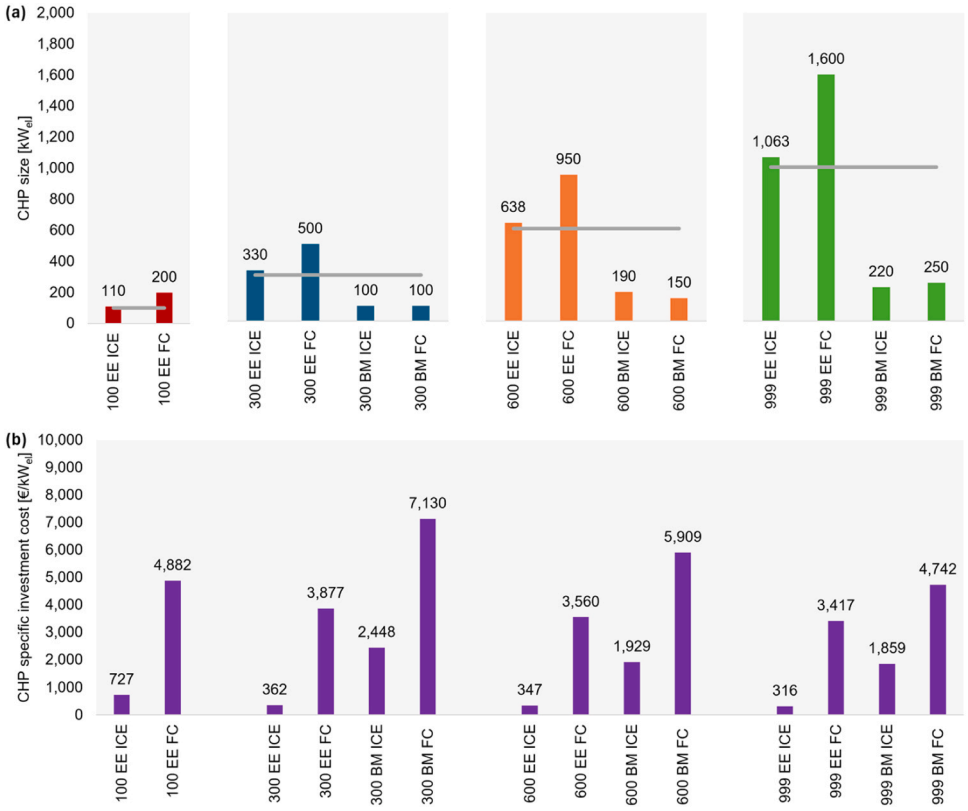

Figure A.1. (a) CHP size, evaluated for both EE and BM configurations. (b) CHP specific investment cost for the same system sizes and configurations

Appendix B. Supporting information

Supplementary data associated with this article can be found in the online version at doi:10.1016/j.egyr.2026.109716.

Data availability

Data will be made available on request.

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