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# Installation of high efficiency fuel cells within the ACEA Pinerolese waste treatment site: an energy and economic analysis

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## Abstract

Energy transition is a crucial topic in the modern society and is the only way to act against climate change and shift towards a more sustainable and efficient energy paradigm.

In this framework, one of the most promising ways to generate energy vector without creating a negative impact on the environment requires the implementation of waste-to-energy processes. Among them, biogas plays an important role since it represent an energy vector easy to process and store and is compatible with most of the current final uses, included ICEs and gas boilers.

This document provides a description of the main technologies involved in the production of biogas and its possible final utilizations (chapter 2). Then in the following chapter an overview of the different biogas production policies adopted by different European nations is reported, with a special focus on the Italian policy and the Biomethane decree of 2018.

In the fourth chapter a real case study is considered, the plant of Acea Pinerolese is described and the different input and output streams are characterized. The energetic balance of the plant is studied, and different future possible development of the plant are proposed.

In the fifth chapter different possible plant layouts are considered, and the technical and economic methods used to compare them are explained. The results of the energetic and economic analysis are reported in the sixth chapter, while in the seventh the main conclusions of this work are presented.

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# 1. Introduction:

In the actual world energy scenario, the need to react to a growing energy demand in an efficient and sustainable manner is becoming more and more important. The effects of climate change are clear and highlights the need to shift from a fossil fuel-based economy to a renewable one. This concept, usually called energy transition, is the main issue we will face in the next years, since changing from a classical energy production paradigm to a renewable one introduces some serious challenges. In fact, to reduce the pressure of the energy system on the environment requires to lower the global consumption of fossil fuels and to move towards a higher share of renewables in the energy mix.

Since the energy transition is a quite complex theme and involves different aspects including social environmental and economic ones, it has been discussed in many international meetings, like the recent Conference Of Parties (COP26) held in Glasgow in November. At the COP26 the main decisions were to limit the average global temperature increment at a value of +1.5°C and the reduction of carbon dioxide emissions (reduction of 45% within 2030 and net zero emissions within 2050), as reported in [1].

The necessity to find affordable and reliable technologies that could lead to a more sustainable growth is becoming more and more important, and in the energy field is mainly focused on the following points:

- Optimization of existing technologies to make them as efficient as possible and reducing their impact on the environment.
- Research of innovative techniques to exploit renewable sources not yet considered.
- Utilization of waste streams and by products of certain production chains, like for example heat discharge toward the environment in industrial applications.

In the field of electric power generation, the transition is represented by a shift from fossil fuels to renewable energy sources, whose increasing share present some relevant issues. However, with the greater diffusion of renewable energy systems such as wind and photovoltaic (PV), the limits of these technologies have been revealed, such as the difficulty in modulation of the power output, an energy production strongly dependent on the resource availability, impossibility to help balancing the grid. These problems are considered the main drawbacks that limits the diffusion of large-scale renewable production plants and that keep the role of fossil fuels still crucial in our energetic system.

## 1.1 Role of fossil fuels and possible alternatives

Nowadays the fossil fuels are the most diffused source of energy exploited worldwide, with large use in the transport sector, power generation and domestic applications. However, their extraction and utilization are the main cause of environmental problems our society is facing nowadays, like greenhouse effect and global warming.

Beside environmental issues, caused by the emission in the combustion of those fuels, there are many other drawbacks in the continuous exploitation of fossil resources. First, they're limited, which means that an economic and industrial system based on those resources could not be sustainable in the long term. Then they're present only in certain limited geographical regions of the globe, (i.e. strongly non homogeneous distribution) and this cause several problems in terms of security of access and energetic independence of countries without reserves.

So far, despite all these limitations, the exploitation of fossil resources has been the main method to respond to the growing energy needs of our society, given that energy carriers of fossil origin have some undeniable advantages, including the high energy content (energy density) and the ease of storage and distribution.

In fact, one of the major limits on the development and large-scale diffusion of renewable energy sources is their dependence on uncontrollable environmental factors, such as solar radiation or the presence of wind, which make the energy production profile extremely discontinuous and irregular. This leads to a complicated management of these types of plants and their interconnections with the distribution grid (i.e., the match operation between generation and instantaneous consumption of electrical power), and this require the development of technologies for energy storage and conversion. Furthermore, it must be considered that even if renewable energy sources such as wind and photovoltaic are suitable for stationary energy generation, these technologies are not used in the transport sector, where the need of a more flexible fuel or energy carrier is crucial.

From these problems arises the interest in biofuels and innovative fuels, since those fluids are characterized by properties very similar to traditional fuels but can be obtained by the elaboration of organic matter of renewable origin, such as waste from the livestock, agricultural, dairy, or other industrial process.

Among them the most promising one seems to be:

- Bio diesel
- Hydrogen, obtained by electrolysis or by anaerobic digestion.
- Biogas and biomethane, obtained mainly from anaerobic digestion of organic matter.

In this thesis we will focus on the products obtained from anaerobic digestion and their possible use, the main phases of the biological process and actual policies regulation are illustrated in the following paragraphs.

## 1.2 Biogas role in a circular economy paradigm

To move towards a more sustainable society, in which resources are used more and more effectively, it is necessary that what in the past was considered waste is introduced again into a production cycle. This is the principle behind the circular economy, the paradigm that is increasingly applied replacing the concept of linear economy, which has characterized modern society from the advent of industrial processes. In fact, as the world population grows and new industrial and developed areas expand, the linear economy will move towards constraint of supply of materials, including food. This may lead to economic hardship, human suffering, and conflicts.

As reported in [2] the aim of circular economy is to keep products, components, and materials at their highest utility and value, at all times.

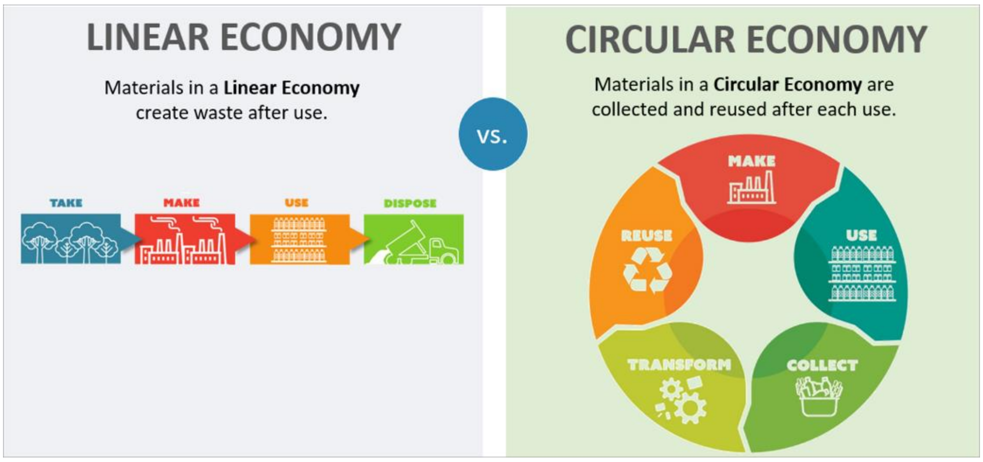


*Figure 1 Linear and circular economy comparison*

A practical field in which this concept can be successfully applied is the management of organic waste, since those streams are extremely frequent today, for example in the food supply chain, where food waste is generated daily in supermarkets, restaurants, and food industries. Other sources of organic waste are farms, which generate agricultural residues, manure but also residential facilities, that produce streams of wastewater and municipal solid waste. Treating these wastes through anaerobic digestion could boost the production of high-value products and chemical building blocks, fuels, advanced energy vectors without causing any negative impact on the environment.

When the anaerobic digestion process is used to treat organic waste, the waste stream is converted into valuable product through the simultaneous generation of biogas and digestate in a continuous way. If the input flow of organic matter comes from the process of purification of wastewater or from the management of livestock waste, this type of valorization helps to reduce the effects of eutrophication of watercourses that could be caused by the mismanagement of these flows. Similarly, even in the case of organic waste that would otherwise be directed to the landfill, this reduces the risk of contamination of local waterways and the uncontrolled emission of methane into the atmosphere. Several studies such as [3] report the advantages of the application of integrated anaerobic digestion systems for the management of livestock, agricultural, food and fish waste.

## 1.3 Advantages of biogas over major fossil fuels

The advantages of using biogas as an alternative to fossil fuels can be summarized as follows:

- It allows the enhancement of waste materials, which can thus be converted from waste to resource.
- It allows the generation of renewable power and heat or provide energy carriers with a high energy content together with the production of digestate, which can be used as fertilizer in agricultural processes.
- It can be the starting point for the development of advanced chemical compounds.
- It provides a renewable fuel with low impact on the environment. (GHG reduction potential)
- Unlike most renewable sources, it allows the generation of energy in a controlled and modular way.
- It is a carrier with a high energy content, easily stored and distributed without the need to develop special infrastructures.
- The use of biogas compared to natural gas reduces dependence on the import of fuels from foreign countries and enhance the local production of energy (distributed generation paradigm).
- Since it is obtained from the processing of different by-products, it allows the integration of numerous sectors, including agriculture, livestock, energy. This aspect leads to benefit also from a social and economic point of view.

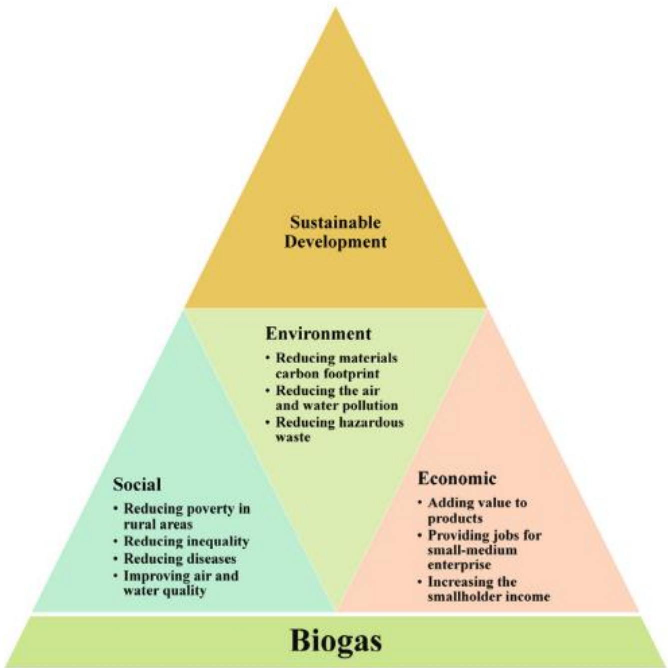


*Figure 2 Most relevant impact of Biogas use in the SDG path [Obaideen et al. 2022]*

# 2. Biogas production and utilization

## 2.1 Brief description of the stages of anaerobic digestion

Anaerobic digestion is an extremely interesting organic waste treatment process that can lead to two beneficial effects: the generation of an energy carrier and the control of the emission of pollutants. It is a natural biochemical process in which the degradation of organic compounds occurs by microorganisms in environments with low oxygen concentrations. Thanks to technological innovation it is possible to control this biological process based on the degradation of organic material to valorize urban waste and residual from the agricultural and livestock sector. Currently anaerobic digestion is an extremely widespread process to produce biogas, a mixture of gases whose main components are methane ($CH_4$) and carbon dioxide ($CO_2$).

Compared to aerobic digestion processes, it is characterized by a lower energy input and lower waste production.[4]

The process of anaerobic digestion can be described through the succession of the following stages:

- Hydrolysis
- Acidogenesis
- Acetogenesis
- Methanogenesis

These different phases are associated with the action of several microbial groups, which act under different temperature and pH conditions and are responsible for a specific chemical reprocessing of the substrate.

In the **hydrolysis** phase, the main groups of macromolecules that make up the organic substance (lipids, carbohydrates, and proteins) are broken down into simpler structures, called monomers. Lipids are converted into long-chain fatty acids and sugars; carbohydrates are broken down into sugars while amino acids are obtained from proteins. As reported in [5] the hydrolysis phase occurs in a few hours if the substrate is composed of carbohydrates, and in a few days if the substrate is composed of protein and lipids. However, if substrate compounds include lignin and lignocellulose, the process can take several days and complete digestion cannot be completed.

In the **acidogenic phase** the formation of volatile fatty acids and solvents takes place. The products of the previous phase are processed by anaerobic bacteria that transform them into organic acids (among which the main ones are acetic, butyric, and propionic acid) with the formation of alcohols, carbon dioxide and hydrogen. The products are related to the substrate types, operating conditions, and microorganism types. In this stage, the amount of $CO_2$ and $H_2$ in the products are approximately 70% and acids and alcohols are approximately 30%.

**Acetogenesis:** in this phase the acetogenic bacteria convert the product of acidogenesis into a methanogenic substrate. Acetate, H2, and CO2 are products of acetogenic bacteria produced with the oxidation of VFAs and alcohols. When the partial pressure of hydrogen is increased due to acetogenic bacteria's products, the acetogenic bacteria are inhibited. [6]

In the **methanogenesis** phase most components of biogas are produced. As reported in [7] methanogenic bacteria generate 70% of the methane from acetate and the rest of it from the transformation of H2 and CO2.

During the AD process, methanogenesis is the most critical phase because methanogenic bacteria are the most sensitive group. Operating conditions have significant effects on methanogenic bacteria such as substrate type, temperature, pH and feeding rate. Overloading the digester, temperature fluctuation more than 3 °C and large amounts of oxygen present can terminate the AD process due to methanogenic bacteria sensitivity. [7]

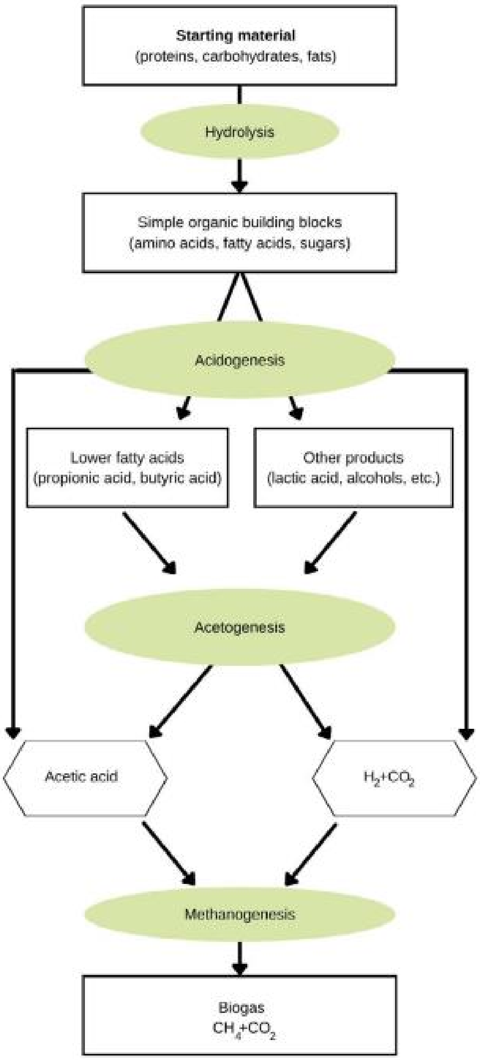


*Figure 3 Main phases of anaerobic digestion [DiBiCoo]*

## 2.2 Typical biogas composition and preliminary purification processes

As reported in [8] usually the term “biogas” is used to refer to the CH4–CO2 combustible mixture produced by the anaerobic decomposition of organic matter. This biogas is made up of 45–75% methane (CH4), the residual being mainly CO2 between 20–55%, with traces of other gaseous compounds (impurities) such as hydrogen sulfide (H2S), nitrogen (N2), hydrogen (H2), oxygen (O2), and others.

The most valuable biogas component for further application is methane, and to lesser extent hydrogen. Hydrogen sulfide and ammonia would also offer energy yield but can cause unwanted emissions or even damage to equipment, so they are usually removed in the purification process. Biogas is usually characterized by an energy content between 5 and 7 kWh/m³, mainly determined by the methane content.[9]

According to [10] impurities appear for various reasons in raw biogas. Among them, many are present due to the composition of feedstock that is introduced into the reactor, since it may contain some impurities; these are later found in the generated biogas after the evaporation of part of them in the digester. Siloxanes are an example of such compounds. Similarly, during anaerobic digestion, impurities can be formed in a similar way, like it happens for ammonia and hydrogen. Additionally, the temperature inside the reactor and the volatility of the compound influences the quantity that evaporates. In raw biogas, water is also found.

| Compound | Agricultural Waste | Landfills | Industrial Waste | Wastewater | Standard Biogas (EAB *) | Natural Gas |
|---|---|---|---|---|---|---|
| $CH_4$ % | 50–80 | 35–80 | 50–70 | 60–70 | 50–75 | 81–97 |
| $CO_2$ % | 19–50 | 15–50 | 30–50 | 19–40 | 24–45 | 0.2–1.5 |
| $H_2O$ % | ≤6 | 1–5 | 1–5 | 1–5 | 1–2 | - |
| $N_2$ % | 0–1 | 0–3 | 0–3 | 0–1 | 1–5 | 0.28–14 |
| $O_2$ % | 0–1 | 0–1 | 0–5 | <0.5 | Traces | - |
| $H_2$ % | 0–2 | 0–5 | 0–3 | 0 | 0–3 | - |
| $H_2S$ ppm | 2160–10,000 | 0.1 | 0.8 | 0–4,000 | 0.1–0.5% | 1.1–5.9 |
| $NH_3$ ppm | 50–144 | ~5 | - | 100 | - | - |
| CO % | 0–1 | 0–1 | 0–1 | - | 0–0.3 | - |
| Total Cl mg/m$^3$ | - | 5 | - | 100 | - | - |
| Siloxanes % | Traces | Traces | Traces | - | - | - |

*Figure 4 Composition of different kind of BG compared with NG and EBA standards [11]*

The final composition of the gas mixture obtained from anaerobic digestion can vary significantly depending on the organic matter treated, as shown in table 1.

**Preliminary biogas purification**

When raw biogas is produced from anaerobic digestion of biomass, before being directed to final uses, it must be purified by contaminants, such as hydrogen sulfide, ammonia, water, and siloxanes. Regardless biogas use, this process is crucial for reduction of maintenance costs and avoid the substitutions of downstream appliances. For example, hydrogen sulfide can easily react with water to form an acid that may cause corrosion of tubes and components the stream encounters, while ammonia can react with oxygen producing NOx and contribute to greenhouse gases emission, in case of future combustion.

About water content, when biogas is produced, it is initially at the same temperature as the digester content and is saturated with water vapor. As it starts to cool, for example in the gas pipelines, water vapor starts to condense, and this phenomenon may cause malfunction or even damage of mechanical devices, for example if condensed water blocks the piston of an ICE. It is therefore important to remove condensed water at the lowest point in the gas pipes, to avoid water flowing into the CHP (or other devices where it could cause damage). It is also necessary to reheat the biogas before critical applications so that the biogas is no longer saturated with water vapor (which could start to condense and damage the CHP).

Depending on the final uses of the biogas, different concentration of impurities can be tolerated, as reported in the table below:

| Technology | $H_2S$ | $CO_2$ | $H_2O$ | Siloxanes |
|---|---|---|---|---|
| Boiler | <1000 ppm | No | No | No |
| Stationary Engine | 542–1742 ppm | No | No | 9–44 ppm |
| Kitchen Stove | <10 ppm | No | No | No |
| Vehicle Fuel | <5 ppm | Recommended | Yes | No |
| Natural Gas Grid | <4 ppm | Yes | Yes | Yes |
| Liquid Biomethane | <4 ppmv | <25 ppmv | <1 ppmv | No |

*Figure 5 Maximum impurities tolerance depending on final uses [11]*

**Water and siloxanes removal**

Since raw biogas is saturated with water vapor, when the flow temperature is lowered in the pipes downstream the digester vapor starts to condense. In case of CHP application, to avoid water entering the engine, most plants cool the biogas in underground pipes or via a water cooler. In this way the condensate can be collected at the lowest point of the pipes and discharged in a condensate trap [9]. Since the biogas is still contains saturated vapor after cooling, it is important to heat the biogas up again so that the relative humidity drops below 100%. This is usually done with exhaust heat from the blower and with a back-up electric heating system.

Siloxanes are only present in the case biogas is produced from sewage sludge or if special foam-inhibiting agents are applied in the digester. If biogas is used in engines for CHP purpose, siloxanes could cause deposits on the spark plug, the injection valves, the exhaust valves and on the surface of the piston, leading to damage to the engine. Most plants using sewage sludge install a safety step in the form of an activated coal filter so that possible siloxane can be removed if it occurs[9].

**Hydrogen sulfide removal**

Sulphur is a nutrient element present in all living species; it is transported into the biogas plant in the feedstock and is partly converted to H2S in the digester. The concentration of hydrogen sulfide in raw biogas depends very much on the sulfur content of the feedstock. Typical concentrations can range from below 100 ppm up to several thousand ppm[9].

As reported in [12], H2S can be reduced by means of several desulphurization techniques, including biological conversion, chemical or physical treatment of raw biogas. The choice of technology depends on the biogas plant design and on the feedstock used.

If the sulfur content of the input feedstock is relatively low, biological treatment within the gas space of the digester is a very cost-effective technique. During this treatment, the bacteria Sulfobacter oxidants convert hydrogen sulfide in the presence of oxygen to elementary sulfur. The great advantage of this technique is the quite simple equipment set-up since it is only required a blower to blow air at the top of the digester. Air, together with other nutrients (provided inside the digester) allow the development of bacteria species. Some digesters are constructed in such a way as to offer enough surface for these bacteria to settle. This process can also be carried out in external desulphurization devices, like airtight towers containing areas where bacteria can get established, fed by a nutrient solution which is spread from above, washing down any elementary sulfur that is produced. Biogas is blown through this type of desulfurization tower from the bottom up[9].

Chemical desulfurization is carried out adding iron compounds (iron III chloride, iron II chloride, etc.). Iron compounds fed into the liquid digester content will bind to the sulfur in the digestion liquid, so chemically bonded sulfur cannot be released into the biogas[9].

The third commonly used method is adsorption on activated carbon. This method is typically used (often in combination with other methods) if the biogas is to be upgraded to biomethane and needs to comply with very low and strict maximum values for H2S. The hydrogen sulfide is adsorbed on specially conditioned activated coal[12].

## 2.3 Possible biogas uses

Considering the importance of biogas in a transition scenario towards renewable and less polluting fuels, it becomes extremely important to understand which kind of process or use can exploit this resource in the most efficient way.

Several studies have been carried out on this issue in recent years and various articles have been published to evaluate the best process for the use of biogas. For a complete analysis it is necessary to take into account different energy, economic, environmental aspects that allow assess the sustainability of one process and the effectiveness compared to another one.

Based on the research carried out among the scientific articles dealing with these topics, four different methods of use of biogas obtained from anaerobic digestion can be substantially distinguished:

- Heat or steam production
- Cogeneration by classical methods (ICE or micro-GT)
- Upgrading of biogas to biomethane (for feeding into the network or use in the field of transport)
- Cogeneration through fuel cells

Subsequently, the different options are explained and deepened one by one:

**Heat or steam production**

The most common use of biogas produced by small plants is related to domestic applications, especially in developing areas. In those countries, in which electrical power is limited and people rely on biomass utilization for covering their energy needs, biogas is extensively employed for fueling cooking stoves and for providing lightning. The biogas reactors in these areas are household scaled with a typical size of only 2–10 m3, which does not allow the accommodation of CHP or purification processes [12].

Equipment such as kitchens and gas lamps can be easily converted to biogas by acting on the air-gas mixing ratio. In more industrialized countries, biogas is instead used to produce process heat in industry, to generate steam, or to provide peak load and failure reserve heat for district heating systems. In Europe, this is not done very often because electricity has a much higher value and can be used more flexibly than heat. The greatest advantages of this type of use can be identified in the fact that it takes advantages of long-proven technologies and does not require specific biogas purification treatments.

### 2.3.1 Cogeneration with traditional technologies (ICE or micro-GT)

This method of energy valorization is surely the most widespread in the current panorama of anaerobic digestion systems, since it allows to obtain simultaneous production of electricity and heat with compact systems, although characterized by reduced efficiency. According to [14], the reference efficiency of cogeneration systems of medium and large power (up to 1MWe) powered by biogas is around 35% of electrical efficiency, 40% of thermal efficiency. This type of plant is particularly common in the countries of northern Europe, where the presence of district heating networks is extremely widespread, a factor that allows to find a constant use for the thermal power generated. If a nearby district heating network is not available or accessible, as well as in the summer period when the heat demand is extremely low, this power remains unsold, except in cases where there is an industrial thermal user to be served.

Despite the important development in recent years, this method of using biogas reveals some rather obvious limitations. First of all, the conversion of energy requires the combustion of gas, which causes the formation of polluting chemical species that must be taken into account (environmental aspect). Moreover, by exploiting a thermal cycle, this process of energy generation has quite low efficiencies due to thermodynamic limits (typical values are around 40-45% efficiency). Finally, although cogenerators of different sizes are available on the market (rated power ranging from a few kW to several MW), it must be considered that the electrical efficiency is significantly reduced in the case of small cogenerators (around 30% in the case of engines under 100 kWe). Similarly, there are significant drops in efficiency when the power supplied by the system is reduced, causing it to work outside the conditions of rated power (partial load operations).

As far as gas turbines are concerned, their application is extremely widespread in the case of plants with a power of more than 800kW. In recent decades, small-scale applications (rated power around 25-100 kW) are being studied, obtaining good results but with rather reduced efficiency. Currently the electrical efficiency of these types of systems is in fact equal to or lower than the one of internal combustion systems (25-30%).

### 2.3.2 Biogas upgrading to biomethane

This process is used to treat the biogas obtained from digestion, to obtain a product free of impurities and usable in current domestic equipment instead of natural gas. The main reason for the interest in biogas upgrading processes is the possibility of injecting the product obtained into the existing gas distribution network. This allow the connection of production facilities (normally located in rural contexts) securely and efficiently with urban areas where the presence of end users is much higher.

However, before the gas produced by anaerobic digestion can be fed into the network, it is necessary to purify it to obtain a product that meets the standards indicated by the network operator. These standards typically concern the composition of the gas and its calorific value and are imposed to ensure compatibility between the fuel and the equipment installed (domestic stoves, cookers and so on…) in order to avoid contamination of the distribution network. The purposes of the upgrading process can be identified as follows:

- Meet the criteria needed to power current equipment (kitchens, boilers, vehicles...)
- Increase the calorific value of the treated gas
- Obtaining a standardized gas

The main technologies for decarbonization of biogas are:

1. **Water scrubbing**
2. **Organic solvent scrubbing**
3. **Chemical scrubbing**
4. **Pressure swing adsorption (PSA)**
5. **Membrane separation**
6. **Cryogenic separation**

Currently, the decarbonization of biogas at industrial scale is primarily performed using membrane separation and water scrubbing, but physical and chemical $CO_2$ absorption methods are quickly growing technologies. In general, the methane recovery from physicochemical processes can reach values higher than 96%.

1. **Water scrubbing**

Physical absorption method using water scrubbing system is the most diffused technology for biogas cleaning and upgrading. This process performs the separation of $CO_2$ and $H_2S$ from the biogas stream due to their increased solubility in water compared to $CH_4$ (since according to Henry's law, the solubility of $CO_2$ in water at 25 °C is approximately 26 times higher compared to methane). Firstly, the biogas is pressurized (6–10 bar, up to 40 °C) and injected into the absorption column via the bottom side of the tank, while water is provided from the top side of the column and flows in the opposite direction of the gas stream. The absorption column is usually filled with random packing material to increase the interaction between gas and liquid [15].

The biomethane is then collected from the top of the scrubber, while the water phase containing the $CO_2$ and $H_2S$ is circulated into a flush column, where the pressure decreases (2.5–3.5 bar) and some traces of $CH_4$ dissolved in the water are recovered; after a drying step, the $CH_4$ can reach up to 99% purity [16].

Since large quantities of water are required for this upgrading technology, usually a regeneration step, called “regenerative absorption” is implemented. The water can be regenerated in a desorption column by decompression at atmospheric pressure, resulting in the removal of $CO_2$ and $H_2S$. Water decompression usually occurs by air stripping. However, in cases that the biogas contains high concentrations of $H_2S$, steam or inert gas are used in the desorption process to avoid formation of elemental sulfur by the application of air stripping, which will in turn lead to operational problems [11]. In case the water is derived from sewage treatment plants, the regeneration step is avoided, and a “single pass scrubbing” configuration is adopted. The typical water flow that is needed to upgrade 1000 $Nm^3/h$ of raw biogas ranges between 180 and 200 $m^3/h$ depending on the pressure and water temperature[17].

**2. Organic solvent scrubbing**

This method relies on the same principle as water scrubbing, however, the absorption of $CO_2$ and $H_2S$ is performed with the use of organic solvent instead of water. Commonly, the used organic solvents are mixtures of methanol and dimethyl ethers of polyethylene glycol. Marketable chemical products are available under the trade names of Selexol® and Genosorb®. The advantage of the solvents compared to water is the considerably higher solubility of $CO_2$ that can be reached. For example, Selexol® can absorb 3 times more $CO_2$ than water, which practically means reducing liquid consumption of the system, and therefore, smaller dimensions of the upgrading unit. Nevertheless, the organic solvents are difficult to be regenerated due to the high solubility of $CO_2$ and this constitutes a major obstacle of the process. Furthermore, the solubility of $H_2S$ in Selexol® is significantly higher than the one of $CO_2$ and therefore its separation during the solvent regeneration requires increased temperatures. In fact, higher concentrations of $H_2S$ in the raw biogas require higher regenerating temperature. For this reason, it is recommended to remove $H_2S$ before the gas is fed to the solvent to avoid increased energy consumption.

Initially, the raw biogas is compressed (7–8 bars) and is cooled at around 20 °C prior to its injection from the bottom of the absorption column. Similarly, the organic solvent is cooled down prior to its addition as the temperature affects the Henry's constant [17] Afterwards, the organic solvent is regenerated by heating it up to 80 °C and adding it in a desorption column in which the pressure is decreased to 1 bar [17][16]. The final content of $CH_4$ in the upgraded biogas using this technology can reach 98%.

**3. Chemical scrubbing**

Chemical scrubbers use aqueous amine solutions to bind the $CO_2$ molecules contained in the biogas. One of the advantages of this technology is that $H_2S$ can also be completely absorbed in the amine scrubber. Amine scrubbing systems mainly consists of an absorber unit and a stripper. In the absorption column, the biogas (at a pressure of 1–2 bars) is fed from the bottom of the tank while the amine solution flows from the top in a counter-current configuration. The $CO_2$ is bound to the solvent by an exothermic chemical reaction. Then, the resultant amine solution (rich in $CO_2$ and $H_2S$) is sent to a stripping unit for regeneration. The stripping column has a pressure of 1.5–3 bars and is equipped with a boiler that provides heat (steam at 120-160°C) required to disrupt the chemical bonds formed in the absorption phase. Finally, the steam that contains $CO_2$ is cooled in a condenser allowing the condensate to recirculate to the stripper and the trapped $CO_2$ to be released.

Apart from amine solutions, other aqueous alkaline salts, such as sodium, potassium, and calcium hydroxides, can be used as solvent in the chemical scrubbing process [14]. As an example, sodium hydroxide has higher $CO_2$ absorption capacity compared to amine-based solvents such as mono-ethanolamine, allowing to reach the same result with a lower amount of solvent. More specifically, in order to capture 1 ton of $CO_2$, the theoretical amount of mono-ethanolamine that will be needed reaches 1.39 tons, while the corresponding amount of sodium hydroxide is 0.9 tons [18].

Main disadvantages of amine chemical scrubbing methods include the toxicity of the solvents to human and environment, the significant energy that is needed for regeneration of the chemical solutions, the initial cost of the amine solvents and their loss due to evaporation. Therefore, aqueous alkaline salts are preferred in comparison with amines as they are more cost efficient and more abundant [18] .

By applying this technology, the final methane content in the output gas can reach 99% purity since the chemical reaction is strongly selective and thus the methane loss can be lower than 0.1%

### 4. Pressure swing absorption

This technology separates $CO_2$ from biogas based on their molecular characteristics and the affinity with the adsorbent material. The most employed adsorbents are carbon molecular sieves, activated carbons, zeolites and other material with high surface area and a particular pore size [19]. PSA technology relies on the properties of pressurized gasses to be attracted to specific solid surfaces. Therefore, under high pressure, large amounts of gas will be adsorbed, while a decrease of pressure will result in gas release.

When biogas is fed into the first PSA column, the pressure increases, and the activated carbon physically adsorbs $CO_2$ while methane passes through the process and exits at the top of the column. When the activated carbon has reached a full load of carbon dioxide, the column inlet is closed and the flow of raw biogas is fed into another column, installed in parallel, which also contains activated carbon. In order to remove the carbon dioxide from the activated carbon once it saturated, the gaseous content of the column is partly fed into another one, until the two columns have reached equal pressure. This lower pressure level releases the trapped $CO_2$, so it can be removed with a vacuum, allowing the column to begin the process again and separate carbon dioxide from the next batch of biogas. To maintain continuous operation, in most of the industrial applications, at least four vessels are connected in a parallel configuration.

This method is advantageous due to equipment compactness, it requires low energy and capital investment cost, and finally, due to its safety and simplicity of operation [19]. The raw biogas can be upgraded up to 96–98% methane concentration; however, up to 4% methane can be lost within the off-gas stream [17]; [15].

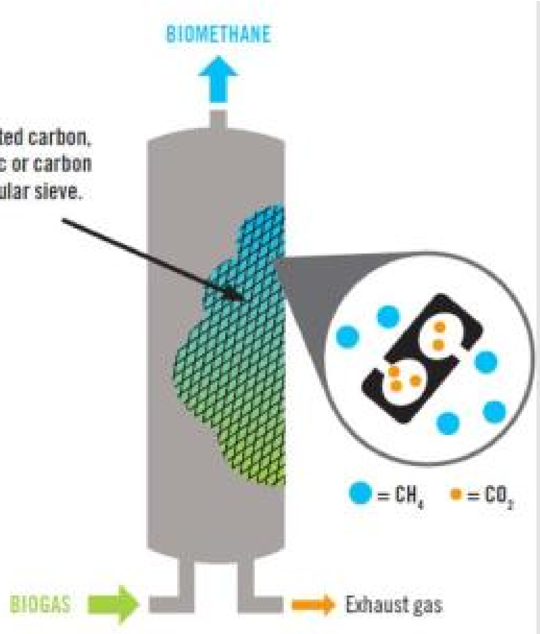


*Figure 6 Working principle of a PSA column [Fachverband Biogas 2017]*

## 5. Membrane separation

Membrane technology is a competitive alternative to the conventional absorption-based biogas upgrading system. Membrane separation technique uses the different permeability and size of various gaseous molecules to separate gases using specially conditioned polymeric membranes composed of cellulose acetate and polyimide. The permeation rate of such membranes is dependent on the sorption coefficients of the gasses and on the membrane construction material, but in general these membranes are 20 times more permeable for CO2 than for CH4.

Considering the diffusion and the sorption coefficient of different gasses as a function of their molar volume, it can be observed that smaller molecules (e.g. CO2) are less condensable and more favorable to become permeant from the membrane compared to larger molecules (e.g. CH4) (Baker, 2012). Therefore, in many polymeric membranes the diffusion coefficient and the solubility of CO2 is higher compared to CH4 resulting in higher permeability. For this reason, the gas that is rich in CH4 will remain to the side of the membrane with the higher pressure, while the CO2 (together with a significant amount of methane that can reach 10–15%) will be diffused to the side with the lower pressure. The CO2 separation efficiency is strictly dependent on the type and material of the membrane used. An ideal membrane should have large permeability difference between CH4 and CO2 to minimize the CH4 losses and efficiently purify the biogas [20]

To achieve a high methane content in the purified gas and avoid an excessive amount of methane in the exhaust gas, the membrane separation technique is usually applied in a two- or three-stage process. Nitrogen does not diffuse through the membrane wall and therefore remains together with the methane, so it is important to avoid any accumulation of nitrogen in the biogas. Biogas needs to be dewatered, de-oiled and desulphurized before entering the membranes to avoid causing excessive wear.

The CH4 content in the upgraded biogas is commonly around 95% [17]. Major disadvantages of this technology are the high cost of the membranes and their fragility. It is estimated that the lifetime of the membranes for biogas purification varies between 5 and 10 years [13].

### 6. Cryogenic separation

This technique is performed through a gradual decrease of biogas temperature, that allow the separation of liquefied CH4 from CO2 and residual components [21] in order to obtain a product in accordance with the quality standards for Liquefied Natural Gas (LNG).

The separation is carried out by initially drying and compressing the raw biogas up to 80 bars followed by a stepwise temperature drop up to -110 °C [11]. Thus, the low contained impurities (i.e. H2O, H2S, siloxanes, halogens etc.) and subsequently, CO2 which is the second most dominant component of biogas are gradually removed in order to recover almost pure biomethane (> 97%). As reported by [20], despite the promising results, the cryogenic separation process is still under development and only few facilities are operating in commercial scale [17] The high investment and operation costs, losses of CH4 and practical problems (e.g. clogging) derived from either the increased concentration of solid CO2 or presence of rest impurities limit the wider establishment of this technique.

A comparison between different upgrading technologies and the relative diffusion of each technique are reported respectively in the table and the image reported below.

| Parameter | Membrane Separation | Pressure Swing Adsorption | Water Scrubbing | Chemical (Amine) Scrubbing | Organic Solvent Scrubbing |
|---|---|---|---|---|---|
| Off-gas treatment recommended | Yes | Yes | Yes | No | No |
| Desulfurization Requirement | Yes | Yes | No | Yes | No |
| Water Demand | No | No | Yes | Yes | No |
| $N_2$ and $O_2$ removal | Partial | Possible | No | No | No |
| Chemical Requirement | No | No | No | Yes | Yes |
| Operation Pressure (bar) | 6–8 | 4–10 | 4–10 | Atmospheric | 4–8 |
| Outlet Pressure (bar) | 4–6 | 4–5 | 7–10 | 4–5 | 1.3–7.5 |
| Heat Demand | None | None | None | 100–180 °C | 55–80 °C |
| Energy Demand (kWh/$m^3$ biomethane) | 0.25–0.43 | 0.46 | 0.46 | 0.27 | 0.49–0.67 |
| Running Cost (€) | 81,750 | 187,250 | 110,000 | 134,500 | – |
| Investment Cost (€) | 233,000 | 680,000 | 265,000 | 353,000 | – |
| Maintenance cost (€/year) | 25000 | 56000 | 15000 | 59000 | 39000 |
| Methane Losses (%) | <1.5 | <2 | <2 | <0.1 | <2 |
| Maximum recovery (%) | 96–98 | >96 | >97 | 99.5 | >99 |
| Technical Availability | 98 | 94 | 96 | 91 | – |

*Figure 7 Comparison of different biomethane upgrading technologies [11]*

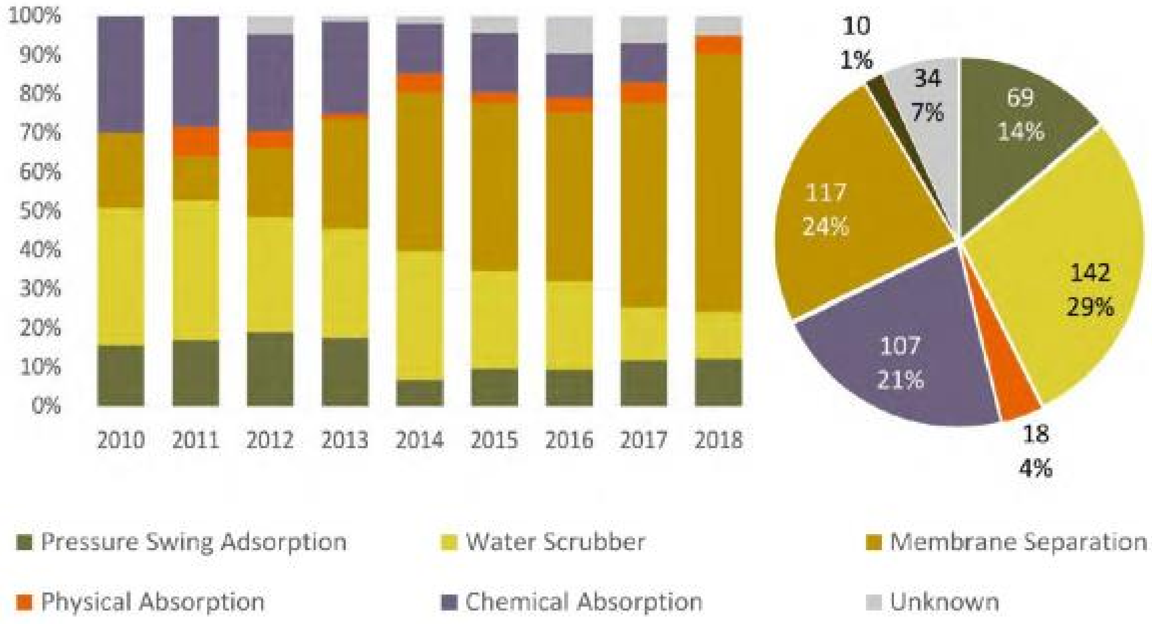


*Figure 8 Different upgrading technologies worldwide (left) and in the EU (right) [EBA 2020]*

### 2.3.3 Cogeneration using fuel cells

This method is undoubtedly the most innovative, since it involves extremely recent technologies that allow energy to be produced with a significantly higher conversion efficiency than conventional methods. Thanks to the fuel cells, in fact, an electrochemical oxidation of the fuel takes place and allow to make the most of the full potential of the fuel without the need to go through a heat exchange.

The generation of electrical power or cogeneration using fuel cells is much closer to a "classic" generation method, such as a gas turbine system. In fact, the fuel that powers the fuel cell group can be stored with ease, and the feed rate modulated to provide different useful power values. This objective is achieved, indeed, through the electrochemical oxidation of the fuel which, compared to the combustion of the same, allows to obtain significantly higher efficiency values and a lower production of undesirable compounds such as CO2, NOx etc.

**Principle of operation of a fuel cell**

A fuel cell is a device that allows the electrochemical oxidation of specific species of compounds, including hydrogen, hydrocarbons or alcohols allowing the exploitation of their internal energy without requiring any form of combustion. These devices are typically characterized by a high conversion efficiency not affected by the thermodynamic limits related to the use of a thermal machine. Although over the years different types of devices have been developed suitable to be powered by different gases, most fuel cells have a very similar basic structure, as schematically indicated in fig. 9.

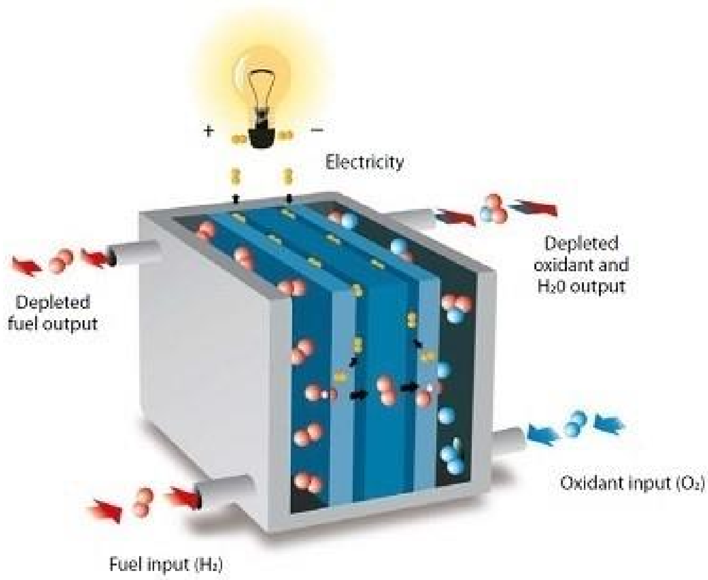


*Figure 9 Schematical representation of a fuel cell [2]*

The essential components of a fuel cell are the two electrodes (anode and cathode) and the electrolyte. The fuel is sent to the anode, while the oxidizer is sent to the cathode and in these two compartments oxidation and reduction reactions take place. The electrolyte has the function of allowing the selective passage of the active chemical species only (i.e. proton or oxygen ion). To increase the power supplied by the system generally several cells are connected in series, to form the stack. In this case, between two successive cells is placed an additional new element, called interconnection plate.

These elements constitute the core of the fuel cell system (i.e. its power section), then to obtain a commercial product have to be added all the components that are generally indicated under the name of "balance of plant" and that are necessary for the reprocessing of the fuel, for the supply of the oxidizer in the appropriate conditions and for the conversion of the generated power into alternating current.

In the fuel reprocessing section, all the transformations to make the fuel suitable for properly feeding the cell take place. If the cell requires high-purity hydrogen, as for example in the case of PEM cells, the fuel must be treated by removing all compounds that may be harmful to the cell's catalytic system, such as carbon monoxide and sulfur compounds. To achieve this objective, three different fuel processing sections are generally required, the first one perform desulphurization of the fuel, the second one the steam reforming process, while in the third there is a cleaning of the gas obtained from reforming.

In the case of cells operating at high temperature, such as MCFC or SOFC, the fuel processing conditions are less severe, and allow the use of fuels other than hydrogen, such as natural gas, propane, butane, biogas, and synthesis gas.

**Type of fuel cells and their applications**

Fuel cells have different characteristics according to the field of application: in the automotive sector the most common type is the proton exchange membrane, which works at relatively low temperatures (around 80°C - 100°C) while for electricity generation (stationary use) solid oxide cells (SOFC) or molten carbonates (MCFC) are generally used.

Among the advantages of cells that work at a higher temperature (typically in a range between 700°C and 1000°C) there is the fact that they allow to achieve efficiency values significantly higher than those operating at low temperatures. This explain why they are generally preferred in the field of power generation, where the purpose is to convert the most of the energy potential of the fuel, while in the case of applications in the automotive sector the flexibility of the cell is clearly preferred to the conversion efficiency.

**Possibility to feed fuel cells with natural gas or biogas**

Although fuel cells were initially designed to be powered by pure hydrogen, in recent years excellent results have also been achieved by using natural gas or biogas as fuels. In fact, by analyzing and trying to minimize the effects of carbon deposition, these types of fuels are also suitable for use in fuel cells. Unlike hydrogen, which must be obtained through special chemical treatments from water or methane (processes with high energy input), natural gas is one of the most widespread energy carriers and easy to transport and store.

However, even if natural gas among fossil sources is the one that is generally considered the "cleanest" due to the easy combustion and the lower number of unwanted products that are generated during the same, it is still a non-renewable source, whose long-term extraction causes an unsustainable impact on the environment.

This is the reason why coupling fuel cell CHP units with biogas production facilities seems a promising choice to implement in the future, and in some cases (e.g. DEMOSOFC project) has already proved to be an interesting option to exploit waste streams.

## 3. European biogas production, market trends and policies

As reported in [22] global biogas production in the last 20 years passed from 78 to 364 TWh in the years between 2000 and 2017, due to the development of many new plants. The biggest players are mainly Europe, which contributes for the 54%, Asia (31%) and America (14%). While in developing countries the biogas is used as an alternative to firewood in rural applications, such heating and cooking, in developed countries it is produced in apposite industrial plants and valorized in the form of electricity or biomethane injected in the distribution grid.

From an analysis of the biogas sector development in Europe, it is possible to realize that in the last decade there was a strong shift in the final uses from CHP valorization to biomethane upgrading in almost all European countries. In fact, in 2018 in the EU, it can be estimated that about 88% of the biogas is valorized directly on-site, through CHP units (total primary energy production from biogas was 178 TWh and biomethane upgrading capacity was 22 TWh). This result is strongly related to energy policies, set between 2000 and 2015, from several state members based on subsidies incentives for this technology [23]. However, the recent decline in subsidy levels explain the slowdown of the “biogas to power” path in the last few years.

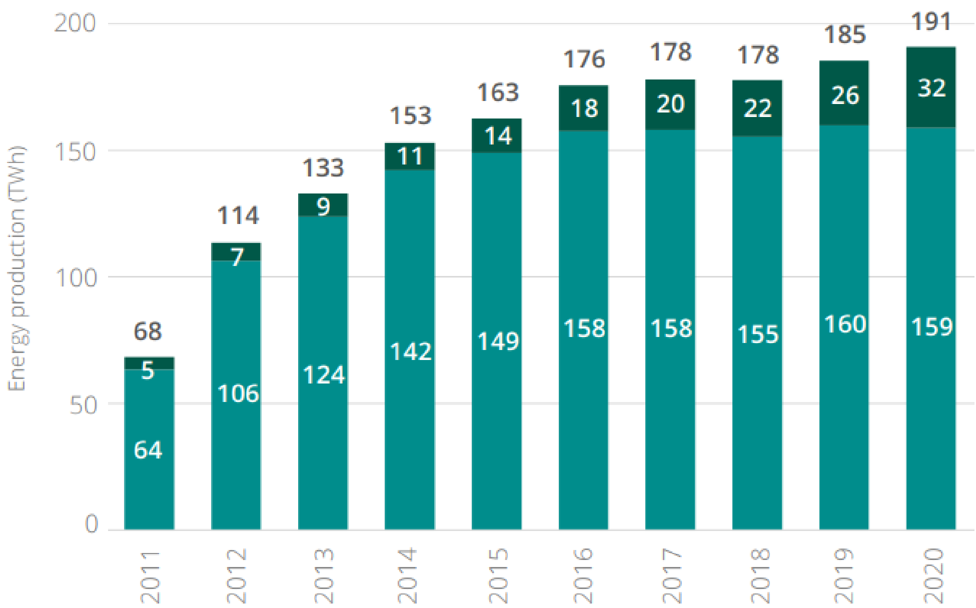


*Figure 10 Growing trend of Biogas (blue) and biomethane (green) production of EU [EBA]*

Each year, more European countries are shifting incentives from biogas production to biomethane production, allowing the quick development of biomethane industry. This process is helped from the flexibility of the sector, that allow quite easy conversion of AD-biogas facilities to biomethane production plants. The growth of the biogas and biomethane production in the last decade is captured in Figure 10.

## 3.1 Development of biogas sector in different EU countries

Among the European countries with higher investments in the biogas sector there is Germany, which in 2018 was the European leader with almost 9500 biogas plants, result of the Renewable energies act started in 2000. This decree forced energy distribution company to buy electricity from renewable sources at guaranteed feed-in-tariffs over a period of 20 years. This effect, coupled with the presence of high incentives for energy crop cultivation, resulted in a quick development of the biogas industry between 2000 and 2012.

However, this uncontrolled growth of the sector lead to some serious issues:

- The massive diffusion of monoculture for energy purpose caused soil degradation, use of pesticides, low biodiversity, and increased water consumption. All these effects introduced a sensible decrease in the environmental beneficial influence of biogas production, reduced social acceptance and disturbed the agricultural market equilibrium (land rental price increment, smaller farms issues…)
- Electricity cost from biogas technologies were still high compared to other renewable sources, since from 2010 the LCOE of PV and wind plants strongly decreased up to 0.06-0.05 USD per kWh, while biogas LCOE has remained quite constant over time close to 0.08-0.09 USD per kWh.
- Especially in rural area, the lack of an efficient utilization of the heat generated caused a sensible reduction in the efficiency of the systems, affecting plants economic viability.

Considered those effects, the German legislation was changed from 2012 limiting the use of energy crops and reducing feed-in-tariffs or replacing them with auctions. In this way the biogas sector would be essentially composed by large scale plants (>1MW), which are characterized by the best economic performances. These decisions caused a slowdown of the electricity production from biogas since the competition with other sources like solar PV became even more challenging.

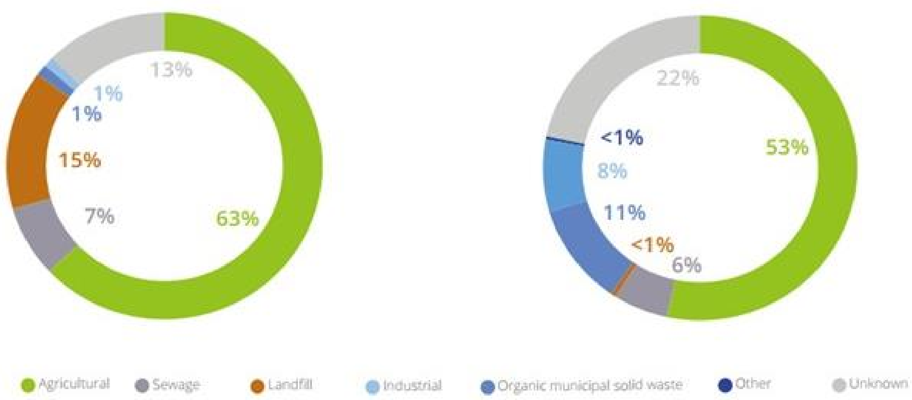


*Figure 11 European biogas (left) and biomethane production (right) from different sources [EBA]*

**EU Biomethane sector development**

A new perspective was introduced in the last years with the possibility to purify the biogas produced in the plants to the biomethane grade, and so allowing grid injection of the obtained product. The reasons why biomethane upgrading were not considered in early stages is due to a lack of subsidies and in the higher cost of upgrading units with respect to CHP systems. However, biogas upgrading to biomethane has been identified as a good alternative to power and heat generation as it can be stored in the natural gas grid. It can then be used for clean transportation or in urban CHP units, where heat is efficiently valorized [24].

In fact, Biogas is most often used in a CHP to generate both electricity and heat, while biomethane can be used for a variety of end-use applications, as it can replace all the end-uses of natural gas. The end-uses of biomethane are influenced by market mechanisms, regulations, and support mechanisms, all of which vary between countries. As reported by many studies [25], one of the most promising fields for the use of biomethane is the transport sector, whose decarbonization is quite difficult compared to others.

## 3.2 EU biofuels policies and future perspectives

The main goal of the European Union for the next 10 years is to reduce the net greenhouse gas emissions by 55%. Thanks to existing climate and energy legislation, the EU's GHG emissions have already fallen by 24% relative to 1990. However, to complete the transition to a European net-zero economy by 2050, increasing efforts are still needed. Policies play an important role in the effort to achieve systems transition and transform the economy into a more sustainable one.

Transformation will involve many segments of the economy. The sector involved vary from agriculture to renewable energy, carbon economy and green financial markets. In this framework the Fit-for-55 Package was published in July 2021 to reform the previous climate, energy, and transport legislation.

In this optic, the Renewable Energy Directive (RED II) will be modified to include a more ambitious target of 40% renewable energy in final energy consumption by 2030 (a considerable increase on the current target of 32 %) [25]. The Energy Efficiency Directive (EED) revision will require EU Member States to invest in energy savings. By 2030, an energy efficiency improvement of 36% to 39% must be achieved, as well as a 9% reduction in total energy demand.

As reported in [25] the scope of the Emission Trading System (ETS), the EU CO2 market, will be broadened to include maritime transport and a parallel ETS for buildings and transport will be developed to encourage more efficient and cleaner energy consumption leading to greenhouse gas savings of 61 % in sectors covered by the current ETS and 43% in the buildings and road transport sectors.
The scope of the Land Use, Land Use Change and Forestry Regulation (LULUCF), which covers

emissions, including the removal of greenhouse gas emissions, will also be edited to include non CO2 agricultural emissions (such as methane) as of 2031.
The ReFuel EU Aviation & Fuel EU Maritime Regulations encourage the use of sustainable fuels for aircraft and ships. Changes to the Alternative Fuels Infrastructure Directive (AFID) will bring alternative fuel infrastructure deployment rules into line with new climate targets.

Current and future policies to guide the biogas utilization put a specific focus on renewable heating, transport sector, agriculture, and reduction of methane emissions.

**Renewable heating**

Higher targets for renewable energy in heating, included in the Renewable Energy Directive, create potential opportunities for biogas to contribute. An EU-level target of 49% renewable energy in buildings has also been proposed, as well as a 1.1 percentage point annual increase in renewable energy use in heating in each Member State. The revision of the Energy Efficiency Directive sets a series of increasing thresholds for renewable energy use in district heating.

**Transport sector**

The European transport sector has not achieved the same gradual reduction in emissions as other sectors and its emissions are a major contributor to climate change. The sector was therefore a particular target of the Commission's Fit-for-55 package, which aims to align the regulatory network for fuels, vehicles, and infrastructure with the 2030 and 2050 climate objectives.
The Commission's approach to road transport is focused on so-called zero-emission solutions, so the origin of the fuel is secondary to the combustion emissions. Such an approach naturally favors electricity and fuel cells. Light-duty vehicles must reach 100% emissions savings by 2035 which means that no new CNG vehicles can be sold from 2035, even though CNG vehicles powered by BioCNG can reach the same or even better levels of emissions savings as vehicles powered by electricity.

This proposal by the Commission, if adopted by the European Parliament and the Council, will have an enormous negative impact on the biogas sector, limiting the use of biogas to heavy-duty transport and the maritime sector. In line with the vehicle legislation, the Alternative Fuels Infrastructure Regulation does not put forward any targets for improved CNG infrastructure. Any remaining gaps in LNG infrastructure (road and maritime) will be filled by 2025. The Renewable Energy Directive still includes a target for advanced biofuels, but the multipliers have been removed from road transport altogether. The use of biofuels in the shipping and aviation sectors is incentivized, but by a moderate multiplier of 1.2. More positively, the Commission's impact assessment for the Fuel EU Maritime Regulation predicts that as soon as 2030, advanced biofuels will make up three quarters of all fuel used in the maritime sector and by 2050, the portion of advanced biofuels in the maritime sector should exceed 90%.

**Agriculture**

Anaerobic Digestion is a reliable way for Member States to reduce their carbon and methane footprint in agriculture. Investment in the construction of additional AD capacity, especially where the aim is to reduce pollution and emissions from excess manure and to recycle nutrients in organic fertilizers, should be considered in line with the sustainability objectives of the CAP and the Renewable Energy Directive as long as the risk causing indirect land use change (ILUC) through the planting of monocultures for energy purposes is kept to a minimum. In addition, the CAP will seek to reduce dependence on chemical fertilizers and pesticides and thus protect biodiversity and ecosystems.

**Methane emissions**

In order to achieve carbon neutrality, it is also crucial to address emissions of methane, the most powerful greenhouse gas after CO2. The European Commission published its Methane Strategy in 2020 and this communication will be followed by legislation to regulate methane emissions from the energy sector, which will form part of the upcoming Hydrogen and Decarbonised Gas Market Package in December 2021.

Biogas plays a major role preventing methane emissions from agriculture and waste management. The biogas industry is therefore a large net reducer of methane emissions per se and methane emissions attributable to AD itself are minimal (according to voluntary or mandatory measurements made in several European countries), although steps must nevertheless be taken to avoid them.

## 3.3 Biogas and Biomethane production trends in Italy

Italy has experimented a biogas sector growth very close to what happened in other EU countries, like Germany: high incentives between 2008 and 2012 caused a quick development of the sector, especially for small CHP units. Feed-in-tariffs of around 280€/MWh for plants below 1MW lead to the large diffusion of energy crops-based plants. Regulation changed and the incentive plan has been revised since 2013 in order to reduce FIT and promote the use of agriculture by-products instead of energetic crops and resulted into a reduction of the sector growth.

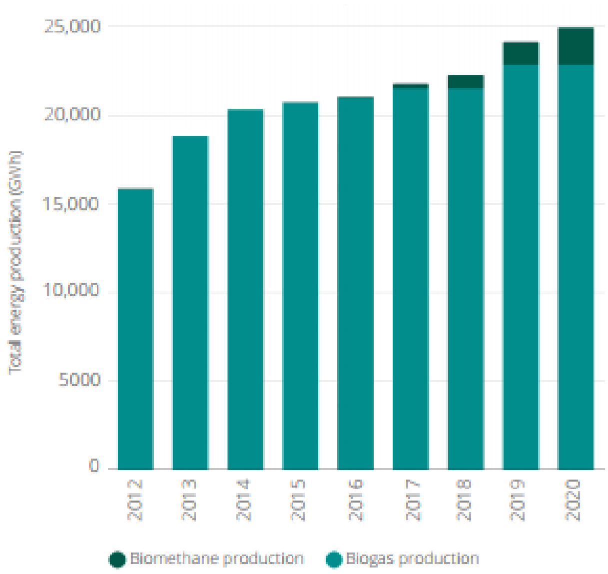


*Figure 12 Italian biogas and biomethane production [EBA]*

In 2018 the Biomethane decree was released by the Italian government and to support advanced biofuels development, especially for the transport sector. The decree aims at increasing the use of biomethane and other advanced biofuels in the transport segment, constituting a crucial step in the integration of more RES in this specific sector. In addition to this, the decree intention is to facilitate the conversion of biogas CHP plants into more sustainable biomethane injection systems, with the effect to reduce the cost of electricity production and improve the generation of advanced biofuels [26].

The biomethane decree instituted a fund of 4.7 billion euros provided by transport fuel suppliers that need to meet increasing biofuel blending obligation (quota system). This fund allocated between 2018 and 2022 should cover the development of the biomethane sector (plants and infrastructure such as filling stations) up to 1.1 billion m3/year [27]. Incentives must provide a minimum income for biomethane producer that could vary depending on the kind and amount of feedstock used. In this way the production from selected input biomass like manure, sequential crops, agriculture by-product and OFMSW was privileged. As reported by [28] the decree is making investment in upgrading technologies profitable for existing biogas plants (investment payback time would range between 3 and 6 years), while it would have not been the case without.

As reported in [25] at the end of 2020 Italy was the second biggest player (after Germany) in the EU biogas market, both for number of plants and total gas production. The total number of active biogas plant was equal to 1710 that ensured a production of 23 TWh in 2020 allowing the production of 9 TWh of electric energy.

Around 80% of input feedstock for biogas production is represented by agricultural streams. Following the path “Biogas done right” the sector growth is coherent with the concept of sustainable farming, to make better use of land by the choice of multiple crops and integrating additional biomass for biomethane and biogas production. Future legislative acts are expected to promote the development of small-scale biogas plants (under 300 kW) and the use of 100% agricultural by-products.

### 3.4 Biomethane development in Italy

The first biogas upgrading unit in Italy was installed in 2012, followed in the subsequent years by many small demonstration plants (producing less than 50 m3/h of biomethane) without grid connection. Then after the releasing of the “biomethane decree” in 2018 the sector grew continuously, reaching 27 fully operating plants in mid-2021 and making Italy the second fastest growing market in Europe.

The decree has a production target of 1.1 billion m3/year of biomethane per year, which is also the maximum limit of production to be covered by the decree. To qualify for the subsidies granted in the decree, biomethane must be used in the transport sector. Other legislative acts are expected in 2022 to promote also the use of biomethane in industrial sector or the injection in the NG distribution grid (without favoring specific end use applications).

As a result of the decree application, nowadays 100% of the Italian biomethane production is used as transport fuel, and the target production of 1.1 billion m3/year will probably be reached by the end of 2023. The substitution of fossil NG with biomethane could be helped by the high share of natural gas vehicle (highest number in Europe) and the number of CNG (1400) and LNG (85) filling stations installed in the country.

Out of the 23 plants operating in Italy at the end of 2020, 17 were connected to the NG transport grid, while 4 to the distribution grid. The production of biomethane was based mainly on the digestion of OFMSW and the most diffused upgrading technology was membrane separation, as reported in the fig.13.

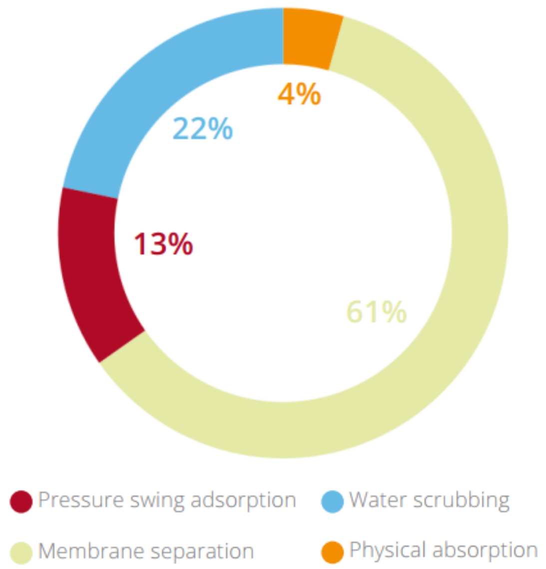


*Figure 13 Most relevant upgrading technologies in Italy [EBA]*

### 3.5 Biomethane incentivation scheme

As reported in [29] the Biomethane decree substitute the older legislative acts of 2011 and 2013, whose results were not compliant with the minimum target of the EU biomethane share in transport field. The decree aims at the promotion of:

- Biomethane injection in the distribution grid without a specific end use (art.4)
- Biomethane injection in the grid destinated to use in the transport sector (art.5)
- Advanced biomethane in the grid destinated to the transport use (art.6)
- Advanced biofuels (apart from biomethane) destinated to transport use (art.7)
- Conversion of existing biogas plants to promote biomethane upgrading (art.8)

The mechanism that rules the biomethane market refers to the decree 10 October 2014 and impose a minimum share of biofuels to the subject who perform fuel release in the market. This minimum percentage depends on the energetic content of conventional fuels released for consumption in the same year. The fulfillment of the legal obligation is controlled by GSE (Gestore Sistemi Energetici), an authority which release apposite certification, called CIC (certificati immissione in consumo) to the producer whose plant has been certified as compliant to the decree.

Each CIC correspond to an amount of 10 Gcal of non-advanced biofuels or 5 Gcal of advanced biofuels, produced from advanced feedstock or non-advanced "double counting" feedstock.

Each CIC has an economic value equal to 375,00 €

Differences between advanced and non-advanced biofuels and double or single counting feedstocks are deepened in the appendix. [30]

# 4. Case study: ACEA pinerolese plant

Acea Pinerolese is a company involved in the supply of energy services for municipalities, private companies, and citizens. The main areas in which the company operates are the collection and disposal of waste, street cleaning, management of infrastructures for the collection and processing of wastewater, the supply of gas and electricity.

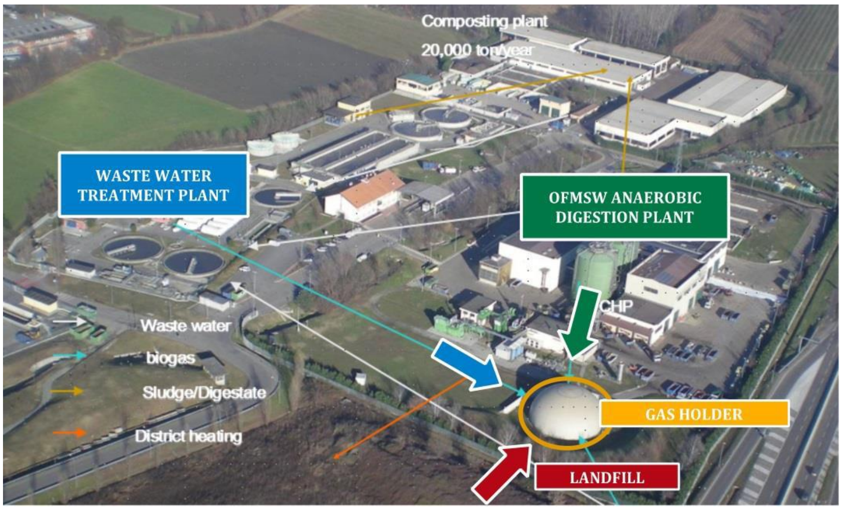

*Figure 14 Picture of Acea plant in Pinerolo*

Since 2002, the company has directed in Pinerolo one of the most advanced integrated urban waste management systems in Europe, which includes a wastewater treatment plant (WWTP) and the plant for treatment of OFMSW, and a municipal landfill. A dedicated anaerobic digestion integrated treatment facility allows to obtain biogas and a special organic compost, that is commercialized as an advanced fertilizer.

To be more specific, ACEA collects the organic fraction of urban waste of about a third of the population of the metropolitan city of Turin (about 800,000 people)[31] and reprocesses it implementing an anaerobic digestion process. The bio-organic (humid) fraction of solid urban waste (OFMSW) entering the AD process is fermented to yield biogas and a solid digestate (OFMSWD) that contains residual organic matter not converted into biogas. The OFMSWD is then mixed with green home gardening and park trimmings residues and/or with sewage sludge (SS) coming from the WWTP. Finally, this mix goes for fermentation under aerobic conditions to obtain compost, a fertilizer used in the agricultural sector. In addition to the processing of OFMSW, the company manages the nearby landfill and the wastewater treatment plant serving the town of Pinerolo. From these additional activities two more biogas streams are obtained, which are then directed to a storage facility.

The overall plant could be considered as the connection of four different treatment facilities:

1. AD = anaerobic digestion of OFMSW;

2. CP = composting plant for the aerobic digestion of the solid digestate from the AD;

3. WWTP = anaerobic digestion of sewage sludge from Pinerolo Municipality;

4. LBG = landfill with biogas collection.

The main feature that distinguishes the Pinerolo plant and makes it so innovative at national and European level is precisely the way in which these flows are managed in an integrated way, realizing the concept "waste to resource" in the best possible way.

## 4.1 Plant overview and evolution

**Only CHP asset (2002-2020)**

The energy utilization of biogas takes place into 3 Internal Combustion Engines CAT3516LE (1.2 MWel and 1.37 MWth), where the heat recovery system produces both diathermic oil from exhaust and cooling water. The 2 cylindrical bioreactors, for the 2 identical OFMSW treatment lines, have a volume of 2’500 m3/each and are fed in batch-mode with a maximum volume equal to the volume of each buffer tank (185 m3); each digester is insulated, but not heated and it is equipped with a mechanical agitation system combined with a biogas injection system. Under these conditions the temperature in the digester is kept at 50-55°C (thermophilic conditions) by a sludge recirculation through a shell tube heat exchangers in which it receives the heat flux provided by the water circulating on the internal heating grid.

Due to the availability of excess heat, since autumn 2008, the IUWT plant satisfies the thermal energy demand of a DH system (4 MWth peak), providing hot water for a 30’000 m2 shopping mall with a supermarket and 52 shops and for a residential area of about 4’800 m2. At the moment the project for the expansion of a further 2.5 km of the DH Grid, thus reaching the school and the sport palace of Pinerolo, has been presented with the opportunity to feed also a cooling system during the summer.

**CHP and biomethane upgrading asset (2020-present)**

In the following years, due to a higher interest in biomethane upgrading techniques and a favorable legislative framework, with the incentive scheme introduced by the Biomethane decree in 2018, the company installed a biomethane upgrading facility in its plant. This additional section, installed by Hysytech (an important company based in Turin), can elaborate a flowrate of about 565000 Nm3/month and provide high purity biomethane, which is injected in the distribution grid. Currently the upgrading unit is not working at its full load yet, but it is constantly monitored, and its performances are getting better, as shown in the picture fig.15.

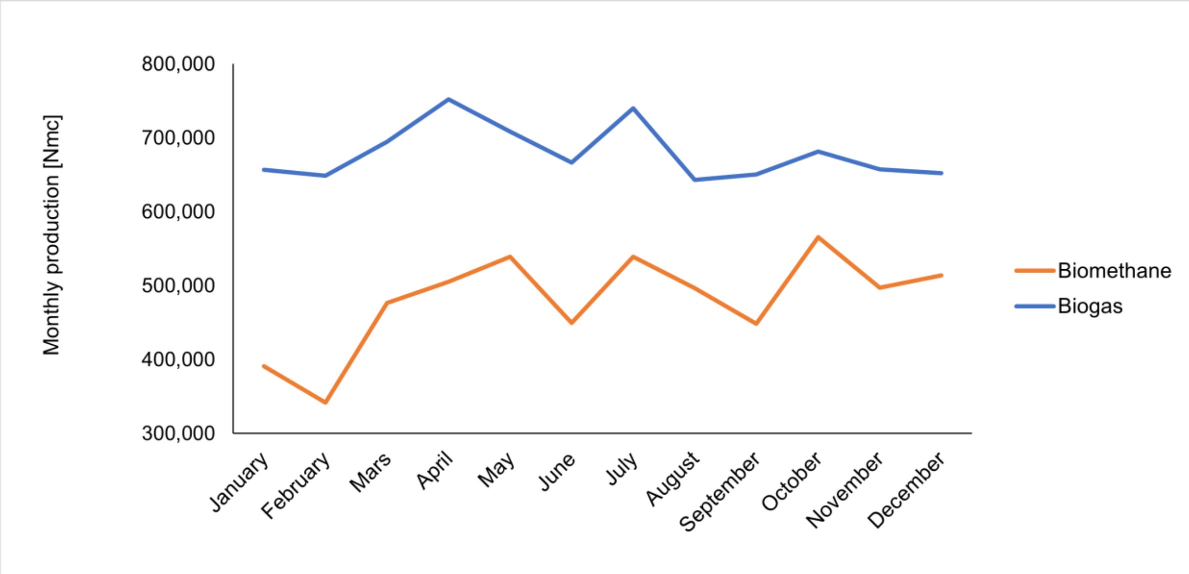


*Figure 15  Actual biogas and biomethane production (year 2021)*

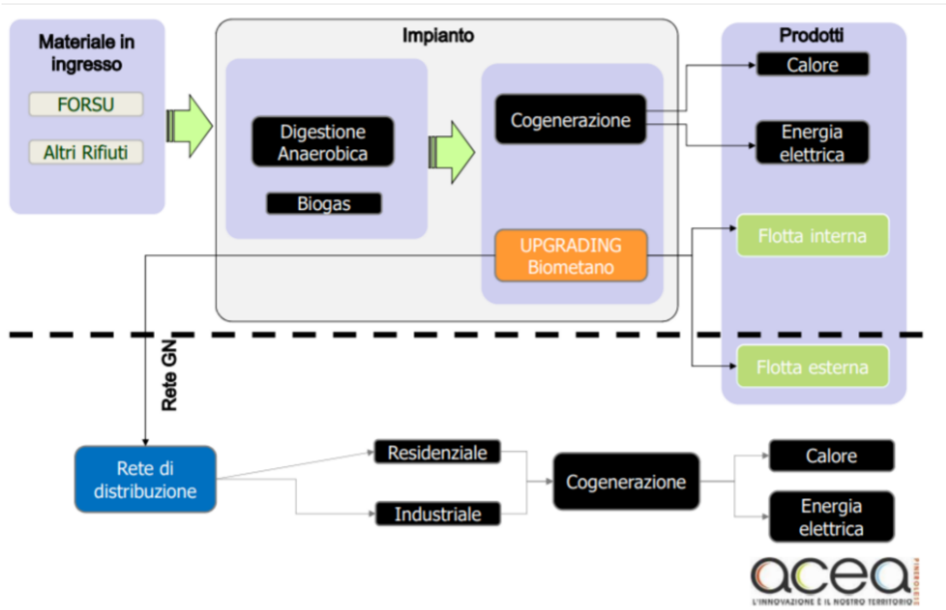


*Figure 16  Acea plant current configuration*

## 4.2 Biogas streams characterization

To analyze the plant and its energetic performances, the company gave us data about the mass and energy streams elaborated in the plant, those data were reported on monthly base and provide the starting point of the analysis.

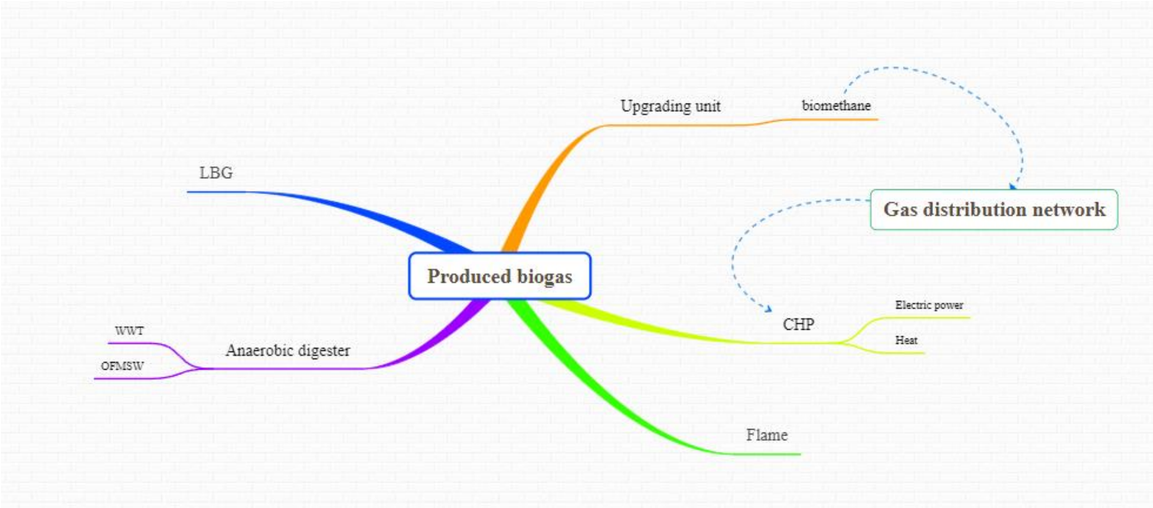


*Figure 17 Biogas mass streams*

First of all, the definition of biogas streams has to be performed: to do so, the biogas input and output streams have been identified and quantified. Biogas comes from Wastewater treatment, OFMSW digestion and landfill, and is used in the upgrading unit and CHP facility. In addition to these, a flare is used to burn the excess biogas that could not be stored, this condition could happen when for example the upgrading unit is not available due to maintenance or other issues.

The visual representation of the different biogas streams is reported in the figure 17.

**Biogas sources**

To understand which contribute is the most relevant for biogas production in the plant, the average volume coming from each source has been calculated, in order to obtain a mean monthly value, and is represented in figure 18.

Then, once the abundancy of each stream is defined, it is important to calculate its energetic content. Since the most valuable component in biogas is methane, a good approximation of the energetic relevance of input each flow can be obtained evaluating its methane content.

Following this approach, the methane percentage of each stream is highlighted, and combining these data with the volumetric ones, the energetic content is determined.

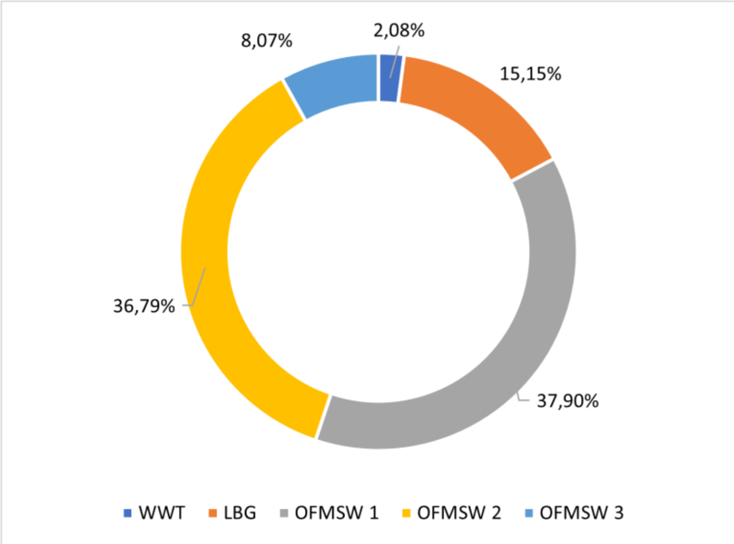


*Figure 18 Relative contribution of biogas input streams (year 2021)*

In the following graph the methane content and energetic equivalent are reported on two different axes.

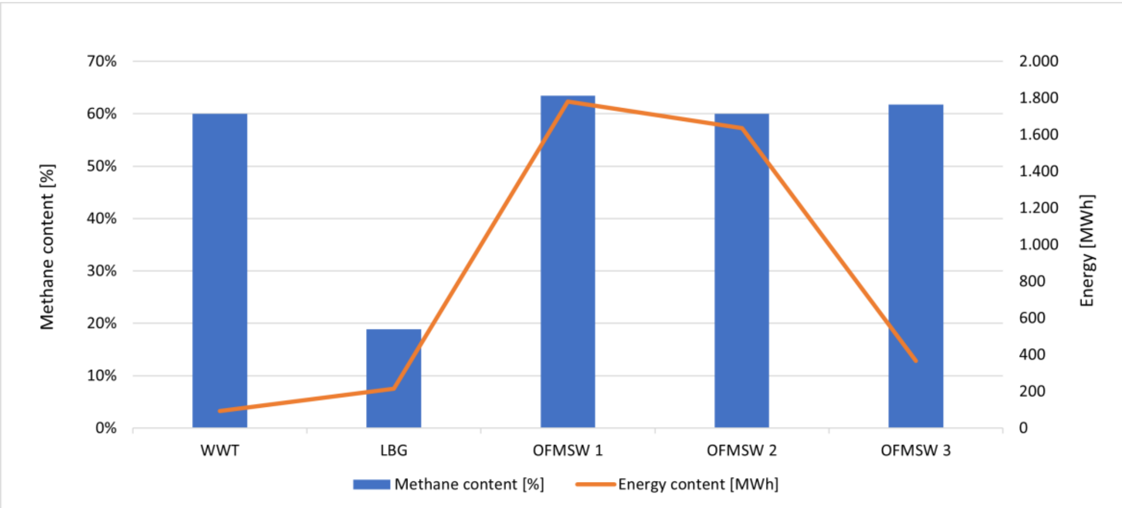


*Figure 19 Methane percentage and energetic content of input streams (year 2021)*

As the graph shows, for what concern WWT and OFMSW3 streams, the low energetic relevance is related to a quite low flowrate compared to the other streams, while even if the LBG represent a significant amount of the biogas input, its energetic contribution is quite poor. This happens because the methane percentage of LBG is always lower than 20% while for the other streams the average methane content is around 60%.

In fact, according to what the company declares, the treatment of LBG is primarily an environmental issue since landfill gas cannot be directly released in the atmosphere due to the presence of GHG and pollutant species. To avoid this negative effect, part of the LBG is sent to the CHP unit, in which is mixed with NG from the distribution grid to obtain a fuel for the cogenerators, while the rest is burnt in an apposite flare located in the surroundings of the landfill.

**Biogas utilization**

Once the input streams have been quantified, the utilization of biogas can be analyzed. The main uses adopted in the actual plant layout are biomethane upgrading and CHP valorization. To be more specific, the upgrading section elaborates part of the stream obtained by digestion of OFMSW and WWT residuals, while the CHP facility is used to treat the biogas coming from the landfill, after mixing it with NG from the grid. The residual part, that cannot be elaborated or stored because of temporal mismatching between production and utilization, or due to maintenance to downstream component, is sent to a flare, which burns it without any economic or energetic advantage. Since this portion of biogas represent a loss in terms of energy and money, in the various future scenario proposed the aim will be to minimize this quantity.

The percentages of flow sent to these final uses is captured in the graph fig.20

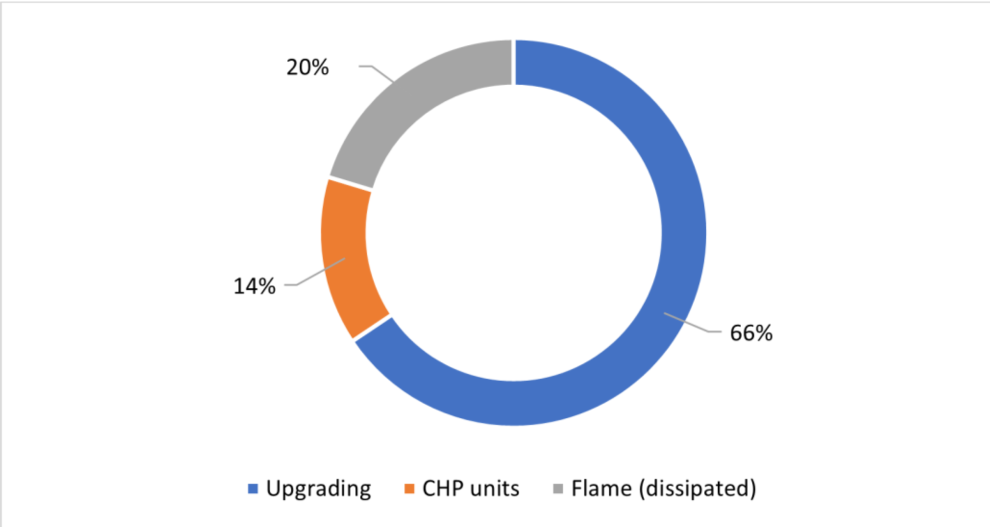


*Figure 20 Utilization of biogas in the actual layout (year 2021)*

## 4.3 Energy balance of the ACEA plant

The energy balance aims at identifying the different energy exchange and conversions that take places inside the plant.

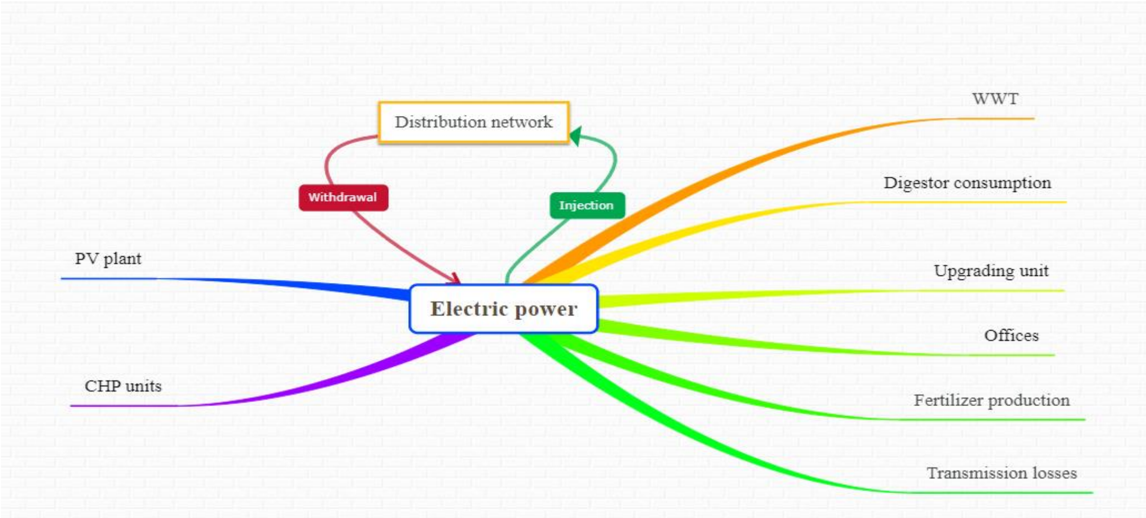


*Figure 21 Electric balance visualization*

Considering the electric energy, from the provided data it is possible to identify three main sources of energy that are used within the plant, which correspond to the contribution of ICEs (CHP unit) which cover about 92% of the needs, the PV plant (1%) and a quota withdrawn from the distribution grid (6%).

For what concerns the utilization of the electricity, the higher consumptions are related to the management of OFMSW, which include pre-treatment and AD digester needs, then there is the consumption of the WWT plant and the upgrading unit. A significant percentage is sold to the grid (around 15%) while office needs, compost production are less relevant in the balance.

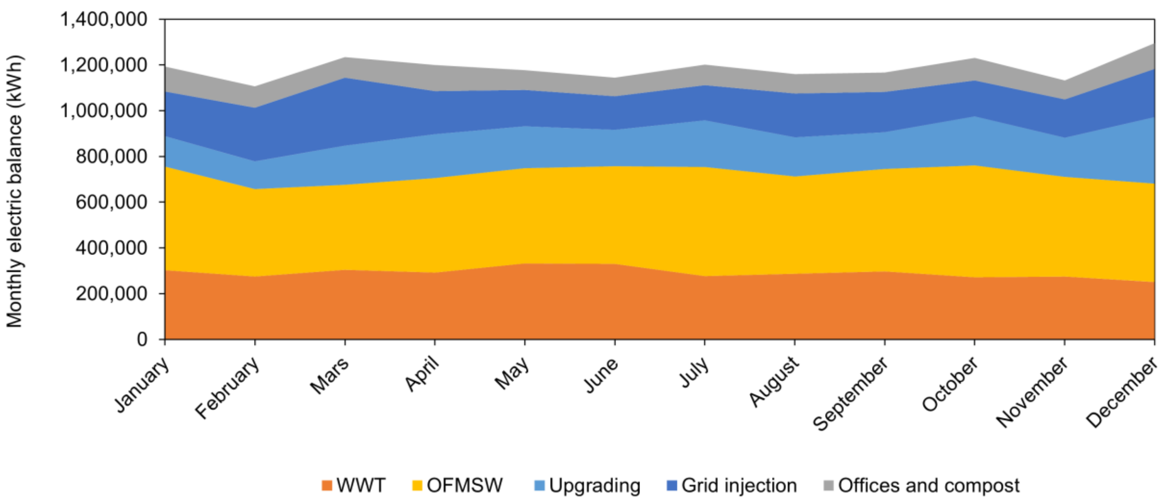


*Figure 22 Electric output of the plant (year 2021)*

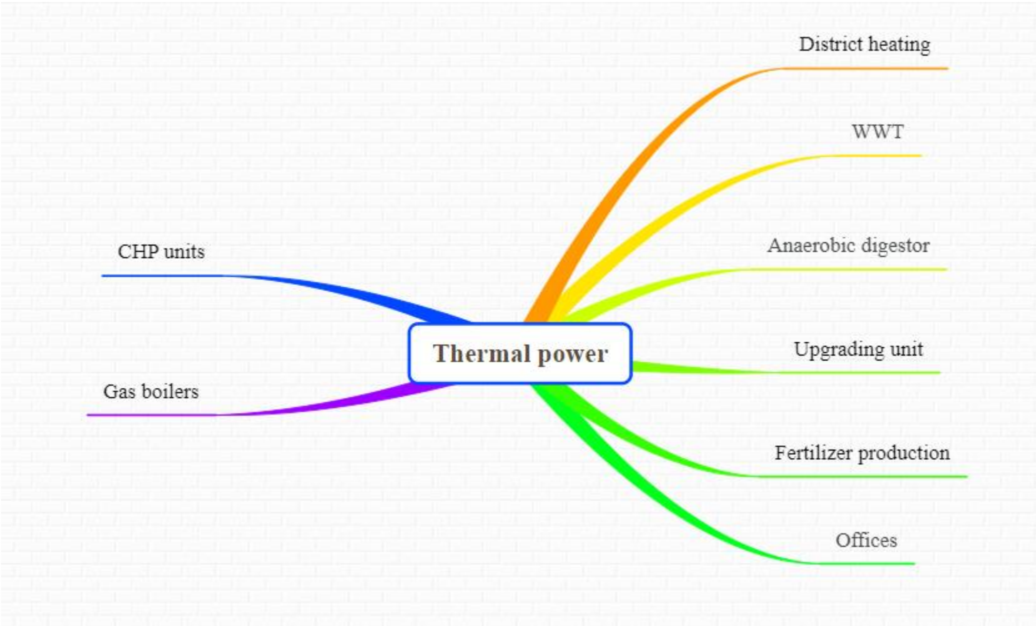


*Figure 23 Thermal balance visualization*

Analyzing thermal energy fluxes involved, it is possible to identify as an input the heat produced by the CHP unit, which accounts for 40% of the plant thermal needs, and the contribution of auxiliary gas boilers, which provide the other part (around 60%).

Considering the final uses of the thermal energy, the biggest amount is related to the consumption of the district heating network, followed by the AD digester consumption, upgrading unit and WWT. The less relevant voices in the thermal balance are the consumption related to the compost facility and office heating. A chart to highlight those fractions is reported in the graph below.

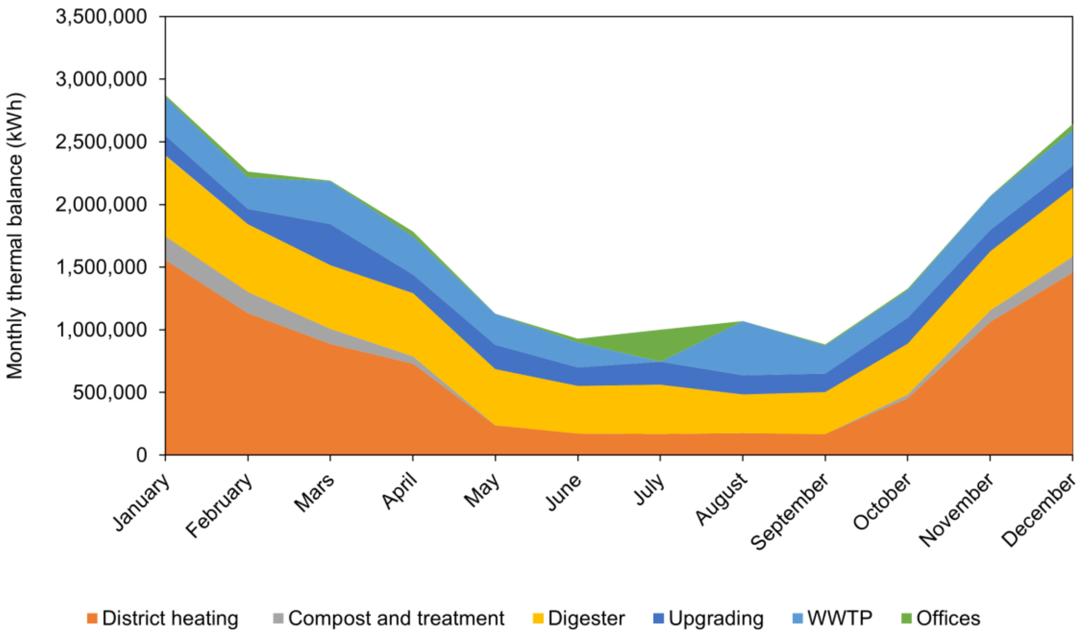


*Figure 24 Thermal output of the plant (year 2021)*

### 4.4 Future perspectives and development scenarios

To evaluate which could be the future development of the plant of Acea pinerolese, different possible scenarios are evaluated. Since the evolution of an energy facility is strongly affected by the incentive scheme adopted at national or regional level, different assumptions are proposed to understand which solution could fit better in case of different legislative framework.

In the economic part the different possible scenarios are compared, in other to the define which could represent the better solution. With different sensitivity analysis the impact of expected future FC technical development on the business are evaluated, and finally the role of NG and electricity price on the investment plan is investigated.

The considered scenarios are reported in the table below:

| Scenario | Analysis performed |
|---|---|
| **Only CHP asset:** | 1) Study of the performance of an integrated microGT - SOFC system |
| | 2) Study of the performance of a SOFC unit |
| | 3) Study of the performance of a MCFC unit |
| **Hybrid Upgrading and CHP asset:** | 4) Maximization of Biomethane Production |
| | 5) Covering electric internal loads |

*Table 1 Different analysis performed*

# 5. Methodologies and input data

## 5.1 Energy analysis

In this section are described the most important steps followed to perform a comparison of different plant layouts depending on the performances and the energetic framework. Different incentives scenarios are considered and for each of them the best possible configuration is proposed.

The first step consists in scanning the market of fuel cell to identify which companies are able to supply FC of the desired size and provide information about their energetic performances and cost.

### 5.1.1 Choice of the fuel cell model

What emerges from a preliminary market analysis is that there are only few companies worldwide which provide complete CHP systems based on FC able to provide hundreds of kW, since many producers developed only portable systems or small-scale solution (power range of some kW). Another issue to consider is that even if there are many stack manufacturers since the FC market is rapidly growing, only few producers sell the entire CHP system, ready for industrial applications. As discussed in chapter 2.3.3 the stack is only one of the elements present in a CHP unit, but to correctly operate it must be properly connected to a fuel processing unit, a blower and other auxiliaries that are generally indicated as "balance of plant ".

So, the choice of FC model to install is limited to the products that are:

- Available for a power production of some hundreds of kW
- Provided as complete CHP systems

From the market analysis three major solutions are identified:

- Mitsubishi Megamie 250
- Fuel cell energy SOFC 200
- Fuel cell energy Sure source 3000 (MCFC)

For each of these power systems the producer indicates the energetic performances in dedicated datasheet. The following analysis and feasibility study are based on the data declared by the company in those reports. [32][33][34]

### Mitsubishi Megamie 250

Mitsubishi provides a hybrid system SOFC-microGT module with a size of 250 kWel. The company developed this model and reached commercialization level between 2015 and 2017. It is a unique model in the current scenario, since there are no other players in the market that offer an integrated solution.  As the company claims, this two-stage system achieves significantly higher power generation efficiency and, as a result, saves substantial energy. [35]

Air pressurized in the microGT's compressor is supplied to the SOFC stack for use in generating power, and then high-temperature exhaust is fed to the MGT and the heat and pressure, together with the residual fuel, are used to generate power. The pressurized SOFC, having substantially increased voltage because of pressurization, lead to enhanced power generation efficiency.[36]

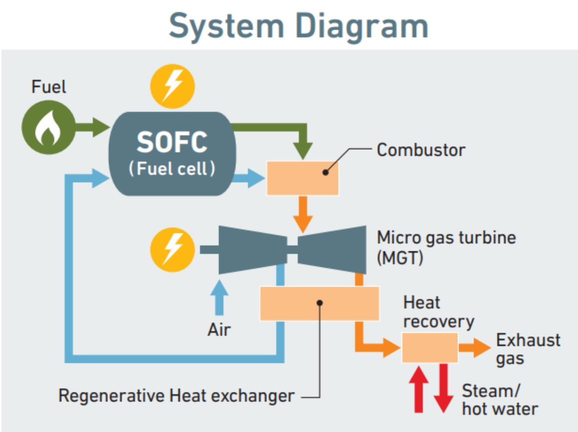


*Figure 25 Megamie 250 working scheme [32]*

In the table below are reported the most important data needed for developing the feasibility study, taken from [32].

Specifications (for reference) : LNG use

| Model | | MEGAMIE |
|---|---|---|
| Type | | Solid Oxide Fuel Cell [Solidia®] |
| Fuel | | LNG<br>Max. 50 Nm³/h (about 36 Nm³/h at rated power output) |
| Electrical output *1 | Rated output | 210 kW |
| | Frequency, Phase | 50/60 Hz, 3 phases |
| | Voltage | 200 V/220 V |
| Thermal output *1 | Thermal output | 86 kW (hot-water recovery)<br>54 kW (steam recovery) |
| | Hot-water/ steam flow rate | 15 t/h (hot water from 83°C to 88°C)<br>80 kg/h (0.78 MPa steam*2/water-supply temperature 60°C) |
| Efficiency *1 | Electrical efficiency | 53% LHV |
| | Total efficiency (Electrical + Thermal) | 73% LHV (hot-water recovery)<br>65% LHV (steam recovery) |
| Unit size | | W 3.2 m × L 11.4 m × H 3.3 m |
| Weight | | 33 t |
| Startup time | | Cold 24 hr / Hot 2 hr |
| Environmental performance | Exhaust gas | 1,400 Nm³/h |
| | NOx | 15 ppm or less (16% $O_2$ at rated power output) |
| | SOx | Less than 0.1 ppm |
| | Noise | 70 dBA or less (at 1m from the machine) |
| | Vibration | 45 dBA or less |
| Installation locations | | Indoors/outdoors |
| Options | | Capability of Island mode |

*1 At ambient temperature of 15°C. Output and efficiency vary according to operating conditions.
*2 At saturated steam temperature of 175°C

*Figure 26 Mitsubishi Megamie SOFC 250 datasheet [32]*

## Fuel cell energy SOFC 200

To evaluate different alternatives, the first scenario study is repeated with other two kind of fuel cell systems. The first one is a 200kW electric SOFC module produced by Fuel cell energy, whose datasheet is available online [33] and is currently under development (estimated availability in the European market: 2024).

The company Fuel cell energy has a great experience and important production skills in the field of molten carbonate fuel cells, in which are one of the biggest players worldwide, with different multi-MW plant installations, especially in the United States and in South Korea. In the last years (from 2019 on) the company has also developed prototypes of solid oxide fuel cells and proposed a 200 kWel model that is analyzed in the following chapters. In the table reported below a copy of the datasheet of this SOFC model. For data elaboration is assumed the SOFC would work at rated condition (third column of the table).

200 kW SOFC System Performance Summary

| SOFC Gross Power | Normal Operating Conditions | | Rated Power | |
|---|---|---|---|---|
| **DC Power** | **225.0** | **kW** | **244.0** | **kW** |
| **Energy & Water Input** | | | | |
| Natural Gas Fuel Flow | 19.7 | scfm | 21.6 | scfm |
| Fuel Energy (LHV) | 323.2 | kW | 355.5 | kW |
| Water Consumption @ Full Power | 0 | gpm | 0 | gpm |
| **Consumed Power** | | | | |
| AC Power Consumption | 10.8 | kW | 12.5 | kW |
| Inverter Loss | 11.3 | kW | 12.2 | kW |
| **Total Parasitic Power Consumption** | **22.0** | **kW** | **24.7** | **kW** |
| **Net Generation &Waste Heat Availability** | | | | |
| **SOFC Plant Net AC Output** | **203.0** | **kW** | **219.3** | **kW** |
| **Available Heat for CHP (to 48.9°C)** | **84.7** | **kW** | **90.8** | **kW** |
| **Exhaust Temperature - nominal** | **370** | **°C** | **370** | **°C** |
| **Efficiency** | | | | |
| **Electrical Efficiency (LHV)** | **62.8** | **%** | **61.7** | **%** |
| **Total CHP Efficiency (LHV) to 48.9°C** | **89.0** | **%** | **87.2** | **%** |

*Figure 27 FCE SOFC datasheet from [33]*

## Fuel cell energy Sure source 3000 (MCFC)

The last fuel cell CHP system which is studied in the first scenario belongs to another type of cell, called molten carbonate fuel cell (MCFC). This technology is quite different from SOFC (as discussed in chapter 2.3.3) and is characterized by a slightly lower electrical efficiency.

The biggest advantage of this solution is that is more diffused worldwide, that means is been tested and operated for more time with respect to SOFC systems. A higher number of devices installed has also a beneficial effect on investment and operating cost, that are quite lower with respect to SOFC, as will be analyzed in the economic section.

Another relevant advantage is that the higher experience of the company in the MCFC field allowed the scale up of the systems, as the producer currently provide modular solutions up to 4 MW each. At the moment this is the higher power output produced by a single module available on the market.

In the image below is reported part of the product datasheet.

**PERFORMANCE**

| Gross Power Output | |
|---|---|
| Power @ Plant Rating | 2,800 kW |
| Standard Output AC voltage | 13,800 V |
| Standard Frequency | 60 Hz |
| Optional Output AC Voltages | By Request |
| Optional Output Frequency | 50 Hz |

| Efficiency | |
|---|---|
| LHV | 47 +/- 2 % |

| Available Heat | |
|---|---|
| Exhaust Temperature | 700 +/- 50 °F |
| Exhaust Flow | 36,600 lb/h |
| Allowable Backpressure | 5 iwc |

| Heat Energy Available for Recovery | |
|---|---|
| (to 250 °F) | 4,433,000 Btu/h |
| (to 120 °F) | 7,460,000 Btu/h |

| Fuel Consumption | |
|---|---|
| Natural gas (at 930 Btu/ft3) | 362 scfm |
| Heat rate, LHV | 7,260 Btu/kWh |

| Water Consumption | |
|---|---|
| Average | 9 gpm |
| Peak during WTS backflush | 30 gpm |

| Water Discharge | |
|---|---|
| Average | 4.5 gpm |
| Peak during WTS backflush | 30 gpm |

| Pollutant Emissions | |
|---|---|
| NOx | 0.01 lb/MWh |
| SOx | 0.0001 lb/MWh |
| PM10 | 0.00002 lb/MWh |

| Greenhouse Gas Emissions | |
|---|---|
| CO2 | 980 lb/MWh |
| CO2 (with waste heat recovery) | 520-680 lb/MWh |

| Sound Level | |
|---|---|
| Standard | 72 dB(A) at 10 feet |

*Figure 28 MCFC Sure source datasheet, available at [34]*

### 5.1.2 Sizing the FC unit

To evaluate the power to be installed in the different configurations and so the number of modules needed, some considerations about the available resource are made:

First of all, since the utilization of fuel cell devices require the utilization of cleaner fuels with respect to traditional combustion-based generators, the inlet flow considered is only composed of biogas from OFMSW and WWT. In other terms, the utilization of landfill gas is not considered in these phases, since the methane content is quite negligible and the percentage of contaminants in that flow is significantly higher than in the other streams. Fuel cells are not able to manage a high amount of these contaminants [37], that would cause premature deterioration of the stack, increasing maintenance cost of the whole system.

Then it must be considered that most of fuel cell are designed to be fed with natural gas coming from the distribution grid, and not biogas from AD. So, we cannot size the system based on the available flowrate of the gas, since it would cause an overestimation of the installed power. Instead, a different approach is adopted: knowing the methane content of the input stream and considering a LHV equal to 10.88 kWh/Nm3 for the methane [38] the input energy is calculated. Then assuming a CHP system efficiency equal to the declared one, the energy output is obtained, and this value is compared to the rated output of a single module, to get the number of modules needed.[32] [33]

## Different approaches to biogas utilization

### Only CHP asset

In the first scenario we assume no incentives on biomethane production are present, so the entire biogas production is directed to the fuel cell CHP unit, to produce electricity and thermal energy. In this case a comparison between the use of different fuel cell technologies is used to highlight which could be the best solution from an energetic and economic point of view.

### Hybrid FC unit and upgrading solution

In the second scenario the possibility of an integrated solution which comprehend both fuel cell and biomethane upgrading is analyzed. This approach can valorize at its best the recent investments the company sustained to install the upgrading unit in the existing plant. In fact, developing a “all electric approach” could not be the best option in the current energy context, since the subsidies on the electric energy injected into the grid [39] are not so significant with respect to the incentives dedicated to the biomethane produced from renewable sources. [29]

For this reason, two alternative solutions are proposed and discussed in the following section: in the first one, the BG flowrate sent to the upgrading section is maximized, while the residual is directed to a specifically sized FC power unit, for cogeneration. The second one aims at minimizing the electricity withdrawal from the grid, for this purpose the FC will be sized according to the plant electric consumption and fed coherently while the residual flowrate of BG will be sent to the upgrading section.

### Maximization of biomethane production

As discussed in chapter 4, the biomethane decree of 2018 introduces significant incentives on the production of biomethane from renewable source, as a method to reduce the carbon impact of the transport sector. In this direction, the company installed a biomethane upgrading unit which started its operations during the year 2021, however many issues occurred during the first working period, leading to a quite not continuous biomethane production trend. As captured in the following plot, the best performances were obtained in October, when almost 570.000 $Nm^3$ of biomethane were produced, with an energy content approximately equal to 3.500.700 kWh, while in January, February, June, and September the production were significantly lower. This trend can be explained since during the year many problems affected the unit, which required the suspension of normal operation to be fixed.

### Minimization of electricity withdrawal from the grid

In this scenario the idea is to promote the plant self sufficiency, at least for what concern the dependency from the electric grid. For this purpose, the fuel cell unit is sized in order to cover the internal demand, while the residual biogas is sent to the upgrading section.

This kind of layout is the most interesting when the electricity sold to the grid is not incentivized, and so revenues from grid injection wouldn't be so high. In this scenario could be preferred to reduce the dependency from the distribution grid in order to get lower operational costs.

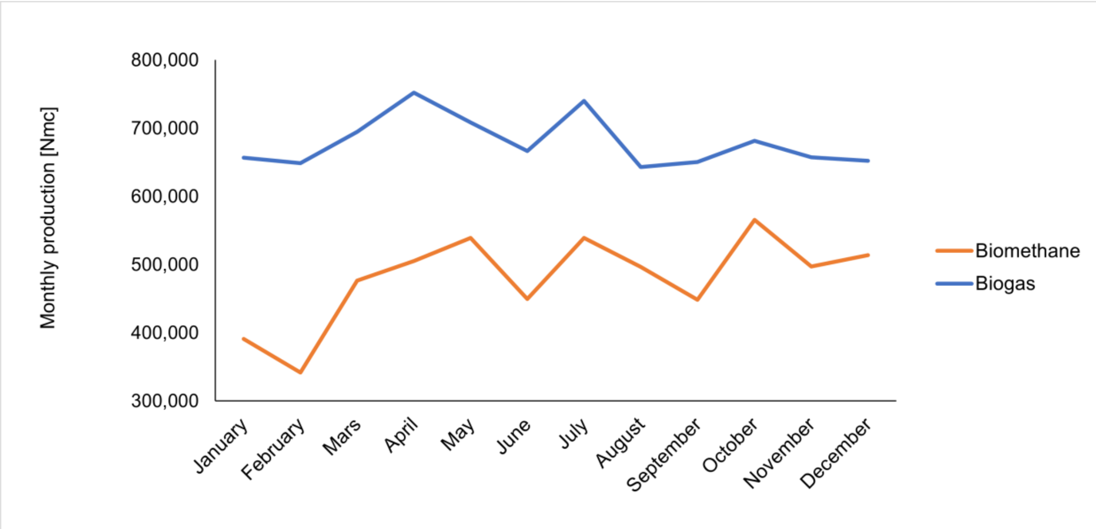


*Figure 29 Biomethane production trend in 2021*

*The different scenario studied in the following chapter are briefly reported in the table below:*

| Scenario | Percentage of biogas to upgrading |
|---|---|
| **Only CHP** | - |
| **Maximization of biogas production** | 100 % |
| **Hybrid scenario** | 83 % |
| **Minimization of electricity withdrawal from the grid** | 55 % |

*Table 2 Different scenarios studied*

### 5.1.3 Energy balance of the specific plant configuration

Once the plant size is defined and so the number of modules is determined, the energy production is considered. For this purpose, the assumption about the capacity factor of the plant is made, setting the number of working hours in a year equal to 8600, which means imposing a CF equal to 0.98.

The energy analysis highlights which amount of energy would be used internally to fulfill the plant demand and eventually, which quota is available to inject in the electric grid. These considerations will allow the development of an economic plan in the following chapters, identifying which could be the source of revenues in each different plant configuration.

## 5.2 Economic evaluation

To perform this analysis, the main data from the energetic study are collected (for each kind of cell), and reported in dedicated tables, as represented in the chapter 6.2

One of the problems faced during the economic study is the lack of precise indication of the SOFC system costs, since in many cases producers tend to not publish detailed cost, and current data are mostly referred to real plant installation costs. But since FC-based plants development is still marginal in the world energy scenario, these data are specific of the single installation. However, in the last years some indication about FC costs were provided by reports of European agencies or the American department of energy; those are interesting studies that provide range of cost for different typologies of FC and perform even some future projections. To develop the following analysis, economic data were taken from the study "Advancing Europe's energy systems" [40] published in 2015.

In a dedicated chapter of the paper, the authors recap which are the expected capital and operational costs of a 400 kWel biogas fed FC system, provide a breakdown of the system cost and highlights which are the expected lifetime of the FC stack and of the whole plant. In fact, when considering fuel cell, an important parameter to evaluate is the stack lifetime, due to the reactions taking place in the cells, the degradation of materials can seriously damage the stack and so the stack substitution must be planned periodically. This issue has a relevant effect on the economy of the plant, since the FC stack is the core of the power systems, and its price ranges between 35% and 40% of the total cost, according to [40]

For what concern other energetic data like the selling price for energy to the DH network and maintenance cost of auxiliary boilers, records provided by ACEA are applied, while for the cost of natural gas and the selling price of the energy to the distribution grid we refer to data from mercato elettrico[41] and Arera[39].

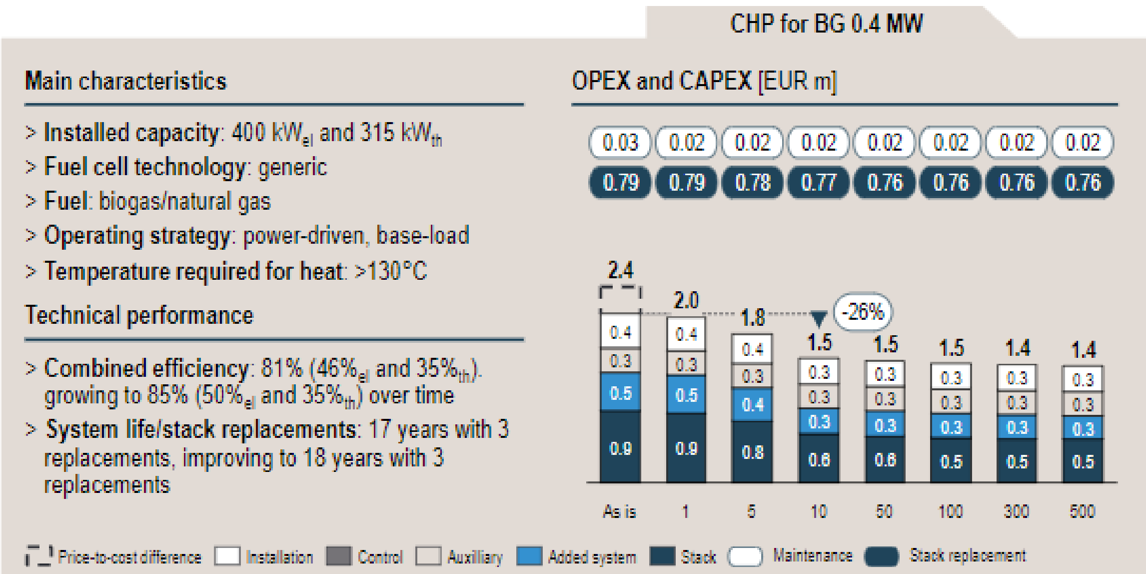


*Figure 30 Main characteristics of a 400 kWel BG fed FC system [38]*

### 5.2.1 Cash flow analysis

Cash flow is defined as the movement of money in and out of the considered business, it is a useful economic tool to evaluate the feasibility and profitability of a planned investment and is obtained comparing expected inflow and outflow of the business. Generally speaking, inflow is represented by revenues coming from sale of goods and services while outflow is composed of business expenditures, equipment purchasing and maintenance etc.

| Term | | | Value | Unit | Frequency of occurrence | | Kind of cost | Reference |
|---|---|---|---|---|---|---|---|---|
| **Revenues** | **Electricity sold** | Selling price | 96.30 | €/MWh | yearly | | - | [39] |
| | **Biomethane sold** | Incentives | 64.49 | €/MWh | yearly for t<10 | | - | [29] |
| | | Selling price | 85.50 | €/MWh | yearly for t≥10 | | - | |
| | **Heat to TLR** | Selling price | 62.00 | €/MWh | yearly | | - | [38] |
| **Costs** | **FC** | FC system | 5000.00 | €/kW | t=0 | | CAPEX | [40] |
| | | FC installation | 10.0% | of the system cost | t=0 | | CAPEX | |
| | | Stack replacement | 36.0% | of the system cost | 7 | years | OPEX | |
| | | FC maintenance | 1.3% | of the CAPEX | yearly | | OPEX | |
| | **Boilers** | Installation | 50.00 | €/kW | t=0 | | CAPEX | [38] |
| | | Maintenance | 10.00 | €/MWh | yearly | | OPEX | |
| | | NG consumption | 90.00 | €/MWh | yearly | | OPEX | [41] |
| | **Upgrading unit** | Installation | 1478.40 | €/Nm$^3$ | t=0 | | CAPEX | [38] |
| | | operational cost | 0.47 | €/Nm$^3$ | yearly | | OPEX | |
| | **Electricity grid withdrawal** | buying price | 50.00 | €/MWh | yearly | | OPEX | [41] |

*Table 3 Cost and revenues of the FC system*

In the study of an energetic facility, we could consider as an Inflow all the revenues coming from the sale of valuable energy vector, which in the considered scenarios are represented by the electric energy injected in the grid, the heat sold to the DH network and the biomethane sold to GSE. On the other hand, the Outflow considers all the costs which have to be sustained to generate those energy vectors, mainly represented by the FC unit, boilers and upgrading costs (electricity withdrawal cost is also considered when the FC production has to be integrated to fulfill the internal demand).

When considering expected costs, a further distinction can be highlighted, between the so called "capital expenditure" CAPEX and operational expenditure OPEX. With the first term are usually indicated all those costs that belong to the initial investment i.e. they happen only at t=0 in the plan, while with OPEX are indicated costs which are regularly repeated, like operation and maintenance costs.

In the table 2 are reported expected cost and revenues of the system in the different scenarios, their typology and their occurrence, while the effect of the variation of those parameters will be deeply analyzed in following chapters.

In the following cashflow analysis these assumptions are made:

- Expected lifetime of the plant equal to 25 years.
- Investment costs wholly referred to the first year of the plan (t=0).
- Discount rate equal to 5%.
- FC stack replacement every 7 years.

### 5.2.2 LCOE evaluation

Another economic parameter which can be used to evaluate the feasibility of the investment in an energy production plant is the Levelized cost of electricity LCOE. This is an index which is usually used to compare alternative technologies with different scale of operations, different investment, and operation time period[42]. In this case it is used to evaluate the differences between the three FC model considered.

LCOE, according to [43] is defined as the average unitary energy revenue required to compensate all capital and operational costs during the expected lifetime of the energy plant.

Its analytical formulation is provided by [44] and reported in the expression reported below:

$$LCOE = \frac{(\Sigma_{n=1}^{25} CAPEX_n + \Sigma_{n=1}^{25} OPEX_n - \Sigma_{n=1}^{25} R_n\ )(1+\mathrm{i})^{-t}}{\Sigma_{n=1}^{25} Ep_n\ \ (1+\mathrm{i})^{-t}} \qquad \text{Eq. (1)}$$

In which:

$CAPEX_n$ is the total investment cost referred to the year n

$OPEX_n$ is the total "operational and maintenance" cost referred to the year n

$R_n$ is the total revenue referred to the year n

$Ep_n$ is the total electric energy produced in the year n

$(1 + \mathrm{i})^{-t}$ is the actualization factor

Because of the way it is defined, the LCOE index is not the best parameter to compare all the different plant configuration proposed, for this purpose a new index is introduced.

### 5.2.3 LCOB definition

To evaluate the economic performance in case different output streams are produced from the plant, like in the hybrid configuration, a different economic parameter is introduced. The idea is to refer the actualized CAPEX, OPEX and revenues to the unit of biogas processed. In this way the production of biomethane and electricity can be compared without penalization.

The analytical formulation of LCOB is provided by the following expression:

$$LCOB = \frac{(\Sigma_{n=1}^{25} CAPEX_n + \Sigma_{n=1}^{25} OPEX_n - \Sigma_{n=1}^{25} R_n\ )(1 + \mathrm{i})^{-t}}{\Sigma_{n=1}^{25} Vb_n\ (1 + \mathrm{i})^{-t}} \qquad \text{Eq. (2)}$$

In which:

$CAPEX_n$ is the total investment cost referred to the year n

$OPEX_n$ is the total “operational and maintenance” cost referred to the year n

$R_n$ is the total revenue referred to the year n

$Vb_n$ is the total biogas volume processed in the year n

$(1 + \mathrm{i})^{-t}$ is the actualization factor

In the paragraph 6.2.2 are reported the trends of LCOB in the different plant configuration analyzed.

### 5.2.4 Sensitivity analysis

The sensitivity analysis is used in this section in order to verify which could be the different investment trend in case of different economic and technical context. This kind of study could help to evaluate how the return of the invested capital could change as function of specific parameters, like the frequency of substitution of FC stack or the installation cost.

Since FC technology is not so diffused in Europe, at least in the multi-MW plant scale, looking for precise economic data were not easy, as already discussed in the previous chapter. For this reason, many studies provide ranges of costs depending on parameters like the FC power capacity installed yearly or making projections of future possible targets to be reached in a certain time period (target for 2030 or 2050).

Another great element of uncertainty is the current price of NG and electricity, which strongly affect the feasibility of energy plants. For example, with the rising of the NG price due to geopolitical tension between Europe and Russia, also technologies for gas production which weren't economically viable in the past are now rising more and more interest.

In this direction, performing a sensitivity analysis could help simulate different future scenario from an economical point of view. In the table below are reported the most important parameters whose influence is evaluated and the respective range of variation.

| Free Parameter | Range of variation | Evaluation parameter |
|---|---|---|
| **FC Capex** | 5500 to 3500 €/kW | LCOE |
| **FC Opex** | 1.5% to 1% of Capex | LCOE |
| **Stack replacement frequency** | 5 to 12 years | LCOE |
| **Stack replacement cost** | 38% to 30% of Capex | LCOE |
| **Electricity price** | 50 to 250 €/MWh | LCOE and LCOB |
| **Biogas fraction to upgrade** | 55% to 93% of total BG flowrate | LCOE |

*Table 4 Sensitivity analysis parameters*

# 6. Results

## 6.1 Energy analysis

In this section are reported the results of the energy analysis performed, including the dimension of each FC unit and analysis of balance in the resulting plant configuration.

### 6.1.1 Only CHP asset

In the first scenario we assume no incentives on biomethane production are present, so the entire biogas production is directed to the fuel cell CHP unit, to produce electricity and thermal energy. In this case a comparison between the use of different fuel cell models is used to highlight which could be the best solution from an energetic and economic point of view.

### Mitsubishi GT-SOFC

| | | | |
|---|---|---|---|
| **Stream data** | Biogas available | 576,383 | $Nm^3$/month |
| | Methane content | 61.71% | - |
| | LHV mean | 6.73 | kWh/ $Nm^3$ |
| | Energy content (AVG) | 3,877 | MWh/ month |
| | Flowrate available | 800 | $Nm^3$/h |
| | Equivalent methane flowrate | 494.02 | $Nm^3$/h |
| **SOFC selection** | Electrical efficiency* | 53.00% | - |
| | Expected electrical output | 2,054 | MWh/ month |
| | Expected power output | 2,853 | kW |
| **Auxiliary boilers** | Efficiency** | 96.00% | - |
| | LHV methane** | 10.88 | kWh/ $Nm^3$ |

*Table 5 Sizing the Mitsubishi SOFC CHP unit*

In table 5 are reported the input stream data and the ones found in the datasheet of the FC[32] while the efficiency of gas boilers and the LHV of methane are obtained by the analysis of plant data[38].

| SOFC Mitsubishi Megamie 250 | | |
|---|---|---|
| **Single module power (AC net)** | 210.00 | kW |
| **Single module NG consumption*** | 50.00 | $Nm^3/h$ |
| **Single module biogas consumption** | 81.02 | $Nm^3/h$ biogas |
| **Number of modules (calculated)** | 13.59 | - |
| **Number of modules (real)** | 14 | - |
| **Installed power** | 2,940 | kW |
| **Working hours (yearly based)** | 8,600 | h/year |
| **Net electricity produced (annual)** | 24,541 | MWh/year |
| **Net electricity produced (monthly avg.)** | 2,045 | MWh/month |
| **Capacity factor** | 0.98 | - |
| **Single module thermal output** | 86.00 | kW |
| **Heat produced yearly** | 10,050 | MWh/year |
| **Electric efficiency** | 52.75% | - |
| **Thermal efficiency** | 21.60% | - |
| **Biogas not utilized** | - | $Nm^3/year$ |

Table 6 Elaboration of data about Mitsubishi SOFC

In table 4 are reported the results of the sizing process, it is possible to appreciate how data of electric and thermal efficiency are obtained, to check if the declared performances are verified. In the following chapters, data about monthly electric and thermal output will be used to evaluate how the SOFC can fulfill the energy demand of the plant.

### FCE SOFC

In the table below (figure 30) the main characteristics of input stream and SOFC declared performance are reported, together with efficiency of gas boilers and LHV of methane obtained by the analysis of plant data (provided by ACEA).

| | | | |
|---|---|---|---|
| **Stream data** | Biogas available | 576,383 | $Nm^3/month$ |
| | Methane content | 61.71% | - |
| | LHV mean | 6.73 | kWh/ $Nm^3$ |
| | Energy content (AVG) | 3,877 | MWh/ month |
| | Flowrate available | 800.53 | $Nm^3/h$ |
| | Equivalent methane flowrate | 494.02 | $Nm^3/h$ |
| **SOFC selection** | Electrical efficiency* | 61.70% | - |
| | Expected electrical output | 2,392 | MWh/ month |
| | Expected power output | 3,322 | kW |
| **Auxiliary boilers** | Efficiency** | 96.00% | - |
| | LHV methane** | 10.88 | kWh/ $Nm^3$ |

*Table 7 Sizing the Mitsubishi SOFC CHP unit*

To proceed with the sizing of the system, the same model of the Mitsubishi SOFC is applied, obtaining the data reported in the table below.

| FCE SOFC 200 | | |
|---|---|---|
| **Single module power (AC net)** | 219.30 | kW |
| **Single module NG consumption*** | 36.70 | $Nm^3/h$ |
| **Single module biogas consumption** | 59.47 | $Nm^3/h$ biogas |
| **Number of modules (calculated)** | 15.15 | - |
| **Number of modules (real)** | 15 | - |
| **Installed power** | 3,289 | kW |
| **Working hours (yearly based)** | 8,600 | h/year |
| **Net electricity produced (annual)** | 28,289 | MWh/year |
| **Net electricity produced (monthly avg.)** | 2,357 | MWh/month |
| **Capacity factor** | 0.98 | - |
| **Single module thermal output** | 90.80 | kW |
| **Heat produced yearly** | 11,713 | MWh/year |
| **Electric efficiency** | 60.81% | - |
| **Thermal efficiency** | 25.18% | - |
| **Biogas not utilized** | - | $Nm^3/year$ |

*Table 8 Elaboration of data about FCE SOFC*

## FCE MCFC

The sizing process follow the same procedure already applied for the previous FC systems, the available energy content of the stream is computed, and then comparing it with the single module power output the number of modules can be determined. The results of this process are reported in the tables below.

| | | | |
|---|---|---|---|
| **Stream data** | Biogas available | 576,383 | $Nm^3/month$ |
| | Methane content | 61.71% | - |
| | LHV mean | 6.73 | kWh/ $Nm^3$ |
| | Energy content (AVG) | 3,876 | MWh/ month |
| | Flowrate available | 800 | $Nm^3/h$ |
| | Equivalent methane flowrate | 494.02 | $Nm^3/h$ |
| **SOFC selection** | Electrical efficiency* | 47.00% | - |
| | Expected electrical output | 1,822 | MWh/ month |
| | Expected power output | 2,530 | kW |
| **Auxiliary boilers** | Efficiency** | 96.00% | - |
| | LHV methane** | 10.88 | kWh/ $Nm^3$ |

*Table 9 Sizing the FCE MCFC CHP unit*

| MCFC FCE Sure source 3000 | | |
|---|---|---|
| **Single module power (AC net)** | 2,800 | kW |
| **Single module NG consumption*** | 615 | $Nm^3/h$ |
| **Single module biogas consumption** | 997 | $Nm^3/h$ biogas |
| **Number of modules (calculated)** | 0.90 | - |
| **Number of modules (real)** | 1.00 | - |
| **Installed power** | 2,800 | kW |
| **Working hours (yearly based)** | 8,600 | h/year |
| **Net electricity produced (annual)** | 21,763 | MWh/year |
| **Net electricity produced (monthly avg.)** | 1,814 | MWh/month |
| **Capacity factor** | 0.98 | - |
| **Single module thermal output** | 1,299 | kW |
| **Heat produced yearly** | 10,098 | MWh/year |
| **Electric efficiency** | 46.78% | - |
| **Thermal efficiency** | 21.71% | - |
| **Biogas not utilized** | - | $Nm^3$/year |

*Table 10 Elaboration of data about FCE MCFC*

In this case the size of the systems produced by FCE allow the utilization of a single module of 2.8 MWel. Once the installed power is obtained, the electricity and heat produced can be computed. This allows to analyze the electric and thermal balance of the plant, comparing the MCFC production with the demand of Acea plant month by month. Since the MCFC is characterized by a lower thermal efficiency it is expected a higher heat required to the auxiliary boiler unit.

### 6.1.2 Hybrid FC unit and upgrading solution

In this scenario the process of FC sizing is quite different, since it is based on the biogas flowrate sent to the upgrading section. A modified model is elaborated, and two different assets are studied:

- Maximization of biomethane production (considering October 2021 as a reference)
- Electric self sufficiency

In the following tables are reported the main results of the FC sizing in those different plant layouts, while in the chapter 6.2 a sensitivity analysis will be performed to highlight the optimal BG fraction to upgrade in order to get the best economic performances.

## Maximization of biomethane production

| | | | |
|---|---|---|---|
| Stream data | Total biogas produced | 576,383 | $Nm^3$/month |
| | BG sent to upgrading | 565,372 | $Nm^3$/month |
| | BG "surplus" available | 11,011 | $Nm^3$/month |
| | Methane content | 61.71% | - |
| | LHV mean | 6.73 | kWh/ $Nm^3$ |
| | Energy content (AVG) | 74.06 | MWh/ month |
| | Flowrate available | 800 | $Nm^3$/h |
| | Equivalent methane flowrate | 494 | $Nm^3$/h |
| SOFC selection | Electrical efficiency* | 61.70% | - |
| | Expected electrical output | 45.70 | MWh/ month |
| | Expected power output | 63.47 | kW |
| Auxiliary boilers | Efficiency** | 96.00% | - |
| | LHV methane** | 10.88 | kWh/ $Nm^3$ |

*Table 11 Sizing FC max upgrading scenario*

* Data from [33]

** Data of Acea pinerolese[38]

| SOFC FCE – max Upgrading | | |
|---|---|---|
| Single module power (AC net)* | 219.30 | kW |
| Single module NG consumption* | 36.70 | Nm3/h |
| Single module biogas consumption | 59.47 | Nm3/h biogas |
| Number of modules (calculated) | 0.29 | - |
| Number of modules (real) | 1.00 | - |
| Installed power | 219.30 | kW |
| Working hours (yearly based) | 8,600 | h/year |
| Net electricity produced (annual) | 545.82 | MWh/year |
| Net electricity produced (monthly avg.) | 45.48 | MWh/month |
| Capacity factor | 0.98 | - |
| Single module thermal output* | 90.80 | kW |
| Heat produced yearly | 780.88 | MWh/year |
| Electric efficiency | 61.41% | - |
| Thermal efficiency | 87.86% | - |

*Table 12 Data elaboration max upgrading scenario*

## Electric self sufficiency

| | | | |
|---|---|---|---|
| **Stream data** | Total biogas produced | 576,383 | $Nm^3$/month |
| | BG sent to upgrading | 320,000 | $Nm^3$/month |
| | BG "surplus" available | 256,383 | $Nm^3$/month |
| | Methane content | 61.71% | - |
| | LHV mean | 6.73 | kWh/ $Nm^3$ |
| | Energy content (AVG) | 1,724 | MWh/ month |
| | Flowrate available | 800 | $Nm^3$/h |
| | Equivalent methane flowrate | 494.02 | $Nm^3$/h |
| **SOFC selection** | Electrical efficiency* | 61.70% | - |
| | Expected electrical output | 1,063 | MWh/ month |
| | Expected power output | 1,478 | kW |
| **Auxiliary boilers** | Efficiency** | 96.00% | - |
| | LHV methane** | 10.88 | kWh/ $Nm^3$ |

*Table 13 Sizing FC electric sufficiency scenario*

| **SOFC FCE - Covering electric load** | | |
|---|---|---|
| **Single module power (AC net)*** | 219.30 | kW |
| **Single module NG consumption*** | 36.70 | Nm3/h |
| **Single module biogas consumption** | 59.47 | Nm3/h biogas |
| **Number of modules (calculated)** | 6.74 | - |
| **Number of modules (real)** | 7.00 | - |
| **Installed power** | 1,535 | kW |
| **Working hours (yearly based)** | 8,600 | h/year |
| **Net electricity produced (annual)** | 12,708 | MWh/year |
| **Net electricity produced (monthly avg.)** | 1,059 | MWh/month |
| **Capacity factor** | 0.98 | - |
| **Single module thermal output*** | 90.80 | kW |
| **Heat produced yearly** | 5,466 | MWh/year |
| **Electric efficiency** | 61.41% | - |
| **Thermal efficiency** | 26.42% | - |

*Table 14 Data elaboration electric sufficiency scenario*

### 6.1.3 Energy balances

Once the plant size is correctly defined and so the number of modules is determined, the energy production is considered. For this purpose, the assumption about the capacity factor of the plant is made, since FC systems are characterized by a high efficiency and require low maintenance with respect to traditional energy plants (no rotating parts or turbine blades involved) the number of working hours in a year is assumed equal to 8600, that means imposing a CF equal to 0.98.

So, it is possible to consider the electric and thermal output of the systems in terms of MWh/year, and to evaluate the behavior month by month considering the data provided by ACEA for the year 2021. For each month, given the electrical production of the CHP unit, is possible to evaluate how the internal uses of the plant are covered and how much energy can be sold to the electric network.

For what concern the thermal energy, since the efficiency of the FC is not so high, it is possible to appreciate that part of the load has to be fulfilled by a back-up unit of gas boilers, which produce thermal power from the combustion of NG from the gas distribution network.

The energetic balance of the first model of FC considered (Mitsubishi Megamie 250) is graphically represented in the plots below.

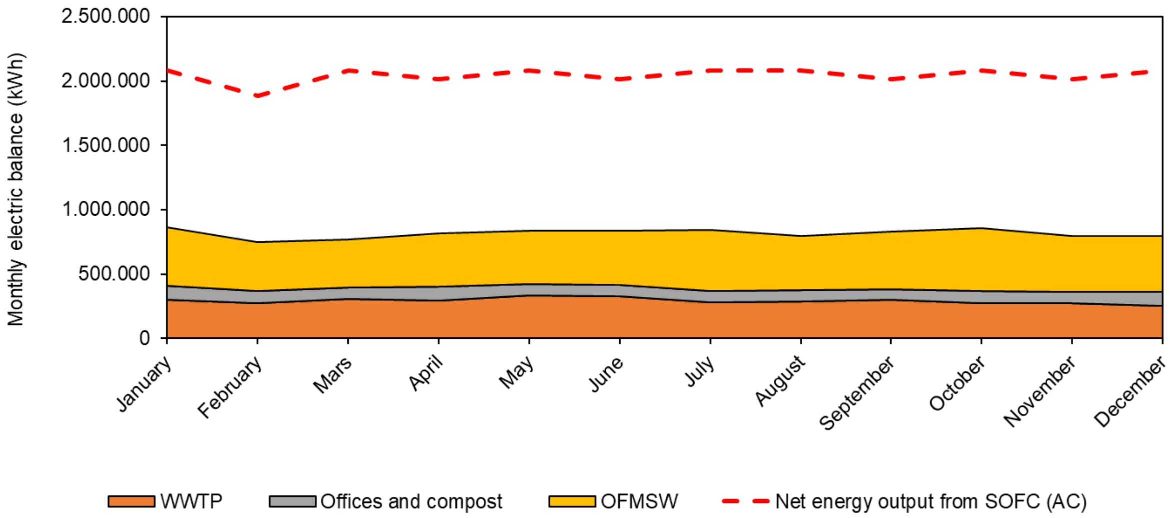


*Figure 31 Electric balance of the plant with Mitsubishi SOFC*

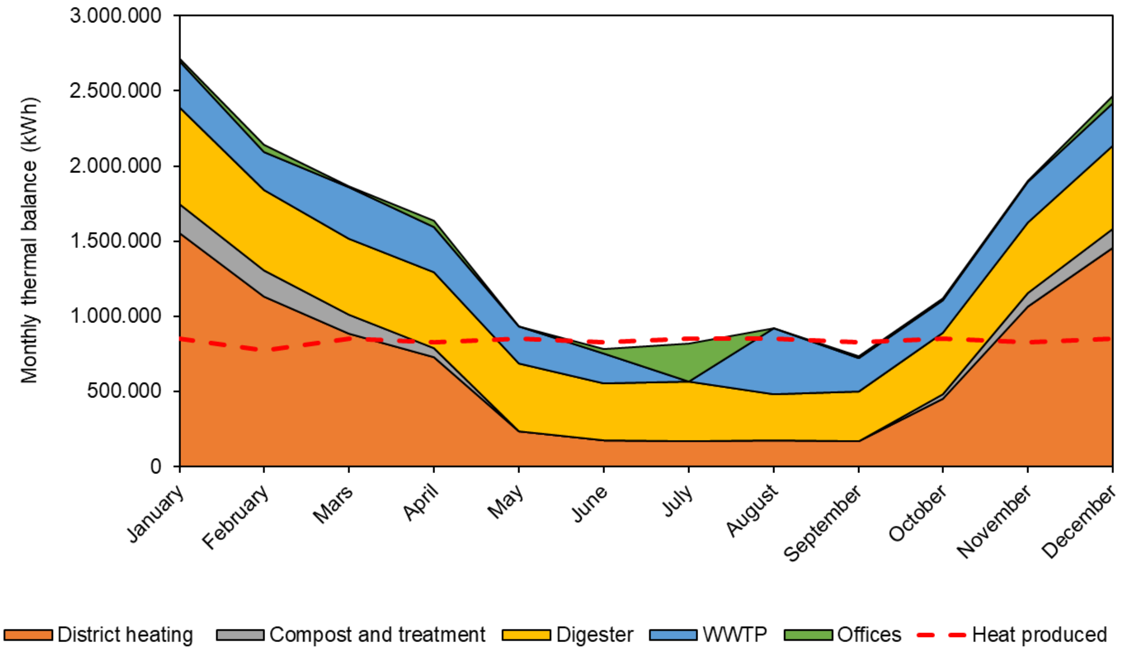


*Figure 32 Thermal balance of the plant with Mitsubishi SOFC*

From the plots emerges how the electrical production of the system represent roughly the double of the energy required from the plant to operate, that means that around a half of the energy produced could be sold to the grid. Considering the thermal balance, the system could provide enough energy in the summer months (from June to September) while in the other months heat integration from auxiliary boilers is needed. However, since the heat production of the system is much higher than the one from the ICE in the actual configuration (10050 Mwh/year of the SOFC with respect to 7670 Mwh/year by ICE) the boilers that are already installed in the plant could provide the amount of heat to integrate the SOFC, without the need of any new installation.

### FCE SOFC

So, it is possible to consider the electric and thermal output of the systems in terms of MWh/year and comparing them month by month with the energy demand data provided by ACEA for the year 2021. In this way, for each month is possible to evaluate how the internal uses of the plant are covered and how much energy can be sold to the electric network.

For what concern the thermal energy, since the efficiency of the FC is not so high, it is possible to appreciate that part of the load has to be fulfilled by a back-up unit of gas boilers, which produce thermal power from the combustion of NG from the gas distribution network.

The energetic balance of the first model of FC considered (FCE SOFC 200) is graphically represented in the plots below.

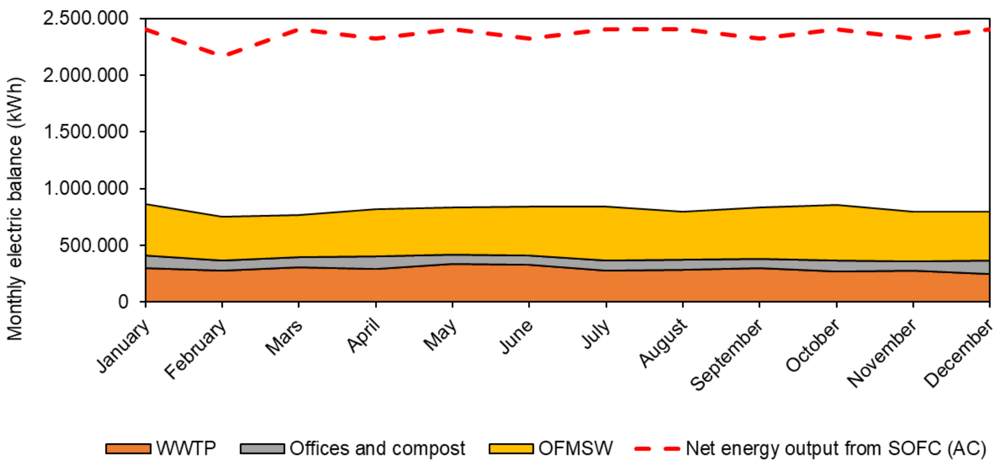


*Figure 33 Electric balance of the plant with FCE SOFC*

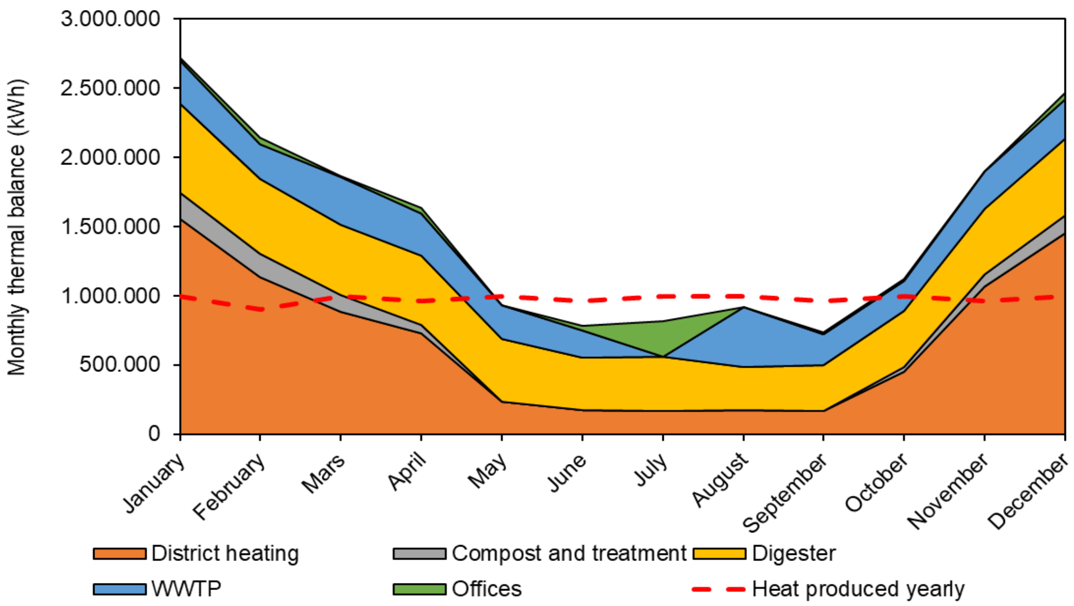


*Figure 34 Thermal balance of the plant with FCE SOFC*

From the plots emerges how the electrical production of the system represent roughly 2.5 times the electric energy required from the plant to operate, that means that around 60% of the energy produced could be sold to the grid. Considering the thermal balance, the system could provide enough energy in the summer months (from May to September) while in the other months heat integration from auxiliary boilers is needed. However, since the heat production of the system is much higher than the one from the ICE in the actual configuration (11700 Mwh/year of the SOFC with respect to 7670 Mwh/year by ICE) the boilers that are already installed in the plant could provide the amount of heat to integrate the SOFC, without the need of any new installation.

### FCE MCFC

In case of the MCFC system due to the lower efficiency it is possible to appreciate a lower energy output (both electric and thermal), however the system is able to produce roughly the double of the energy required by the plant at the moment, as emerges from the graph reported below.

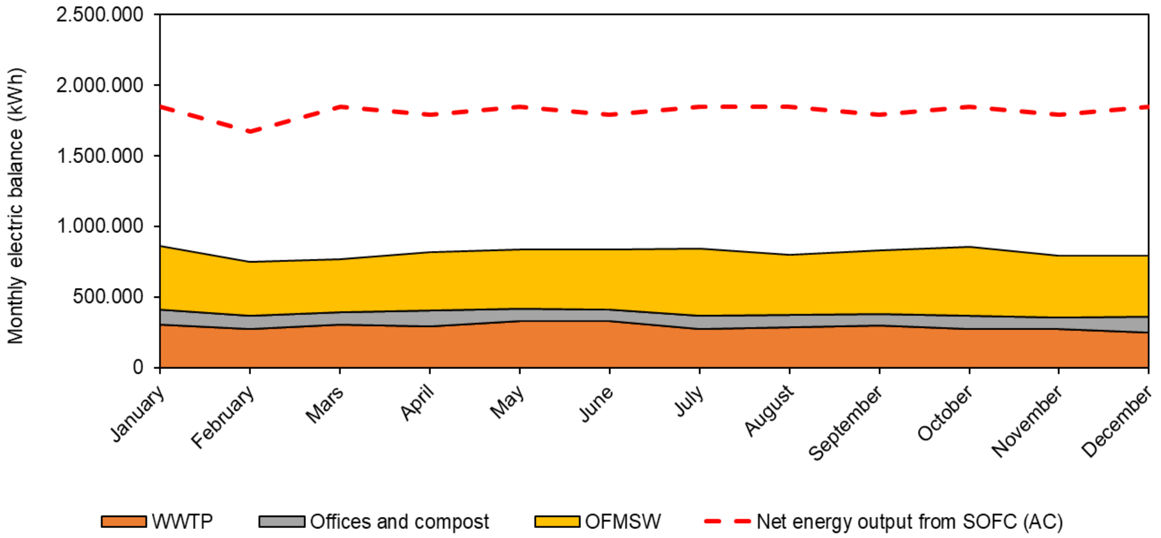


*Figure 35 Electric balance of the plant with FCE MCFC*

The energy performances of the MCFC are slightly worse also when considering heat production, as can be noticed in the figure 39, with the system which is able to fulfill the thermal load only in June, July, and September.

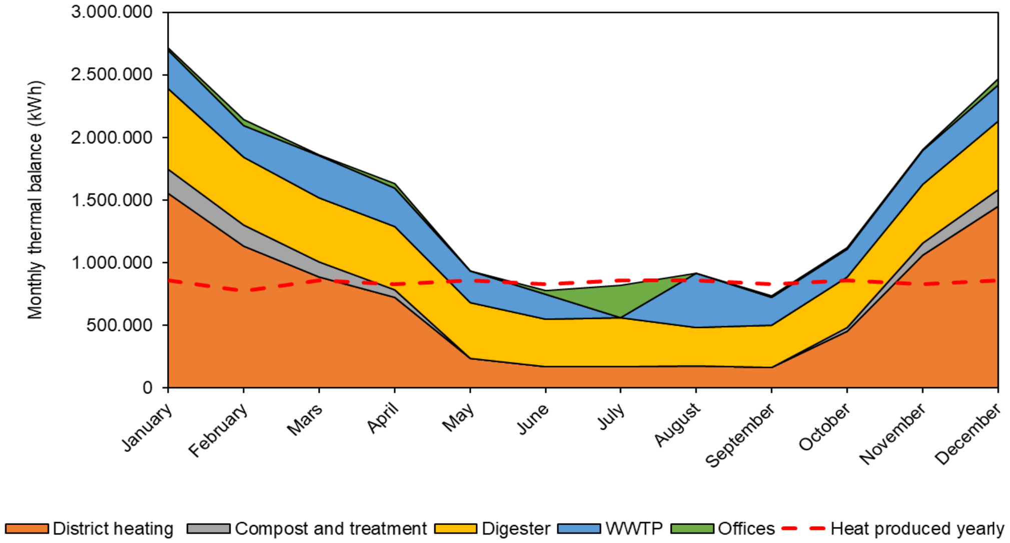


*Figure 36 Thermal balance of the plant with FCE MCFC*

### Considerations on first scenario and FC comparison

To complete the energetic analysis of the first scenario a comparison between the fuel cell is proposed. The behavior of each single system has been described in the previous sections, and now the goal is to determine which system could be the most suitable, at least from an energetic point of view.

For this purpose, in the following graph the electric and thermal production of each system is plotted, with reference to the plant load.

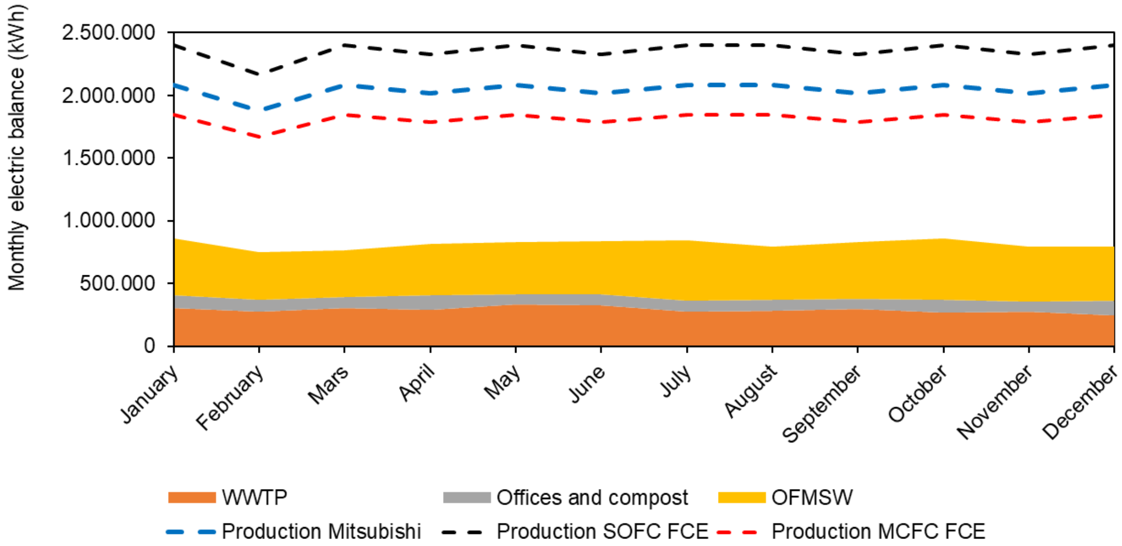


*Figure 37 Comparison of electric performance of different FC units*

As highlighted in the figure 40, the best performances are obtained by the FCE SOFC system, followed by the Mitsubishi unit and then the FCE MCFC. As deeply explained in the next chapter, the higher efficiency of a systems affects in a positive way the return of the initial investment, so it is always a good choice to look for efficiencies as high as possible.

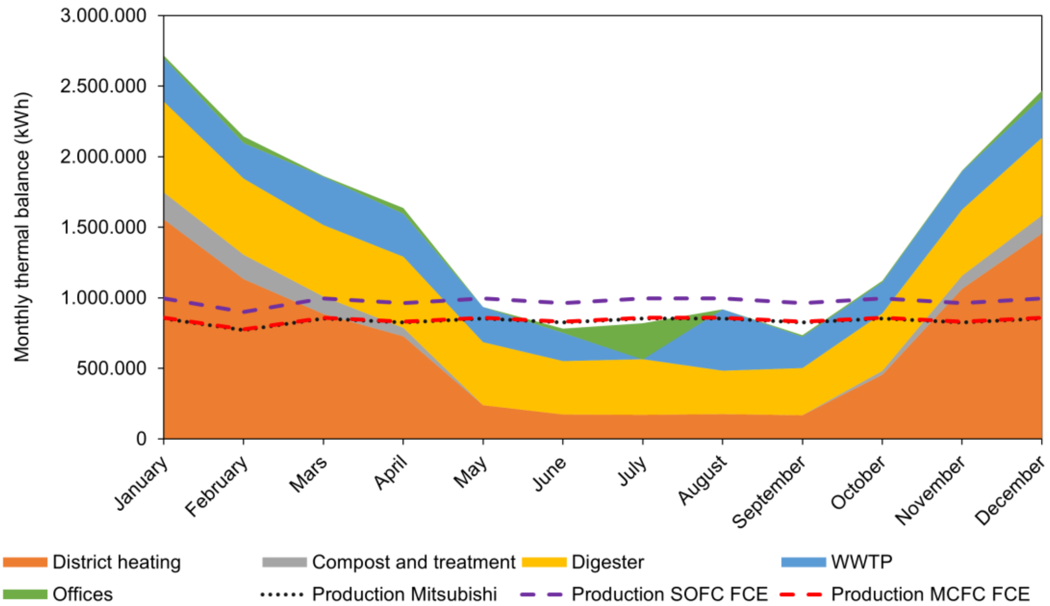


*Figure 38 Comparison of thermal performance of different FC units*

For what concern the thermal output, the performances of the Mitsubishi SOFC and MCFC are very close, and are slightly lower compared to FCE SOFC, as emerges in the plot figure 41.

When analyzing heat production, some consideration can be made, because the system with the highest output is not always the better choice. In fact, considering the production trend captured in the figure 41, it is possible to appreciate how during summer month there is a surplus of heat produced with respect to the consumption of the plant, and this quota must be somehow managed. The easiest way could be represented by the dissipation of the exceeding heat but is the most inefficient way of handling it, not only because of the thermal energy wasted, but also because it would require the installation of a heat dissipator and its auxiliaries. As an alternative it is possible to consider if the heat could be sold to any industrial facility in the proximity of the ACEA plant, since we can imagine during the summer the thermal request from the residential sector is minimum.

On the other hand, a higher thermal output means that except in summer months, the heat demand of the plant is covered in a more efficient way, reducing sensibly the energy required from the auxiliary boilers and so the gas consumption. This could lead to a lower dependance of the plant on not renewable source. As many energetic issues, there is not a unique solution, but it represents a threshold problem that has to be deeply analyzed to find the better way to manage it.

As already discussed in the paragraph 3.1 in Europe one of the biggest limits to the expansion of biogas-based CHP units were exactly this: the lack of infrastructure (DH networks, industrial facilities) able to properly exploit the heat generated by CHP systems.

### Hybrid FC and upgrading solutions

In this section the performance of different layouts is showed, elaborating data obtained in the chapter about FC sizing. In the plots below are graphically reported the difference in the behavior of the FC unit in the different scenarios considered, and their ability to cover the internal demand of the plant.

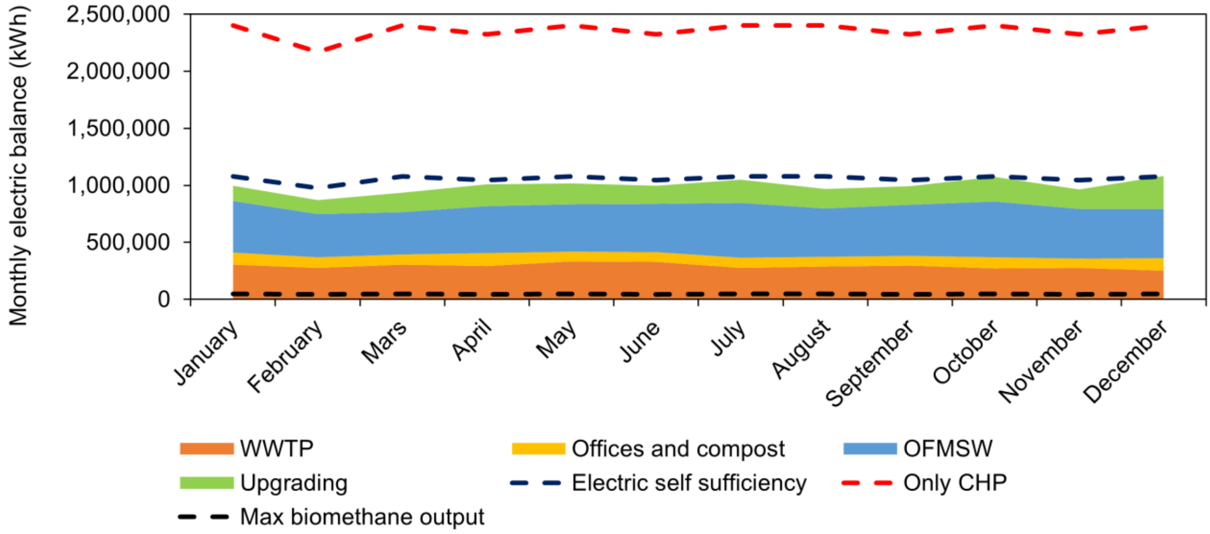


*Figure 39 Electric load coverage in the hybrid configuration*

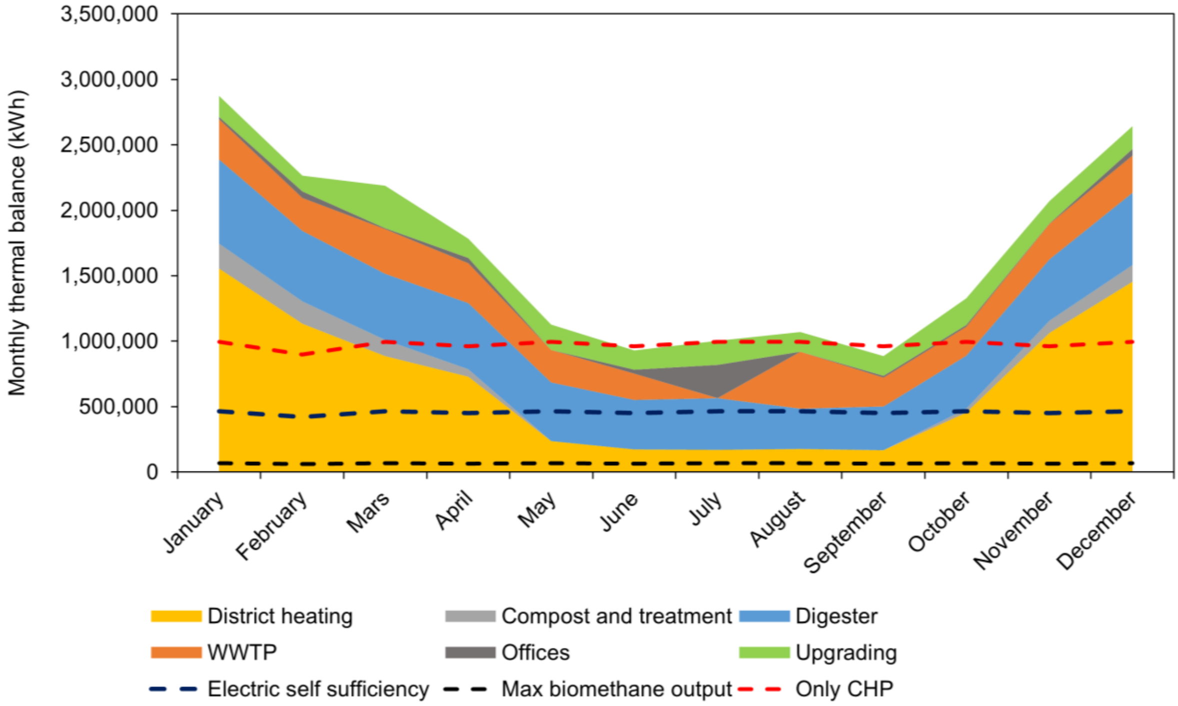


*Figure 40 Thermal load coverage in the hybrid configuration*

## 6.2 Economic analysis

In the economic analysis the cost and revenues related to the FC installation are compared, to get a measure of the feasibility of the investment, in this section the various economic tools described in paragraph 5.2 are applied to each specific scenario and the results are reported in apposite graphs.

### 6.2.1 Cashflow comparison

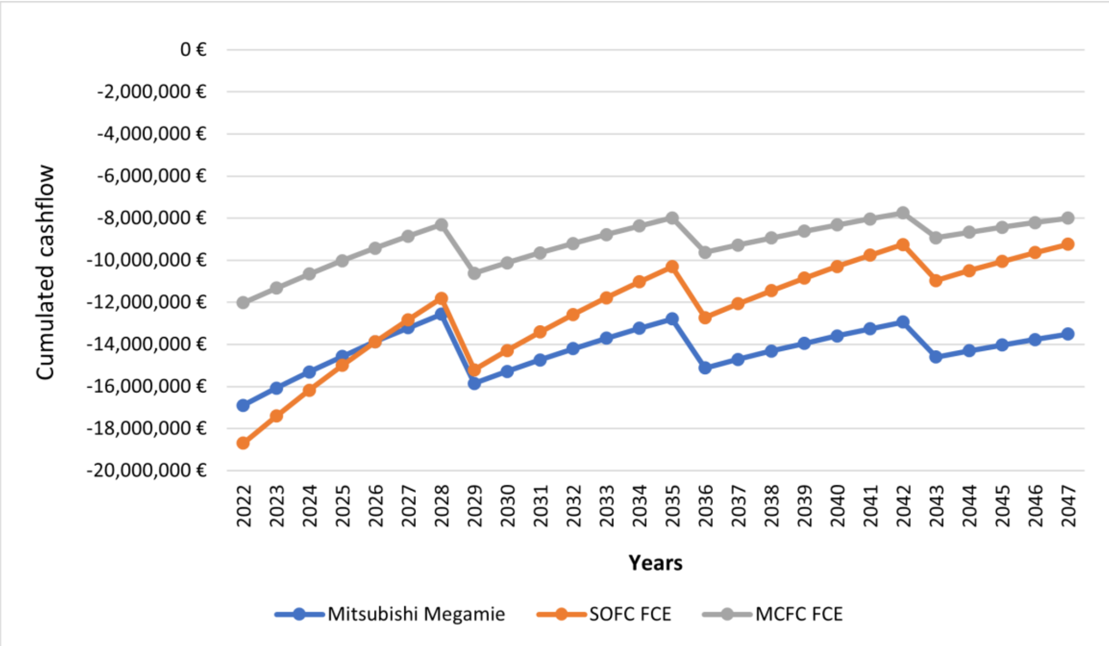


*Figure 41 Cumulated cashflow trend for the three different FC considered*

The cashflow analysis is used in the first scenario (only CHP) to compare the possible investment evolution in the case no subsidies are applied to the energy injected in the grid. As highlighted by the graph, the three cashflow are always negative, mainly due to the really high initial investment cost a 3 MW FC plant requires. Anyhow, it is interesting to consider the differences between the cashflow obtained applying the three different FC system presented in chapter 5.1.

As captured in the graph figure 47, the worst economic performances are obtained with the Mitsubishi SOFC, while the two products from FCE present more interesting cashflow trends. The MCFC is characterized by a lower initial economic expenditure, but also the electric output is limited, and so the revenues for energy injection in the grid are lower. On the other hand, the FCE SOFC present a higher investment cost but with a higher power output is able to generate higher revenues too, as highlighted by the steepness of the cashflow trend.

As a general rule, it is possible to expect a better economic performance by the MCFC in the short term, while the choice of SOFC could be convenient if a long term investment has to be performed. At this stage the Mitsubishi Megamie seems to be the less interesting FC from an economic point of view, even if the concept of an integrated SOFC-microGT system is quite promising for future development.

### 6.2.2 LCOE results

LCOE is used in this paragraph as a tool to investigate which is the weight in economic term of each plant cost. This analysis could provide really interesting results especially in case of FC related costs, since the fuel cell technology is becoming more and more relevant in the stationary power generation sector.

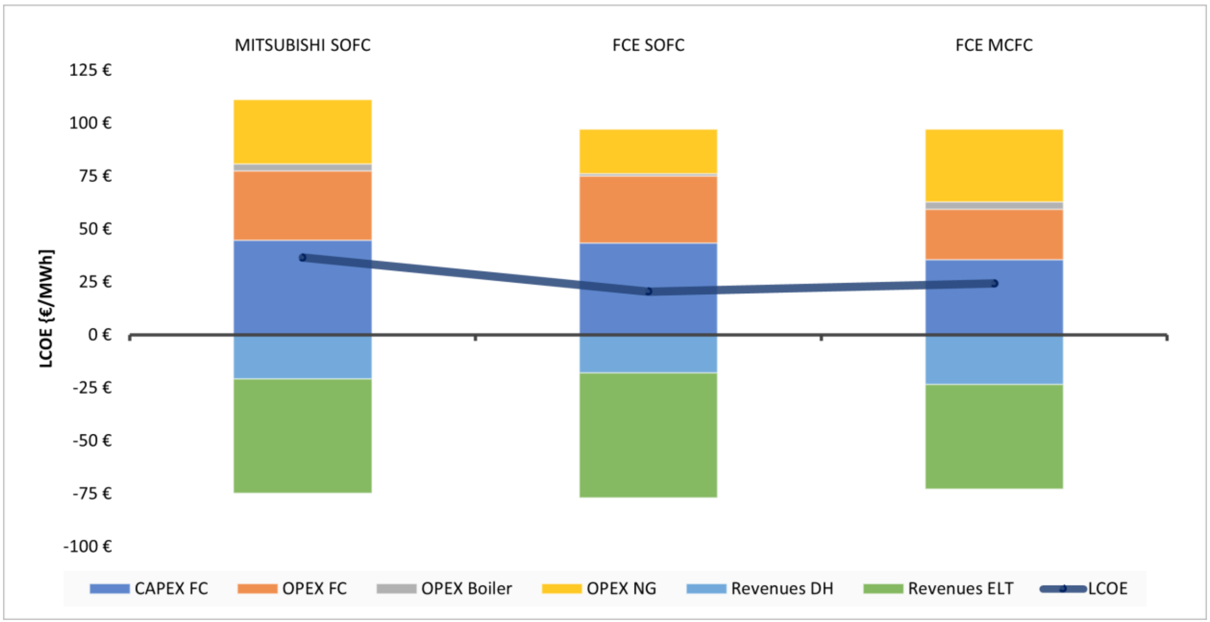


*Figure 42 LCOE comparison between different FC technologies*

| FC model | LCOE [€/MWh] |
|---|---|
| **Mitsubishi SOFC** | 36.50 |
| **FCE SOFC** | 20.50 |
| **FCE MCFC** | 24.34 |

*Table 15 LCOE value of different FC technologies*

As reported in the graph figure 54 in the actual economic condition, the highest cost contribution are related to the FC capex and opex, since the evolution of these systems is still at the first stages (at least for what concern multi-MW installations). As already said the costs related to MCFC are quite lower than the SOFC ones, since the materials required to realize the stack of cell are less expensive. A crucial issue in the economic development of FC technologies is the cost of the stack and the frequency of substitution, as emerges in the cashflow plot, since it represents a significant cost (around 1/3 of the CAPEX) to be repeated every 5-7 years. For this reason, there is a lot of effort in extending the stack duration time and reducing its cost, exploiting new materials and implementing different construction methodologies.

In the following chapters the possible effect of the evolution of those costs will be evaluated in depth.

### Effect of the FC readiness level on the economic investment

As described in the section 5.2 the FC part of the economic analysis is based on papers like [40] which provide cost ranges for each type of FC technology and perform some future projections of those same cost, referring them to a specific year or to a certain amount of power annually installed.

Based on those documents, in the following table different cost scenario are individuated, and the LCOE parameter is used to consider which effect each cost variation would generate on the investment. This kind of analysis gives a measure of the economic feasibility of the investment with respect to the technology readiness level.

| Reference year | Kind of cost | | | | LCOE [€/MWh] | | |
|---|---|---|---|---|---|---|---|
| - | CAPEX [€/kW] | Stack replacement frequency [years] | Stack replacement [%of capex] | FC OPEX [%of capex] | Only CHP | 55% UPG | 83% UPG |
| **2015** | 5,500 | 5 | 38.0% | 1.5% | 41.01 | 9 | 37 |
| **actual (2022)** | 5,000 | 7 | 36.0% | 1.3% | 16.37 | 4 | 32 |
| **2024** | 4,500 | 8 | 35.0% | 1.2% | 6.72 | 0 | 27 |
| **2027** | 4,000 | 10 | 33.0% | 1.1% | -5.88 | -4 | 22 |
| **target (2030)** | 3,500 | 12 | 30.0% | 1.0% | -14.14 | -9 | 17 |

*Table 16 LCOE sensitivity to FC readiness level*

The LCOE trend in the different FC development cost framework is highlighted in the graph below, in which are further distinguished several cases with a different percentage of upgraded biogas. As represented in the plot, the case which would benefit more of the reduced cost is the "only CHP" scenario, since it's the one in which the FC size is bigger, and so the FC related cost have a major impact on the economic balance.

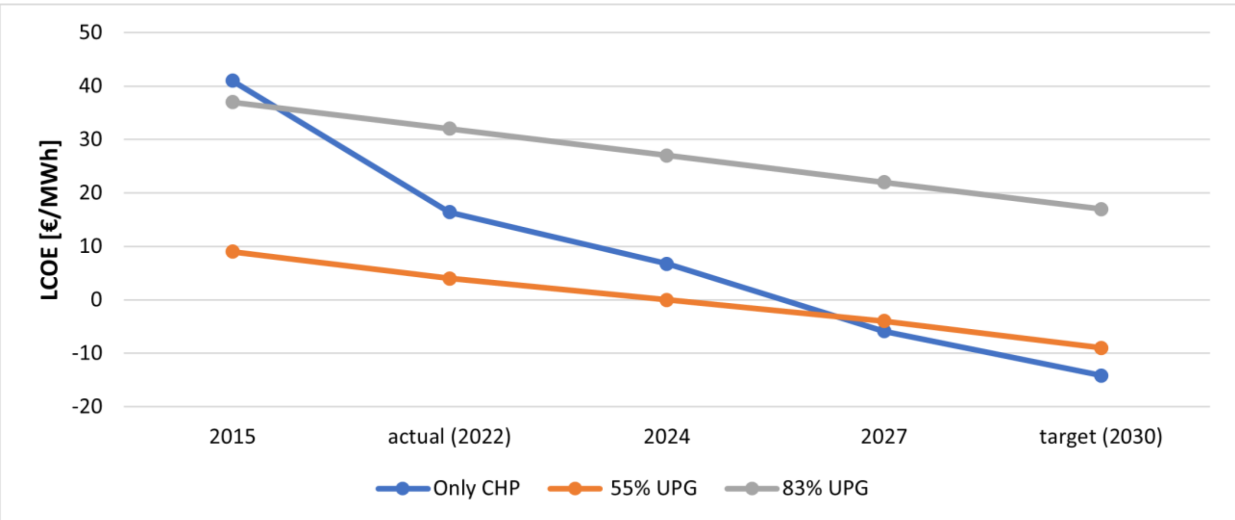


*Figure 43 LCOE future trends in different scenarios*

### Effect of electricity price on the economic investment

In a further analysis, the feasibility of the investment is evaluated in different energetic scenario. To be more specific, the sensitivity of the investment to the price of electricity is studied in this section. This could be a crucial parameter to consider deciding which amount of biogas flowrate use for power generation and so to size the FC unit.

We could expect that a steep increment of the electricity price would make the power generation more convenient to internally generate the energy required from the plant, while in case of low electricity price the most profitable choice would be to increase the biomethane production.

| | | | Only CHP 2022 | Only CHP 2030 (target) | 55 %UPG | 83 %UPG |
|---|---|---|---|---|---|---|
| Parameter | **Value [€/MWh]** | **% Of the current value** | **LCOE [€/MWh]** | **LCOE [€/MWh]** | **LCOE [€/MWh]** | **LCOE [€/MWh]** |
| Electricity price | 50 | 41.7% | 19.28 | -14 | 4 | -73 |
| | 100 | 83.3% | 19.28 | -14 | 4 | 2 |
| | 120 | 100.0% | 19.28 | -14 | 4 | 32 |
| | 150 | 125.0% | 19.28 | -14 | 4 | 77 |
| | 200 | 166.7% | 19.28 | -14 | 4 | 153 |
| | 250 | 208.3% | 19.28 | -14 | 4 | 228 |

*Table 17 LCOE sensitivity to electricity price*

As highlighted in the following plot the electricity price does not affect the investment when the production of the CHP is higher than the system demand, since there is no withdrawal from the grid (constant horizontal lines), however increasing the biomethane production, the trend changes becoming linear. The most interesting point to analyze is the crossing point between the yellow line and the other lines, since it represents (moving left to right) the exact point in which electric generation become more convenient than biomethane production.

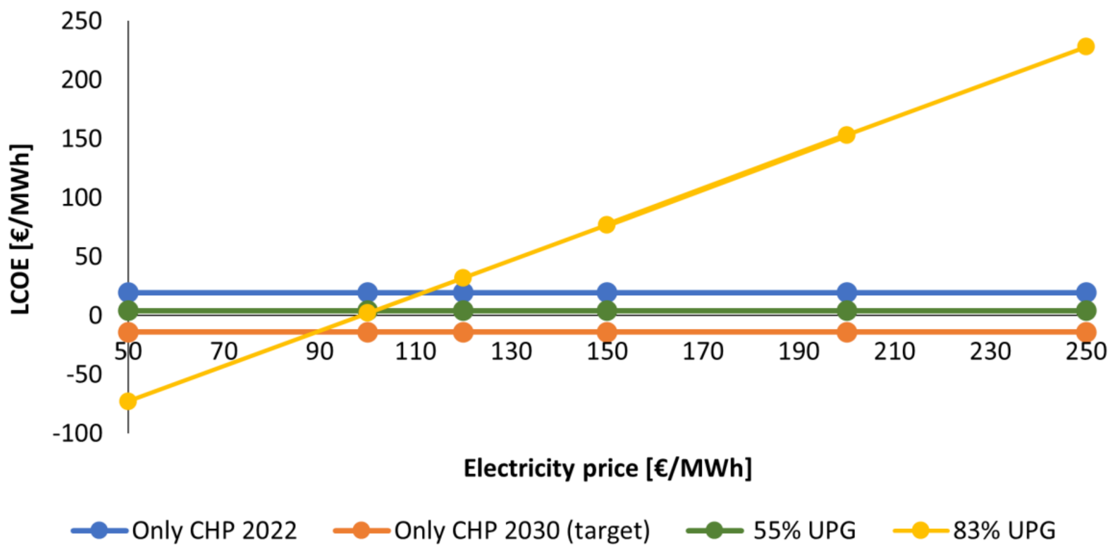


*Figure 44 LCOE sensitivity to electricity price*

### Limits of the LCOE analysis

Because of the way it is defined, the LCOE is a very useful index. However, in the scenario in which the electric production decreases the effect is this parameter grow steeply, as captured in the following graphs. This effect makes it not suitable to describe scenario with a high biomethane production, since they would be roughly penalized.

| Parameter | Value [Nm3] | Portion of the total biogas produced [%] | Electric load coverage [%] | LCOE [€/MWh] |
|---|---|---|---|---|
| **Biogas to upgrading** | 320,000 | 55.5% | 100.0% | 4 |
| | 374,650 | 65.0% | 78.9% | 16 |
| | 432,290 | 75.0% | 59.7% | 17 |
| | 480,212 | 83.3% | 39.9% | 32 |
| | 538,000 | 93.3% | 15.8% | 108 |

*Table 18 LCOE sensitivity to increasing upgrading flowrate*

For this reason, a new index is defined, considering the volume of biogas processed instead of the electric production, this new index, called LCOB, will be adopted in the following analysis.

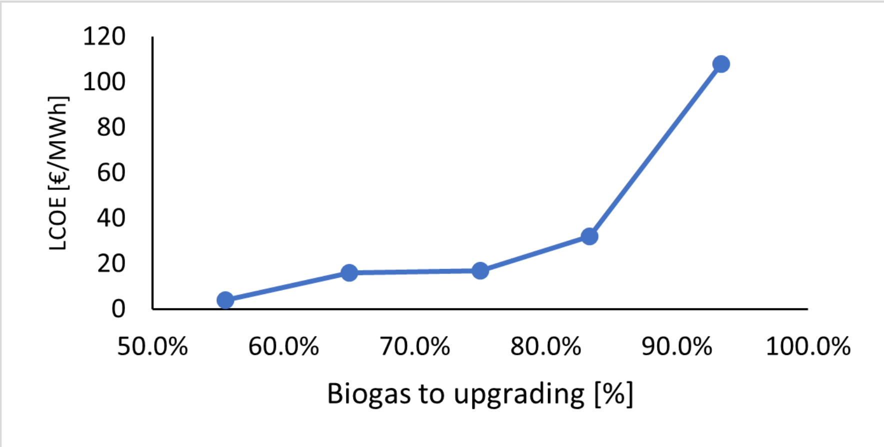


*Figure 45 LCOE sensitivity to increasing upgrading flowrate*

### 6.2.2 LCOB results

The new parameter defined on chapter 5 is used to evaluate different development scenario. In the following table the results of the sensitivity analysis to the electricity price are reported.

| | | | Only CHP 2022 | 55% UPG | 83% UPG | 100% UPG |
|---|---|---|---|---|---|---|
| Parameter | Value [€/MWh] | % Of the current value | LCOB [€/Nm3] | LCOB [€/Nm3] | LCOB [€/Nm3] | LCOB [€/Nm$^3$] |
| Electricity price | 50 | 41.7% | 0.033 | 0.008 | -0.051 | -0.009 |
| | 100 | 83.3% | 0.033 | 0.008 | 0.001 | -0.002 |
| | 120 | 100.0% | 0.033 | 0.008 | 0.022 | 0.032 |
| | 150 | 125.0% | 0.033 | 0.008 | 0.053 | 0.084 |
| | 200 | 166.7% | 0.033 | 0.008 | 0.105 | 0.170 |
| | 250 | 208.3% | 0.033 | 0.008 | 0.157 | 0.275 |

*Table 19 LCOB sensitivity to electricity price*

The following graph provide a visual comparation of the effect of a growing electricity price on different scenarios. When the percentage of biogas sent to upgrading is lower than 55% the trend is constant, since the residual biogas allow an energy production able to fulfill the internal demand. Instead, when the upgraded flowrate increases, the trend changes, increasing proportionally to the electricity price, since a major biomethane production requires a higher electricity consumption and so a higher cost.

The most interesting portion of the graph is the one in which the lines cross, since it provides an indication of the cost of electricity that makes the CHP solution more convenient than the upgrading one. For example, considering the blue line we can realize the 100% upgrading solution offer very good performances up to an electricity price around 120 €/MWh, while for a higher price the solution "only CHP" seems to be a better option.

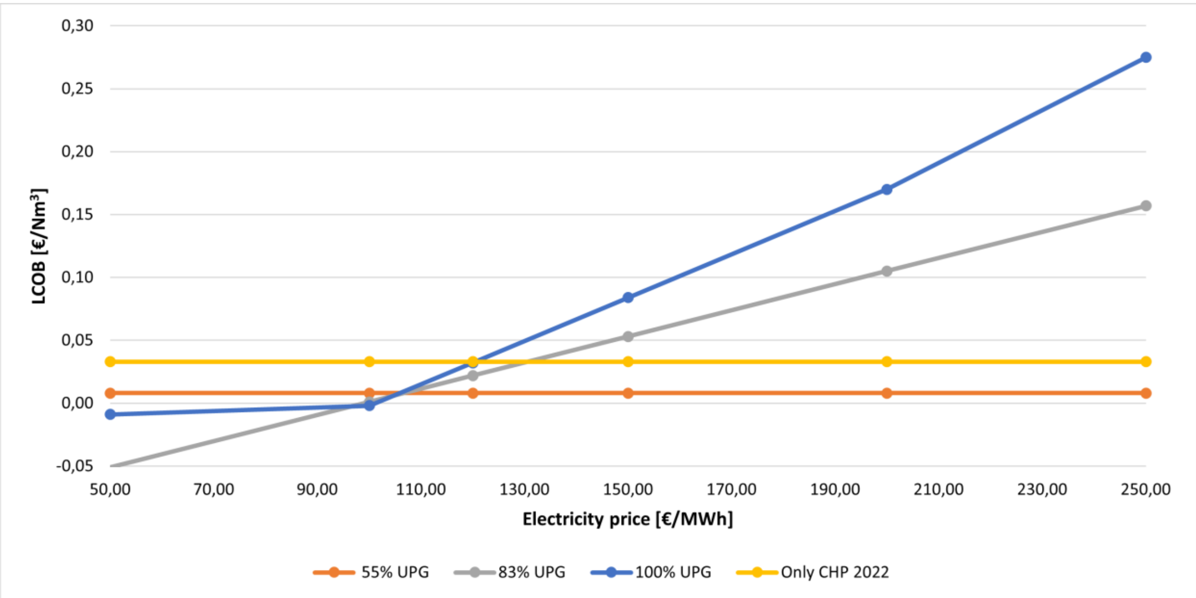


*Figure 46 LCOB sensitivity to electricity price*

# 7. Conclusions

In this work the possible future development scenarios of a real plant were considered, evaluating them both from an energetic and economic point of view. From the economic results emerges that in the current legislative scenario the idea of an only-CHP solution is not the best option, even if the employment of FC could ensure a very efficient conversion of the biogas potential. At the moment the electric production is too much sensible to the high cost of installation and maintenance of this technology. The LCOE analysis of different future scenario depending on the technology FC development stage shows how relevant is the impact of the stack replacement price (and the frequency of substitution) on the whole investment.

So, we can expect a total conversion of the plant to be not convenient, unless a new incentive scheme on the electricity produced by high efficiency CHP system is released by the government or European Union.

On the other hand, the incentives on biomethane production makes the upgrading option really interesting, at least in a short-term perspective. It is worth considering that since the biofuels sector is really promising in the optic of energy transition, legislation tends to change quite fast. In this direction a new decree is expected to be released by the Italian government in 2022, and this would certainly affect the future growth of the sector.

This thesis work gave the opportunity to examine a real energy plant, perform balances and proposing solution for the development of future strategies of the company. It helped to adopt new approaches with respect to what was done during the university path, giving an indication of how plant management choices are taken.

## List of acronyms

AFID: Alternative Fuels Infrastructure Directive

BG: Biogas

CF: Capacity factor

CHP: Combined heat and power (cogeneration)

CIC: Certificati di immissione in consumo

CNG: Compressed natural gas

COP: Conference of parties

EBA: European biogas association

EED: Energy Efficiency Directive

ETS: Emission Trading System

EU: European Union

FC: Fuel cell

FIT: Feed-in-tariffs

GSE: Gestore servizi energetici

GT: Gas turbine

ICE: Internal combustion engine

LCOE: Levelized Cost of Electricity

LNG: Liquified natural gas

MCFC: Molten carbonate fuel cell

NG: Natural gas

OFMSW: Organic fraction of municipal solid waste

PSA: Pressure swing absorption

PV: Photovoltaic

RED: Renewable Energy Directive

RES: Renewable energy sources

SDG: Sustainable development goals

SOFC: Solid oxide fuel cell

VFA: Volatile fatty acids

## List of figures

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