Politecnico di Torino

M. Sc. Energy and Nuclear Engineering

Master Thesis

Complete C-recovery from sewage biogas through upgrading and methanation

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December 2020

Abstract

In this thesis work different schemes and scenarios for the techno-economic analysis of a plant producing biogas from sewage sludges have been studied. The focus was set in particular on carbon recovery. The waste water treatment plant (WWTP) of Collegno, a municipality in the Metropolitan City of Turin, was taken as the base plant for the research. In the study three different layouts, called base cases, have been considered. The most complete scheme is made up of the following components:

- Upgrading system able to split CO_2 and CH_4 composing biogas, to ensure the trade with the natural gas grid;
- Methanator in which the reaction of methanation occurs: thanks to this reaction it is possible to obtain further methane adding carbon dioxide to hydrogen;
- Electrolyser system, which exploits water electrolysis: a process that produces hydrogen and oxygen from water molecules;
- PV system, supposed to be already present in the plant, which supplies some of the electrolyser's electricity demand.

In the other layouts analysed have been removed some of the components in order to understand their influence on the results and to figure out if the system can be sustainable not only environmentally, but also economically.

To appreciate how much some of the main parameters affect the research, four scenarios for the three different base cases have been studied: In the first are considered different values for the biomethane incentive. In the second is analysed the influence of grid's electricity price variation. In the third scenario the focus is on the variation of carbon dioxide captured. The last scenario takes into account the variation of PV share on the total electricity demand.

According to the results: the lower the CO_2 captured, the higher the suitability of the system, both in economical and environmental terms. This trend is related to the very high electricity demand of the electrolyser, which size becomes larger as carbon captured increases. From an environmental point of view, if the PV share on the total system's electricity demand is higher than about 60%, the plant will release less carbon dioxide every cubic meter of biomethane produced than that needed by the grid's natural gas.

Acknowledgments

Vorrei innanzitutto ringraziare la professoressa Gandiglio e il professor Ferrero per avermi dato la possibilità di affrontare con loro questo lavoro di tesi. Si sono dimostrati disponibili in ogni occasione e sono stati capaci di arricchirmi molto, nonostante il percorso a "distanza".

Un grazie speciale ai miei genitori che mi hanno sempre supportato e consigliato; sono e saranno sempre un punto di riferimento per me: purtroppo, dopo una triennale all'insegna del papiro, sarà difficile godersi anche i festeggiamenti per la magistrale, ma sicuramente ci sarà modo di rimediare.

Ai miei zii Manuela e Alberto, lontani ma vicini, dei quali mi è molto mancata la compagnia e le prelibatezze in questi anni a Torino.

Grazie ai miei fratelli che sono da sempre un sostegno e un porto sicuro, e alla piccola Ludovica, capace di alleviare i giorni di quarantena.

Un enorme grazie a Beatrice, presente, disponibile, che sa capirmi e starmi vicino in ogni circostanza.

Per finire impossibile non ringraziare i miei amici, sia quelli di sempre che i nuovi di Torino, per avermi regalato momenti di spensieratezza anche nei periodi più difficili.

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Chapter 1

Introduction

The global energy demand is continuing to grow over the years, this will lead to a depletion of natural resources [17]. The main share of the energy demand is still ensured by fossil fuels: they cause emissions of greenhouse gas (GHG) and other pollutants during combustion, in addition to this they create a strong dependence on importations with possible political issues. For these reasons, renewable energy must play a central role in long-term sustainability. In the European Union, climate and energy package was set a target of 20% renewable energy in the overall energy mix of the EU by 2020 [11]. Renewable energy sources present the problem of fluctuation, so there is a need to store the peaks: the power to gas can be an attractive storage method as compared to other large scales storage technologies such as pumped hydroelectric storage and compressed air energy storage [31]. The most utilized storage technology today is the pumped hydropower one and it is generally sufficient to manage the peaks, anyway probably it is inadequate to store large amounts of energy [6]. In this context, the production of biogas from organic wastes is a very interesting renewable energy source, not only in a perspective of circular economy and waste valorization but also for the possibility to store energy directly into the natural gas grid. The biogas, rich in CO_2, to be injected into the grid or to be used as a vehicle fuel needs an upgrading stage: this stage splits methane from carbon dioxide; the CO_2 separated can be further used to produce additional CH_4, thanks to a reaction with hydrogen.

1.1 Global warming

Global warming indicates the terrestrial climate changes developed from the beginning of the 20th century and still ongoing. These changes are characterized by the increase of the global average temperature and by atmospheric phenomena associated with it [33]. According to the scientific community, the predominant causes are attributable to anthropic activity, due to the emissions into the Earth's atmosphere of increasing quantities of greenhouse gases. It could therefore be said that global warming is a phenomenon of increase of Earth's surface average temperatures not attributable to natural causes. Most of the temperature increases have been observed since the mid-20th century, the distribution of climate warming is not uniform across the globe: the peak is in the northern hemisphere, from mid and high latitudes up to the North Pole. This trend is due to a greater distribution of lands and so anthropization.

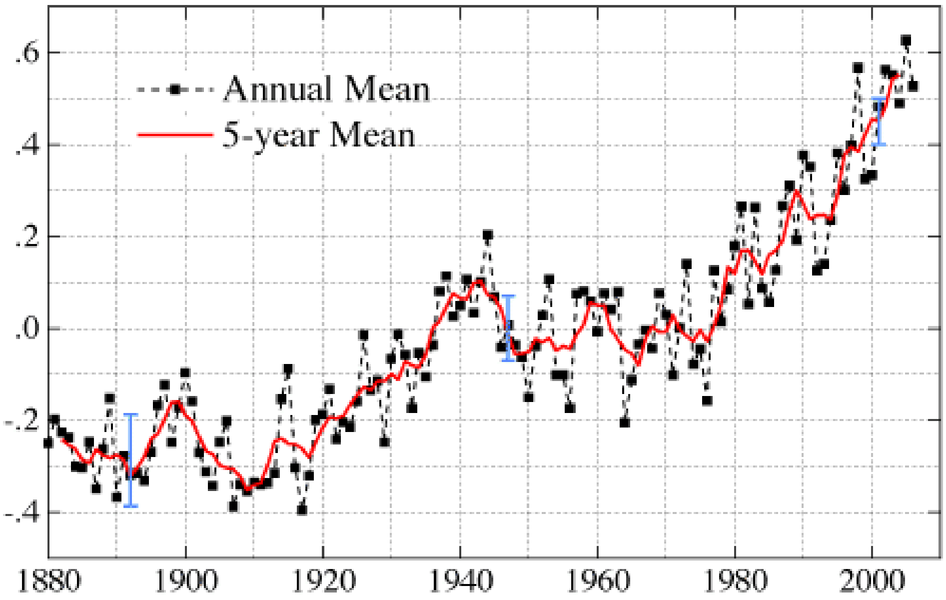


Figure 1.1: Global-Mean Surface Temperature Anomaly (°C) [33].

1.1.1 Kyoto Protocol

The world starts to be aware of the global warming problem with the Kyoto Protocol: it is an international treaty concerning global warming published on 11th December 1997 in the Japanese city of Kyoto by more than 180 countries [32]. According to this treaty, all the acceding countries must undertake to reduce, before 2012, at least by 8.65% the emissions of greenhouse gases with respect to 1990 levels. With the Doha agreement, the deadline for the protocol was extended from 2012 to 2020. The Kyoto Protocol came into force only on 16th February 2005, thanks to the ratification by the Russian Government: indeed it has to be ratified by 55 countries, that have to release at least 55% of the total greenhouse emissions. The greenhouse gases that have to be reduced are: carbon dioxide, methane, nitrogen oxide, haloalkane, fluorocarbon, sulfur hexafluoride. In order to evaluate the contribution of a gas to the greenhouse effect, it is used the GWP (Greenhouse Warming Potential) index. This parameter is defined considering its potential equal to 1 for the carbon dioxide. Every value of the GWP is calculated for a specific time interval (generally 20, 100, or 500 years).

Gas	Atmospheric Lifetime	100-year GWP
Carbon dioxide (CO_2)	50-200	1
Methane (CH_4)	12±3	21
Nitrous oxide (N_2O)	120	310
HFC-23	264	11,700
HFC-125	32.6	2,800
HFC-134a	14.6	1,300
HFC-143a	48.3	3,800
HFC-152a	1.5	140
HFC-227ea	36.5	2,900
HFC-236fa	209	6,300
HFC-4310mee	17.1	1,300
CF_4	50,000	6,500
C_2F_6	10,000	9,200
C_4F_{10}	2,600	7,000
C_6F_{14}	3,200	7,400
SF_6	3,200	23,900

Table 1.1: Global Warming Potentials (GWP) and Atmospheric Lifetimes [5].

The problem of the Kyoto protocol is that the United States has not ratified it, even if they are responsible for 36.2% of the total emissions [5]. Moreover, China, India, and other developing countries were exempted from the requirements of the protocol, because they have not been responsible for the emissions during the industrialization period.

1.1.2 European Union climate and energy package (20-20-20)

The European Union climate and energy package is the set of measures intended by the European Union for the period after the deadline of the Kyoto Protocol. The goal of the "three 20 targets" is to reduce greenhouse gas emissions by 20%, increase the energy produced by renewable sources at 20% and bring to 20% the energy savings [24]. The targets were set in 2007 by European leaders and enacted in legislation in 2009. The EU is moving to different areas in order to achieve the goals [7].

Emissions trading system (ETS): is the main tool of EU to reduce greenhouse gas emissions of facilities concerning industry and power sectors. The ETS deals with about 45% of the EU's greenhouse gas emissions. The target is to reduce, in 2020, by 21% the emissions in these sectors with respect to 2005.

National emission reduction targets: these targets regard sectors that are not included in ETS, and that represent 55% of the total EU's emissions, such as:

- housing;
- agriculture;
- waste;
- transport (excluding aviation).

European countries have satisfied the annual targets regarding emission reduction for these sectors until 2020 (with respect to 2005), under the "Effort-sharing decision". Targets are different according to the national incomes, from a 20% reduction for the wealthiest countries to a 20% increase for the least wealthy. The Commission checks the progresses every year.

Renewable energy – national targets: also this target is different for each country, which varies in order to take into account the starting point and the possibility to further increase the energy production from renewable sources: from 10% of Malta to 49% of Sweden [7]. The overall effect will allow the EU to achieve:

- 20% target of 2020, (more than double the 2010 level of 9.8%) [7];
- 10% share of renewable sources in the transport sector [7].

Innovation and financing: the European unit supports the development of low carbon emissions technology, with different programs.

Energy Efficiency: there are also measures to improve the energy efficiency that are set out in the:

- Energy Efficiency Plan;
- Energy Efficiency Directive.

Benefits: the achievement of the targets of the 2020 package will help:

- increase the energy security of EU: reducing the imported energy and contributing to create a European Energy Union;
- create jobs and make Europe more competitive.

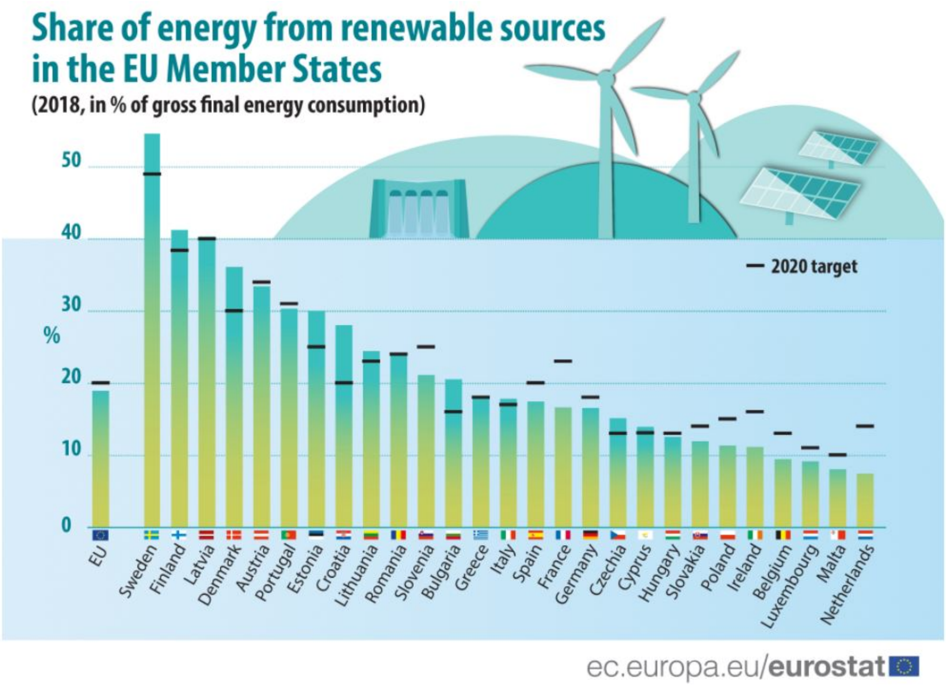


Figure 1.2: Share of energy from renewable sources in the EU Member States [11].

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2011-2012 average	2013-2014 average	2015-2016 average	2017-2018 average	S_{2005} (1)	2011-2012	indicative 2013-2014	2015-2016	trajectory 2017-2018	2020 target
EU-27	9.6	10.2	10.8	11.9	12.6	13.9	14.4	14.6	16.1	16.7	17.5	17.9	18.1	18.5	18.9	15.3	17.1	18.0	18.7	:	:	:	:	:	20
EU-28	8.5	9.1	9.7	10.6	11.4	12.6	13.2	13.4	14.7	15.4	16.2	16.7	17.0	17.5	18.0	14.1	15.8	16.9	17.7	:	:	:	:	:	20
Belgium	1.9	2.3	2.6	3.1	3.6	4.7	5.6	6.3	7.2	7.5	8.0	8.0	8.7	9.1	9.4	6.7	7.8	8.4	9.2	2.2	4.4	5.4	7.1	9.2	13
Bulgaria	9.2	9.2	9.4	9.1	10.3	12.0	13.9	14.2	15.8	18.9	18.0	18.3	18.8	18.7	20.5	15.0	18.5	18.5	19.6	9.4	10.7	11.4	12.4	13.7	16
Czechia	6.8	7.1	7.4	7.9	8.7	10.0	10.5	10.9	12.8	13.9	15.1	15.1	14.9	14.8	15.1	11.9	14.5	15.0	15.0	6.1	7.5	8.2	9.2	10.6	13
Denmark	14.8	16.0	16.3	17.7	18.5	20.0	21.9	23.4	25.5	27.2	29.3	30.9	32.0	35.0	36.1	24.4	28.3	31.5	35.6	17.0	19.6	20.9	22.9	25.5	30
Germany	6.2	7.2	8.5	10.1	10.1	10.9	11.7	12.5	13.6	13.8	14.4	14.9	14.9	15.5	16.5	13.0	14.1	14.9	16.0	5.8	8.2	9.5	11.3	13.7	18
Estonia	18.4	17.4	16.0	17.0	18.6	22.9	24.6	25.3	25.5	25.3	26.1	28.2	28.7	29.1	30.0	25.4	25.7	28.5	29.6	18.0	19.4	20.1	21.2	22.6	25
Ireland	2.4	2.8	3.0	3.5	3.9	5.2	5.7	6.6	7.1	7.6	8.6	9.1	9.3	10.6	11.1	6.8	8.1	9.2	10.8	3.1	5.7	7.0	8.9	11.5	16
Greece (2)	7.2	7.3	7.5	8.2	8.2	8.7	10.1	11.2	13.7	15.3	15.7	15.7	15.4	17.0	18.0	12.4	15.5	15.5	17.5	6.9	9.1	10.2	11.9	14.1	18
Spain	8.3	8.4	9.1	9.7	10.7	13.0	13.8	13.2	14.3	15.3	16.1	16.2	17.4	17.6	17.4	13.8	15.7	16.8	17.5	8.7	11.0	12.1	13.8	16.0	20
France	9.5	9.6	9.3	10.2	11.2	12.2	12.7	11.0	13.4	14.0	14.6	15.0	15.7	16.0	16.6	12.2	14.3	15.3	16.3	10.3	12.8	14.1	16.0	18.6	23
Croatia	23.4	23.7	22.7	22.2	22.0	23.6	25.1	25.4	26.8	28.0	27.8	29.0	28.3	27.3	28.0	26.1	27.9	28.6	27.7	12.6	14.1	14.8	15.9	17.4	20
Italy	6.3	7.5	8.3	9.8	11.5	12.8	13.0	12.9	15.4	16.7	17.1	17.5	17.4	18.3	17.8	14.2	16.9	17.5	18.0	5.2	7.6	8.7	10.5	12.9	17
Cyprus	3.1	3.1	3.3	4.0	5.1	5.9	6.2	6.3	7.1	8.5	9.2	9.9	9.9	10.5	13.9	6.7	8.8	9.9	12.2	2.9	4.9	5.9	7.4	9.5	13
Latvia	32.8	32.3	31.1	29.6	29.8	34.3	30.4	33.5	35.7	37.0	38.6	37.5	37.1	39.0	40.3	34.6	37.8	37.3	39.7	32.6	34.1	34.8	35.9	37.4	40
Lithuania	17.2	16.8	16.9	16.5	17.8	19.8	19.6	19.9	21.4	22.7	23.6	25.8	25.6	26.0	24.4	20.7	23.1	25.7	25.2	15.0	16.6	17.4	18.6	20.2	23
Luxembourg	0.9	1.4	1.5	2.7	2.8	2.9	2.9	2.9	3.1	3.5	4.5	5.0	5.4	6.3	9.1	3.0	4.0	5.2	7.7	0.9	2.9	3.9	5.4	7.5	11
Hungary	4.4	6.9	7.4	8.6	8.6	11.7	12.7	14.0	15.5	16.2	14.6	14.5	14.3	13.5	12.5	14.8	15.4	14.4	13.0	4.3	6.0	6.9	8.2	10.0	13
Malta	0.1	0.1	0.1	0.2	0.2	0.2	1.0	1.8	2.9	3.8	4.7	5.1	6.2	7.3	8.0	2.4	4.3	5.7	7.6	0.0	2.0	3.0	4.5	6.5	10
Netherlands	2.0	2.5	2.8	3.3	3.6	4.3	3.9	4.5	4.7	4.7	5.4	5.7	5.8	6.5	7.4	4.6	5.1	5.7	6.9	2.4	4.7	5.9	7.6	9.9	14
Austria	22.6	24.4	26.3	28.2	28.9	31.0	31.2	31.6	32.7	32.8	33.7	33.5	33.4	33.1	33.4	32.1	33.2	33.5	33.3	23.3	25.4	26.5	28.1	30.3	34
Poland	6.9	6.9	6.9	6.9	7.7	8.7	9.3	10.3	10.9	11.4	11.5	11.7	11.3	11.0	11.3	10.6	11.4	11.5	11.1	7.2	8.8	9.5	10.7	12.3	15
Portugal	19.2	19.5	20.8	21.9	22.9	24.4	24.2	24.6	24.6	25.7	29.5	30.5	30.9	30.6	30.3	24.6	27.6	30.7	30.5	20.5	22.6	23.7	25.2	27.3	31
Romania	16.8	17.6	17.1	18.2	20.2	22.2	22.8	21.2	22.8	23.9	24.8	24.8	25.0	24.5	23.9	22.0	24.4	24.9	24.2	17.8	19.0	19.7	20.6	21.8	24
Slovenia	16.1	16.0	15.6	15.6	15.0	20.1	20.4	20.3	20.8	22.4	21.5	21.9	21.3	21.1	21.1	20.5	22.0	21.6	21.1	16.0	17.8	18.7	20.1	21.9	25
Slovakia	6.4	6.4	6.6	7.8	7.7	9.4	9.1	10.3	10.5	10.1	11.7	12.9	12.0	11.5	11.9	10.4	10.9	12.5	11.7	6.7	8.2	8.9	10.0	11.4	14
Finland	29.3	28.8	30.1	29.6	31.4	31.3	32.4	32.8	34.4	36.7	38.8	39.3	39.0	40.9	41.2	33.6	37.8	39.2	41.0	28.5	30.4	31.4	32.8	34.7	38
Sweden	38.7	40.7	42.4	43.9	44.7	47.9	47.0	48.2	50.2	50.8	51.9	53.0	53.4	54.2	54.6	49.2	51.3	53.2	54.4	39.8	41.6	42.6	43.9	45.8	49
United Kingdom	0.9	1.1	1.3	1.6	2.7	3.3	3.8	4.3	4.4	5.5	6.7	8.3	9.0	9.7	11.0	4.4	6.1	8.7	10.4	1.3	4.0	5.4	7.5	10.2	15
Norway	58.5	60.1	60.5	60.3	61.9	64.9	61.3	65.0	65.5	66.7	69.2	69.1	70.2	71.6	72.8	65.3	68.0	69.6	72.2	58.2	60.1	61.0	62.4	64.2	67.5
Montenegro	:	35.9	35.0	33.1	32.5	39.5	40.7	40.7	41.5	43.7	44.1	43.1	41.6	39.7	38.8	41.1	43.9	42.3	39.3	:	27.6	28.3	29.3	30.7	33
North Macedonia	15.7	16.5	16.5	15.0	15.6	17.2	16.5	16.4	18.1	18.5	19.6	19.5	18.0	19.6	18.1	17.3	19.0	18.8	18.9	:	19.0	19.5	20.2	21.3	23
Albania	29.6	31.4	32.1	32.7	32.4	31.4	31.9	31.2	35.2	33.2	31.5	34.4	35.5	34.5	34.9	33.2	32.3	34.9	34.7	:	32.6	33.2	34.3	35.6	38
Serbia	12.7	14.3	14.5	14.3	15.9	21.0	19.8	19.1	20.8	21.1	22.9	22.0	21.1	20.3	20.3	20.0	22.0	21.6	20.3	:	22.4	22.9	23.8	25.0	27
Turkey	16.2	15.5	14.1	13.2	13.5	14.1	14.0	12.8	13.2	13.9	13.6	13.6	13.7	12.8	13.7	13.0	13.8	13.7	13.2	:	:	:	:	:	:
Kosovo*	20.5	19.8	19.5	18.8	18.4	18.2	18.2	17.6	18.6	18.6	19.5	18.5	24.5	23.1	24.9	18.1	19.1	21.5	24.0	:	20.1	20.7	21.6	22.9	25

Note: ":" means data not available

** This designation is without prejudice to positions on status, and is in line with UNSCR 1244/1999 and the ICJ Opinion on the Kosovo declaration of independence.*

(1) S_{2005} is the share of energy from renewable sources in 2005, baseline used for the calculation of the indicative trajectory (in accordance with Directive 2009/28/EC on the promotion of the use of energy from renewable sources).

(2) Estimate

Source: Eurostat (online data code: nrg_ind_ren)

eurostat

Figure 1.3: Share of energy from renewable sources, 2004-2018. (% of gross final energy consumption) [11].

Chapter 2

State of the Art

2.1 Biogas and anaerobic digestion

Biogas is a mixture of gases mainly composed of CH_4 (from 50 to 75% vol) and CO_2 (45-20% vol), with traces of N_2, O_2, and contaminants (Sulphur, Halogens, Siloxanes). However, the precise composition depends on the initial makeup of matter from which biogas is obtained.

1. Landfill wastes;
2. Organic fraction of municipal solid wastes (OFMSW);
3. Agricultural wastes (manure, crops);
4. Sludge from WWTP (waste water treatment plant);
5. other (dedicated crops, yogurt industry wastes).

Biogas has a lower heating value (LHV) between 18.6 and 21.6 MJ/Nm^3. Even if the combustion of biogas produces carbon dioxide because of its composition, the production of this mixture is considered carbon-neutral. This is due to the way the fuel is produced: it comes from organic matter that is formed by the remains of organisms such as plants, animals, and their waste products in the environment. Organisms, particularly plants, fix the carbon from atmospheric CO_2 in short times if compared to fossil fuels. For this reason, biogas is a renewable energy source and represents a valid option for the fulfillment of global energy demand. It is produced by microorganisms (bacteria), performing anaerobic respiration: a sequence of processes by which microorganisms break down biodegradable material in the absence of oxygen. Such a process can be roughly subdivided into four subprocesses:

1. Hydrolysis: process in which macromolecules (carbohydrates, proteins, lipids) are split into monomers through a reaction with H_2O activated by bacteria;
2. Acidogenesis: a process where monomers are split into acids medium chains (C_2 - C_5), alcohols, CO_2 and H_2;
3. Acetogenesis: biological reaction in which products of the previous reaction (acids + alcohols) are reacted with H_2O in presence of bacteria to obtain acetic acid CH_3COOH;

4. Methanogenesis: process driven by methanogen bacteria where acetic acid is transformed into methane and carbon dioxide, in presence of low amounts of oxygen (as it moves equilibrium towards reactants).

Anaerobic digestion can be performed at different temperatures, which determine the residence time in the digester. The most common are the temperatures that guarantee mesophilic conditions (about 35°C), with a residence time between 15 and 50 days. It is also possible to work at thermophilic conditions (55°C) with a residence time of 14-16 days, or also with low temperatures (20°C) and high residence time (60-120 days). The main contaminants for biogas are sulphur and siloxane. The first one is highly critical because is very expensive to remove and because it is the contaminant with lower breakthrough time: the lapse of time the sulphur takes to make the cleanup system unable to remove further sulphur. Siloxanes are extremely dangerous because they will produce glass, which is a problematic material for combustion chambers, heat exchangers, fuel cells, and any device where catalytic processes are fundamental (chemical and electrochemical reactors).

	$\mathbf{CH_4}$	$\mathbf{CO_2}$	$\mathbf{H_2}$	$\mathbf{N_2}$	**CO**	$\mathbf{H_2S}$	$\mathbf{H_2O}$	$\mathbf{R_2SiO}$
% vol	50-75%	25-45%	1-10%	0.5-3%	0.10%	0.02-0.2%	saturation	taces

Table 2.1: Typical composition of biogas after anaerobic digestion.

2.1.1 Biogas in Europe

Biogas production in Europe has experienced a real boom in recent years. The number of European biogas plants between 2009 and 2016 has almost tripled, passing from 6,200 to 17,662 [2], and the growth was particularly intense especially from 2010 to 2012. A similar development is due to the increase in the number of agricultural plants, which are by far the most numerous, enlarged from 4,797 in 2009 to 12,496 in 2016 [2]. To follow, sewage sludge plants (2,838), urban waste (1,604), and other types of wastes (688). According to Eurostat, the annual biogas production in the European Union was 181,565 GWh in 2015, with Germany, UK, Italy, and France representing the most productive nations. In 2016, the most dynamic countries concerning the construction of new plants were France (+93) and the United Kingdom (+41).

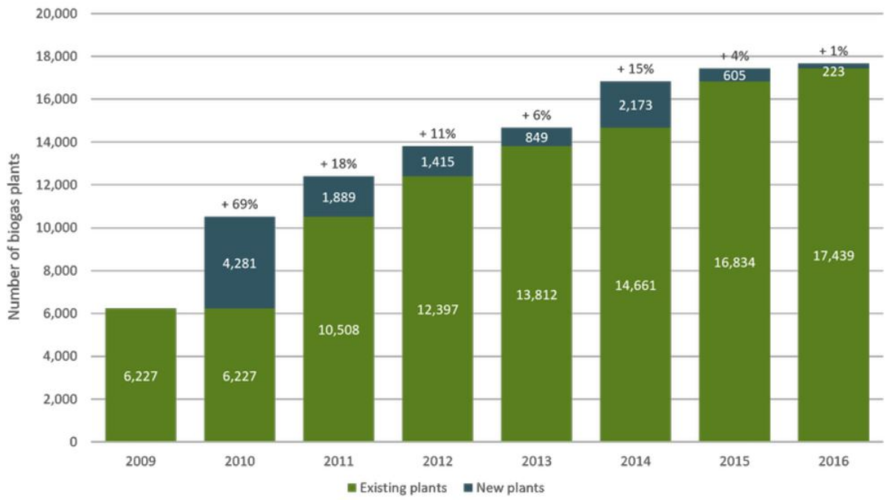


Figure 2.1: Number of biogas Plants in Europe [1]

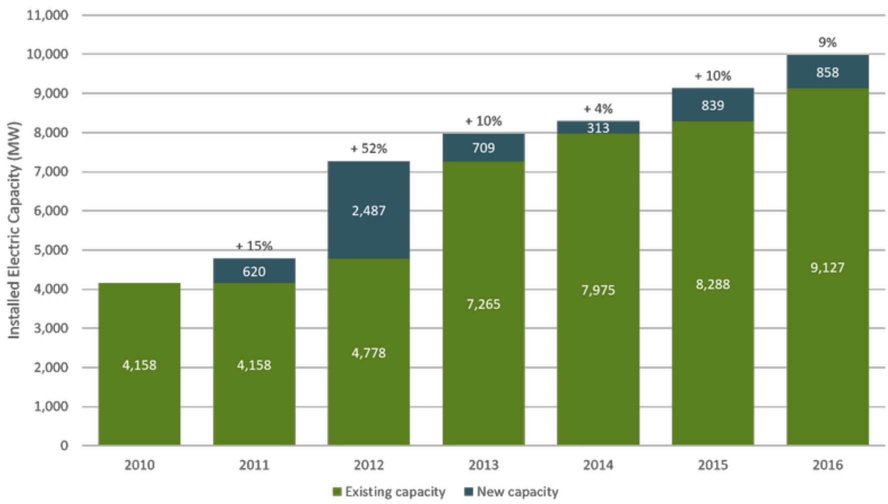


Figure 2.2: Electrical capacity installed in Europe from 2010 to 2016 (MW) [1]

The slower increase in the number of biogas plants in Europe recorded in the last years is mainly attributable to the changes introduced in national regulations. From 2016 there has been a significant increase even in the quantity of biomethane produced in Europe.

Like for biogas, biomethane plants mainly exploit resources from the agricultural sector, followed by those that use waste and sewage sludge. In 2016, EU biomethane production amounted to 17,264 GWh, with growth driven by Germany (+900 GWh), France (+133 GWh), and Sweden (+78 GWh).

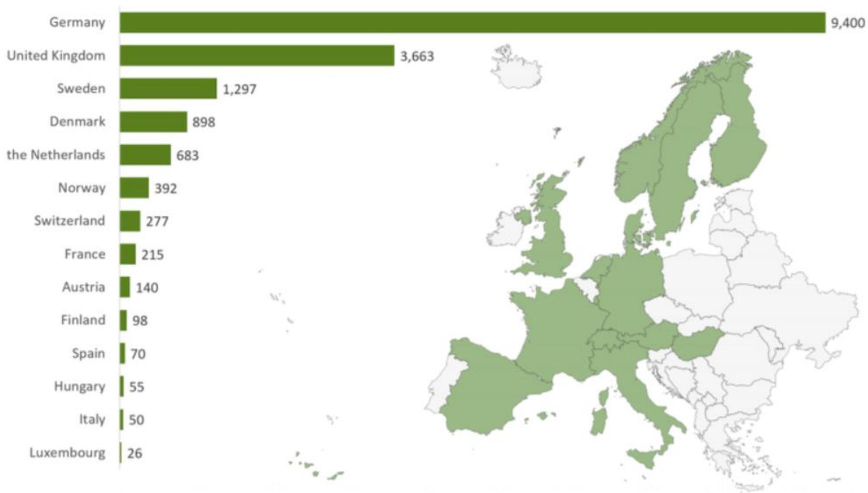


Figure 2.3: Production of biomethane in Europe (GWh) [1]

Even if the total number of plants has stabilized since 2015, the electric capacity installed has increased from 4,158 MW of 2010 to 9,985 MW of 2016 (+5,827 MW). Starting from 2011, the increasing trend is mainly due to the construction of new plants that convert biomass of agricultural origin, whose contribution in terms of capacity has grown from 3,408 MW in 2011 to 6,348 MW in 2016. Germany is the main producer of biogas in Europe (with 10,846 production plants, that represent 63% of the EU's total). The electricity produced by biogas covers 16.8% of the energy produced by renewable sources in Germany [12]. The production of biogas was strongly encouraged over the past 20 years by legal provisions, such as:

- For each plant was secured a priority connection to the grid;
- It has been possible to sell energy at a fixed rate for 20 years.

In 2013, a surface of about 1,157,000 hectares (6.9% of the total agricultural area) was utilized to produce energy crops. Nevertheless, the increased land exploitation for energy purposes, especially corn, has generated disagreement in Germany. This last sentence is introduced to say that the production of biogas from dedicated crops have to take into account that the land could be used for other purposes, so should be considered a cost-benefit analysis.

Italian case The productive potential of biomethane in Italy is promising, estimated to be 10 billion cubic meters by 2030 [18], of which at least eight from agricultural matrices. This amount is equal to approximately 10% of the current annual natural gas requirement and two-thirds of the storage potential of the national grid [18]. Some plants connected to the grid and fed by organic waste are set out below. The first was Montello Spa (Montello, BG), where are produced annually about 32 million cubic meters. In the Calabra Maceri plant (Rende, CS), the treatment of 40 thousand tons of organic waste a year produces 4.5 million cubic meters of biomethane fed into the grid. Methane produced at the Acea Ecological Pole in Pinerolo (TO) is utilized as a fuel for company vehicles used for waste collection. The plant of Sant'Agata Bolognese (BO), belonging to the Hera group, is able to treat about 100 thousand tons of organic waste per year from recycling and nearly 35 thousand tons of pruning residuals. The Aimag plant in Finale Emilia (MO), allows the treatment of 50,000 tons of organic fraction every year, from which three million cubic meters of biomethane and 17,000 tons of compost are obtained. The Faedo (TN) plant is built by BioEnergia Trentino and is able to treat 40 thousand tons per year of organic fraction by municipal solid waste and 14,500 tons per year of pruning residuals, producing electricity and about 450 Sm^3 of biomethane per hour. The Caviro group plant in Faenza (RA) is entirely dedicated to the treatment of agricultural waste and the agri-food industry, with a production of about 12 million cubic meters per year.

2.2 Upgrading technologies

Upgrading is a process that separates methane and carbon dioxide, in order to obtain biomethane having a CH_4 concentration of 90% or greater. It is necessary to adjust HHV and relative density to satisfy the Wobbe index:

$$WI = \frac{HHV}{\sqrt{\rho}} \tag{2.1}$$

The Wobbe index is a critical factor to minimise the impact of the changeover when analyzing the use of biomethane. By upgrading the quality to that of natural gas, it becomes possible to distribute the gas to customers via the existing gas grid within existing appliances. It is also important to guarantee recovery of CH_4 as high as possible, not only for an economic reason but also because methane has a very high greenhouse potential (GWP about 25 times the one of CO_2). The main technologies available in the market for upgrading biogas to biomethane can be divided into the following groups:

- Physical absorption, with water or organic solvents;
- Chemical absorption, with amine or saline solutions (K_2CO_3);
- Pressure Swing Adsorption (PSA);
- Membrane-based biogas upgrading;
- Cryogenic separation.

2.2.1 Physical absorption

Physical absorption techniques exploit the difference in solubility between CH_4 and CO_2 into the absorbent liquid. The choice of absorbent liquid is critical: it needs to be efficient and economical, it must have high solubility with respect to CO_2, it should be readily available, not volatile, not dangerous and it has to maintain low and stable cost over time. In a physical absorption upgrading plant, the raw biogas is placed in counter current contact with the solvent into an absorption column. The liquid solution leaving the absorption column contains CO_2 and any other impurities removed from the fed biogas.

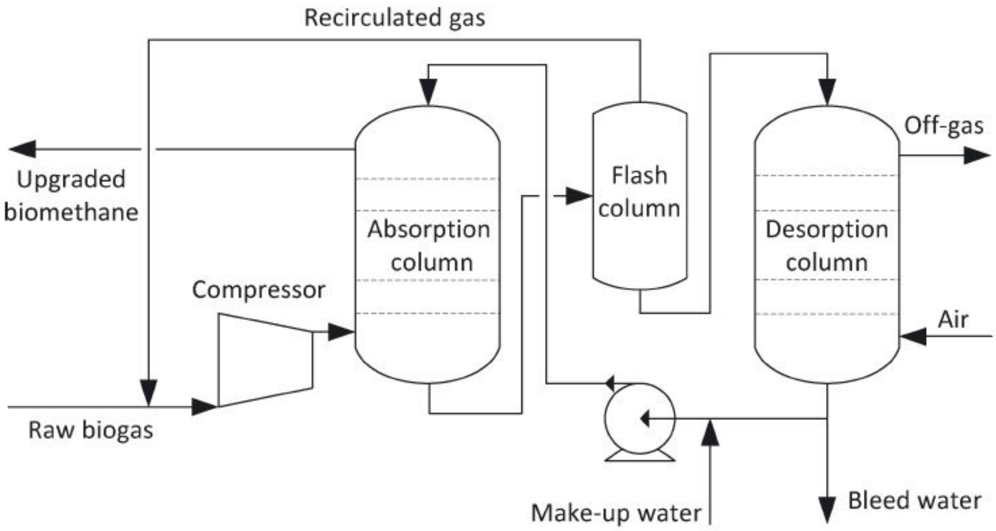


Figure 2.4: Pressure Water Scrubbing Scheme.

Pressure Water Scrubbing (PWS) is a physical absorption technology that utilizes water as the absorption liquid. This is possible because the solubility of CO_2 in water is significantly higher with respect to CH_4 (about 26 times at 25 °C). Furthermore, thanks to its polar nature, it is also possible to dissolve hydrogen sulphide in H_2O, because it is more soluble than carbon dioxide. Absorption is carried out under pressure (generally 6-10 bar) and temperatures are taken as much low as possible (about 10-35 °C) to increase the relative solubility of CO_2 compared to CH_4. Then carbon dioxide is released from the water again in the desorption column, by using air at atmospheric pressure as the stripper medium. Part of the water regenerated is purged to avoid gas accumulation, then the water needed for the process is replenished before re-feeding to the absorption column. This technology allows obtaining a biomethane with a purity of about 98-99%. Despite being a fairly simple and widespread process, PWS requires the circulation in the plant of large water flows. For this reason, the equipment used has considerable dimensions, with high installation costs. It is also important an adequate temperature control: high temperatures involve low CO_2 solubility and, at the same time, high energy costs.

2.2.2 Chemical absorption

This technology combines physical and chemical absorption: the solvent used not only dissolves but also reacts chemically with CO_2. Usually, an amine solution is taken as solvent for this process, the most common are: monoethanolamine (MEA) or dimethylethanolamine (DMEA). It is a technology widely used for fuel gas treatment in large plants or to de-acidify natural gas. In recent years it has been rescaled and also used for biogas upgrading. Generally, an amine scrubber system is made of an absorber, that removes CO_2 from biogas, and a stripper, where, adding heat, CO_2 is removed from the amine solution. The absorption reaction between carbon dioxide and the amine solution is exothermic, heating the solution from 20-40 °C to 45-65 °C. The absorption process prefers low temperatures: the solubility of CO_2 in water decreases with increasing temperatures. Nevertheless, high temperatures are better from a kinetic standpoint (reaction rate between amine and carbon dioxide increases). The enriched solution is therefore preheated with a regenerative exchanger and then regenerated in the stripping column, thanks to a reboiler operating at 120-150 °C and an external condenser useful to avoid significant water losses in the off-gas. To avoid corrosion and unwanted reaction at high temperatures, a preventive desulphurization is required. With this technology methane losses are very low (<0.1%), and methane purity is usually higher than 99%. However, solutions with amine are toxic for men and for the environment, so this system requires a high amount of thermal energy for the regeneration phase. The process layout is shown in figure 2.5:

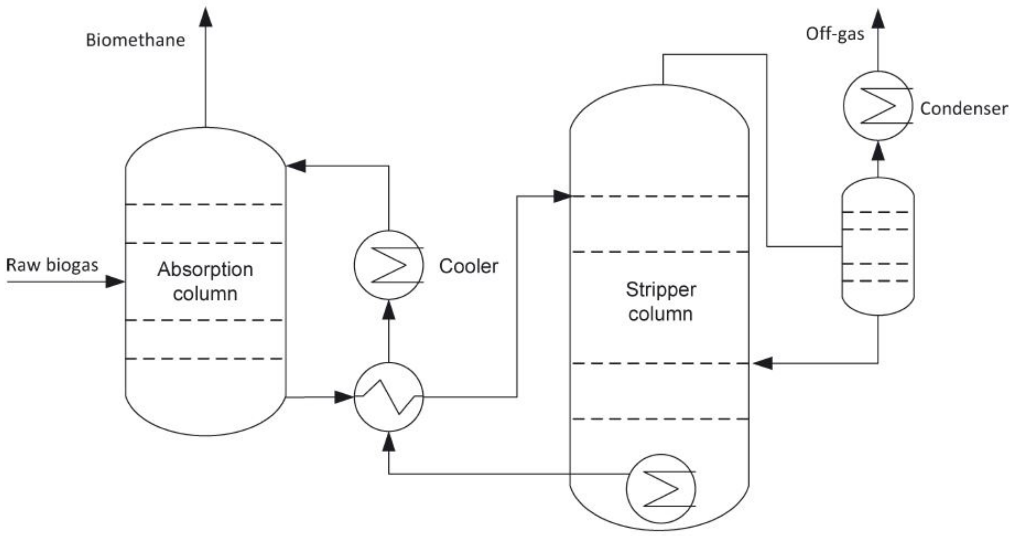


Figure 2.5: Simplified process flow diagram of an amine scrubber.

2.2.3 Pressure swing adsorption (PSA)

Particular porous solid materials with high specific areas are able to adsorb gas molecules at high pressure (4-10 bar), and subsequently to release them at a lower pressure (often under vacuum). This principle is exploited by the Pressure Swing Adsorption technology, a dry method able to separate gases thanks to physical properties. Materials that are commonly utilized are: natural and synthetic zeolites, activated carbons, titanosilicates, carbon molecular sieves, and silica gels. H_2S can damage irreversibly the adsorbent material, so it has to be removed from the gas before the PSA columns. A PSA column cycle principally consists of four phases: pressurization, feed, blowdown, and purge. In the second phase, the raw biogas fed into the column is pressurized to about 4-10 bar. The column bed adsorbs the carbon dioxide, while the methane can pass. The blowdown phase starts when the bed is saturated with CO_2 and so the inlet is closed. In order to desorb carbon dioxide from the adsorbent, the pressure needs to be decreased to 1 bar, some CH_4 is lost with the desorbed CO_2. The purging phase begins at the lowest column pressure. Upgraded gas has to be emptied from all the carbon dioxide that has desorbed from the column bed, so it is blown through the column. The PSA unit consists of several parallel columns: one is always in the adsorption phase, others are in different regeneration phases. Typically are utilized 4 or 6 columns. The process described allows to obtain a biomethane with purity higher than 98%, while CH_4 losses are variable but often about the order of 2%. Thermal energy is not required, electricity is necessary for the compression phase and also for depressurization (if a vacuum pump is needed).

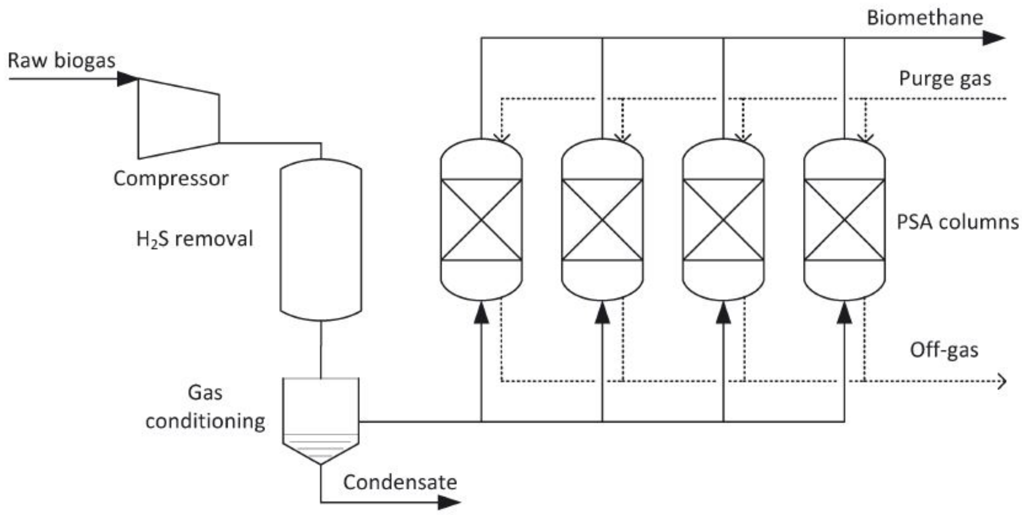


Figure 2.6: Simplified process flow diagram of PSA.

2.2.4 Membranes

This technology takes advantage of membranes: dense filters able to separate the different compounds of a gas (usually the selection is based on molecular size). CO_2 is able to permeate through the membrane, while methane is too big, in terms of the molecular size, to move on. The main advantages of this technology are:

- lack of demand for water;
- lack of demand for chemicals;
- possibility to scale down the system without important efficiency losses.

The biogas needs to be cleaned from contaminants and compressed to 5-20 bar before starting the process. The carbon dioxide is separated from the main gas stream as it permeates through the membrane wall. During the separation of carbon dioxide from the raw gas, other compounds such as water vapor and hydrogen are removed from the biomethane. This technology is well known, it has been used for removing CO_2 from natural gas for decades.

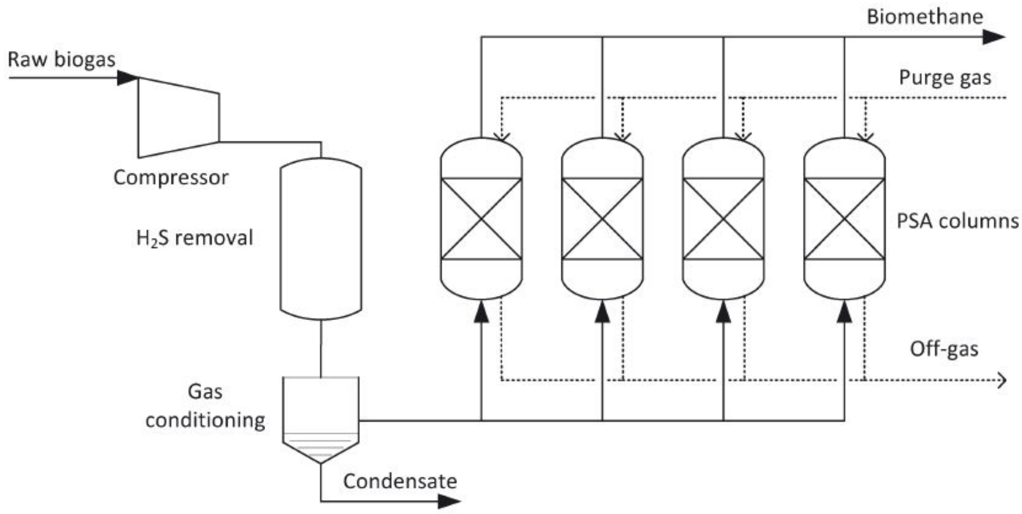


Figure 2.7: Simplified process design for a membrane upgrading process.

2.2.5 Cryogenic upgrading

Cryogenic separation is based on the principle that, at a certain pressure, different gases liquefy at different temperatures. The boiling point of methane at 1 atm corresponds to -161.5 °C and it is significantly lower than the equivalent of CO_2 (-78.2 °C). This technology works at a high operating pressure in order to have quite high temperatures of liquefaction, and also to prevent CO_2 from being separated in the solid state (dry ice), causing the obstruction of pipes. The biogas must be preventively desulphurized and dehumidified to prevent the formation of ice along with the system. Typical operation temperatures and pressures are respectively -90 °C and 40 bar. It is a very expensive technology from an energy point of view, but can reach levels of methane higher than 99%, with losses lower than 1%.

2.3 Methanation

The methanation reaction, involving carbon dioxide and hydrogen, is driven by the following reaction:

$$CO_2 + 4\,H_2 \rightarrow CH_4 + 2\,H_2O \tag{2.2}$$

This means that to produce 1 mol of CH_4, 4 moles of H_2 and 1 mol of CO_2 are required, while 2 moles of H_2 are recoverd. Methane and water are produced in a moderately exothermic reaction (ΔH = -165.1 kJ/mol). The methanation step made it possible to take advantage of carbon dioxide, producing synthetic biomethane that can be pumped into the natural gas grid.

2.4 Electrolyser

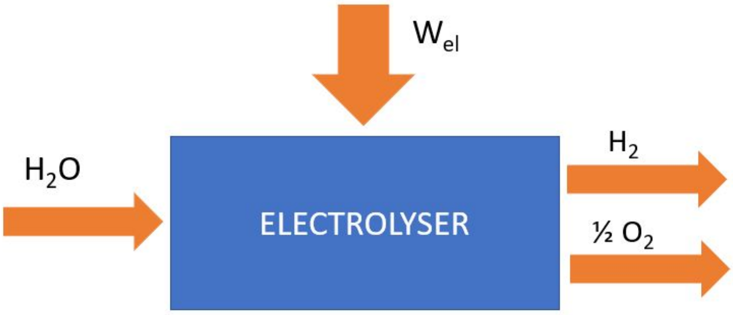


Figure 2.8: Electrolyser's flow rates scheme.

An electrolytic cell (electrolyser) is an electrochemical cell in which a not spontaneous reaction (with $\Delta G > 0$) is driven by electrical power. Electrical energy is transformed into chemical energy associated with a chemical element or compound ($W_{el} \rightarrow \Delta G$). The cell is made of three main sections: anode, electrolyte layer, and cathode.

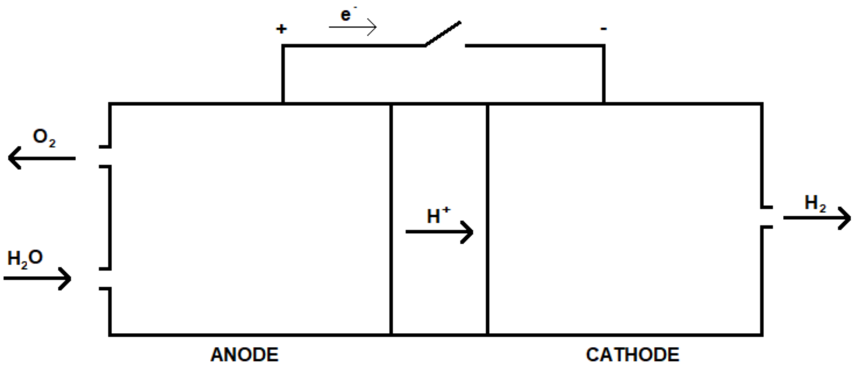


Figure 2.9: Scheme of water molecule splitting electrolyte (PEM)

- The anode is an electrode where the reaction of oxidation occurs (reaction in which there is a delivery of free electrons). At the anode it will be established the equilibrium;
- The electrolyte layer physically separates anode and cathode. It should be characterized by: very low molecular diffusivity and capability to conduct electrons, but very high capability to conduct ions;
- The cathode is an electrode where the reaction of reduction occurs (reaction in which there is a gain of free electrons). At the cathode it will be established the equilibrium

Even if there is no contact between the two reactants, because of the electrolyte layer, the reaction however occurs: ions can travel across the layer, electrons can move in an external circuit (since they cannot travel across the electrolyte they will follow an alternative path). Fuel cells are classified depending on the material that composes the electrolyte, which in turn determines the temperature range of operation.

Temperature	**Cell type**
700 °C - 800 °C	SOFC (Solid-oxide Fuel cell)
600 °C - 650 °C	MSFC (Molten Salt Fuel Cell)
250 °C	PAFC (Phosphoric Acid Fuel Cell)
50 °C - 80 °C	PEMFC (Proton Exchange Membrane Fuel Cell) AFC (Alkaline Fuel Cell) DMFC (Direct Methanol Fuel Cell)

Table 2.2: Fuel cells classification.

2.5 Photovoltaic Energy

The development of our society has always been associated with the demand for energy: starting from fire and coming to coal and oil. Until today the largest part of the electricity has been produced using fossil sources, responsible for the emission of a huge amount of carbon dioxide. This problem, added to the atmospheric pollution of cities, has increased not only the research on electric cars, but also the associated infrastructures. From the perspective of sustainable development, the renewable production of electricity is more important than ever.

In the transition to greener energy production, photovoltaic systems can play a fundamental role. This technology consists of an arrangement of several components that are able, thanks to the photovoltaic effect, to absorb and convert sunlight into electricity. The photovoltaic effect is a physical and chemical phenomenon that allows the transformation of solar energy into voltage and electric current. This is a phenomenon of radiation-matter interaction that is achieved when an electron moves from the valence band of a material to the conduction band. The photovoltaic effect is the basis of electrical production in photovoltaic cells. The operating mechanism is based on the use of semiconductor materials, the most widely used is silicon.

The operation of the solar cell in dark conditions can be explained by the well-known “P-N” junction theory. With reference to crystalline silicon, a diode is constituted by a substrate doped with “P-type” impurities, on which is deposited an ”N-type” layer. The thickness of the “N-type” layer is shallow to permit the solar radiation to penetrate the junction area, where there is an electric field.

To understand the process for electric field generation, it should be noted that the electrons (donors) diffuse from the N-type region near the interface into the P-type, developing a distribution of positive charges in layer N. In the same manner, holes (acceptors) diffuse from P-type to facing layer, producing a distribution of negative charges. In the diffusion operation, the carriers move from a region with a higher concentration to one with lower [28]. The junction zone, also known as the “depletion region” or space-charge region, includes positive charges on the N side and negative charges on the P side, however no mobile charges. A potential barrier (junction field) is created through doping atoms fix charges, this barrier counteracts an additional flow of electrons and holes conducted by diffusion. In open-circuit conditions, the diffusion current is perfectly balanced by the current driven by the electric field (drift current).

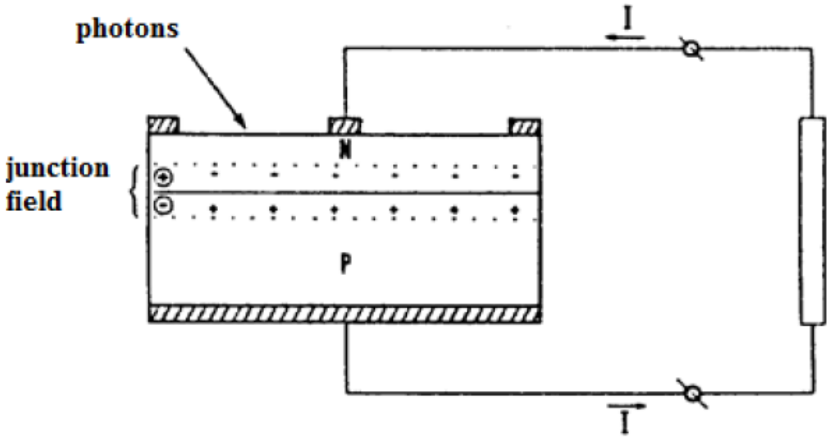


Figure 2.10: Structure of a crystalline silicon "c-Si" solar cell [28].

Equivalent circuit of a solar cell The electrical behavior of a solar cell can be estimated by a current source, proportional to irradiance, and a diode connected in anti-parallel. However, to better define the real cell it is necessary to add two extra dissipative elements: a shunt resistor connected in parallel (R_{sh}) and a series resistor (R_s).
R_{sh} resistance corresponds to leakage tracks on the lateral surfaces between the frontal grid and the plate of the solar cell.
R_s resistance is the sum of the volumetric resistance of the semiconductor, the resistances of the electrodes and of their own contacts.

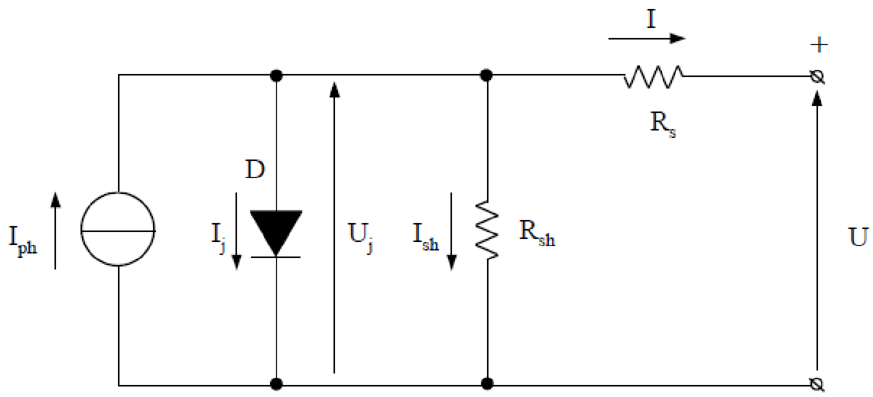


Figure 2.11: Structure of a crystalline silicon "c-Si" solar cell [28]

Applying the voltage and current laws of Kirchhoff to the equivalent circuit, the following equations can be written:

$$I = I_{ph} - I_j - \frac{U_j}{R_{sh}} \tag{2.3}$$

$$U = U_j - R_s\, I \tag{2.4}$$

where I is the current flowing inside the load and U is the voltage across the terminals of the load. To define the equivalent circuit are needed the following independent five parameters: I_{ph}, I_0, m, R_s, R_{sh}.

$$U = \frac{mkT}{q} \cdot ln\left(\frac{I_{ph} - I\,(1 + R_s/R_{sh}) - U/R_{sh} + I_0}{I_0}\right) - R_s\, I \tag{2.5}$$

Dependence on irradiance and temperature The characteristic of the solar cell I(U), at a constant temperature T_{PV}, changes in response to irradiance G. When G decreases, the open-circuit voltage U_{oc} decreases logarithmically, while the short-circuit current I_{sc} decreases proportionally [28].

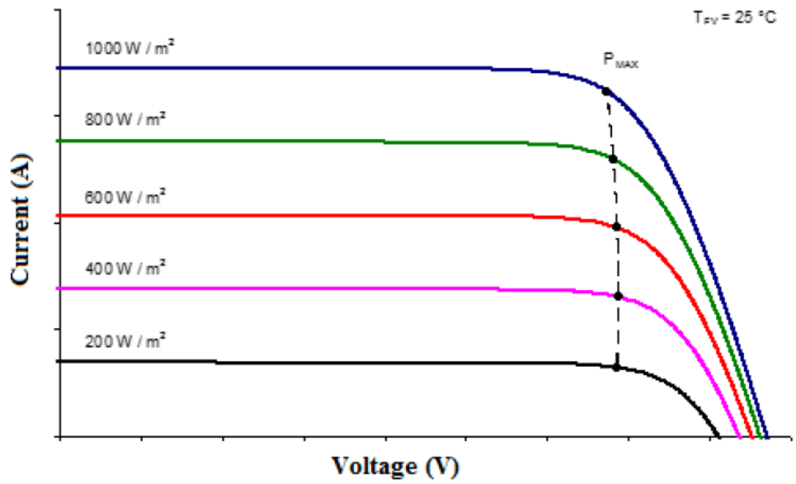


Figure 2.12: I(U) characteristic of a PV generator depending on irradiance [28].

The I(U) characteristic also depends on the temperature T_{PV}. At constant irradiance G, the temperature increase produces:

- a small increase of the photovoltaic current I_{ph} and therefore of I_{sc};
- an increase of diode current I_j which determines a decrease of U_{oc}.

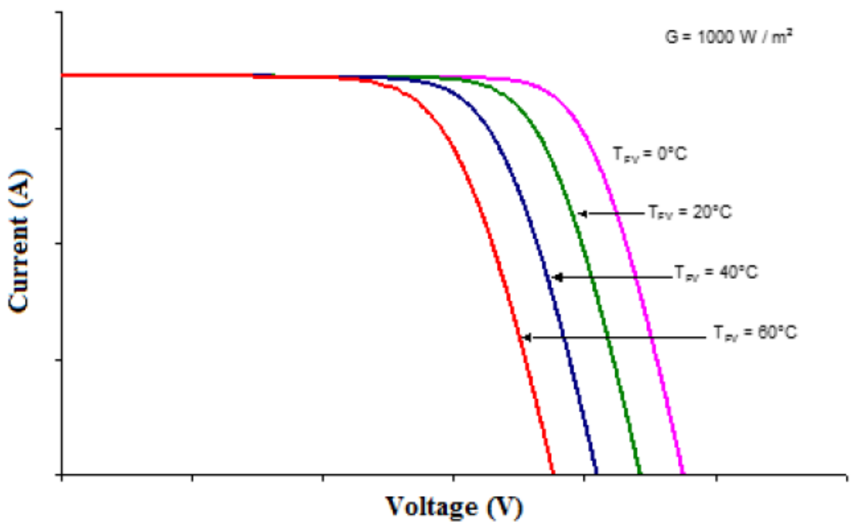


Figure 2.13: I(U) characteristic of a PV generator depending on temperature [28].

Source of losses in a solar cell In a solar cell, the conversion of the irradiated input power into electrical power is associated with losses for the following reasons:

- Reflection and covering of the surface of the cell (about 10%). A portion of the radiation that reaches the cell surface is reflected or hits the front grid.

- Energy surplus of the incident photons (about 25%). A share of the absorbed photons has an energy higher than necessary to generate electron-hole pairs: this energy surplus becomes heat.
- Lack of energy (deficit) of the incident photons (about 20%). On the other hand, some of the incident photons have not enough energy to generate an electron-hole pair.
- Recombination factor (about 2%). Not every electron-hole pairs are maintained separate from the electric junction field.
- Fill Factor (about 20%). Not the entire produced electricity is transferred to the external circuit.

Commercial PV cells can achieve a conversion efficiency up to 23%, where conversion efficiency is the ratio between the maximum power output P_{MAX} (W) and the incident power $P_i = G \cdot A$ on the surface A (m^2) of the cell [28].

Chapter 3

Model description

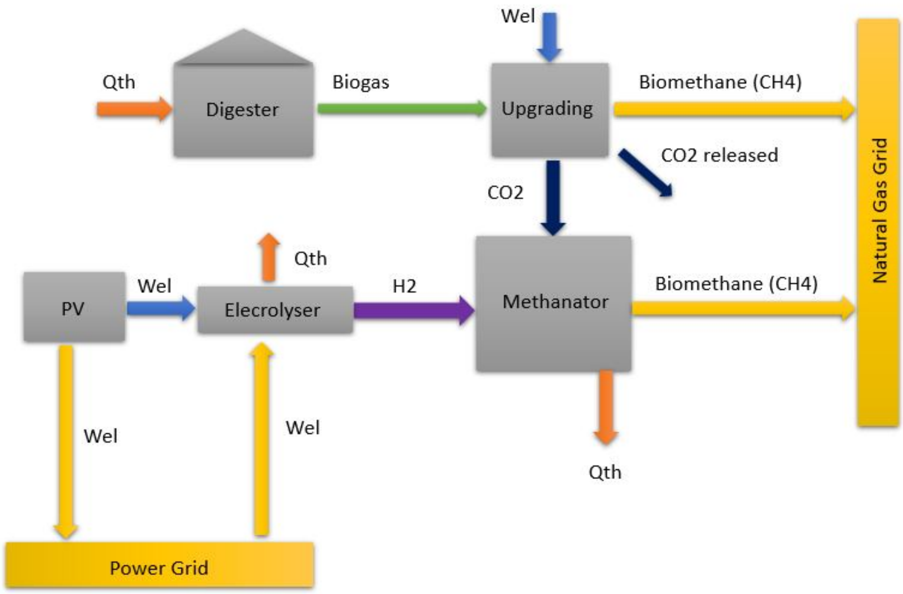
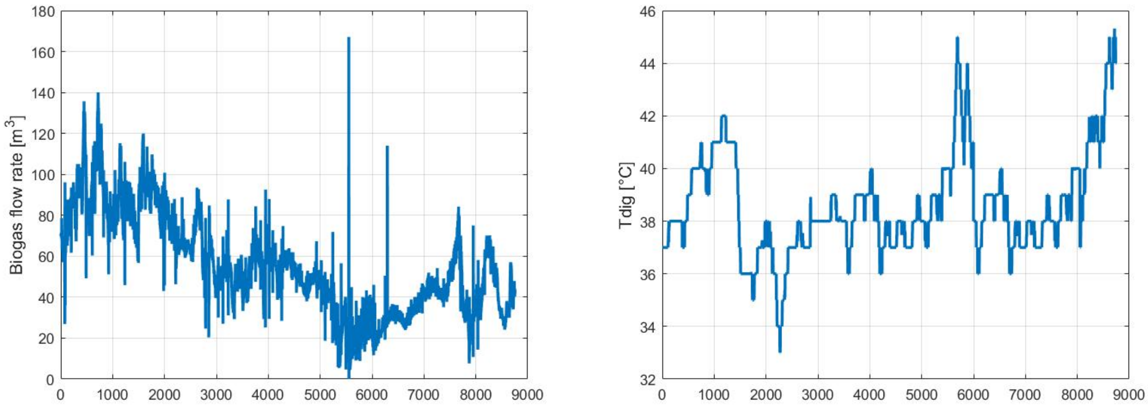


Figure 3.1: System layout.

In figure 3.1 is represented the complete plant scheme. In the next sections the different components of the system are analyzed more in detail. According to the figure, after the digestion process, the biogas produced into the digester is driven to an upgrading section where it is split into biomethane and CO_2. The CH_4 produced has very high purity, so it can be sold directly into the grid. Part of the carbon dioxide processed is exploited from the methanation reactor, able to produce further biomethane thanks to a reaction with H_2 and CO_2. The hydrogen needed in the methanator is produced by an electrolyser, which electricity demand is satisfied with photovoltaic modules and grid's energy.

3.1 Anaerobic Digester

The biomass for the considered plant is supplied by a medium-sized wastewater treatment plant (WWTP) located at Collegno city near Turin - Italy. The mentioned reference WWTP serves around 270,000 equivalent inhabitants collecting an overall of 59,000 m^3 of wastewater on a daily basis that corresponds nearly to 220 L/day/capita [22]. Wastewater treatment is a process that removes contaminants from wastewater or sewage and transforms it into a fluid that can be brought back to the water cycle with an acceptable impact on the environment. The data available for the Collegno's plant are hourly and include: the flow rates both of the sludge at the inlet of the digester and of the biogas produced, as well as the digester's temperature. The biogas flow rate trend (fig. 3.2a) is higher in winter than in summer: this could be due to the fact that some factories work less and more people are on holidays producing a lower quantity of waste. The mean biogas flow rate is 54.7 m^3/h.



(a) Biogas flow rate *(b) Digester's temperature*

Figure 3.2: Hourly biogas flow rate and temperature of the digester.

Figure 3.3: WWTP in Collegno (Turin).

Digester energy demand In this paragraph are analysed the WWTP's thermal and electrical demand. The wastewater treatment plant presents fluctuating demand for electricity from illumination, process equipment, etc. This trend is due to the variations in the wastewater inflow during the year. The digester thermal load is required for boosting the anaerobic reaction into the anaerobic digester [22] and it is calculated thanks to the following equation:

$$Q_{dig} = Q_{sl} + Q_{los} + Q_{pipes} \tag{3.1}$$

where:

- Q_{sl}: is the power required for the sludge heating from an inlet temperature (14°C on Gen, Feb, Nov, Dec; 23°C on Jun, Jul, Aug; 18.5°C on Mar, Apr, May, Sept, Oct) to the digester temperature (hourly value from the data 2019 for Collegno, with a medium value of 35°C);

- Q_{los}: is the extra heat needed to compensate the heat losses through the digester walls;

- Q_{pipes}: is the heat lost through pipes.

The first term is calculated by the following equation:

$$Q_{sl} = \dot{m}_{sl} \cdot c_p \cdot (T_{dig} - T_{sl,in}) \tag{3.2}$$

- $\dot{m}_{sl}$: is the average hourly sludge flow rate;

- c_p: is the specific heat capacity: it is considered the same of water (4.186 $kJ/kg\ K$) because the solid content in sludge is lower than 2% (weight basis);

- T_{dig}: is the hourly digester process temperature, taken from the WTTP measurements;

- $T_{sl,in}$: is the sludge inlet temperature, as previously said it is considered 14°C, 18.5°C, 23°C respectively for winter, autumn-spring and summer months.

The digester thermal losses are evaluated using:

$$Q_{los} = Q_{ug} + Q_{ext} \tag{3.3}$$

Q_{ug} is used to consider losses through the underground surface (heat from walls to the ground):

$$Q_{ug} = U_{ug} \cdot A_{ug} \cdot (T_{dig} - T_{gr}) \tag{3.4}$$

Q_{ext} takes into account losses through the external surface (heat from walls to external air):

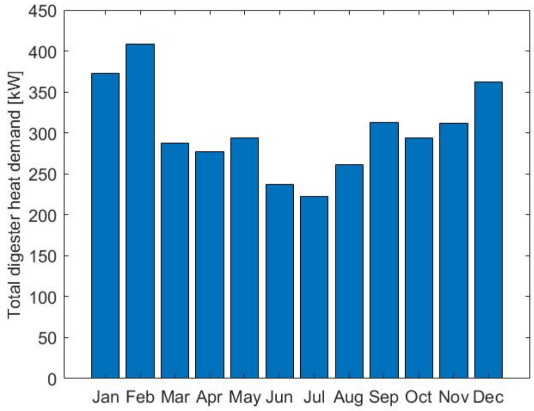
$$Q_{ext} = U_{ext} \cdot A_{ext} \cdot (T_{dig} - T_{ext}) \tag{3.5}$$

T_{ext} is the ambient temperature, hourly values from PVgis data. The last term of the equation (3.1) is used to evaluate the thermal losses through piping, it is a fixed share of the total sludge pre-heating duty and digester thermal losses:

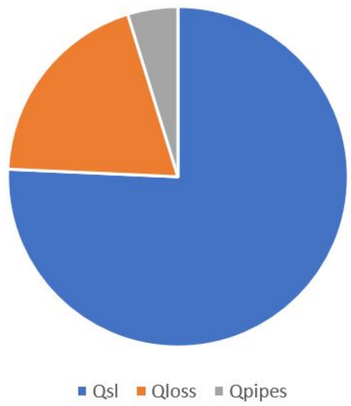
$$Q_{pipes} = \%_{pipes} \cdot (Q_{sl} - Q_{los}) \tag{3.6}$$

Parameter	Symbol	Average value	Unit
Sludge inlet temperature	$T_{sl,in}$	14 (winter)-18.5 (aut, spr) 23 (summer)	°C
Sludge mass flow rate	$\dot{m}_{sl}$	10 (average)	kg/s
Heat transfer coefficient (underground)	U_{ug}	2.326	W/m²°C
Heat transfer coefficient (non-underground)	U_{ext}	0.930	W/m²°C
Area of underground walls	A_{ug}	450.8	m²
Area of non-underground walls	A_{ext}	1132.1	m²
Ground temperature	T_{gr}	5 (winter)-7.5 (aut, spr) 10 (summer)	°C
Digester temperature	T_{dig}	35	°C
Percentage of losses through pipes	$\%_{pipes}$	5	%

Table 3.1: Main parameters for digester thermal load calculations



(a) Monthly energy demand



(b) Main contributions

Figure 3.4: Digester's energy demand and main contributions.

3.2 Upgrading

The Upgrading system is essential to remove from the biomass most of the present carbon dioxide. Thanks to this process the biomass free from CO_2, called biomethane, can be pumped and so sold directly to the natural gas grid. The average flow rate of biogas produced from the Collegno's Wastewater Treatment Plant digester is about 55 m^3/h. The systems evaluated in the literature are bigger than the one studied in this thesis, so it has been considered a particular small scale biogas upgrading: High pressure batchwise water scrubbing. It is a special type of water scrubber, used in Kalmari farm in Finland. The main differences to conventional water scrubbing is the very high operational pressure (150 bar) and that the system is operated batchwise with two absorption columns. Water drives gas from the absorption column, which at the end is filled with water. The column is then emptied and the cycle starts again. To minimize the methane slip, the water is treated with a flash tank. The electricity consumption is about 0.4-0.5 kWh/Nm^3

of raw biogas [3], higher than in conventional water scrubbers: this is due to the high operational pressure. The high pressure allows the components in the system (absorption and desorption columns) to be smaller than in conventional water scrubbers: the footprint of the plant will be lower as well as the investment cost.

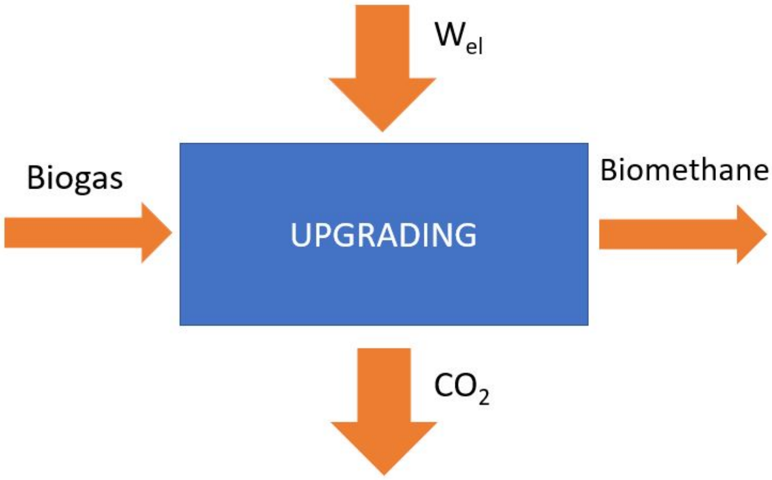


Figure 3.5: Upgrading scheme.

Parameter	Value	Unit	Reference
Methane content in upgraded gas	97	% mol	[6]
Methane recovery	98	%	[6]
Electricity demand	0.4	kWh/m^3 (of biogas)	[3]
CO_2 in biogas	40	%	Assumption
CH_4 in biogas	60	%	Assumption
ρ_{CO_2}	1.9763	kg/m^3 (at 0 °C)	[34]
ρ_{CH_4}	0.717	kg/m^3 (at 0 °C)	[35]
MW_{CO_2}	0.044	kg/mol	[34]
MW_{CH_4}	0.016	kg/mol	[35]

Table 3.2: Main parameters for UPGRADING calculations.

The following calculations are necessary to find out the flow rate of carbon dioxide and biomethane leaving the upgrading section.

- CH_4 volumetric flow rate in biomethane:

$$\dot{V}_{CH_4}\left[\frac{m^3}{h}\right] = 0.6 \cdot \dot{V}_{biogas}\left[\frac{m^3}{h}\right] \cdot 0.98 \tag{3.7}$$

- CH_4 mass flow rate:

$$\dot{m}_{CH_4}\left[\frac{kg}{h}\right] = \dot{V}_{CH_4}\left[\frac{m^3}{h}\right] \cdot \rho_{CH_4}\left[\frac{kg}{m^3}\right] \tag{3.8}$$

- CH_4 molar flow rate in biomethane:

$$n_{CH_4}\left[\frac{mol}{h}\right] = \frac{\dot{m}_{CH_4}}{MW_{CH_4}} \tag{3.9}$$

- Total number of moles in the biomethane:

$$n_{tot}\left[\frac{mol}{h}\right] = \frac{n_{CH_4}}{Methane\ content\ in\ upgraded\ gas\ [\%\ mol]} \tag{3.10}$$

- Carbon dioxide molar flow rate in biomethane:

$$n_{CO_2}\left[\frac{mol}{h}\right] = n_{tot}\cdot 0.03 \tag{3.11}$$

- CO_2 mass flow rate in biomethane:

$$\dot{m}_{CO_2\,biom}\left[\frac{kg}{h}\right] = n_{CO_2}\cdot MW_{CO_2} \tag{3.12}$$

- CO_2 mass flow rate in the incoming biogas

$$\dot{m}_{CO_2\,biog}\left[\frac{kg}{h}\right] = \dot{V}_{biogas}\left[\frac{m^3}{h}\right]\cdot(\%CO_2)\cdot\rho_{CO_2} \tag{3.13}$$

- <u>CO_2 mass flow rate for methanation</u>:

$$\dot{m}_{CO_2\,meth}\left[\frac{kg}{h}\right] = \dot{m}_{CO_2\,biogas} - \dot{m}_{CO_2\,biom} \tag{3.14}$$

- Conversion efficiency:

$$\eta_{conv} = \frac{\dot{m}_{CO_2\,meth}}{\dot{m}_{CO_2\,biogas}} \tag{3.15}$$

The second to last term is underlined because it is the parameter that represents the carbon dioxide blown into the methanator, the next stage.

Parameter	Value	Unit
CO_2 Volum. flow rate (to methanation)	20.94	m^3/h (average)
Electricity demand	191,695	kWh/y
Biomethane	290,179	m^3/y

Table 3.3: UPGRADING main results.

3.3 Methanator

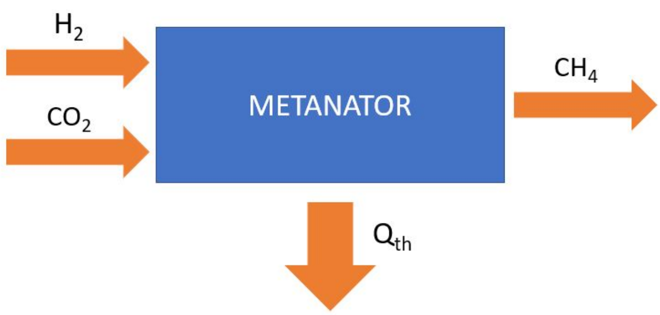


Figure 3.6: Methanation reactor scheme, with flow rates.

The methanator is a reactor where the methanation reaction occurs on a catalyst, for example Ni/Al_2O_3, in a temperature range of 250 °C - 700 °C [26]. In this study, catalyst deactivation phenomena and temperature profiles were not considered. The heat recovered in the methanation reaction (Q_{th}) can be used for the components of the system that require thermal energy, such as the digester section. The carbon dioxide molar flow rate is calculated by means of the CO_2 mass flow rate that exits from the upgrading stage:

$$n_{CO_2}\left[\frac{mol}{h}\right] = \frac{\dot{m}_{CO_2\,meth}}{MW_{CO_2}} \tag{3.16}$$

According to the reaction 2.2, to find the hydrogen molar flow rate it is sufficient to multiply the carbon dioxide flow rate by 4:

$$n_{H_2}\left[\frac{mol}{h}\right] = 4 \cdot n_{CO_2} \tag{3.17}$$

The moles of methane are the same as carbon dioxide, so the equation to calculate the biomethane flow rate is the following:

$$\dot{m}_{CH_4}\left[\frac{kg}{h}\right] = n_{CO_2} \cdot MW_{CH_4}\left[\frac{kg}{mol}\right] \tag{3.18}$$

As already mentioned, it is possible to recover thermal energy from methanation. In order to calculate this quantity, it is used the following equation:

$$(4+1) : \Delta H = (n_{CO_2} + n_{H_2}) : x \tag{3.19}$$

where x is the energy recovered:

$$Thermal\,energy\,recovered = -\frac{\Delta H \cdot (n_{CO_2} + n_{H_2})}{5 \cdot 3600}\ [kWh] \tag{3.20}$$

3.4 Electrolyser

In this study are considered two technologies of low temperature electrolysers: proton exchange membrane electrolytic cell (PEMEC) and alkaline electrolytic cell (AEC). These systems are cheaper compared to high temperature technologies. PEM electrolysers are able to operate at high current densities. This means reduced operational costs especially for systems coupled with very dynamic energy sources such as wind and solar.

		ALK						PEM					
		2017 @ P atm			2025 @ 15 bar			2017 @ 30 bar			2025 @ 60 bar		
Nominal Power	UNITS	1 MW	5 MW	20 MW	1 MW	5 MW	20 MW	1 MW	5 MW	20 MW	1 MW	5 MW	20 MW
Minimum power	% Pnom	15%			10%			5%			0%		
Peak power – for 10 min	% Pnom	100%			100%			160%			200%		
Pressure output	Bar	0 bar			15 bar			30 bar			60 bar		
Power consumption @ P nom	kWhe/kg	58	52	51	55	50	49	63	61	58	54	53	52
Water consumption	L/kg	15 L/kg											
Lifetime – System	Years	20 years											
Lifetime – Stack @ full charge	hr	80 000 h			90 000 h			40 000 h			50 000 h		
Degradation – System	%/1000 h	0,13%/ 1000 h			0,11%/ 1000 h			0,25%/ 1000 h			0,20%/ 1000 h		
Availability	%/year	>98%											
CAPEX – Total system Equipment	€/kW	1200	830	750	900	600	480	1500	1300	1200	1000	900	700
OPEX – Electrolyser system	%CAPEX	4%	3%	2%	4%	3%	2%	4%	3%	2%	4%	3%	2%
CAPEX – Stack replacement	€/kW	420	415	338	315	300	216	525	455	420	300	270	210

Figure 3.7: Summary of electrolyser selected cost and performance data [4].

For the alkaline electrolyser it can be supposed a thermal recovery, which value is calculated thanks to the following steps. The water that goes out from the electrolyser is defined by the reaction below:

$$2\,H_2O \rightarrow 2\,H_2 + O_2 \tag{3.21}$$

The number of water's moles is equal to the one of hydrogen, so multiplying this value by the molecular weight of the water it is founded the water flow rate:

$$\dot{m}_{H_2O}\;\left[\frac{kg}{s}\right] = n_{H_2}\;\left[\frac{mol}{s}\right]\cdot MW_{H_2O}\;\left[\frac{g}{mol}\right]\cdot 10^{-3}\;\left[\frac{kg}{g}\right] \tag{3.22}$$

The temperature of the alkaline electrolyser is supposed to be 60°C. The maximum thermal power available cooling down water from 60°C to the ambient temperature (20°C) is obtained by the following equation:

$$Q_{max}\;[kW] = \dot{m}_{H_2O}\;\left[\frac{kg}{s}\right]\cdot cp_{H_2O}\;\left[\frac{kJ}{kg\,K}\right]\cdot \Delta T\;[K] \tag{3.23}$$

An efficiency is introduced to take into account losses, the equation becomes:

$$\begin{aligned} Q_{rec}\;[kW] &= \eta\cdot\dot{m}_{H_2O}\;\left[\frac{kg}{s}\right]\cdot cp_{H_2O}\;\left[\frac{kJ}{kg\,K}\right]\cdot \Delta T\;[K] \\ &= 0.8\cdot\dot{m}_{H_2O}\;\left[\frac{kg}{s}\right]\cdot 4.186\;\left[\frac{kJ}{kg\,K}\right]\cdot 40\;[K] \end{aligned} \tag{3.24}$$

3.5 Photovoltaic system

The photovoltaic panels are located on the roofs of the available buildings of Collegno's wastewater treatment plant. In the flat roofs are installed non-integrated panels, in the tilted ones the panels are integrated into the building. The coordinates of the site are: 45.091583 N, 7.608750 E. In the table 3.4 are considered the areas of all the roofs of the buildings composing the WWTP [19]. The total area that can be occupied is used to calculate the maximum power.

Building	**Area [m^2]**	**Roof type**	**P$_{max}$ [kW]**
Digester treatment	373.2	(F)	36.83
Staff 1	632.8	(F)	62.45
Services	462.2	(F)	45.61
Workshop	1088	(F)	107.37
Boiler and pumps room	279.8	(F)	27.61
Parking 1	82.1	(F)	8.1
Deodorization	266.9	(F)	26.34
Warehouse 1	612.6	(F)	60.46
Warehouse 2	110.8	(F)	10.93
Dressing room EAST-WEST	242.1	(T)	53.45
Offices EAST-WEST	378	(T)	83.45
Ozonolysis	110.7	(F)	10.93
Distribution board NORTH-SOUTH	163.7	(T)	36.14
Staff 2	112.3	(F)	11.08
Transformers	446.1	(F)	46
Parking 2	70.1	(F)	6.92
TOTAL	**5451.4**		**633.64**

Table 3.4: Area of the roofs (flat and tilted) of buildings and maximum power [19].

At this point, it is necessary to choose a type of photovoltaic module among the many on the market: the panels must have high efficiency and duration. The choice was SunPower's modules: this company for the third consecutive year has been confirmed as the first commercial solar provider in the U.S. and has over 35 years of experience across a diverse range of industries [29]. The commercial module chosen is SunPower X-Series X22-360-COM and presents the following features:

Electrical Data	SPR-X22-360-COM
Nominal Power (Pnom)[6]	360 W
Power Tolerance	+5/−3%
Avg. Panel Efficiency[7]	22.2%
Rated Voltage (Vmpp)	59.1 V
Rated Current (Impp)	6.09 A
Open-Circuit Voltage (Voc)	69.5 V
Short-Circuit Current (Isc)	6.48 A
Max. System Voltage	1000 V UL & 1000 V IEC
Maximum Series Fuse	15 A
Power Temp Coef.	−0.29% / ° C
Voltage Temp Coef.	−167.4 mV / ° C
Current Temp Coef.	2.9 mA / ° C

(a) Electrical Data

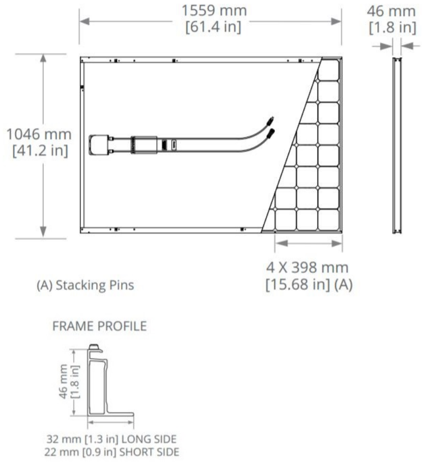
Tests And Certifications	
Standard Tests[8]	UL1703 (Type 2 Fire Rating), IEC 61215, IEC 61730
Management System Certs	ISO 9001:2015, ISO 14001:2015
EHS Compliance	RoHS, OHSAS 18001:2007, lead free, REACH SVHC-163, PV Cycle
Sustainability	Cradle to Cradle Certified™ Silver (contributes to LEED categories)[9]
Ammonia Test	IEC 62716
Desert Test	10.1109/PVSC.2013.6744437
Salt Spray Test	IEC 61701 (maximum severity)
PID Test	1000V: IEC62804, PVEL 600hr duration
Available Listings	UL, TUV, CEC

(b) Tests And Certifications

Figure 3.8: Electrical data and tests [30].

Operating Condition And Mechanical Data	
Temperature	−40° F to +185° F (−40° C to +85° C)
Impact Resistance	1 inch (25 mm) diameter hail at 52 mph (23 m/s)
Appearance	Class B
Solar Cells	96 Monocrystalline Maxeon Gen III
Tempered Glass	High-transmission tempered anti-reflective
Junction Box	IP-65, MC4 compatible
Weight	41 lbs (18.6 kg)
Max. Load	Wind: 50 psf, 2400 Pa front & back Snow: 112 psf, 5400 Pa front
Frame	Class 2 silver anodized; stacking pins

(a) Operational conditions



(b) PV scheme

Figure 3.9: Operational conditions and scheme [30].

To estimate the maximum power, it is needed to calculate the number of photovoltaic modules that can be installed and then multiply it by the nominal power of the chosen module [19]. However, the area that can be occupied by the modules installed on flat roofs does not correspond to the total flat area, because to optimize the power produced by modules, they need to be tilted. Therefore, it is necessary to find the minimum distance between the strings of photovoltaic modules to avoid shading phenomena [23]. It is considered the worst possible condition: the winter solstice (23° 27'), where the declination angle is the smallest.

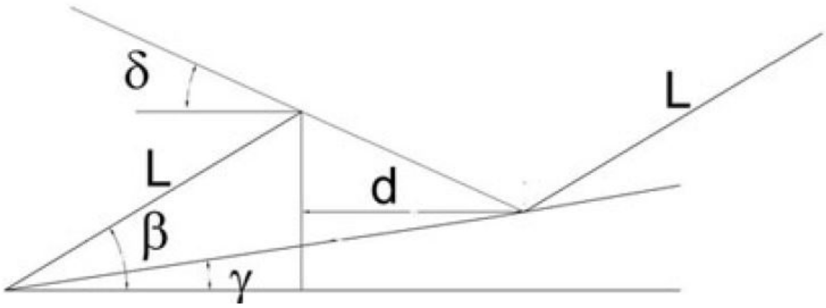


Figure 3.10: PV panel shading.

- L = panel width;
- d = minimum distance from the neighbouring panel;
- β = angle of inclination of the panel with respect to the horizon;
- γ = angle of inclination of the roof with respect to the horizon;
- δ = declination angle at the winter solstice.

d represents the horizontal projection of the distance "traveled" by the solar rays between the upper edge of a photovoltaic module and the horizontal plane on the day of the winter solstice: therefore, it constitutes the minimum distance between the rows of photovoltaic modules to avoid shading phenomenon. By applying the principles of trigonometry to the representation in figure 3.10, the following equation is obtained:

$$L \cdot sin(\beta) = d \cdot tan(\delta) + d \cdot tan(\gamma) + L \cdot cos(\beta) \cdot tan(\gamma) \tag{3.25}$$

From which it is possible to calculate the minimum distance between the rows of photovoltaic modules:

$$d = L \cdot \left(\frac{sin(\beta) - cos(\beta) \cdot tan(\gamma)}{tan(\delta) \cdot tan(\gamma)} \right) \tag{3.26}$$

It is necessary to calculate the optimal value of β, this is done thanks to PVGIS: an online software by the Joint Research Center (JRC). The software input data includes: the type of photovoltaic panel, the nominal power of the single module, the type of installation (which will be integrated into the building for tilted roofs and placed on the ground for flat roofs). It is also needed to insert the geographical coordinates of the place as an input so the software can calculate the average irradiation. In addition to β it is possible to calculate the hourly, daily, monthly and annual production of the photovoltaic system. The optimal angle of inclination of the photovoltaic module with respect to the horizon, calculated through PVGIS is 40°. Now it is possible to estimate d:

$$\begin{aligned} d &= L \cdot \left(\tfrac{sin(\beta) - cos(\beta) \cdot tan(\gamma)}{tan(\delta) \cdot tan(\gamma)} \right) = 1.046 \cdot \left(\tfrac{sin(40°) - cos(40°) \cdot tan(0°)}{tan(27.45°) \cdot tan(0°)} \right) \\ &= 1.294\, m \end{aligned} \tag{3.27}$$

In order to estimate the area that can be occupied by the photovoltaic modules, it is necessary to make geometric considerations to calculate the total area occupied by the rows of modules and the empty areas between the strings. The area occupied by the photovoltaic panels is obtained thanks to the following equation:

$$\begin{gathered} \frac{A_v}{A_{mp}} = \frac{l \cdot d}{l \cdot L} = \frac{1.294}{1.046} = 1.237 \\ A_{mp} + A_v = A_{tp} \end{gathered} \tag{3.28}$$

- A_{mp} = Area of modules on flat roofs;
- A_v = Empty area of flat roofs;
- l = Length of photovoltaic modules string.

It is first necessary to calculate the total area occupied by the flat roofs, A_{tp}. The structures with tilted roofs are: changing room building, office building and the technical room for electrical panels. It is possible to calculate the area of the flat roofs by subtracting from the total area, the area of the tilted roofs. The area of tilted (A_i) and flat (A_{tp}) roofs are calculated thanks to the following equations:

$$A_i = A_s + A_u + A_q = 242.1 + 378 + 163.7 = 783.8\, m^2 \tag{3.29}$$

$$A_{tp} = A_t - A_i = 5451.4 - 783.8 = 4667.6\, m^2 \tag{3.30}$$

At this point it is possible to calculate the total area occupied by the photovoltaic modules installed on flat roofs:

$$A_{mp} = \frac{A_{tp}}{2.237} = \frac{4667.6}{2.237} = 2086.5\, m^2 \tag{3.31}$$

Knowing the total area occupied by the panels mounted on the ground and the one of the panels integrated into the buildings, it is possible to estimate the number of photovoltaic modules that can be installed on flat roofs (N_{mp}) and on inclined ones (N_{mi}):

$$N_{mp} = \frac{A_{mp}}{A_m} = \frac{A_{mp}}{L \cdot b} = \frac{2086.5}{1.046 \cdot 1.559} = 1279 \tag{3.32}$$

$$N_{mi} = \frac{A_i}{A_m} = \frac{A_i}{L \cdot b} = \frac{783.8}{1.046 \cdot 1.559} = 480 \tag{3.33}$$

Where:

- A_m = Area of the photovoltaic module;
- L = width of the photovoltaic module;
- b = length of the photovoltaic module.

The nominal power of the modules is:

$$P_t = N_{mp} \cdot P_m = 1279 \cdot 360 = 460\, kW \tag{3.34}$$

$$P_i = N_{mi} \cdot P_m = 480 \cdot 360 = 173\, kW \tag{3.35}$$

So the maximum power that can be installed is 633 kW.
For this study it is necessary to calculate the total hourly energy production of the PV system, given by the following equation:

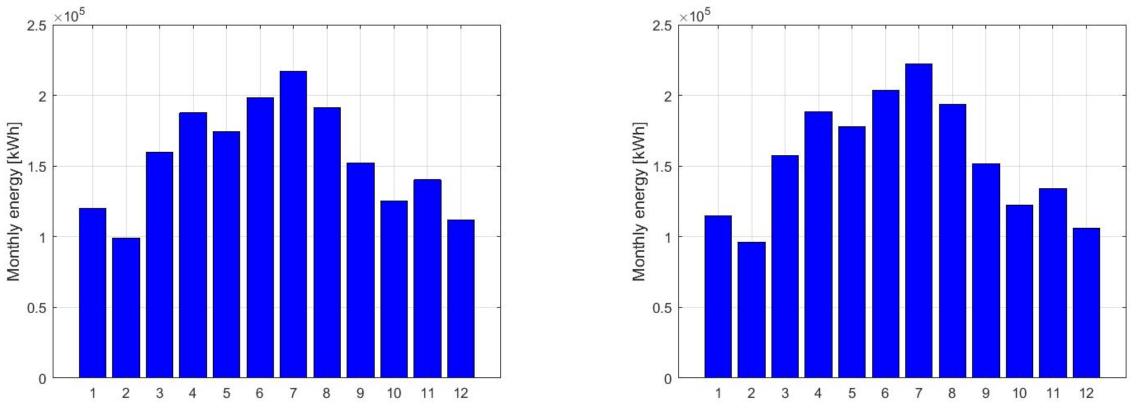
$$E_{tot} = \eta \cdot (G_{h,p} \cdot A_{mp} + G_{h,i} \cdot A_i) \tag{3.36}$$

Where:

- η is the efficiency of the solar photovoltaic module: 22.1% [30];
- $G_{h,p}$ is the global in-plane irradiance for the modules on flat roofs;
- $G_{h,i}$ is the global in-plane irradiance for the modules on tilted roofs;
- A_{mp} is the area occupied by the modules on flat roofs;
- A_i is the area occupied by the modules on titled roofs.

	Modules Inclination	**Modules Orientation**
FLAT ROOFS	40°	1°
TILTED ROOFS	35°	1°

Table 3.5: Inclination and orientation of the modules.



(a) Monthly global in-plane irradiance (flat) *(b) Monthly global in-plane irradiance (tilted)*

Figure 3.11: Monthly global in-plane irradiance.

The small differences between figure 3.11a and figure 3.11b are due to the modules inclination.

Parameter	**Value**	**Unit**
Number of modules	1759	
Nominal Power	360	W
Module price	351.74	€/module
Energy (flat)	865,340	kWh/y
Energy (tilt)	323,700	kWh/y
Total energy	1,189,040	kWh/y
CAPEX	618,710.7	€

Table 3.6: PV main results.

The cost of the modules is taken from a Swiss site [27] and then converted from Swiss franc to euro.

3.6 Economic Analysis

In this section are defined the different prices, incentives and costs that have been used for the economic analysis of this study.

3.6.1 Electricity price

The Electricity price is taken from the Eurostat database, in the data for non-household consumers [9]. The price chosen is the Italian one, for the second semester of 2019 (0.093 €/kWh), without taxes and for the consumption band 500 MWh < consumption < 2,000 MWh.

TIME / GEO		2017-S2	2018-S1	2018-S2	2019-S1	2019-S2
European Union - 27 countries (from 2020)		0.0751	0.0775	0.0779	0.0836	0.0777
European Union - 28 countries (2013-2020)		0.0765	0.0794	0.0801	0.0852	0.0799
Euro area (EA11-1999, EA12-2001, EA13-2007, EA15-2...		0.0772	0.0798	0.0799	0.0853	0.0797
Belgium		0.0721	0.0765	0.0812	0.0807	0.0802
Bulgaria		0.0780	0.0800	0.0835	0.0877	0.0858
Czechia		0.0699	0.0722	0.0710	0.0646	0.0661
Denmark		0.0629	0.0593	0.0651	0.0635	0.0617
Germany (until 1990 former territory of the FRG)		0.0786	0.0771	0.0780	0.0855	0.0718
Estonia		0.0697	0.0731	0.0790	0.0768	0.0766
Ireland		0.1093	0.1171	0.1240	0.1294	0.1273
Greece		0.0870	0.0790	0.0793	0.0810	0.0815
Spain		0.0982	0.1008	0.1045	0.0925 (d)	0.0889
France		0.0666	0.0736	0.0669	0.0812	0.0737
Croatia		0.0812	0.0848	0.0867	0.0887	0.0907
Italy		0.0813	0.0892	0.0885	0.0952	0.0930
Cyprus		0.1258	0.1241	0.1703	0.1291	0.1479
Latvia		0.0891	0.0811	0.0833	0.0837	0.0854
Lithuania		0.0686	0.0701	0.0762	0.0833	0.0853
Luxembourg		0.0719	0.0746	0.0754	0.0816	0.0822
Hungary	(e)	0.0649	0.0738	0.0737	0.0861	0.0856
Malta		0.1349	0.1331	0.1337	0.1330	0.1340

Figure 3.12: Electricity prices for non-household consumers.

3.6.2 Natural gas price

As for the electricity, the natural gas price is taken from the Eurostat database, for non-household consumers [10], with taxes and for the consumption band 10,000 GJ < consumption < 100,000 GJ. The price in the table is set in €/kWh, so, to find the value in €/Sm^3, it is necessary to consider the lower heating value of the natural gas (10.69 kWh/Sm^3), and apply the following equation:

$$\begin{aligned} Price\left[\frac{€}{kWh}\right] &= LHV\left[\frac{kWh}{Sm^3}\right]\cdot Price\left[\frac{€}{kWh}\right] \\ = 10.69\left[\frac{kWh}{Sm^3}\right]\cdot 0.0331\left[\frac{€}{kWh}\right] &= 0.353839\left[\frac{€}{kWh}\right] \end{aligned} \tag{3.37}$$

TIME / GEO	S2	2018-S1	2018-S2	2019-S1	2019-S2
European Union - 27 countries (from 2020)	6	0.0373	0.0378	0.0400	0.0372
European Union - 28 countries (2013-2020)	7	0.0366	0.0373	0.0392	0.0366
Euro area (EA11-1999, EA12-2001, EA13-2007, EA15-2...	6	0.0375	0.0377	0.0398	0.0367
Belgium	7	0.0280	0.0304	0.0289	0.0274
Bulgaria	3	0.0307	0.0347	0.0370	0.0365
Czechia	7	0.0310	0.0323	0.0354	0.0346
Denmark	9	0.0717	0.0731	0.0675	0.0630
Germany (until 1990 former territory of the FRG)	5	0.0378	0.0375	0.0378	0.0367
Estonia	2	0.0367	0.0390	0.0412	0.0400
Ireland	0	0.0377	0.0427	0.0383	0.0355
Greece	2	0.0336 (e)	0.0394	0.0380	0.0354
Spain	2	0.0351	0.0361	0.0372	0.0371
France	4	0.0414	0.0456	0.0443	0.0431
Croatia	9	0.0320	0.0354	0.0374	0.0375
Italy	1	0.0320	0.0325	0.0391	0.0331
Latvia	5	0.0362	0.0392	0.0379	0.0338
Lithuania	0	0.0395	0.0468	0.0396	0.0332
Luxembourg	8	0.0345	0.0359	0.0361	0.0307
Hungary	3	0.0308	0.0361	0.0368	0.0347
Netherlands	6	0.0465	0.0360	0.0468	0.0344

Figure 3.13: Natural gas prices for non-household consumers.

3.6.3 PV incentives

The incentives for the electricity produced by the photovoltaic system are taken from the rules of the Italian GSE (Gestore Servizi Energetici). This company, owned by the Ministry of Economy and Finance, has the goal to pursue and achieve the targets of environmental sustainability, in the two pillars of renewable sources and energy efficiency. The GSE publishes several official articles in the energy sector. The D.M. 04/07/2019 divides the plants that can access the incentives into four groups [13]:

- Group A: includes plants:
  - On-shore wind turbines that are newly built, full reconstructed, reactivated, enhanced;
  - Newly built photovoltaic systems.
- Group A-2: includes photovoltaic plants of new construction, which modules are installed to replace eternit or asbestos roofs.
- Group B: includes plants:
  - Hydroelectric newly built, full reconstructed, reactivated or enhanced;
  - Residual gases from purification processes newly built, reconstructed, reactivated or enhanced.
- Group C: includes systems subjected to total or partial reconstruction:
  - On-shore wind turbines;
  - Hydroelectric plants;
  - Residual gases from purification processes.

To access the incentives, for photovoltaic plants from 20 kW to 1 MW belonging to the Groups A, A-2, B and C, it is needed the inclusion into the Register (from the portal FER-E), by which it is assigned the part of the available power based on priority criteria. The register's available power is defined in the figure 3.14.

Nr. Procedura	GRUPPO A [MW]	GRUPPO A-2 [MW]	GRUPPO B [MW]	GRUPPO C [MW]
1	45	100	10	10
2	45	100	10	10
3	100	100	10	10
4	100	100	10	10
5	120	100	10	20
6	120	100	10	20
7	240	200	20	40
TOTALE	770	800	80	120

Figure 3.14: Register quotas.

The electricity produced by means of the PV system considered in this study can be sold to the grid at 90 €/MWh. The power of the photovoltaic plant is 633 kW, so we are in the range 100<P<1000 kW related to the figure 3.15.

Fonte rinnovabile Impianti	Gruppo di appartenenza	Tipologia	Potenza	VITA UTILE degli IMPIANTI	TARIFFA DI RIFERIMENTO (Tr)	PREMI (Pr): Fotovoltaici appartenenti al Gruppo A-2 di P<1000 kW	PREMI (Pr): Impianti su edifici con autoconsumo di P≤100 kW
						art.7.10	art.7.12
			kW	anni	€/MWh	€/MWh	€/MWh
Eolici	Gruppo A Gruppo C	on-shore	1<P≤100	20	150		10
			100<P<1000	20	90		
			P≥1000	20	70		
Fotovoltaici	Gruppo A		20<P≤100	20	105		10
			100<P<1000	20	90		
			P≥1000	20	70		
	Gruppo A-2	installati in sostituzione di coperture con completa rimozione eternit e amianto	20<P≤100	20	105	12	10
			100<P<1000	20	90	12	
Idroelettrici	Gruppo B Gruppo C	ad acqua fluente (compresi gli impianti su acquedotto)	1<P≤400	20	155		
			400<P<1000	25	110		
			P≥1000	30	80		
		a bacino o a serbatoio	1<P<1000	25	90		
			P≥1000	30	80		
Alimentati a gas residuati dai processi di depurazione	Gruppo B Gruppo C		1<P≤100	20	110		
			100<P<1000	20	100		
			P≥1000	20	80		

I valori della Tabella 1 sono ridotti (esclusi i premi), a decorrere dall'1 gennaio 2021, del 2% per gli impianti idroelettrici e a gas residuati dai processi di depurazione e del 5% per gli impianti eolici e fotovoltaici (DM2019, All.1 Tabella 1.1).

Figure 3.15: Renewable energy incentives (GSE).

3.6.4 Biomethane incentives

The biomethane incentives considered are from the Italian GSE (Gestore Servizi Energetici). For the plants that produce biomethane for transport consumption, the incentives are supplied releasing CIC (Certificati di Immissione in consumo) [15]. It is established for the producers of advanced biomethane:

- An economic value of 375 € for every CIC admitted, this rule has a duration of 10 years;
- The possibility to sold advanced biomethane directly to the GSE at 95% of the average monthly price noticed on the market. In alternative the biomethane can be sold autonomously.

The total incomes achieved from the biomethane are given by the following equation:

$$Incomes\ [€] = 375 \left[\frac{€}{CIC}\right] \cdot n_{CIC} + 0.95 \cdot V_{CH_4}\,[Smc] \cdot 0.353839 \left[\frac{€}{Smc}\right] \tag{3.38}$$

Since the plant in this study is included in the attached 3 of the D.M. MiSE 2 Marzo 2018 [16], it is guaranteed an increase in the CIC's number: 1 CIC every 5 Gcal (instead of 1 CIC every 10 Gcal). Taking into account that 1 Gcal = 1,163 kWh the total number of CIC is calculated as follows:

$$n_{CIC} = \frac{10.69\,\left[\frac{kWh}{Smc}\right] \cdot V_{CH_4}\,[Smc]}{5815\,[kWh]} \tag{3.39}$$

3.6.5 OPEX

The operating expense of the plant is calculated considering all the systems included in the control volume of interest (Upgrading, Methanator, Elecrolyser), the cost for an employee and a carbon tax.

Cost for	Value	Unit
Upgrading	178,276.25	€/y
Methanator	59.8	€/y
Labour cost	31,200	€/y
Carbon tax	50	€/ton

Table 3.7: Operational costs constant in the different scenarios.

Upgrading The Opex related to the Upgrading system is calculated considering its electricity consumption equal to 0.4 kWh/m^3 of raw biogas [3]:

$$\begin{aligned} OPEX_{UP}\left[\frac{€}{year}\right] &= V_{biogas}\left[\frac{m^3}{year}\right]\cdot elect.\ cons.\left[\frac{kWh}{m^3}\right]\cdot elect.\ cost\left[\frac{€}{kWh}\right] \\ &= 479{,}237.24\left[\frac{m^3}{year}\right]\cdot 0.4\left[\frac{kWh}{m^3}\right]\cdot 0.93\left[\frac{€}{kWh}\right] = 178{,}276.25\left[\frac{€}{year}\right] \end{aligned} \tag{3.40}$$

Methanator The operational cost of the methanator (OPEX) is calculated considering a yearly replacement of the Ni/Al_2O_3 catalyst, with a price of 29.88 €/m^3 [26]. To estimate the quantity of catalyst needed it is considered a residence time, into the reactor, of 2 minutes. Moreover, the volume of the reactor is calculated considering the maximum flow rate at the inlet of the methanator [m^3/s] and multiplying it for the residence time [s]. Since there are no specific data in the literature it is assumed that the catalyst will occupy 20% of the reactor, so 2.13 m^3.

Electrolyser The yearly operative cost related to the electrolyser is given by two contributions:

- Electricity demand needed to produce hydrogen;
- 4% of the Electrolyser CAPEX [4].

The first value is calculated by multiplying the mass of hydrogen produced in the system by the power consumption of the electrolyser (kWhe/kg), which is taken from the figure 3.7.

Labour cost Since this type of plant can work quite autonomously, it is considered that would be sufficient an employee with a part-time contract, so the labor cost is calculated thanks to the following equation:

$$\begin{aligned} Labour\ cost\left[\frac{€}{year}\right] &= Salary\left[\frac{€}{h}\right]\cdot working\ hours\left[\frac{h}{week}\right]\cdot 52\left[\frac{weeks}{year}\right] \\ &= 30\left[\frac{€}{h}\right]\cdot 20\left[\frac{h}{week}\right]\cdot 52\left[\frac{weeks}{year}\right] = 31{,}200\left[\frac{€}{year}\right] \end{aligned} \tag{3.41}$$

Stack replacement Electrolysers are not yet able to work for the whole lifetime of a plant (20 years for this study), so at least one replacement must be considered. To calculate the cost of the stack replacement is utilized an exponential estimation, written in the following equation:

$$C_1 = C_0 \cdot \left(\frac{S_0}{S_1}\right)^n \tag{3.42}$$

Where C_0 and S_0 are respectively the cost for stack replacement and the size of an electrolyser taken from the figure 3.7, with 1 MW of power and referred to the year 2025.

C_0 [€/kW]	S_0 [kW]	n	S_1 [kW]	C_1 [€/kW]
315	1000	0.27	500	379.8
			400	403.4
			320	428.5
			260	453.2
			210	480.1

Table 3.8: Cost of alkaline electrolyser replacement for different sizes [4].

C_0 [€/kW]	S_0 [kW]	n	S_1 [kW]	C_1 [€/kW]
300	1000	0.27	500	361.7
			400	384.2
			320	408.1
			260	431.6
			210	457.2

Table 3.9: Cost of PEM electrolyser replacement for different sizes [4].

3.6.6 CAPEX

The total plant cost is the sum of the purchasing prices of the system's components, the values have been calculated as follows.

Upgrading The investment cost of the upgrading system (including dispenser and basic storage) is around 380,000 € [3]. This price remains constant for every plant's configuration analysed.

Methanator In order to calculate the cost of the methanation reactor it is considered an exponential estimation, using the following equation:

$$C_1 = C_0 \cdot \left(\frac{S_1}{S_0}\right)^n \tag{3.43}$$

Where C_0 and S_0 are respectively the cost and the carbon dioxide flow rate of a plant by Collet article [6]. S_1 is the average CO_2 flow rate, calculated from the hourly value of the reference plant. In the table 3.10 the methanator flow rate is calculated, considering different carbon dioxide flows. Indeed, to restrict prices, it is possible to capture only a percentage of the total CO_2 flow rate.

C_0 [€]	S_0 [m^3/h]	n	S_1 [m^3/h]	C_1 [€]
650,000	80	0.6	23	307,678
			15.56	243,369
			13.9	227,441
			12	208,242

Table 3.10: Cost of the methanator for different CO_2 flow rates [6].

Electrolyser The cost of the electrolyser, as for the methanator, is calculated thanks to an exponential estimation, using the following equation:

$$C_1 = C_0 \cdot \left(\frac{S_0}{S_1}\right)^n \tag{3.44}$$

Where C_0 and S_0 are respectively the cost and the size of an electrolyser taken from the figure 3.7 [4], with 1 MW of power and referred to the year 2025.

C_0 [€/kW]	S_0 [kW]	n	S_1 [kW]	C_1 [€/kW]
900	1000	0.27	500	1,085
			400	1,153
			320	1,224
			260	1,295
			210	1,372

Table 3.11: Cost of alkaline electrolyser for different sizes [4].

C_0 [€/kW]	S_0 [kW]	n	S_1 [kW]	C_1 [€/kW]
1000	1000	0.27	500	1,206
			400	1,281
			320	1,360
			260	1,439
			210	1,524

Table 3.12: Cost of PEM electrolyser for different sizes [4].

The value of the exponential n has been calculated in order to satisfy, as much as possible, the non linear variation of costs according to figure 3.7.

Chapter 4

Scenarios

In this chapter are defined the most relevant scenarios that have been analysed in the study. The focus is set on the variation of some main parameters to better understand if, and under which conditions, the plant is favorable in environmental and economical terms.

An interesting point that has been examined is the quantity of CO_2 needed to produce one cubic meter of biomethane: in order to estimate this value, it is considered that to process grid's electricity in Italy are necessary 0.2562 kg CO_2/kWh [8]. From the equation below it is measured the effective quantity of carbon dioxide released per unit volume of biomethane produced:

$$CO_2\,released\left[\frac{kg_{CO_2}}{m^3}\right] = \frac{0.2562\left[\frac{kg_{CO_2}}{kWh}\right]\cdot Elect.\,demand\left[\frac{kWh}{y}\right] + \dot{m}_{CO_2}\left[\frac{kg}{y}\right]}{V_{CH_4}\left[\frac{m^3}{y}\right]} \tag{4.1}$$

The different scenarios are analysed considering three plant layouts, called base cases. In these configurations, not all the components illustrated in the figure 3.1 are taken into account, as we will see in the next sections.

4.1 Base cases

Multiple cases are considered to give an overview about the effect of the different modules on the final result founded. In the three main cases selected as the most interesting, it is not examined the one that includes the PV system's purchasing price, because the cost will be too high to validate the investment. In order to distinguish easily the different base cases, they will be called also B1, B2, B3.

4.1.1 B1: upgrading only

This scenario considers only the Upgrading section, as a result all the CO_2 produced is released into the environment. As we will see, this layout can be attractive economically: not only the total plant cost is very low, but as well the operational costs (due to low electricity demand).

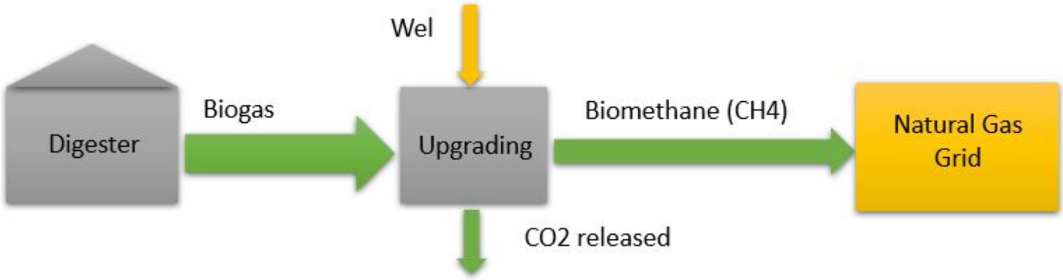


Figure 4.1: Plant scheme (B1).

Green arrows in figure 4.1 represent yearly volumetric flow rates, and their thickness is proportional to the value which they stand for. Instead, the yellow arrow represents the electricity demand of the Upgrading system. In this layout, even if the CO_2 produced by the upgrading system is totally released into the environment, the carbon dioxide's mass needed per unit volume of biomethane produced is moderate: this is mainly due to the low electricity demand of the plant.

Parameter	**Value**	**Unit**
Electricity demand	191,695	kWh/y
Biogas Volumetric flow rate	479,237	m^3/y
Biomethane to the grid	290,179	m^3/y
Carbon dioxide released in environment	183,307.5	m^3/y
kg of CO_2 to generate 1 m^3 of biogas	1.412	$kg_{CO_2}/m^3_{Biomethane}$

Table 4.1: First base case flow rates.

4.1.2 B2: upgrading and methanation

This layout presents, in addition to the Upgrading system, the process for the methanation of carbon dioxide, able to produce further methane, and an alkaline electrolyser (500 kW), which electricity demand is satisfied buying grid's energy. Indeed, as mentioned in section 2.3, the methanation reaction needs hydrogen to take place. From the two new components, it is also possible to recover some thermal energy as shown in details in the dedicated sections. In figure 4.2 are illustrated the flow rates present in this configuration, the arrows can be of three different colors:

- green: represents the yearly volumetric flow rate;
- yellow: reflects the yearly electricity demand;
- orange: illustrates the thermal energy recovered.

The thickness of arrows of the same color is proportional to the value which they represent, so it is possible to compare flow rates with alike unit of measurement.

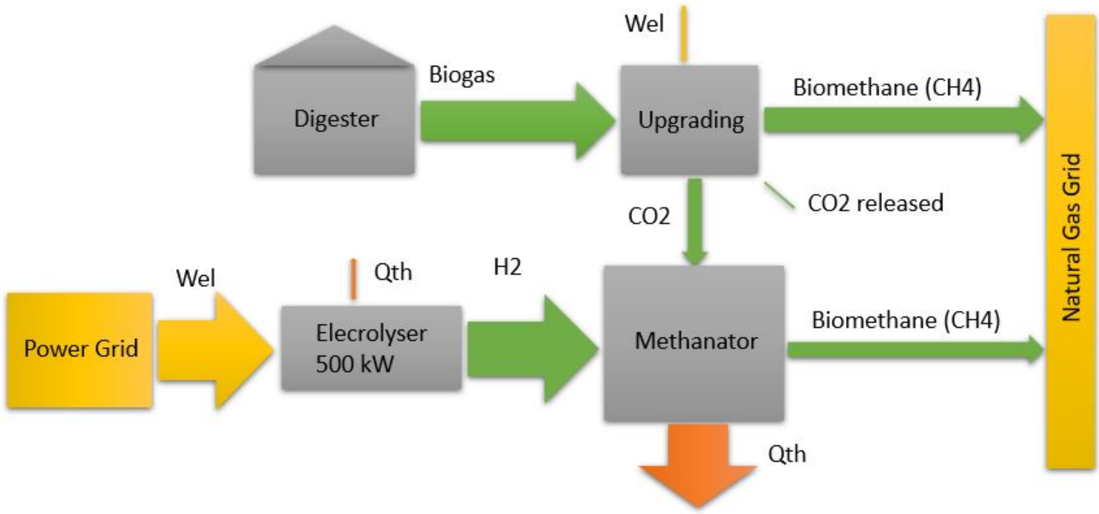
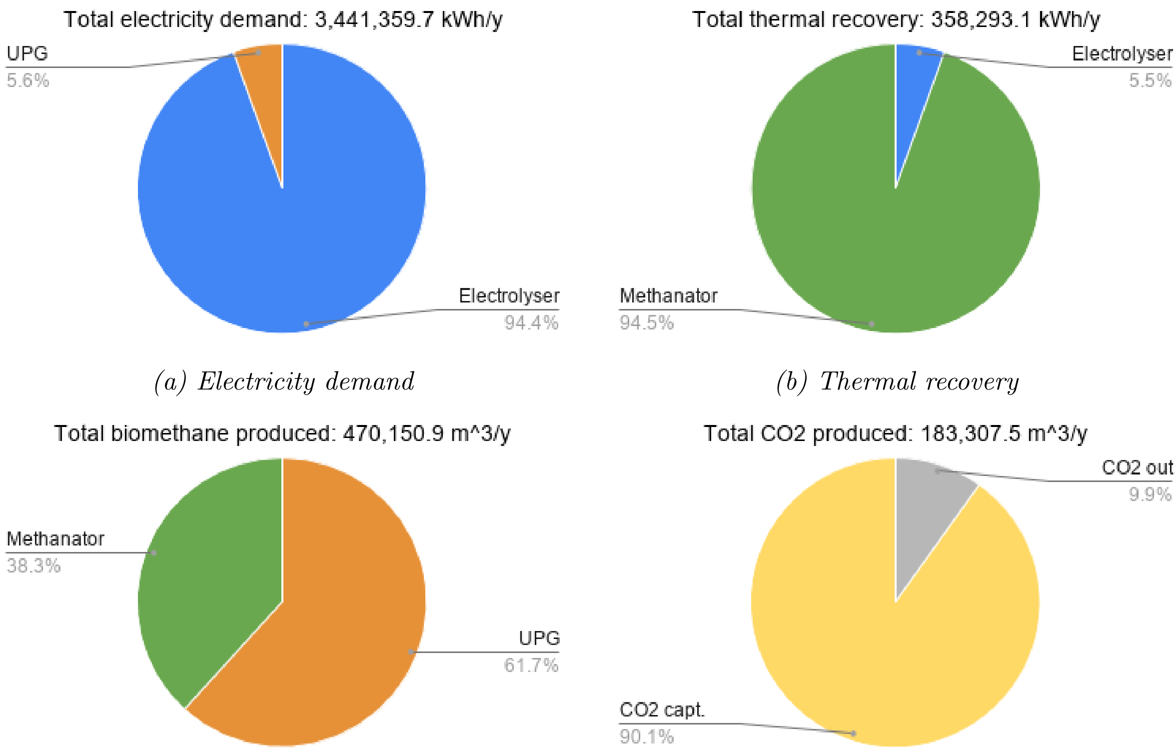


Figure 4.2: Plant scheme (B2).



(a) Electricity demand *(b) Thermal recovery*

(c) Biomethane production *(d) Carbon captured*

Figure 4.3: Energy and flow rates share for B2 configuration.

Since in this scenario the electrolyser's dimension is significant, the portion of the carbon dioxide captured is very high ($\simeq 90\%$). This trend is illustrated well in figure 4.2, in which the arrow representing the CO_2 released is very thin. Thanks to this figure it is possible to deduce some other interesting features:

- the main responsible for the energy consumption is the electrolyser, which electricity demand is the 94.4% of the total;

- thermal recovery is ruled by the methanator, from which is obtained the 94.5% of the total;

- the system that produces more biomethane is the upgrading one, with 61.7% of share.

The quantity of carbon dioxide released into the environment to produce biomethane is the highest with respect to all other cases. This result is found because the electrolyser's electricity demand is entirely fulfilled by the grid.

Parameter	**Value**	**Unit**
Electricity demand (Upgrading)	191,695	kWh/y
Electricity demand (Electrolyser)	3,249,665	kWh/y
Biogas Volumetric flow rate	479,237	m^3/y
Biomethane to grid (Upgrading)	290,179	m^3/y
Biomethane to grid (Methanator)	179,972	m^3/y
Carbon dioxide released in environment	18,098	m^3/y
Carbon dioxide to Methanator	165,209	m^3/y
Hydrogen to Methanator	657,228	m^3/y
Thermal recovery (Methanator)	338,507	kWh/y
Thermal recovery (Electrolyser)	19,786	kWh/y
kg of CO_2 to generate 1 m^3 of biogas	1.951	$kg_{CO_2}/m^3_{Biomethane}$

Table 4.2: Second base case flow rates.

4.1.3 B3: upgrading, methanation and PV

In this layout, in addition to B2 it is considered a PV system already bought and amortized. The total modules' power is supposed to be 633 kW, able to produce 1,189,040 kWh/y, as shown in details in section 3.5. Since PV energy is subjected to fluctuation, especially in summer can happen that the energy available is higher than the one needed. There are two possible ways to face this eventuality:

- consider to install batteries, able to store energy peaks;

- sell the energy peaks directly to the national grid.

As introduced in section 3.6.3, the selling price of electricity is 90 €/MWh, 3 euros lower than the electricity purchase price (93 €/MWh). Nevertheless, in this study it was decided to consider the hypothesis with energy sold directly to the grid: this choice reduces the plant complexity and furthermore the economic savings due to battery utilization will not justify the investment.

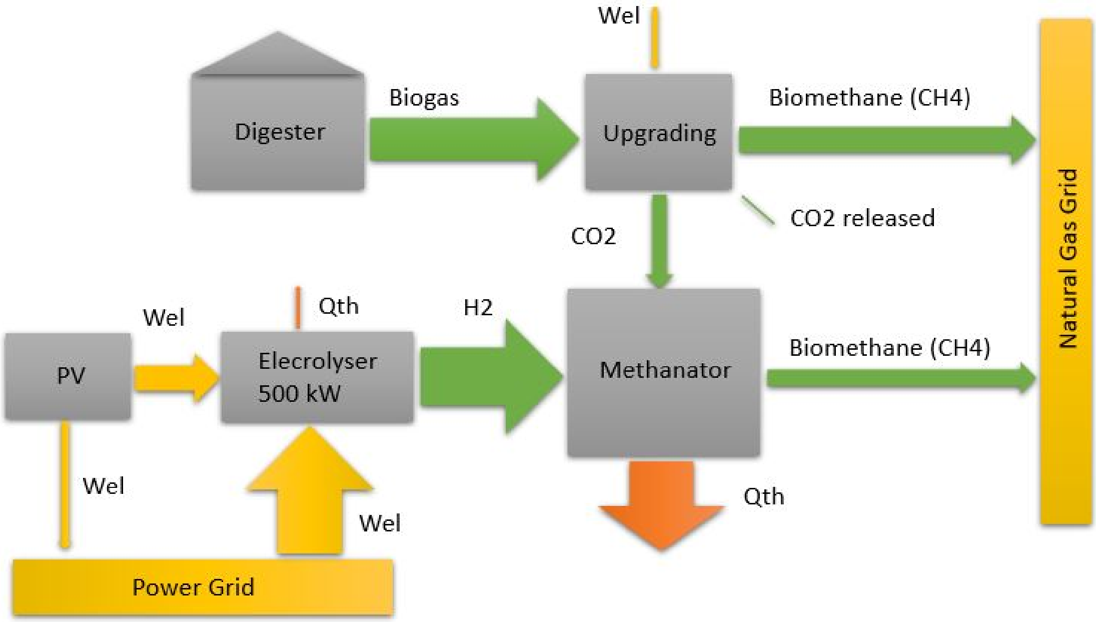


Figure 4.4: Plant scheme (B3).

With respect to the previous section, green and orange arrows are unchanged and represent respectively volumetric flow rates and thermal recovery. There are instead some differences in the yellow arrows, that show electricity flows: in figure 4.4 are illustrated, with proportional thickness, the electricity from the grid and PV to the electrolyser as well as the energy surplus sold to the grid. From an energy point of view, it is remarkable to consider together the electricity from PV to electrolyser and from PV to grid: this will help to better understand the real energetic advantage brought from the photovoltaic system. In figure 4.5 it is well illustrated the PV share, able to reduce the grid's electricity demand by 34.6%.

Although in this layout a photovoltaic system is included, the mass of carbon dioxide released to produce biomethane is slightly higher than the one of B1's system. This is due to the balance between CO_2 captured and the grid's electricity bought.

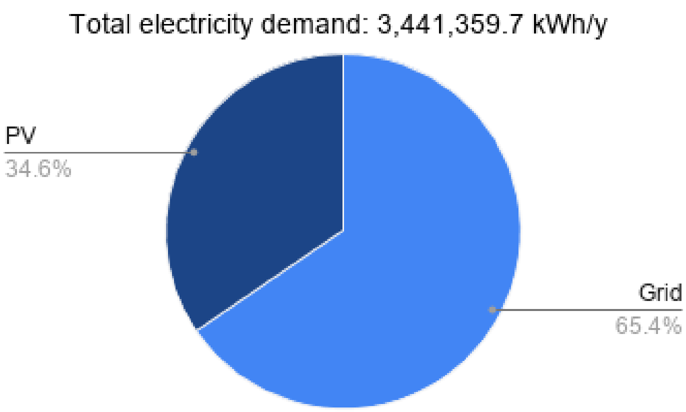


Figure 4.5: Electricity flows share.

Parameter	Value	Unit
Electricity demand (Upgrading)	191,695	kWh/y
Electricity demand from grid (Electrolyser)	2,329,600	kWh/y
PV electricity to electrolyser	920,065	kWh/y
PV electricity sold to grid	268,976	kWh/y
Biogas Volumetric flow rate	479,237	m^3/y
Biomethane to grid (Upgrading)	290,179	m^3/y
Biomethane to grid (Methanator)	179,972	m^3/y
Carbon dioxide released in environment	18,098	m^3/y
Carbon dioxide to Methanator	165,209	m^3/y
Hydrogen to Methanator	657,228	m^3/y
Thermal recovery (Methanator)	338,507	kWh/y
Thermal recovery (Electrolyser)	19,786	kWh/y
kg of CO_2 to generate 1 m^3 of biogas	1.45	$kg_{CO_2}/m^3_{Biomethane}$

Table 4.3: Third base case flow rates.

4.2 Scenario 1: Variation of biomethane incentives

This first case study is analysed because the biomethane incentives guaranteed for 10 years by GSE are very profitable, so can be interesting to examine if the system will be cost-effective even with lower incomes. The specific incentive is calculated by dividing the total biomethane incomes by the yearly flow rate:

$$Biom_{incentive}\left[\frac{€}{Sm^3}\right] = \frac{375\left[\frac{€}{CIC}\right]\cdot n_{CIC} + 0.95\cdot V_{CH_4}\left[\frac{Sm^3}{y}\right]\cdot NG_{price}\left[\frac{€}{Sm^3}\right]}{V_{CH_4}\left[\frac{Sm^3}{y}\right]} = 1.0255\left[\frac{€}{Sm^3}\right] \tag{4.2}$$

The hypothesis is decreasing biomethane incentive by 30%, 40%, 50%, 60% and 70%, as shown in the table 4.4

Reduction [%]	Incentive's value [€/Sm^3]
30	0.718
40	0.615
50	0.513
60	0.410
70	0.308

Table 4.4: Variation of biomethane incentives.

4.3 Scenario 2: Variation of electricity price

The electricity cost is considerably variable with countries: this is due mainly to differences in taxes and portions of raw material used as an energy source. For this reason in the research are considered multiple prices, even in this case the value is changed in percentage: from +40% to -40% of the base case price, as specified in the table 4.5.

Variation [%]	Electricity cost [€/kWh]
+40	0.130
+20	0.112
-20	0.074
-40	0.056

Table 4.5: Variation of electricity prices.

4.4 Scenario 3: Variation of CO_2 recovery

In this scenario it is analysed the variation of carbon dioxide recovered from the methanator. This value represents the quantity of CO_2 that is directly released into the environment by the upgrading system. To study this parameter, it has been variated the electrolyser's size and so the methanator's one. Thanks to the changes described above, the volumetric flow rate of hydrogen (and therefore of carbon dioxide) that feeds the methanator is modified. The result is a decrease in biomethane produced by methanation reaction and in CO_2 captured. On the other hand, a smaller electrolyser means not only lower investment's cost but also lower plant's global electricity demand. The idea of this research is to decrease the CO_2 captured by 10% every step, the percentage is not always precise to guarantee a plausible electrolyser's size, without decimals involved. For this scenario are taken into account only the second and third base case layout, because they implicate methanation reaction. From a perspective of carbon capture, to limit greenhouse gas emissions, it is also interesting to analyse the trend of carbon dioxide released into the environment per cubic meter of biomethane sold to the grid.

Scenario 3 for B2 layout In figure 4.10 the arrows are proportional to the flow rates, as for the previous sections. Green, yellow and orange arrows represent respectively: volumetric flow rates (m^3), electricity demand (kWh) and thermal recovery (kWh). In this image are represented all the flow rates involved in the layouts for different alkaline system sizes: 400 kW, 320 kW, 260 kW, 210 kW. At first sight, it is noticed from the images that the thickness of the arrows representing inlet and outlet flows from electrolyser and methanator decreases proportionally to the electrolyser's size. As a result, also the volumetric flow rate of CO_2 released is higher step by step. Nevertheless, the carbon dioxide needed for every cubic meter of biomethane produced is inversely proportional to the size of the electrolyser (figure 4.6). This is due to the electricity demand, that will strongly influence this item: the trend is not linear for the opposite effect of carbon capture and electricity demand.

The upgrading share with respect to the total electricity demand will grow with the electrolyser's size (figure 4.7): indeed the upgrading section is constant and so the electricity that it needs, while it is not the same for the electrolyser. By the way, the predominant share is provided by the alkaline section for all sizes.

In figure 4.8 are represented the shares of methanator and upgrading system on the total biomethane sold to the grid. Even in this case, being the UPG layout constant, its share will grow as the electrolyser's size decreases.

The figure 4.9 depicts the portions of CO_2 out and CO_2 captured with respect to the total carbon dioxide produced by the upgrading system. As we can see from the percentage in the figure, this scenario and so the electrolyser's sizes have been defined to guarantee a carbon captured nearly equal to: 80%, 70%, 60% and 50%.

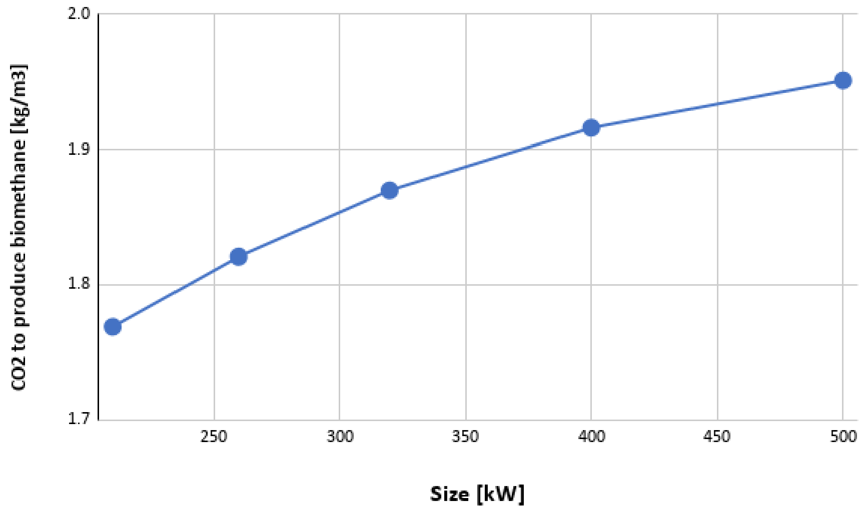
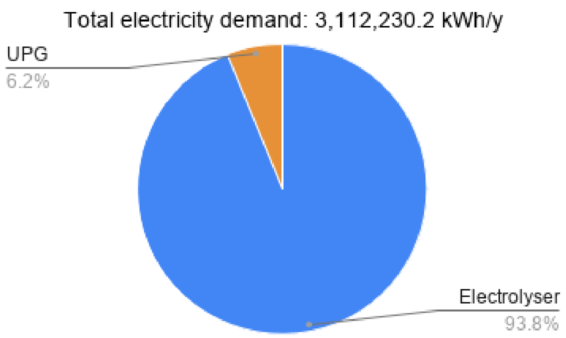
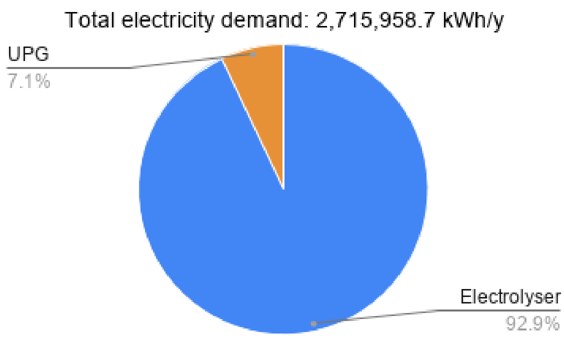


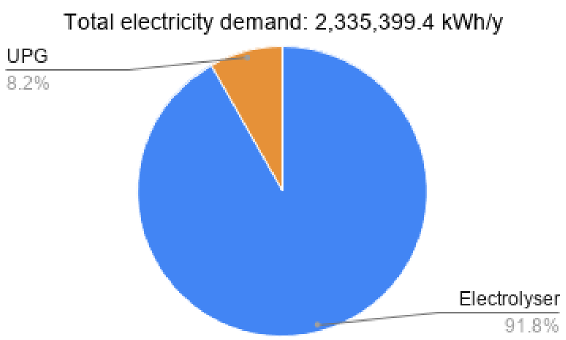
Figure 4.6: Carbon dioxide released every cubic meter of biomethane (B2).



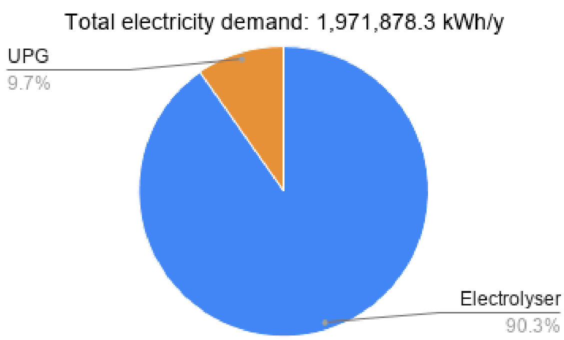
(a) 400 kW



(b) 320 kW

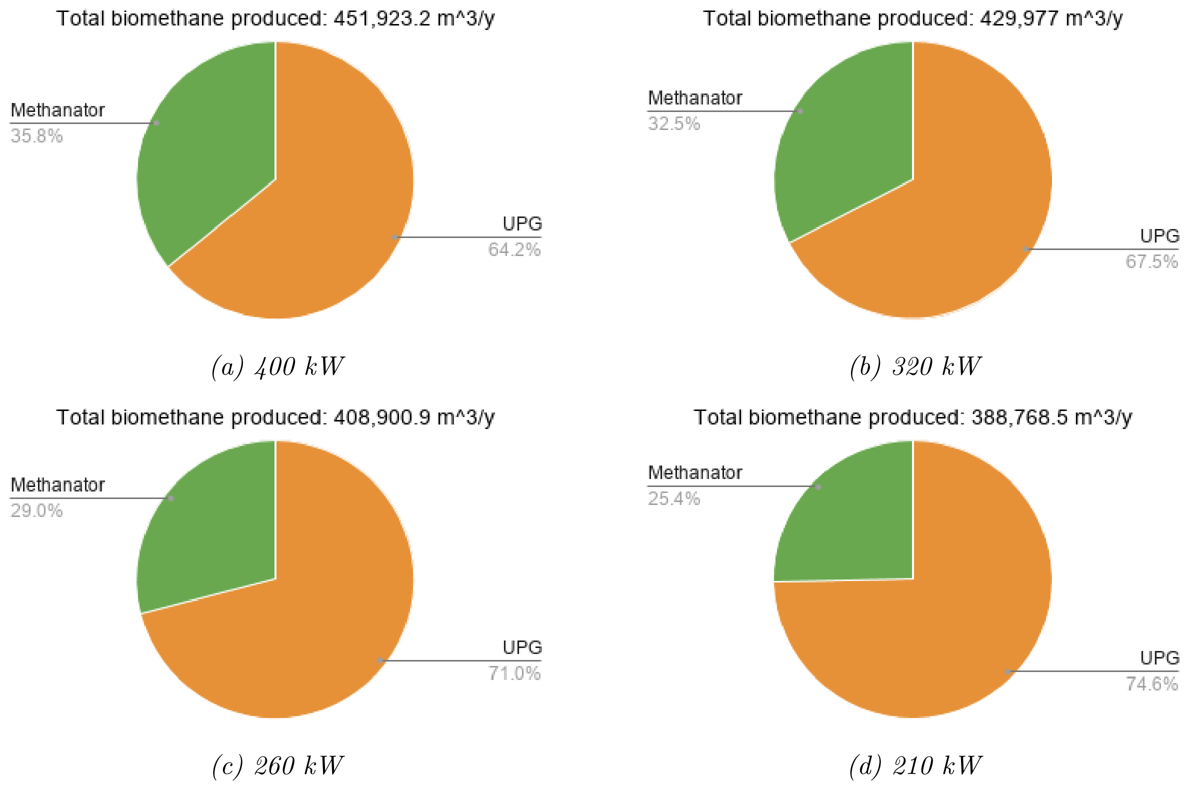


(c) 260 kW



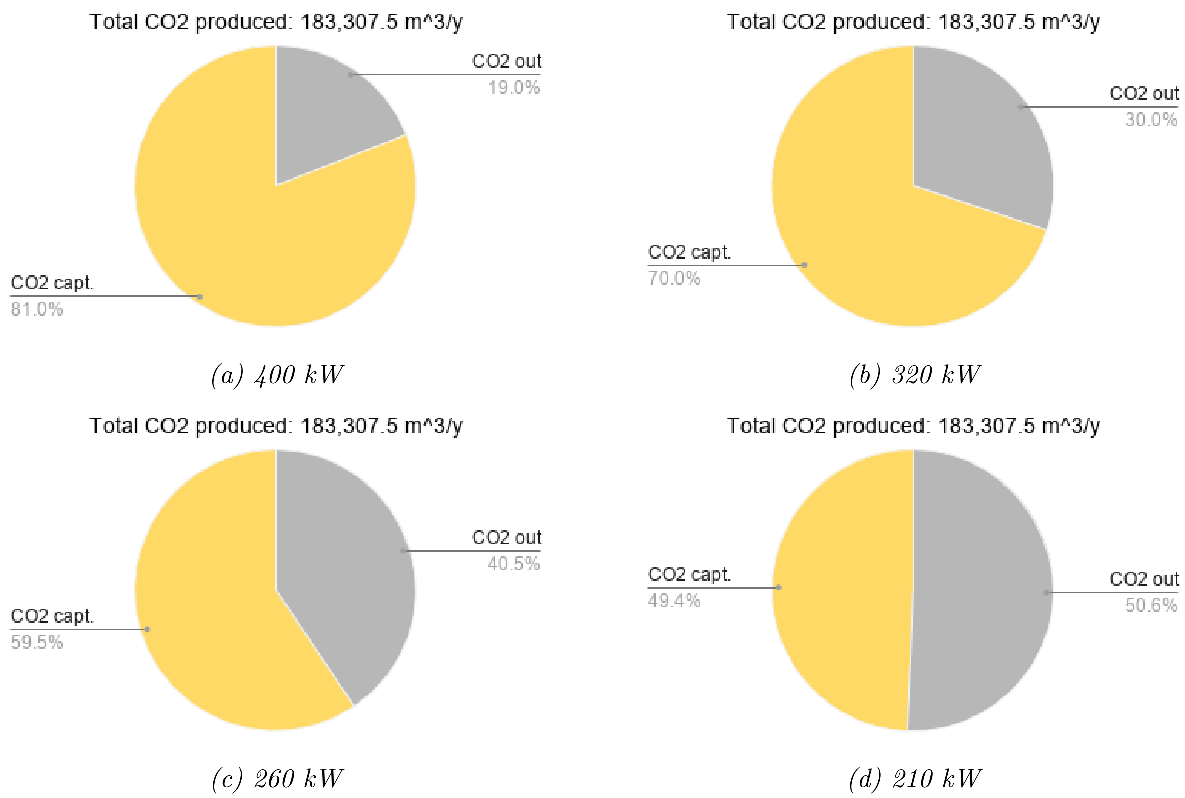
(d) 210 kW

Figure 4.7: Electricity demand share for different electrolyser's sizes (B2).



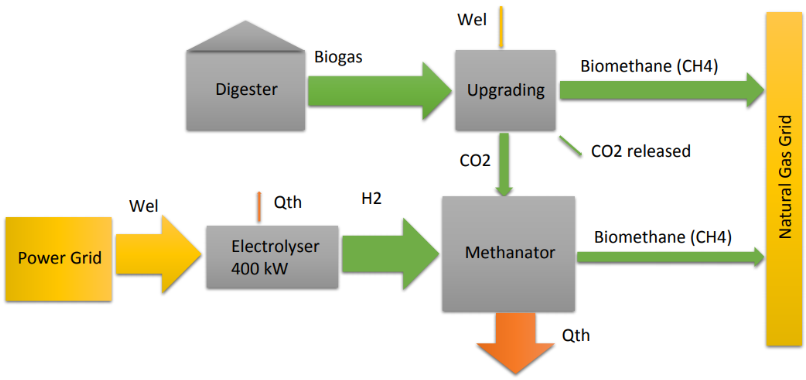
(a) 400 kW *(b) 320 kW* *(c) 260 kW* *(d) 210 kW*

Figure 4.8: Biomethane share for different electrolyser's sizes (B2).

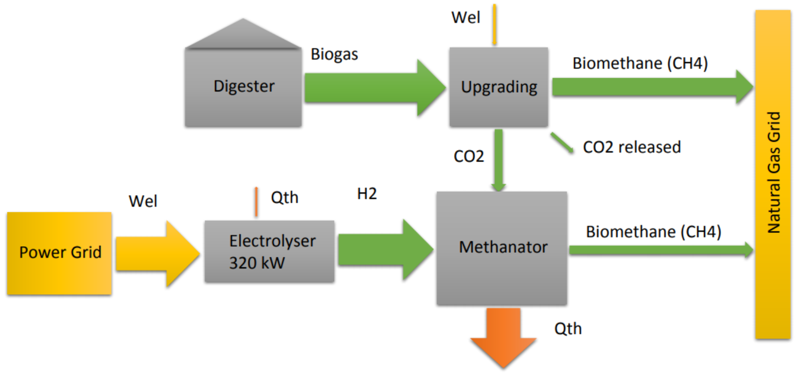


(a) 400 kW *(b) 320 kW* *(c) 260 kW* *(d) 210 kW*

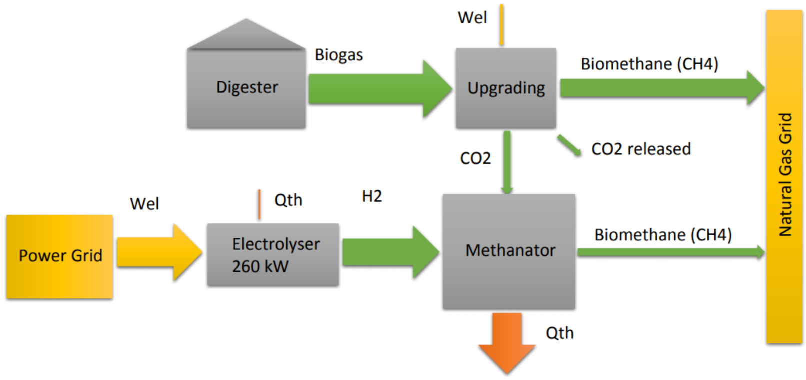
Figure 4.9: CO_2 share for different electrolyser's sizes (B2).



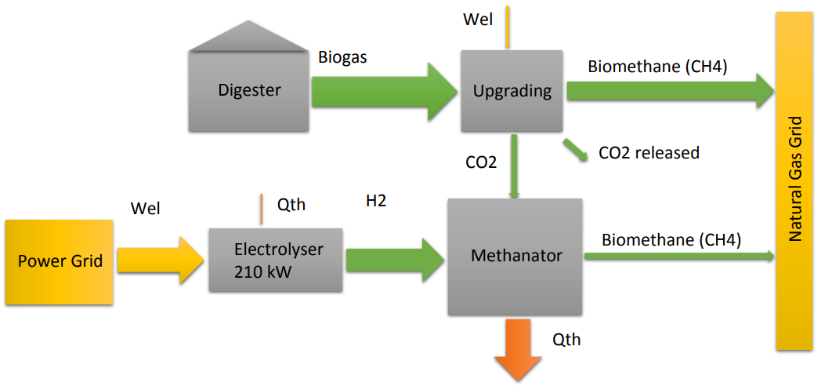
(a) 81% carbon captured



(b) 70% carbon captured



(c) 59.5% carbon captured



(d) 49.4% carbon captured

Figure 4.10: Variation of CO_2 recovery for the layout B2.

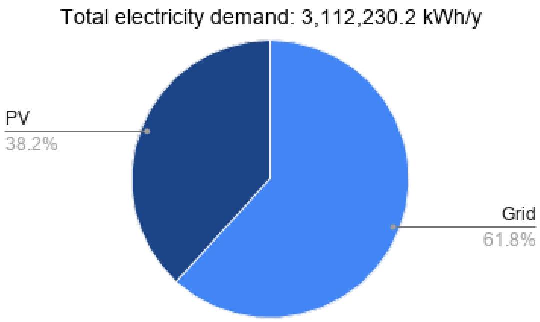
Parameter	400 [kW]	320 [kW]	260 [kW]	210 [kW]
Electricity demand from grid (Upgrading) [kWh/y]	191,695	191,695	191,695	191,695
Electricity demand from grid (Electrolyser) [kWh/y]	2,920,535	2,524,264	2,143,705	1,780,183
Biogas Volumetric flow rate [m^3/y]	479,237	479,237	479,237	479,237
Biomethane to grid (Upgrading) [m^3/y]	290,179	290,179	290,179	290,179
Biomethane to grid (Methanator) [m^3/y]	161,744	139,798	118,722	98,590
Carbon dioxide released in environment [m^3/y]	34,831	54,977	74,324	92,805
Carbon dioxide to Methanator [m^3/y]	148,477	128,331	108,983	90,502
Hydrogen to Methanator [m^3/y]	590,663	510,520	433,553	360,033
Thermal recovery (Methanator) [kWh/y]	304,222	262,944	223,303	185,436
Thermal recovery (Electrolyser) [kWh/y]	17,782	15,370	13,052	10,839
kg of CO_2 to generate 1 m^3 of biogas [$kg_{CO_2}/m^3_{Biomethane}$]	1.916	1.87	1.821	1.769

Table 4.6: Flow rates for different electrolyser's size (B2).

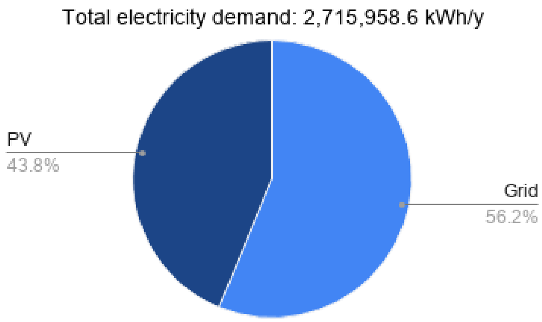
Scenario 3 for B3 layout In this paragraph, the variation of CO_2 recovery is applied to the layout B3, so it is taken into account the PV's contribution. As in previous sections, the thickness of the arrows in figure 4.13 is proportional to the flow rates represented, and green, yellow, orange colors are related respectively to volumetric flow rates [m^3], electricity flows [kWh], thermal recovery [kWh]. The only difference between this figure and the 4.10 one is the portion that symbolizes the module involving the photovoltaic system: so green and orange arrows will remain constant. The energy produced by PV is assumed to be constant for all the schemes, instead will change the electricity demand of the alkaline system. As the electrolyser's size decreases, the share of energy bought from the grid on the total electricity demand will decrease. At the same time, a higher portion of the PV's electricity will be sold to the grid and a lower one will be exploited by the electrolyser.

The figure 4.11 considers that all the PV energy is used to satisfy the electrolyser's needs, this is interesting in an energetic analysis viewpoint. As the energy produced by PV and UPG's electricity demand is constant for all the layouts, their share on the global electricity flow becomes higher with the decreasing of electrolyser's size.

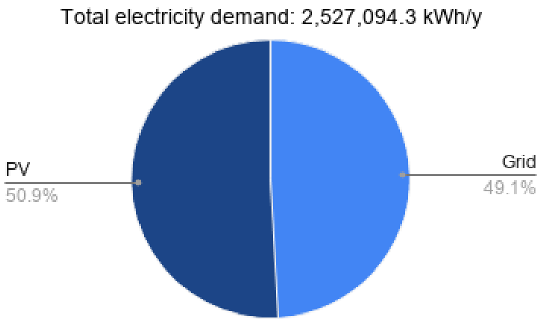
On a greenhouse gases emissions point of view, the trend of carbon dioxide released into the environment for every cubic meter of biomethane is represented in figure 4.12: in this graph is represented the comparison between base cases B2 and B3. Even if the CO_2 captured by the system grows with electrolyser's size, the carbon dioxide's mass demand to produce one m^3 of biomethane will increase as well. This behavior is due to the electricity demand: indeed, as already said, the production of grid's energy causes CO_2 emissions. The curve of this scenario (blue) increases slower than the one of the previous scenario (orange): the difference in trend is linked to the presence of PV system that guarantees a lower system's electricity demand.



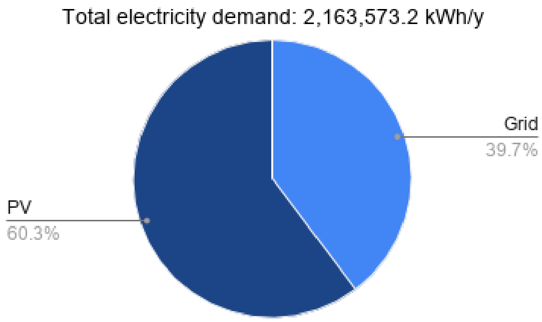
(a) 400 kW



(b) 320 kW



(c) 260 kW



(d) 210 kW

Figure 4.11: Electricity share for different electrolyser's sizes (B3).

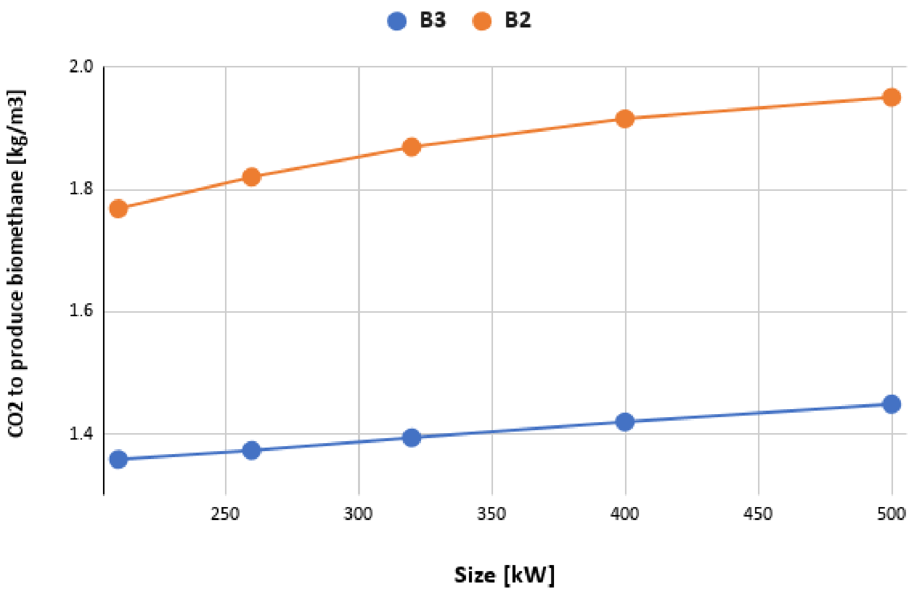
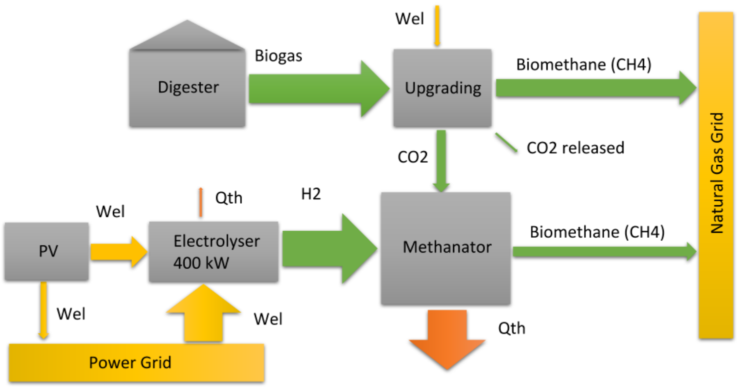
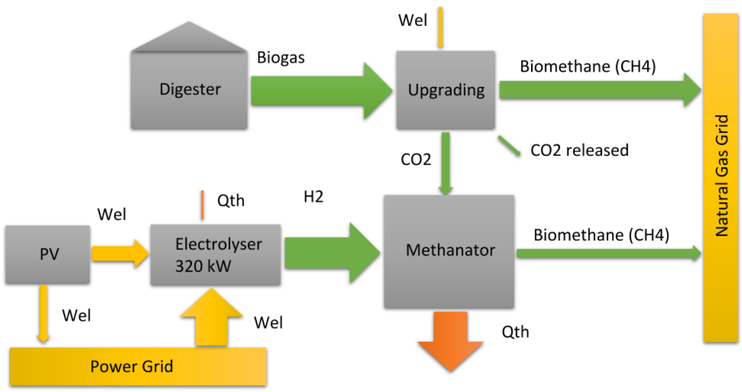


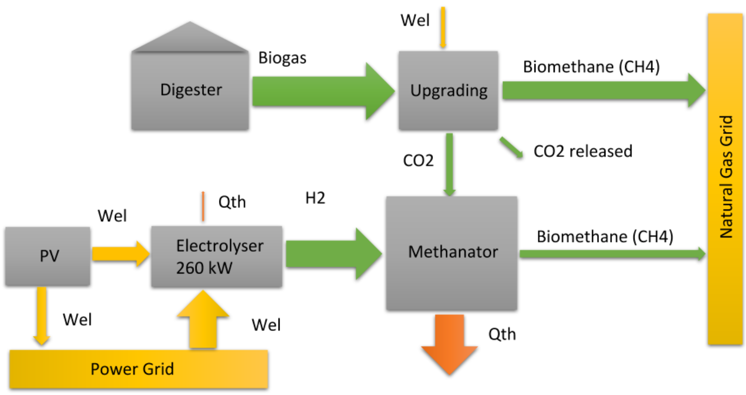
Figure 4.12: Carbon dioxide released every cubic meter of biomethane (B3-B2).



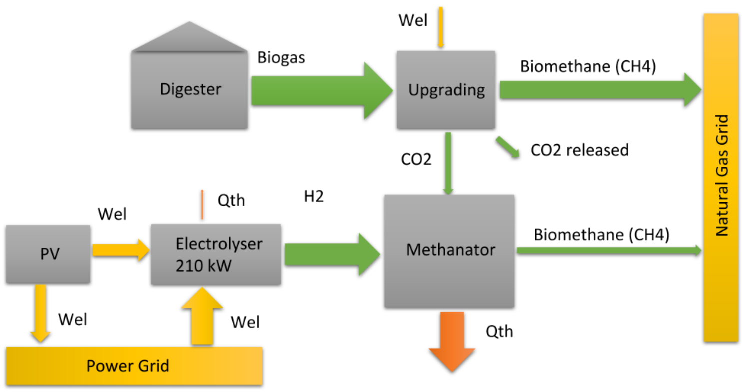
(a) 81% carbon captured



(b) 70% carbon captured



(c) 59.5% carbon captured



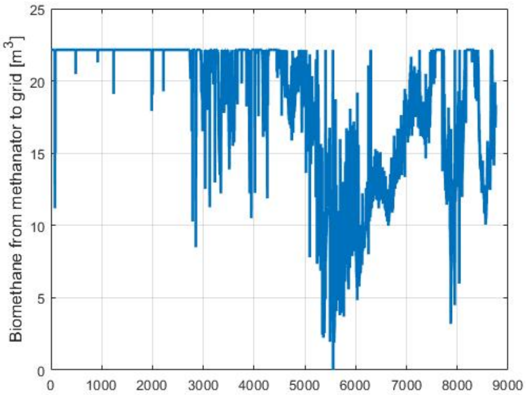
(d) 49.4% carbon captured

Figure 4.13: Variation of CO_2 recovery for the layout B3.

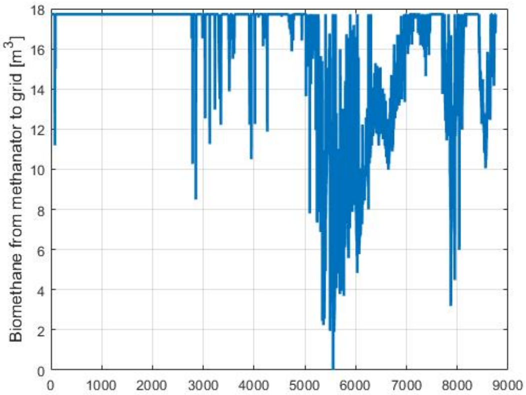
Parameter	400 [kW]	320 [kW]	260 [kW]	210 [kW]
Electricity demand from grid (Upgrading) [kWh/y]	191,695	191,695	191,695	191,695
Electricity demand from grid (Electrolyser) [kWh/y]	2,047,070	1,727,142	1,430,642	1,158,546
PV electricity to electrolyser [kWh/y]	873,465	797,122	713,063	621,638
PV electricity sold to grid [kWh/y]	315,575	391,918	475,977	567,402
Biogas Volumetric flow rate [m^3/y]	479,237	479,237	479,237	479,237
Biomethane to grid (Upgrading) [m^3/y]	290,179	290,179	290,179	290,179
Biomethane to grid (Methanator) [m^3/y]	161,744	139,798	118,722	98,590
Carbon dioxide released in environment [m^3/y]	34,831	54,977	74,324	92,805
Carbon dioxide to Methanator [m^3/y]	148,477	128,331	108,983	90,502
Hydrogen to Methanator [m^3/y]	590,663	510,520	433,553	360,033
Thermal recovery (Methanator) [kWh/y]	304,222	262,944	223,303	185,436
Thermal recovery (Electrolyser) [kWh/y]	17,782	15,370	13,052	10,839
kg of CO_2 to generate 1 m^3 of biogas [$kg_{CO_2}/m^3_{Biomethane}$]	1.421	1.395	1.374	1.359

Table 4.7: Flow rates for different electrolyser's size (B3).

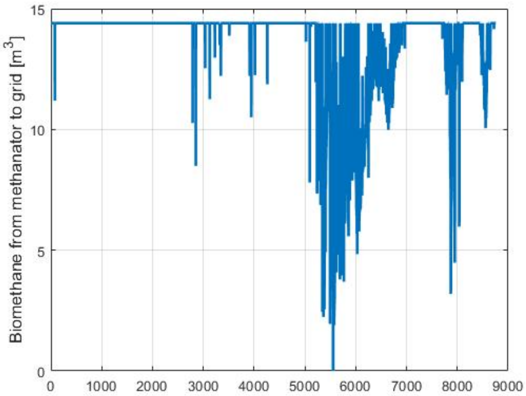
The hourly value's trend of the parameters considered in table 4.7 follows the one of the biogas flow rate (figure 3.2a). The difference is that values influenced by the electrolyser's size have a measure that they cannot exceed, moreover the trend is constant for all these parameters (Biomethane produced by methanator, CO_2 to methanator, electrolyser's electricity demand).



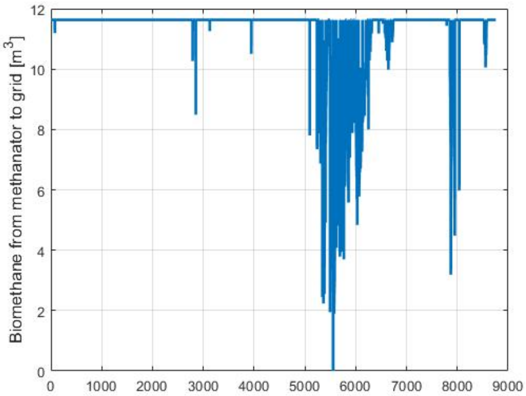
(a) 400 kW



(b) 320 kW



(c) 260 kW



(d) 210 kW

Figure 4.14: Hourly biomethane from methanator flow rate [m^3].

4.5 Scenario 4: Variation of renewable share

In order to inspect deeper the environmental impact of a carbon recovery system similar to the one studied in this research, it is interesting to analyse the trend of CO_2 released every cubic meter of biomethane produced. For this reason, it is examined the variation of PV share with respect to the total plant's electricity demand. This analysis can be done only for the third base case because it is the only one in which a PV system is included. It is supposed to keep unchanged the total electricity demand, as a result the sum of grid and PV shares is constant for every sample considered.

Chapter 5

Results

This chapter is mainly focused on the economic analysis for the different scenarios. Taxes are strongly variable state by state: so to have a study as general as possible it was decided to not include them.

5.1 Base cases

In this section are analysed the results related to the three base cases specified in the previous chapter. The operational costs are calculated considering the assumptions defined in section 3.6.5. The main parameters considered to perform the economic analysis are specified in table 5.1

Parameter	**Value**	**Unit**
Electricity price (buy)	0.093	€/kWh
Electricity price (sale)	0.09	€/kWh
Thermal energy	0.354	€/m^3
Biomethane incentive	1.026	€/m^3
CO_2 tax	50	€/ton

Table 5.1: Parameters for the economic analysis.

B1 layout For the B1 pattern, the total plant cost (CAPEX) is composed only by the upgrading system's purchasing price: 380,000 €. The operational costs are calculated considering:

- 31,200 € for the annual salary of the employee (price constant for every scenario);
- The electricity cost, that in this template is very low compared to the others, as a matter of fact, are not included electrolyser and methanator;
- The cost of carbon dioxide's tax, for the same reason as the previous point it is very high, indeed all the CO_2 produced by the upgrading system is released into the environment.

Incomes are determined by multiplying the upgrading system's biomethane (that corresponds to the total produced) by the value of the incentive. The yearly cash flow is calculated just subtracting the total costs from the total incomes. The parameter that is interesting to evaluate in economic analysis is the cumulative cash flow, composed by the sum of the cash flow related to the year of interest and the cash flows of the previous years. The payback time (PBT) is defined as the year when the cumulative cash flow becomes positive: so when the investment starts to become favorable.

For this layout the payback time is very low, this is due both to the cheap total plant cost (only UPG included) and to low operational costs (small electricity demand).

B2 layout The base case B2 presents in addition to B1 other two components: methanator and electrolyser. As a result, not only the total plant cost will be higher, but also the operational one: the electrolyser's electricity demand for this layout is very high and completely bought from the grid, this will cause a large yearly expense. In addition, there is the need to replace alkaline electrolyser's stack every 10 years: causing a drop in the cash flow analysis' curve. For the reasons listed above the plant's operational cost and CAPEX are high, and so the payback time is very large compared to the other base cases. As for the previous layout, the opex includes also the labour cost (constant) and the carbon tax. The value for the latter parameter is low because nearly 90% of the CO_2 is exploited by the methanator section.

The incomes are calculated considering selling the biomethane to the grid, at the incentivized price. Furthermore, it is supposed to sell the thermal energy recovered thanks to electrolyser and methanator to the grid. To manage thermal energy recovered it is considered to save the quantity of natural gas that will produce its same energy, therefore to exploit the hypothetical fuel in a boiler with 90% efficiency. As a result, this voice is included in the incomes, multiplying the volumetric flow rate of natural gas that is saved by its grid's purchase cost. The value is calculated thanks to the following equation:

$$\begin{aligned} Incomes\,[€/y] &= \dot{V}_{meth}\,[Sm^3/y] \cdot NG_{price}\,[€/Sm^3] \\ &= \frac{W_{th_{alk}}\,[kWh/y] + W_{th_{meth}}\,[kWh/y]}{LHV_{meth}\,[kWh/Sm^3] \cdot \eta_{boiler}} \cdot NG_{price}\,[€/Sm^3] \\ &= 37{,}225.4\,[Sm^3/y] \cdot 0.354\,[€/Sm^3] = 13{,}178\,[€/y] \end{aligned} \tag{5.1}$$

B3 layout In this configuration, it is considered to have a portion of the electricity demand supplied by a PV system. The total plant cost is the same as base case B2 because it is considered that the photovoltaic modules are already present in the scheme. This choice was taken because the PV share on the total CAPEX is predominant, especially for small electrolyser's sizes. Considering the size (500 kW) able to capture 90% of the carbon dioxide produced by the UPG system, the PV share on the total plant cost will be about 34%. For the size able to save 50% of the CO_2 (210 kW) the share increases up to 42%.

The operating expenses are the same as the B2 layout, except for the electricity's one. The energy produced by PV satisfies 34.6% of the global electricity demand, this guarantees an important yearly economical saving.

The total yearly incomes are determined not only considering to sell biomethane to the grid and to save the natural gas that matches the thermal energy recovered, but also to sell the PV's peaks at an incentivized price (90 €/MWh). As a result, with respect to B2, this layout presents lower OPEX, higher incomes and the same CAPEX.

Base cases comparison The most advantageous scenario between the three base cases is the first one: even with a very high value of the biomethane incentives, bigger production and related incomes are not enough to overcome larger CAPEX and OPEX.

In the table 5.2 are illustrated the main costs for each scenario and the results of the economic analysis: it is very interesting the difference in operational costs between case B1 and the others. Its value is about 18% of the B2 yearly OPEX and 23% of the B3 one. Another point that is clearly notable from the table is that the voice influencing more the operational cost is the one related to electricity demand.

The net present value (NPV) is the total earning referred to the last year of the plant's lifetime, the highest value is also this time the B1 scheme's one, followed by B3 and B2 as it is specified in the table 5.2.

In figure 5.1 are drawn the curves representing the cash flow analysis for the three cases, the trend reflects the expectations: B1 is economically the most convenient layout and is a straight line (no need to replace the stack). The PV share guarantees the second place for the B3 scheme, indeed the lower grid's electricity demand, and the higher incomes ensure a curve with a larger slope. The trend of B1 and B3 are nearly parallel because the yearly cash flows are almost equal (table 5.2).

	Parameter	**B1**	**B2**	**B3**
OPEX	Electrolyser [€/y]	0	21,704.5	21,704.5
	Methanator [€/y]	0	59.8	59.8
	Labour cost [€/y]	31,200	31,200	31,200
	CO_2 price [€/y]	18,028	1,780	1,780
	C_{Wel} [€/y]	17,828	320,046	234,480
	Stack Replacement [€/10y]	0	189,915	189,915
CAPEX	Upgrading [€]	380,000	380,000	380,000
	Methanator [€]	0	273,210	273,210
	Electrolyser [€]	0	542,614	542,614
Economic Analysis	Tot Opex [€/y]	67,056	374,791	289,225
	Tot Opex (with Stack rep) [€/10y]		564,705	479,139
	nCIC	533	864	864
	Incomes [€/y]	297,587	495,325	519,532
	Cash flow [€/y]	230,531	120,534	230,308
	NPV [€]	4,230,613	1,024,941	3,220,417
	PBT [years]	1.65	11.50	5.19

Table 5.2: Economic analysis' results for base cases.

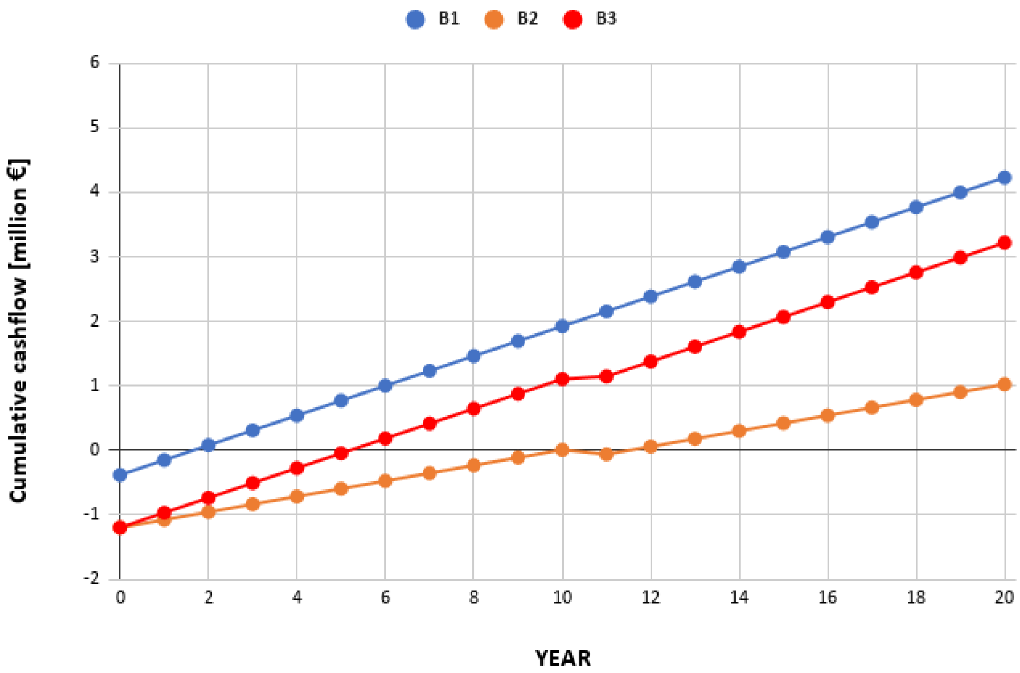


Figure 5.1: Cash flow analysis for base cases.

5.2 Scenario 1

The first scenario is related to the variation of biomethane incentives, for this reason energetic fluxes are the same as base cases. The differences are related to the economic analysis, indeed changing the biomethane incentives will influence total incomes and so parameters that are calculated from them, such as: yearly cash flow, net present value and payback time. It was decided to consider only lower incentives than the value examined in the base cases, this because the GSE's incentives are favorable. Furthermore the analysis has been stopped at the first incentive's decrease not able to guarantee a return on the investment.

B1 layout In the B1 scheme the slope of the cumulative cash flow curve decreases proportionally to the value of the incentive (figure 5.2). In this layout, thanks to the low operational costs, in all the cases considered is guaranteed the return of the investment. Nevertheless, in the hypothesis of decreasing the incentive by 70%, the NPV at the end of the lifetime will be only around 64,000 €. In figure 5.3 it is analysed the evolution of PBT related to different values of the incentive, red dashed line represents the grid's natural gas cost. This curve is built by considering two further decreases in the incentive compared to figure 5.2. This is done to guarantee a better view of the analysis. It is notable that without incentives the plant will not be advantageous from an economical point of view. In the table 5.3 are added to table 5.2 regarding economic analysis' results, the parameters that are changed for the different values of the incentive.

Parameter	-30%	-50%	-70%
Biomethane Incentive [€/Sm^3]	0.718	0.513	0.308
Incomes [€/y]	208,311	148,793	89,276
Cash flow [€/y]	141,255	81,737	22,220
NPV [€]	2,445,094	1,254,747	64,401
PBT [years]	2.69	4.65	17.10

Table 5.3: Parameters for the economic analysis (S1-B1).

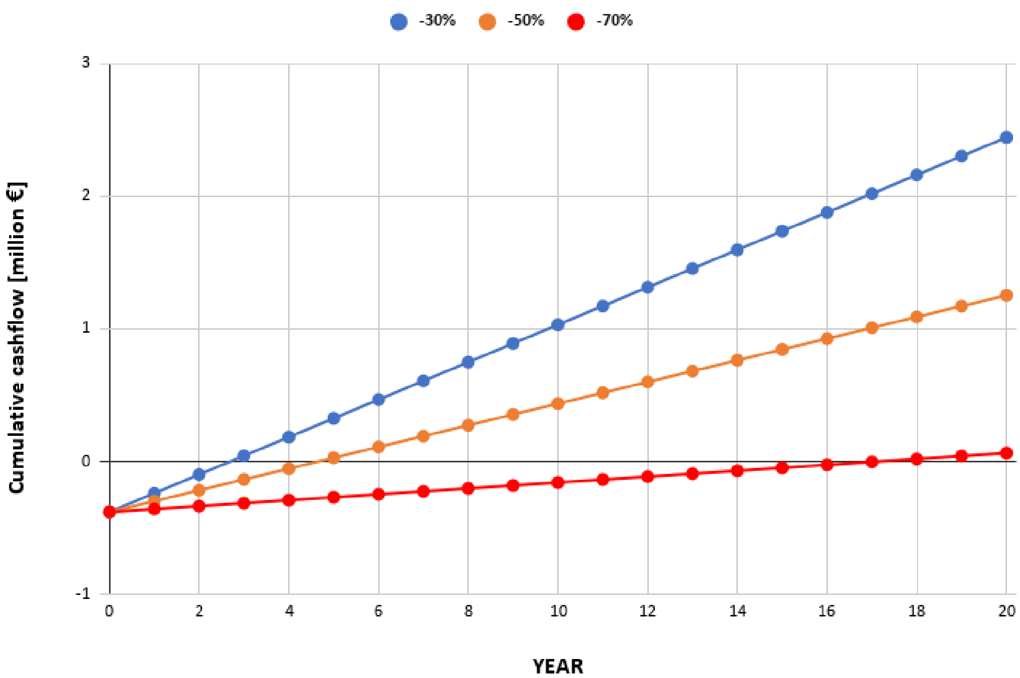


Figure 5.2: Cash flow analysis S1, for B1 layout. Variation of the biomethane incentive.

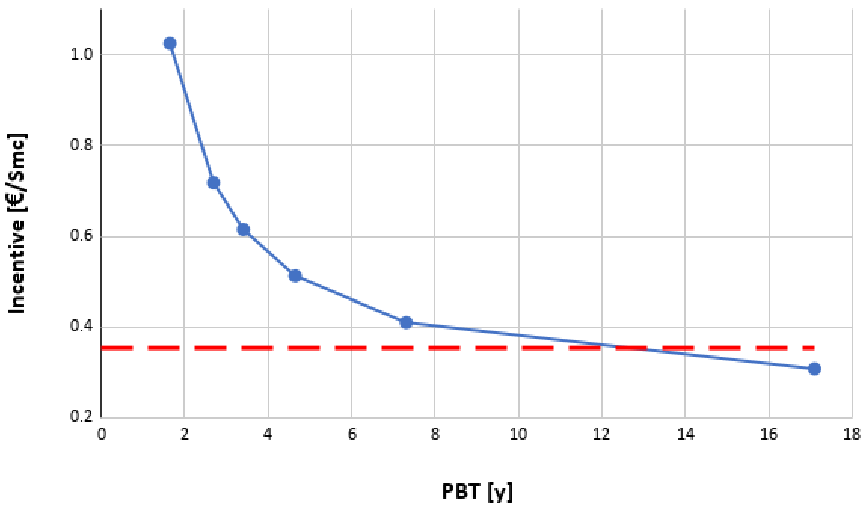


Figure 5.3: Incentive vs PBT (S1-B1). Red dashed line represents the grid's natural gas cost.

B2 layout As already seen in the previous section, the B2 scheme is economically the worst. This trend is maintained also in the present scenario: reducing biomethane incentives by 30% the plant will not be profitable. No return in the investment is achieved in all the lifetime and the curve representing cumulative cash flow decreases every year. This is due to the fact that the yearly cash flow is negative: incomes are lower than operating expenses. So are not calculated, for this layout, further lower percentages of the incentive.

Parameter	**-30%**
Biomethane Incentive [€/Sm^3]	0.718
Tot Opex [€/y]	374,791
Tot Opex (with Stack rep) [€/10y]	564,705
Incomes [€/y]	350,679
Cash flow [€/y]	-24,112

Table 5.4: Parameters for the economic analysis (S1-B2).

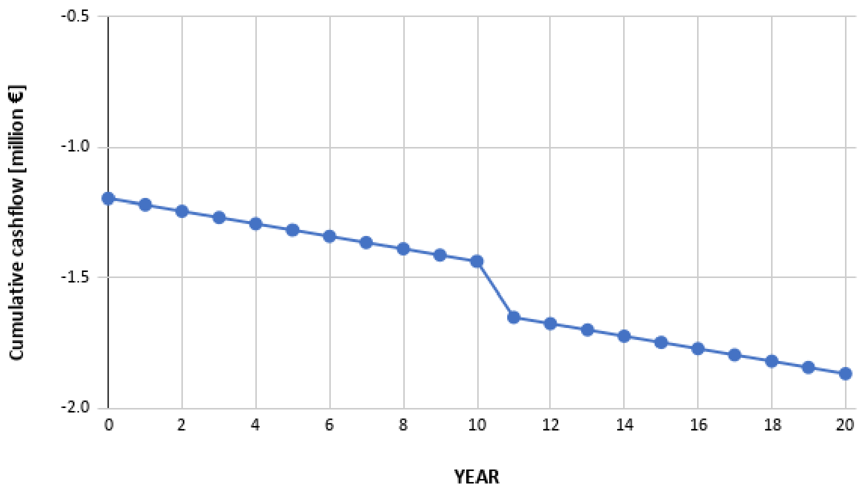


Figure 5.4: Cash flow analysis S1, for B2 layout.

B3 layout The scheme including PV modules guarantees higher incomes and lower costs than the previous one. The figure 5.5 illustrates the influence of the incentive's decrease on the cumulative cash flow. With a biomethane incentive 30% lower than the present one, there is still a return on the investment but at the end of the lifetime. Decreasing by further 10% the value of the incentive, no payback time is guaranteed. However, the cumulative cash flow curve's trend is increasing year by year: incomes are higher than operational costs and so the yearly cash flow is positive.

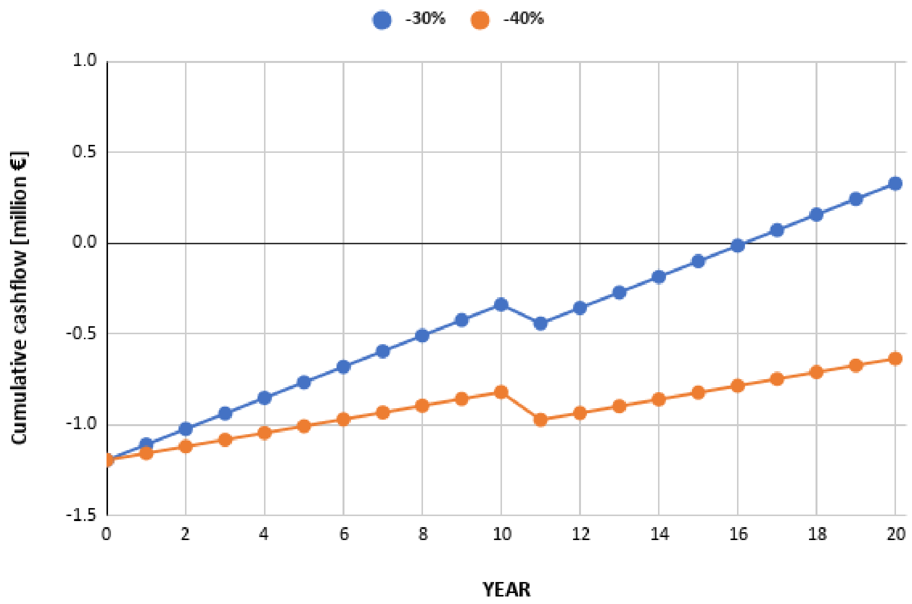


Figure 5.5: Cash flow analysis S1, for B3 layout.

Parameter	-30%	-40%
Biomethane Incentive [€/Sm^3]	0.718	0.615
Tot Opex [€/y]	289,225	289,225
Tot Opex (with Stack rep) [€/10y]	479,139	479,139
Incomes [€/y]	374,887	326,671
Cash flow [€/y]	85,662	37,447
NPV [€]	327,500	
PBT [years]	16.18	

Table 5.5: Parameters for the economic analysis (S1-B3).

5.3 Scenario 2

In this scenario is analysed the variation of the electricity price. As already mentioned, this research has been managed because the price of energy is significantly variable state by state. The electricity cost is changed form +40% to -40% with respect to the Italian one.

B1 layout This scheme without electrolyser presents a very low electricity demand, involving very little differences between cumulative cash flow curves. As a result, it has been decided to consider only the borderline cases with +40% and -40% electricity price's variation. To understand how low is the influence of this parameter in the first layout it is interesting to have a look to the net present value at the end of the lifetime. The difference in NPV between the two cases analysed is only the 6.5%. In this paragraph is not included the graph representing the variation of PBT, indeed its value presents a difference between the two cases only about 36 days.

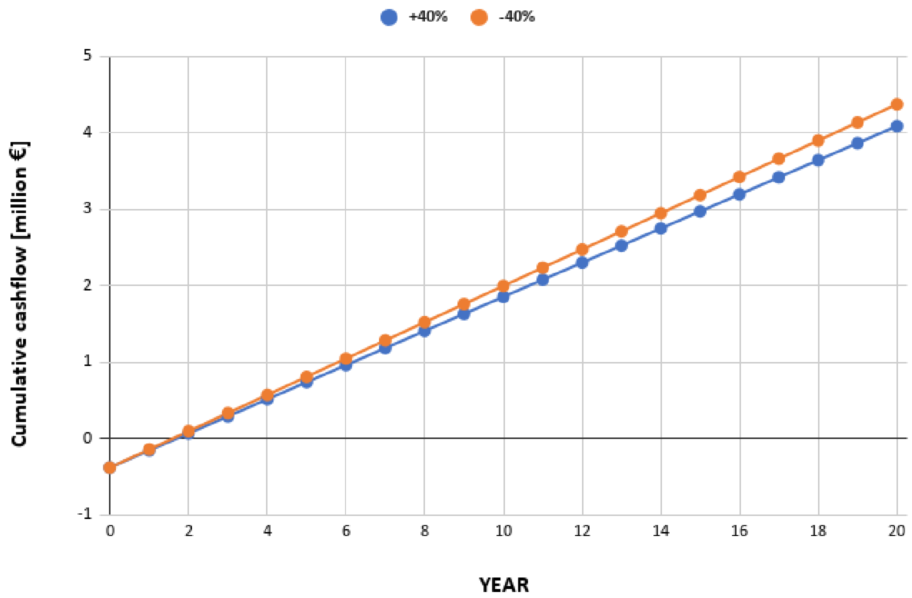


Figure 5.6: Cash flow analysis S2, for B1 layout.

Parameter	**+40%**	**-40%**
Electricity price (buy) [€/kWh]	0.130	0.056
Tot Opex [€/y]	74,187	59,925
Incomes [€/y]	297,587	297,587
Cash flow [€/y]	223,400	237,662
NPV [€]	4,087,992	4,373,234
PBT [years]	1.70	1.60

Table 5.6: Parameters for the economic analysis (S2-B1).

B2 layout This configuration is the most sensitive to electricity price variation. Indeed it includes the electrolyser, which electricity demand is totally fulfilled by the grid. In figure 5.7 is clear that in the two configurations where the electricity is cheaper than in the base case, the cumulative cash flow curves increase strongly every year, with low payback time involved. Instead, in the configuration presenting higher electricity cost, there is no return on investment. The trend of the curve with price variation +40% is even decreasing: this is due to a negative yearly cash flow. In figure 5.8 is represented the changing in payback time with respect to electricity price variation. The trend is not linear: the final NPV decreases for every step by 1,280,186 €, causing a variable curve's tendency.

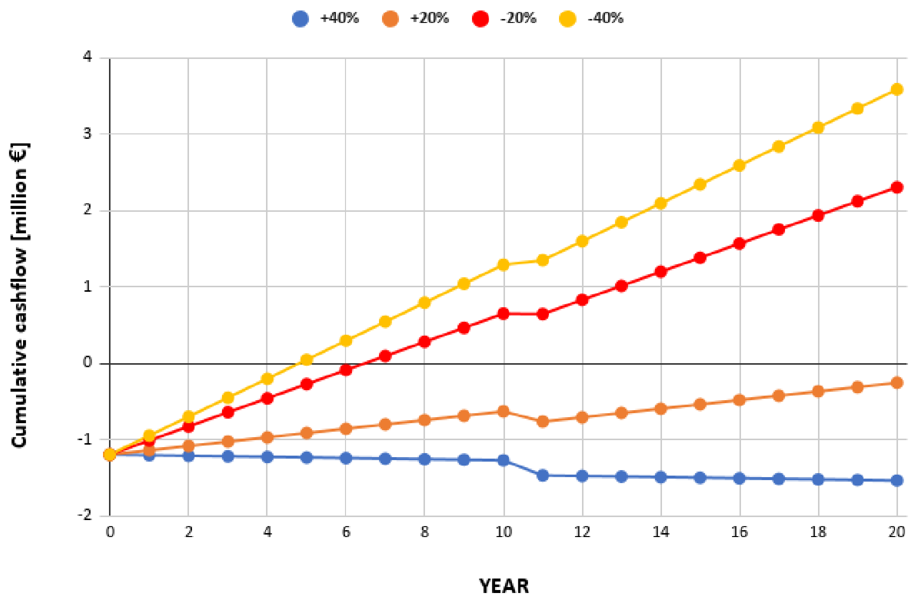


Figure 5.7: Cash flow analysis S2, for B2 layout.

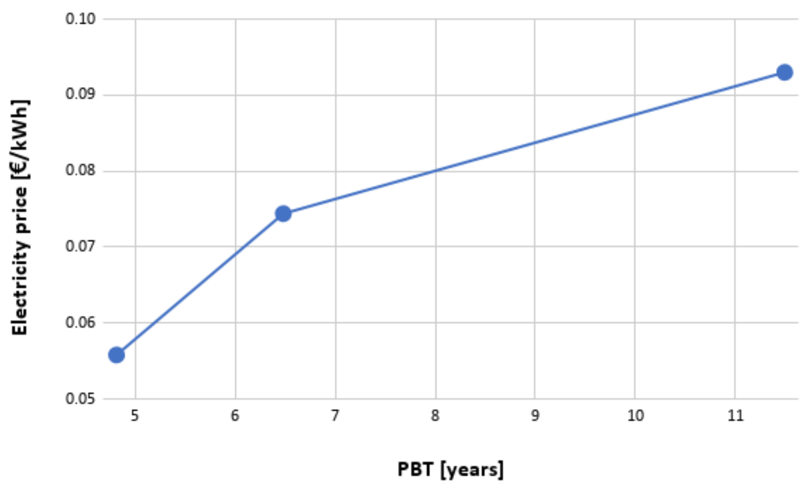


Figure 5.8: Cost of electricity vs PBT (S2-B2).

Parameter	**+40%**	**+20%**	**-20%**	**-40%**
Electricity price (buy) [€/kWh]	0.130	0.112	0.074	0.056
Tot Opex [€/y]	502,809	438,800	310,781	246,772
Tot Opex (with Stack rep) [€/10y]	692,724	628,715	500,696	436,687
Incomes [€/y]	495,325	495,325	495,325	495,325
Cash flow [€/y]	-7,485	56,525	184,543	248,553
NPV [€]			2,305,127	3,585,313
PBT [years]			6.48	4.81

Table 5.7: Parameters for the economic analysis (S2-B2).

B3 layout In this configuration the electricity demand is partially satisfied by the PV modules: for this reason it is less influenced by the cost of the electricity than the previous layout. As it is illustrated in the figure 5.9, in all the cases the system guarantees a return on the investment. The difference in net present value between every step is 937,922 €, moreover the starting point with respect to B2 case is significantly better. Also for this configuration the variation in payback time concerning the parameter of interest is not linear, for the same reasons of the previous layout.

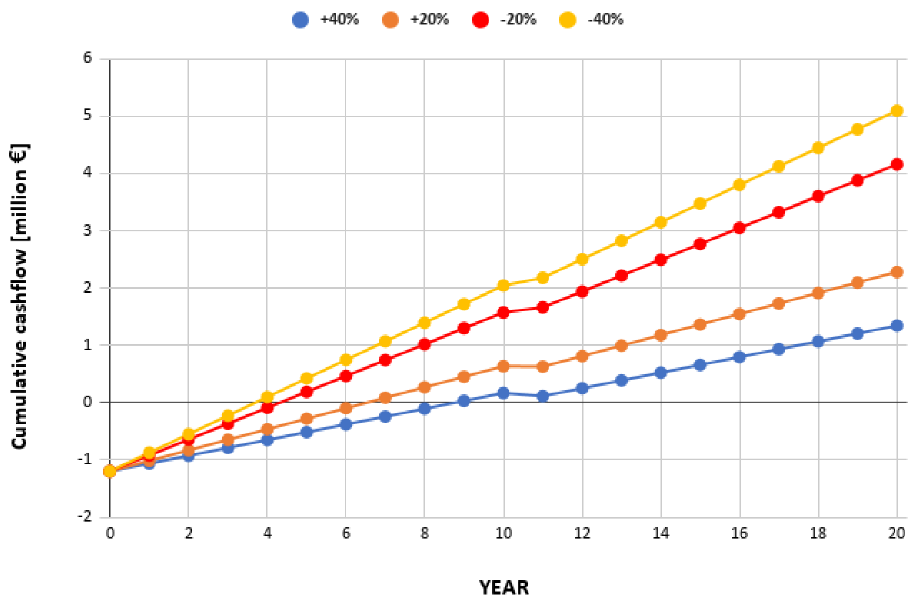


Figure 5.9: Cash flow analysis S2, for B3 layout.

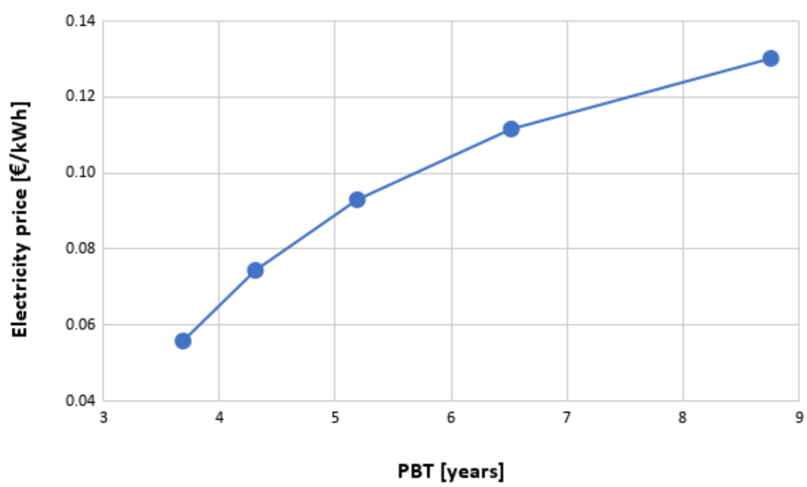


Figure 5.10: Cost of electricity vs PBT (S2-B3).

Parameter	+40%	+20%	-20%	-40%
Electricity price (buy) [€/kWh]	0.130	0.112	0.074	0.056
Tot Opex [€/y]	383,017	336,121	242,329	195,433
Tot Opex (with Stack rep) [€/10y]	572,932	526,036	432,243	385,347
Incomes [€/y]	519,532	519,532	519,532	519,532
Cash flow [€/y]	136,516	183,412	277,204	324,100
NPV [€]	1,344,574	2,282,495	4,158,339	5,096,261
PBT [years]	8.76	6.52	4.31	3.69

Table 5.8: Parameters for the economic analysis (S2-B3).

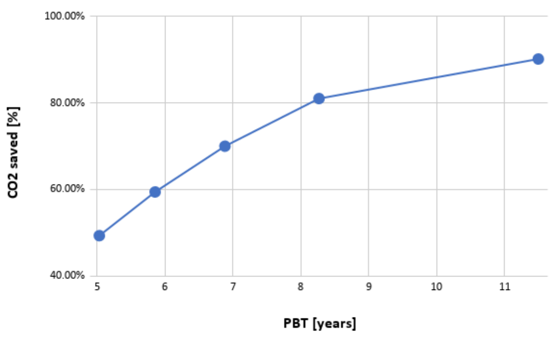
5.4 Scenario 3

In the third scenario is examined the variation of carbon dioxide recovery by changing the electrolyser's size. Its dimensions are decreased about 10% each step, trying to keep plausible sizes. The base case B1 cannot be examined because it is composed only by the upgrading system and the other two cases are analysed together because they present small differences in cumulative cash flow trend. In this scenario also the CAPEX is different for every scheme: this is due to the variation of electrolyser and methanator sizes. The method used to calculate the different purchasing costs have been illustrated in section 3.6.5. Furthermore, changing the electrolyser cost causes a modification of the price for the stack replacement, also the equation used to calculate this value is specified in the section previously mentioned.

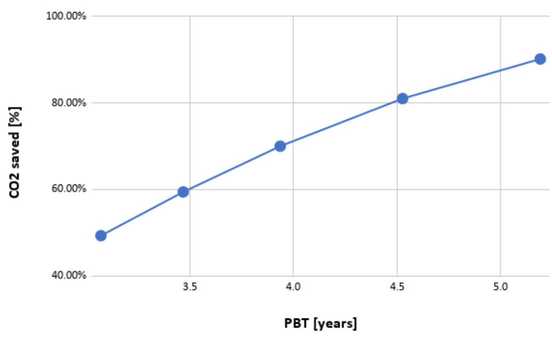
Carbon dioxide captured and electricity demand decrease with alkaline system's dimension. This means that the carbon tax will be higher step by step and, on the contrary, the cost for electricity will be lower. The influence of the latter parameter on the operational cost is stronger than the one of the first term, this trend, added to the stack replacement cost, causes a decreasing in the OPEX with components' sizes.

Incomes are ensured mainly by the biomethane sold to the grid. Reducing the electrolyser size will diminish the biomethane produced by the methanation reaction. As a result incomes are lower step by step. The curves in figure 5.12 and 5.13 show that the cumulative cash flow is higher for lower elecrolyser's size: this is due to the fact that incomes decrease slower than operational costs.

For this scenario CAPEX related to base cases B2 and B3 are the same every step. B2 is more sensible to sizes variation because all the electricity demand is bought from the grid. As a result the differences in net present values are stronger for the second than for the third base case and at the same time the NPV is higher for the last case. This means more linear PBT every step considered as illustrated in figure 5.11.



(a) layout B2



(b) layout B3

Figure 5.11: CO_2 saved vs PBT.

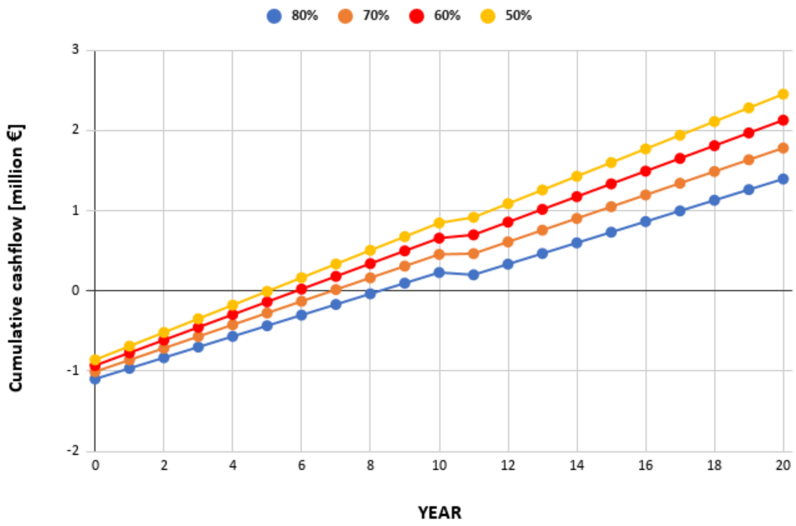


Figure 5.12: Cash flow analysis S3, for B2 layout.

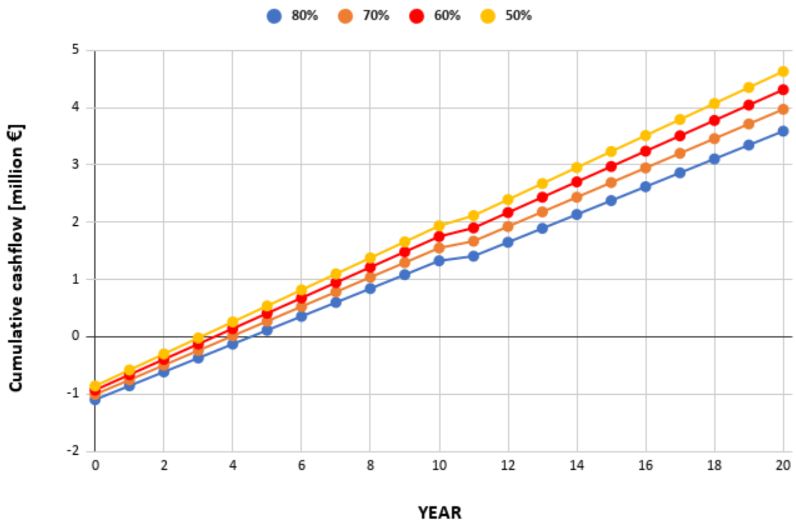


Figure 5.13: Cash flow analysis S3, for B3 layout.

Parameter	81%	70%	60%	50%
Electrolyser's size [kW]	400	320	260	210
CAPEX meth [€]	256,254	234,787	212,859	190,402
CAPEX electr [€]	461,048	391,744	336,646	288,047
Total CAPEX [€]	1,097,302	1,006,531	929,505	858,449
Tot Opex [€/y]	342,565	304,921	242,329	235,294
Tot Opex (with Stack rep) [€/10y]	503,932	442,031	269,228	336,110
nCIC	831	790	752	715
Incomes [€/y]	475,298	451,185	387,054	405,909
Cash flow [€/y]	132,733	146,264	158,801	170,615
NPV [€]	1,395,989	1,781,646	2,128,686	2,453,031
PBT [years]	8.27	6.88	5.85	5.03

Table 5.9: Parameters for the economic analysis (S3-B2).

Parameter	81%	70%	60%	50%
Electrolyser's size [kW]	400	320	260	210
CAPEX meth [€]	256,254	234,787	212,859	190,402
CAPEX electr [€]	461,048	391,744	336,646	288,047
Total CAPEX [€]	1,097,302	1,006,531	929,505	858,449
Tot Opex [€/y]	261,332	230,788	202,913	177,481
Tot Opex (with Stack rep) [€/10y]	422,699	367,899	320,739	278,298
nCIC	831	790	752	715
Incomes [€/y]	503,699	486,458	470,866	456,975
Cash flow [€/y]	242,367	255,669	267,954	279,493
NPV [€]	3,588,669	3,969,745	4,311,741	4,630,601
PBT [years]	4.53	3.94	3.47	3.07

Table 5.10: Parameters for the economic analysis (S3-B3).

5.5 Scenario 4

The last scenario is focused on the variation of the renewable share. In figure 5.14 the specific mass' trend of carbon dioxide released for the different PV shares considered in the study is analysed. The horizontal red dashed line represents the value of CO_2 released by the national grid for every cubic meter of natural gas produced. In table 5.11 we can notice that the trend of CO_2 released every biomethane's cubic meter is inversely proportional to the PV share. From the share represented by the third row on, the specific carbon dioxide's mass released into the environment is lower than in the first base case. This means that, from this point on, the plant is less polluting in terms of greenhouse gases than the one without methanation. The third to last row is highlighted because the carbon dioxide released at this share is equal to the value needed to produce one cubic meter of grid's natural gas (0.76615 [14]): so if the portion of electricity demand satisfied by PV is equal or higher than 63.18%, the CO_2 released per cubic meter of biomethane is lower with respect to the one produced by grid's natural gas. The results founded in this scenario are very promising on an environmental point of view and paves the way for future researches.

Share [%]	Grid's electricity demand [kWh/y]	PV energy [kWh/y]	CO_2 released [kg_{CO_2}/m^3_{biom}]
0	3,441,360	0	1.951
26.7	2,521,295	920,064.5	1.45
28.8	2,450,248	991,112	1.41
40	2,064,816	1,376,544	1.201
50	1,720,680	1,720,680	1.013
63.18	1,267,005	2,174,354	0.76615
70	1,032,408	2,408,952	0.638
80	688,272	2,753,088	0.451

Table 5.11: Variation of PV share.

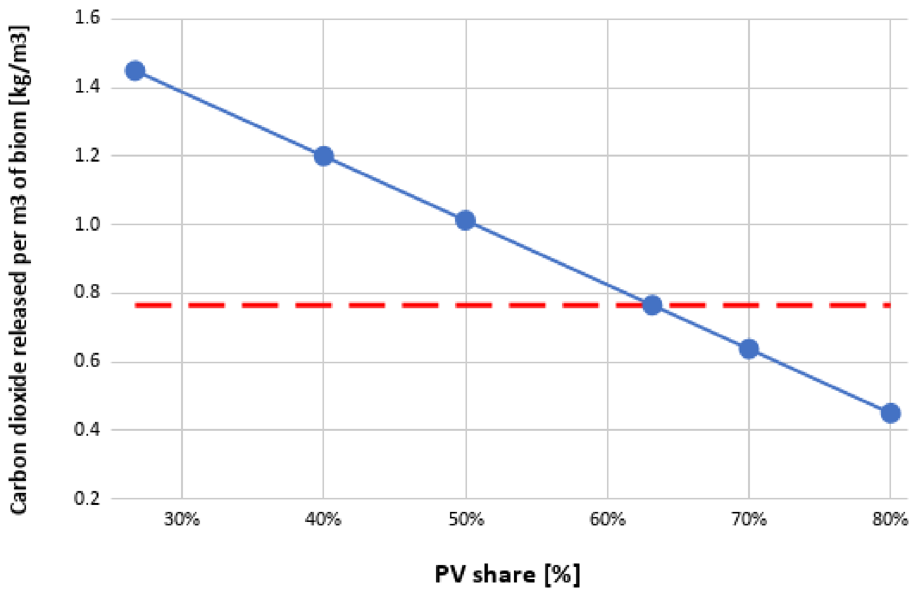


Figure 5.14: Carbon dioxide released per cubic meter of biomethane for different PV shares. Red dashed line represents the CO_2 released to produce grid's natural gas.

Conclusions

The aim of this master thesis work is the techno-economic analysis of carbon recovery, through upgrading and methanation, from a medium-sized wastewater treatment plant (WWTP). The study has been developed considering three base cases to better understand the effect of the system's components in the final results. In the first base case, it was considered to include in the layout only the upgrading system, in the second are added methanator and electrolyser, and in the last one PV modules. For these cases have been studied multiple scenarios, changing some of the main parameters: scenario S1 is related to the variation of the biomethane incentives; S2 is focused on the effect of electricity cost on the results; S3 takes into account different amounts of CO_2 captured, and so multiple electrolyser's sizes; the last scenario (S4) helps to study the effects of the PV energy share on the quantity of CO_2 released into the environment.

Results founded show that this kind of plant is more interesting from an environmental point of view than from an economical one. Increasing the CO_2 exploited by the methanation reactor will produce a decrease in the cumulative cash flow, furthermore the most favorable layout from an economic perspective is the one including only the upgrading system. The electrolyser needs a huge amount of electricity to produce hydrogen used in the methanator reactor. The cost to satisfy the electricity demand is higher than the incomes guaranteed by the increased biomethane production, even for favorable incentives.

From the research has been deduced that CO_2 released into the environment for every cubic meter of biomethane is lower in configurations with smaller electrolyser's size, and so lower CO_2 captured by methanator. This is due to the electricity consumption, indeed it was considered also the carbon dioxide released to produce grid's electricity.

The plant releases less carbon dioxide per cubic meter of biomethane than that needed to produce grid's natural gas, from the 63.18% of PV energy share on.

In conclusion, biogas to biomethane upgrading can be a very promising way to store renewable energy fluctuations using the natural gas grid. The hypothesis to capture the carbon dioxide that is produced by the upgrading system is environmental friendly only if the share of renewable energy on the total electrolyser's electricity demand is higher than 60%.

Appendix A

Cash flow analysis tables

year [€/y]	Costs [€/y]	Incomes [€/y]	Cashflow [€/y]	Cum [€/y]
0	-380,000	0	-380,000	-380,000
1	-67,055.92	297,586.58	230,530.66	-149,469.34
2	-67,055.92	297,586.58	230,530.66	81,061.31
3	-67,055.92	297,586.58	230,530.66	311,591.97
4	-67,055.92	297,586.58	230,530.66	542,122.63
5	-67,055.92	297,586.58	230,530.66	772,653.29
6	-67,055.92	297,586.58	230,530.66	1,003,183.95
7	-67,055.92	297,586.58	230,530.66	1,233,714.60
8	-67,055.92	297,586.58	230,530.66	1,464,245.26
9	-67,055.92	297,586.58	230,530.66	1,694,775.92
10	-67,055.92	297,586.58	230,530.66	1,925,306.57
11	-67,055.92	297,586.58	230,530.66	2,155,837.23
12	-67,055.92	297,586.58	230,530.66	2,386,367.89
13	-67,055.92	297,586.58	230,530.66	2,616,898.55
14	-67,055.92	297,586.58	230,530.66	2,847,429.20
15	-67,055.92	297,586.58	230,530.66	3,077,959.86
16	-67,055.92	297,586.58	230,530.66	3,308,490.52
17	-67,055.92	297,586.58	230,530.66	3,539,021.18
18	-67,055.92	297,586.58	230,530.66	3,769,551.83
19	-67,055.92	297,586.58	230,530.66	4,000,082.49
20	-67,055.92	297,586.58	230,530.66	4,230,613.15

Table A.1: Cumulative cash flow (B1).

year [€/y]	Costs [€/y]	Incomes [€/y]	Cashflow [€/y]	Cum [€/y]
0	-1,195,823.40	0	-1,195,823.40	-1,195,823.40
1	-374,790.72	495,324.70	120,533.98	-1,075,289.42
2	-374,790.72	495,324.70	120,533.98	-954,755.45
3	-374,790.72	495,324.70	120,533.98	-834,221.47
4	-374,790.72	495,324.70	120,533.98	-713,687.49
5	-374,790.72	495,324.70	120,533.98	-593,153.52
6	-374,790.72	495,324.70	120,533.98	-472,619.54
7	-374,790.72	495,324.70	120,533.98	-352,085.56
8	-374,790.72	495,324.70	120,533.98	-231,551.59
9	-374,790.72	495,324.70	120,533.98	-111,017.61
10	-374,790.72	495,324.70	120,533.98	9,516.37
11	-564,705.42	495,324.70	-69,380.72	-59,864.36
12	-374,790.72	495,324.70	120,533.98	60,669.62
13	-374,790.72	495,324.70	120,533.98	181,203.60
14	-374,790.72	495,324.70	120,533.98	301,737.57
15	-374,790.72	495,324.70	120,533.98	422,271.55
16	-374,790.72	495,324.70	120,533.98	542,805.53
17	-374,790.72	495,324.70	120,533.98	663,339.50
18	-374,790.72	495,324.70	120,533.98	783,873.48
19	-374,790.72	495,324.70	120,533.98	904,407.46
20	-374,790.72	495,324.70	120,533.98	1,024,941.43

Table A.2: Cumulative cash flow (B2).

year [€/y]	Costs [€/y]	Incomes [€/y]	Cashflow [€/y]	Cum [€/y]
0	-1,195,823.40	0	-1,195,823.40	-1,195,823.40
1	-289,224.72	519,532.49	230,307.77	-965,515.63
2	-289,224.72	519,532.49	230,307.77	-735,207.86
3	-289,224.72	519,532.49	230,307.77	-504,900.09
4	-289,224.72	519,532.49	230,307.77	-274,592.32
5	-289,224.72	519,532.49	230,307.77	-44,284.55
6	-289,224.72	519,532.49	230,307.77	186,023.22
7	-289,224.72	519,532.49	230,307.77	416,330.99
8	-289,224.72	519,532.49	230,307.77	646,638.76
9	-289,224.72	519,532.49	230,307.77	876,946.53
10	-289,224.72	519,532.49	230,307.77	1,107,254.30
11	-479,139.42	519,532.49	40,393.07	1,147,647.37
12	-289,224.72	519,532.49	230,307.77	1,377,955.14
13	-289,224.72	519,532.49	230,307.77	1,608,262.91
14	-289,224.72	519,532.49	230,307.77	1,838,570.68
15	-289,224.72	519,532.49	230,307.77	2,068,878.45
16	-289,224.72	519,532.49	230,307.77	2,299,186.22
17	-289,224.72	519,532.49	230,307.77	2,529,493.99
18	-289,224.72	519,532.49	230,307.77	2,759,801.76
19	-289,224.72	519,532.49	230,307.77	2,990,109.53
20	-289,224.72	519,532.49	230,307.77	3,220,417.30

Table A.3: Cumulative cash flow (B3).

year [€/y]	Costs [€/y]	Incomes [€/y]	Cashflow [€/y]	Cum [€/y]
0	-380,000.00	0	-380,000.00	-380,000.00
1	-67,055.92	208,310.60	141,254.68	-238,745.32
2	-67,055.92	208,310.60	141,254.68	-97,490.63
3	-67,055.92	208,310.60	141,254.68	43,764.05
4	-67,055.92	208,310.60	141,254.68	185,018.74
5	-67,055.92	208,310.60	141,254.68	326,273.42
6	-67,055.92	208,310.60	141,254.68	467,528.11
7	-67,055.92	208,310.60	141,254.68	608,782.79
8	-67,055.92	208,310.60	141,254.68	750,037.48
9	-67,055.92	208,310.60	141,254.68	891,292.16
10	-67,055.92	208,310.60	141,254.68	1,032,546.85
11	-67,055.92	208,310.60	141,254.68	1,173,801.53
12	-67,055.92	208,310.60	141,254.68	1,315,056.22
13	-67,055.92	208,310.60	141,254.68	1,456,310.90
14	-67,055.92	208,310.60	141,254.68	1,597,565.59
15	-67,055.92	208,310.60	141,254.68	1,738,820.27
16	-67,055.92	208,310.60	141,254.68	1,880,074.96
17	-67,055.92	208,310.60	141,254.68	2,021,329.64
18	-67,055.92	208,310.60	141,254.68	2,162,584.33
19	-67,055.92	208,310.60	141,254.68	2,303,839.01
20	-67,055.92	208,310.60	141,254.68	2,445,093.69

Table A.4: Cumulative cash flow (S1-B1 30%).

year [€/y]	Costs [€/y]	Incomes [€/y]	Cashflow [€/y]	Cum [€/y]
0	-380,000.00	0	-380,000.00	-380,000.00
1	-67,055.92	178,551.95	111,496.03	-268,503.97
2	-67,055.92	178,551.95	111,496.03	-157,007.95
3	-67,055.92	178,551.95	111,496.03	-45,511.92
4	-67,055.92	178,551.95	111,496.03	65,984.11
5	-67,055.92	178,551.95	111,496.03	177,480.14
6	-67,055.92	178,551.95	111,496.03	288,976.16
7	-67,055.92	178,551.95	111,496.03	400,472.19
8	-67,055.92	178,551.95	111,496.03	511,968.22
9	-67,055.92	178,551.95	111,496.03	623,464.24
10	-67,055.92	178,551.95	111,496.03	734,960.27
11	-67,055.92	178,551.95	111,496.03	846,456.30
12	-67,055.92	178,551.95	111,496.03	957,952.33
13	-67,055.92	178,551.95	111,496.03	1,069,448.35
14	-67,055.92	178,551.95	111,496.03	1,180,944.38
15	-67,055.92	178,551.95	111,496.03	1,292,440.41
16	-67,055.92	178,551.95	111,496.03	1,403,936.43
17	-67,055.92	178,551.95	111,496.03	1,515,432.46
18	-67,055.92	178,551.95	111,496.03	1,626,928.49
19	-67,055.92	178,551.95	111,496.03	1,738,424.52
20	-67,055.92	178,551.95	111,496.03	1,849,920.54

Table A.5: Cumulative cash flow (S1-B1 40%).

year [€/y]	Costs [€/y]	Incomes [€/y]	Cashflow [€/y]	Cum [€/y]
0	-380,000.00	0	-380,000.00	-380,000.00
1	-67,055.92	148,793.29	81,737.37	-298,262.63
2	-67,055.92	148,793.29	81,737.37	-216,525.26
3	-67,055.92	148,793.29	81,737.37	-134,787.89
4	-67,055.92	148,793.29	81,737.37	-53,050.52
5	-67,055.92	148,793.29	81,737.37	28,686.85
6	-67,055.92	148,793.29	81,737.37	110,424.22
7	-67,055.92	148,793.29	81,737.37	192,161.59
8	-67,055.92	148,793.29	81,737.37	273,898.96
9	-67,055.92	148,793.29	81,737.37	355,636.33
10	-67,055.92	148,793.29	81,737.37	437,373.70
11	-67,055.92	148,793.29	81,737.37	519,111.07
12	-67,055.92	148,793.29	81,737.37	600,848.43
13	-67,055.92	148,793.29	81,737.37	682,585.80
14	-67,055.92	148,793.29	81,737.37	764,323.17
15	-67,055.92	148,793.29	81,737.37	846,060.54
16	-67,055.92	148,793.29	81,737.37	927,797.91
17	-67,055.92	148,793.29	81,737.37	1,009,535.28
18	-67,055.92	148,793.29	81,737.37	1,091,272.65
19	-67,055.92	148,793.29	81,737.37	1,173,010.02
20	-67,055.92	148,793.29	81,737.37	1,254,747.39

Table A.6: Cumulative cash flow (S1-B1 50%).

year [€/y]	Costs [€/y]	Incomes [€/y]	Cashflow [€/y]	Cum [€/y]
0	-380,000.00	0	-380,000.00	-380,000.00
1	-67,055.92	119,034.63	51,978.71	-328,021.29
2	-67,055.92	119,034.63	51,978.71	-276,042.58
3	-67,055.92	119,034.63	51,978.71	-224,063.86
4	-67,055.92	119,034.63	51,978.71	-172,085.15
5	-67,055.92	119,034.63	51,978.71	-120,106.44
6	-67,055.92	119,034.63	51,978.71	-68,127.73
7	-67,055.92	119,034.63	51,978.71	-16,149.02
8	-67,055.92	119,034.63	51,978.71	35,829.70
9	-67,055.92	119,034.63	51,978.71	87,808.41
10	-67,055.92	119,034.63	51,978.71	139,787.12
11	-67,055.92	119,034.63	51,978.71	191,765.83
12	-67,055.92	119,034.63	51,978.71	243,744.54
13	-67,055.92	119,034.63	51,978.71	295,723.26
14	-67,055.92	119,034.63	51,978.71	347,701.97
15	-67,055.92	119,034.63	51,978.71	399,680.68
16	-67,055.92	119,034.63	51,978.71	451,659.39
17	-67,055.92	119,034.63	51,978.71	503,638.10
18	-67,055.92	119,034.63	51,978.71	555,616.82
19	-67,055.92	119,034.63	51,978.71	607,595.53
20	-67,055.92	119,034.63	51,978.71	659,574.24

Table A.7: Cumulative cash flow (S1-B1 60%).

year [€/y]	Costs [€/y]	Incomes [€/y]	Cashflow [€/y]	Cum [€/y]
0	-380,000.00	0	-380,000.00	-380,000.00
1	-67,055.92	89,275.97	22,220.05	-357,779.95
2	-67,055.92	89,275.97	22,220.05	-335,559.89
3	-67,055.92	89,275.97	22,220.05	-313,339.84
4	-67,055.92	89,275.97	22,220.05	-291,119.78
5	-67,055.92	89,275.97	22,220.05	-268,899.73
6	-67,055.92	89,275.97	22,220.05	-246,679.67
7	-67,055.92	89,275.97	22,220.05	-224,459.62
8	-67,055.92	89,275.97	22,220.05	-202,239.56
9	-67,055.92	89,275.97	22,220.05	-180,019.51
10	-67,055.92	89,275.97	22,220.05	-157,799.46
11	-67,055.92	89,275.97	22,220.05	-135,579.40
12	-67,055.92	89,275.97	22,220.05	-113,359.35
13	-67,055.92	89,275.97	22,220.05	-91,139.29
14	-67,055.92	89,275.97	22,220.05	-68,919.24
15	-67,055.92	89,275.97	22,220.05	-46,699.18
16	-67,055.92	89,275.97	22,220.05	-24,479.13
17	-67,055.92	89,275.97	22,220.05	-2,259.08
18	-67,055.92	89,275.97	22,220.05	19,960.98
19	-67,055.92	89,275.97	22,220.05	42,181.03
20	-67,055.92	89,275.97	22,220.05	64,401.09

Table A.8: Cumulative cash flow (S1-B1 70%).

year [€/y]	Costs [€/y]	Incomes [€/y]	Cashflow [€/y]	Cum [€/y]
0	-1,195,823.40	0	-1,195,823.40	-1,195,823.40
1	-374,790.72	350,678.83	-24,111.89	-1,219,935.29
2	-374,790.72	350,678.83	-24,111.89	-1,244,047.18
3	-374,790.72	350,678.83	-24,111.89	-1,268,159.08
4	-374,790.72	350,678.83	-24,111.89	-1,292,270.97
5	-374,790.72	350,678.83	-24,111.89	-1,316,382.86
6	-374,790.72	350,678.83	-24,111.89	-1,340,494.75
7	-374,790.72	350,678.83	-24,111.89	-1,364,606.64
8	-374,790.72	350,678.83	-24,111.89	-1,388,718.53
9	-374,790.72	350,678.83	-24,111.89	-1,412,830.42
10	-374,790.72	350,678.83	-24,111.89	-1,436,942.32
11	-564,705.42	350,678.83	-214,026.59	-1,650,968.91
12	-374,790.72	350,678.83	-24,111.89	-1,675,080.80
13	-374,790.72	350,678.83	-24,111.89	-1,699,192.69
14	-374,790.72	350,678.83	-24,111.89	-1,723,304.58
15	-374,790.72	350,678.83	-24,111.89	-1,747,416.47
16	-374,790.72	350,678.83	-24,111.89	-1,771,528.37
17	-374,790.72	350,678.83	-24,111.89	-1,795,640.26
18	-374,790.72	350,678.83	-24,111.89	-1,819,752.15
19	-374,790.72	350,678.83	-24,111.89	-1,843,864.04
20	-374,790.72	350,678.83	-24,111.89	-1,867,975.93

Table A.9: Cumulative cash flow (S1-B2 30%).

year [€/y]	Costs [€/y]	Incomes [€/y]	Cashflow [€/y]	Cum [€/y]
0	-1,195,823.40	0	-1,195,823.40	-1,195,823.40
1	-289,224.72	374,886.62	85,661.90	-1,110,161.50
2	-289,224.72	374,886.62	85,661.90	-1,024,499.60
3	-289,224.72	374,886.62	85,661.90	-938,837.69
4	-289,224.72	374,886.62	85,661.90	-853,175.79
5	-289,224.72	374,886.62	85,661.90	-767,513.89
6	-289,224.72	374,886.62	85,661.90	-681,851.99
7	-289,224.72	374,886.62	85,661.90	-596,190.09
8	-289,224.72	374,886.62	85,661.90	-510,528.18
9	-289,224.72	374,886.62	85,661.90	-424,866.28
10	-289,224.72	374,886.62	85,661.90	-339,204.38
11	-479,139.42	374,886.62	-104,252.80	-443,457.18
12	-289,224.72	374,886.62	85,661.90	-357,795.28
13	-289,224.72	374,886.62	85,661.90	-272,133.37
14	-289,224.72	374,886.62	85,661.90	-186,471.47
15	-289,224.72	374,886.62	85,661.90	-100,809.57
16	-289,224.72	374,886.62	85,661.90	-15,147.67
17	-289,224.72	374,886.62	85,661.90	70,514.23
18	-289,224.72	374,886.62	85,661.90	156,176.13
19	-289,224.72	374,886.62	85,661.90	241,838.04
20	-289,224.72	374,886.62	85,661.90	327,499.94

Table A.10: Cumulative cash flow (S1-B3 30%).

year [€/y]	Costs [€/y]	Incomes [€/y]	Cashflow [€/y]	Cum [€/y]
0	-1,195,823.40	0	-1,195,823.40	-1,195,823.40
1	-289,224.72	326,671.33	37,446.61	-1,158,376.79
2	-289,224.72	326,671.33	37,446.61	-1,120,930.18
3	-289,224.72	326,671.33	37,446.61	-1,083,483.56
4	-289,224.72	326,671.33	37,446.61	-1,046,036.95
5	-289,224.72	326,671.33	37,446.61	-1,008,590.34
6	-289,224.72	326,671.33	37,446.61	-971,143.72
7	-289,224.72	326,671.33	37,446.61	-933,697.11
8	-289,224.72	326,671.33	37,446.61	-896,250.50
9	-289,224.72	326,671.33	37,446.61	-858,803.89
10	-289,224.72	326,671.33	37,446.61	-821,357.27
11	-479,139.42	326,671.33	-152,468.09	-973,825.36
12	-289,224.72	326,671.33	37,446.61	-936,378.75
13	-289,224.72	326,671.33	37,446.61	-898,932.14
14	-289,224.72	326,671.33	37,446.61	-861,485.52
15	-289,224.72	326,671.33	37,446.61	-824,038.91
16	-289,224.72	326,671.33	37,446.61	-786,592.30
17	-289,224.72	326,671.33	37,446.61	-749,145.69
18	-289,224.72	326,671.33	37,446.61	-711,699.07
19	-289,224.72	326,671.33	37,446.61	-674,252.46
20	-289,224.72	326,671.33	37,446.61	-636,805.85

Table A.11: Cumulative cash flow (S1-B3 40%).

year [€/y]	Costs [€/y]	Incomes [€/y]	Cashflow [€/y]	Cum [€/y]
0	-380,000.00	0	-380,000.00	-380,000.00
1	-74,186.97	297,586.58	223,399.61	-156,600.39
2	-74,186.97	297,586.58	223,399.61	66,799.21
3	-74,186.97	297,586.58	223,399.61	290,198.82
4	-74,186.97	297,586.58	223,399.61	513,598.43
5	-74,186.97	297,586.58	223,399.61	736,998.04
6	-74,186.97	297,586.58	223,399.61	960,397.64
7	-74,186.97	297,586.58	223,399.61	1,183,797.25
8	-74,186.97	297,586.58	223,399.61	1,407,196.86
9	-74,186.97	297,586.58	223,399.61	1,630,596.46
10	-74,186.97	297,586.58	223,399.61	1,853,996.07
11	-74,186.97	297,586.58	223,399.61	2,077,395.68
12	-74,186.97	297,586.58	223,399.61	2,300,795.29
13	-74,186.97	297,586.58	223,399.61	2,524,194.89
14	-74,186.97	297,586.58	223,399.61	2,747,594.50
15	-74,186.97	297,586.58	223,399.61	2,970,994.11
16	-74,186.97	297,586.58	223,399.61	3,194,393.72
17	-74,186.97	297,586.58	223,399.61	3,417,793.32
18	-74,186.97	297,586.58	223,399.61	3,641,192.93
19	-74,186.97	297,586.58	223,399.61	3,864,592.54
20	-74,186.97	297,586.58	223,399.61	4,087,992.14

Table A.12: Cumulative cash flow (S2-B1 +40%).

year [€/y]	Costs [€/y]	Incomes [€/y]	Cashflow [€/y]	Cum [€/y]
0	-380,000.00	0	-380,000.00	-380,000.00
1	-70,621.44	297,586.58	226,965.13	-153,034.87
2	-70,621.44	297,586.58	226,965.13	73,930.26
3	-70,621.44	297,586.58	226,965.13	300,895.40
4	-70,621.44	297,586.58	226,965.13	527,860.53
5	-70,621.44	297,586.58	226,965.13	754,825.66
6	-70,621.44	297,586.58	226,965.13	981,790.79
7	-70,621.44	297,586.58	226,965.13	1,208,755.93
8	-70,621.44	297,586.58	226,965.13	1,435,721.06
9	-70,621.44	297,586.58	226,965.13	1,662,686.19
10	-70,621.44	297,586.58	226,965.13	1,889,651.32
11	-70,621.44	297,586.58	226,965.13	2,116,616.46
12	-70,621.44	297,586.58	226,965.13	2,343,581.59
13	-70,621.44	297,586.58	226,965.13	2,570,546.72
14	-70,621.44	297,586.58	226,965.13	2,797,511.85
15	-70,621.44	297,586.58	226,965.13	3,024,476.99
16	-70,621.44	297,586.58	226,965.13	3,251,442.12
17	-70,621.44	297,586.58	226,965.13	3,478,407.25
18	-70,621.44	297,586.58	226,965.13	3,705,372.38
19	-70,621.44	297,586.58	226,965.13	3,932,337.51
20	-70,621.44	297,586.58	226,965.13	4,159,302.65

Table A.13: Cumulative cash flow (S2-B1 +20%).

year [€/y]	Costs [€/y]	Incomes [€/y]	Cashflow [€/y]	Cum [€/y]
0	-380,000.00	0	-380,000.00	-380,000.00
1	-63,490.39	297,586.58	234,096.18	-145,903.82
2	-63,490.39	297,586.58	234,096.18	88,192.37
3	-63,490.39	297,586.58	234,096.18	322,288.55
4	-63,490.39	297,586.58	234,096.18	556,384.73
5	-63,490.39	297,586.58	234,096.18	790,480.91
6	-63,490.39	297,586.58	234,096.18	1,024,577.10
7	-63,490.39	297,586.58	234,096.18	1,258,673.28
8	-63,490.39	297,586.58	234,096.18	1,492,769.46
9	-63,490.39	297,586.58	234,096.18	1,726,865.64
10	-63,490.39	297,586.58	234,096.18	1,960,961.83
11	-63,490.39	297,586.58	234,096.18	2,195,058.01
12	-63,490.39	297,586.58	234,096.18	2,429,154.19
13	-63,490.39	297,586.58	234,096.18	2,663,250.37
14	-63,490.39	297,586.58	234,096.18	2,897,346.56
15	-63,490.39	297,586.58	234,096.18	3,131,442.74
16	-63,490.39	297,586.58	234,096.18	3,365,538.92
17	-63,490.39	297,586.58	234,096.18	3,599,635.10
18	-63,490.39	297,586.58	234,096.18	3,833,731.29
19	-63,490.39	297,586.58	234,096.18	4,067,827.47
20	-63,490.39	297,586.58	234,096.18	4,301,923.65

Table A.14: Cumulative cash flow (S2-B1 -20%).

year [€/y]	Costs [€/y]	Incomes [€/y]	Cashflow [€/y]	Cum [€/y]
0	-380,000.00	0	-380,000.00	-380,000.00
1	-59,924.87	297,586.58	237,661.71	-142,338.29
2	-59,924.87	297,586.58	237,661.71	95,323.42
3	-59,924.87	297,586.58	237,661.71	332,985.12
4	-59,924.87	297,586.58	237,661.71	570,646.83
5	-59,924.87	297,586.58	237,661.71	808,308.54
6	-59,924.87	297,586.58	237,661.71	1,045,970.25
7	-59,924.87	297,586.58	237,661.71	1,283,631.95
8	-59,924.87	297,586.58	237,661.71	1,521,293.66
9	-59,924.87	297,586.58	237,661.71	1,758,955.37
10	-59,924.87	297,586.58	237,661.71	1,996,617.08
11	-59,924.87	297,586.58	237,661.71	2,234,278.79
12	-59,924.87	297,586.58	237,661.71	2,471,940.49
13	-59,924.87	297,586.58	237,661.71	2,709,602.20
14	-59,924.87	297,586.58	237,661.71	2,947,263.91
15	-59,924.87	297,586.58	237,661.71	3,184,925.62
16	-59,924.87	297,586.58	237,661.71	3,422,587.32
17	-59,924.87	297,586.58	237,661.71	3,660,249.03
18	-59,924.87	297,586.58	237,661.71	3,897,910.74
19	-59,924.87	297,586.58	237,661.71	4,135,572.45
20	-59,924.87	297,586.58	237,661.71	4,373,234.15

Table A.15: Cumulative cash flow (S2-B1 -40%).

year [€/y]	Costs [€/y]	Incomes [€/y]	Cashflow [€/y]	Cum [€/y]
0	-1,195,823.40	0	-1,195,823.40	-1,195,823.40
1	-502,809.30	495,324.70	-7,484.60	-1,203,308.00
2	-502,809.30	495,324.70	-7,484.60	-1,210,792.61
3	-502,809.30	495,324.70	-7,484.60	-1,218,277.21
4	-502,809.30	495,324.70	-7,484.60	-1,225,761.82
5	-502,809.30	495,324.70	-7,484.60	-1,233,246.42
6	-502,809.30	495,324.70	-7,484.60	-1,240,731.03
7	-502,809.30	495,324.70	-7,484.60	-1,248,215.63
8	-502,809.30	495,324.70	-7,484.60	-1,255,700.23
9	-502,809.30	495,324.70	-7,484.60	-1,263,184.84
10	-502,809.30	495,324.70	-7,484.60	-1,270,669.44
11	-692,724.00	495,324.70	-197,399.30	-1,468,068.75
12	-502,809.30	495,324.70	-7,484.60	-1,475,553.35
13	-502,809.30	495,324.70	-7,484.60	-1,483,037.96
14	-502,809.30	495,324.70	-7,484.60	-1,490,522.56
15	-502,809.30	495,324.70	-7,484.60	-1,498,007.16
16	-502,809.30	495,324.70	-7,484.60	-1,505,491.77
17	-502,809.30	495,324.70	-7,484.60	-1,512,976.37
18	-502,809.30	495,324.70	-7,484.60	-1,520,460.98
19	-502,809.30	495,324.70	-7,484.60	-1,527,945.58
20	-502,809.30	495,324.70	-7,484.60	-1,535,430.18

Table A.16: Cumulative cash flow (S2-B2 +40%).

year [€/y]	Costs [€/y]	Incomes [€/y]	Cashflow [€/y]	Cum [€/y]
0	-1,195,823.40	0	-1,195,823.40	-1,195,823.40
1	-438,800.01	495,324.70	56,524.69	-1,139,298.71
2	-438,800.01	495,324.70	56,524.69	-1,082,774.03
3	-438,800.01	495,324.70	56,524.69	-1,026,249.34
4	-438,800.01	495,324.70	56,524.69	-969,724.66
5	-438,800.01	495,324.70	56,524.69	-913,199.97
6	-438,800.01	495,324.70	56,524.69	-856,675.28
7	-438,800.01	495,324.70	56,524.69	-800,150.60
8	-438,800.01	495,324.70	56,524.69	-743,625.91
9	-438,800.01	495,324.70	56,524.69	-687,101.22
10	-438,800.01	495,324.70	56,524.69	-630,576.54
11	-628,714.71	495,324.70	-133,390.01	-763,966.55
12	-438,800.01	495,324.70	56,524.69	-707,441.87
13	-438,800.01	495,324.70	56,524.69	-650,917.18
14	-438,800.01	495,324.70	56,524.69	-594,392.49
15	-438,800.01	495,324.70	56,524.69	-537,867.81
16	-438,800.01	495,324.70	56,524.69	-481,343.12
17	-438,800.01	495,324.70	56,524.69	-424,818.43
18	-438,800.01	495,324.70	56,524.69	-368,293.75
19	-438,800.01	495,324.70	56,524.69	-311,769.06
20	-438,800.01	495,324.70	56,524.69	-255,244.38

Table A.17: Cumulative cash flow (S2-B2 +20%).

year [€/y]	Costs [€/y]	Incomes [€/y]	Cashflow [€/y]	Cum [€/y]
0	-1,195,823.40	0	-1,195,823.40	-1,195,823.40
1	-310,781.43	495,324.70	184,543.27	-1,011,280.13
2	-310,781.43	495,324.70	184,543.27	-826,736.87
3	-310,781.43	495,324.70	184,543.27	-642,193.60
4	-310,781.43	495,324.70	184,543.27	-457,650.33
5	-310,781.43	495,324.70	184,543.27	-273,107.06
6	-310,781.43	495,324.70	184,543.27	-88,563.80
7	-310,781.43	495,324.70	184,543.27	95,979.47
8	-310,781.43	495,324.70	184,543.27	280,522.74
9	-310,781.43	495,324.70	184,543.27	465,066.00
10	-310,781.43	495,324.70	184,543.27	649,609.27
11	-500,696.13	495,324.70	-5,371.43	644,237.84
12	-310,781.43	495,324.70	184,543.27	828,781.10
13	-310,781.43	495,324.70	184,543.27	1,013,324.37
14	-310,781.43	495,324.70	184,543.27	1,197,867.64
15	-310,781.43	495,324.70	184,543.27	1,382,410.91
16	-310,781.43	495,324.70	184,543.27	1,566,954.17
17	-310,781.43	495,324.70	184,543.27	1,751,497.44
18	-310,781.43	495,324.70	184,543.27	1,936,040.71
19	-310,781.43	495,324.70	184,543.27	2,120,583.97
20	-310,781.43	495,324.70	184,543.27	2,305,127.24

Table A.18: Cumulative cash flow (S2-B2 -20%).

year [€/y]	Costs [€/y]	Incomes [€/y]	Cashflow [€/y]	Cum [€/y]
0	-1,195,823.40	0	-1,195,823.40	-1,195,823.40
1	-246,772.14	495,324.70	248,552.56	-947,270.84
2	-246,772.14	495,324.70	248,552.56	-698,718.29
3	-246,772.14	495,324.70	248,552.56	-450,165.73
4	-246,772.14	495,324.70	248,552.56	-201,613.17
5	-246,772.14	495,324.70	248,552.56	46,939.39
6	-246,772.14	495,324.70	248,552.56	295,491.94
7	-246,772.14	495,324.70	248,552.56	544,044.50
8	-246,772.14	495,324.70	248,552.56	792,597.06
9	-246,772.14	495,324.70	248,552.56	1,041,149.62
10	-246,772.14	495,324.70	248,552.56	1,289,702.18
11	-436,686.84	495,324.70	58,637.86	1,348,340.03
12	-246,772.14	495,324.70	248,552.56	1,596,892.59
13	-246,772.14	495,324.70	248,552.56	1,845,445.15
14	-246,772.14	495,324.70	248,552.56	2,093,997.71
15	-246,772.14	495,324.70	248,552.56	2,342,550.26
16	-246,772.14	495,324.70	248,552.56	2,591,102.82
17	-246,772.14	495,324.70	248,552.56	2,839,655.38
18	-246,772.14	495,324.70	248,552.56	3,088,207.94
19	-246,772.14	495,324.70	248,552.56	3,336,760.49
20	-246,772.14	495,324.70	248,552.56	3,585,313.05

Table A.19: Cumulative cash flow (S2-B2 -40%).

year [€/y]	Costs [€/y]	Incomes [€/y]	Cashflow [€/y]	Cum [€/y]
0	-1,195,823.40	0	-1,195,823.40	-1,195,823.40
1	-383,016.90	519,532.49	136,515.59	-1,059,307.81
2	-383,016.90	519,532.49	136,515.59	-922,792.22
3	-383,016.90	519,532.49	136,515.59	-786,276.63
4	-383,016.90	519,532.49	136,515.59	-649,761.05
5	-383,016.90	519,532.49	136,515.59	-513,245.46
6	-383,016.90	519,532.49	136,515.59	-376,729.87
7	-383,016.90	519,532.49	136,515.59	-240,214.28
8	-383,016.90	519,532.49	136,515.59	-103,698.69
9	-383,016.90	519,532.49	136,515.59	32,816.90
10	-383,016.90	519,532.49	136,515.59	169,332.49
11	-572,931.60	519,532.49	-53,399.11	115,933.38
12	-383,016.90	519,532.49	136,515.59	252,448.96
13	-383,016.90	519,532.49	136,515.59	388,964.55
14	-383,016.90	519,532.49	136,515.59	525,480.14
15	-383,016.90	519,532.49	136,515.59	661,995.73
16	-383,016.90	519,532.49	136,515.59	798,511.32
17	-383,016.90	519,532.49	136,515.59	935,026.91
18	-383,016.90	519,532.49	136,515.59	1,071,542.50
19	-383,016.90	519,532.49	136,515.59	1,208,058.09
20	-383,016.90	519,532.49	136,515.59	1,344,573.67

Table A.20: Cumulative cash flow (S2-B3 +40%).

year [€/y]	Costs [€/y]	Incomes [€/y]	Cashflow [€/y]	Cum [€/y]
0	-1,195,823.40	0	-1,195,823.40	-1,195,823.40
1	-336,120.81	519,532.49	183,411.68	-1,012,411.72
2	-336,120.81	519,532.49	183,411.68	-829,000.04
3	-336,120.81	519,532.49	183,411.68	-645,588.36
4	-336,120.81	519,532.49	183,411.68	-462,176.68
5	-336,120.81	519,532.49	183,411.68	-278,765.00
6	-336,120.81	519,532.49	183,411.68	-95,353.32
7	-336,120.81	519,532.49	183,411.68	88,058.36
8	-336,120.81	519,532.49	183,411.68	271,470.04
9	-336,120.81	519,532.49	183,411.68	454,881.71
10	-336,120.81	519,532.49	183,411.68	638,293.39
11	-526,035.51	519,532.49	-6,503.02	631,790.37
12	-336,120.81	519,532.49	183,411.68	815,202.05
13	-336,120.81	519,532.49	183,411.68	998,613.73
14	-336,120.81	519,532.49	183,411.68	1,182,025.41
15	-336,120.81	519,532.49	183,411.68	1,365,437.09
16	-336,120.81	519,532.49	183,411.68	1,548,848.77
17	-336,120.81	519,532.49	183,411.68	1,732,260.45
18	-336,120.81	519,532.49	183,411.68	1,915,672.13
19	-336,120.81	519,532.49	183,411.68	2,099,083.81
20	-336,120.81	519,532.49	183,411.68	2,282,495.49

Table A.21: Cumulative cash flow (S2-B3 +20%).

year [€/y]	Costs [€/y]	Incomes [€/y]	Cashflow [€/y]	Cum [€/y]
0	-1,195,823.40	0	-1,195,823.40	-1,195,823.40
1	-242,328.63	519,532.49	277,203.86	-918,619.54
2	-242,328.63	519,532.49	277,203.86	-641,415.68
3	-242,328.63	519,532.49	277,203.86	-364,211.82
4	-242,328.63	519,532.49	277,203.86	-87,007.96
5	-242,328.63	519,532.49	277,203.86	190,195.90
6	-242,328.63	519,532.49	277,203.86	467,399.77
7	-242,328.63	519,532.49	277,203.86	744,603.63
8	-242,328.63	519,532.49	277,203.86	1,021,807.49
9	-242,328.63	519,532.49	277,203.86	1,299,011.35
10	-242,328.63	519,532.49	277,203.86	1,576,215.21
11	-432,243.33	519,532.49	87,289.16	1,663,504.37
12	-242,328.63	519,532.49	277,203.86	1,940,708.23
13	-242,328.63	519,532.49	277,203.86	2,217,912.09
14	-242,328.63	519,532.49	277,203.86	2,495,115.95
15	-242,328.63	519,532.49	277,203.86	2,772,319.81
16	-242,328.63	519,532.49	277,203.86	3,049,523.67
17	-242,328.63	519,532.49	277,203.86	3,326,727.54
18	-242,328.63	519,532.49	277,203.86	3,603,931.40
19	-242,328.63	519,532.49	277,203.86	3,881,135.26
20	-242,328.63	519,532.49	277,203.86	4,158,339.12

Table A.22: Cumulative cash flow (S2-B3 -20%).

year [€/y]	Costs [€/y]	Incomes [€/y]	Cashflow [€/y]	Cum [€/y]
0	-1,195,823.40	0	-1,195,823.40	-1,195,823.40
1	-195,432.54	519,532.49	324,099.95	-871,723.45
2	-195,432.54	519,532.49	324,099.95	-547,623.50
3	-195,432.54	519,532.49	324,099.95	-223,523.55
4	-195,432.54	519,532.49	324,099.95	100,576.41
5	-195,432.54	519,532.49	324,099.95	424,676.36
6	-195,432.54	519,532.49	324,099.95	748,776.31
7	-195,432.54	519,532.49	324,099.95	1,072,876.26
8	-195,432.54	519,532.49	324,099.95	1,396,976.21
9	-195,432.54	519,532.49	324,099.95	1,721,076.16
10	-195,432.54	519,532.49	324,099.95	2,045,176.12
11	-385,347.24	519,532.49	134,185.25	2,179,361.37
12	-195,432.54	519,532.49	324,099.95	2,503,461.32
13	-195,432.54	519,532.49	324,099.95	2,827,561.27
14	-195,432.54	519,532.49	324,099.95	3,151,661.22
15	-195,432.54	519,532.49	324,099.95	3,475,761.17
16	-195,432.54	519,532.49	324,099.95	3,799,861.13
17	-195,432.54	519,532.49	324,099.95	4,123,961.08
18	-195,432.54	519,532.49	324,099.95	4,448,061.03
19	-195,432.54	519,532.49	324,099.95	4,772,160.98
20	-195,432.54	519,532.49	324,099.95	5,096,260.93

Table A.23: Cumulative cash flow (S2-B3 -40%).

year [€/y]	Costs [€/y]	Incomes [€/y]	Cashflow [€/y]	Cum [€/y]
0	-1,097,302.30	0	-1,097,302.30	-1,097,302.30
1	-342,564.73	475,297.62	132,732.90	-964,569.40
2	-342,564.73	475,297.62	132,732.90	-831,836.51
3	-342,564.73	475,297.62	132,732.90	-699,103.61
4	-342,564.73	475,297.62	132,732.90	-566,370.72
5	-342,564.73	475,297.62	132,732.90	-433,637.82
6	-342,564.73	475,297.62	132,732.90	-300,904.93
7	-342,564.73	475,297.62	132,732.90	-168,172.03
8	-342,564.73	475,297.62	132,732.90	-35,439.14
9	-342,564.73	475,297.62	132,732.90	97,293.76
10	-342,564.73	475,297.62	132,732.90	230,026.65
11	-503,931.63	475,297.62	-28,634.00	201,392.65
12	-342,564.73	475,297.62	132,732.90	334,125.54
13	-342,564.73	475,297.62	132,732.90	466,858.44
14	-342,564.73	475,297.62	132,732.90	599,591.33
15	-342,564.73	475,297.62	132,732.90	732,324.23
16	-342,564.73	475,297.62	132,732.90	865,057.12
17	-342,564.73	475,297.62	132,732.90	997,790.02
18	-342,564.73	475,297.62	132,732.90	1,130,522.92
19	-342,564.73	475,297.62	132,732.90	1,263,255.81
20	-342,564.73	475,297.62	132,732.90	1,395,988.71

Table A.24: Cumulative cash flow (S3-B2 80%).

year [€/y]	Costs [€/y]	Incomes [€/y]	Cashflow [€/y]	Cum [€/y]
0	-1,006,530.70	0	-1,006,530.70	-1,006,530.70
1	-304,920.64	451,184.98	146,264.35	-860,266.35
2	-304,920.64	451,184.98	146,264.35	-714,002.01
3	-304,920.64	451,184.98	146,264.35	-567,737.66
4	-304,920.64	451,184.98	146,264.35	-421,473.31
5	-304,920.64	451,184.98	146,264.35	-275,208.96
6	-304,920.64	451,184.98	146,264.35	-128,944.62
7	-304,920.64	451,184.98	146,264.35	17,319.73
8	-304,920.64	451,184.98	146,264.35	163,584.08
9	-304,920.64	451,184.98	146,264.35	309,848.42
10	-304,920.64	451,184.98	146,264.35	456,112.77
11	-442,030.94	451,184.98	9,154.05	465,266.82
12	-304,920.64	451,184.98	146,264.35	611,531.17
13	-304,920.64	451,184.98	146,264.35	757,795.51
14	-304,920.64	451,184.98	146,264.35	904,059.86
15	-304,920.64	451,184.98	146,264.35	1,050,324.21
16	-304,920.64	451,184.98	146,264.35	1,196,588.56
17	-304,920.64	451,184.98	146,264.35	1,342,852.90
18	-304,920.64	451,184.98	146,264.35	1,489,117.25
19	-304,920.64	451,184.98	146,264.35	1,635,381.60
20	-304,920.64	451,184.98	146,264.35	1,781,645.94

Table A.25: Cumulative cash flow (S3-B2 70%).

year [€/y]	Costs [€/y]	Incomes [€/y]	Cashflow [€/y]	Cum [€/y]
0	-929,504.80	0	-929,504.80	-929,504.80
1	-269,227.52	428,028.34	158,800.82	-770,703.98
2	-269,227.52	428,028.34	158,800.82	-611,903.16
3	-269,227.52	428,028.34	158,800.82	-453,102.33
4	-269,227.52	428,028.34	158,800.82	-294,301.51
5	-269,227.52	428,028.34	158,800.82	-135,500.69
6	-269,227.52	428,028.34	158,800.82	23,300.13
7	-269,227.52	428,028.34	158,800.82	182,100.96
8	-269,227.52	428,028.34	158,800.82	340,901.78
9	-269,227.52	428,028.34	158,800.82	499,702.60
10	-269,227.52	428,028.34	158,800.82	658,503.42
11	-387,053.52	428,028.34	40,974.82	699,478.24
12	-269,227.52	428,028.34	158,800.82	858,279.07
13	-269,227.52	428,028.34	158,800.82	1,017,079.89
14	-269,227.52	428,028.34	158,800.82	1,175,880.71
15	-269,227.52	428,028.34	158,800.82	1,334,681.53
16	-269,227.52	428,028.34	158,800.82	1,493,482.36
17	-269,227.52	428,028.34	158,800.82	1,652,283.18
18	-269,227.52	428,028.34	158,800.82	1,811,084.00
19	-269,227.52	428,028.34	158,800.82	1,969,884.82
20	-269,227.52	428,028.34	158,800.82	2,128,685.65

Table A.26: Cumulative cash flow (S3-B2 60%).

year [€/y]	Costs [€/y]	Incomes [€/y]	Cashflow [€/y]	Cum [€/y]
0	-858,448.80	0	-858,448.80	-858,448.80
1	-235,293.76	405,908.55	170,614.79	-687,834.01
2	-235,293.76	405,908.55	170,614.79	-517,219.22
3	-235,293.76	405,908.55	170,614.79	-346,604.43
4	-235,293.76	405,908.55	170,614.79	-175,989.65
5	-235,293.76	405,908.55	170,614.79	-5,374.86
6	-235,293.76	405,908.55	170,614.79	165,239.93
7	-235,293.76	405,908.55	170,614.79	335,854.72
8	-235,293.76	405,908.55	170,614.79	506,469.51
9	-235,293.76	405,908.55	170,614.79	677,084.30
10	-235,293.76	405,908.55	170,614.79	847,699.09
11	-336,110.06	405,908.55	69,798.49	917,497.57
12	-235,293.76	405,908.55	170,614.79	1,088,112.36
13	-235,293.76	405,908.55	170,614.79	1,258,727.15
14	-235,293.76	405,908.55	170,614.79	1,429,341.94
15	-235,293.76	405,908.55	170,614.79	1,599,956.73
16	-235,293.76	405,908.55	170,614.79	1,770,571.52
17	-235,293.76	405,908.55	170,614.79	1,941,186.31
18	-235,293.76	405,908.55	170,614.79	2,111,801.09
19	-235,293.76	405,908.55	170,614.79	2,282,415.88
20	-235,293.76	405,908.55	170,614.79	2,453,030.67

Table A.27: Cumulative cash flow (S3-B2 50%).

year [€/y]	Costs [€/y]	Incomes [€/y]	Cashflow [€/y]	Cum [€/y]
0	-1,097,302.30	0	-1,097,302.30	-1,097,302.30
1	-261,332.45	503,699.34	242,366.89	-854,935.41
2	-261,332.45	503,699.34	242,366.89	-612,568.52
3	-261,332.45	503,699.34	242,366.89	-370,201.63
4	-261,332.45	503,699.34	242,366.89	-127,834.73
5	-261,332.45	503,699.34	242,366.89	114,532.16
6	-261,332.45	503,699.34	242,366.89	356,899.05
7	-261,332.45	503,699.34	242,366.89	599,265.94
8	-261,332.45	503,699.34	242,366.89	841,632.83
9	-261,332.45	503,699.34	242,366.89	1,083,999.72
10	-261,332.45	503,699.34	242,366.89	1,326,366.62
11	-422,699.35	503,699.34	80,999.99	1,407,366.61
12	-261,332.45	503,699.34	242,366.89	1,649,733.50
13	-261,332.45	503,699.34	242,366.89	1,892,100.39
14	-261,332.45	503,699.34	242,366.89	2,134,467.28
15	-261,332.45	503,699.34	242,366.89	2,376,834.17
16	-261,332.45	503,699.34	242,366.89	2,619,201.06
17	-261,332.45	503,699.34	242,366.89	2,861,567.96
18	-261,332.45	503,699.34	242,366.89	3,103,934.85
19	-261,332.45	503,699.34	242,366.89	3,346,301.74
20	-261,332.45	503,699.34	242,366.89	3,588,668.63

Table A.28: Cumulative cash flow (S3-B3 80%).

year [€/y]	Costs [€/y]	Incomes [€/y]	Cashflow [€/y]	Cum [€/y]
0	-1,006,530.70	0	-1,006,530.70	-1,006,530.70
1	-230,788.28	486,457.60	255,669.31	-750,861.39
2	-230,788.28	486,457.60	255,669.31	-495,192.07
3	-230,788.28	486,457.60	255,669.31	-239,522.76
4	-230,788.28	486,457.60	255,669.31	16,146.55
5	-230,788.28	486,457.60	255,669.31	271,815.87
6	-230,788.28	486,457.60	255,669.31	527,485.18
7	-230,788.28	486,457.60	255,669.31	783,154.49
8	-230,788.28	486,457.60	255,669.31	1,038,823.81
9	-230,788.28	486,457.60	255,669.31	1,294,493.12
10	-230,788.28	486,457.60	255,669.31	1,550,162.44
11	-367,898.58	486,457.60	118,559.01	1,668,721.45
12	-230,788.28	486,457.60	255,669.31	1,924,390.76
13	-230,788.28	486,457.60	255,669.31	2,180,060.08
14	-230,788.28	486,457.60	255,669.31	2,435,729.39
15	-230,788.28	486,457.60	255,669.31	2,691,398.70
16	-230,788.28	486,457.60	255,669.31	2,947,068.02
17	-230,788.28	486,457.60	255,669.31	3,202,737.33
18	-230,788.28	486,457.60	255,669.31	3,458,406.64
19	-230,788.28	486,457.60	255,669.31	3,714,075.96
20	-230,788.28	486,457.60	255,669.31	3,969,745.27

Table A.29: Cumulative cash flow (S3-B3 70%).

year [€/y]	Costs [€/y]	Incomes [€/y]	Cashflow [€/y]	Cum [€/y]
0	-929,504.80	0	-929,504.80	-929,504.80
1	-202,912.70	470,866.30	267,953.60	-661,551.20
2	-202,912.70	470,866.30	267,953.60	-393,597.60
3	-202,912.70	470,866.30	267,953.60	-125,644.00
4	-202,912.70	470,866.30	267,953.60	142,309.60
5	-202,912.70	470,866.30	267,953.60	410,263.21
6	-202,912.70	470,866.30	267,953.60	678,216.81
7	-202,912.70	470,866.30	267,953.60	946,170.41
8	-202,912.70	470,866.30	267,953.60	1,214,124.01
9	-202,912.70	470,866.30	267,953.60	1,482,077.61
10	-202,912.70	470,866.30	267,953.60	1,750,031.21
11	-320,738.70	470,866.30	150,127.60	1,900,158.81
12	-202,912.70	470,866.30	267,953.60	2,168,112.41
13	-202,912.70	470,866.30	267,953.60	2,436,066.01
14	-202,912.70	470,866.30	267,953.60	2,704,019.61
15	-202,912.70	470,866.30	267,953.60	2,971,973.22
16	-202,912.70	470,866.30	267,953.60	3,239,926.82
17	-202,912.70	470,866.30	267,953.60	3,507,880.42
18	-202,912.70	470,866.30	267,953.60	3,775,834.02
19	-202,912.70	470,866.30	267,953.60	4,043,787.62
20	-202,912.70	470,866.30	267,953.60	4,311,741.22

Table A.30: Cumulative cash flow (S3-B3 60%).

year [€/y]	Costs [€/y]	Incomes [€/y]	Cashflow [€/y]	Cum [€/y]
0	-858,448.80	0	-858,448.80	-858,448.80
1	-177,481.44	456,974.73	279,493.29	-578,955.51
2	-177,481.44	456,974.73	279,493.29	-299,462.21
3	-177,481.44	456,974.73	279,493.29	-19,968.92
4	-177,481.44	456,974.73	279,493.29	259,524.37
5	-177,481.44	456,974.73	279,493.29	539,017.67
6	-177,481.44	456,974.73	279,493.29	818,510.96
7	-177,481.44	456,974.73	279,493.29	1,098,004.25
8	-177,481.44	456,974.73	279,493.29	1,377,497.55
9	-177,481.44	456,974.73	279,493.29	1,656,990.84
10	-177,481.44	456,974.73	279,493.29	1,936,484.13
11	-278,297.74	456,974.73	178,676.99	2,115,161.13
12	-177,481.44	456,974.73	279,493.29	2,394,654.42
13	-177,481.44	456,974.73	279,493.29	2,674,147.71
14	-177,481.44	456,974.73	279,493.29	2,953,641.01
15	-177,481.44	456,974.73	279,493.29	3,233,134.30
16	-177,481.44	456,974.73	279,493.29	3,512,627.59
17	-177,481.44	456,974.73	279,493.29	3,792,120.89
18	-177,481.44	456,974.73	279,493.29	4,071,614.18
19	-177,481.44	456,974.73	279,493.29	4,351,107.47
20	-177,481.44	456,974.73	279,493.29	4,630,600.76

Table A.31: Cumulative cash flow (S3-B3 50%).

Appendix B

Matlab script

In this appendix is shown the Matlab script created for the most complete base case, which includes upgrading system, methanator and photovoltaic modules. To find all cases and scenarios analysed in the thesis it is sufficient to change the parameters of interest from the script represented below.

```
clear all
close all
clc

%% Dati input

[Text, Tdig1, Pfanghi]=readvars('Digestore.txt');
[Pbiog]=readvars('portateh.txt');
[Gh_p, Gh_i]=readvars('Rad_oraria.txt');

mesi=[744 1416 2160 2880 3624 4344 5088 5832 6522 7296 8016
   8760];
for i=1:length(Tdig1)
    if i>=6000 && i<=8050
        Tdig(i)=Tdig1(i-2500);
    else
        Tdig(i)=Tdig1(i);
    end
end
%Hp Digestore
cp=4.186; %kJ/kg/K, ipotizzato uguale a quello dell'acqua
rhof=1000; %densit  dei fanghi 1000 kg/m^3 = a quella dell'
   acqua
Uug=2.326; %W/m^2/K
Aug=450.8; %m^2
Uext=0.93; %W/m^2/K
Aext=1132.1; %m^2

%Hp upgrading
PerConv=0.97; % ipotesi perc conversione al 97 perc
perMet=0.6; % ipotesi perc metano 60
```

```
Methrec=0.98;
Xch4=0.97; %percentuale molare di metano nel biometano dopo upgrade
rhom20=0.668; % kg/m^3 T=0
rhoco20=1.967; % kg/m^3 T=0
MWch4=16; %g/mol
MWco2=44; %g/mol
MWh20=18; %g/mol

%Hp Metanazione
Tmet=450; %  C  temperatura del metanatore
rhoch4_Smc= 0.6566; % kg/Sm3
MWh2=2; % g/mol
Deltah=-165; % kJ/mol
rhoh2=0.0899; % kg/m^3 densit  idrogeno a 0 gradi

%Hp OPEX
media_2019=0.353839; %    /smc
% prezzo_ee=0.04; %   /kWh eni
prezzo_ee=0.093; %    /kWh eurostat
prezzo_vendita_ee=0.09; %    /kWh
prezzo_met=0.353839; %   /Smc
O_prezzo_UP=0.25; %kWh/m^3 biogas;
PCI_ch4=10.69; % kWh/Sm3
en_CIC=5.815; % MWh
eur_CIC=375; %    /per ogni CIC
costo_met=29.88; %    /m^3 biometano
carbon_tax=50; %   /ton
% costo del lavoro

%Hp CAPEX
prezzopannello_PV=351.74; %     per pannello da 360 W
N_moduli=1759; % numero pannelli installati
C_prezzo_UP=0.22; %   /m^3 ch4
taglia=500; %kW
C_prezzo_El=900; %   /kW
C_prezzo_rep=315; %   /kW
nn=0.27;
C_st_rep=C_prezzo_rep*(1000/taglia)^nn;

%% Energy Demand Digestore

% Tsl_in ipotesi: 14  C  per Gen, feb, nov, dic - 23 C  giu, lug, ago -
% 18.5  C  Mar, apr, mag, sett, ott

% Tground ipotesi: 5 C  Gen, feb - 7.5 C  Mar, Apr, Mag, Set - 10 C  Giu, Lug, Ago
```

```
% Text preso da PVgis

for i=1:length(Tdig)
    if i<=1416
        Tsl_in(i,1)=14;
        Tground(i,1)=5;
    elseif (i>1416 && i<=3624) || i>5832
        Tsl_in(i,1)=18.5;
        Tground(i,1)=7.5;
    else
        Tsl_in(i,1)=23;
        Tground(i,1)=10;
    end

    Qslp(i,1)=Pfanghi(i)*rhof*cp*(Tdig(i)-Tsl_in(i))/3600; %
       Kw, divido per 3600 altrimenti risultato in KJ/h
    %Quando la temperatura dei fanghi in ingresso    maggiore
        di quella del
    %digestore si considera Qsl=0
    if Qslp(i)>=0
        Qsl(i,1)=Qslp(i,1);
    else
        Qsl(i,1)=0;
    end
    Qug(i,1)=Aug*Uug*(Tdig(i)-Tground(i))*10^(-3); %Kw,
       moltiplico per 10^-3 altrimenti risultato in W
    Qext(i,1)=Aext*Uext*(Tdig(i)-Text(i))*10^(-3); %Kw,
       moltiplico per 10^-3 altrimenti risultato in W
    Qloss(i,1)=Qug(i)+Qext(i);
    Qpipes(i,1)=0.05*(Qloss(i)+Qsl(i));
    Qdig(i,1)=Qsl(i)+Qloss(i)+Qpipes(i);
end

mesi=[744 1416 2160 2880 3624 4344 5088 5832 6522 7296 8016
   8756];
Qmese(1)=sum(Qdig(1:mesi(1)))/(mesi(1));
for i=2:12
   if mesi(i)<=length(Pfanghi)
        Qmese(i,1)=sum(Qdig((mesi(i-1)+1):mesi(i)))/(mesi(i)
           -(mesi(i-1)+1));
   end
end

%% UPGRADING

for i=1:length(Tdig)
    Wel(i,1)=0.25*Pbiog(i); %0.25 KWh/m^3, biogas in m^3
```

```
    Vmet(i,1)=perMet*Methrec*Pbiog(i); %m^3 portata
       volumetrica metano nella miscela
    rhom(i,1)=rhom20*(273.15+20)/(Text(i)+273.15);
    mch4(i,1)=Vmet(i)*rhom(i); %kg portata massica metano
    Vch4(i,1)=mch4(i)/rhoch4_Smc; %Sm3 portata volumetrica
       metano
    nch4(i,1)=mch4(i)/(MWch4*10^-3); %mol portata molare
    ntot(i,1)=nch4(i)/Xch4; %mol portata molare totale di
       biometano
    nco2(i,1)=ntot(i)*(1-Xch4); %mol portata molare co2 nel
       biometano
    mco2_biom(i,1)=nco2(i)*(MWco2*10^-3); %kg portata massica
        co2 nel biometano
    rhoco2(i,1)=rhoco20*273.15/(Text(i)+273.15);
    Vco2_biom(i,1)=mco2_biom(i)/rhoco20; %m^3 portata
       volumetrica co2 nella miscela
    mco2_biogas(i,1)=rhoco20*Pbiog(i)*(1-perMet); %kg portata
        massica co2 biogas
    mco2_meth1(i,1)=mco2_biogas(i)-mco2_biom(i); %kg portata
       massica co2 per la metanazione
    Vco2_meth1(i,1)=mco2_meth1(i)/rhoco20; %m^3 portata
       volumetrica co2 per la metanazione
    Pbiomet(i,1)=Pbiog(i)*perMet; % m^3 ipotesi 60 perc ch4
    Pmix(i,1)=Vmet(i)+Vco2_biom(i); %m^3 portata volmetrica
       miscela
end

eff_conv_co2=mco2_meth1(end)/mco2_biogas(end);

figure
plot([1:length(Tdig)],Pbiog(1:length(Tdig)),'r','linewidth'
   ,2)
% set(gca,'xtick',mesi1,'xticklabel',{'Jan', 'Feb', 'Mar', '
   Apr', 'May', 'Jun', 'Jul', 'Aug', 'Sep'},'fontsize',12)
set(gcf,'color','w')
ylabel('Biogas flow rate [m^3]','fontsize',12)
% axis([0 length(Tdig) 30 110])
title('Biogas flow rate')
grid on

%% METHANATION

cons_en=55; %kWh/kg di idrogeno

for i=1:length(Tdig)
    nco2_m1(i,1)=mco2_meth1(i)/(MWco2*10^-3); %moli di co2
    nh2_1(i,1)=4*nco2_m1(i); %moli di h2
    mh2_m1(i,1)=nh2_1(i)*MWh2*10^-3; %kg massa h2
```

```
    Wel_m1(i,1)=cons_en*mh2_m1(i); %Kwh riferiti all'ora
       della portata
    if Wel_m1(i)>taglia
        Wel_m(i,1)=taglia;
        mh2_m(i,1)=taglia/cons_en;
        nh2(i,1)=mh2_m(i)/(MWh2*10^-3);
        nco2_m(i,1)=nh2(i)/4;
        mco2_meth(i,1)=nco2_m(i)*(MWco2*10^-3);
        Vco2_meth(i,1)=mco2_meth(i)/rhoco20;
    else
        Wel_m(i,1)=Wel_m1(i);
        mh2_m(i,1)=mh2_m1(i);
        nh2(i,1)=nh2_1(i);
        nco2_m(i,1)=nco2_m1(i);
        mco2_meth(i,1)=mco2_meth1(i);
        Vco2_meth(i,1)=mco2_meth(i)/rhoco20;
    end
    Vh2_m(i,1)=mh2_m(i)/rhoh2; %Nm^3 h2
    mch4_m(i,1)=nco2_m(i)*MWch4*10^-3; %kg di ch4, stesse
       moli della co2 (portata in uscita)
    Vch4_m(i,1)=mch4_m(i,1)/rhoch4_Smc; %Sm^3 di ch4 in
       uscita
    Nmc_ch4_m(i,1)=Vch4_m(i)*273.15/288.15;
    enterm(i,1)=-Deltah*(nco2_m(i)+nh2(i))/5/3600; %KJ/h
       quindi divido 3600 ottenendo kWh energia termica
       dovuta alla reazione esotermica
    V_ingresso(i,1)=Vh2_m(i)+Vco2_meth(i); %volume ingresso
       al metanatore
end

co2_ventata=sum(mco2_meth1)-sum(mco2_meth) %quantit  di CO2
   rilasciata in ambiente in un anno
Vol_co2ventata=co2_ventata/rhoco20;
co2_utilizzata=sum(mco2_meth)
Energiat_met=sum(Vch4_m)
perc_co2=co2_ventata/(co2_ventata+co2_utilizzata)

%% ELETTROLIZZATORE e PV

cons_en=55; %kWh/kg di idrogeno

for i=1:length(Tdig)
    Vh2_m(i, 1)=mh2_m(i)/rhoh2; %Nm^3 di idrogeno
    mol_h2(i,1)=mh2_m(i)/3600/(MWh2*10^-3); %mol/s portata
       molare di idrogeno
    mh2o(i,1)=mol_h2(i)*(MWh20*10^-3); %kg/s portata massica
       acqua
```

```
    Wel_m(i,1)=cons_en*mh2_m(i); %Kwh riferiti all'ora della
       portata
    Wterm(i,1)=cp*mh2o(i)*(60-20)*0.8;
end

eta=0.221; %rendimento modulo
Amp=2086.5; % m^2 area dei moduli fotovoltaici sui tetti
   piani
Ai=783.8; %m^2 area dei moduli fotovoltaici sui tetti
   inclinati

for i=1:length(Gh_p)
    En_p(i,1)=eta*Gh_p(i)*10^-3*Amp; %kWh
    En_i(i,1)=eta*Gh_i(i)*10^-3*Ai;
    En_tot(i,1)=En_p(i)+En_i(i);
end
En_PV=sum(En_tot);

figure
plot([1:length(En_tot)],En_tot,'b','linewidth',2)
% set(gca,'xtick',mesi1,'xticklabel',{'Jan', 'Feb', 'Mar', '
   Apr', 'May', 'Jun', 'Jul', 'Aug', 'Sep'},'fontsize',12)
set(gcf,'color','w')
ylabel('Energia elettrica [kWh]','fontsize',12)
title('Energia elettrica da fotovoltaico [kWh]','fontsize'
   ,15)
% axis([0 length(Tdig) 30 110])
grid on

figure
plot([1:length(Wel_m)],Wel_m,'b','linewidth',2)
% set(gca,'xtick',mesi1,'xticklabel',{'Jan', 'Feb', 'Mar', '
   Apr', 'May', 'Jun', 'Jul', 'Aug', 'Sep'},'fontsize',12)
set(gcf,'color','w')
ylabel('Energia elettrica [kWh]','fontsize',12)
title('Energia elettrica per metanazione [kWh]','fontsize'
   ,15)
% axis([0 length(Tdig) 30 110])
grid on

dem_rete(1)=Wel_m(1)-En_tot(1);
En_ven(1)=0;

for i=2:length(Tdig)
    rete(i)=Wel_m(i)-En_tot(i);
    if Wel_m(i)>En_tot(i)
        dem_rete(i)=Wel_m(i)-En_tot(i);
        En_ven(i)=0;
```

```
    else
        En_ven(i)=En_tot(i)-Wel_m(i);
        dem_rete(i)=0;
    end
end

figure
plot([1:length(dem_rete)],dem_rete,'b','linewidth',2)
% set(gca,'xtick',mesi1,'xticklabel',{'Jan', 'Feb', 'Mar', '
   Apr', 'May', 'Jun', 'Jul', 'Aug', 'Sep'},'fontsize',12)
set(gcf,'color','w')
ylabel('Richiesta energetica rete [kWh]','fontsize',12)
title('Richiesta energetica rete [kWh]','fontsize',14)
% axis([0 length(Tdig) 30 110])
grid on

mens(1)=sum(En_tot(1:mesi(1)));
for i=2:length(mesi)
    mens(i,1)=sum(En_tot(mesi(i-1)+1:mesi(i)));
end
figure
plot([1:length(Tdig)],En_tot(1:length(Tdig)),'b','linewidth'
   ,2)
% set(gca,'xtick',mesi1,'xticklabel',{'Jan', 'Feb', 'Mar', '
   Apr', 'May', 'Jun', 'Jul', 'Aug', 'Sep'},'fontsize',12)
set(gcf,'color','w')
ylabel('Energia da PV [kWh]','fontsize',12)
% axis([0 length(Tdig) 30 110])
grid on

figure
bar(mens(1:length(mens)),'b')
% set(gca,'xtick',mesi1,'xticklabel',{'Jan', 'Feb', 'Mar', '
   Apr', 'May', 'Jun', 'Jul', 'Aug', 'Sep'},'fontsize',12)
set(gcf,'color','w')
ylabel('Energia da PV mensile [kWh]','fontsize',12)
% axis([0 length(Tdig) 30 110])
grid on

%% CAPEX

C_UP=380000;
C0_met=650000;
C_met=C0_met*((sum(Vco2_meth)/length(Vco2_meth))/80)^0.6;

%elettrolizzatore
c_sp_elettr=C_prezzo_El*(1000/taglia)^nn;
TMC=taglia*c_sp_elettr;
```

```
TPC=C_UP+C_met+TMC;

%% CAPEX specifici    /kW
avg_Pbiog=sum(Pbiog)/length(Pbiog);
C_sp_Up=C_UP/avg_Pbiog; %   /m^3 di biogas
avg_Vch4_m=sum(Vch4_m)/length(Vch4_m);
Csp_meth=C_met/avg_Vch4_m;

%% OPEX

Portata_tot_ch4=sum(Pmix)+sum(Vch4_m); %smc di metano
guadagno_met=eur_CIC*PCI_ch4*sum(Vch4_m)/(en_CIC*10^3)+0.95*
   sum(Vch4_m)*media_2019
guadagno_UP=eur_CIC*PCI_ch4*sum(Pmix)/(en_CIC*10^3)+0.95*sum(
   Pmix)*media_2019
en_ch4=PCI_ch4*Portata_tot_ch4; %kWh
nCIC=en_ch4/(en_CIC*10^3);
ricavi_ch4=eur_CIC*nCIC+0.95*Portata_tot_ch4*media_2019;
valore_incentivo=ricavi_ch4/Portata_tot_ch4;
ricavi_ee=sum(En_ven)*prezzo_vendita_ee;
en_UP=0.4*sum(Pbiog); % consumo elettricit  kWh/y
en_elettrica=sum(dem_rete)+en_UP;
%necessit  catalizzatore
costo_en=en_elettrica*prezzo_ee;
% Energia termica
E_recupero=sum(enterm)+sum(Wterm); %kWh
Vol_metano_recupero=E_recupero/PCI_ch4/0.9; %Smc rendimento
   considerato 0.9
recupero_et=Vol_metano_recupero*prezzo_met; %costo dell'
   energia termica
Operatore=31200;
OP_electrolyser=0.04*TMC;
Op_met=costo_met*2;
tax_car=co2_ventata*10^-3*carbon_tax; %

present_cashflow(1)=-TPC;
cum_cashflow(1)=present_cashflow(1);

for i=2:21
    if mod(i-2,10)==0 && ((i-2)>0)
        Stack_repl(i,1)=C_st_rep*taglia;
    else
        Stack_repl(i,1)=0;
    end
    cashflow(i,1)=ricavi_ch4+ricavi_ee+recupero_et-costo_en-
       Stack_repl(i)-Operatore-OP_electrolyser-Op_met-tax_car
       ;
    cum_cashflow(i,1)=cashflow(i)+cum_cashflow(i-1);
```

```
end


yy= @(x) (x.*(x>=0 & x<=length(cum_cashflow)-1));
kk=[0:length(cum_cashflow)-1];
figure
plot([0:length(cum_cashflow)-1],cum_cashflow(1:length(
   cum_cashflow)),'b','linewidth',2)
% set(gca,'xtick',mesi1,'xticklabel',{'Jan', 'Feb', 'Mar', '
   Apr', 'May', 'Jun', 'Jul', 'Aug', 'Sep'},'fontsize',12)
% axis([0 length(Tdig) 30 110])
hold on
plot(kk,yy(kk),'--r','linewidth',2)
grid on
set(gcf,'color','w')
ylabel('Cumulative cashflow','fontsize',12)

%% Analisi economica

NPV=cum_cashflow(end);
aus1=0;
i=0;
    while aus1==0
        i=i+1;
        if cum_cashflow(i)>0
            PBT=i-1;
            aus1=1;
        else
        end
    end
```

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