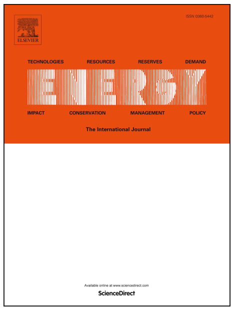
Accepted Manuscript



Internalizing the external costs of biogas supply chains in the Italian energy sector

P. Patrizio, S. Leduc, D. Chinese, F. Kraxner

PII: S0360-5442(17)30033-6

DOI: 10.1016/j.energy.2017.01.033

Reference: EGY 10168

To appear in: *Energy*

Received Date: 23 September 2015

Revised Date: 2 January 2017

Accepted Date: 6 January 2017

Please cite this article as: Patrizio P, Leduc S, Chinese D, Kraxner F, Internalizing the external costs of biogas supply chains in the Italian energy sector, *Energy* (2017), doi: 10.1016/j.energy.2017.01.033.

Internalizing the external costs of biogas supply chains in the Italian energy sector

P. Patrizio [a,b,]*, S. Leduc [b], D. Chinese [a], F. Kraxner [b]

[a] DIEGM, University of Udine, Via delle Scienze, 33100 Udine, Italy

[b] International Institute for Applied Systems Analysis (IIASA), Schlossplatz 1, A-2631 Laxenburg, Austria

Corresponding email address: patrizio.piera@spes.uniud.it

ABSTRACT:

In Italy biogas support schemes are being revised to include subsidies for the production of biomethane. Energy policies should foster environmentally optimal solutions, especially because social acceptance issues often arise in the case of biogas. In this paper we use the external cost methodology to quantify the environmental impact of airborne emissions associated with biogas-based energy vectors and their corresponding fossil substitutes These are evaluated at supply chain level and incorporated in a spatially explicit optimization model. The method is applied to northern Italy to compare the potential impact of alternative policy options. It is found that, while the external costs of biogas-based pathways are always lower than corresponding fossil fuel based pathways, the differences are generally so small that policies based on internalization of external costs alone would not lead to further development of biogas-based technologies. For all utilization pathways, consideration of local externalities leads to a less favourable evaluation of biogas-based technologies, which results in external costs even higher than the substituted fossil fuel if biogas is allocated to local heating.

Keywords: External costs, biomethane, biogas supply chain, CHP, BeWhere model , Environmental impact

1 INTRODUCTION

Growing concerns about climate change made the reduction of CO_2 and equivalents a major motive for enhancing the use of biomass for power generation, since is generally considered to be carbon neutral [1]. Combustion is the most commonly used technology for solid biomass rich in lignin, but low lignin and wet substrates can also be exploited through anaerobic digestion to produce biogas, which can easily fuel internal combustion engines for power generation. For these reasons, financial incentives for the production of electricity via anaerobic digestion were introduced in many European countries, leading to a massive expansion of anaerobic digestion (AD) installations. In Italy for example, almost 800 biogas power plants were operating at the end of 2012 with a total capacity of 650 MW [2]. However different utilization patways, such as upgarding the biogas to biomethane for heating or vehicle transport, are technically feasible.

In energy policy modelling, greenhouse gases (GHG) emissions are often considered a satisfactory index for environmental assessment, and it is common practice in energy systems planning to evaluate environmental impact only in terms of CO_2 equivalent emissions reductions: [3] developed a two-stage stochastic optimization model to address interactions among energy supply, processing and demand activities, and the associated GHG emissions; With the aim of planning energy systems in association with GHG-emission mitigation a stochastic approach has also been adopted by [4], who dealt with multiple uncertainties by considering probability distributions and fuzzy intervals. Within the same objective, [5] developed a deterministic input output model in order to identify opportunities to foster the transition of the actual Hungarian energy sector towards higher renewable energy penetration and lower GHG emissions system.

Numerous studies can be found in the energy policy literature dealing with alternative energy production sources such as agricultural biogas [6–8]. In several cases the main focus is on the environmental performance of single [9] or multiple [10, 11] biogas conversion technologies, in terms of carbon equivalent reduction. The assessment is generally done by comparing the use of different raw materials [12], biogas supply chain configurations [13] or biogas utilization pathways.

However, the environmental benefit of using agricultural biogas may be reduced due to the energy consumption required for its production (especially considering farming activities) and the local airborne pollution generated in the process [14]. Such factors, which are also often a major concern to local communities, are not adequately reflected in current energy policy measures.

In order to consider the additional environmental issues in energy system planning (for instance by incorporating the LCA approach in the optimization procedure, as in [15,16]) several authors [17–19] propose the monetization procedure, that is, incorporating the so-called external costs in energy prices. In particular: [17] estimated the externalities associated with the coal-based power sector in Poland, concluding that investments in biogas technologies for power production would certainly reduce the environmental impact of the energy sector as well as reduce unemployment in rural areas; [18] compared the external costs of the main electricity generation technologies for Lithuania so to identify the technologies having the lowest damage costs, while [19] evaluated the sustainability of a biogas supply chain by considering the monetary values of four main impact categories (global warming, acidification, eutrophication, and PM formation).

The external costs are the expenses imposed on society by the environmental disadvantages generated from energy conversion that are not reflected in the price of energy. The externalities arising from the environmental impact of energy production are significant in most EU countries, especially when it comes to electric energy production, and reflect the dominance of fossil fuels in the energy generation mix: in 2005 - 2010 the average external cost of electricity production in the EU was about 6 EUR_{cent}/kWh [18].

As highlighted by [20] the task of quantifying externalities arising from energy conversion technologies is difficult because of a range of problems inherent to the methodology. These include: dependence on a specific technology and on its location; uncertainties in the causes and nature of impacts to health and the environment; and lack of suitable economic valuation studies. Nonetheless, the use of monetary values make the estimation of environmental damages of energy conversion processes more comprehensible in the market place and thus easier to incorporate in energy decisions.

Moreover, as highlighted by [21], in spite of the difficulty in determining monetary values for all environmental impacts and the many uncertainties in the valuation procedure, it is possible to estimate a significant part of the externalities associated with different energy sources and power generation technologies and thus to identify the most advantageous among them. So, even if the absolute values are still debatable, the comparative examination of externalities calculated for different energy sources allow for reconsidering existing pricing mechanisms.

Analyses in the existing literature are mostly performed for general assessments to support policy making [22,23], rather than to evaluate the environmental impact of energy conversion options. In any case, the evaluation is limited to a comparison of the environmental performance of a single renewable energy plant with its fossil energy alternative [21, 22].

The present work intends to fill this gap, by focusing on the external costs associated with airborne emissions along the biogas production supply chain. To do so, the spatially explicit optimization model BeWhere [23, 24] was used with the external cost approach. The model developed is a spatial renewable energy systems optimization model, and thus constructs least-cost biogas supply chains, selecting feedstock supply areas and a mix of energy demand. This allows it to optimize plant location, capacity, and conversion technologies.

The total (internal and external) costs of different biogas utilization pathways were incorporated in the model and compared with the performance of the current mix of corresponding energy vectors, which is mainly based on fossil fuels and will therefore be labelled “fossil” in the following.

Beside internal cost, the external costs considered are those caused by most significant air pollutant emissions generated from stationary production and energy conversion processes, as well as from transportation processes related to biomass logistics.

The system boundaries are described in detail in Section 2 and encompass most significant steps of agricultural biogas supply chains: crop farming and harvesting, the collection and transport of substrates, the anaerobic digestion plant operations and the utilization of biogas for either combined heat and power production (CHP), injection to the gas grid or as a vehicle fuel. Three alternative policy options have been included in the optimization procedure, corresponding to different levels of internalization of external costs, in order to assess the environmental impact of each.

The methodology was implemented with data related to northern Italy, which is characterized by intensive farming.

Results and conclusions are discussed in Section 3, along with a sensitivity analysis for the fossil energy market prices.

2 MATERIALS AND METHODS

The BeWhere model has been adopted in a similar work by the same authors [6] to assess the least costly and more environmentally beneficial biogas supply chain configuration for northern Italy. In that work, as well as in the majority of analogous models [28–30], the environmental impactwas only evaluated in terms of GHG emissions deriving from the biogas production, incorporated in the optimization process through a carbon tax. The present work, which refers to the same geographical context and considers the same biogas utilization pathways, aims at extend the environmental analysis by including other relevant pollutants emissions through the external cost methodology. This method, which follows the impact pathway approach (IPA) [31], allows monetization of the environmental damage associated with emissions of a wide range of pollutants, which can be consequently incorporated in the model objective function. According to the IPA, the chain of casual relationships starts from the specification of the quantities of the relevant pollutants emitted and the location of the pollution sources considering people and ecosystems that are potentially affected . Welfare losses resulting from general emission impacts are converted into monetary coefficients, reported in literature for the European context [32] which are used as weights of air pollutant emissions to assess the external costs for the systems of concern

It should be pointed out that that, as the ecological impacts of products and processes, (e.g. impacts on water, eutrophication or acidification) are not been monetized, such approach might lead to very different results as compared to the LCA methodology conventionally used for environmental damage assessment [33].

For the purposes of this work, the Global Emissions Model for integrated Systems (GEMIS) emission inventory [34] databases for the stationary processes and the IMPACT database [35] for transport activities have been coupled with corresponding external costs derived from the ExternE project [31], which is financed by the European Commission to support the assessment of impacts on human health, crops, building materials and ecosystems resulting from the exposure to airborne pollutants.

2.1 The evaluation of external costs

In this work, external costs associated with the emissions of each biogas utilization pathway, were estimated and compared to the corresponding fossil alternative in a three-step procedure. First, the emission inventory databases [34,35] were used to identify and quantify airborne emissions released in each step of biogas supply chains, whose system boundaries are defined in Section 2.2. Second, the pollutant-specific damage cost factors were estimated using the EcoSenseWeb software [36], developed within the ExternE project. Such tool, was designed for the analysis of single point sources (electricity and heat production) in Europe or it can also be used to derive the site specific damage cost factor of a certain pollutant in a certain region. As such, it resulted particularly suitable for the purpose of this study. With regards to the fossil energy vectors considered in this work, determining the exact location of pollution sources is not always possible (e.g. 90% of the Italian natural gas demand is met by imports from several countries, including Russia, the Netherlands and Algeria), thus average European (EU27) damage cost factors have been used instead, as Table 1 highlights. Conversely, the location of feedstock and of the energy infrastructures were mapped in a spatially explicit way, which allow us to consider national Italian data from EcoSenseWeb when calculating the damage cost factors of the biogas energy vectors.

Finally, the environmental external cost (EEC) of each energy vector was calculated by multiplying the amount of each pollutant arising from the production of 1 GJ of each end product (e.g. chemical, electric power, heat feeding district heating networks) by its damage cost factor (EUR/g).

2.2 System boundaries and main assumptions

Within the systems boundaries of this analysis, three biogas conversion technologies are considered, namely cogeneration, upgrading for injection into the municipal gas distribution grids, and upgrading for vehicle use, which entails a further compression of biomethane obtained from upgrading. The resulting energy vectors, and their corresponding fossil substitutes, are summarized in Table 2, where their energy generation mix is also specified.

We assumed that cogeneration was performed in 1,000 kW or larger reciprocating gas engines. We also assumed that electricity from biogas generated in a co-generation process, controlled under priority dispatch benefits, was completely distributed to the electricity grid by associating it to the local electricity demand. The net heat produced via co-generation, excluding internal uses to sustain anaerobic digestion (AD) processes, was assumed to be consumed via district heating (DH) networks. As we accept that new biogas to power plants should be coupled with existing external heat exploitation infrastructures we considered electricity and heat deriving from generative processes in combination in this study. For this reason, location of existing district heating systems has been incorporated in GIS databases coupled with the model, and biogas-based CHP plants are only assumed to be installed in grid cells containing DH systems. Heat demand for each grid cell was previously estimated in [6] and new biogas CHP plants have been dimensioned based on district heat demand within a 20 km radius and assuming an average pipeline loss coefficient of 15%.

In general, we always consider distribution stations as model boundaries, such as DH networks or local gas distribution grids for the delivery of heat, or a CNG refueling station. The existence of such infrastructures in the area of concern has been mapped based on previous work, and their relevant logistics costs are accounted for [6].

Since the gas grid is highly distributed in study area, and almost 90% of the municipalities considered are served with a low pressure (4 bar) local gas grid, the delivery of methane for heating purposes is assumed to be performed via injection in low pressure pipelines, thus reducing the amount of compression required to reach the national gas standard. Finally, the delivery of biomethane for vehicles entails the compression of the fuel at 60 bar, as it is transported to the refueling stations by the national gas pipeline. Figure 1 also highlights the supply chain of the fossil fuel substituted costs and emissions for these have been accounted for by considering their national energy mix as the reference scenario [37] .

2.3 Emission assessment

In this work, the GEMIS database [34] was used as an inventory for assessing emissions of biogas-and fossil-based processes. This emissions database is not only freely available but is also currently the most extensive inventory of agricultural biogas processes as it adopts typical biogas plant sizes, compared to the wide ranges (e.g. “up to 50 MW”) that are used by other software packages for process or product life cycle assessment, such as [31, 32] [27, 28]. The GEMIS software includes the key energy, material, and transport processes for more than 50 countries, and was extended to cover the EU-25 and EU-28 for the year 2000, 2010, 2020, and 2030. The reference values for all processes considered in this study were taken from the GEMIS database.

As with most LCA studies of biomethane as a fuel, the analysis was limited to the following airborne emissions: CO_2, CH_4, N_2O, NH_3, NMVOC (non-methane volatile organic compounds), SO_2, NOx (nitrous oxides), and PM_{10} (particles with diameter bigger than 2.5 µm).

These pollutants mainly affect local air quality, as NOx and NMVOC react in the atmosphere to form ozone, which may result in short term respiratory problems and irritation of mucous membranes; SO_2 emissions result in similar impacts. PM_{10}, along with NMVOC, also operates as a vector of toxic substances on its surface, and may cause respiratory problems in the short term and cancer in the long term. As well as such local impacts, SO_2 and NOx also have more widespread impacts as they contribute to the formation of acid rain, which threatens ecosystems and vegetation in particular.

The biogas system studied includes four main steps (see Figure 1): farming, feedstock logistics, AD for the production of raw biogas, and conversion of biogas to end energy vectors. These steps were analyzed by considering their associated processes and emissions.

2.3.1 Step I: Farming

We used maize silage as a reference energy crop. Animal manure and sewage production derive from pig-, cattle-, and chicken-breeding farms, since they contribute to almost 70% of the overall amount of substrates commonly used in the northern Italian biogas plants. Their specific volatile solid contents and biogas yields were derived from [6,40].

Emissions were determined for the cultivation and harvesting of maize, and for the collection of manure in the farm based biogas plant. The calculations consider direct emissions from tractor and field machinery operations, including the provision of chemical fertilizers and the management of digestate, with the assumption that it is spread in proximity of the biogas plants.

GEMIS assumes that the fraction of nitrogen as ammonium in digestate represents 65% of its weight, and that 120 kg of digestate are annually spread per hectare , complying with the legal maximum of organic nitrogen fertilization. The digestate transportation is assumed to be by truck to within a distance of 10 km from the biogas plant, in line with [34, 35].

For simplicity, we assumed that maize was cultivated in the existing agricultural land traditionally assigned for its production. This means that there is no land use change. In this way we could exclude any direct land use change (dLuc) emissions which are mainly caused by modifications in the carbon soil content, as for [1, 36]. Field machinery operations are assigned to a tractor having a capacity of 9.8 t and a specific fuel consumption of 10.6 MJ/km.

2.3.2. Step II: Feedstock logistics

Biomass transport to the biogas plant was assigned to a truck trailer with an average capacity of 14 t, based on a gasoil price of 1.1 EUR/l. Distances between the supply sources and the production plants were calculated by the GIS-based transport network model linked with the BeWhere model. In this way, rather than deriving overall emissions from an average fuel consumption for reference distances, as in GEMIS, we adopted a specific database [35] for the quantification of the external costs in the transport sector, and accounted for external costs associated with actual transportation in the supply chains structured by the optimization model.

2.3.3. Step III: Anaerobic digestion

Reference biogas plants considered in this, and a previous study [6], are assumed to operate under mesophilic conditions at a temperature of approximately 37°C. The electricity consumption for the anaerobic digestion (for pumping, stirring, etc.) was assumed to be 4% of the amount of energy in the biogas produced, which corresponds to 0.15 kWh/Nm^3 of raw biogas. For comparison, electricity consumption in anaerobic digestion reported in the literature varies between 0.12 and 0.27 kWh/Nm^3 [44,45]. The same authors reported specific thermal energy consumption between 0.60 and 0.85 kWh/Nm^3 of biogas, in line with the value of 0.70 kWh/Nm^3 indicated by [21], which was used in this study.

In addition to the energy input, methane losses need to be accounted for when assessing emissions from the digestion process. A detailed literature review of studies dealing with methane emissions from biogas production, was carried out by [46], who reported that limited emissions during digestion are normally used, ranging from 0.02 to 0.07% of the total methane production. Consequently we used a reference value of 0.43 g/Nm^3, corresponding to 0.06% of the total methane production.

2.3.4. Step IV: Biogas conversion technologies

When considering the biogas-to-CHP process, the use of an internal combustion engine (ICE) for electricity production is the most common option. The efficiency of CHP units, which generally increases with plant size, were derived from [40]. Reported efficiencies also account for plant self-consumption of electricity and for heat to maintain the mesophilic process, equaling 11% of produced power and 25% of by-produced heat, respectively.

Before biogas is injected into the natural gas grid or used as a vehicle fuel, it needs to be upgraded to biomethane, primarily by removing any presence of CO_2 in order to comply with the national standard requirement (generally represented by the Wobbe index). In this study we used pressurized water scrubbing (PWS) as reference upgrading technology, since it represents one of the most efficient techniques in terms of resource consumption (e.g. water and electricity consumption) and total cost [47]. Data related to cost components and efficiencies for the upgrading technologies as well as the operative costs have been taken from [6].

The electricity demand for biogas purification can range from 3% to 6% of the energy content in the biogas produced [1], depending on the compression required. Within the system boundaries considered in this study, the biomethane is injected into the low-pressure gas network (4 bar), thus the specific electric demand has been estimated as 0.23 kWh/Nm^3 in line with [48]. Methane losses during purification can range from 1% to 4% of purified biogas and specifically from 0.5% - 2% of purified biogas when PWS technology is used. Thus, given that purification technology is rapidly evolving and lower losses are expected in the near future, a central value of 1% was used, in line with the value indicated in [34].

A higher compression is required when the purified biogas is used as a vehicle fuel, since it is assumed to be transported to the existing refueling station by the national gas pipeline, having an operating pressure of 60 bar. Thus, when considering the adoption of biomethane for transport , we assumed a centrifugal compressor would be used, according to the technical information in [34]. This led to an additional electric demand of 0.11 kWh/Nm^3 of purified gas.

2.4 Scenario definition

In order to quantify the contribution of the GHGs to the overall externalities, beside the scenario accounting for the local as well as the global effects of the airborne pollutants (full-scale scenario), an additional scenario, the GHG scenario, was carried out, for which only CO_2 equivalent emissions were considered. Additionally, since the current version of the EcoSenseWeb tool [34], covers only the emission of ‘classical’ pollutants SO_2, NOx, primary particulates, NMVOC and NH_3, the associated external cost of greenhouse gases have been calculated by using a specific carbon tax.

Carbon prices resulting from CO_2 emissions trading, represent the development of the avoidance costs in the least cost path towards the 2050 target and are found to gradually increase from 15 €/t_{CO2} in 2010 to 65 €/t_{CO2} in 2030 [49]. Various recent studies move away from avoidance cost and instead use external cost factors based on damage costs. At the same time, improved insight in the impacts of global warming leads to higher estimates of these damage costs.

According to [50] the external cost factor for CO_2 should depend on the year of emission. For emissions in the following decades, increasing external cost factors are recommended: 26 €/t_{CO2} for 2010-2019, 32 €/t_{CO2} for 2020-2029, 40 €/t_{CO2} for 2030-2039. Following the damage cost approach, a central value of 26 €/t_{CO2} was used.

In our baseline scenario, production costs are internal costs only, while in the GHG scenario they include GHG external costs, internalized through e.g. carbon taxes, and in the full-scale scenario they also include the external costs of other emissions, whose impact is mainly local.

Thus, we determine the most feasible technology mix, both in terms of economic profitability and environmental impact reduction, when the externalities are partially or completely internalized and when they are neglected.

As in [51], in this study the spatial model is used to combine a total cost analysis with a feed-in tariff analysis. The model implies that energy demand is met either with biogas-based energy vectors or with traditional fossil fuels and aims to minimize total costs. The final cost of biogas-based energy vectors are reduced by revenues from selling wholesale at feed-in-tariff levels. Since no biogas plants would be erected under current energy market prices, feed-in tariffs do make up for greater production costs of biogas-based vectors, which are always higher than fossil equivalents.

For the three scenarios, an analysis of sensitivity to changing feed-in tariffs for each bioenergy vector was performed.

3 RESULTS AND DISCUSSION

Table 3 analyses the competitiveness of the biogas energy vectors with their corresponding fossil alternatives by comparing their wholesale prices. For each of them the corresponding break-even tariff was calculated, representing the market price above which the biogas energy vector considered becomes economically profitable. Therefore, the internal costs expressed with reference to the unit of biogas energy vectors (1 GJ) have been compared with current energy market values.

If no feed-in tariffs are introduced, average national wholesale price for each energy vector, i.e. power, heat from district heating, natural gas for heating and natural gas for vehicles, have been assumed as reference market prices [52], as reported in Table 3.

The results show that at current market prices, no additional plants would be installed in the study region, either in the baseline or the global or full-scale scenarios. This means that, while each biogas energy vector presents lower external costs than its corresponding fossil alternative, both when considering the full-scale and the GHG scenario, the benefits are too small to make up for additional production costs of biogas-based alternatives. As shown in Table 3, in fact, the externalities contribute with a minimum amount to the total expenditure, representing less than 10% of the internal cost in each option.

The feed-in tariffs required to start production are generally much higher than current energy market prices: in the baseline scenario, break-even values in the case of biomethane production equal 25.9 €/GJ for transport application and 27.9 €/GJ for injection, as costs for network connection and propane addition required for heating purposes overtake savings in compression costs. Such values are more than double the current market value of fossil alternatives (11.8 EUR/GJ).

In other words, to achieve a minimum production of 140 TJ of biomethane, corresponding to the installation of one biogas plant, a feed-in tariff of 16.1 EUR/GJ for biomethane injection and of 14.1 EUR/GJ for biomethane as a vehicle fuel would be needed. Larger premiums would be required to make more installations affordable, as these break-even values reflect production costs for plants located in the most favourable situations in terms of biomass logistics and connection costs.

In spite of larger production costs, the cogeneration option, although unfeasible under current market conditions, requires smaller incentives because the joint production of heat and electricity provides a double source of income. Thus, a feed-in tariff of 38.1 EUR/GJ for power or 27.3 EUR/GJ of heat would be enough for the model to allow a minimum production of 25 TJ from one CHP plant. Premiums to add to market prices would thus equal 10.4 EUR/GJ for power or 5.1 EUR/GJ for heat.

In the global scenario, when the external costs of GHG are internalized, reductions in the break-even tariffs are recognizable for each alternative: internalizing the carbon emissions would require a minimum feed in tariff of 26.8 EUR/GJ (premium of 15.1 EUR/GJ) for biomethane injection and of 23.1 (premium of 11.2 EUR/GJ) for biomethane for transport. Minimum feed-in tariffs decrease for each technology in the global scenario, implying that all options entail net benefits from GHG emissions reductions at assumed levels of external costs. This is confirmed by the carbon emission saving reported in Table 3 in terms of tonnes of carbon equivalent emissions savings per energy unit of renewable energy. This is favourable for each option, although with lowest efficiency for biomethane generation.

When considering the production of pollutants as well, the environmental efficiency of the biomethane energy vectors decreases, especially in the case of biomethane injection. In fact, with a value of 28.5 EUR/GJ, the break-even tariff is even higher than in the baseline scenario, suggesting that when internalizing pollutants emissions, the use of biogas for heating purposes would entail higher external costs than its fossil alternatives. It should be noted that, since we compared final energy products, the analysis was conducted with reference to the unit of energy (1 GJ) of different types of energy vectors (e.g. electric power, natural gas for domestic heating), having diverse exegetic performances and final uses. Therefore it is arguable that such approach might alter the results with regard to the internal cost values of each biogas option.

However, when referring the internal costs to the unit of energy of biogas, for instance by considering the conversion efficiencies or by analysing the marginal internal cost of each biogas vector, it emerges that cogeneration technology remains the most costly option. Figure 2 shows the marginal internal costs of each biogas conversion option with reference to the unit of energy of biogas (1 GJ of raw biogas). This cost can be calculated by imposing fixed increments in production levels assigned to each utilization pathway, while conversion to other energy forms is kept constant at given production levels. With internal marginal costs of 23.88 EUR/GJ, the CHP option requires high expenses although the joint production of heat and electricity gives a double source of income and the current market price of electricity allows this option to partially cover its production expenses.

3.1 External costs of the baseline scenario

It is interesting to study how external costs of biogas generation change, depending on feed-in tariffs, and how the environmental impact varies when the external costs are partially (GHG scenario) or completely (full-scale scenario) internalized.

Minimizing the cost of the biogas production alone, cogeneration would be the most favourable biogas utilization pathway; with a feed-in tariff of 13.4 EUR/GJ, three additional CHP plants would be selected. At the same time, increasing natural gas price would firstly encourage the production of biomethane for vehicles, rather than injection into the gas grid. In fact, at a natural gas price of 25.9 EUR/GJ, the model selects five biogas plants producing vehicle fuel, while the injection of biomethane into the gas grid is feasible only at a price level of 28.6 EUR/GJ, due to its higher production cost.

Figure 3 highlights the effect of subsidizing either the production of electricity or of biomethane (by applying specific feed-in tariffs named FITel and FITgas respectively) on the external costs and primary energy reduction, here calculated in terms of tonnes of oil equivalent (TOE).

Public investment corresponding to such tariff levels, calculated as total feed-in tariffs for power and gas, is reported on the horizontal axis of Figure 3, while reduction of external costs and fossil fuel consumption is reported in percentages on the vertical axis. When no incentives are applied, the value of all externalities is approximately 4,000 MEUR/year, which is due to meeting energy demands (data taken from [6]) by adopting fossil energy sources. Fostering the substitution of fossil methane with a biogas-based alternative, and applying increasing feed-in tariffs to the production of biomethane (FITgas), would weakly contribute to lowering the level of these externalities. When external costs are not internalized (red dotted lines in Figure 3), very little variations occurs regardless of the amount of the annual investment in the biogas upgrading technology. Only when a total expenditure of 24 MEUR/year is introduced, does a reduction of 0.03% in total externalities occur (equal to 12 MEUR/year).

The trend in total externalities differs when production of biogas-based electricity is subsidized (red continuous line in Figure 3). With investments of almost 6 MEUR/year in the cogeneration technology, the same reduction of total external cost is obtained, whereas increasing FITel would lead to a total reduction of 0.13%.

Small reductions in the overall energy consumption can be seen both cases (red lines of the right figure) since even with high levels of investment, the energy consumed by the system decreases by 1% with the application of FITel (from 90 MTOE to 89.1 MTOE) and by 0.1% with the introduction of FITgas.

However, considering that the national Renewable Energy Action Plan (nREAP) has set a target for 2020 to reduce the national primary energy consumption equal to 3% of the value registered in 2010 (from 165 MTOE to 158 MTOE), it is clear that a reduction of 0.1%, which seems negligible in absolute terms, would strongly contribute to reaching that target.

Introducing FITel always leads to a major reduction of the total externalities, which decrease by 0.1% when the investment is set to 24 MEUR/year. This is in contrast to promoting technology upgrades using increasing FITgas values.

3.2 Environmental impact of partial and total internalization of external costs

The yellow lines of Figure 3 show that, when the external costs are accounted for in the objective function, achieving the same primary energy and external costs reduction would require smaller incentives both for natural gas and for electricity, since the externalities generated from biogas energy vectors are always lower than their fossil alternatives.

While in Figure 3 the effect of changing one factor at a time on aggregate indicators is shown, Figures 4-9 highlight the variation in the key model parameters under different combinations of energy market prices, ranging from 5 to 25 EUR/GJ for natural gas and from 30 to 50 EUR/GJ for electricity. In addition, since the results of the one-factor-at-time sensitivity analysis reported in Table 3 highlight that a natural gas price around 26 EUR/GJ is a threshold value, corresponding to the first adoption of the upgraded technology, we conducted a deeper analysis of the model behaviour around this value conducted. Thus, we used an additional range of natural gas prices, varying from 25 EUR/GJ to 29 EUR/GJ.

Figures 4 and 5 show the allocation of raw biogas when the external costs of all the pollutants are accounted for in the model objective function (full-scale scenario). The colour gradient varies from blue to red according to the share of raw biogas allocated to the production of CHP (Figure 4) and to the production of biomethane (Figure 5). In this scenario, we see an overall dominance of the cogeneration technology (majority of green to red colours in Figure 4), while the use of biogas for the production of biomethane as vehicle fuel is preferred only in the case of higher natural gas prices and disadvantageous electric power market conditions (i.e. an electricity price lower than 30 EUR/GJ). This effect is even stronger when considering the injection technology: raw biogas starts to be allocated to biomethane for heating production only when the price of natural gas is above 28.8 EUR/GJ.

The way external costs influence this behaviour can be seen in Figure 6, where the scales express the total (left) or the partial (right) externalities reduction. The most remarkable reduction of total externalities occurs along the horizontal axis (with squares' colours shifting from blue to red), rather than the vertical one, meaning that increasing the electric market price and consequently the use of cogeneration technology has the best environmental benefits. Conversely, installing biogas plants for the production of biomethane as a vehicle fuel induces substantial improvement only in terms of carbon emissions: production of biomethane alone, which occurs when an electric price of 27.7 EUR/GJ is applied, leads to a 0.1% reduction of carbon externalities (square colours shifting from dark blue to light blue).

It is therefore clear that, due to the good environmental performance of the biomethane in terms of CO_2 reduction, a more promising scenario for biomethane would occur when only carbon externalities are internalized. Comparing Figure 7 with Figure 4, we see lower shares of the cogeneration technology at each electricity price level, meaning that more raw biogas is allocated to the production of biomethane for each combination of energy market prices. In fact, at a natural gas price of 28.6 EUR/GJ, the possibility of injecting biomethane into the gas grid opens up, because 14 additional biogas plants for the production of biomethane for injection are installed (in line with the

break-even tariffs expressed in Table 3). In fact, looking at the left part of Figure 8, we see a greater use of raw biogas for such technology, compared with the previous scenario (left part of Figure 5).
This fact, however, leads to considerable changes in the total externalities balance: the right part of Figure 9 shows that, while the values of the carbon externalities decrease as high natural gas prices are applied (with colours passing from blue to red), the introduction of the injection technology has a negative effect in terms of total emissions. In fact, the left figure shows a shift from warm colours (third upper line) to cold colours, meaning that the overall reduction in externalities is smaller.
The trends of the total and GHG externalities, as well as the high break-even fossil tariffs found for each scenario, can be explained by considering the marginal external cost of dispatching the raw biogas for each utilization pathway. Marginal external costs of biogas conversion to different utilization pathways are basically independent from production levels in the ranges considered in this work, and equal average values are shown in Figure 10 for total (green) and GHG (red) externalities. We have confirmed that, considering external costs of carbon alone, all the biogas utilization pathways are favourable, and cogeneration has the best performance. Conversely, when externalities from local emissions are also considered, the environmental advantage over fossil alternatives decreases in all the cases, and in case of biomethane injection it becomes negative.
Since local emissions have such an adverse impact on the external costs of biogas production and as they often constitute the major concern of local residents when biogas projects are proposed, we conclude our analysis by highlighting the different contribution to the total externalities of each production step (Figure 11).
We see that, as confirmed by [1, 34], farming activities (Step I) generate high emissions per MJ biogas, especially regarding non-carbon emissions such as NO_x, SO_2 and particles. This is mainly caused by the use of chemical fertilizers (corresponding to 47%, 63% and 46% of the total NO_x, SO_2 and particles emissions, respectively, according to GEMIS database) and by high diesel consumption occurring during farm work (corresponding to almost 6% of the energy content of the raw biogas produced). The second cause of external costs is transportation of the biomass, which mainly causes local emissions of NOx. The grounds for local concerns about this issue, which is a main cause of opposition to new plants, appear reasonable.
Conversely, the external costs of anaerobic digestion (step III) are almost negligible, and external costs of energy conversion (step IV) are quite small, especially in the case of upgrading. Upgrading may thus appear particularly attractive in terms of social acceptance because of its limited emissions, because no additional combustion from stationary engines is needed.
However, Figure 11 confirms that not only marginal but also average external costs from total emissions generated for the production of fossil energy vectors (grey bars) are higher than the

biogas-based alternatives and that the benefits of biogas are especially high in the case of electricity. Given the high contribution of fossil fuels to the Italy's energy generation mix, biogas-based cogeneration is environmentally more favourable, both when considering the CO_2 equivalent emissions and all pollutants. Fossil methane for vehicles has the second worst performance in terms of total emissions, which is mainly due to different steps required to deliver the product to the filling stations (e.g. compression to 220 bar and transport).

4 CONCLUSIONS

In this work the environmental effect of subsidizing different biogas utilization pathways with the application of several policy instruments was investigated. The adoption of the external costs methodology allowed us to monetize the environmental impact of different biogas-based energy vectors. At the same time, by considering a wider range of pollutant emissions, it was also possible to include additional environmental burdens in the optimization procedure. The results showed that, under the present energy market conditions, the partial or total internalization of the external costs have limited impact on the model optimal results, since the benefit of the biogas energy vectors, in terms of local and total emissions reductions, is very small compared to their overall production costs.

Introducing premium prices on electricity or biomethane production would firstly favor the cogeneration technology, both when the pure internal cost (baseline scenario) and the external costs of GHG and pollutant emissions are considered (global and full scenario, respectively). However, it should be remembered that the CHP technology was included in the model under the assumption of efficient heat exploitation, since each biogas CHP plant was coupled with an adjacent district heating network. This is in line with [53], who suggested that the CHP technology performs best out of all the biogas utilization pathways, in terms of emissions and primary energy reduction, only when an efficient external use of heat is considered.

The results also showed that external costs increased sharply when airborne emissions were included in the assessment, because each biogas technology produced high amounts of non-carbon emissions, mostly in terms of NOx and particulates. Such negative environmental performances are mainly the results of the first steps of the biogas supply chain, because of the use of chemical fertilizers and transportation during the farming.

In particular, with regard to the farming activities associated to the biogas production processes, a special feature of biogas supply chains is that, besides input flows, an output material flow must be managed, i.e. digestate. While anaerobic digestion is known to improve the environmental impact of spreading digestate on land compared to the conventional practice of liquid manure spreading, it does not improve nitrogen concentration. Such aspects have already been investigated in a previous study on biogas supply chain optimization [40]. However the regional scale of the abovementioned study allowed to account for some site-specific factors (such as the Nitrate Vulnerable municipalities), that can be difficultly integrated in a more aggregated case study such as Northern Italy.

Finally these results, suggest that the climate change mitigation alone is not a satisfactory measure to evaluate the sustainability of biogas technologies in order to define energy policies, and confirm some concerns of local communities for the local impacts of renewable energy plants On the other hand, one should bear in mind that, since some ecological impacts are not incorporated in the external cost methodology and values, the total impact of alternative fuels could be even larger, particularly at local level. Future work could thus entail the development and application of new methodologies, other than monetization, in order to weight other environmental impact categories so that they can be incorporated in spatially explicit energy systems models.

Acknowledgments

The Erasmus Traineeship Program and the Italian Ministry of Education, University and Research are gratefully acknowledged for their financial support in the form of a visiting researcher grant at IIASA and of a Ph.D. Scholarship for Miss Piera Patrizio.

Bibliografy

[1]Jury C, Benetto E, Koster D, Schmitt B, Welfring J. Life Cycle Assessment of biogas production by monofermentation of energy crops and injection into the natural gas grid. Biomass and Bioenergy 2010;34:54–66. doi:10.1016/j.biombioe.2009.09.011.

[2]Lin. Energy production from biogas in the Italian countryside: Policies and organizational models. Energy Policy 2013;63:3–9. doi:10.1016/j.enpol.2013.08.072.

[3]Lin QG, Huang GH. An inexact two-stage stochastic energy systems planning model for managing greenhouse gas emission at a municipal level. Energy 2010;35:2270–80. doi:10.1016/j.energy.2010.01.042.

[4]Li YP, Huang GH, Chen X. Planning regional energy system in association with greenhouse gas mitigation under uncertainty. Appl Energy 2011;88:599–611. doi:10.1016/j.apenergy.2010.07.037.

[5]Sáfián F. Modelling the Hungarian energy system - The first step towards sustainable energy planning. Energy 2014;69:58–66. doi:10.1016/j.energy.2014.02.067.

[6]Patrizio P, Leduc S, Chinese D, Dotzauer E, Kraxner F. Biomethane as transport fuel – A comparison with other biogas utilization pathways in northern Italy. Appl Energy

2015;157:25–34. doi:10.1016/j.apenergy.2015.07.074.

[7]Østergaard PA. Comparing electricity, heat and biogas storages' impacts on renewable energy integration. Energy 2012;37:255–62. doi:10.1016/j.energy.2011.11.039.

[8]Starr K, Villalba G, Gabarrell X. Upgraded biogas from municipal solid waste for natural gas substitution and CO2 reduction--a case study of Austria, Italy, and Spain. Waste Manag 2015;38:105–16. doi:10.1016/j.wasman.2015.01.001.

[9]Akbulut A. Techno-economic analysis of electricity and heat generation from farm-scale biogas plant: Çiçekdağı case study. Energy 2012;44:381–90. doi:10.1016/j.energy.2012.06.017.

[10] Rehl T, Müller J. CO2 abatement costs of greenhouse gas (GHG) mitigation by different biogas conversion pathways. J Environ Manage 2013;114:13–25. doi:10.1016/j.jenvman.2012.10.049.

[11] Kitson L. Subsidies and External Costs in comparative review of estimates. Sustain Dev 2011.

[12] Fuchsz M, Kohlheb N. Comparison of the environmental effects of manure- and crop-based agricultural biogas plants using life cycle analysis. J Clean Prod 2015;86:60–6. doi:10.1016/j.jclepro.2014.08.058.

[13] Novosel T, Pukšec T, Duić N. 24th European Symposium on Computer Aided Process Engineering. vol. 33. Elsevier; 2014. doi:10.1016/B978-0-444-63455-9.50146-X.

[14] Poeschl M, Ward S, Owende P. Environmental impacts of biogas deployment - Part II: Life Cycle Assessment of multiple production and utilization pathways. J Clean Prod 2012;24:184–201. doi:10.1016/j.jclepro.2011.10.030.

[15] Münster M, Lund H. Use of waste for heat, electricity and transport—Challenges when performing energy system analysis. Energy 2009;34:636–44. doi:10.1016/j.energy.2008.09.001.

[16] Milutinović B, Stefanović G, Dassisti M, Marković D, Vučković G. Multi-criteria analysis as a tool for sustainability assessment of a waste management model. Energy 2014;74:190–201. doi:10.1016/j.energy.2014.05.056.

[17] Igliński B, Buczkowski R, Cichosz M. Biogas production in Poland—Current state, potential and perspectives. Renew Sustain Energy Rev 2015;50:686–95. doi:10.1016/j.rser.2015.05.013.

[18] Streimikiene D, Alisauskaite-Seskiene I. External costs of electricity generation options in Lithuania. Renew Energy 2014;64:215–24. doi:10.1016/j.renene.2013.11.012.

[19] Massaro V, Digiesi S, Mossa G, Ranieri L. The sustainability of anaerobic digestion plants: a win–win strategy for public and private bodies. J Clean Prod 2015;104:445–59. doi:10.1016/j.jclepro.2015.05.021.

[20] Eyre N. External costs. Energy Policy 1997;25:85–95. doi:10.1016/S0301-4215(96)00124-3.

[21] Mirasgedis S, Diakoulaki D. Multicriteria analysis vs. externalities assessment for the comparative evaluation of electricity generation systems. Eur J Oper Res 1997;102:364–79. doi:10.1016/S0377-2217(97)00115-X.

[22] Krewitt W, Heck T, Trukenmüller A, Friedrich R. Environmental damage costs from fossil electricity generation in Germany and Europe. Energy Policy 1999;27:173–83. doi:10.1016/S0301-4215(99)00008-7.

[23] Sener C, Fthenakis V. Energy policy and financing options to achieve solar energy grid penetration targets: Accounting for external costs. Renew Sustain Energy Rev 2014;32:854–68. doi:10.1016/j.rser.2014.01.030.

[24] Galetovic A, Muñoz CM. Wind, coal, and the cost of environmental externalities. Energy Policy 2013;62:1385–91. doi:10.1016/j.enpol.2013.07.140.

[25] Faaij A, Meuleman B, Turkenburg W, Van Wijk A, Bauen A, Rosillo-Calle F, et al. Externalities of biomass based electricity production compared with power generation from coal in the Netherlands. Biomass and Bioenergy 1998;14:125–47. doi:10.1016/S0961-9534(97)10005-8.

[26] Wetterlund E, Leduc S, Dotzauer E, Kindermann G. Optimal localisation of biofuel production on a European scale. Energy 2012;41:462–72. doi:10.1016/j.energy.2012.02.051.

[27] Leduc S, Starfelt F, Dotzauer E, Kindermann G, McCallum I, Obersteiner M, et al. Optimal location of lignocellulosic ethanol refineries with polygeneration in Sweden. Energy 2010;35:2709–16. doi:10.1016/j.energy.2009.07.018.

[28] Wetterlund E, Leduc S, Dotzauer E, Kindermann G. Optimal localisation of biofuel production on a European scale. Energy 2012;41:462–72. doi:10.1016/j.energy.2012.02.051.

[29] Schmidt J, Leduc S, Dotzauer E, Schmid E. Cost-effective policy instruments for greenhouse gas emission reduction and fossil fuel substitution through bioenergy production in Austria. Energy Policy 2011;39:3261–80. doi:10.1016/j.enpol.2011.03.018.

[30] Leduc S, Lundgren J, Franklin O, Dotzauer E. Location of a biomass based methanol production plant: A dynamic problem in northern Sweden. Appl Energy 2010;87:68–75. doi:10.1016/j.apenergy.2009.02.009.

[31] European Commission. ExternE Externalities of Energy; Methodology 2005 Update. vol. EUR 21951. 2005. doi:ISBN 92-79-00423-9.

[32] Ciemat. ExternE - Externalities of Energy (Vol XX : National Implementation). Eur Comm 2000;XX:534.

[33] De Nocker L, Spirinckx C, Torfs R. Comparison of LCA and external-cost analysis for biodiesel and diesel. 2nd Int Conf LCA Agric Agro-Industry For 1998:1–10.

[34] Fritsche UR, Schmidt K. Global Emission Model of Integrated Systems (GEMIS) manual. vol. 111. 2007. doi:10.1213/ANE.0b013e3181e3ddbc.

[35] van Essen H, Schroten a, Otten M, Sutter D, Schreyer C, Zandonella R, et al. External costs of transport in Europe-Update study for 2008. UIC, Delft, Netherlands, Nov 2011.

[36] Droste-franke B, Bickel P. Estimating external costs using EcoSense 2005:1–25.

[37] Gse. Incentivazione della produzione di energia elettrica da impianti a fonti rinnovabili diversi dai fotovoltaici. WwGseIt 2012:1–139.

[38] Spatari S, Betz M, Florin H, Baitz M, Faltenbacher M. Using GaBi 3 to perform life cycle assessment and life cycle engineering. Int J Life Cycle Assess 2001;6:81–4. doi:10.1007/BF02977842.

[39] Ciroth A. ICT for environment in life cycle applications openLCA — A new open source software for life cycle assessment. Int J Life Cycle Assess 2007;12:209–10. doi:10.1007/s11367-007-0337-1.

[40] Chinese D, Patrizio P, Nardin G. Effects of changes in Italian bioenergy promotion schemes for agricultural biogas projects: Insights from a regional optimization model. Energy Policy 2014;75:189–205. doi:10.1016/j.enpol.2014.09.014.

[41] Börjesson P, Berglund M. Environmental systems analysis of biogas systems-Part I: Fuel-cycle emissions. Biomass and Bioenergy 2006;30:469–85. doi:10.1016/j.biombioe.2005.11.014.

[42] Delzeit R, Kellner U. The impact of plant size and location on profitability of biogas plants in

Germany under consideration of processing digestates. Biomass and Bioenergy 2013;52:43–53. doi:10.1016/j.biombioe.2013.02.029.

[43] Boulamanti AK, Donida Maglio S, Giuntoli J, Agostini A. Influence of different practices on biogas sustainability. Biomass and Bioenergy 2013;53:149–61. doi:10.1016/j.biombioe.2013.02.020.

[44] Buratti C, Barbanera M, Fantozzi F. Assessment of GHG emissions of biomethane from energy cereal crops in Umbria, Italy. Appl Energy 2013;108:128–36. doi:10.1016/j.apenergy.2013.03.011.

[45] Lantz M, Börjesson P. Greenhouse gas and energyassessment of the biogas from co-digestion injected into the natural gas grid: A Swedish case-study including effects on soil properties. Renew Energy 2014;71:387–95. doi:10.1016/j.renene.2014.05.048.

[46] Mathieu Dumont NL, Luning L, Yildiz I, Koop K. The Biogas Handbook. Elsevier; 2013. doi:10.1533/9780857097415.2.248.

[47] Beil M, Beyrich W. The Biogas Handbook. Elsevier; 2013. doi:10.1533/9780857097415.3.342.

[48] Lantz M. The economic performance of combined heat and power from biogas produced from manure in Sweden - A comparison of different CHP technologies. Appl Energy 2012;98:502–11. doi:10.1016/j.apenergy.2012.04.015.

[49] European Commission. Europe 2020 – Europe's growth strategy. Eur Website - Eur 2020 2011. doi:10.1016/j.resconrec.2010.03.010.

[50] Bickel P, Friedrich R, Burgess a, Fagiani P. HEATCO–Developing harmonised European approaches for transport costing and project assessment. IER Univ Stuttgart 2006:1–193.

[51] Drechsler M, Meyerhoff J, Ohl C. The effect of feed-in tariffs on the production cost and the landscape externalities of wind power generation in West Saxony, Germany. Energy Policy 2012;48:730–6. doi:10.1016/j.enpol.2012.06.008.

[52] Distr T, Impre U. Energia dei costi. n.d.

[53] Patterson T, Esteves S, Dinsdale R, Guwy A. Life cycle assessment of biogas infrastructure options on a regional scale. Bioresour Technol 2011;102:7313–23. doi:10.1016/j.biortech.2011.04.063.

TABLES AND FIGURES

Energy source	N_20	CO_2	CH_4	NO_X	SO_2	NMVOC	NH_3	PM_{10}
Fossil	7.24	0.026	0.575	7.06	6.75	1.06	12.71	15.2
Biogas	7.24	0.026	0.575	3.66	4.26	1.89	11.28	18.2

Table 1: Damage cost factors for fossil and biogas-based energy sources (EUR/kg) [21]

Energy vector	**Infrastructure**	**Technology**	**Energy Source (%)**
Electric power	National electric grid	National electricity generation mix	RES (35,6) - Coal (12,8) - NG (42,4) – Nuclear (1,7) - Oil (1,6) - Others (5,9)
		Internal Combustion Engine (1 MW)	Agricultural feedstock (Energy crops and animal manure)
Heat	Existing district heating	National energy mix in DH	NG (76) - Biomass (11) - Oil (11) – RSU (6)
		Internal Combustion Engine (1 MW)	Agricultural feedstock (Energy crops and animal manure)
Methane for pipeline injection	National gas grid (60 bar)	National natural gas mix	Domestic (11) Foreign (90)
	Local gas grid (4 bar)	PWS upgrading technology (500 Nm^3/h)	Agricultural feedstock (Energy crops and animal manure)
Methane as transport fuel	National gas grid (60 bar)	Compression (200 bar)	Domestic (11) Foreign (90)
	National gas grid (60 bar)	PWS upgrading technology (500 Nm^3/h) + Compression	Agricultural feedstock (Energy crops and animal manure)

Table 2: Energy vectors and infrastructure considered

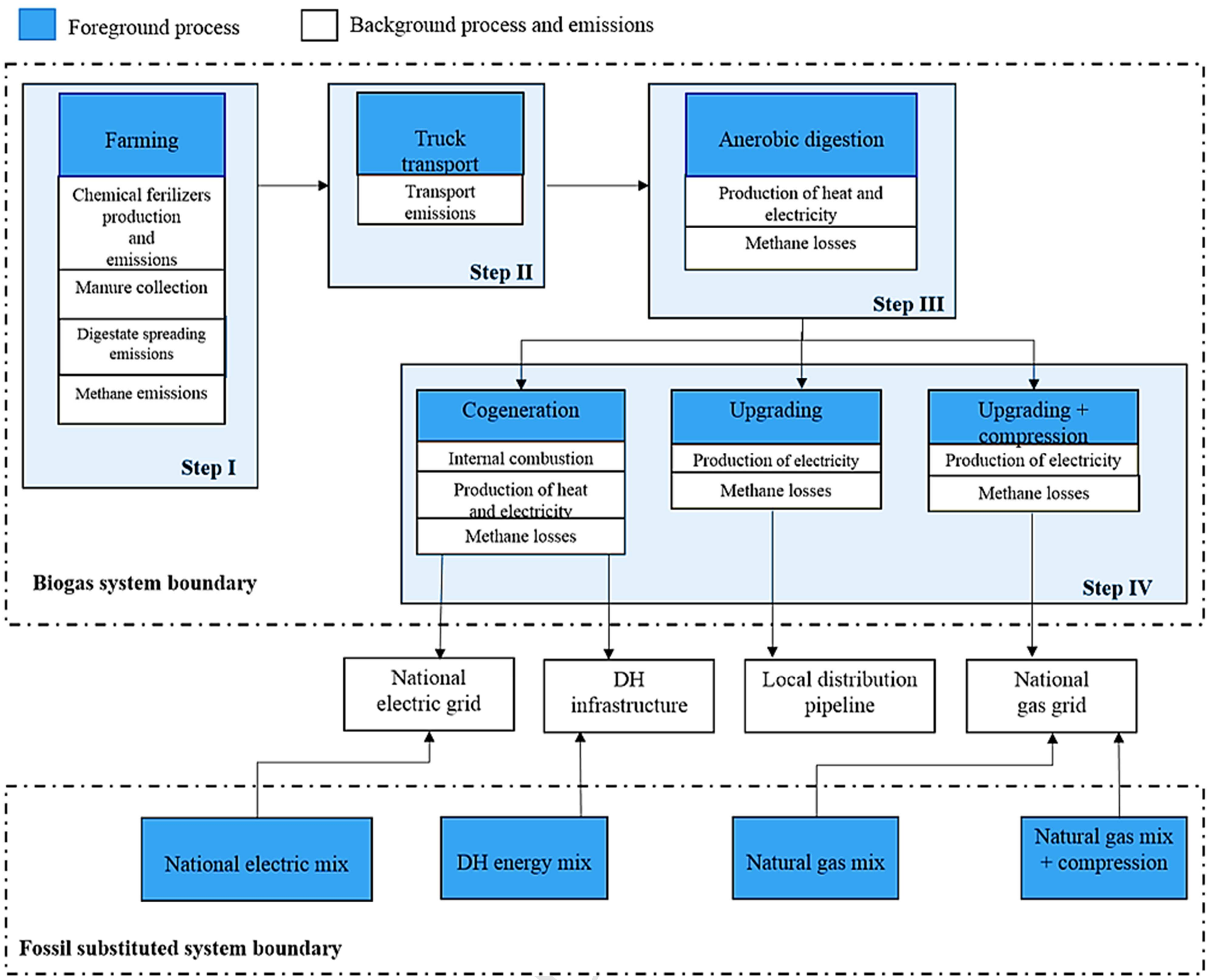
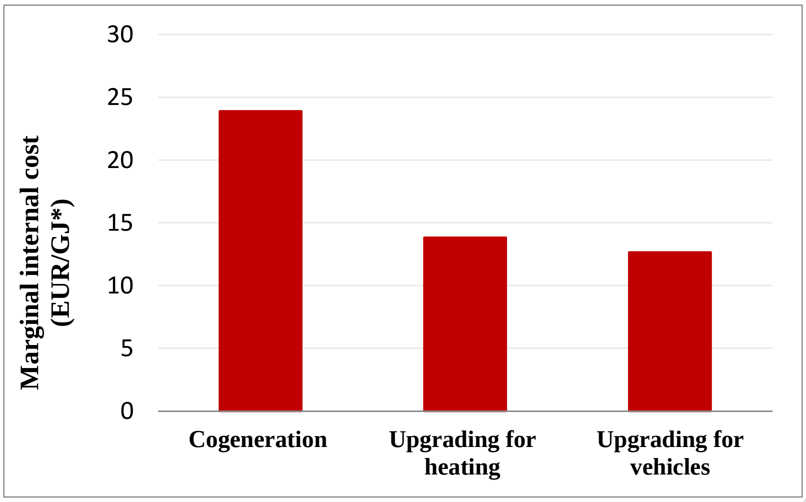


Figure 1: Biogas System and Fossil Substituted system Boundaries

		Electricity			**Heat**			**Biomethane for injection**			**Biomethane for transport**		
Scenario		Baseline	GHG	Full-scale	Baseline	Global-scale	Full-scale	Baseline	GHG	Full-scale	Baseline	GHG	Full-scale
Energy vector market price	EUR/GJ	27.7			22.2			11.77			11.77		
Bio internal cost		58.2			55.4			25.9			27.9		
Bio external cost		0	1.3	4.3	0	0.9	3.6	0	0.6	2.9	0	0.6	2.9
Fossil External cost		0	3.6	6.5	0	2.2	2.8	0	1.9	3.0	0	1.6	2.4
Break-even feed-in-tariff		38.1	31.6	30.8	27.3	25.4	24.6	25.9	23.1	24.2	27.9	26.8	28.5
CO_2 balance	tco_2/GJ	0.138			0.141			0.052			0.042		

Table 3: Economic analysis for each biogas energy vector



* the marginal external cost refers to GJ of raw biogas

Figure 2: Marginal internal cost of the biogas energy vectors considered

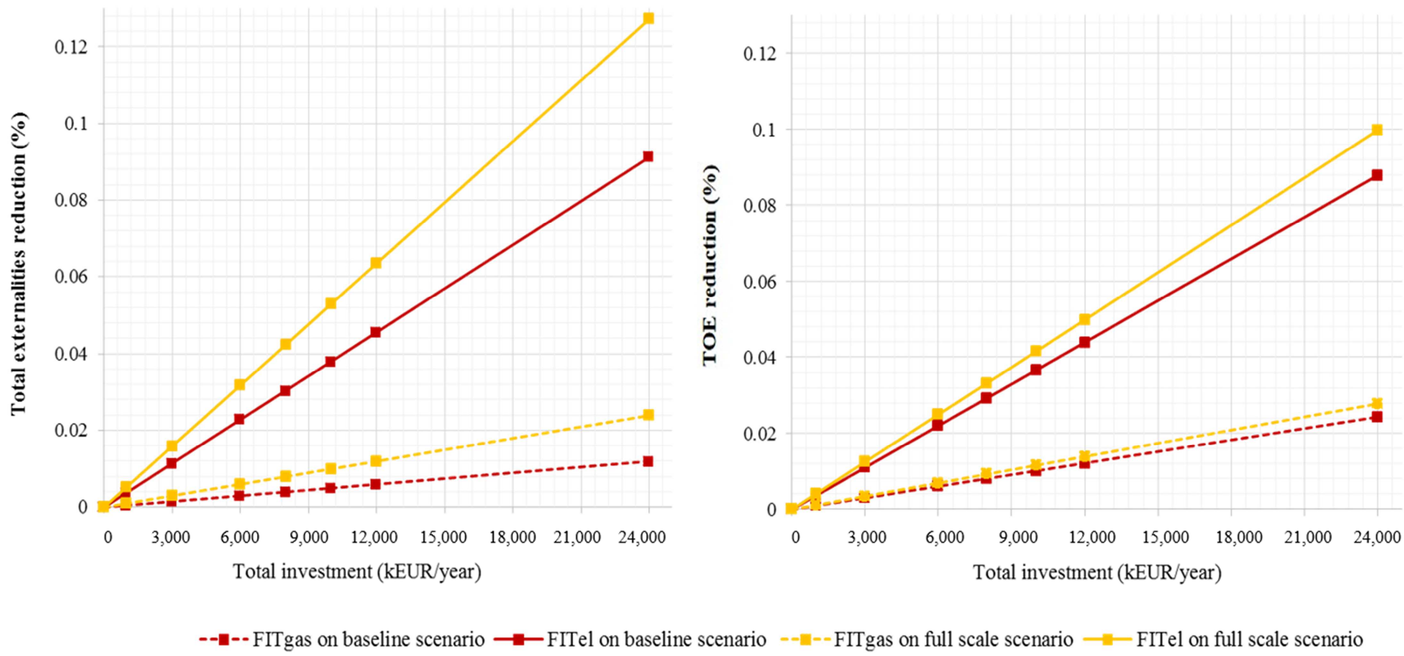


Figure 3: Total externalities variation according to the application of Feed in Tariffs

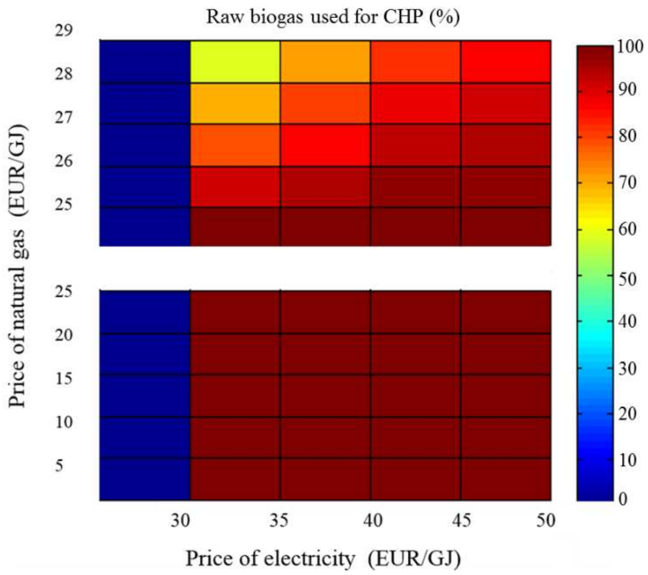
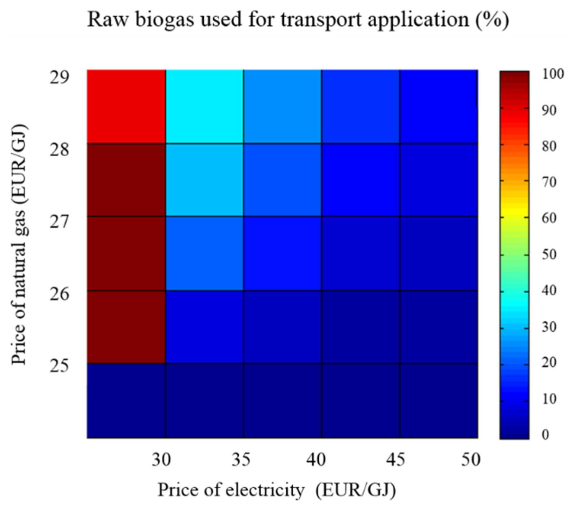


Figure 4: Raw biogas used (%) for CHP in the full-scale scenario for different combination of energy market price



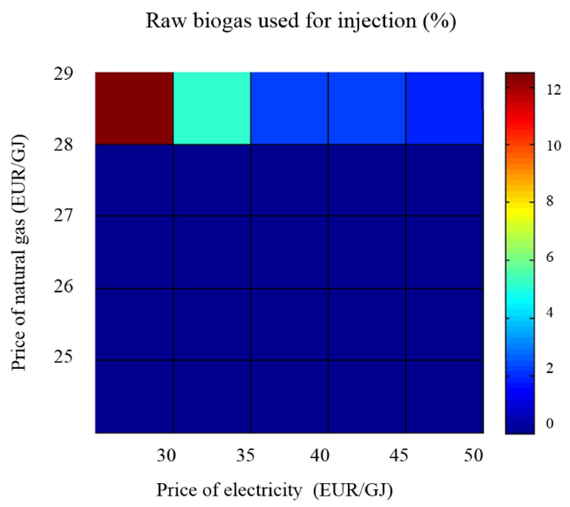


Figure 5: Raw biogas used (%) for biomethane for transport application (left) and for biomethane injection (right) in the full-scale scenario for different combination of energy market price

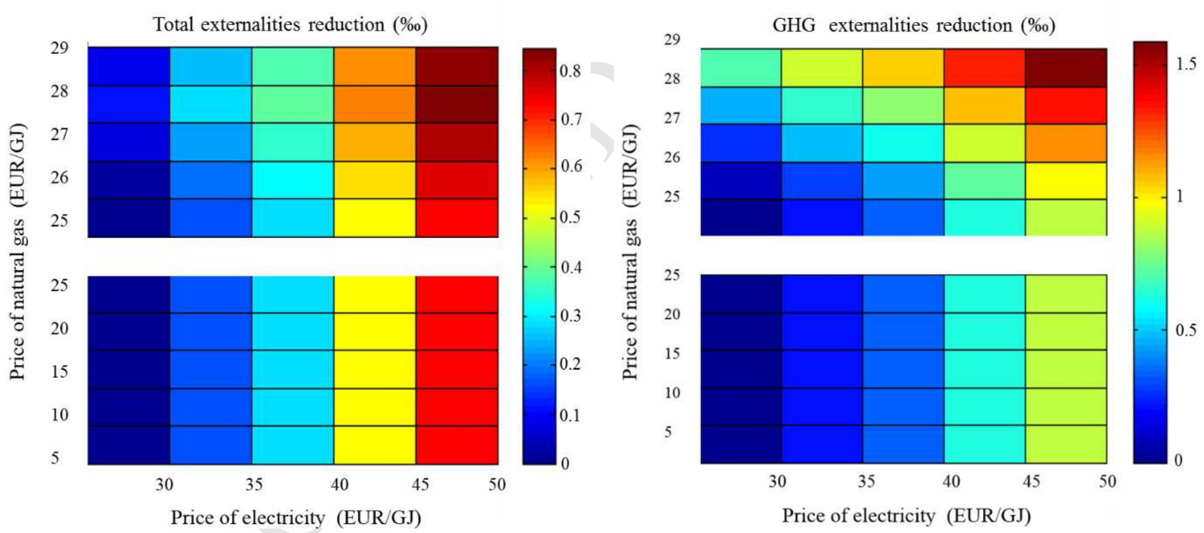


Figure 6: Total (left) and GHG externalities reduction (right) in the full-scale scenario for different combination of energy market price

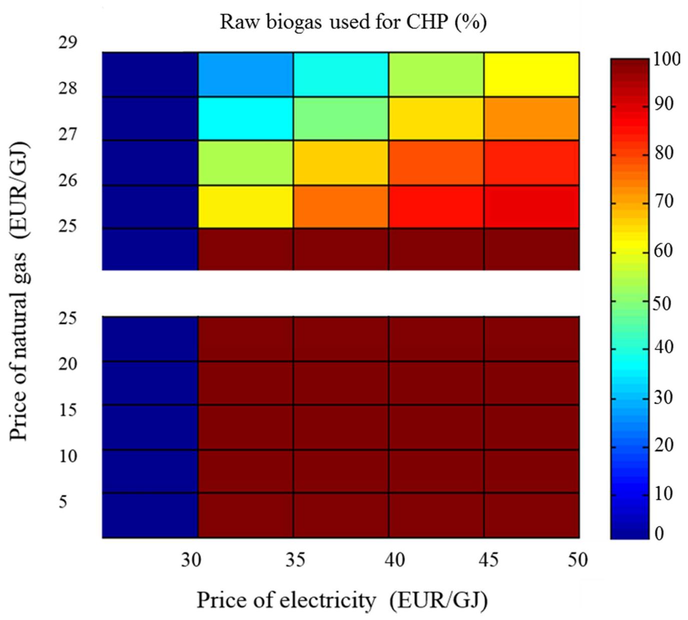


Figure 7: Raw biogas used (%) for CHP in the GHG scenario for different combination of energy market price

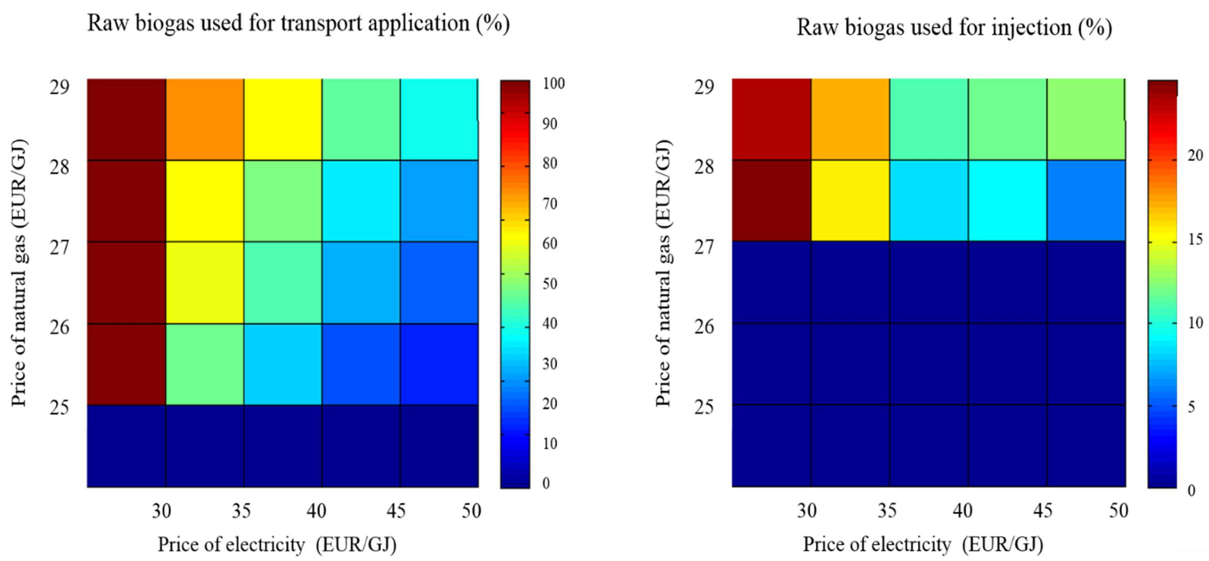


Figure 8: Raw biogas used (%) for biomethane injection (left) and for biomethane for transport application (right) in the GHG scenario for different combination of energy market price

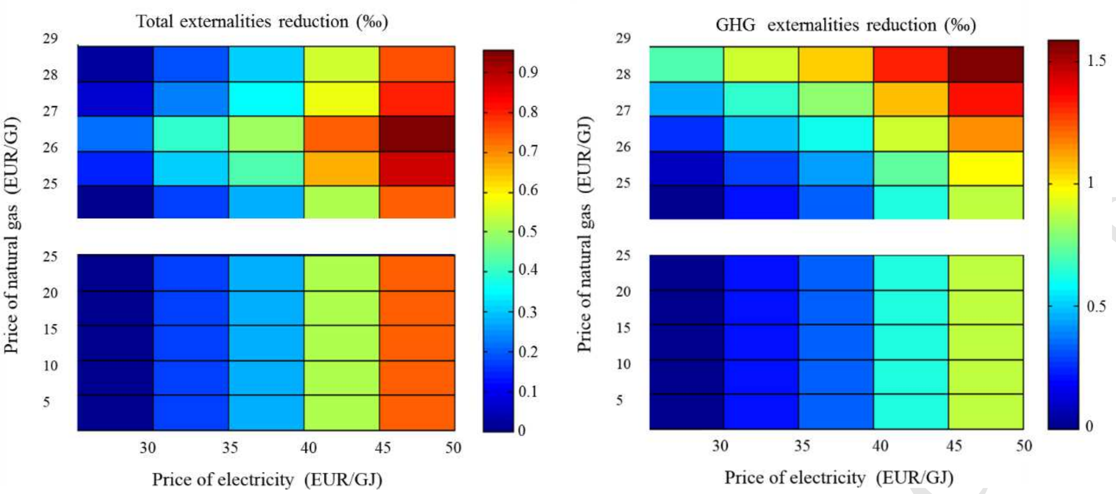
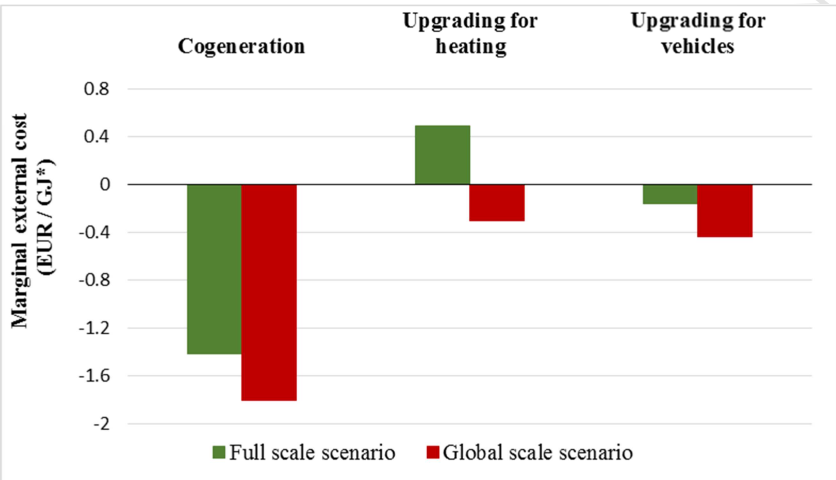


Figure 9: Total (left) and GHG (right) externalities reduction in the GHG scenario for different combination of energy market price



* the marginal external cost refers to GJ of raw biogas

Figure 10: Marginal external cost of the biogas energy vectors in both scenarios

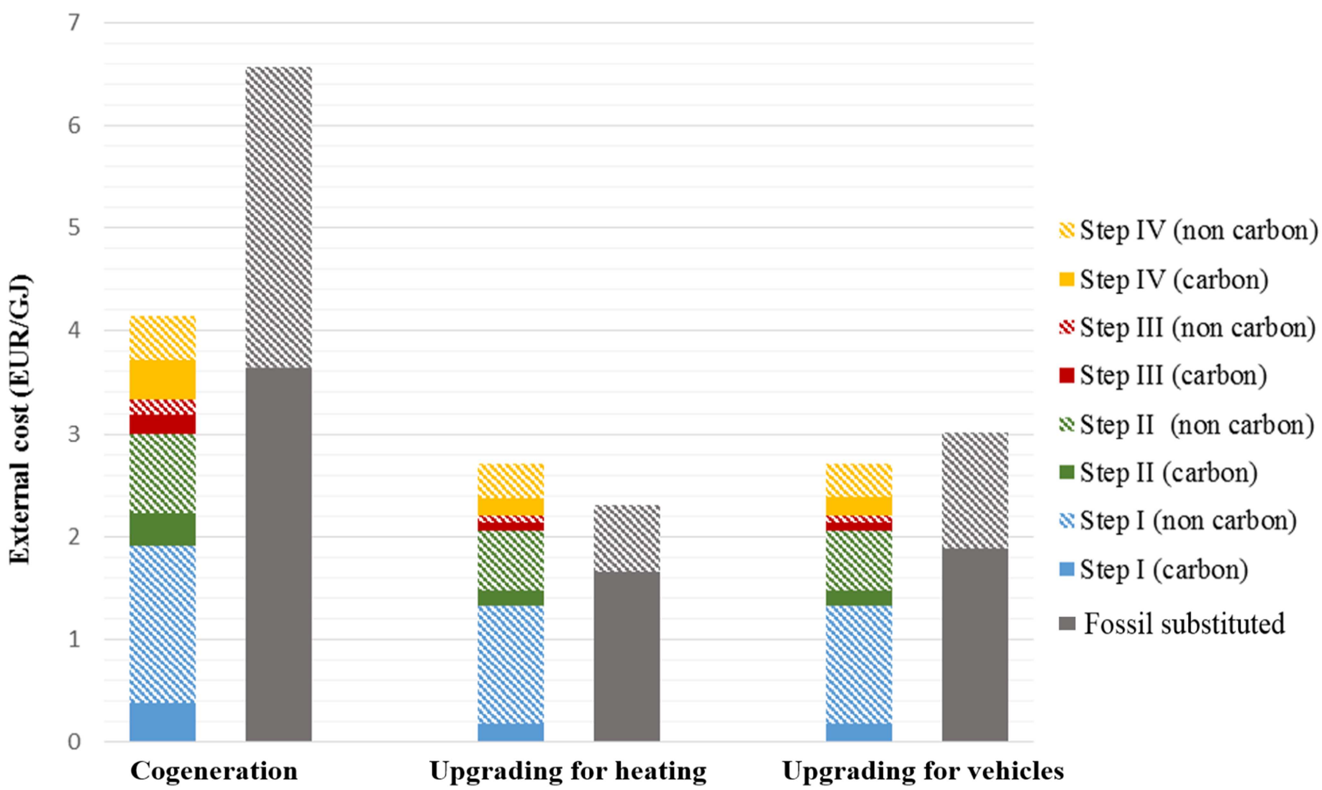


Figure 11: Contribution to the external cost of each biogas process step for the energy vectors considered in the full-scale scenario

Highlights:

- A MILP model has been developed to optimize the economic and environmental performance of the biogas supply chain
- The external costs methodology has been included in the optimization process
- The emissions of the most relevant pollutants generated along the supply chain have been included in the assessment
- Different biogas utilization pathways have been considered