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

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ABSTRACT:

In Italy biogas support schemes are being revised to allocate subsidies also to 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 the external cost methodology is adopted to quantify the environmental impact of airborne emissions associated with biogas based energy vectors and their corresponding fossil alternatives. These are evaluated at supply chain level and incorporated in a spatially explicit optimization model. The study is applied to Northern Italy to compare the potential impact of alternative policy options. It is found that, while external costs of biogas based pathways are always lower than corresponding fossil fuel based pathways, 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 even results in external costs higher than fossil natural gas 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 have CO_2 neutral potentials [1]. Combustion is the most commonly used technology for solid biomass rich in lignin, but also low lignin and wet substrates can be exploited through anaerobic digestion to produce biogas, which can easily fuel internal combustion engines for power generation. For these reasons, financial incentive for the production of electricity via anaerobic digestion were introduced in many European countries, leading to a massive expansion of anaerobic digestion (AD) installations: considering the Italian scenario, 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 purposes or for vehcile applications, are technically feasible.

In energy policy modelling, greenhouse gases (GHG) emissions are often considered a satisfactory index for environmental assessment, and the evaluation of environmental impact only in terms of carbon dioxide equivalent emission reduction has become a common practice in energy systems planning [3–5], especially when considering alternative energy production sources such as agricultural biogas [6–8].

In fact in several studies can be found in energy policy literature which focus on the environmental performance of single [9] or multiple [10, 11] biogas conversion technologies, in terms of carbon equivalent reduction. In many cases the assessment is done by comparing the use of different raw materials [12], biogas supply chain configurations [13] or biogas utilization pathways.

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

In order to consider 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, consisting in incorporating in energy prices the so called external costs.

The external costs are expenses imposed on society by the environmental disadvantages generated from energy conversion that are not reflected in the price of energy commodities (e.g. electric energy, vehicle fuels or domestic heat). 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, including:

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 more efficiently includible in energy decisions.

Moreover, as highlighted by [21], in spite of the difficulty to determine monetary values for all environmental impacts and of 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.

Reviewing literature it can be observed that these analyses 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 spatial explicit optimization model BeWhere [23, 24] has been implemented with the external cost approach. Being a spatial renewable energy systems optimization model, the model developed constructs least cost biogas supply chains, selecting feedstock supply areas and a mix of energy demand, therefore optimizing plant location, capacity and conversion technologies.

The total (internal and external) costs of different biogas utilization pathways, have been 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 briefly 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 plants operations and the utilization of biogas for either CHP, injection to the gas grid or as a vehicle fuel. Three different alternative policy options have been included in the optimization procedure, corresponding to different levels of internalization of their

associated external costs, in order to assess the environmental impact of fostering each biogas alternatives.
The methodology is implemented with data related to the Northern Italian scenario, characterized by intensive agricultural and farming activities.
Results and conclusions are discussed in Section 3, where a sensitivity analysis for the fossil energy market prices is also carried out.

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 the Northern Italian scenario. As in [28–30] the environmental impact, in terms of GHG emissions deriving from the biogas production, has been incorporated in the optimization process by applying 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. Such methodology, which follows the impact pathway approach (IPA), allows to monetize the environmental damage associated with the emissions of a wide range of pollutants. The chain of casual relationship starts from the specification of the quantities of the relevant pollutants emitted in the atmosphere and the location of the pollution source to the impact on various receptors (i.e. human being and ecosystems). Subsequently welfare losses resulting from these impact are transferred into monetary values.
For the purposes of this work, the GEMIS emission inventory [31] databases for the stationary processes and the IMPACT database [32] for transport activities have been coupled with corresponding external costs derived from the ExternE project [33].

2.1 The evaluation of external costs

In this work, external costs associated with the emissions of each biogas utilization pathway, have been estimated and compared to its corresponding fossil alternative in a three-step procedure. Firstly, the emission inventory databases [31,32] has been used to identify and quantify airborne emissions released in each step of biogas supply chains, whose system boundaries are defined in section 2.2. Subsequently, the pollutant specific damage cost factors was estimated using the EcoSenseWeb software [34], developed within the ExternE project 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.

The environmental external cost (EEC) of each energy vector is finally 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).

With regard to fossil energy vectors considered in this study, 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, in this study the location of feedstock and of the energy infrastructures have been mapped in a spatial explicit way, which allow to consider national Italian data from EcoSenseWeb when calculating the damage cost factors of the biogas energy vectors.

2.2 System boundaries and main assumptions

Within the systems boundaries of this analysis, three technologies of biogas conversion 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.

Cogeneration is assumed to be performed in 1,000 kW or larger reciprocating gas engines. The electricity from biogas generated in a co-generation process, controlled under priority dispatch benefits, is assumed to be 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 AD processes, is assumed to be consumed via district heating (DH) networks. The hypothesis is that new biogas to power plants should be coupled with existing external heat exploitation infrastructures: thus, electricity and heat deriving from generative processes will be always considered 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%.

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

Since the gas grid is highly distributed in the territory of concern and almost 90% of the municipalities considered are served with 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 substituted which costs and emission have been accounted for by considering their national energy mix as reference scenario [35,36] .

2.3 Emission assessment

In this work, the Global Emissions Model for integrated Systems (GEMIS) database [31] has been used as an inventory for assessing emissions of biogas and fossil based processes. Such emission database, not only it is freely available but at the moment of the study it displays the most complete inventories for agricultural biogas processes. Moreover comparing GEMIS with other and software packages for process or product life cycle assessment, such as [31, 32] [27, 28], a good level of consistence can be observed as order of magnitude, whereas the capacities considered by the GEMIS model better correspond to the typical biogas plant size than the wide ranges (e.g. “up to 50 MW”) from general inventories. The GEMIS software includes the main 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.

According to the purpose of this study, the GEMIS database has been taken as reference values for the process considered. In particular, as in most LCA studies on 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, along with NMVOC, react in the atmosphere to form ozone, whose strong concentrations in urban areas may result in short term respiratory problems and irritation of mucous membranes; similar impacts derive from SO_2 emissions. Fine particulate, on the other hand, also operates as a vector of toxic substances on its surface: along with NMVOC, PM_{10} may be bound to patogenicity at respiratory level and cancerogenicity in the long term. Beside such local impacts, SO_2 and NOx also have geographically wider impacts as they contribute to the formation of acid rain, which threatens ecosystems and vegetation in particular.

The biogas system studied includes 4 main steps as highlighted in figure 1: farming, feedstock logistics, anaerobic digestion (AD) for the production of raw biogas and conversion of biogas to end energy vectors. Such steps have been analyzed by considering their corresponding background processes and their associated emissions.

2.3.1 Step I: Farming

In this study, maize silage has been selected as reference energy crops, while animal manure and sewage productions 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 have been derived from [6,39].

In this step, the 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, assuming its spreading in proximity of the biogas plants.

The main assumptions in GEMIS is that the fraction of N as ammonium in digestate represent 65% of its weight, and that 120 kg of digestate are annually spread in the field, complying to the maximal legal amount of organic nitrogen fertilization. The transportation of digestate is assumed to be done by truck, within a distance of 10 km from the biogas plant, in line with [34, 35].

For simplicity, maize is assumed to be cultivated in the existing agricultural land traditionally assigned for their production, which means that the soil does not change its occupation. 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 is 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 have been 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, in this step we adopted a specific database [32] for the quantification of the external costs in the transport sector, and account 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 previous study [6] are assumed to operate under mesophilic conditions at a process temperature of approximately 37 C. The electricity consumption considered for the anaerobic digestion (for pumping, stirring, etc.) was 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 [43,44]. 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 adopted in this study.

In addition to the energy input, methane losses need to be accounted for when assessing the emission from the digestion process. A detailed literature review of studies dealing with methane emissions from biogas production, have been given by [45], which reported that limited emissions during digestion are generally considered, ranging from 0.02 to 0.07% of the total methane production. According to that, a reference value of 0.43 g/Nm^3 have been considered, 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. Efficiencies of CHP units, which generally grow with size, were derived from [39]. 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 byproduced 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 carbon dioxide in order to comply with the national standard requirement (generally represented by the Wobbe index). In this study we adopted the pressurized water scrubbing (PWS) as reference upgrading technology, since it represents one of the most efficient technique in terms of resource consumption (e.g. water and electricity consumption) and total cost [46]. 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 the 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 supposed to be 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 [47]. Methane losses during purification can range from 1% to 4% of purified biogas and specifically from 0.5% - 2% of purified biogas when the Water Scrubber technology is adopted. Thus, given that purification technology is rapidly evolving and lower losses are expected in the next future, a central value of 1% has been adopted, in line with the value indicated in [31].

An 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 , the use of a centrifugal compressor is assumed according to the technical information founded in [31], which 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 greenhouse gases 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 (global scale scenario) has been carried out, for which CO_2 equivalent emissions alone have been 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 [48]. 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 [49] 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} have been adopted.

In our baseline scenario, production costs are internal costs only, while in the global scale scenario they include GHG external costs, internalized through e.g. carbon taxes, and in the full scale scenario they include also 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 totally internalized and when they are neglected.

As in [50], in the present work 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 at total cost minimization. The final cost of biogas based energy vectors are reduced by revenues from wholesales at feed-in-tariff levels. Since no biogas plants would be erected under current level of energy market prices, feed in tariffs do make up for larger production costs of biogas based vectors, which are always higher than fossil equivalents.

For the three scenarios, a sensitivity analysis to changing feed-in-tariffs for each bioenergy vector considered in the study will be performed.

3 RESULTS AND DISCUSSION

Table 3 analyses the competitiveness of the biogas energy vectors with their corresponding fossil alternatives by comparing their whole sales prices. For each of them the corresponding break even tariff has been 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 [51], as reported in table 3.

At current market prices, no additional plants are found to be installed in the region of concern, both in the baseline as well as in 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 global scale scenario, 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 in each option less than 10% of the internal cost.

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 of 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, these break-even values reflect production costs for plants located in 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 gives a double source of income. Thus, a feed-in-tariff of 38.1 EUR/GJ for power or alternatively of 27.3 EUR/GJ of heat would be enough for the model to allow a minimum production of 25 TJ from one CHP plants. 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, thus implying that all options entail net benefits from GHG emission reduction 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 emission savings per energy unit of renewable energy, which is favourable for each option, although with lowest efficiency for biomethane generation options.

When considering also the total production of pollutants, 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 whole pollutants emissions, the use of biogas for heating purposes would entail higher external costs than its fossil alternatives. It should be observed that, since we are comparing final energy products, the analysis is 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 the 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). Such 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. It can be noticed that, with an 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 current level of electricity market price allows to partially cover its production expenses.

3.1 External costs of baseline scenario

It is thus 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 (global scale scenario) or totally (full scale scenario) internalized.

Pursuing the minimization of the biogas production cost alone, the cogeneration would be the most favourable biogas utilization pathway: with a feed in tariff of 13.4 EUR/GJ, three additional CHP plants are selected. At the same time, increasing natural gas price would firstly promote the production of biomethane for vehicle, rather than its injection into the gas grid. In fact, at a natural gas price of 25.9 EUR/GJ, the model selects 5 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 on external costs and the primary energy reduction, here calculated in terms of tonnes of oil equivalent (TOE), of subsidizing either the production of electricity or of biomethane, by applying specific feed-in-tariffs named FITel and FITgas respectively.

Public investment corresponding to such tariff levels, calculated as total feed-in-tariffs for power and gas, is reported on the horizontal axis, while reduction of external costs and fossil fuel consumption is reported in percent terms on the vertical axis. When no incentives are applied, the value of the total externalities is approximately 4,000 MEUR/year, which is due to the fulfilment of the 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 on the production of biomethane (FITgas), would weakly contribute to lowering such level of externalities. When external costs are not internalized (red dotted lines in figure 3), it can be noticed that very little variations occurs, regardless the amount of the annual investment in the biogas upgrading technology: only when a total expenditure of 24 MEUR/year is introduced, a reduction of 0.03% of total externalities is registered (equal to 12 MEUR/year) .

Different considerations can be drawn for the total externalities trend when the production of biogas based electricity is subsidized (red continuous line in the figure): 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 appreciated in both cases (red lines of the right figure) since even with high levels of investment, the energy consumed by the system decreases of 1% with the application of FITel (from 90 MTOE to 89.1 MTOE) and of 0.1% with the introduction of FITgas.

However, considering that the national Renewable Energy Action Plan (nREAP) have set for 2020 a reduction of the national primary energy consumption equal to 3% of the value registered in 2010 (passing from 165 MTOE to 158 MTOE),it is clear that such reduction of 0.1%, which seems negligible in absolute terms, would strongly contribute to reach 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), rather than in the case of promoting the upgrading technology, with increasing FITgas values.

3.2 Environmental impact of partial and total internalization of the external costs

Yellow lines of figure 3 shows 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 effect of changing one factor at a time on aggregate indicators is shown, figures from 4 to 9 highlight the variation in the model key parameters under different combination 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 results of 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 upgrading technology, a deeper analysis of the model behaviour around such value has been conducted here. Thus, we adopted an additional range of natural gas prices, varying from 25 EUR/GJ to 29 EUR/GJ.

Figure 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, as expressed in the scale, 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, an overall dominance of the cogeneration technology can be identified (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 case of higher natural gas prices and disadvantageous electric power market conditions (i.e. for an electricity price lower than 30 EUR/GJ). This is even truer when considering the injection technology: raw biogas starts to be allocated to biomethane for heating production only above a natural gas price of 28.8 EUR/GJ.

The way external costs influence this behaviour can be deduced from figure 6, where the scales express the total (left) or the partial (right) externalities reduction. The most remarkable reduction of the 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 thus 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 the sole carbon externalities are internalized. Comparing figure 7 with figure 4, lower shares of the cogeneration technology can be appreciated for 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, for a natural gas price of 28.6 EUR/GJ, the possibility of injecting biomethane in the gas grid is also promoted, since 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, higher utilization of raw biogas for such technology can be appreciated, 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 externalities reduction 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 result basically independent from production levels in the ranges considered in this work, and equal average values reported in figure 10 for total (green) and GHG (red) externalities. It is confirmed that, considering external costs of carbon alone, all the biogas utilization pathways are favourable, and cogeneration has the best performance. Conversely, when also externalities from local emissions are considered, the environmental advantage over fossil alternatives decreases in all the cases, and in case of biomethane injection it turns negative.

Since local emissions have such an adverse impact on external costs of biogas production and since they constitute the major concern of residents when biogas projects are proposed, we conclude our analysis highlighting the different contribution to the total externalities of each production step diagramming the results in figure 11.

It can be noticed 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 usage 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 field operations (corresponding to almost 6% of the energy content of the raw biogas produced). The second cause of external costs is transportation of biomass, which mainly causes local emissions of NOx. The grounds of local concerns about this issue, which is a main cause of opposition to new plants, appear acceptable.

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, in that no additional combustions from stationary engines are introduced in regional systems.

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 Benefits are especially high in the case of electricity. Given the high contribution of fossil fuels to the Italian generation mix, biogas based cogeneration is environmentally more favourable, both when considering the CO_2 equivalent emissions and the totality of pollutants. Fossil methane for vehicles has the second worst performance in terms of total emissions, which is mainly due to different steps required for delivering 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 has been investigated. The adoption of the external costs methodology allowed to monetize the environmental impact of different biogas based energy vectors. At the same time by considering a wider range of pollutant emissions, within such methodology it was 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 reduction, 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 has been included in the model under the assumption of an efficient heat exploitation, since each biogas CHP plant has been coupled with an adjacent district heating network. This is in line with [52], 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.

Results also showed that, when external costs of airborne emissions are included in the assessment, each biogas technology induces high amounts of non carbon emissions, mostly in terms of NOx and particulates. Such negative environmental performances are mainly introduced in the first steps of the biogas supply chain, because of the use of chemical fertilizers and the transportation activities occurring during the farming activities. Such results, and the raise of social concern of the local communities, that are chiefly interested in the local impact of energy conversion plants, 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.

Since it is also important to consider the trade-off between local and global environmental impacts when determining the optimal energy production technologies, a clear assessment of the environmental burdens generated along its supply chain is crucial. Moreover, given the relevant contribute to the local airborne emissions of the transport activities (step II), reducing the feedstock supply radius might induce significant improvement to the final environmental balance.

Thus, further studies on spatial modelling of the environmental effects of renewable energy are needed to promote efficiency and social acceptance of alternative energy vectors. In particular with regard to the logistic activities considering in this study a special feature of biogas supply chains is that, besides input flows, an output material flow should be managed, i.e. digestate: while anaerobic digestion is known to improve the environmental impact of digestate spreading on land compared with the conventional practice of liquid manure spreading under many respects (e.g. through sanification and odour reduction), it does not improve nitrogen concentration. Such aspects has already been investigated in a previous study on biogas supply chain optimization at regional level (). Future works will entail to include the digestate management practice in the optimization procedure and for a wider geographical scale, by taking into account the Nitrates Directive limits on the application of manure fertilizer on cropland in Northern Italy.

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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

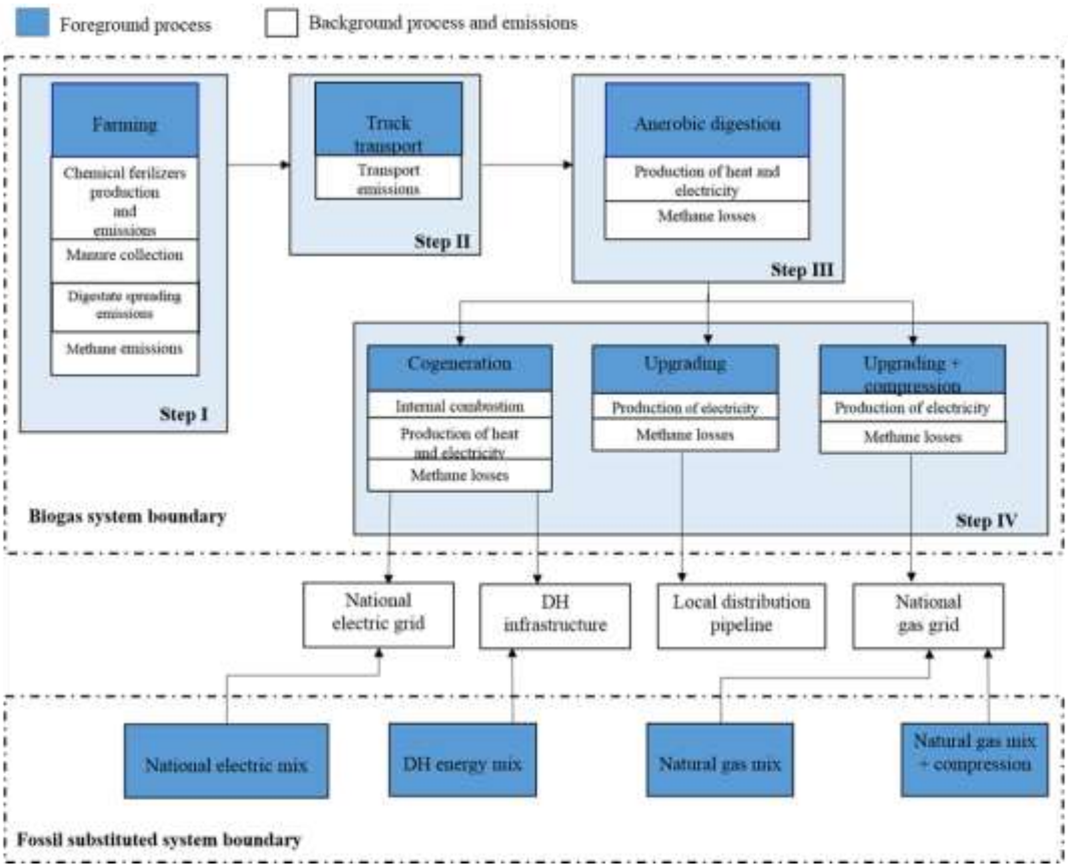
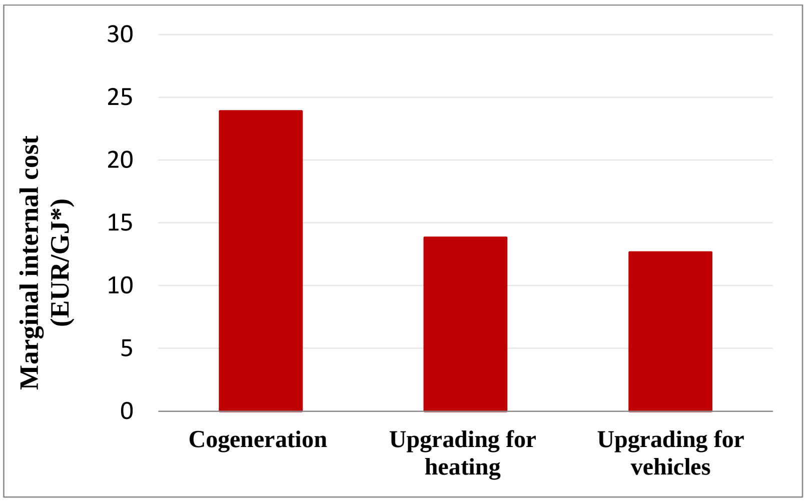


Figure 1: Biogas System and Fossil Substituted system Boundaries

		Electricity			**Heat**			**Biomethane for injection**			**Biomethane for transport**		
Scenario		Baseline	Global scale	Full scale	Baseline	Global scale	Full scale	Baseline	Global scale	Full scale	Baseline	Global scale	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

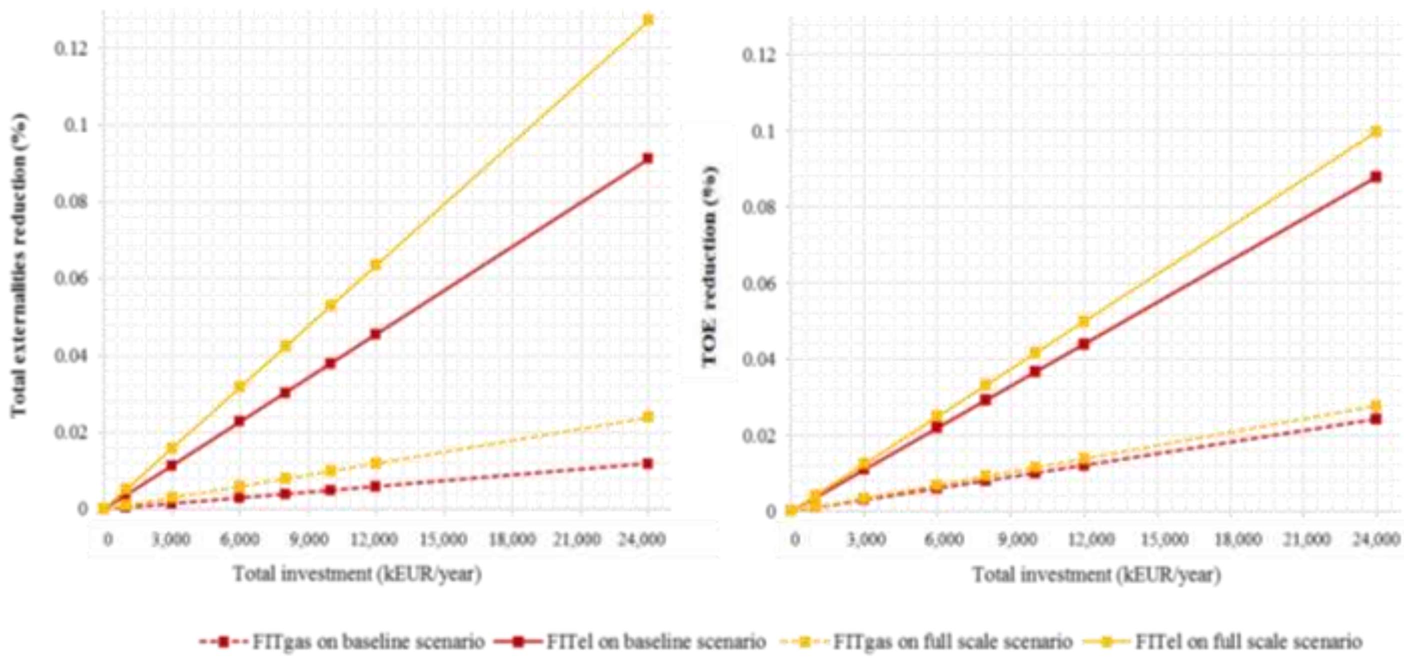


Figure 3: Total externalities variation according to the application of Feed in Tariffs

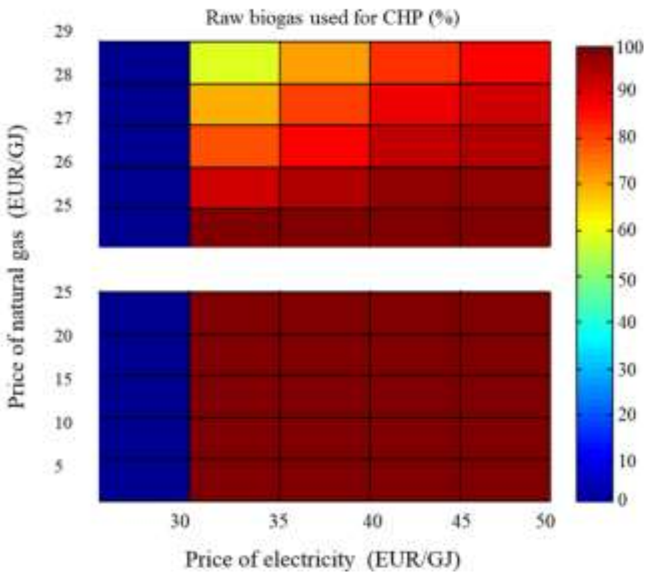
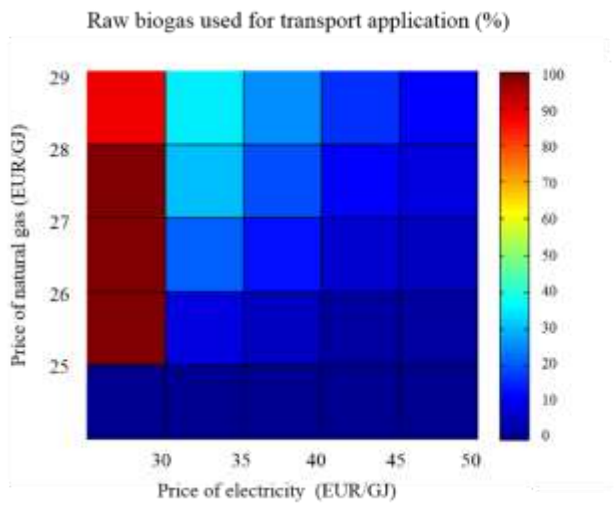


Figure 4: Raw biogas used (%) for CHP in the full scale scenario for different combination of energy market price



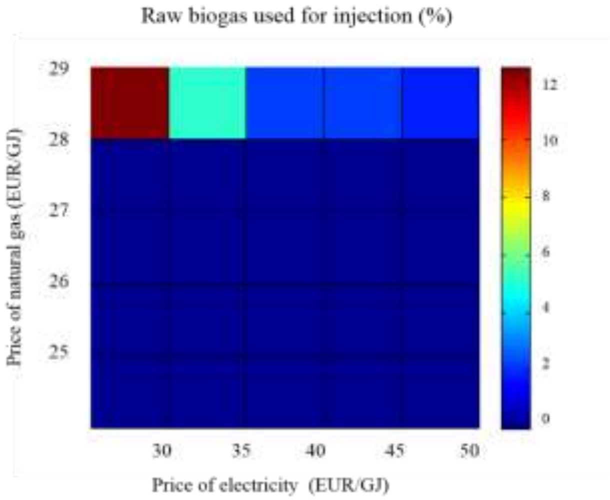


Figure 5: Raw biogas used (%) for biomethane for transport application (left) and for biomethane injection (right) in the full scale scenario for different combination of energy market price

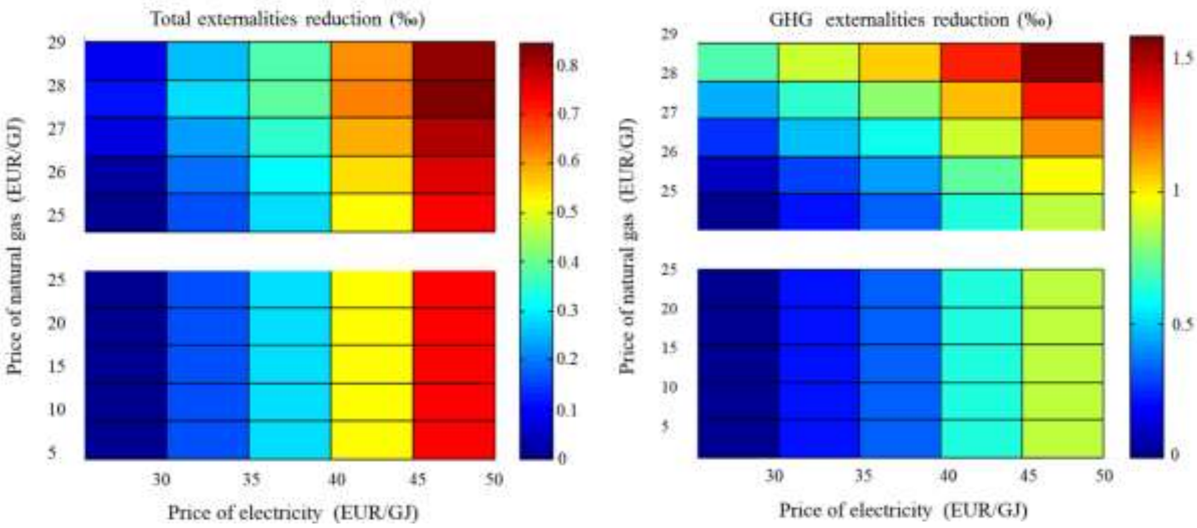


Figure 6: Total (left) and GHG externalities reduction (right) in the full scale scenario for different combination of energy market price

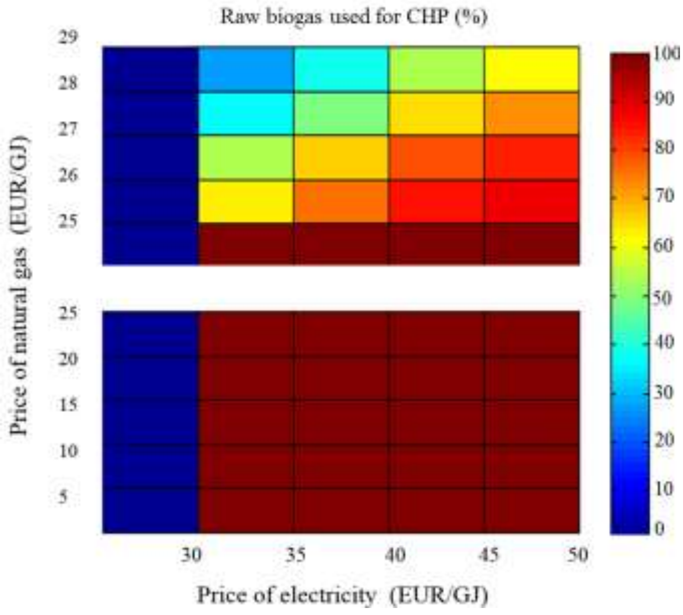


Figure 7: Raw biogas used (%) for CHP in the global scale scenario for different combination of energy market price

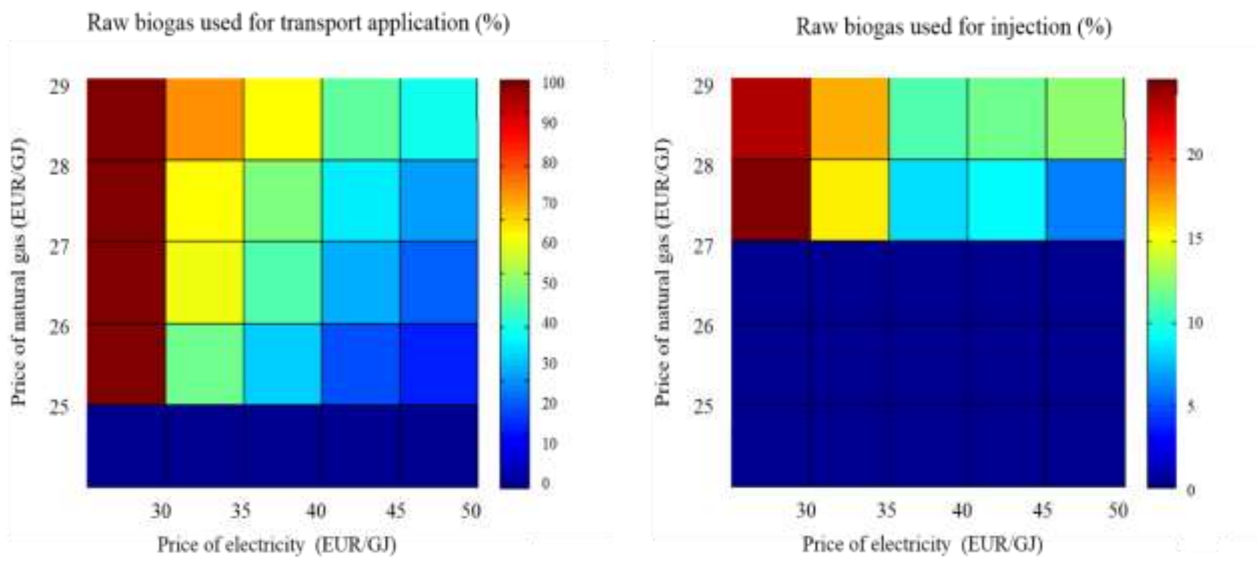


Figure 8: Raw biogas used (%) for biomethane injection (left) and for biomethane for transport application (right) in the global scale scenario for different combination of energy market price

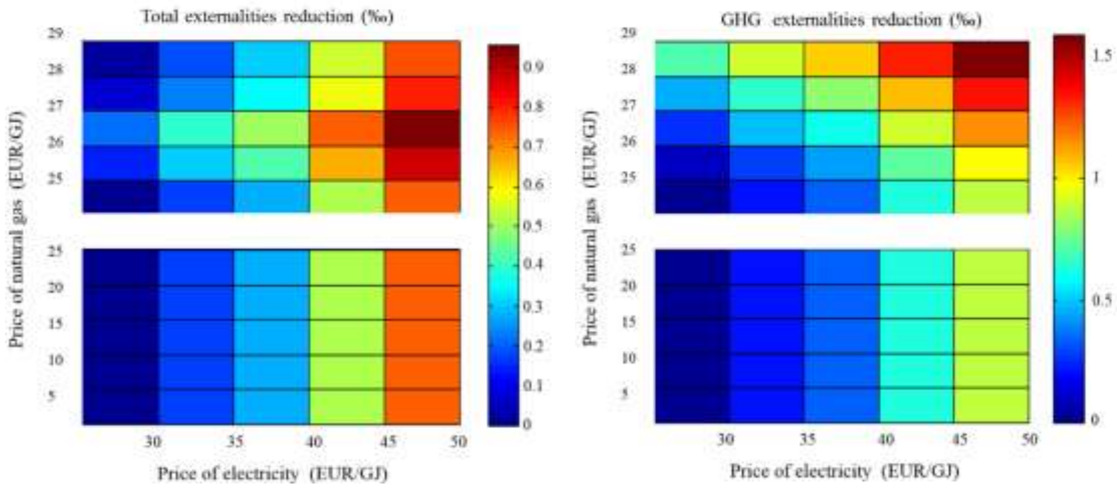
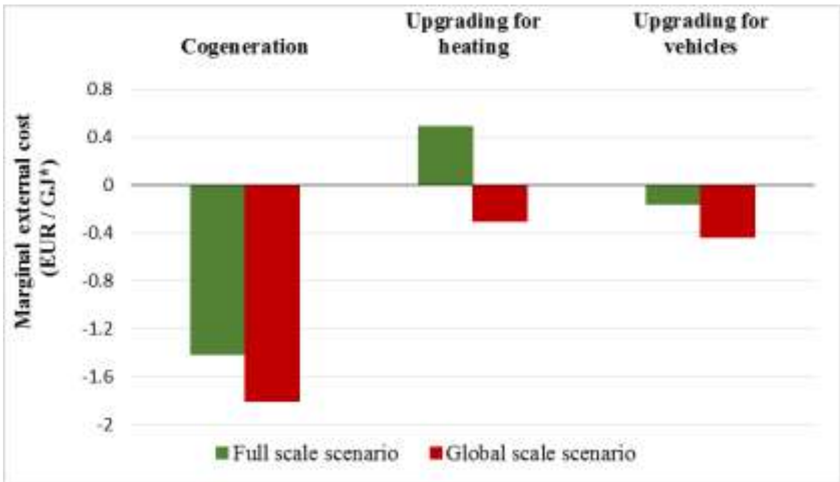


Figure 9: Total (left) and GHG (right) externalities reduction in the global scale scenario for different combination of energy market price



* the marginal external cost refers to GJ of raw biogas

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

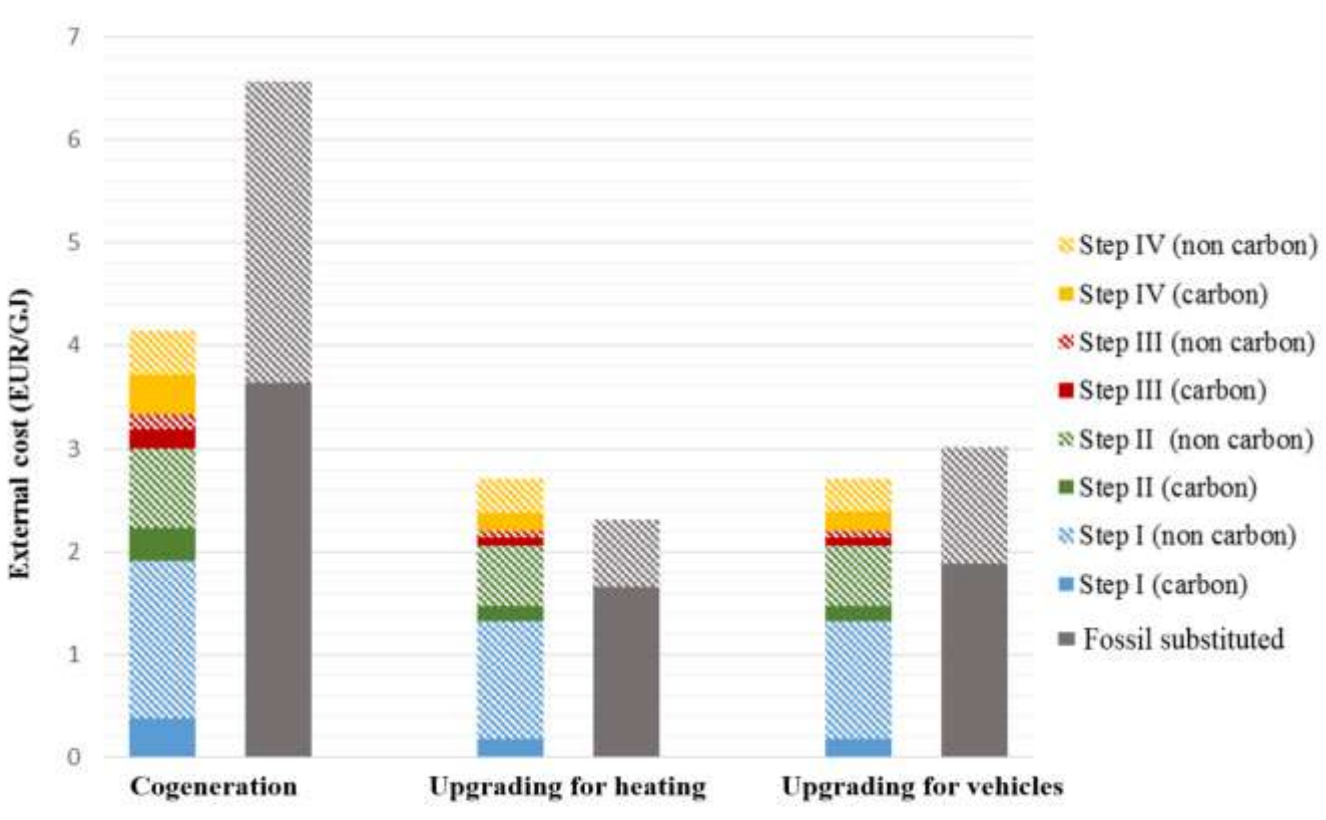


Figure 11: Contribution to the external cost of each biogas process step for the energy vectors considered in the full scale scenario

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