Beyond energy crops and subsidised electricity – A study on sustainable biogas production and utilisation in advanced energy markets

Robert Bedoić[a,*], Filip Jurić[a], Boris Ćosić[a], Tomislav Pukšec[a], Lidija Čuček[b], Neven Duić[a]

[a]Faculty of Mechanical Engineering and Naval Architecture, University of Zagreb, Zagreb, Croatia

[b]Faculty of Chemistry and Chemical Engineering, University of Maribor, Maribor, Slovenia

*Corresponding author

E-mail address: Robert.Bedoic@fsb.hr

ABSTRACT

The aim of this study is to investigate the operation of biogas plants in advanced energy markets after energy crops become limited in their use and biogas plants exit subsidy schemes for electricity production. Continuous biogas combined heat and power production and sale of electricity on the day-ahead market could be a viable operation strategy only in the case of low-cost substrates. When the break-even cost of electricity production in biogas power plants reaches 100 €/MWh$_{el}$, selling electricity on the day-ahead market does not create profit. The study shown that a more profitable operation strategy involves coupling biogas power plant operation on the electricity balancing market with biomethane production or combining a small-scale sugar beet processing facility with a biogas upgrading plant to cover heat demand for sugar beet processing. Techno-economic analysis showed that the viability of both alternative operation strategies is severely impacted by the selling price of biomethane. In the given market conditions, a selling price of biomethane below 50 €/MWh is not viable for a biogas plant. The model developed could be used as a guideline for biogas plant operators on how to proceed after significant changes appear in both biogas production and biogas utilisation.

KEYWORDS

Anaerobic Digestion, Biomethane, Electricity markets, Heat utilisation, Sugar beet

1 INTRODUCTION

Biogas is a renewable energy fuel produced during the degradation of complex organic matter in an oxygen-free atmosphere [1]. Biogas composition is ca. 50-75% methane and 25-45% carbon dioxide, with small amounts of water vapour, oxygen, nitrogen, ammonia, hydrogen and hydrogen sulphide [2]. Over the years, production of biogas was based on utilising energy crops, of which maize silage was (and still is) the most common [3]. However, the European Commission has recently adopted an assessment that beyond 2020, the application of maize silage to biogas production will be limited or even restricted, owing to future sustainability policies [4].

Cultivation of maize silage involves environmental burdens related to the consumption of energy and fertilisers, as well as changes in indirect land use [5]. As an alternative to cultivated energy crops, other biomass sources have shown potential to produce biogas, such as residues from agriculture and industry, municipal organic waste and various sludge types [6]. Agricultural waste and industry co-products and by-products have been recognised as a wide source of sustainable biomass in the European Union [7]. Of all these, animal manure has proven to have the highest biomass technical potential (in t/km^2) compared to other agricultural residues such as harvest leftovers, processing by-products and food waste [7]. Although animal manure has been recognised as a sustainable substrate for biogas production, it has a relatively low biogas yield of only about 0.09 m^3/kg total solids (TS) [8]. To increase the biogas production of cattle manure, co-digestion with other biomass sources is usually performed [9].

Residue grass from landscape management has the potential to serve as a sustainable source of biomass to produce biogas. In the case of river embankments, current practice shows that riverbank grass is mowed a couple of times per year and usually left on the riverbank. The digestion that occurs within the piles of grass left on the bank causes methane and carbon dioxide release into the atmosphere [10]. To avoid unnecessary GHG emissions, riverbank residue grass has been studied as a potential replacement for maize silage in biogas production in Croatia [11]. The biogas yield of riverbank grass co-digested with cattle manure in a 1:1 ratio on a dry basis was about 0.289 Nm^3/kg TS, which was about 28% lower, compared to co-digestion with maize silage. On the other hand, residue grass shows better pH control during the process, compared to maize silage.

Except for animal manure and energy crops, biogas can be produced using industry co-products and by-products as co-substrates. Dairy waste from the dairy processing industry has shown high energy potential to serve as a feedstock for biogas production in Poland [12]. A study has shown that dairy whey produces about 0.86 Nm^3 of biogas per kg of volatile solids (VS), dairy sludge yields biogas production of about 0.48 Nm^3/kg VS, while fatty sludge produces about 1.2 Nm^3 biogas/kg VS. Grease trap sludge has shown synergistic effects in increasing the methane yield of sewage sludge from 0.18 to 0.35 Nm^3/kg VS during anaerobic digestion [13]. Food waste [14] and the organic fraction of municipal solid waste [15] have also attracted attention as sustainable substrates for biogas production. The composition of food waste and organic municipal solid waste is significantly affected by seasonal changes, geographical position, cooking procedures and consumption patterns [16]. These variables strongly effect the AD in terms of process control and inhibition occurrence, usually caused by compounds like salts, heavy metals, ammonia, long chain fatty acids, etc. Looking at the variety of feedstocks available to produce biogas, it is clear that biogas can act as a sustainable alternative to fossil fuels in energy production [17].

According to the latest EU directive (2018/2001) on promoting the use of energy from renewable sources [18], the future use of biogas will be aimed toward biofuel production to be used in industry and the transport sector. Therefore, biogas will play an important role in reaching the future energy policy targets of the European Union (EU). In 2015, the installed capacity of biogas in the EU was ca. 15 GW_{el}, with more than 17,400 biogas plants [19]. Most biogas plants currently use biogas for combined heat and electricity production (CHP), for which biogas plants receive financial support for the energy produced in the form of a Feed-in-Tariff (FIT) or a Premium Tariff (PT) system [20]. The highest incentive for biogas plants is found in Bulgaria, where biogas plants earn 248 EUR/MWh_{el}, while the lowest is reported for the Netherlands, at 85 EUR/MWh_{el} [21]. In the case of Croatia, FIT for 1 kWh of produced electricity using biogas is about 1.20 HRK, or 160 EUR/MWh_{el} [22]. It is important to emphasise that the period of a guaranteed electricity price for biogas CHP is between 12 and 14 years, depending on the country [23].

Soon, biogas plants in the EU will be facing operational issues. Besides the regulations on limited use of maize silage in biogas production, loss of subsidy schemes for electricity production will make possible new options for biogas utilisation. A possible solution for keeping electricity production in biogas CHP after subsidies expire is an orientation towards the operation of biogas plants on the electricity energy market, since biogas plants are flexible in their operation in the power sector, compared to other renewable energy sources [24].

The International Energy Agency has recognised the energy from biomass as a stabilising element in balancing the electricity grid and providing options for energy storage in the EU [25]. The flexible operation of biogas-driven CHP units in terms of load and frequent starts and stops is growing in importance, owing to the increasing share of variable RES in energy systems [26]. The potential of biogas plants to balance the power supply from wind power plants was examined in the case of Latvia [27]. Results showed that the surplus of wind power capacity could be balanced using currently installed biogas CHP plants. In the case of Germany's power system [28], it has been shown that the flexible power generation of biogas plants, integrated with the substitution of fossil fuels in the heating sector, could contribute to economic benefits, compared to subsidised electricity production. Dynamic analysis of the operation of biogas plants in the peak power reserve market in Germany [29] has shown that biogas plants with excess capacity can profitably exploit peak power prices. Results of the study have also shown that a single oversized CHP unit (2 MW_{el}) is economically more feasible than two smaller CHP units (2 x 1 MW_{el}). The market-based optimisation model for biogas plants operating on the spot market [30] showed that biogas facilities can control electricity production through their storage capability and flexible operation in time, duration and amount. For flexible operation of a biogas plant using a CHP of 1.36 MW_{el} and an upgrading unit of 600 Nm^3/h capacity, the size of installed gas storage of 4,800 m^3 proved to be sufficient to provide control reserves and biomethane simultaneously [31].

Another option for maintaining the profitability of biogas plants after loss of the subsidy scheme for electricity production is the upgrading of biogas to biomethane, a gas with more than 95 vol.% of CH_4 [32], as an alternative to heat and electricity production in cogeneration plants [33]. Biogas upgrading in general consists of two steps [34]. The first step is “biogas cleaning”, where toxic compounds like hydrogen sulphide, volatile organic compounds, and ammonia are removed. The next step is the separation of carbon dioxide from methane, which is usually achieved through absorption, adsorption or membrane separation. The cost of upgrading depends heavily on the amount of upgraded biogas and the economy of scale [34]. The total cost of biogas upgrading is estimated to be between 58 and 78 EUR/MWh of upgraded biogas. Energy analysis of biomethane and biogas CHP [35] has shown that the energy efficiency of biomethane production is about 90%, which is much greater compared to the electricity efficiency in CHP (35-40%). Moreover, it has been shown that the incentivising instrument (subsidy) required for biomethane production is at the level of about 30 EUR/MWh, while in the case of electricity from CHP, the lowest subsidy is at the level of about 80 EUR/MWh_{el} [35]. Production of heat from biogas CHP and its utilisation in a small local district heating network, combined with biogas upgrading to biomethane and its injection into a local gas grid, has proven to be a more advantageous option for biogas plant operation compared to electricity production alone [36]. Apart from a district heating network, biogas heat can also be utilised in greenhouses, farming stables, industry, etc [36]. The market potential of biomethane is very broad, since it can be used either in energy production (power generation, vehicle fuel), or as a raw material for the chemical industry, replacing natural gas [37]. The unitary value of subsidies for biomethane and the selling price depend on the business model [38]. In Germany, biomethane producers do not receive FIT for feeding biomethane into the gas grid [39]. However, the German Energy Agency supports biomethane producers through a bonus system for guaranteeing biomethane origin when sustainable substrates like manure and waste are used for biogas production. Such an approach in the biogas sector is given in the latest Renewable Energy Directive recast (RED II) [40], where the guarantee of origin for biomethane production is not declared as a support scheme and should be distinguished from the green certificates for biomethane that are used in support schemes. The selling price of sustainably produced biomethane under the guarantee of origin in Germany is between 65 and 80 €/MWh [41]. Other recent studies have reported that, on average, the selling price of biomethane is ca. 70 €/MWh [42,43]. Detailed analysis of biomethane production and its economic viability has revealed that there are many advantages over biogas CHP in reaching the EU climate and energy goals. Still, the main reasons why biogas upgrading is not currently the dominant biogas utilisation technology are the relatively high subsidy support for biogas CHP and the relatively high capital and operational cost of the upgrading process.

In this study, the economic viability of biogas plant operation in advanced energy markets integrated with sugar production will be analysed. The production of sugar is among the most energy-intensive industries within the agri-food sector [44]. Sugar beet processing constitutes the most energy-intensive phase in sugar production because of its high demand for electricity and heat [44]. Intensive energy users during sugar beet processing are extraction, juice heating, evaporating crystallisation and sugar drying [45]. The specific electricity consumption during sugar beet processing varies between 17 and 30 kWh_{el}/t of processed sugar beet, while specific heat demand varies between 140 and 200 kWh_{th}/t of processed sugar, excluding sugar beet pulp drying [46]. Currently, natural gas is the most common fossil-based fuel for energy production in sugar beet factories [47]. The latest report in 2019 from the European Association of Sugar Manufacturers [48] stated that renewable energy producers should coordinate their operation with the sugar industry to reduce dependency on fossil fuels and reduce GHG emissions. Therefore, anaerobic digestion and biogas technologies have shown high potential for integration within the sugar industry to reduce the requirement for natural gas [49]. Integration of anaerobic digestion technology in a sugar beet processing facility has proven to be more feasible in the case of small-scale, decentralised sugar production [50] than in the case of large, robust centralised facilities. By-products from sugar production like sugar beet pulp, sugar beet tops and tails can be used to reduce waste and give additional value to sugar [51]. Dried sugar beet pulp has been successfully applied in mesophilic co-digestion with animal manure, where it has been shown to increase the methane yield of manure by almost 130% [52].

The contribution of this research is to develop operational methods for existing biogas plants that currently operate in CHP mode once they lose subsidies for energy production in terms of feed-in-tariffs, based on the use of alternative substrates to maize silage in biogas production (sugar beet by-products, riverbank residue grass and cattle manure) and biogas utilisation in advanced energy markets, combined with a small-scale sugar beet processing plant. Objectives of the research are as follows:

(i) to evaluate the viability of biogas CHP plant operation on the day-ahead electricity market after feed-in-tariffs expiry relative to the cost of substrate;

(ii) to determine the threshold of the biomethane selling price relative to the investment in the biogas upgrading unit and biogas CHP operation on the balancing electricity market;

(iii) to assess the economics of integrating biogas plants with industry processes in order to establish sustainable energy and mass flows.

The hypothesis of the research states that the operation of biogas plants using sustainable substrates in advanced energy markets integrated with industry processes can yield economic benefits even after existing biogas plants which have paid out their investment lose support for electricity production by using food-competitive energy crops.

2 MATERIALS & METHODS

In this section, an overview of applied materials and methods is presented. First, biogas yields of alternative substrates to those energy crops in the study are presented. Second, the analysis of biogas production and utilisation under advanced energy markets integrated with sugar production is given.

2.1 Feedstock for biogas production

Riverbank residue grass is selected to be an alternative feedstock to maize silage in biogas production, based on the research already conducted [11]. The daily production of biogas, Q(biogas), using riverbank grass and cattle manure is defined using the following relation:

$$Q(\text{biogas}) = q_{\text{RG+CM}} \cdot M_{\text{RG+CM}} \qquad (1)$$

where $M_{\text{RG+CM}}$ represents the daily input of riverbank residue grass and cattle manure to the digester and $q_{\text{RG+CM}}$ represents the biogas yield of residue riverbank grass and animal manure co-digestion. According to previous research, the $q_{\text{RG+CM}}$ was estimated on 80 Nm^3/t of fresh feedstock [11].

The production period of sugar beet in a small-scale factory (capacity of 100 t/day of processed sugar beet) is assumed to be between October and March. Sugar beet pulp takes around 25% of the mass of processed sugar beet, while the waste plant is around 1.6% of processed beet mass [53]. During sugar production, the biogas plant utilises sugar beet by-products additional to riverbank grass and cattle manure in biogas production:

$$Q(\text{biogas}) = q_{\text{RG+CM}} \cdot M_{\text{RG+CM}} + q_{\text{SBP}} \cdot M_{\text{SBP}} + q_{\text{WP}} \cdot M_{\text{WP}} \qquad (2)$$

where M_{SBP} and M_{WP} represent the daily quantity of sugar beet pulp and the waste plant generated during beet processing, while $M_{\text{RG+CM}}$ represents the daily input of riverbank residue grass and cattle manure to the digester. The average specific biogas yield of sugar beet pulp (q_{SBP}) was found to be 105 Nm^3/t of raw sugar beet pulp, while the average specific biogas yield of the waste plant (q_{WP}) at the same time is 40 Nm^3/t of raw waste residue [53].

2.2 Biogas plant operation under advanced markets integrated with sugar production

In the MATLAB/Simulink® models, all processes inside the anaerobic digester are assumed to be continuous processes, with average biogas production in the unit of time [54]. The computational time of the models was one year, with time intervals of one hour, where the operating point in all scenarios was switch-controlled in real-time, based on market prices. A complementary approach was implemented for the experimental switch-controlled energy harvesting in LabView® [55]. Electricity and heat production (E_{CHP}, H_{CHP}) based on the utilisation of biogas in the CHP unit can be calculated using:

$$E_{\mathrm{CHP}} = \Delta H(\mathrm{biogas}) \cdot \eta_{\mathrm{el}} \int_{0}^{8760\ \mathrm{h}} Q_1(\mathrm{biogas})\ \mathrm{d}t \tag{3}$$

$$H_{\mathrm{CHP}} = \Delta H(\mathrm{biogas}) \cdot \eta_{\mathrm{th}} \int_{0}^{8760\ \mathrm{h}} Q_1(\mathrm{biogas})\ \mathrm{d}t \tag{4}$$

where Q_1(biogas) is the intake flow of biogas to the CHP unit, ΔH (biogas) is the lower calorific value of biogas estimated on 6 kWh/Nm^3 [56], η_{el} is the efficiency of electricity production in the CHP (40%), and η_{th} is the efficiency of thermal energy (heat) in the CHP (50%) [4].

To ensure flexible operation of the biogas CHP on the electricity market, additional biogas storage is included as part of the post-feed-in era investment. Currently, digester headspace is used as temporary storage for biogas for several hours [57], usually not longer than 4 hours. The dynamics of biogas storage depends on the electricity price on the market; the biogas from anaerobic digestion is stored or utilised in the CHP unit to generate electricity. The storage fill percentage is calculated as:

$$x_{storage\%} = \int \left(Q_1 - Q_1^*\right) dt \tag{5}$$

where $Q_1^*$is the biogas storage outflow, which is zero for electricity prices on the day-ahead market and lower than the marginal price. If the electricity price is above the break-even cost of electricity production, the Q_1^* will increase up to the maximum flow at which the CHP unit can operate. If biogas storage falls below 20%, the Q_1^* is limited to the maximum value of Q_1 in order to avoid a completely empty biogas storage unit.

The system dynamics is determined by the electricity price and biomethane price, where the biogas is supplied to storage, the upgrading unit or the CHP, in order to maximize profit, known as advanced unit commitment with economic dispatch [58]. A similar approach is described in [59], where the combined operation between wind power generation and pumped hydro energy storage was analysed, employing MATLAB/Simulink®. For biogas upgrading, a membrane separation system was selected, also known as gas permeation technology, owing to its suitability for smaller upgrading capacities (250 - 750 Nm^3/h) [60]. The specific membrane upgrading electricity consumption for raw biogas ranges between 0.35 and 0.40 kWh_{el}/Nm^3 [60]. The total energy potential of biomethane outflow from upgrading is:

$$H_{up} = \Delta H(\text{biogas}) \cdot \eta_{up} \int_{0}^{8760\ \text{h}} Q_2(\text{biogas})\ \mathrm{d}t \tag{6}$$

where Q_2(biogas) is the intake flow of biogas to the upgrading unit, and η_{up} is the efficiency of the upgrading unit, 90 % [60].

Specific heat demand for sugar beet processing is set at h_{SB}=170 kWh_{th}/t of processed sugar beet when the sugar beet pulp is not dried [46]. This study considerers a small-scale sugar beet processing facility [50] with an average daily input of sugar beet set at M_{SB}=100 t. To calculate the daily heat demand (H_{SB}) for the daily processing of sugar beet, the following relations were used:

$$H_{SB} = h_{SB} \cdot M_{SB} \tag{7}$$

A constraint in the calculation is set on the production of heat to fulfil the heat requirements in the sugar beet processing:

$$H_{SB} = \Delta H(\text{biogas}) \cdot \eta_{gb} \int_{0}^{8760\ \text{h}} Q_3(\text{biogas})\ \mathrm{d}t \tag{8}$$

where Q_3(biogas) is the volume flow rate of biogas required to achieve the proposed heat demand, and the efficiency of the gas boiler (η_{gb}) used in beet processing facility is set at 90% [46].

3 CASE STUDY

The study follows a virtual biogas plant that operated in the past using maize silage and animal manure as substrates, while selling heat in the local district heating network and electricity under a Feed-in-Tariff. The biogas plant operates with two anaerobic digesters, each with a capacity of 4,500 m^3. An installed CHP electric power is 1.00 MW_{el} with electric power efficiency of CHP 40% and thermal power efficiency of 50% [4]. To maintain the heat and electricity production performance, it is required to utilise 10,000 Nm^3/day of biogas in CHP. It is assumed that the biogas CHP engine works for 60,000 h [61] in the period between general overhauls. The capacity of the upgrading unit was assumed at 420 Nm^3/h of upgraded biogas.

3.1 Scenario selection

After the prohibition of maize silage for use in biogas production and the end of the existing subsidy scheme, biogas plants will need to apply different operation strategies. The following three strategies (scenarios) are considered in this work (a schematic representation of these scenarios is shown in Figure 1):

- *Scenario I):* the reference case, where an existing biogas plant continues its operation after a general CHP overhaul and starts to sell electricity on the day-ahead market. Maize silage is replaced by riverbank residue grass, while animal manure further remained to be used for anaerobic digestion. To ensure the flexible operation of CHP on the day-ahead electricity market, given fluctuating prices, an additional investment in biogas external storage is included. The heat produced is sold to a local district heating network.
- *Scenario II):* investment in an upgrading unit to produce biomethane and in the compressor to inject biomethane into a local natural gas grid are considered. The upgrading unit operates in the period when the potential profit obtained by selling electricity on the electricity market is below the biomethane profit from the upgrading unit. The restored CHP unit produces electrical energy during peak power needs and sells it on an hour-ahead electricity market (a balancing market). In this scenario selling heat to the local district heating network is rather limited by the energy production in CHP which is driven by fluctuating conditions on the electricity market. Feedstock for biogas production is the same as in Scenario I).

- *Scenario III):* connection between a biogas plant and a small-scale sugar beet processing plant with a capacity of 100 t/d of processed sugar beet. In the period when sugar beet is not processed in the plant (March-October), biogas will be produced by digestion of residue riverbank grass and animal manure, as in Scenarios I and II, using the biogas produced as a biomethane. In the period when sugar beet is processed, biogas will be produced from sugar beet by-products (wet exhausted sugar beet pulp and beet plant residues), riverbank residue grass and animal manure. Part of the biogas produced will be sold to the sugar beet processing facility as a replacement for natural gas in covering the heat demand for sugar beet processing, while the other part will be upgraded to biomethane and injected into the natural gas grid.

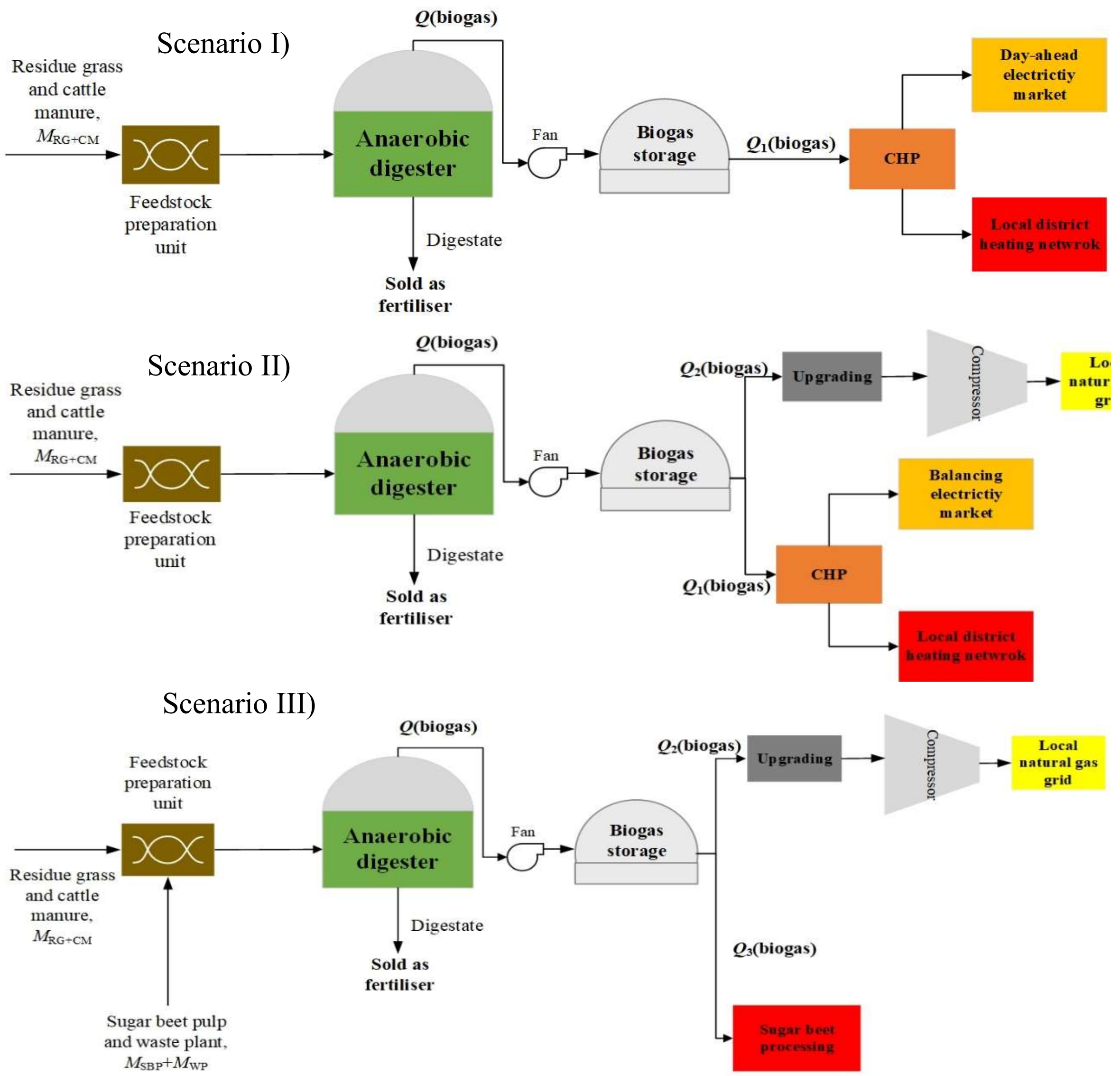

Figure 1 A schematic representation of the 3 scenarios

3.2 Process economics

To earn profit under the new market conditions, the biogas plant must sell electricity on the day-ahead market − prices adopted from Nord Pool [62] for the case of Denmark (DK1) in 2018, only when the price is higher than the break-even cost of electricity production ($BECP_{\mathrm{el}}$), which can be calculated using (9):

$$BECP_{\mathrm{el}} = \frac{OPEX - p(\mathrm{heat}) \cdot H_{\mathrm{CHP}}}{E_{\mathrm{CHP}}} \tag{9}$$

where *OPEX* represents the daily cost of feedstock (which includes harvesting and transport of the feedstock [63]), and the daily cost of maintenance, salaries and other costs not associated with the purchase of substrates, or their harvesting and transport [64], as shown in Eq. (10); $p($heat) is the biogas heat price(€/$\mathrm{MWh_{th}}$); H_{CHP} is the daily production of heat ($\mathrm{MWh_{th}}$). and E_{CHP} is the daily production of electricity ($\mathrm{MWh_{el}}$). Equation (9) considers the continued dispatching of the biogas plant based on the $BECP_{\mathrm{el}}$, after the payback period of the investment, on the day-ahead electricity market. The structure of the *OPEX* is as follows (10):

$$OPEX = \sum_{i=1}^{N} p_i(\mathrm{substrate}) \cdot M_i(\mathrm{substrate}) + MSO \tag{10}$$

where p(substrate) is the price of substrates from Table 1 (€/t) and M(substrate) is the mass of substrate put in the digester, and *MSO* is the cost of maintenance, salary and other costs found in Table 2. In Scenario I) and Scenario II), the daily input of riverbank grass and cattle manure can be calculated using (1) and corresponds to $M_{\mathrm{RG+CM}}$=125 t/day, or 62.5 t/day each. In Scenario III), the daily amount of sugar beet pulp and plant waste utilised in anaerobic digestion is M_{SBP}=25 t/day and M_{WP}=1.6 t/day. To achieve the daily biogas production of 10,000 Nm^3 in Scenario III) when sugar beet is processed, it is required to utilise an additional 45.5 t/day of riverbank grass and cattle manure each, or in total $M_{\mathrm{RG+CM}}$=91 t/day.

Table 1. Price of fuels and substrates

Substrate/fuel	Price
Natural gas for industry [65]	30 €/MWh
Biomethane	40-80 €/MWh
Biogas heat [66,67]	20-40 €/MWh_{th}, on average 30 €/MWh_{th}
Waste sugar beet plant [65]	4 €/t
Pressed sugar beet pulp [65]	15 €/t
Cattle manure [68]	0.60 €/t
Riverbank grass transport [69]	16.1 €/t
Digestate [8]	2.24-4.48 $/t, on average 3.0 €/t

The transportation cost of delivering grass to the biogas plant is estimated at ca. 16.1 €/t of fresh grass [69]. In Germany, cultivated grass silage costs ca. 30 €/t [70], while in Ireland, the price of grass silage paid by biogas plants ranges between 15 and 40 €/t [71]. The lower limit relates to grass from uncultivated land, while the upper limit refers to cultivated grass. In this study, the price of grass consists of the transportation cost for the grass. The price of animal (cattle) manure is lower, about 0.6 €/t [68].

The total profit of the system operation in Scenario II) (P_2) is defined with the following term:

$$P_2 = \begin{cases} p(\text{electricity}) \cdot E_{\text{CHP}} + p(\text{heat}) \cdot H_{\text{CHP}} & , p(\text{electricity}) > p(\text{biomethane}) \,\&\, BECP_{el} \\ p(\text{biomethane}) \cdot H_{\text{up}} & , p(\text{biomethane}) > p(\text{electricity}) \,\&\, BECP_{el} \\ 0 & , BECP_{el} > p(\text{electricity}) \,\&\, p(\text{biomethane}) \end{cases} \tag{10}$$

where p(electricity) is the hourly based price of electricity on the balancing market adopted from Nord Pool [62] for the case of Denmark (DK1) in 2018. The operating point for each hour is selected based on the conditions in the previous Equation, where change in the electricity price was the primary determinant for the operating model.

In Scenario III), the total profit P_3 can be estimated as:

$$P_3 = \begin{cases} p(\text{biomethane}) \cdot (1-f) \cdot H_{\text{up}} + p(\text{heat}) \cdot H_{\text{SB}} \cdot f & \text{, during sugar beeet processing} \\ p(\text{biomethane}) \cdot H_{\text{up}} & ,\quad p(\text{biomethane}) > BECP_{el} \\ 0 & ,\quad BECP_{el} > p(\text{biomethane}) \end{cases} \qquad (11)$$

where f is the part of the biogas flow that is sent to the sugar plant during the processing period when the demand for natural gas is high. An additional determiner for the operating mode of Scenario III is the biogas price, which is related to the electricity price, through the parameter marginal price, and provides a more profitable solution in that time period.

The costs of substrates on a yearly basis are calculated based on the amounts required to produce biogas using (1) and (2). All capital and operating costs for all scenarios are presented in Table 2.

Table 2. Economic specifications of the scenarios in the study

Investment	Cost [€]
1 MW_{el} biogas engine overhaul [72]	458,200
Membrane upgrading unit of ca. 420 Nm^3/h biogas capacity [60]	1,400,000
External biogas storage of 2,500 m^3 capacity and biogas fan [73]	100,000
Compressor to inject biomethane into the local gas grid at 10 bar [74]	165,000
Operation	**Cost [€/year]**
Maintenance, salaries and other costs (*MSO*) [75]	100,000
Membrane upgrading electricity cost and maintenance [60]	340,000

To perform the techno-economic analysis, cumulative cashflow, Payback Period (PBP) and Internal Rate of Return (IRR) were used. The discount rate for cumulative cash flow calculation was set at 10% and the tax profit at 18% [76]. The period of the studied investment for the techno-economic analysis was set at 15 y. Furthermore, a sensitivity analysis was performed to study the impact of natural gas price changes on the project economics in Scenario III).

4 RESULTS AND DISCUSSION

This section presents the results of the analysis considering the three scenarios under analysis, where the dynamic biogas dispatching operation scenarios and the techno-economic analysis are discussed.

4.1 Break-even cost of electricity production on the day-ahead electricity market

Results of the analysis of the $BECP_{el}$ impact on the CHP operational time using day-ahead electricity prices are shown in Figure 2.

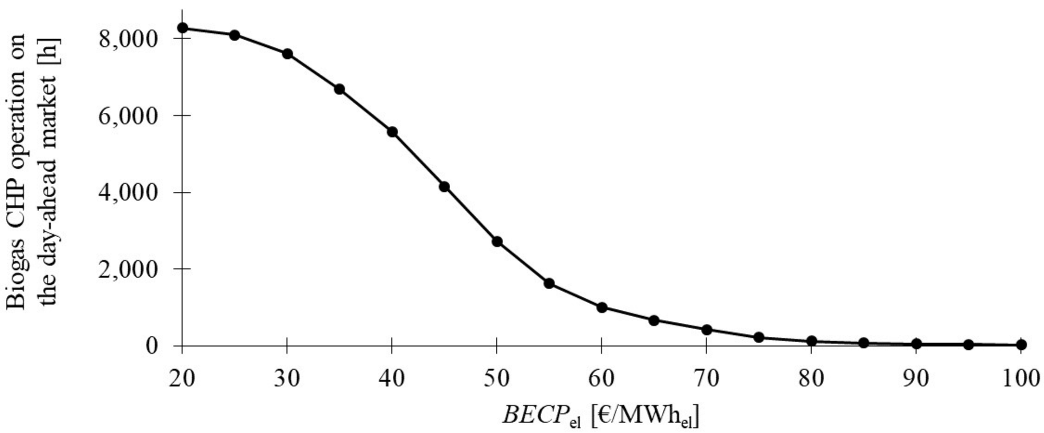

Figure 2 The impact of $BECP_{el}$ value on CHP operational time on the day-ahead electricity market

CHP operation on the day-ahead market is seriously impacted by the $BECP_{el}$ value. Beyond the value of 40 €/MWh$_{el}$, the CHP operational time decreases significantly, even below 4,000 h/y. At the price of 100 €/MWh$_{el}$, biogas energy production equals the biogas production costs, and the operation is no longer viable. In current conditions in Germany, the $BECP_{el}$ value for maize silage is estimated at ca. 100 €/MWh$_{el}$ [77]. Without subsidies for electricity production, biogas plants could not make a profit while operating using relatively expensive raw materials, such as maize silage. In addition, biogas plants should instead utilise cheaper substrates or even substrates with a negative price, like food waste from canteens, restaurants, etc. [5] to make their operation profitable. The highest gradient in Figure 2 is shown for an approximately 45 €/MWh$_{el}$, which can be attributed to the median electricity price on the day-ahead market. Additionally, in Figure 2 the inflection point is at approximately 45 €/MWh$_{el}$, where the rate of gradient change is maximal, which indicates the $BECP_{el}$ for which the CHP system will experience the most starting up and shutting down of the system.

4.2 Dynamic operation of the biogas plant under advanced energy markets

Results of dynamic operation of the biogas plant analysed through the three scenarios are given in the subsections below.

4.2.1 Scenario I)

The break-even cost of electricity production using riverbank grass and cattle manure is calculated for two cases, when both electricity and heat are sold on the market, and when only electricity is sold. Using the prices given in Table 1, the $BECP_{el}$ including heat sold is about 20 €/MWh$_{el}$, and when heat is not sold, the $BECP_{el}$ is about 40 €/MWh$_{el}$. In the case of AD of manure and agro-industrial waste, the break-even cost of electricity production ranges from 25 to 60 €/MWh$_{el}$ [78]. Based on the comparison between $BECP_{el}$=40 €/MWh$_{el}$ and day-ahead electricity prices in this study, the longest period of CHP non-operation is estimated at ca. 10 h. Therefore, external storage for biogas will be added to hold produced biogas for an additional 6 h. Based on hourly biogas production (417 Nm^3/h), its volume should be ca. 2,500 m^3. For low-pressure biogas storage (biogas dome), the specific investment price ranges between 25 and 55 €/m^3 [73]. Using the average cost of 40 €/m^3 and defined storage volume, the investment is estimated at 100,000 €. In total, a digester headspace and the added external storage together form a 10 h capacity storage that has a volume of about 4,500 Nm^3. Total storage dynamics based on $BECP_{el}$ values and market conditions is given in Figure 3. The dynamics for two representative $BECP_{el}$ values is shown in Figure 3, where the biogas storage is fully filled during the operating time of low electricity prices, which is more pronounced in the case of $BECP_{el}$=40 €/MWh$_{el}$. In contrast, in the case of $BECP_{el}$=20 €/MWh$_{el}$, the storage level for most of the time is not fully filled across the whole operating time. The period when both cases do not store the biogas indicates a high electricity price, during which the all biogas is dispatched to the CHP. The selected prices show the price boundaries from which the CHP unit is dominantly operating or secondarily, on the day-ahead market.

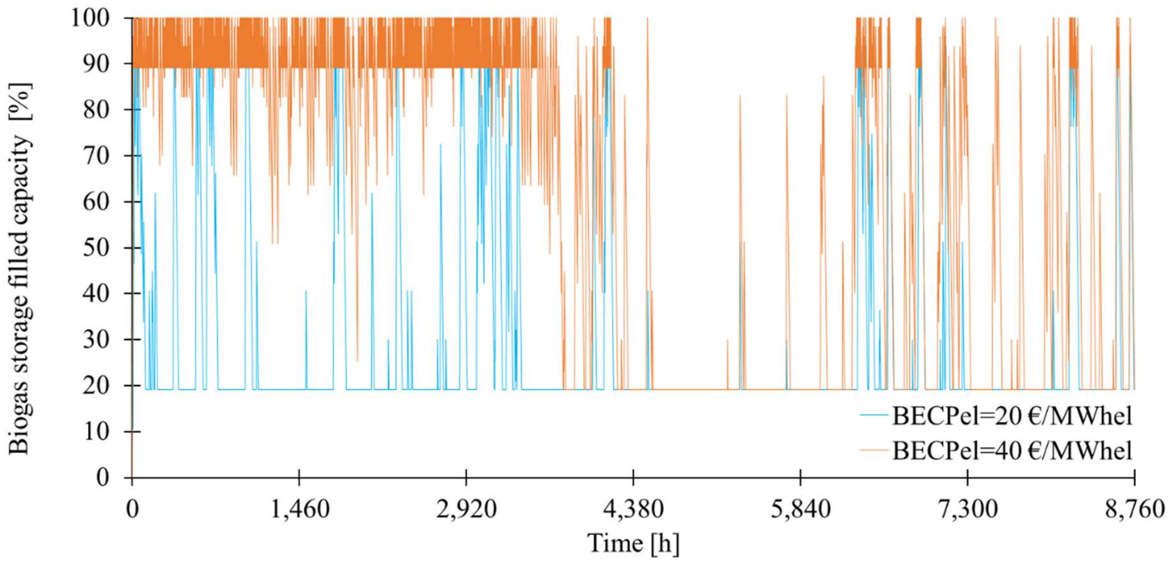

Figure 3 Biogas storage dynamics due to fluctuating market conditions and the break-even cost of electricity production

Selling heat in Scenario I) (lower $BECP_{el}$ value) has a significant impact on biogas storage dynamics, and on CHP operation. There are only short periods when energy production in the CHP is not viable, owing to fluctuating market conditions. On the other hand, if heat selling is not included in the CHP operation on the day-ahead electricity market (higher $BECP_{el}$), there are many periods when biogas is not utilised in the CHP and stored. In addition, using biogas heat in a district heating application gains a saving in GHG emissions and contributes to waste reduction [79]. Therefore, it can be observed that in the post-feed-in-tariff era, biogas plants should become more attractive for biogas heat utilisation, owing to low electricity prices on the market. The impact of $BECP_{el}$ value on the electrical energy and heat produced in biogas CHP in Scenario I) is given below.

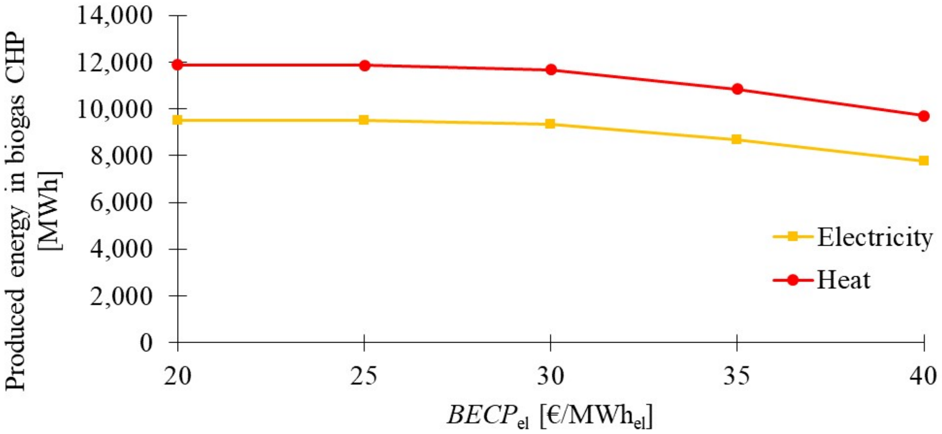

Figure 4 Energy produced in biogas CHP, Scenario I)

For the $BECP_{el}$ value of 20 €/MWh$_{el}$, energy produced in CHP accounts for ca. 9,508 MWh$_{el}$ and ca. 11,900 MWh$_{th}$. If the $BECP_{el}$ value is doubled, energy generation decreases by 18.5%. Based on the analysis, it was determined that the biogas plant in the study can still achieve profitable operation after exiting the subsidy scheme if the price of substrate for AD is not too high and if heat is utilised. More detailed analysis of the application of biogas in the heating processes is given in Scenario III).

4.2.2 Scenario II)

In Scenario II), the analysis of the biogas operation strategy was studied by changing the selling price of biomethane from 40 €/MWh to 80 €/MWh, at intervals of 10 €/MWh. The operation proposed in Scenario II) is not sensitive to change in the $BECP_{el}$ value, since the primary target is to produce biomethane, and biogas CHP is viable only when the price of electricity is high. Overall, because the market price of biomethane needs to be high enough to yield profit in continuous operation, biogas storage does not occur. As a result, the biogas storage is continuously charging and discharging with the same flow of biogas. An example of CHP operation on the balancing market is given in Figure 5 for defined prices of biomethane. For the period between 5,500 h and 7,000 h, when the CHP is mainly working, for all biomethane prices in Figure 5, a high electricity price is present, which was also visible in Figure 3. The different dispatching in operation of the scenario is between the biomethane price of 40 €/MWh and 50 €/MWh, which corelate to the largest gradients from Figure 2, and a greater difference in the overall electricity generated.

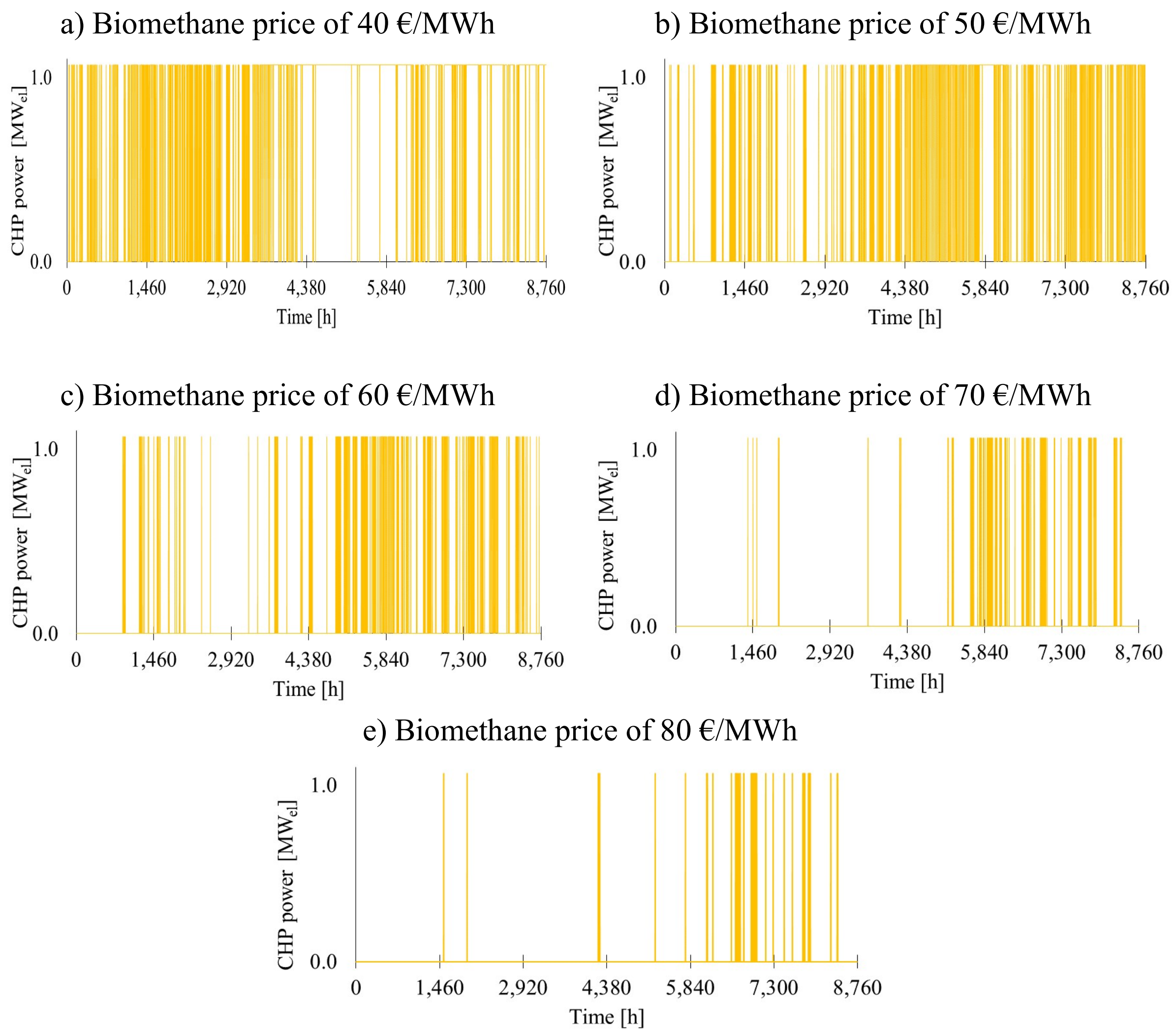

Figure 5 CHP operation on the balancing market for the biomethane price of a) 40 €/MWh, b) 50 €/MWh, c) 60 €/MWh, d) 70 €/MWh and e) 80 €/MWh

For the lowest biomethane selling price (40 €/MWh), biogas CHP has an operational time close to 5,600 hours/year, while for the biomethane price of 80 €/MWh, the CHP operational time is 112 hours. The analysis results show that the most frequent operation of CHP on that balancing market was detected in the last quarter of the year, between hours 6,000 and 8,000. Electricity prices on the DK1 balancing market are significantly influenced by wind penetration, the influence of which is especially marked in the fall period (September, October, November) [80]. The impact of the biomethane selling price on the energy produced in CHP and biomethane itself on the yearly level is given in Figure 6.

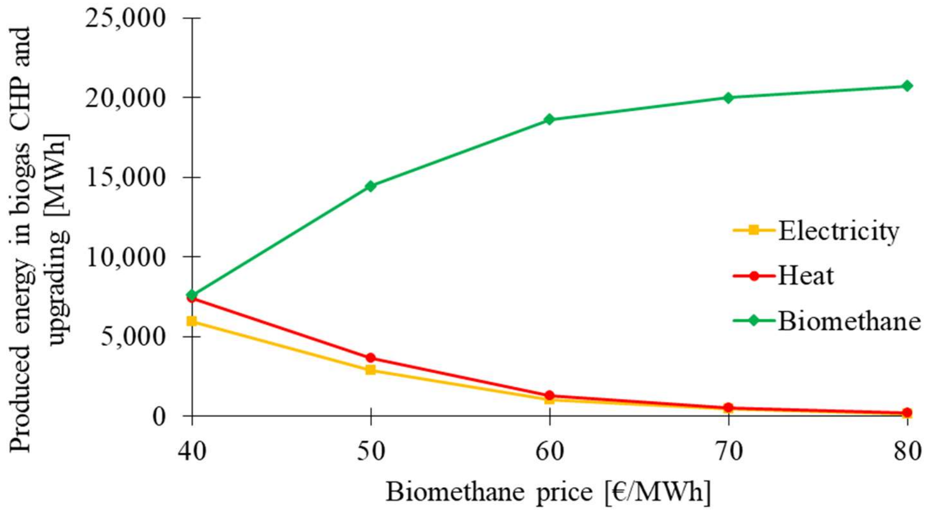

Figure 6 The impact of biomethane selling price on energy production in CHP and biomethane production

For the biomethane price of 40 €/MWh, the electricity generation (5,953 MWh_{el}) is still competitive with upgrading and biomethane production (7,616 MWh). As the biomethane price rises, the electricity and heat generation in CHP become non-viable, and the biogas plant turns to biomethane production. At the highest biomethane price of 80 €/MWh, electricity generation is at its lowest −152 MWh_{el}, while biomethane production is ca. 21,000 MWh. However, results indicate that in the post-feed-in-tariff era, the biogas operation on the electricity balancing market could in some periods be even more viable than production of biomethane, even though those periods are rare. It is important to stress that the results of this analysis have been tested for an electricity market (DK1) with a high penetration of wind. Flexible power generation and continuous biomethane production in the case of Austrian biogas plants did not show significant profit compared to biomethane production alone [81]. The market conditions under which the CHP will operate in the future will have a serious impact on the viability of its operation. Major European economies are already promoting biomethane grid injection as an environmentally acceptable solution and a viable path for biogas plant operation [21]. Surplus to that trend, this analysis has shown that biomethane production could support exiting biogas CHP while operating under different market conditions and enable them to keep biogas production running.

4.2.3 Scenario III)

Scenario III) shows how the current biogas plants could be combined with the processing industry to replace the use of natural gas with biogas. Figure 7 shows the operational strategy of biogas plant upgrading, combined with the sugar beet processing industry.

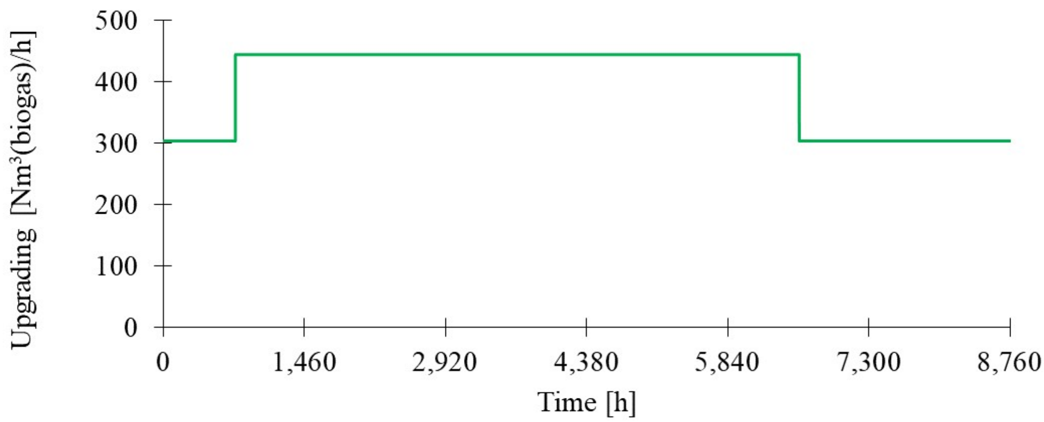

Figure 7 The operation strategy for upgrading at the biogas plant combined with sugar beet processing

At the start of the year and in the last quarter of the year, sugar beet is processed into sugar. Part of the biogas produced in the biogas plant during that period is utilised in the heat demand for sugar beet processing as a replacement for natural gas. The daily amount of biogas used in sugar beet processing to replace natural gas is calculated using (8), and it is Q_3=3,150 Nm^3. In that period, the biogas upgrading unit works with 32% lower biomethane production. Scenario III) presents an option for substituting natural gas in two ways: in the natural gas grid by producing biomethane, and in the processing industry by replacing natural gas with biogas. In addition, production of biogas using sugar beet by-products in a digester is ca. 2,700 Nm^3, which is very close to the self-consumption of biogas for heating purposes. This analysis has shown that the sugar beet processing industry could replace almost 85% of natural gas consumption by using their own by-products in biogas production. In the Netherlands, sugar beet processing plants are building new digesters to utilise sugar beet by-products for biogas and to use it on site, as part of the decarbonisation process [82]. Therefore, small-scale processing industries should take advantage of biogas production using their own biomass sources and invest part of their profit in building an AD plant.

4.3 Techno-economic analysis of biogas operation

In this section, a techno-economic analysis of the scenarios is presented and discussed. Figure 8 gives the cumulative cashflow of the investment for Scenario II) and Scenario III) with reference to Scenario I) at a duration of 15 years. The selling price of biogas in Scenario III) is set at 30 €/MWh, which corresponds to the price of natural gas that the industry is currently charged [65].

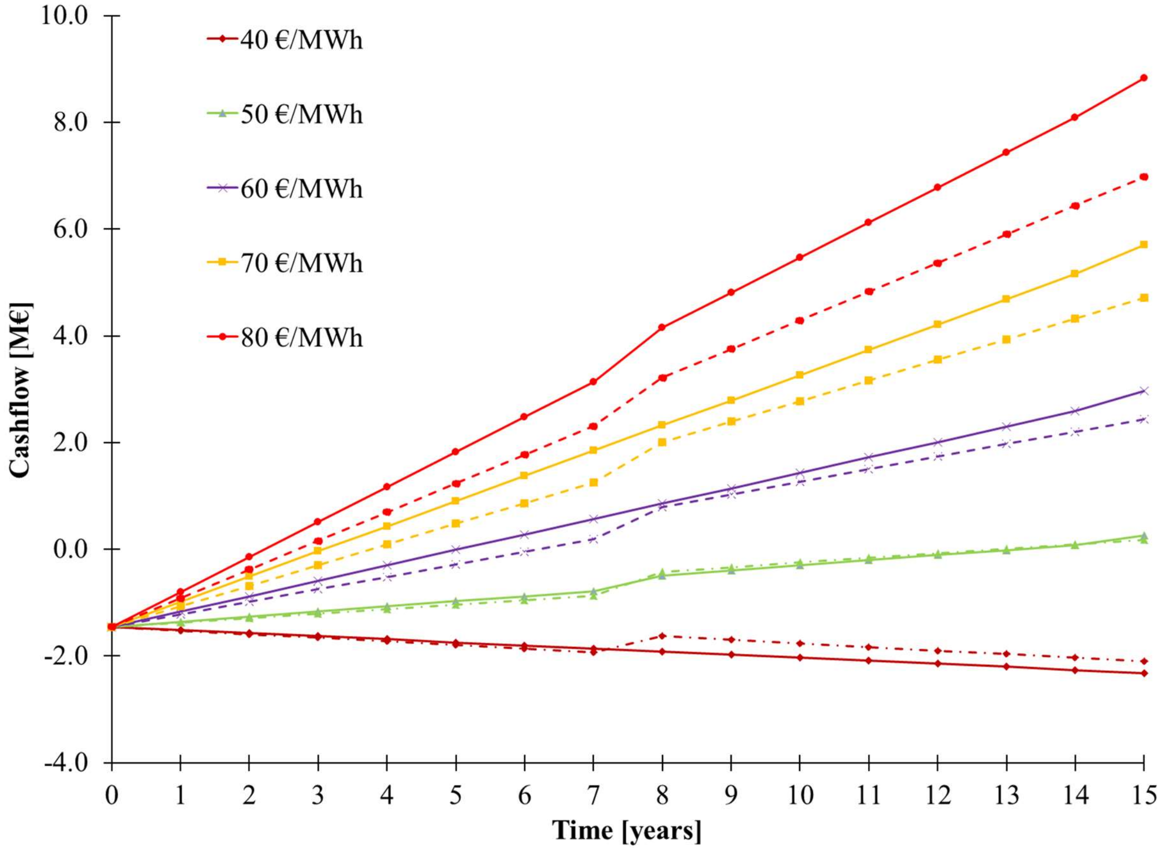

Figure 8 Generated cashflow of the investment for Scenario II) with reference to Scenario I) (solid line) and generated cashflow of the investment for Scenario III) with reference to Scenario I) (dashed line) in the 15-year period, discount rate 10%

Scenario II) yields higher revenue compared to Scenario III) for the same biomethane selling price. For the lowest price of biomethane (40 €/MWh), there is no possibility of paying back the investment in the upgrading unit and CHP general overhaul for either Scenario II) or Scenario III). As presented in the previous section for Scenario II), with the price of biomethane at 40 €/MWh, the CHP operates for ca. 5,600 hours, which indicates that market conditions for electricity production are more viable than biomethane production and its utilisation. The bottom-line total cost of biomethane production is estimated to be ca. 0.46-0.49 €/Nm^3 (46-49 €/MWh) [83]. As shown by the results presented, when the price of biomethane rises to 50 €/MWh, the operation strategy in Scenario II) and Scenario III) is more profitable, but still not very promising. The payback period for both scenarios is almost 14 years. When the selling price of biomethane reaches 60 €/MWh, the investment in the upgrading unit becomes feasible, and the payback period is ca. 6.0 years in Scenario II) and ca. 6.7 years for Scenario III). For higher biomethane prices, 70 and 80 €/MWh, the payback period is 4.0 and 3.2 years in Scenario II) and 4.6 and 3.7 years in Scenario III). The payback period of the investment in water-scrubbed biogas upgrading and biomethane grid injection for the biomethane price of 0.74 €/Sm^3 (it corresponds to the price of ca. 80 €/MWh) was estimated to be ca. 4.2 years [84]. Results of the analysis show that the biomethane selling price has a significant impact in both Scenario II) and Scenario III), where slightly higher revenues come from CHP operation on the electricity balancing market combined with biogas upgrading, in comparison to biogas upgrading combined with selling biogas to the process industry. The sensitivity analysis of the biogas selling price (corresponds to price of natural gas) for Scenario III) is given in Figure 9.

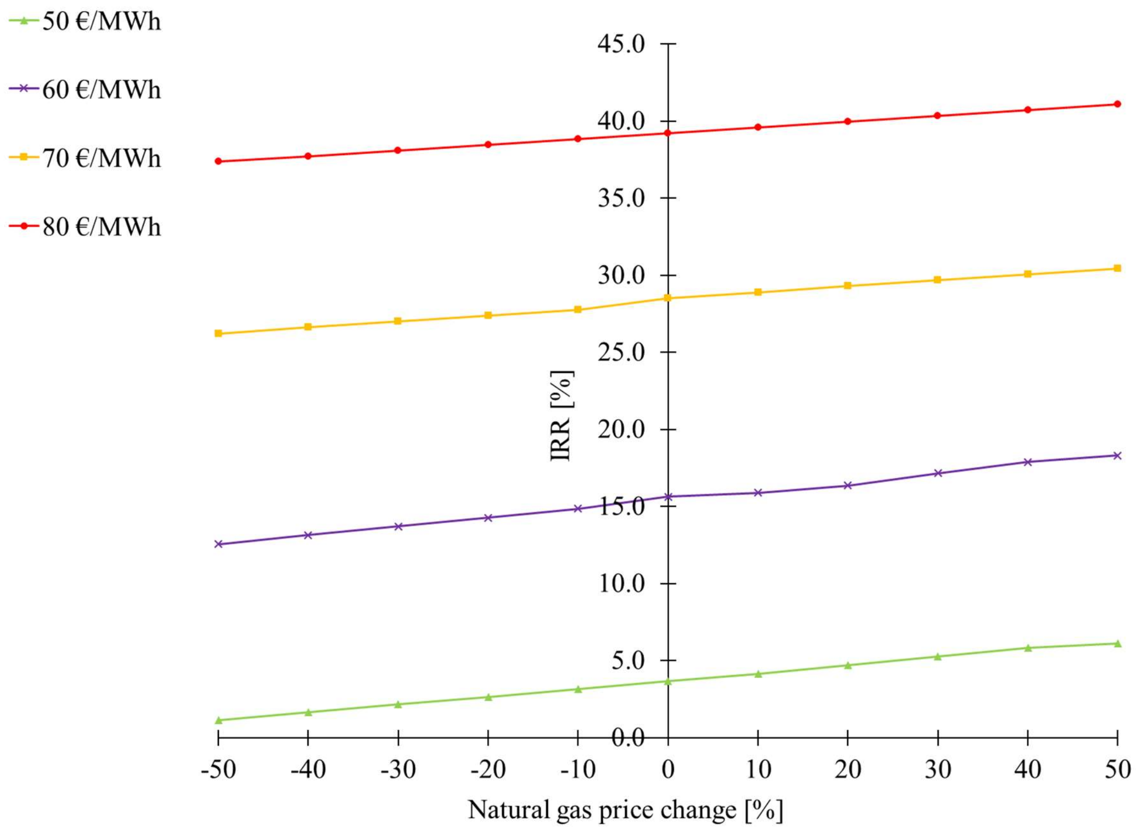

Figure 9 Sensitivity analysis of IRR on the price change in the system inputs and outputs

Sensitivity analysis was performed for the biomethane price of 50 €/MWh and above, since the biomethane price of 40 €/MWh is not viable in operation at all. Even a biomethane price of 50 €/MWh is not profitable, since its IRR value is lower than the initial discount rate of 10%. The analysis showed that, as the biomethane selling price increases, the IRR values in Scenario III) also increase. Biogas upgrading projects are reported to have an IRR value between 16.4 and 29.2%, with the PBP between 3 and 5 years [85]. Similar results were obtained by this study. Additionally, this research showed that the change in IRR value follows the change in natural gas price linearly. Reported changes in IRR values due to changes in the natural gas price are not significant, since a higher portion of biogas generated in the biogas plant is upgraded to biomethane, a value-added material that earns a higher selling price.

5 CONCLUSION

The study of the post-feed-in-tariff era for biogas plants was successfully carried out. Three scenarios were developed to reveal the potential for biogas plants to operate under advanced energy markets, an electricity balancing market, a process heat market and a biomethane market to replace natural gas. Replacement of energy crops on the biogas production side by alternative substrates like residue grass and processing by-products yields better prospects and lower production costs. As even more attractive substrates, biogas plants should consider substrates with a negative price, like food waste, to earn higher profits and whose energy recovery can contribute to GHG mitigation. Production of heat and electricity in biogas CHP after leaving the subsidy schemes does not seem like a favourable option. Owing to penetration by intermittent renewables like solar and wind, the prices of electricity on the day-ahead market are very low, which makes biogas operation non-viable. On the other hand, high penetration of intermittent renewables in energy systems opens the space for biogas CHP to be in operation only in the short period of time when balancing prices are high. This study has shown that even at the very high biomethane selling price of 80 €/MWh, there are still periods in the year (112 hours) when generation of electricity and selling it on the balancing market can be more viable than upgrading of biogas. In general, it was established that viable operation in these cases can be achieved if the price of biomethane is 50 €/MWh or above. Using biogas to replace natural gas in industry processes in the case of a small-sugar beet processing facility could be viable if the processing facility decides to invest in their own AD plant. Thus, the studied biogas plant pays for the substrate and sells the biogas relatively cheaply, instead of converting it to biomethane. Economic analysis of these scenarios showed that projects are profitable with high IRR values (between 15 and 40%) and low payback periods (between 3 and 7 years), only if biomethane is sold for the price of 60 €/MWh or above.

ACKNOWLEDGMENT

The authors acknowledge financial support from the European Union's Horizon 2020 research and innovation programme under grant agreement No: 690142-2 (AgroCycle project), from the Slovenian Research Agency (research core funding No. P2-0412) and from the Slovenia-Croatia bilateral projects Integration of Renewable Energy within Energy Systems (INTEGRES) and Interdisciplinary Research on Variable Renewable Energy Source and Biomass in Clean and Circular Economy (BIOVARES).

REFERENCES

[1] Ullah Khan I, Hafiz Dzarfan Othman M, Hashim H, Matsuura T, Ismail AF, Rezaei-DashtArzhandi M, et al. Biogas as a renewable energy fuel – A review of biogas upgrading, utilisation and storage. Energy Convers Manag 2017;150:277–94. doi:10.1016/j.enconman.2017.08.035.

[2] Al Seadi T, Drosg B, Fuchs W, Rutz D, Janssen R. Biogas digestate quality and utilization. Biogas Handb. Sci. Prod. Appl., 2013, p. 267–301.

doi:10.1533/9780857097415.2.267.

[3] Herrmann C, Idler C, Heiermann M. Biogas crops grown in energy crop rotations: Linking chemical composition and methane production characteristics. Bioresour Technol 2016;206:23–35. doi:10.1016/j.biortech.2016.01.058.

[4] European Commission. Optimal Use of Biogas from Waste Streams. An Assess Potential Biogas from Dig EU beyond 2020 2017:1–158.

[5] Lijó L, González-García S, Bacenetti J, Moreira MT. The environmental effect of substituting energy crops for food waste as feedstock for biogas production. Energy 2017;137:1130–43. doi:10.1016/j.energy.2017.04.137.

[6] Meyer AKP, Ehimen EA, Holm-Nielsen JB. Future European biogas: Animal manure, straw and grass potentials for a sustainable European biogas production. Biomass and Bioenergy 2018;111:154–64. doi:10.1016/j.biombioe.2017.05.013.

[7] Bedoić R, Ćosić B, Duić N. Technical potential and geographic distribution of agricultural residues, co-products and by-products in the European Union. Sci Total Environ 2019;686:568–79. doi:10.1016/j.scitotenv.2019.05.219.

[8] Egieya JM, Čuček L, Zirngast K, Isafiade AJ, Pahor B, Kravanja Z. Synthesis of biogas supply networks using various biomass and manure types. Comput Chem Eng 2019:129–51. doi:10.1016/j.compchemeng.2018.06.022.

[9] Neshat SA, Mohammadi M, Najafpour GD, Lahijani P. Anaerobic co-digestion of animal manures and lignocellulosic residues as a potent approach for sustainable biogas production. Renew Sustain Energy Rev 2017;79:308–22. doi:10.1016/j.rser.2017.05.137.

[10] Lerman SB, Contosta AR. Lawn mowing frequency and its effects on biogenic and anthropogenic carbon dioxide emissions. Landsc Urban Plan 2019;182:114–23. doi:10.1016/j.landurbplan.2018.10.016.

[11] Bedoić R, Čuček L, Ćosić B, Krajnc D, Smoljanić G, Kravanja Z, et al. Green biomass to biogas – A study on anaerobic digestion of residue grass. J Clean Prod 2019;213:700–9. doi:10.1016/j.jclepro.2018.12.224.

[12] Kozłowski K, Pietrzykowski M, Czekała W, Dach J, Kowalczyk-Juśko A, Jóźwiakowski K, et al. Energetic and economic analysis of biogas plant with using the dairy industry waste. Energy 2019;183:1023–31. doi:10.1016/j.energy.2019.06.179.

[13] Grosser A, Neczaj E. Enhancement of biogas production from sewage sludge by addition of grease trap sludge. Energy Convers Manag 2016;125:301–8. doi:10.1016/j.enconman.2016.05.089.

[14] Mirmohamadsadeghi S, Karimi K, Tabatabaei M, Aghbashlo M. Biogas production from food wastes: A review on recent developments and future perspectives. Bioresour Technol Reports 2019;7:100202. doi:10.1016/j.biteb.2019.100202.

[15] Mondal MK, Banerjee A. Parametric evaluation of digestability of organic fraction of municipal solid waste for biogas production. J Sustain Dev Energy, Water Environ Syst 2015;3:416–24. doi:10.13044/j.sdewes.2015.03.0031.

[16] Xu F, Li Y, Ge X, Yang L, Li Y. Anaerobic digestion of food waste – Challenges and opportunities. Bioresour Technol 2018;247:1047–58. doi:10.1016/j.biortech.2017.09.020.

[17] Paolini V, Petracchini F, Segreto M, Tomassetti L, Naja N, Cecinato A. Environmental impact of biogas: A short review of current knowledge. J Environ Sci Heal - Part A Toxic/Hazardous Subst Environ Eng 2018;53:899–906. doi:10.1080/10934529.2018.1459076.

[18] EU Parliament. Directive (EU) 2018/2002 of the European Parliament and of the Council: Amendement to Directive 2012/27/EU on energy efficiency. vol. L 328/210. 2018. doi:http://eur-

lex.europa.eu/pri/en/oj/dat/2003/l_285/l_28520031101en00330037.pdf.

[19] Scarlat N, Dallemand JF, Fahl F. Biogas: Developments and perspectives in Europe. Renew Energy 2018;129:457–72. doi:10.1016/j.renene.2018.03.006.

[20] Pablo-Romero M del P, Sánchez-Braza A, Salvador-Ponce J, Sánchez-Labrador N. An overview of feed-in tariffs, premiums and tenders to promote electricity from biogas in the EU-28. Renew Sustain Energy Rev 2017;73:1366–79. doi:10.1016/j.rser.2017.01.132.

[21] Banja M, Jégard M, Motola V, Sikkema R. Support for biogas in the EU electricity sector – A comparative analysis. Biomass and Bioenergy 2019;128:105313. doi:10.1016/j.biombioe.2019.105313.

[22] Pukšec T, Duić N. Biogas potential in croatian farming sector. Strojarstvo 2010;52:441–8.

[23] Benato A, Macor A. Italian biogas plants: Trend, subsidies, cost, biogas composition and engine emissions. Energies 2019;12. doi:10.3390/en12060979.

[24] Lauven LP, Geldermann J, Desideri U. Estimating the revenue potential of flexible biogas plants in the power sector. Energy Policy 2019:402–10. doi:10.1016/j.enpol.2019.01.007.

[25] Arasto A, Chiaramonti D, Kiviluoma J, Heuvel E van den, Waldheim L, Maniatis K, et al. Bioenergy´s role in balancing the electricity grid and providing storage options - an EU perspective. IEA Bioenergy 2017:1–64.

[26] Tappen SJ, Aschmann V, Effenberger M. Lifetime development and load response of the electrical efficiency of biogas-driven cogeneration units. Renew Energy 2017;114:857–65. doi:10.1016/j.renene.2017.07.043.

[27] Dzene I, Romagnoli F. Assessment of the Potential for Balancing Wind Power Supply with Biogas Plants in Latvia. Energy Procedia 2015;72:250–5.

doi:10.1016/j.egypro.2015.06.036.

[28] Lauer M, Leprich U, Thrän D. Economic assessment of flexible power generation from biogas plants in Germany's future electricity system. Renew Energy 2020;146:1471–85. doi:10.1016/j.renene.2019.06.163.

[29] Hochloff P, Braun M. Optimizing biogas plants with excess power unit and storage capacity in electricity and control reserve markets. Biomass and Bioenergy 2014;65:125–35. doi:10.1016/j.biombioe.2013.12.012.

[30] Gohsen D, Allelein HJ. Development of a market-based optimisation model for a demand-based and storable electricity production from biogas. Energy Procedia 2015;73:79–86. doi:10.1016/j.egypro.2015.07.565.

[31] Saracevic E, Woess D, Friedl A, Miltner A. Dynamic simulation of a biogas plant providing control energy reserves. Chem Eng Trans 2017;61:931–6. doi:10.3303/CET1761153.

[32] Corbellini V, Kougias PG, Treu L, Bassani I, Malpei F, Angelidaki I. Hybrid biogas upgrading in a two-stage thermophilic reactor. Energy Convers Manag 2018;168:1–10. doi:10.1016/j.enconman.2018.04.074.

[33] Vogtenhuber H, Hofmann R, Helminger F, Schöny G. Process simulation of an efficient temperature swing adsorption concept for biogas upgrading. Energy 2018;162:200–9. doi:10.1016/j.energy.2018.07.193.

[34] Angelidaki I, Treu L, Tsapekos P, Luo G, Campanaro S, Wenzel H, et al. Biogas upgrading and utilization: Current status and perspectives. Biotechnol Adv 2018;36:452–66. doi:10.1016/j.biotechadv.2018.01.011.

[35] Budzianowski WM, Budzianowska DA. Economic analysis of biomethane and bioelectricity generation from biogas using different support schemes and plant configurations. Energy 2015;88:658–66. doi:10.1016/j.energy.2015.05.104.

[36] Wagner I. Development of sustainable heat markets for biogas plants in Europe. Euroheat Power (English Ed 2014;11:34–6.

[37] Stephan B. Market development and certification schemes for biomethane. Biogas Handb Sci Prod Appl 2013:444–62. doi:10.1533/9780857097415.3.444.

[38] D'Adamo I, Falcone PM, Ferella F. A socio-economic analysis of biomethane in the transport sector: The case of Italy. Waste Manag 2019;95:102–15. doi:10.1016/j.wasman.2019.06.005.

[39] Krohn RA. Biomethane via Woodroll ® - Investigation of Revenues & Profitability Analysis 2016.

[40] European Council. DIRECTIVE (EU) 2018/2001 OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL of 11 December 2018 on the promotion of the use of energy from renewable sources (recast). Off J Eur Union 2018;2018.

[41] Horschig T, Adams PWR, Gawel E, Thrän D. How to decarbonize the natural gas sector: A dynamic simulation approach for the market development estimation of renewable gas in Germany. Appl Energy 2018;213:555–72. doi:10.1016/j.apenergy.2017.11.016.

[42] Rosa M De. Economic assessment of producing and selling biomethane into a regional market. Energy Environ 2018. doi:10.1177/0958305X18762581.

[43] Götz M, Lefebvre J, Mörs F, McDaniel Koch A, Graf F, Bajohr S, et al. Renewable Power-to-Gas: A technological and economic review. Renew Energy 2016;85:1371–90. doi:10.1016/j.renene.2015.07.066.

[44] Spoerri A, Kaegi T, Com Europeen Fabricants S. LCA of EU beet sugar. Part I: Conducting a LCA of sugar production in the European Union. Sugar Ind 2015;140:492–9.

[45] Pablos C, Felipe Acebes L, Merino A. Sugar plant simulator for energy management purposes. 29th Eur Model Simul Symp EMSS 2017, Held Int Multidiscip Model Simul

Multiconference, I3M 2017 2017.

[46] Jensen AS, Morin B. Energy and the environment in beet sugar production. Eur Soc Sugar Technol 2015:10.

[47] Chantasiriwan S. Optimum imbibition for cogeneration in sugar factories. Appl Therm Eng 2016;103:1031–8. doi:10.1016/j.applthermaleng.2015.08.113.

[48] European Association of Sugar Manufacturers. The EU Sugar Industry: Our Vision For the Next Five Years 2019-2024. Brussels: 2019.

[49] Janke L, Leite A, Nikolausz M, Schmidt T, Liebetrau J, Nelles M, et al. Biogas Production from Sugarcane Waste: Assessment on Kinetic Challenges for Process Designing. Int J Mol Sci 2015;16:20685–703. doi:10.3390/ijms160920685.

[50] Kolfschoten RC, Bruins ME, Sanders JPM. Opportunities for small-scale biorefinery for production of sugar and ethanol in the Netherlands. Biofuels, Bioprod Biorefining 2014;8:475–86. doi:10.1002/bbb.1487.

[51] Finkenstadt VL. A Review on the Complete Utilization of the Sugarbeet. Sugar Tech 2014;16:339–46. doi:10.1007/s12355-013-0285-y.

[52] Aboudi K, Álvarez-Gallego CJ, Romero-García LI. Influence of total solids concentration on the anaerobic co-digestion of sugar beet by-products and livestock manures. Sci Total Environ 2017;586:438–45. doi:10.1016/j.scitotenv.2017.01.178.

[53] Ogrodowczyk D, Olejnik TP, Kaźmierczak M, Brzeziński S, Baryga A. Economic analysis for biogas plant working at sugar factory. Biotechnol Food Sci 2016;80:129–36.

[54] Rieke C, Stollenwerk D, Dahmen M, Pieper M. Modeling and optimization of a biogas plant for a demand-driven energy supply. Energy 2018;145:657–64. doi:10.1016/j.energy.2017.12.073.

[55] Khan MAS, Rajkumar RK, Aravind C V., Wong YW, Bin Romli MIF. A LabVIEW-

based Real-Time GUI for Switched Controlled Energy Harvesting Circuit for Low Voltage Application. IETE J Res 2018. doi:10.1080/03772063.2018.1510747.

[56] Ardolino F, Arena U. Biowaste-to-Biomethane: An LCA study on biogas and syngas roads. Waste Manag 2019;87:441–53. doi:10.1016/j.wasman.2019.02.030.

[57] Mulat DG, Fabian Jacobi H, Feilberg A, Adamsen APS, Richnow HH, Nikolausz M. Changing feeding regimes to demonstrate flexible biogas production: Effects on process performance, microbial community structure, and methanogenesis pathways. Appl Environ Microbiol 2016;82:438–49. doi:10.1128/AEM.02320-15.

[58] O'Shea R, Wall D, Murphy JD. Modelling a demand driven biogas system for production of electricity at peak demand and for production of biomethane at other times. Bioresour Technol 2016;216:238–49. doi:10.1016/j.biortech.2016.05.050.

[59] Jamii J, Abbes D, Mimouni MF. Joint operation between wind power generation and pumped hydro energy storage in the electricity market. Wind Eng 2019. doi:10.1177/0309524X19868473.

[60] Beil M, Beyrich W. Biogas upgrading to biomethane. Biogas Handb Sci Prod Appl 2013:342–77. doi:10.1533/9780857097415.3.342.

[61] Benato A, Macor A, Rossetti A. Biogas Engine Emissions: Standards and On-Site Measurements. Energy Procedia 2017;126:398–405. doi:10.1016/j.egypro.2017.08.278.

[62] Nord Pool: Market Data. Data Downloads 2019. https://www.nordpoolgroup.com/ (accessed November 14, 2019).

[63] Eder A. Cost efficiency and economies of diversification of biogas-fuelled cogeneration plants in Austria: a nonparametric approach. 2017.

[64] Bundgaard SS, Kofoed-Wiuff A, Herrmann IT, Karlsson KB. Experiences with biogas in Denmark. 2014:34.

[65] Šutalo Z. The application of the biorefinery concept to increase the efficiency and

economic viability of the sugar factory. University of Zagreb, Faculty of Mechanical Engineering and Naval Architecture, 2017.

[66] Herbes C, Halbherr V, Braun L. Factors influencing prices for heat from biogas plants. Appl Energy 2018;221:308–18. doi:10.1016/j.apenergy.2018.03.188.

[67] Saracevic E, Koch D, Stuermer B, Mihalyi B, Miltner A, Friedl A. Economic and global warming potential assessment of flexible power generation with biogas plants. Sustain 2019;11. doi:10.3390/su11092530.

[68] Pukšec T, Duić N. Geographic distribution and economic potential of biogas from Croatian farming sector. Chem Eng Trans 2011;25:899–904. doi:10.3303/CET1125150.

[69] Griffith AP, Haque M, Epplin FM. Cost to produce and deliver cellulosic feedstock to a biorefinery: Switchgrass and forage sorghum. Appl Energy 2014;127:44–54. doi:10.1016/j.apenergy.2014.03.068.

[70] Güsewell J, Härdtlein M, Eltrop L. A plant-specific model approach to assess effects of repowering measures on existing biogas plants: The case of Baden-Wuerttemberg. GCB Bioenergy 2019;11:85–106. doi:10.1111/gcbb.12574.

[71] Ricardo Energy & Environment. Assessment of Cost and Benefits of Biogas and Biomethane in Ireland. 2017.

[72] Ready DH. Cogeneration engine/generator maintenance agreement. 2015.

[73] Vienna University of Technology (Austria). Guide To Cooperative Biogas To Biomethane Developments. 2012.

[74] Vagonyte E. Biogas & biomethane in Europe. 2012.

[75] Castellucci S, Colantoni A, Villarini M, Mosconi E, Carlini M. An Economical Evaluation of Anaerobic Digestion Plants Fed with Organic Agro-Industrial Waste. Energies 2017;10:1165. doi:10.3390/en10081165.

[76] Turner J. Economic analysis of a biogas digester. Appropedia 2013.

https://www.appropedia.org/Economic_analysis_of_a_biogas_digester (accessed April 17, 2019).

[77] Rebhann M, Karatay YN, Filler G, Prochnow A. Profitability of management systems on German fenlands. Sustain 2016;8. doi:10.3390/su8111103.

[78] Verbeeck K, Buelens LC, Galvita V V., Marin GB, Van Geem KM, Rabaey K. Upgrading the value of anaerobic digestion via chemical production from grid injected biomethane. Energy Environ Sci 2018;11:1788–802. doi:10.1039/c8ee01059e.

[79] Picardo A, Soltero VM, Peralta ME, Chacartegui R. District heating based on biogas from wastewater treatment plant. Energy 2019;180:649–64. doi:10.1016/j.energy.2019.05.123.

[80] Unger EA, Ulfarsson GF, Gardarsson SM, Matthiasson T. The effect of wind energy production on cross-border electricity pricing: The case of western Denmark in the Nord Pool market. Econ Anal Policy 2018;58:121–30. doi:10.1016/j.eap.2018.01.006.

[81] Saracevic E, Theuretzbacher F, Woess D, Friedl A, Miltner A. Economic and Technical Evaluation of Flexible Power Generation Scenarios for a Biogas Plant. J Sustain Dev Energy, Water Environ Syst 2017;0:0–0. doi:10.13044/j.sdewes.d7.0289.

[82] Rademaker K, Marsidi M. Decarbonisation options for the Dutch sugar industry. 2019.

[83] Cucchiella F, D'Adamo I. Technical and economic analysis of biomethane: A focus on the role of subsidies. Energy Convers Manag 2016;119:338–51. doi:10.1016/j.enconman.2016.04.058.

[84] Rotunno P, Lanzini A, Leone P. Energy and economic analysis of a water scrubbing based biogas upgrading process for biomethane injection into the gas grid or use as transportation fuel. Renew Energy 2017;102:417–32. doi:10.1016/j.renene.2016.10.062.

[85] Barbera E, Menegon S, Banzato D, D'Alpaos C, Bertucco A. From biogas to biomethane: A process simulation-based techno-economic comparison of different

upgrading technologies in the Italian context. Renew Energy 2019;135:663–73. doi:10.1016/j.renene.2018.12.052.