Demand-orientated power production from biogas – modelling and simulations under Swedish conditions

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Abstract

The total share of intermittent renewable electricity is increasing, intensifying the need for power balancing in future electricity systems. Demand-orientated combined heat and power (CHP) production from biogas has potential for this purpose. An agricultural biogas plant, using cattle manure and sugar beet for biogas and CHP production was analysed here. The model Dynamic Biogas plant Model (DyBiM) was developed and connected to the Anaerobic Digestion Model No. 1 (ADM1). Flexible scenarios were simulated and compared against a reference scenario with continuous production, in order to evaluate the technical requirements and economic implications of demand-orientated production. The study was set in Swedish conditions regarding electricity and heat price and the flexibility approaches assessed were increased CHP and gas storage capacity and feeding management. The results showed that larger gas storage capacity was needed for demand-orientated CHP production, but that feeding management reduced the storage requirement because of fast biogas production response to feeding. Income from

electricity increased by 10%, applying simple electricity production strategies to a doubled CHP capacity. However, as a result of the currently low Swedish diurnal electricity price variation and lack of subsidies for demand-orientated electricity production, the increase in income was too low to cover the investment costs. Nevertheless, DyBiM proved to be a useful modelling tool for assessing the economic outcome of different flexibility scenarios for demand-orientated CHP production.

Keywords

Biogas, Demand-orientated power production, Combined heat and power, Biogas storage, Feeding management, Dynamic simulations.

Introduction

Worldwide, there is an urgent need to convert electricity production from non-renewable to renewable energy sources (RES). In future power systems, a large fraction of intermittent power, such as wind and solar energy, will be needed, which poses a challenge in balancing demand and supply.[1-4] According to the Swedish Transmission System Operator (TSO), the Swedish secondary power balancing requirement will increase from 1800 MW in 2013 to 2300-3200 MW in 2025 due to increased wind power capacity.[5,6] Today, most secondary power balancing in Sweden is achieved by starting or stopping hydropower aggregates, but there is great unused capacity in other types of power plants.[7] Implementing power regulation ability in combined heat and power (CHP) plants has been identified as key to integrating fluctuating RES.[4,8-10] In this context, bioenergy has the advantage of being both renewable and storable, and use of biogas from anaerobic digestion (AD) for power balancing has gained interest recently.[8,11-14] The biogas can be used in gas engines or turbines with comparatively short start-up times.[8,15] Conventional operation of biogas CHP plants aims at continuous biogas and CHP production, however. For example; most of the over 7500 biogas plants in Germany have more than 7000 full load hours per year.[11,16] However, in 2012, a flexibility premium was introduced in Germany, which encourages technological development for demand-orientated production.[8,11] Financial subsidies for higher flexibility can also be expected in Sweden in the future.[5]

From the plant owner's perspective, selling electricity when demand is high can increase income. There are daily variations in the Swedish electricity spot price, with higher prices during the day than at night and also weekly and seasonal variations (Figure 1), which could be exploited by focusing electricity production to high-price periods. However, flexible operation is associated with higher investment and maintenance costs.[13] The economics of CHP plants operating on both day-ahead and balancing power markets have been widely investigated for CHP in general,[17-20] and for a few types of biogas CHP plants in particular.[14,21] Hochloff and Braun[14] showed for Germany that when the flexibility premium is included, demand-orientated CHP production from biogas is profitable if based on economic optimised participation in the day-ahead and tertiary control markets.

Additional CHP capacity in combination with gas storage enables demand-orientated CHP production for steady-state production of biogas.[8,11,13] However, flexible biogas production can be achieved by feeding management, which includes varying feeding intervals and rate and substrate composition. In order to achieve a rapid feeding response, easy degradable substrates such as sugar beet, cereals, etc. are advantageous.[8,11-13,22] Use of slowly degradable substrates may be feasible in combination with biological, chemical or physical pre-treatment, which increase substrate accessibility to microbes and lead to faster degradation.[23] Mauky *et al.*[12] analysed feeding management strategies with sugar beet silage, maize silage and cattle manure in long term laboratory-scale experiments in continuously stirred tank reactors (CSTR), and found that high flexibility of biogas production could be achieved. A concern regarding feeding management is that abrupt changes in the feeding regime may lead to process disturbances such as rising volatile fatty acid (VFA) concentrations and reduced pH.[24-27] However, Mauky *et al*.[12] found no such negative effects of feeding management on process stability, even at high loads. After feeding, the VFA, hydrogen (H_2) and hydrogen sulphide (H_2S) concentrations increased slightly, but during the non-feeding phase they returned to their normal values and there was no accumulation over time. Lv *et al.*[22] analysed the impact of reactor feeding regime on methanogenic activities and observed no difference in total gas yield, although the methane concentration decreased temporarily after feeding.

The complexity of the biogas process, flexibility approaches and the electricity market make modelling an attractive analytical tool. Dynamic simulations of a biogas plant in operation, including the digestion process, gas storage and CHP unit as well as heat and electricity production and sale, could facilitate identification of the conditions and determination of the feasibility of demand-orientated production.

The objective of the present study was to develop a model for dynamic simulations of demand-orientated CHP production from biogas in order to: i) evaluate the technical requirements of different flexibility approaches and ii) compare flexible scenarios to a reference scenario with constant CHP production in terms of changed income and additional costs. The flexibility approaches assessed were additional CHP capacity, biogas storage and feeding management and the study was carried out in a Swedish context regarding energy system and electricity prices, from the perspective of the owner of a farm-scale biogas plant. As a first stage, participation in the Nordic day-ahead electricity spot market was evaluated. Since heat utilisation is an important aspect for energy efficiency, resource management and profitability,[28-30] it was also included.

Materials and methods

Model

The Dynamic Biogas plant Model (DyBiM) was developed in MATLAB Simulink® and contained a biogas storage unity and CHP unit(s). Feeding management was included by connecting the International Water Association (IWA) model "Anaerobic Digestion Model no 1" (ADM1),[31] implemented in Simulink, to DyBiM. The combined model layout is described in Figure 2.

DyBiM used biogas and methane production as inputs to calculate the level and average methane concentration in the gas storage, assuming a perfect mixing of the gas. The operation of the one or two CHP units was controlled by a pre-defined electricity production strategy, but was limited by the gas storage capacity. The electricity production strategy gave a target load (0-100% of total CHP capacity) and if the biogas storage capacity was within its limits, the CHP unit produced accordingly. However, if the storage was empty (or full), the CHPs were forced to decrease (or increase) production. Thus, e.g. if the storage was full and the target load was below 50%, the load was increased to 50%, meaning that if there were two CHP units, one unit ran on full load.

The start-up dynamics of the CHP-unit(s) will influence the electrical- and heat efficiency during the start-up time and hence the biogas consumption. However, this dynamic behavior takes place in a minute-based time-scale, while the time resolution in DyBiM was three minutes. A test run with shorter time steps showed that the change in biogas consumption during start-ups was negligible in comparison to the total daily consumption. Therefore, the start-up and stop dynamics of the CHP unit(s) were neglected in the simulations. However, the number of CHP starts and operational time were recorded in DyBiM for each unit.

The heat production was determined by the electricity production and the heat/electricity factor that was dependent on the heat and electricity efficiency values, which in turn were functions of the load. The methane consumption of the CHP unit was determined from the electricity and heat production and the efficiency values, and the corresponding biogas consumption depended on the average methane concentration in the biogas storage. At the start of the simulation, the biogas storage level was set to 50%. The income from electricity was calculated using hourly prices from the Swedish spot market Elspot (data from 2013,[32] excluding green certificates). The income from heat was calculated using an average secondary heat price, obtained using a pricing system developed in a pilot project in Stockholm by the energy company Fortum, where the price for secondary heat (need for additional heating to be injected into the supply line) is set daily using the average outdoor temperature.[33] Since the flexible scenarios developed in this study only affected heat production on a daily basis, a mean yearly price could be used. Daily temperature data for Uppsala during 2013 gave an average heat price of 262.1 SEK MWh^{-1} (€ 27.6 MWh^{-1}).

The substrate data and kinetic parameters in ADM1 were adapted (see *Substrate characterisation* section) and the feeding was modified to enable multiple substrates and feeding management. In ADM1, substrates are specified as particulate or soluble concentrations of chemical oxygen demand (COD) and the reaction system is divided into biochemical and physico-chemical reactions, including extracellular disintegration and hydrolysis steps and three overall cellular steps, acidogenesis, acetogenesis and methanogenesis, plus ion association/dissociation and gas-liquid transfer.[31] ADM1 has been applied to various substrates, e.g. grass silage, cattle manure and agricultural substrates,[34-37] and has been modified and extended by a great number of research groups.[38-42] Several studies report good model performance.[42,43]

A MATLAB script was developed to connect ADM1 to DyBiM, since the models needed different solvers. The script loaded the required data, specified the parameters and ran the simulations for a period of one year. To stabilise the digester conditions, ADM1 was run for 300 days before its output was used. After the simulation, the biogas production, methane concentration, propionate concentration, electricity production and gas storage level were plotted against time. The accumulated electricity and heat production, revenue and number of CHP starts and operation times were printed in the Matlab Workspace.

Reference scenario

The reference scenario was a fictitious farm-scale mesophilic CSTR biogas plant in Sweden digesting cattle manure (CM) and sugar beet (SB). These substrates were chosen since they are common in agricultural AD and have interesting properties for feeding management, SB being quickly and CM slowly degradable.[12] The active digester volume was assumed to be 3000 m^3 and the total feeding 62.7 t d^{-1}, consisting of (on wet weight (WW) basis) 70% CM and 30% SB (Table 1). The organic loading rate (OLR) was 2.19 kg VS $m^{-3}d^{-1}$ and the hydraulic retention time (HRT) was 47.8 d. One CHP unit was used, dimensioned to the substrate amount and the corresponding biogas production to an average loading of 80%. That was a reasonable assumption, since in practice there needs to be some margin for fluctuating biogas production. The feeding, and hence biogas production, was assumed to be constant and disturbances to plant operation (e.g. equipment breakdowns) were neglected. The external gas storage capacity was assumed to be 1200 m^3 usable volume and thereby accommodated 6 hours of biogas production, which is the average for German farm-based biogas plants.[44] The plant was assumed to be connected to the Swedish electricity grid, operating on the day-ahead electricity market Elspot at Nord Pool, and to a district heating system, where the heat was sold as secondary heat whenever produced. The internal heat and electricity demands were not included, and all energy produced was assumed to be sold.

Table 2 shows the characteristics of the CHP unit. The electricity and heat efficiency curves were calculated using a generator efficiency of 95% and manufacturer's data[45] for the mechanical and heat efficiencies at 50, 75, 90 and 100% (fitting with an R^2 value of 0.9997 and 0.9878 for electricity and heat efficiency, respectively).

Flexible scenarios

The flexible scenarios were defined in terms of number of CHP units, electricity production strategy, biogas storage capacity and feeding management. The reference gas storage and CHP unit were complemented, not replaced, and all scenarios were based on using either only the reference CHP unit, or adding one extra identical unit. The electricity production strategies were based on full load production during a period of the day corresponding to the total biogas production in the reference scenario. The CHP production was started at the same time every day, and the best starting time was found through simulations. With one CHP unit, the strategy DP 19.2 (Daily Production during 19.2 hours) was used, implying that the CHP unit produced at full capacity during 19.2 consecutive hours each day. In the scenarios with doubled CHP capacity, the electricity production strategy DP 9.6, maximising the production during 9.6 consecutive hours, was used. The biogas storage capacities implemented were 1200 m^3 and 2000-3000 m^3 usable volume for flexible CHP production. The additional storage was assumed to consist of external gas balloons.

Feeding management was implemented on a daily basis, by targeted feeding during one continuous period of the day. The total daily feeding was the same as in the reference scenario. Feeding periods of 1, 3, 6 and 12 h were implemented for the whole substrate mixture (Mix 1h, 3h, 6h and 12h). For SB, feeding periods of 1 and 3 h (SB 1h and 3h) were implemented in combination with continuous feeding of CM. As with electricity production, the feeding started at the same time every day and the best starting times were found through simulations.

The net present value (NPV) of the additional investments in the flexible scenarios was calculated using the change in electricity and heat income compared with the reference scenario for an economic lifespan of 10 years, 7% discount rate and cost assumptions (Table 3). Increased maintenance costs for the CHP units were included by using a cost per CHP start value taken from Hochloff and Braun.[14]

Substrate characterisation

For ADM1 implementation, CM and SB were characterised (Table 4). For SB, this characterisation was based on the Weender/Van Soest analysis by Potthast *et al.*[46], equations adapted from Lübken *et al.*[36] and parameters to transform volatile solids (VS) to COD from Koch *et al.*[34] The non-degradable fraction of SB cellulose was assumed to be 30%. The stoichiometric parameters for disintegration of the particular composite fraction (Xc) of the CM (Table 5) were calculated assuming a composition corresponding to the ratio between Xch, Xpr, Xli, Xi and Si. Kinetic parameters for hydrolysis rates, propionate, valerate and butyrate maximum and half saturation uptake rates, acetate maximum uptake rate and hydrogen half saturation uptake rate were adapted according to Lübken *et al.*[36]

Results

Technical requirements of flexibility approaches for demand-orientated production

In the scenario with one CHP unit applying DP 19.2, the reference scenario gas storage capacity (1200 m^3) was able to contain the biogas produced during the 4.8 h in which the CHP was shut off. With two units and DP 9.6, too small gas storage capacity limited CHP production, and the CHP unit was forced to start and stop several times every day. Increasing the gas storage capacity reduced this limitation. With well-timed feeding management, the biogas production was high during CHP production and low during storage, and thereby enabled targeted CHP production with smaller storage capacities (Figure 3). With 2300 m^3 gas storage capacity, one CHP unit was forced to start prior to the target load period because the storage was full, and stop before the end of the target load period because the storage was empty (Figure 3a). With 3000 m^3 storage (3b) or 2300 m^3 storage in combination with feeding management Mix 3h (3c), the CHP was able to produce according to the target load. However, in these cases, a short period (20 min) of forced CHP production took place before the target load period. This was because the full load CHP production, compared with 80% in the reference scenario, affected the efficiency and hence biogas consumption of the CHP unit.

On applying feeding management after running ADM1 for 300 days, biogas production, methane production and propionate concentration increased, whereas the methane concentration decreased at feeding (Figure 4). During the non-feeding period, these returned to their starting values. The differences were greater for the shorter feeding periods and for Mix strategies compared with the SB strategies. For acetate concentration and pH similar variations occurred, with a pH of 7.24, 7.23-7.25 and 7.11-7.25 and an acetate concentration of 0.057, 0.040-0.077 and 0.036-0.193 kg COD m^{-3} on applying constant feeding, Mix 12h and Mix 1h, respectively. Total methane production slightly decreased with feeding management, to a larger extent for the faster feeding strategies. Variations in acetate and propionate concentration can increase the risk of process instability, but the loads tested here did not cause problems.

Implications for plant economics

The change in annual electricity income compared with the reference scenario depended on the starting time of CHP production (Figure 5). There was a general fluctuation in the electricity price, i.e. even though the variations differed between days there was an average pattern that could be exploited. Since the production period was shorter for DP 9.6, the starting time had a larger impact. When the feeding was constant and the gas storage capacity did not limit CHP production, the income for DP 9.6 was highest (+10%) when the CHP unit started at 08.00 h. With one CHP unit running for 19.2 hours, the production had to start at 05.30 h to give 6% higher income. All economic analyses below are based on these starting times of CHP production. Part of the increase in income was due to the higher electricity efficiency, and hence production, when operating at 100% load compared with 80% in the reference scenario.

Well-timed feeding management increased the income compared with constant feeding, but poor timing decreased the income, using DP 9.6 and 2300 m^3 biogas storage capacity as an example (Figure 6). A longer feeding period meant earlier feeding start, but there were rather long starting intervals in which each feeding strategy gave good results.

The impact of gas storage capacity and (well-timed) feeding management on electricity income using DP 9.6 is shown in Figure 7. Greater gas storage capacity increased the electricity income until CHP production was no longer limited by storage. For constant feeding, 2900 m^3 gas storage capacity was required, but with feeding management it was possible to achieve the highest potential income with smaller storage capacity (compare Figures 6 and 7). The maximum level was slightly lower using feeding management, due to the reduced methane and hence total electricity production. If there were several feeding strategies that enabled planned CHP production with the same storage capacity, the longest feeding period, or using SB instead of Mix, was most beneficial.

The economic implications were analysed (Table 6) for one scenario with one CHP unit and DP 19.2 and three scenarios with two CHP units and DP 9.6 applying i) constant feeding in combination with the storage capacity required for targeted CHP production (2900 m^3); ii) the feeding management with the highest income, SB 3h, combined with the storage capacity enabling targeted CHP production (2500 m^3); and iii) smaller storage capacity (2000 m^3) in combination with the best feeding strategy (Mix 3h) for that storage capacity. The scenario with one CHP unit required no new investment and the increased yearly income gave a positive NPV. The scenarios with two CHP units were all unprofitable, mainly due to the large investment costs involved and, to a smaller extent, the maintenance costs consuming part of the increased income. However, feeding management reduced the gas storage investment costs significantly compared with constant feeding (24-53%) and it was favourable to prioritise smaller gas storage capacity over highest possible yearly income.

Sensitivity analysis

Heat valuation and investment costs

The impacts on the main results (Table 6) for changes in investment costs and heat valuation were tested in a sensitivity analysis (Table 7). Hahn *et al.*[13] reported investment costs of € 30-67 m^{-3} for external gas storage, which is significantly lower than the data from Bärnthaler *et al.* [47]

used in this study. Therefore, gas storage costs of € 50 m^{-3} (67% reduction) were evaluated. In addition, the CHP investment costs were decreased by 30%, to € 400 kW^{-1}. For the one CHP unit scenario there was no effect on the NPV, since there were no investments. For the other scenarios the NPV was still negative, but significantly increased. The results were affected more for the scenarios including the larger biogas storage.

Setting the heat value to 0 in both the reference and flexible scenarios led to approximately € 2000 higher yearly net cash flows in all flexible scenarios, since the reduced production of heat did not affect the economic results. In the one CHP unit scenario, this had a large impact on net cash flow and NPV, since these were only affected by income. With two CHP units the electricity income was relatively high compared with the heat income, which led to a lower impact on the net cash flow. However, there was an even smaller effect on the NPV, since the investment costs had a larger impact than the yearly income; the larger the investment, the smaller the impact of the heat valuation.

Electricity price variations

The electricity price variations were amplified for the scenario using two CHPs with 2000 m^3 gas storage capacity and feeding management Mix 3h (Table 8). The electricity price was multiplied by a factor in both the reference and the flexible scenario, thereby imitating a case where the electricity price variations are multiplied by the same factor. The changes in maintenance costs and heat income were as shown in Table 6, regardless of the factor. The NPV was negative for all scenarios except with a factor of 6. Thus with this electricity production strategy, the Swedish electricity price variations would need to increase six-fold in order for the investments to be profitable.

Discussion

The DyBiM model developed here proved to be a useful tool for assessing the technical and economic consequences of different flexibility scenarios related to demand-orientated power production from biogas. The simulations performed provided valuable insights into the relationships between CHP capacity, electricity production strategy, gas storage capacity, feeding management and biogas production.

This study took heat utilisation into account, but the options for real plants to do so depend on local conditions. The heat was assumed to be sold at the same price whenever it was produced, but if this was not the case heat storage would be needed. If the heat price had daily variations or if electricity production was managed on a weekly or monthly basis, the heat price would have to be taken into account to optimise the profitability of the plant. The economic preconditions for heat production affect the choice of electricity production strategy. For example, with demand-orientated electricity production the CHP units are turned off for long periods and this may reduce the heat efficiency, since it takes time to establish temperature equilibriums at the heat transfer surface. The temperature equilibriums could be maintained by always having one CHP unit running, which would limit the number of flexible scenarios possible. On the other hand, the system could include another heat source, which could be used when the biogas CHP was turned off, thereby increasing the flexibility.

The NPV was positive for the flexible scenario with one CHP unit, since the electricity income increased and no new investment was needed. Thus, if there is CHP and gas storage overcapacity, demand-orientated production can be easily and profitably implemented. However, investing in additional CHP and gas storage capacity was not profitable in the scenarios analysed in this study. The increased electricity income, 13 k€ y^{-1}, in the two CHP unit scenarios was low compared with 43-63 k€ y^{-1} for the two 0.6 MW CHP units reported by Hochloff and Braun[14]. However, their values were valid for optimised participation on the German spot and tertiary reserve markets. In addition, German electricity prices were higher than Swedish prices.

In general, the Swedish market for farm-scale biogas CHP plants is not as well developed as the German market. Lantz[48] investigated three types of manure-based 1-6 GWh y^{-1} biogas plants with 35 – 290 kW_{el} installed electrical capacity and found that none of them was profitable under Swedish market conditions. Hochloff and Braun[14] also concluded that none of their scenarios would be profitable without the German flexibility premium, and there is no such incentive in Sweden.

Investment costs have a large impact on the economic outcome and accurate assumptions are therefore crucial. Hochloff and Braun[14] assumed larger CHP investment and lower biogas storage costs compared with this study, but in total the additional investment in their scenario with two 0.6 MW CHP units and gas storage was approximately the same as in the scenario with two units and 2900 m^3 gas storage in this study. Hahn *et al.*[13] used significantly lower investment costs, with a difference between the reference scenario and the scenario with additional CHP capacity and gas storage of € 210,000. However, Hahn *et al.*[13] only considered the additional flexibility costs of the biogas supplied to a CHP unit, thus not including the investment in an additional CHP unit. The additional flexibility cost for the scenario in Hahn *et al.*[13] was € 2-3 MWh^{-1} biogas produced, compared with € 7-9 MWh^{-1} biogas produced in this study (taking investments, maintenance costs and reduced heat income into account). The difference originates mainly from this study including CHP investment cost while Hahn *et al.*[13] did not, and partly from lower gas storage investment assumption in Hahn *et al.*[13] If the CHP investment cost is excluded, the additional flexibility cost in this study become € 2.5-4.5 MWh^{-1} biogas produced, which is in the same range as the results of Hahn *et al*.[13]

Feeding management had a major economic impact by reducing the gas storage requirement, confirming results from other studies.[12,13,44] For example, Mauky *et al*.[12] showed that the gas storage demand could be halved compared with constant feeding if the feeding strategy was optimised to electricity production. Bofinger *et al*.[44] simulated doubled CHP capacity from a 500 kW_{el} reference scenario and found that feeding management reduced the gas storage requirement from 3000 to 2300 m^3. The fast biogas production response to feeding was considered reasonable, since sugar beet is a readily degradable substrate. Mauky *et al*.[12] demonstrated very rapid biogas production response when feeding sugar beet silage, while Lv *et al*.[22] showed that feeding of maize silage increased biogas production from 0.5 to 2 L h^{-1} within 70-80 min. Bofinger *et al*.[44] used feeding periods of about one day and achieved biogas production variations of between 175 and 265 m^3 h^{-1}, which is similar to the results for the Mix 12h strategy in the present study.

The simulation results using ADM1 in this study and the laboratory scale studies using cattle slurry and sugar beet silage by Mauky *et al.*[12] indicate that flexible feeding management do not negatively affect the process stability. However, further studies are required in order to investigate the feasibility for up-scaling to production-scale and the long-term effects in practical operation. In addition, the use of SB as an easy-to-degrade substrate can be associated with practical difficulties regarding storage and damaging impurities such as gravel and sand. Moreover, the strategy of flexible biogas production requires larger biogas storages, which can increase the risk of methane emissions[53], thus reducing the climate benefits of biogas production.

In order to improve the economic outcome, demand-orientated production needs to increase the electricity income to a larger extent compared to continuous production, by e.g. future greater electricity price fluctuations, flexibility subsidies, optimisation of electricity production and feeding management and lower investment costs. The DyBiM model can be developed to accommodate more complex CHP production and feeding strategies depending on electricity and heat price prognoses, gas storage capacity etc. and can include feedback from DyBiM to ADM1 to control the feeding. The internal heat and electricity demand and participation in balance power markets should also be included, as should other flexibility approaches such as grid injection and power-to-gas.

Conclusions

Demand-orientated power production from biogas was dynamically modelled through the specially developed DyBiM model, connected to ADM1. Scenarios including additional CHP, gas storage capacity and feeding management were simulated and compared against a reference scenario with constant biogas and CHP production. The results showed that larger gas storage capacity was needed for demand-orientated CHP production, but that feeding management reduced the storage requirement because of the quick biogas production response to feeding. It proved possible to increase income from electricity by 6-10% by applying simple electricity production strategies. In a flexible scenario with one CHP unit, the NPV was positive. However, for scenarios including additional CHP and gas storage capacity, there was need for increased fluctuations in the electricity price, subsidies, lower investment costs and/or system optimisation to achieve profitability under current Swedish conditions.

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Notes

The authors declare no competing financial interest.

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ABBREVIATIONS

RES, renewable energy sources; TSO, Transmission System Operator; CHP, combined heat and power; AD, anaerobic digestion; CSTR, continuously stirred tank reactor; VFA, volatile fatty acids; DyBiM, Dynamic Biogas plant Model; ADM1, Anaerobic Digestion Model no. 1; COD, chemical oxygen demand; CM, cattle manure; SB, sugar beet; WW, wet weight; TS, total solids; VS, volatile solids; OLR, organic loading rate; HRT, hydraulic retention time; DP, daily production; NPV, net present value.

FIGURES

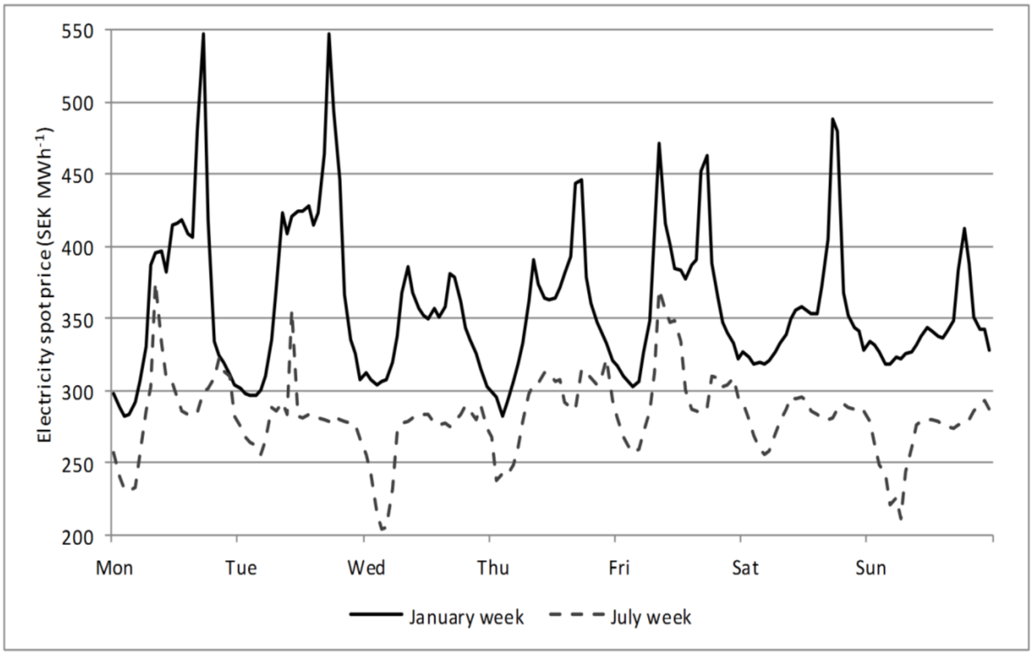

Figure 1. Electricity spot price in southern Sweden (SE4), during a January week (7-13 January) and a July week (8-14 July) 2013. The total income for producers of renewable electricity also includes green certificates.[49]

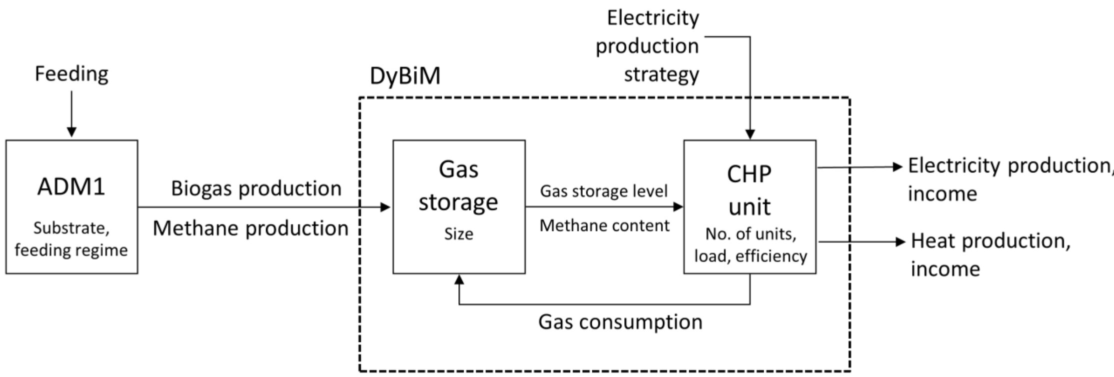

Figure 2. Overview of the DyBiM (Dynamic Biogas plant Model), describing a biogas plant with a gas storage and CHP unit(s), connected to ADM1 (Anaerobic Digestion Model No. 1).

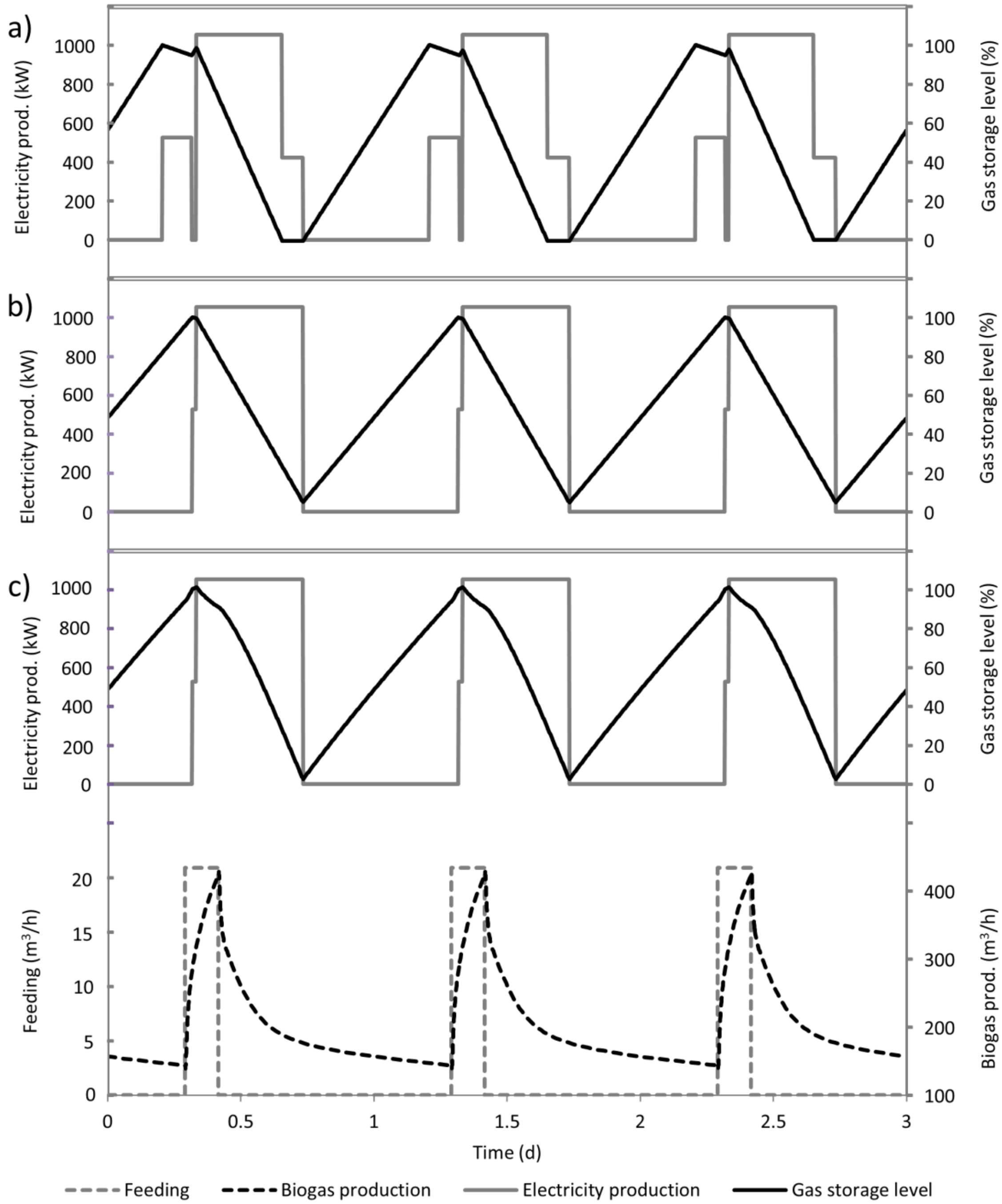

Figure 3. Electricity production and gas storage level on applying DP 9.6 with a biogas storage and feeding management of: a) 2300 m^3 storage capacity and constant feeding, b) 3000 m^3 storage capacity and constant feeding and c) 2300 m^3 storage capacity and feeding the substrate mixture during three hours (Mix 3h) (feeding and biogas production in the lower diagram).

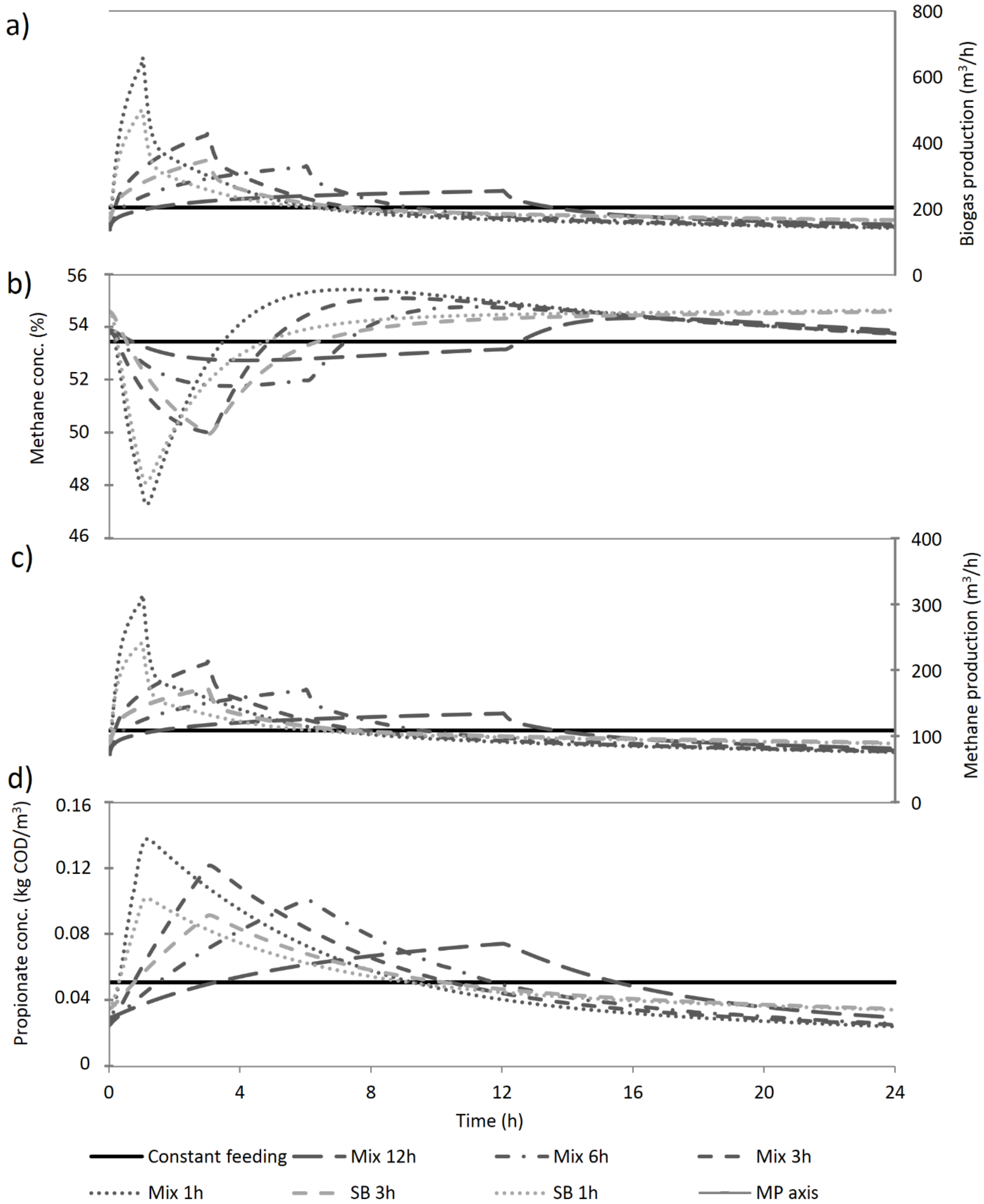

Figure 4. (a) Biogas production, (b) methane concentration, (c) methane production and (d) propionate concentration during one day with constant feeding or applying different feeding management strategies (all starting at time 0).

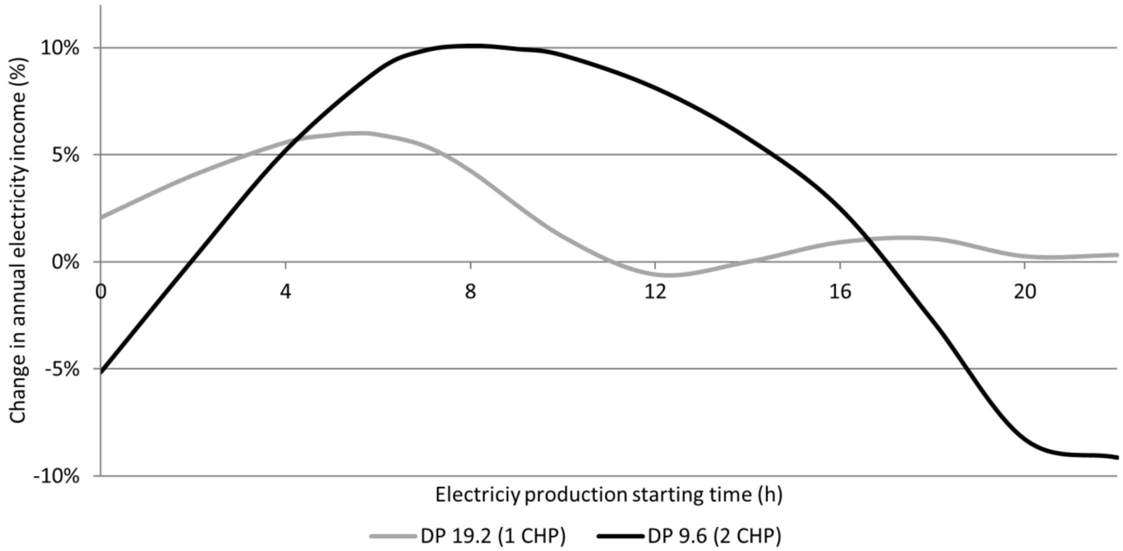

Figure 5. Change in annual electricity income compared with the reference scenario on varying the starting time of CHP production. All starting time results are based on one year's simulation, using spot prices for southern Sweden (SE4).

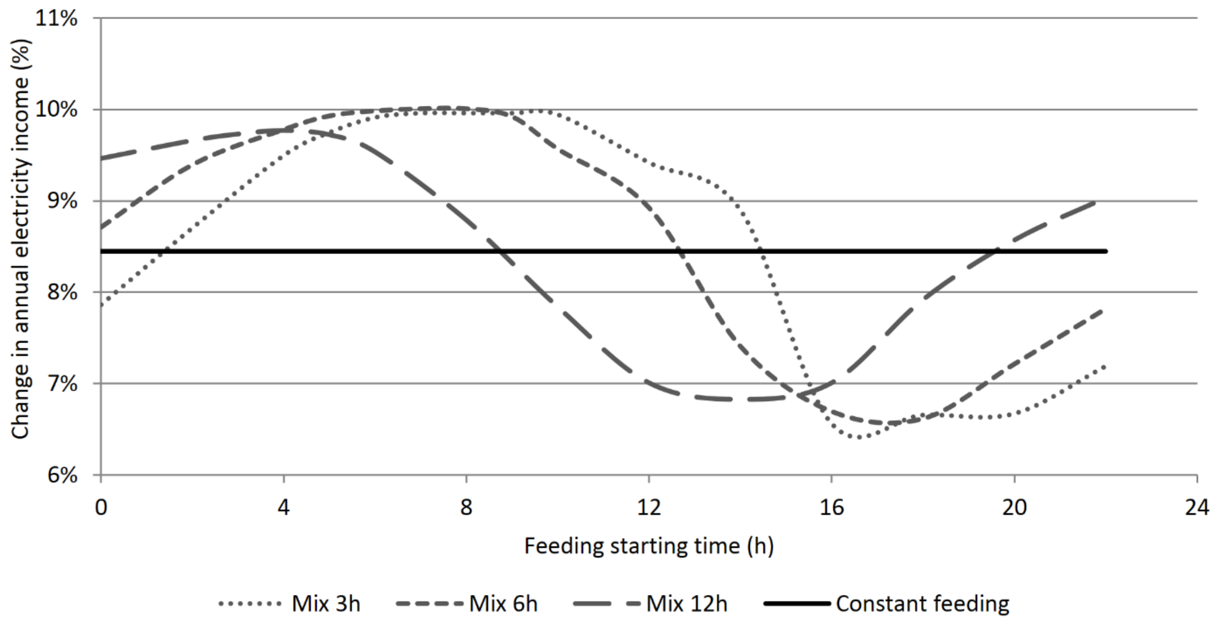

Figure 6. Impact of feeding starting time on change in annual electricity income compared with the reference scenario, using DP 9.6 (starting at 08.00 h) and gas storage capacity of 2300 m^3. All starting time results are based on one year's simulation, using spot prices for southern Sweden (SE4).

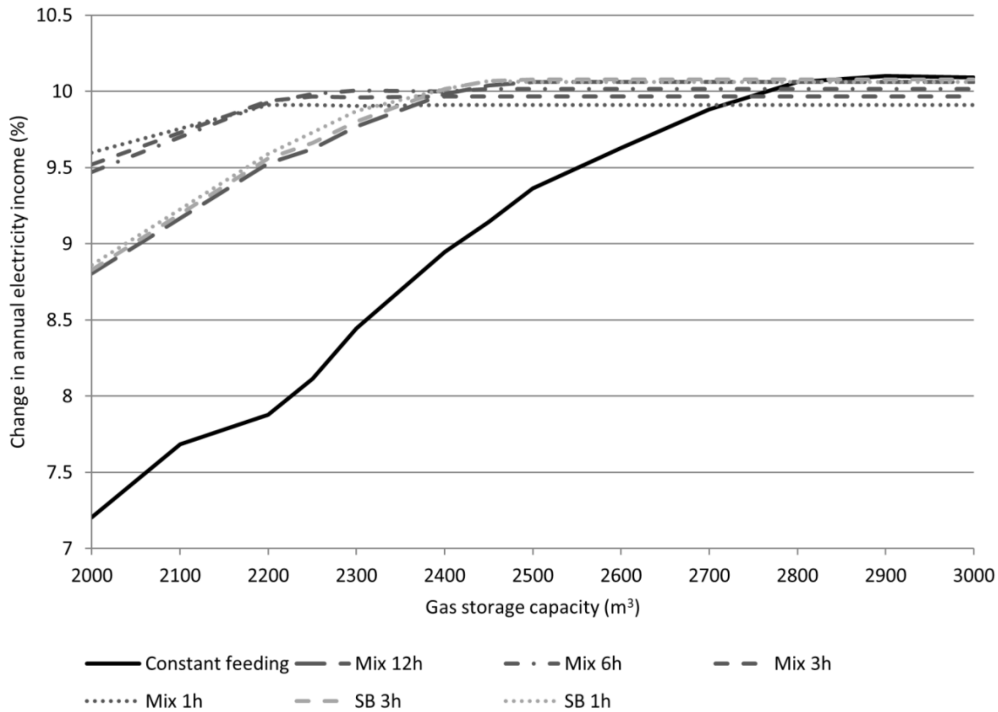

Figure 7. Change in annual electricity income compared with the reference scenario using DP 9.6 and varying gas storage capacity, applying constant feeding and feeding management. All results are based on one year's simulation, using spot prices for southern Sweden (SE4).

TABLES

Table 1. Substrate characteristics for cattle manure (CM),[37] sugar beet (SB)[46] and the substrate mixture.

	CM	SB	Substrate mix
TS (% of WW)	9.3	18.9	12.18
VS (% of TS)	81.7	91.1	86.08

Table 2. CHP unit characteristics.[45]

	Characteristics
Motor	4-stroke Otto, GE Jenbacher, J312GS-C225
Nominal power	527 kW
Electricity efficiency*	$-0.0885x^2+0.2007x+0.2838$
Heat efficiency*	$0.0583x^2-0.1432x+0.5318$
Minimum load	50%

* x = percentage of full load

Table 3. Cost assumptions in the flexible scenarios.

Unit	Cost
Biogas storage (€ m^{-3})	150 [a]
CHP unit (€ kW^{-1})	570 [b]
CHP starting cost (€ $start^{-1}$)	6 [c]

References: [a,47]; [b,50]; [c,14].

Table 4. Characterisations of cattle manure (CM) and sugar beet (SB) for ADM1 implementation.

	Parameter	Unit*	CM	SB
Ssu	Mono saccharides		13.37649 [a]	47.60
Saa	Amino acids		3.344123 [a]	0
Sfa	Long chain fatty acids (LCFA)		0.990851 [a]	0
Sva	Valerate		0 [a]	0
Sbu	Butyrate		0 [a]	0
Spro	Propionate		0 [a]	0
Sac	Acetate		0 [a]	0
Sh2	Hydrogen		0 [b]	0
Sch4	Methane		0 [b]	0
SIC	Inorganic carbon	kmol m^{-3}	0.0068 [a]	0
SIN	Inorganic nitrogen	kmol m^{-3}	0.165777 [a]	0
Si	Soluble inerts		7.059815 [a]	0
Xc	Particular composites		10.04181 [a]	0
Xch	Carbohydrates		29.59211 [a]	164.99
Xpr	Proteins		7.07411 [a]	20.90
Xli	Lipids		5.873149 [a]	16.44
Xsu	Bacteria consuming sugars		0.6 [c]	0
Xaa	Bacteria consuming amino acids		0.6 [c]	0
Xfa	Bacteria consuming LCFA		0.6 [c]	0
Xc4	Bacteria consuming valerate and butyrate		0.6 [c]	0
Xpro	Bacteria consuming propionate		0.6 [c]	0
Xac	Bacteria consuming acetate		0.018 [c]	0
Xh2	Bacteria consuming hydrogen		0.018 [c]	0
Xi	Particulate inerts		46.50395 [a]	29.02
Scat	Cations	kmol m^{-3}	0.04 [c]	0
San	Anions	kmol m^{-3}	0.075 [c]	0

*kg COD m^{-3} unless otherwise stated. References: [a,37]; [b,51]; [c52]

Table 5. Stoichiometric parameters for the disintegration of the composite fraction of cattle manure (CM), adapted from Zhou *et al.*[37]

	Parameter	Value
f_sI_xc	Soluble inerts from composites	0.0735
f_xI_xc	Particulate inerts from composites	0.4839
f_ch_xc	Carbohydrates from composites	0.3079
f_pr_xc	Proteins from composites	0.0736
f_li_xc	Lipids from composites	0.0611

Table 6. Economic outcome compared with the reference scenario for a scenario with one CHP unit and three scenarios with two units.

	1 CHP DP 19.2 1200 m^3 Const. feed	 2900 m^3 Const. feed	2 CHP DP 9.6 2500 m^3 SB 3h	 2000 m^3 Mix 3h
Change in electricity income (k€ y^{-1})	+8.1	+13.5	+13.5	+12.8
Change in heat income (k€ y^{-1})	-2.0	-2.0	-2.1	-2.1
Change in maintenance cost (k€ y^{-1})	-2.2	-4.4	-4.4	-4.4
Change in net cash flow (k€ y^{-1})	+3.8	+7.1	+7.1	+6.3
CHP investment (k€)	0	-300	-300	-300
Gas storage investment (k€)	0	-255	-195	-120
Total investment (k€)	0	-555	-495	-420
NPV of investment (k€)	26.9	-505	-446	-376

Table 7. Impact of reducing investment costs or excluding heat valuation on the total investment/net cash flow and NPV compared with the main results (see Table 6).

	1 CHP DP 19.2 1200 m^3 Const. feed	2900 m^3 Const. feed	2 CHP DP 9.6 2500 m^3 SB 3h	2000 m^3 Mix 3h
Reduced investment costs				
Change in total investment (%)	0	-46.7	-44.3	-40.3
Change in NPV (%)	0	+51.4	+49.3	+45.0
Excluding heat value				
Change in net cash flow (%)	+54.1	+28.7	+29.2	+33.5
Change in NPV (%)	+52.9	+2.8	+3.3	+3.9

Table 8. Change in yearly electricity income compared with the reference scenario and NPV, increasing fluctuations in the electricity price by a factor of 1 to 6 using two CHP units, 2000 m^3 gas storage capacity and Mix 3h.

Factor	Change in electricity income (k€ y^{-1})	NPV (k€)
1	+12.8	-376
2	+25.5	-287
3	+38.3	-197
4	+51.1	-107
5	+63.9	-17
6	+76.7	72

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