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Combined supply of electricity and fuel at biogas plants – economic efficiency of connection scenarios

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Due to the expiry of the original Renewable Energy Sources Act (EEG) remuneration for many biogas plants in the near future, as well as the severe cuts in the promotion of biogas power generation in the amended EEG 2017, the German biogas industry is faced with the question of which future connection concepts could be both economically attractive and promising in the long term. Fuel production from biogas would be one of the possible future options. Several studies forecast a shift in biogas utilization from electricity generation to fuel utilization by 2050. Politicians are also aiming for a higher implementation of bioenergy in the fuel sector. The focus of this paper is the economic evaluation of several connection scenarios with electricity and fuel production for existing biogas plants. In particular, a new flexibility approach with proportional electricity and fuel production with shares of 50% each in biogas utilization is to be investigated. With the help of flexible power generation schedules, local fuel demand data from vehicle fleets and the resulting fuel production schedule, the necessary additional biogas and high-pressure storage capacity and the necessary plant capacity for fuel production was determined. Subsequently, the economic evaluation was carried out according to the net present value method in order to be able to economically evaluate several connection scenarios for a representative model biogas plant. The comparison of the connection scenarios showed that the connection scenarios with fuel production are more economical than those with electricity production alone. Depending on how the planned national implementation of the new version of the European Renewable Energy Directive (RED II) is realized, the plant's economic efficiency – especially when increasing the proportion of liquid manure in the substrate composition – can improve significantly.

Keywords

Flexibilization, upgrading, biogas, biomethane, biofuel, bioCNG, future concept, off-grid, grid-independent, farm fuel station, local refuelling

Both the political efforts until 2050 published in the Impulse Paper of the German Federal Ministry of Economics and Energy (BMWi 2016) and the meta-analysis of Pieprzyk et al. (2016) clearly show the trend of biogas utilization: less electricity generation, but more utilization in the fuel and industry sector (Figure 1). This raises the important question of suitable plant concepts in order to achieve this transformation in the most ecological and cost-optimal way.

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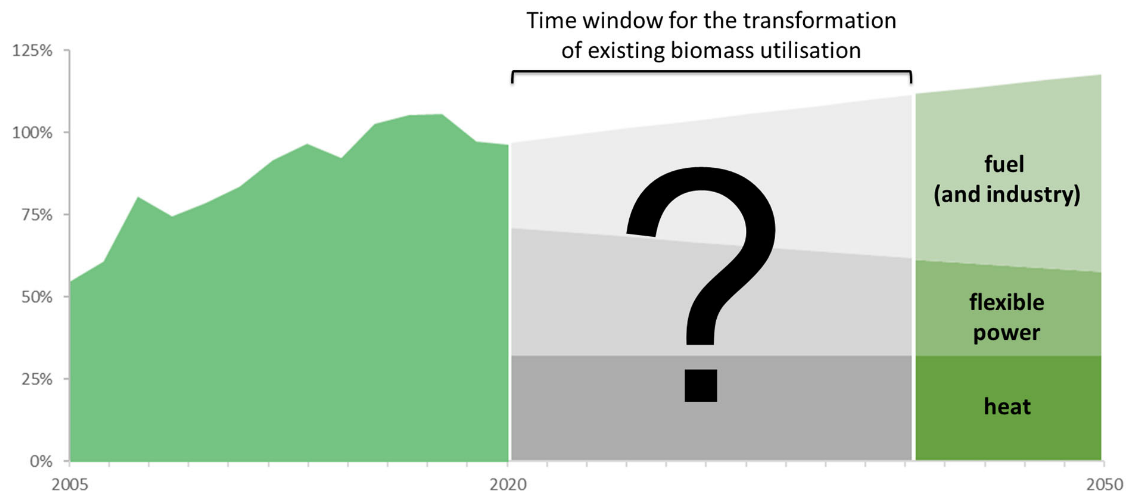

Figure 1: Time window with qualitative progression from previous biomass utilization (FNR 2019) to politically determined efforts until 2050 (BMWi 2016)

A current problem for the biogas plant stock is the omission of the primordial Renewable Energy Sources Act (EEG) remuneration for many plants. Many plant operators would no longer be able to ensure cost-effective operation with the follow-up remuneration under the EEG 2017 due to the tightly fixed maximum bid price and the subsidy with the flexibility supplement. Many operators are therefore faced with the question of which connection concepts can be shown to be economically promising in the long term. One possibility would be to upgrade the biogas and sell the product biomethane in the fuel sector. However, to date - despite some efforts on the part of the Natural Gas Mobility Initiative and the biomethane industry - no significant increase in the use of natural gas and biomethane in the fuel sector has been achieved. Generated biomethane is currently mainly used to provide electricity under the EEG. On the generation side, there has currently been no significant expansion of biogas upgrading plants (BGAA) with biomethane feed-in plants (BGEA) since the deletion of the bonus for gas upgrading in the EEG 2014. Some BGAA operators are currently considering decommissioning the plants, as the additional costs of upgrading cannot be covered by the currently very low sales price (DENA 2019).

For a significant proportion of the BGAA's existing plants with grid feed-in, the analyses show the loss of economic efficiency due to the elimination of the fee due to avoided grid costs as a result of the ten-year time limit under § 20 GasNEV (DENA 2018). In addition, the existing BGAA plants, with an average of 600 m^3 h^{-1} biomethane (figures in standard cubic meters under standard conditions with temperature T_N = 273.15 K corresponding to 0 °C and pressure p_N = 1.01325 bar) or 2.5 $MW_{el,eq}$plant capacity, are more likely to be classified as larger biogas plants (BGA) (DENA 2019). There is therefore a need for new plant concepts that enable as many of the approximately 9,000 BGA (DANIEL-GROMKE et al. 2017) as possible to be converted technically, improve the use of biomethane in the fuel sector, enable plant efficiency independently of the Renewable Energy Sources Act and offer a long-term perspective for the future.

One possible plant concept that consistently addresses these points would be off-grid biogas upgrading (off-grid BGAA) with local fuel sales to vehicle fleets. Especially for most BGA in the range of

150 to 750 kW_{el} (Daniel-Gromke et al. 2017), which corresponds to an equivalent upgrade capacity of 35 to 180 $m^3\ h^{-1}$ biomethane, the specific costs for local sales are significantly lower compared to grid-connected distribution (Figure 2). When determining the specific costs (Table 1), only the two distribution paths, grid feed-in with the grid feed-in plant and local sales with the filling station plant, were examined with regard to their costs, without taking the biogas production and upgrading process into account (Figure 2, balance limits). Thus, the costs for raw gas production as well as for upgrading are not included and only the costs of the two distribution types are compared.

Table 1: Comparison of the specific costs of the two distribution approaches - grid feed versus local sales

Key figures	**Unit**	**Plant size in $m^3\ h^{-1}$ biomethane ($kW_{el,äq}$)** 25 (104)	50 (208)	100 (417)	150 (625)
Specific costs BGEA approach Ø	ct $kWh^{-1}{}_{Hi}$	11.30	5.72	2.89	1.94
Specific costs off-grid approach Ø	ct $kWh^{-1}{}_{Hi}$	4.23	2.92	2.34	1.73
Specific savings through off-grid	ct $kWh^{-1}{}_{Hi}$	7.07	2.80	0.55	0.21
Total costs p.a. BGAA approach	€ a^{-1}	247,492	250,378	253,352	255,133
Total costs p.a. off-grid approach	€ a^{-1}	92,637	127,896	204,984	227,322
Savings with off-grid approach	% a^{-1}	62.6%	48.9%	19.1%	10.9%
Total savings off-grid approach	€ a^{-1}	154,855	122,482	48,368	27,811

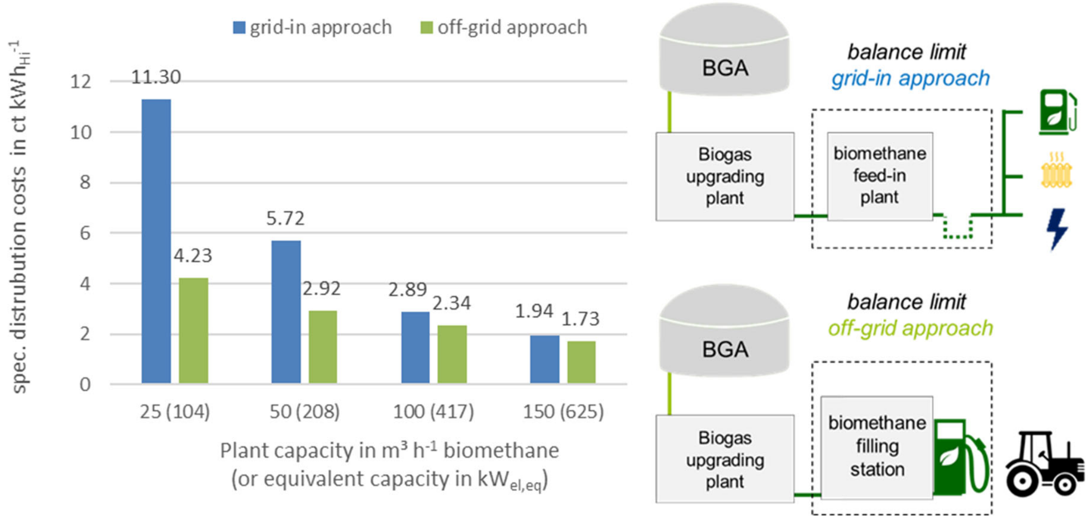

Figure 2: Specific cost comparison of the distribution approaches grid feed-in and off-grid approach for biomethane (grid feed-in costs from eMikroBGAA (Beil and Daniel-Gromke 2019), off-grid costs own calculation)

The specific cost data for grid feed-in are taken from the eMikroBGAA study (Beil and Daniel-Gromke 2019), which are consistent with the cost data from the IRENA study (2018). In the eMikroBGAA study, only the capped costs for the feed-in plant up to 250,000 € for the plant operator were considered. Additional economic costs, which the network operator has to bear in the case of grid-bound distribution, are not considered here. Thus, this is a purely economic comparison. The costs for local sales are taken from the calculations made in this paper. The effect of the “economy of scale” is clearly visible in the specific distribution costs. As the plant output decreases, the specific costs increase. Here it is clearly visible that the specific costs increase more strongly for grid feed-in than for local distribution via filling stations. The percentage cost advantage of local distribution compared to grid feed-in is between 11 and 63%, depending on the system output. It should be noted, however, that despite low-cost distribution, the specific costs for smaller BGAA are currently still very high. In addition to the economies of scale, the reason for this is the lack of demand in Germany for smaller plants, which means that manufacturers tend to offer expensive pilot plants in individual production. However, this is expected to change in 2020. Two plant manufacturers provided relatively favorable price information for micro-processing plants between 6 and 48 m^3/h biomethane in two specialist events at the end of 2019, provided that sufficient orders are also received (handwritten notes: Lecture U. Oester, IBBK Conference 15 Oct 2019 in Schwäbisch Hall; Lecture A. Lenger, Biogas Convention 12 Dec 2019 in Nürnberg).

In addition to the lower specific investment costs, there is another, possibly far more important point for local distribution, namely the additional revenues from the greenhouse gas avoidance quota (GHG quota for short) that the operator can achieve. By placing biofuels on the German market, which produce fewer emissions than fossil fuels, the amount saved can be sold as GHG quota to oil companies subject to quota, either directly or through quota brokers and traders. As a result, BGA operators of local service stations can expect additional GHG quota trading revenues of 4.5 to 5.5 ct kWh_{Hi}^{-1}, in addition to the sales value of biomethane (at the reference price of natural gas-based CNG fuel of 5.4 ct kWh_{Hi}^{-1} net, excluding VAT and energy tax, Hi = calorific value) depending on the emission savings of the biofuel and the price of the fuel quota (currently approx. 200 € $t_{CO_2}^{-1}$, see p. 18). The reference price for CNG fuel is assumed to be 1.10 € kg^{-1} gross as at a filling station. In comparison, the BGA operator would currently only earn an average of 7.1 ct kWh_{Hi}^{-1} as revenue for the biomethane fed into the grid for a substrate composition with renewable resources (NawaRo) and liquid manure (DENA 2019). As a result, the biogas plant and filling station operator has an additional revenue of around 3 ct kWh_{Hi}^{-1} from marketing the biofuel himself. With the planned national implementation of the new version of the European Renewable Energy Directive (RED II 2018) by 2021 at the latest, these revenues from the sale of GHG quotas will rise even further and may even be far higher than the price of fuel, depending on the GHG quota value.

In order to implement this local distribution, however, a basic requirement must be met: fuel sales must be as prompt and continuous as possible, which means that it is very likely that only fleets operated by companies can be considered as direct and plannable customers. Focusing on private car drivers would not be target-oriented, as was shown in a pilot test (BALA et al. 2009), where the results were below expectations. In addition, the figures from the Natural-gas-based mobility initiative (DENA 2016) show that the population is only very slowly switching to the alternative CNG drive despite fuel cost savings. For this reason, the development of a connection concept with fuel production for a post-EEG biogas plant should, if possible, focus on distribution to local fleets with commercial vehicles in order to achieve a defined fuel production and sales volume that is as evenly utilized as possible. Even if the rising quota prices make plant concepts with fuel production appear to be economically promising, it is of great importance to evaluate this new recycling path economically for different fuel-based connection concepts in detail and to compare it with the electricity-based connection concepts known today.

In the case of the electricity-based connection scenarios, the ten-year follow-up remuneration under the EEG 2017 will require a more flexible approach to electricity generation capacity, in which at least twice as much CHP capacity is provided in relation to the rated power fed into the grid. Compared with the usual implementation of flexibilization with overbuilding of the CHP capacity, which requires investments due to the addition of CHP units, transformer and gas storage capacity, etc., there is also the possibility of halving the rated output of the original CHP plant operation. The advantage of this is that no additional investment in flexibility is required. However, this also requires a reduction in biogas production, which leaves 50% of the plant's existing biogas production potential unused. This disadvantage could be avoided by using the remaining 50% of biogas production for fuel production. This results in a new flexibility approach in combination with fuel production: by reducing the rated output of the CHP unit but using the remaining biogas production potential for a proportionate fuel production (cf. Figure 4). This has the advantage for the plant operator that both the EEG follow-up remuneration including the flexibility surcharge and additional revenues can be generated by local fuel sales. Furthermore, there is potential for optimization through the overlapping of the time courses of the requirements of both uses. From a legal point of view, there is nothing to stop biogas production from continuing at the same level with reduced electricity production, as the restrictions on flexibility in the EEG 2017 are on the electricity side (Maslaton 2017).

Within the scope of these investigations, a typical agricultural stock biogas plant with the usual substrate composition (e.g. maize silage and cattle slurry) as well as an on-site power generation with 500 kW_{el} capacity is considered. For this existing biogas plant, several connection concepts with proportional or complete electricity and fuel production should be defined and their economic efficiency individually determined and compared. There are some studies available in the literature that deal with the economic viability of BGAA using off-grid approaches and discuss their cost-effectiveness (Hornbachner et al. 2009 and Scholwin and Grope 2017). However, the economic evaluation and comparison of electricity and fuel-based connection scenarios for existing plants in the post-EEG period, especially for different GHG quota revenue values, has not yet been investigated in such a framework. Furthermore, the effects on the additional demand for biogas storage capacity, high-pressure storage capacity and the necessary upgrading capacity have not yet been dealt with using concrete local refuelling data in order to enable the connection scenarios to be compared with each other as closely as possible.

The aim of the work is:

- to determine the technical parameters such as upgrading capacity, high-pressure and raw biogas storage of the different plant constellations and
- to show the capital values of the connection scenarios and compare them with the help of an economic evaluation.

Materials and methods

A model network with five components was used to evaluate the various connection scenarios with regard to the different revenue potentials for electricity and fuel as well as the individual costs for the respective plant constellation (Figure 3).

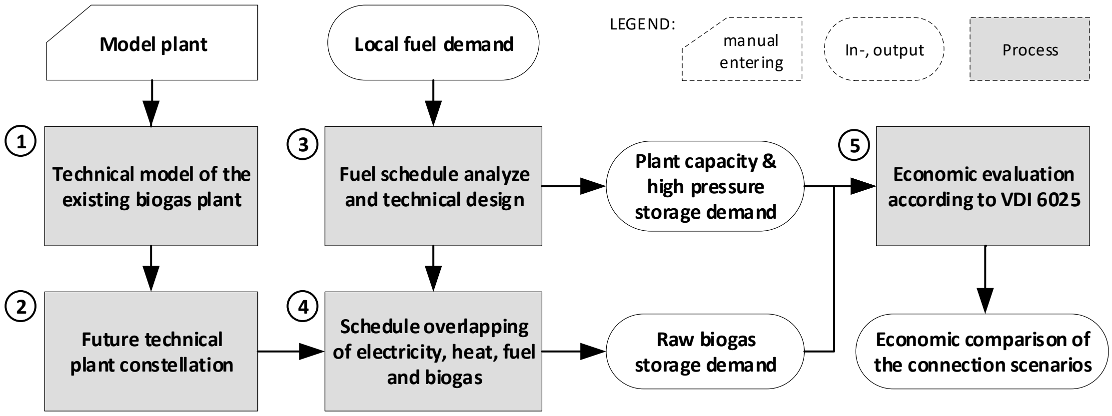

Figure 3: Five model components in the block diagram (represented as rectangular processes) for economic evaluation and comparison of the connection scenarios

Technical model of the biogas plant

In the first component, the model plant is technically defined, in which a rural biogas plant with a rated electrical output of 485 kW is considered, which corresponds to 500 kW of installed electrical output at 8,500 hours of full use. The model biogas plant produces 4,250,000 kWh_{el} of electricity and 4,781,250 kWh_{th} of heat with an electrical efficiency of 40% and a thermal efficiency of 45%. The plant has a biogas storage with a total capacity of 2,200 m^3 distributed between the main fermenter and the secondary fermenter as well as a covered gas-tight fermentation residue storage. The selected substrate mixture consists of 40% cattle manure and 60% maize silage. The information on substrate proportions is all mass-related. All plant-related parameters for the model biogas plant are summarized in Table 2.

Table 2: Plant-related parameters of the model biogas plant in the baseline scenario

Performance related parameters	Value	Other parameters	Value
Installed electrical power	500 kW_{el}	Existing biogas storage capacity	2,200 m^3
Rated electrical power	485 kW_{el}	Full usage hours	8,500 h a^{-1}
Electricity feed	4,250,000 kWh_{el}	Substrate content maize silage	60%
External heat sales 40%	1,912,500 kWh_{th}	Substrate content cattle slurry	40%
Electrical and th. efficiency	40% / 45%	Methane content in biogas	52.8%

In the baseline scenario, commissioning of the model biogas plant starts in 2001 and ends at the end of 2020 after 20 years of EEG remuneration. In order to keep the complexity in the economic assessment low, it is assumed that the CHP plant will reach its service life by the end of 2020 and that new CHP plants will therefore have to be considered for the subsequent period. However, this assumption plays a rather subordinate role for the transferability of the economic results into practice, since the plant costs are calculated accordingly using the residual value calculation for wear and tear during the period under consideration.

Future technical plant constellation

In the second model component, seven possible connection scenarios A to G for the model biogas plant are presented, which start after the end of the first 20-year EEG support period (Figure 4). In 2021, the seven different plant constellations will then be commissioned seamlessly. These will be selected in such a way that both flexibilization approaches with electricity generation (A to C), which are frequently encountered in practice, and new approaches with proportional electricity and fuel production (D to F) as well as the complete conversion to fuel production (G) will be considered individually in order to compare them with each other in the economic evaluation afterwards. The basic prerequisite for participation in the 10-year follow-up subsidy under the EEG 2017, i.e. double the CHP output in relation to the rated output, will also be taken into account. In the scenarios with electricity generation (A to F), participation in the tendering procedure under the EEG 2017 is thus also taken into account. The period under consideration for the economic assessment of the scenarios is limited to 10 years, as the specific climate targets (RED II, Biokraft-NachV, BImSchG) and the promotion of biofuels are only regulated until 2030. Beyond that, the further procedure is still uncertain. In Figure 4, the height of the bars qualitatively represents the required biogas production. Depending on the degree of flexibilization (0.5-fold, 2-fold, 4-fold) and the utilization path (electricity, fuel), biogas utilization is converted from the baseline scenario with constant electricity production (light blue bar).

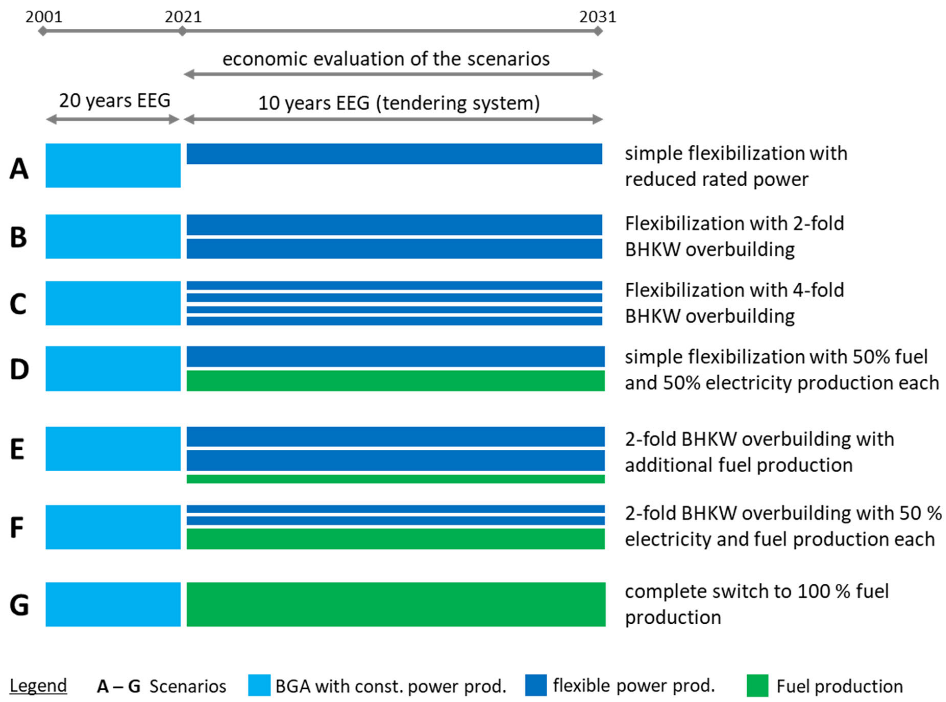

Figure 4: Seven connection scenarios for existing BGA after the end of the first EEG support period

In *scenario A*, the simple flexibilization with reduced rated power can be seen, which manages without increased electricity generation capacity, in which the CHP unit is operated at only half its capacity. The advantage is that no additional investment is required and the operator does not have to make any changes to the overall system. On the other hand, 50% of the possible biogas production remains unused and thus the possibility of generating additional revenues. In *scenario B* and *C*, the flexibilization takes place with a 2-fold or 4-fold CHP overbuilding. Here, the plant operator has to make investments for the increased electricity generation capacity, but can still feed in with the same rated output and generate additional revenues on the EPEX Spot Market through a price-optimized operation. In *scenario D*, a proportional production of electricity and fuel with 50% biogas utilization each is examined. Here the procedure is the same as in scenario A, with the only difference that this time the remaining 50% of biogas production is used in fuel production, thus exploiting the full potential of biogas production capacity in the existing biogas plant. *Scenario E* was developed in the same way as scenario B with the 2-fold CHP overbuilding and an additional lower fuel production. This requires an increased biogas production than previously, which can be achieved within limits, taking legal and technical aspects into account. The penultimate *scenario F* considers the possibility of a proportionate flexible power generation of 50% of the biogas and a fuel production of 50%. Analogous to scenario D, the effect of possible additional revenues on the EPEX Spot Market due to the double CHP overbuilding is thus examined here. Finally, *scenario G* examines the complete conversion of the previous electricity generation to fuel production. The technical system and performance-related data of the connection scenarios presented are summarized in Table 3.

Table 3: Plant related data of the different plant constellations

Plant data	**Unit**	**A**	**B**	**C**	**D**	**E**	**F**	**G**
Installed CHP output	kW_{el}	500	1,000	2,000	500	1,000	1,000	0
Installed BGAT output	$m^3\ h^{-1}\ CH_4$	0	0	0	85	25	85	150
Rated power								
BGA	$kW_{el,\ äq}$	243	485	485	485	554	485	484
CHP el.	kW_{el}	243	485	485	243	485	243	0
BHKW th.	kW_{th}	273	546	546	273	546	273	0
BGAT el,eq	$kW_{el,\ äq}$	0	0	0	242	68	242	484
BGAT	$m^3\ h^{-1}\ CH_4$	0	0	0	58.7	16.7	58.7	117.3
Primary energy demand								
BGA	$10^6\ kWh_{Hi}\ a^{-1}$	5.313	10.625	10.625	10.612	12.125	10.612	10.598
CHP	$10^6\ kWh_{Hi}\ a^{-1}$	5.313	10.625	10.625	5.313	10.625	5.313	0
BGAT	$10^6\ kWh_{Hi}\ a^{-1}$	0	0	0	5.300	1.500	5.300	10.598

The electrically installed capacity varies depending on the degree of flexibility. The installed biogas upgrading and filling station plant (BGAT) is given in $m^3\ h^{-1}$ and is found in three sizes in this study: 25, 85 and 150 $m^3\ h^{-1}$ biomethane. To understand the order of magnitude of the BGAT, the capacity is given in $kW_{el,eq}$, related to the CHP capacity in the model biogas plant. The primary energy demand (biogas production) in scenario E with additional fuel production through additional biogas production amounts to about 12.1 million kWh_{Hi}. With a methane content of 52.8%, the amount of biogas produced is thus below the legally defined maximum of 2.3 million m^3 biogas per year. In the other scenarios D, F and G with fuel production, biogas production is of the same order of magnitude as in the baseline scenario.

Fuel demand analysis and BGAT design

In the third component, the fuel consumption profile as well as the necessary technical system design for a reliable unrestricted fuel supply is determined using existing data on local fuel consumption. The fuel consumption profile and the associated fuel sales are decisive for the technical design as well as the system utilization of the system and thus for the system economy. The more consistent the consumption profile and thus the lower the fluctuations in demand, the lower the necessary plant overdimensioning and thus the resulting plant costs. For the economic evaluation, therefore, the demand profile plays a significant role in addition to the fuel sales volume.

For this reason, in particular to smooth the strongly seasonal agricultural sales profile with its large fluctuations, a location is selected in which the fuel consumption of a seasonally operated tractor fleet (agricultural operation) can be combined locally with a continuously operated bus fleet (public transport). The biogas plant and the tractor fleet are operated by an agricultural cooperative, which provided the necessary refuelling data as part of the study. The public transport company, whose bus depot is located in a distance of approx. 5 km, expressed its interest in a prompt conversion of the bus fleet to CNG engines, which means that this will be taken into account as an additional external sales volume.

Using this fuel consumption data, an aggregated fuel consumption profile for 8,760 annual hours or 52 weeks is now being compiled. Fuel sales are defined as 50% internal to agricultural machinery and 50% external to public transport buses. The following steps were carried out one after the other to achieve this:

1. the refuelling data of the vehicle fleet were extracted from the internal diesel yard filling station of the agricultural cooperative as CSV data sheet in addition to the individual refuelling quantities, the refuelling date and time were recorded.
2. the refuelling data of the local bus depot could be calculated with the help of the publicly available timetable information, the vehicle types and the usual refuelling times.
3. these refuelling data were allocated in a matrix with 365 days of 24 hours each according to the refuelling time and the locally aggregated demand was mapped for 8,760 annual hours.

An exemplary representation of the fuel consumption profiles (in diesel liters) in relation to the internal and external fuel supply with biomethane is shown in Figure 5. The differences in the profiles are due to the different fuel production volumes in the scenarios (Table 3).

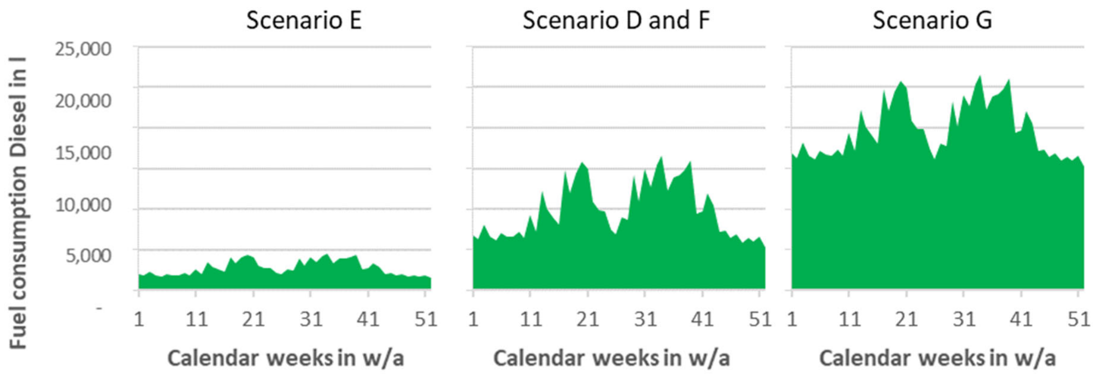

Figure 5: Aggregated fuel demand profiles for the scenarios E, D and F, and G (w = week)

Using the matrix with the aggregated fuel consumption data, the technical system design for the fuel production plant can then be carried out. First of all, the schedule for fuel production was generated hourly on the basis of fuel consumption and the high-pressure storage gear (Table 4).

Table 4: Extract from the schedule generation for BGAT operation based on local fuel demand (exemplary for scenarios D and F)

Day in d	Hour in h	Fuel consumption in kg	Fuel production in kg	Fuel coverage in kg	High-pressure storage course in kg	Biogas consumption in m^3
1	1	16.6	0.0	-16.6	-16.6	0
1	2	16.6	67.8	51.2	34.5	181.1
1	3	16.6	67.8	51.2	85.7	181.1
...	...	...	...	...	...	...
...	...	...	...	...	...	...
365	8,759	16.6	0	-16.6	747.5	0
365	8,760	16.6	0	-16.6	730.8	0

With the help of the consumption and generation schedules, the positive or negative coverage of the demand can now be determined for every hour of the year, and from this in turn the high-pressure storage course can be determined. The course of the high-pressure storage course is shown in Figure 6 as an example for scenario D. Due to the seasonal fuel demand of the agricultural enterprise, there is a high fuel demand in spring and early summer as well as in late summer and autumn. This results in negative values in the storage corridor during these periods due to the insufficient coverage of the fuel demand by local production. Based on this virtual high-pressure storage course, the necessary high-pressure storage capacity can be calculated by the difference between the maximum and minimum value of the storage course. The plant capacity is determined iteratively for each scenario in such a way that the amount for the total investment (BGAT, high-pressure storage, biogas storage requirement) is minimal. This method of calculation can be used to determine the individual necessary high-pressure storage capacity for the various plant constellations with fuel production (Table 5), thus enabling the connection scenarios to be compared economically.

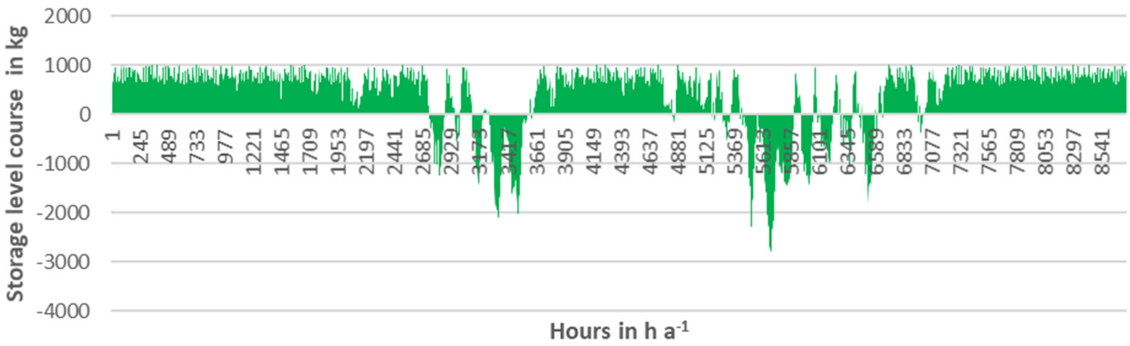

Figure 6: High-pressure storage level course over 8,760 annual hours (exemplary for scenario D)

Table 5: Technically required design for BGAT (fuel production) in scenarios D to G

Scenarios with fuel	Plant size biomethane in $m^3\ h^{-1}$	Plant utilization in%	Average performance in $m^3\ h^{-1}$	Equivalent performance in $kW_{el,eq,rat}$*	Necessary high-pressure capacity in kg
D	85	69.0%	58.7	243	3,890
E	25	66.4%	16.6	69	1,063
F	85	69.0%	58.7	243	3,890
G	150	78.2%	117.3	485	19,733

*rat: rated power

Schedule overlap of electricity, heat, fuel and biogas

The fourth model component is the intersection of the schedules of electricity, heat, fuel and biogas as well as the mostly discontinuously occurring consumption quantities. For this purpose, the methodological approach of Dotzauer et al. (2018) and the "BioFlex Tool Collection" developed by the DBFZ was used as a basis and extended by the fuel path. For this purpose, the generated schedule for fuel production and consumption from the 3rd component is combined with the other processes in the BGA, production and consumption of biogas, electricity and heat, into a common hourly evaluated matrix (Table 6). The table shows the process-relevant variables for generation, consumption and storage for 8,760 annual hours for the year 2017 for the locally generated energy types. In the case of electricity, instead of consumption and storage usage, the prices for short-term electricity wholesale (Epex Spot Se 2018) and the corresponding revenues are listed. The intersection results in the individual necessary raw biogas storage capacity for the seven different plant constellations and their different schedule operations.

Table 6: Extract of the schedule intersection of electricity, heat, fuel, biogas (exemplary for scenarios D and F)

Day	Hour	Biogas			Electricity		Heat			Fuel		
d	h	G	C	SC	G	P	G	C	SC	G	C	SC
		in kWh_{Hi}			in kWh_{el}	in € MWh^{-1}	in kWh_{th}			in kg		
1	1	1,265	0	8,015	0	21	0	163	1,837	0	17	-17
1	2	1,265	905	8,375	0	21	0	169	1,668	68	17	35
1	3	1,265	905	8,735	0	18	0	167	1,501	68	17	86
...	...	...	...	...	...	...	...	...	...	...	...	...
...	...	...	...	...	...	...	...	...	...	...	...	...
365	8,759	949	1,247	29,209	500	1.9	556	152	1,904	0	17	898
365	8,760	949	0	30,157	0	-0.9	0	126	1,778	0	17	881

Legend: G = Generation, C = Consumption, SC = Storage course, P = Electricity price

The necessary raw biogas storage capacity can be determined from Figure 7 by calculating the difference between the maximum and minimum value of the storage course. However, the actual necessary biogas storage capacity (Table 7) is even higher, since an additional lower and upper safety limit of 10% each, as well as a correction factor of 1.25 due to measurement inaccuracies, are also included in the calculation (Barchmann et al. 2016). Table 7 shows that in all scenarios, except scenario A, additional storage capacities are required in addition to the existing storage capacity of 2,200 m^3 in the model plant.

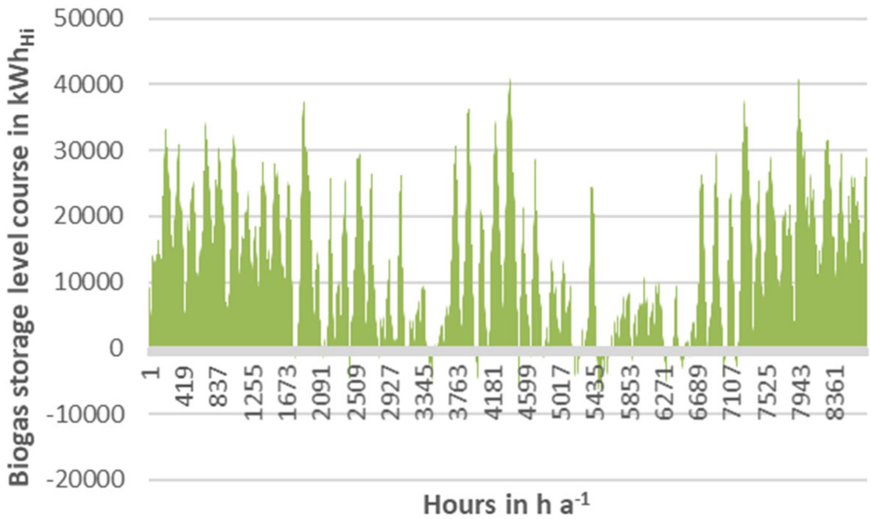

Figure 7: Time course of the biogas storage course over 8,760 annual hours (exemplary for scenario D)

Table 7: Necessary raw biogas storage capacity

Scenarios	Necessary raw biogas storage capacity in m^3
A	1,490
B	2,981
C	6,624
D	13,820
E	8,813
F	13,945
G	39,555

Economic evaluation according to VDI 6025

All technical and economic parameters that have been calculated or assumed now flow into the last component 5, the economic evaluation with the net present value method according to VDI 6025. The aim of the economic evaluation is the monetary comparison of the capital value between the connection scenarios. The capital value, also known as the net present value, is the sum of all discounted future incoming and outgoing payments. Discounting takes place at the time of investment t = 0. Discounting with the calculation interest rate (see below) makes future payments comparable from today's perspective. The net present value method is used instead of the usual annuity method due to non-periodic and specific payments in the period under review, such as:

- No service costs within three years, due to the guaranteed high availability of the filling station technology by the filling station manufacturer
- The specific energy tax rate for natural gas and biomethane as a fuel increases in legally defined years up to the full tax rate (EnergieStG 2006).
- The plant utilization or the hours of full use are set lower in the first years and gradually increased, since in reality the new acquisition or conversion of the local vehicle fleet to CNG will not suddenly take place.

Due to the somewhat short observation period of 10 years, the residual value is calculated according to VDI 6025 and taken into account in the economic evaluation. The individual service life and the wear and tear of the plant components of all seven technical plant constellations are calculated and taken into account individually. This enables the economic comparability of the connection scenarios with each other. In order to determine the average return on the capital employed (average yield), the modified internal rate of return is determined according to VDI. The investment is more economical if the internal rate of return is higher than the comparison interest rate, in this case the calculated calculation interest rate of 5.35%. This is calculated from the equity and debt capital interest (7% and 1.5%) and the respective capital shares (1/3 and 2/3).

For the scenarios with fuel production, the GHG reduction potential through its revenue potential is an important source of income. For this reason, a separate consideration will be made here according to the current calculation values from the Federal Office for Agriculture and Food (BLE) in accordance with Biokraft-NachV (2009), as well as the national implementation of RED II expected by mid 2021 at the latest. Two different substrate compositions are examined for the fuel-based scenarios: the composition presented in the baseline scenario with 40% liquid manure and 60% maize and the composition with an increased liquid manure content of 80% and 20% by mass (Table 8). The same amount of energy or biogas is produced with both substrate mixtures. The difference is only due to the increased GHG reduction potential through liquid manure, and thus the calculation at the GHG quota value. For this purpose, the GHG reduction potential is determined according to the formula in Annex 1 of the BioKraft-NachV. The different specific quota revenues result from the defined standard emission value for the utilization of liquid manure in the calculation basis according to BLE and RED II. According to BLE, this value is currently positive for liquid manure, at 8 kg_{CO_2} GJ^{-1}. However, according to RED II, emissions are saved through the substrate utilization of liquid manure, which is why the emission value here is set at -100 kg_{CO_2} GJ^{-1} (RED II 2018). This results in a much higher GHG reduction potential and quota value compared to the quota value calculation according to BLE.

Table 8: Determined GHG quota values as a function of substrate content and calculation basis based on the GHG quota price of 180 € $t_{CO_2}^{-1}$ in the fuel sector

Scenario	**GHG quota values for fuel sales in ct kWh_{Hi}^{-1}**		
	40M/60R* BLE	**40M/60R RED**	**80M/20R RED**
A - C	0	0	0
D	4.54	7.27	10.56
E	4.95	9.72	12.41
F	4.54	7.27	10.56
G	4.12	4.80	7.27

*The substrate composition is given by mass with M for liquid manure and R for renewable resources in %.

Since scenarios D to F only generate fuel in the biogas plant on a pro rata basis, the high GHG reduction potential of the liquid manure in the entire biogas production (for electricity and fuel) can be credited exclusively and thus advantageously to the fuel side, which means that higher specific quota revenues can be achieved compared to scenario G with the complete switch to fuel production (Table 8, see RED II calculative divisibility). Further calculation-relevant parameters and assumptions can be found in the list in the appendix.

Results and discussion

Figure 8 shows the results of the economic evaluation for the connection scenarios. The net present value, expressed in millions of €, is compared. This value is positive for all, i.e. all connection scenarios are economic under the assumed framework conditions. In the scenarios D to G with fuel production, the net present value was determined for three GHG reduction potentials, which were calculated depending on the substrate content (40% or 80% liquid manure content, by mass) and the standard values according to BLE or RED II. The different specific quota revenues (Table 8) have a significant impact on the plant's economic efficiency despite the same fuel sales volume. The left light green bar represents the current status quo according to BLE. If the negative emission value for liquid manure in RED II in Germany is implemented in 2021 at the latest, the middle green bar will result. If, in addition, the slurry mass proportion is increased to 80%, the dark green bar can be achieved with the generally even higher economic efficiency.

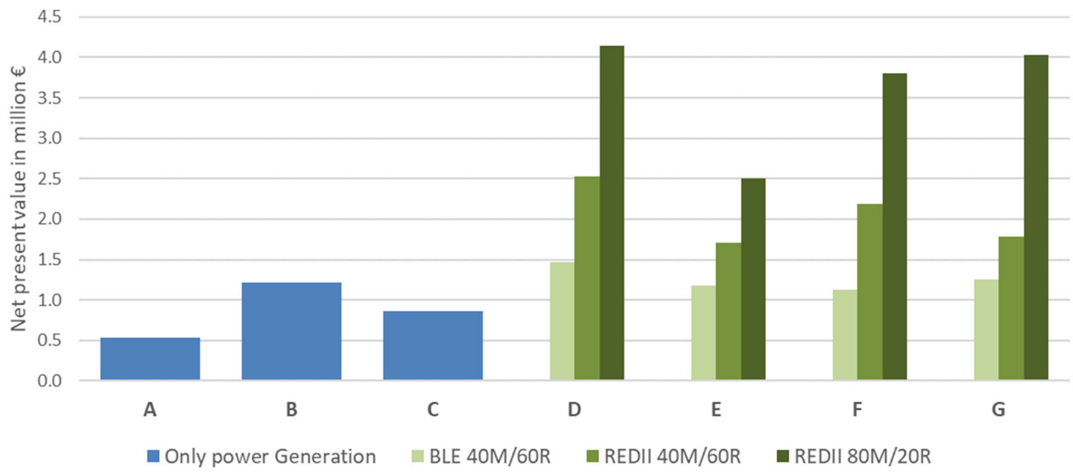

Figure 8: Comparison of the overall profitability of the seven connection scenarios for a 500 $kW_{el,inst}$ BGA – scenarios A to C with electricity generation only, D to F with proportional electricity and fuel production and G with complete fuel production

Among the scenarios A to C with exclusive electricity generation, scenario B with double CHP overbuilding is the most economical, followed by scenario C with quadruple overbuilding and finally scenario A with the same CHP but reduced rated output. The latter has the lowest investment requirement (Table 9).

Table 9: Economic results of connection scenarios A to C with exclusive electricity generation

Scenarios with electricity	Net present value (discounted profit) in €	Internal rate of return (average return) in %	Replacement investment (Investment minus residual value) in €	Investment I_0 in €
A	530,450 €	14.0 %	292,628 €	444,241
B	1,219,636 €	13.7 %	704,254 €	1,062,329
C	862,766 €	9.9 %	1,022,768 €	1,648,932

The reason for the lower economic efficiency of the fourfold overbuilding compared to the twofold overbuilding is the omission of the flexibility premium and instead the lower subsidy with the flexibility surcharge. The reason for the discontinuation of the flexibility premium is that, on the one hand, the ceiling for the flexibility bonus has been exhausted and, on the other, the very last reporting period is before 2021 (mid 2020). With the flexibility bonus, scenario C (€1,702,485) would have proved more economical than scenario B (€1,376,176).

In a comparison of scenarios D to F with proportional fuel production, scenario D, with 50% electricity and fuel production each, is the most economical, independent of the quota revenue variant, followed by scenarios E with additional fuel production and F, with 50% electricity and fuel production each, but with a CHP unit with twofold capacity (Table 10). In the case of the quota revenue variants with RED II, scenario F is again more economical than E, because the higher fuel sales volumes in scenario F multiplied by the increased quota value result in a higher total quota revenue than in scenario E with the low fuel production. Scenario G, with the conversion to complete fuel production, represents the second most economical scenario in the case of the quota revenue variant BLE and

RED II with 80% liquid manure. When considering the quota revenue variants under RED II with 80% liquid manure mass share, scenarios D, F and G result in very high capital values. In Tables 9 and 10, in addition to the capital values, the internal rate of return, the replacement investment with consideration of residual value and the investment at time t=0 with a liquid manure content of 40% are also given.

Table 10: Economic results of the connection scenarios D to F with proportional and G with complete fuel production for three quota revenue variants

Scenarios with fuel	Net present value (discounted profit) in €			Internal rate of return (average return) in %			Replacement Investment in €	Investment I_0 in €
	BLE 40G/60M	RED II 40G/60M	RED II 80G/20M	BLE 40G/60M	RED II 40G/60M	RED II 80G/20M		
D	1,472,367	2,530,459	4,140,216	13.2	16.8	17.4	909,672	1,404,993
E	1,184,318	1,706,299	2,497,830	11.3	13.2	13.3	1,039,446	1,610,675
F	1,130,275	2,188,366	3,798,123	10.2	13.5	15.0	1,228,375	1,972,487
G	1,254,489	1,783,438	4,032,672	10.8	12.5	15.6	1,231,028	1,905,174

When comparing all connection scenarios in their entirety, scenarios D with proportional fuel production and G with complete conversion are the most economical connection scenarios, followed by scenario B with exclusive electricity production. However, this only applies in the case of the status quo, i.e. GHG calculation according to BLE. With the national implementation of RED II, all scenarios with fuel production are more economical than the scenarios with electricity production only. In addition to the economy, other factors are also important in order to be able to make statements about the connection concepts. Some of these would be the individual risks and advantages of the respective connection concepts, their long-term prospects in relation to the forecast trend and the political efforts to convert the biogas sector by 2050 (Figure 1).

Viewed comprehensively, scenario D, with a 50% share of fuel production, offers the best prospects if the economic and operational aspects as well as the risk and development prospects are considered together. On the one hand, it has the highest capital values in all quota revenue variants. On the other hand, the pro rata electricity and fuel production provides the possibility of switching between processes, which means that the technical capacity (such as plant capacity and storage facilities) on both sides can be used for profit-oriented scheduling. In addition to this, this plant constellation offers the possibility of completely converting biogas utilization to fuel production after the successful establishment of fuel production and supply, once the ten-year EEG connection subsidy has expired. It would also be in line with political efforts to reduce (flexible) electricity generation from biogas and increase fuel production by 2050. In addition, it is advantageous that this constellation can be achieved without an increased power generation capacity and without converting the BGA to increased liquid manure fermentation. In comparison, scenario F, the only difference between which is the double CHP overbuilding, has the disadvantage that in the long term the promotion of the conversion of biogas into electricity is likely to find less and less acceptance in view of the very favorable electricity generation from wind and solar energy. Thus, the question arises, of course, whether an investment in the electricity path is appropriate in the long term.

Scenario G, despite the second-highest plant efficiency after the status quo and in the case of RED II with 80% liquid manure content, is associated with a certain risk. The calculated high capital value is only achieved if the calculated plant utilization of 78.2% is achieved (Table 5). Such high fuel sales volumes can currently only be achieved with continuously fuel-consuming fleets that actually implement the changeover to CNG engines. In a particularly favorable case, with 100% liquid manure fermentation (500 $kW_{el,inst}$ liquid manure plant), the capital value for scenario G under RED II is even twice as high (> €9 million). This scenario is particularly attractive for districts with high livestock density or very large livestock farms. However, it must be borne in mind that the complete conversion to a new recycling path currently represents a risk for the plant operator that is difficult to calculate from the point of view of fuel sales. It also represents a risk for the fleet operator, as compared to scenarios D and F, twice as many CNG conversions or new acquisitions would be required.

Conclusions

1. Connection scenarios for existing biogas plants with fuel production are more economical than those with exclusive electricity production. In the case of the quota revenue variant under RED II, the fuel-based scenarios are more economical than the purely electricity-based connection scenarios, even in the case of support with the higher flexibility bonus for electricity production.
2. With the national implementation of RED II and the (on-balance sheet) use of liquid manure for fuel production, plant efficiency increases considerably. In the fuel-based scenarios, it contributes in part to double plant efficiency compared with the status quo. In some scenarios this can be almost doubled again if the proportion of liquid manure in the substrate composition is increased from 40 to 80%.
3. Scenario D is the most promising from the point of view of shared risk through two independent sources of income, the highest level of plant efficiency, the low investment requirement, and the possibilities of subsequent capacity expansion and double-track plant operation in terms of plant and revenue optimization.
4. Scenario G with a complete switch to fuel production also proves to be a very economical option if high plant utilization can be ensured with prompt local fuel sales and a high liquid manure content can be achieved. However, the complete conversion represents a risk that must be taken into account

Thus, the provision of biomethane as a fuel under the assumption of a secured and direct utilization at the site under the currently foreseeable and here assumed framework conditions represents an attractive perspective for the future of biogas plants.

In a further study, the sales profiles of several vehicle fleet companies will be evaluated using concrete refuelling data in order to analyze the technical and economic effects of individual sales fluctuations on the design, fuel production and supply as well as biogas plant operation. In addition to this, the savings potential of additional necessary biogas storage capacity in the case of local fuel distribution will be investigated and demonstrated with the help of flexible substrate feeding and a fuel-led CHP operation.

Annex

List with further calculation relevant parameters and assumptions:

- The production costs for maize silage in own production are estimated at € 37 t_{FM}^{-1} (LfL 2008, without fertilization of fermentation residues). No substrate costs are charged for liquid manure.
- Heat sales in the scenarios with CHP plants amount to either 1.9 million or 0.95 million kWh_{th}, depending on the rated thermal output of 540 or 270 kW_{th} (Table 3). The heat price is set at 4 ct kWh_{th}^{-1}. The more flexible operation results in additional system costs for a heat storage tank and peak load boiler as well as additional operating costs due to the consumption of wood chips.
- The additional costs for the fermenter heating are included in the case of scenario G with complete conversion to fuel production and thus the lack of heat requirement coverage by the CHP through a biogas boiler.
- The additional costs for higher liquid manure fermentation quantities at 80% liquid manure content, which corresponds to a fermentation capacity of liquid manure increased to 150 $kW_{el,eq}$, are taken into account in the economic evaluation. The additional plant investment costs are estimated on the basis of cost data for small-scale manure plants (FNR 2015).
- The sales price for the fuel produced (BioCNG) is set equal to the price for CNG at the public filling station at a gross of 1.10 € kg^{-1}.
- Processing in the smaller capacity segment only makes economic and operational sense with membrane technology (Hinterberger 2011). The costs of the various capacity sizes are calculated on the basis of cost functions (Hornbachner 2009).
- In 2018, the prices for the GHG quota amounted to € 150 $t_{CO_2}^{-1}$ (ALB 2018). At present, market prices for GHG reduction in the fuel sector amount to more than € 200 $t_{CO_2}^{-1}$. According to market players, the price is expected to amount to € 250 $t_{CO_2}^{-1}$ in 2020 and to be a further € 30–50 $t_{CO_2}^{-1}$ higher for advanced biofuels from non-food substrates (e.g. liquid manure) (Mozgovoy 2019). In this economic assessment, however, a conservative price of € 180 $t_{CO_2}^{-1}$ is assumed. Even though the market is volatile in terms of price, it is assumed that the successive introduction of the sub-quota will not cause the prices of advanced biofuels to fall.
- The bid price for participation in the tendering model in the EEG 2017 is set at 16.23 ct kWh_{el}^{-1} with the maximum possible bid price for existing plants in 2021.
- It is assumed that the biogas plant was well maintained in the baseline scenario, which is why no reinvestment measures would be necessary. However, additional unforeseen maintenance costs and unexpected costs are taken into account annually.

All other relevant technical and economic parameters are taken from the FNR guidelines (FNR 2018) and DBFZ project reports (Dotzauer et al. 2018).

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