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Economic and Global Warming Potential Assessment of Flexible Power Generation with Biogas Plants

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Abstract: Demand-oriented power generation by power plants is becoming increasingly important due to the rising share of intermittent power sources in the energy system. Biogas plants can contribute to electricity grid stability through flexible power generation. This work involved conducting an economic and global warming potential (GWP) assessment of power generation with biogas plants that focused on the Austrian biogas sector. Twelve biogas plant configurations with electric rated outputs ranging from 150–750 kW and different input material compositions were investigated. The results from the economic assessment reveal that the required additional payment (premium) to make power generation economically viable ranges from 158.1–217.3 € MWh^{-1}. Further, the GWP of biogas plant setups was analyzed using life cycle assessment. The results range from -0.42 to 0.06 t CO2 eq. MWh^{-1} and show that the 150 kW plant configurations yield the best outcome regarding GWP. Electricity from biogas in all scenarios outperformed the compared conventional electricity sources within the GWP. Greenhouse gas (GHG) mitigation costs were calculated by relating the needed premium to the CO_2 eq. saving potential and range from 149.5–674.1 € (t CO_2 eq.)$^{-1}$.

Keywords: biogas plant; flexible power generation; economic assessment; life cycle assessment; global warming potential; greenhouse gas mitigation costs

1. Introduction

Europe's biogas sector is experiencing an ongoing process of change. In the early 2000s, the sector saw a huge propagation of biogas plants, increasing its count to about 17,700 in 2016 compared to a few thousand in 2000 [1]. The majority of biogas plants are designed for base load power generation with combined heat and power (CHP) units to convert energy from biogas to electricity and heat. The overall efficiency of the energy conversion is about 85–90% [2]. Biogas is produced by anaerobic digestion of organic input material, whereby digestion usually takes place in fermenters that are designed as continuously-stirred tank reactors (CSTR) [3]. A broad range of input materials can be used at biogas plants with energy crops, agricultural residues, biowaste, and sewage being the most common materials in the European region [4]. The produced biogas is typically saturated with water vapour at the given process temperature and the main constituents are methane (55–70% *v/v*) and carbon dioxide (30–45% *v/v*), while the most common trace substances besides nitrogen and oxygen from air are hydrogen sulfide and ammonia [5].

As an alternative to on-site power generation, biogas can also be converted to biomethane by a gas upgrading process through the removal of carbon dioxide and trace substances, drying, and compression. Biomethane can be used as a local fuel or as a renewable substitute for natural gas after injection in the natural gas grid. Various upgrading technologies have been developed in recent decades including membrane and adsorption processes, whereby the optimization of these processes is currently being intensively researched [6]. The number of biogas plants in Europe that focus on biomethane production increased from 187 in 2011 to 503 in 2016 [1].

The realization of globally-stipulated climate targets has led to an increasing integration of power plants with fluctuating power generation in the energy system—mainly wind and photovoltaic power plants. The renewable electricity net generation in European Network of Transmission System Operators for Electricity (ENTSO-E) member countries increased from 1025.6 TWh in 2011 to 1200.0 TWh in 2016 (including hydro power plants), whereby the relative share of electricity generated with wind and photovoltaic power plants rose, respectively, from 16.2% to 26.3% and 0.04% to 8.8% in the same period [7,8]. The increasing fluctuation of electricity supply poses challenges to the electricity grid stability and results in a growing demand for flexibility in the energy system. Flexibility can be provided by demand-side management, smart grid solutions, energy storage systems, and demand-oriented power generation of other power plants [9].

In the last few years, several European countries propagated flexible, demand-oriented power generation with biogas plants by implementing feed-in premiums (FIP). These premiums represent additional payments to the electricity market price and their purpose is to make the direct marketing of biogas plants at electricity markets economically feasible. A compilation of FIP systems applied in the EU-28 can be found in Pablo-Romero et al. [10]. Spot markets and markets for control energy reserves are particularly interesting for the direct marketing of generated electricity from biogas plants. Control energy reserves in Europe are organized by national transmission system operators (TSO) that regulate electricity net frequency, which must be held at 50 Hz [11]. Power capacities placed on the markets for control energy reserves must be kept available by the plant operator at all times. Control energy reserves can be distinguished by the demanded activation time of the power generation unit (primary, secondary, or tertiary reserves), in positive reserves (increase power on demand) and negative reserves (decrease power on demand).

In Austria, 287 biogas plants were operating in 2016 with a total installed electric capacity of about 83.32 MW [12]. Most plants were operated as base load power plants receiving a fixed feed-in tariff regulated in the 2002 Green Electricity Act (Oekostromgesetz) [13]. With the Austrian National Council's unanimous adoption of the Amendment to the Green Electricity Act in June 2017 [14], the framework conditions for new biogas plants were newly regulated. Thus, the installed electrical capacity for biogas plants with on-site conversion of biogas into electricity must not exceed 150 kW. Larger biogas plants must upgrade the biogas to biomethane for injection into the natural gas grid. The biomethane can subsequently be converted into electricity at another place. The use of biomethane in electricity generation plants to balance the fluctuating renewable energy sources is therefore an obvious choice [15].

Furthermore, it is stated in the Amendment that the substrate share of grain and corn (combined) for new biogas plants must not exceed 30%. The overall efficiency (electricity and heat use relative to the energy content of the biogas) has also received more attention: the efficiency must reach at least 67.5% on an annual average. In addition to the Amendment, an associated ordinance from the Green Electricity Act was released at the end of 2017 [16]. The feed-in tariff was set to 189.7 € MWh^{-1} for biogas plants that applied for it by January 2019 at the Austrian settlement agency for green electricity. A 161 € MWh^{-1} tariff has been proposed for cases where biomethane is withdrawn from the gas grid and converted to electricity. If heat utilization is particularly high, an increase of 20 € MWh^{-1} of the green electricity tariff can be expected. For the first time, the Austrian legislator has reacted in such a way that the power supply of new biogas plants must be designed for remote controllability [14], which also represents a first incentive for the market integration of biogas plants.

Several studies have assessed the economic viability of flexible power generation with biogas plants. Hochloff and Braun [17] investigated the economics of biogas plant participation in electricity spot markets and markets for tertiary control energy reserves. Gohsen and Allelein [18] developed a market-based optimization model for comparing different biogas plant marketing forms. Barchmann et al. [19] conducted an economic assessment of optimized power generation schedules and different feeding regimes, while determining the required gas storage capacity. Hahn et al. [20] investigated the economics of concepts for a demand-oriented biogas supply for flexible power generation, concluding that biogas supply costs are mainly affected by substrate costs. Saracevic et al. [21] assessed the economic effects of providing secondary control energy reserves with a biogas plant that focuses on biomethane production.

The ecological impact of power generation with biogas plants has also recently been investigated; for example, Liebetrau et al. [22] examined the methane emissions caused by biogas-producing facilities at agricultural biogas plants and Whiting and Azapagic [23] compared the co-generation of power and heat at biogas plants to fossil fuel-based plants. They concluded that most impacts are significantly lower at biogas plants, e.g., reducing global warming potential (GWP) by up to 50%. A review of life cycle assessments (LCA) with focus on biogas production at European biogas plants can be found in Hijazi et al. [24].

Only few studies assess the ecological effects of flexible power generation with biogas plants. Lauer et al. [25] performed an economic assessment of different flexibilization scenarios that also assess the impact on greenhouse gas (GHG) emissions. Additionally, Hahn et al. [26] compared different configurations for a demand-oriented biogas production within the context of flexible power generation as part of an LCA.

The present study aims to assess flexible power generation with biogas plants in a comprehensive way. The economic effects and GWP impacts of power generation with biogas plants are assessed by focusing on market-oriented power generation schedules. The focus lies on the Austrian biogas sector and the needed economic framework for market integration of biogas plants is discussed against the background of uncertain future developments of the sector. Additionally, the GWP impact of power generation with biogas plants is investigated in the course of an LCA. The most relevant factors regarding the GWP are identified and GHG mitigation costs are calculated.

2. Materials and Methods

Four biogas plants with electric rated outputs of 150, 250, 500, and 750 kW were investigated in this work considering different power generation schedules and input material mixes. The plant sizes 250 kW, 500 kW, and 750 kW were chosen as they represent sizes of typical Austrian biogas plants. Additionally, a 150 kW plant was investigated as this is the maximum size for newly constructed biogas plants in Austria according the 2017 Amendment to the Green Electricity Act. All investigated plants have the same basic plant setup, which is shown in Figure 1 and was chosen to represent a typical Austrian biogas plant setup.
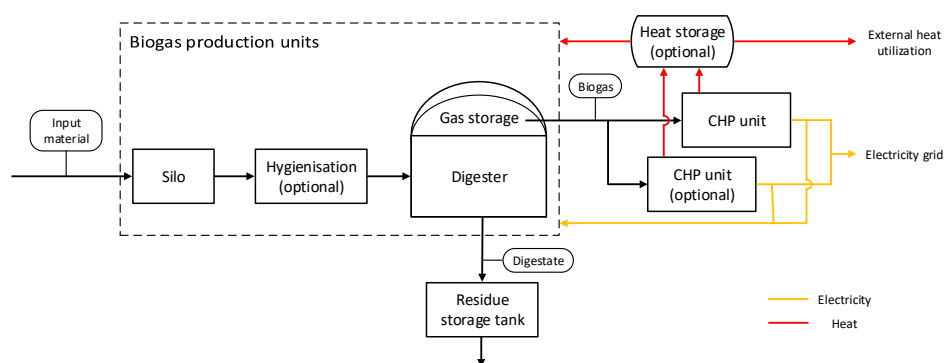

Figure 1. Schematic setup of the investigated biogas plants.

Input materials are stored in silo facilities when delivered before they are transferred to digestion units. If biogenic waste of animal origin is used as input material, it must run through a hygienization process and be heated up for sanitation purposes according to EU regulations [27] before it is digested. Biogas is produced in the digesters that is then stored in a biogas storage or transferred to the CHP units. Double membrane biogas storages were considered in this work, which are installed at the top of the digesters (internal gas storage). One CHP unit was considered in the basic plant concepts, while a second CHP unit was added in two flexibilization concepts described in Section 2.1. The fermentation residue (digestate) is stored in residue storage tanks before it is transferred to agricultural fields and spread as fertilizer. Biogas is converted to electricity and heat by CHP units. A share of the produced heat is used to cover the heat demand from the plant's biogas production units. The remaining heat is either used to cover an external heat demand or is considered as losses. In case of discontinuous heat generation due to flexible electricity generation, a heat storage was considered to ensure continuous heat output. Part of the generated electricity is used to cover the plant's electricity demand and the rest is fed into the electricity grid.

Three different input material mixes were considered for each of the four investigated biogas plant sizes, resulting in a total of 12 plant configurations. The three mixes consist of varied compositions of energy crops, farm manure and biogenic waste, defined as MAIZE, MIX, and WASTE. The input material compositions for each of the plant configurations are shown in Figure 2. Different types of biogenic waste are categorized by common Austrian numeric codes [28]; a description of these categories is in the caption for Figure 2. The composition of each mix was chosen to represent input material mixes that are typically used at Austrian biogas plants, whereas the configurations for 500 kW biogas plant MAIZE and MIX refer to Stuermer [29]. The configuration MAIZE has a high share of maize silage, whereas the configuration WASTE has no maize silage but a share of biogenic waste. No biogenic waste of animal origin was considered in the WASTE mixes for the smaller biogas plants with 150 kW and 250 kW, as this would result in inefficiently high investment needs for substrate pretreatment (hygienization). The input material mixes for the 150 kW plant were chosen to correspond to the regulations stipulated in Austria's 2017 Amendment to the Green Electricity Act (share of grain and corn (combined) less or equal 30%).

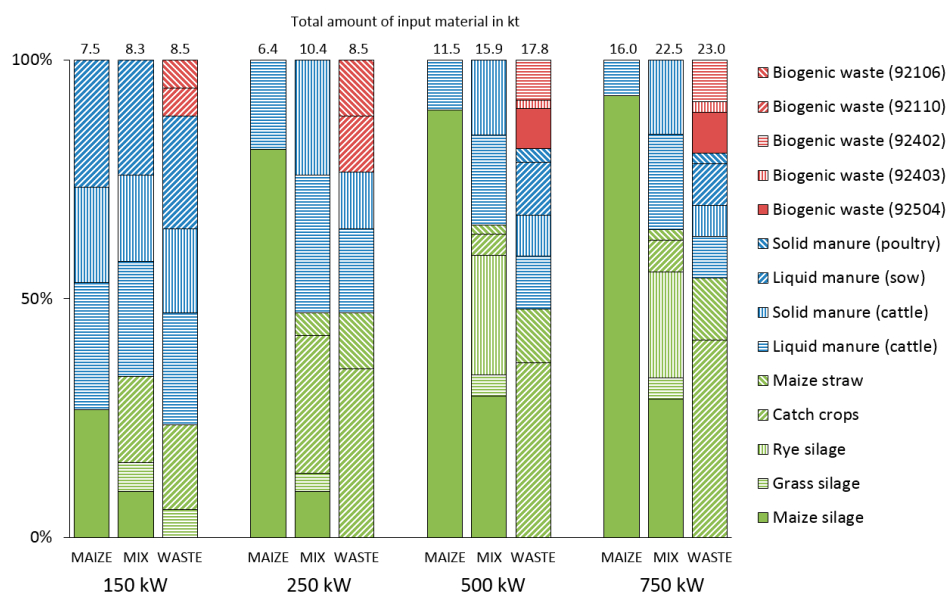**Figure 2.** Input material composition for each of the plant configurations. Categories of biogenic waste: 92106—harvest and processing residues; 92110—pure vegetable press and filter residues from food and feed production; 92402—catering waste containing animal leftovers; 92403—edible oils and fats, grease trap contents with animal components; 92504—flotation sludge, press filter residues from fattening and slaughterhouses.

Table 1 shows input material characteristics. The dimensioning of the plants' tanks and technological equipment differed due to the different plant sizes and input material mixes. The assumptions regarding tank volumes, energy demand, and output of the plants and efficiencies of the CHP units are summarized in Table 2 and are based upon a plant operator inquiry [30,31]. Austrian biogas plants are characterized by a high hydraulic retention time (HRT). In this study a HRT of 100 days in the fermenters was assumed, which is in line with Stuermer et al. [29]. This also responds to the rising importance of feedstocks with higher cellulose contents (grass, stover, catch crops) in Austria. High manure or biogenic waste shares could potentially reduce the HRT along with investment costs of the fermenter, however a HRT of 100 days provides the advantage of a more stable biogas production, especially for poultry manure, oils/fats, or slaughterhouse wastes as input material. Fermentation residue tanks were designed for a retention time of six months.

Table 1. Input material characteristics.

Input Material	Dry Matter (DM) in wt%	Organic Matter (OM) in wt% of DM	Methane Potential in m_N^3 per kg OM
Maize silage	33%	96%	0.32
Grass silage	35%	90%	0.32
Rye silage	25%	90%	0.32
Catch crops	22%	85%	0.25
Maize straw	86%	72%	0.27
Liquid manure (cattle)	10%	80%	0.21
Solid manure (cattle)	25%	85%	0.25
Liquid manure (sow)	7%	80%	0.23
Solid manure (poultry)	25%	70%	0.27
Biogenic waste (92106)	22%	93%	0.36
Biogenic waste (92110)	50%	90%	0.20
Biogenic waste (92402)	13%	85%	0.44
Biogenic waste (92403)	80%	85%	0.70
Biogenic waste (92504)	10%	93%	0.41

A value of 8400 full-load hours was considered when generating power continuously. It was assumed that 10% of the generated electricity is used to cover biogas plant electricity demand and 66% of the generated heat is used externally (the rest of the generated heat was considered to cover the plant's heat demand or regarded as loss).

2.1. Economic Assessment

An economic assessment of biogas plant configurations was conducted regarding newly constructed biogas plants. Different power generation scenarios were investigated and compared to each other in terms of participation in the electricity spot market and markets for secondary control energy reserves. The annuity method was used for the economic assessment according to VDI 2067 [32]. The assessment includes a summary of one-off investments and ongoing payments within the context of the chosen method and compared to revenues over an observation period using an annuity factor, taking replacement procurements and price changes into account. The result is a total annuity of the investment, which can be positive (profitable investment) or negative (not profitable investment).

The annuity of capital-related costs A_I was calculated according to Equation (1), whereby I_i represents the investment costs of biogas plant facilities and R the residual value after the observation period T. No residual value was considered in this work as it was assumed that biogas plant investment is paid off within the observation period. The annuity factor a was calculated according to Equation (2) considering the interest factor q.

$$A_I = \left(\sum_i I_i - R \right) * a \qquad (1)$$

$$a = \frac{q-1}{1-q^{-T}} \qquad (2)$$

Table 2. Assumptions on tank volumes, energy demand, and output and combined heat and power (CHP) unit efficiencies of the investigated biogas plant configurations.

	150 kW			250 kW			500 kW			750 kW		
	MAIZE	**MIX**	**WASTE**	**MAIZE**	**MIX**	**WASTE**	**MAIZE**	**MIX**	**WASTE**	**MAIZE**	**MIX**	**WASTE**
Fermenter volume in m^3	2100	2300	2300	1800	2800	2300	3200	4400	4900	4400	6200	6300
Residue tank volume in m^3	3400	3800	3800	2700	4500	3500	4700	6800	7600	6500	9600	9600
CHP—Electrical efficiency in %	38%	38%	38%	39%	39%	39%	40%	40%	40%	42%	42%	42%
CHP—Thermal efficiency in %	47%	47%	47%	46%	46%	46%	45%	45%	45%	43%	43%	43%
Generated electricity in MWh a^{-1}	1260	1260	1260	2100	2100	2100	4200	4200	4200	6300	6300	6300
Generated heat in MWh a^{-1}	1550	1550	1550	2470	2470	2470	4720	4720	4720	6450	6450	6450
Heat demand in % of generated heat	17%	16%	17%	13%	13%	12%	14%	12%	13%	15%	12%	12%

The annuity of ongoing payments and revenues $A_{O,i}$ was calculated according to Equation (3) (payments yield negative and revenues yield positive values), whereby $A_{1,i}$ represents the costs/revenues in the first year. Ongoing payments include maintenance, personnel, substrate, energy, start-up, and other costs, whereas ongoing revenues include revenues from electricity and heat sales. Price-dynamic cash value factors b_i were used, which are calculated considering price change factors r_i that must be specified beforehand.

$$A_{O,i} = A_{1,i} * a * b_i \tag{3}$$

$$b_i = \frac{1 - \left(\frac{r_i}{q}\right)^T}{q - r_i} \tag{4}$$

The total annuity A_T is calculated as the sum of all annuities of revenues less cost-related annuities (Equation (5)).

$$A_T = \sum_i A_{O,i} - A_I \tag{5}$$

Table 3 summarizes the key parameters that were used in the economic assessment including the assumptions for interest and price change factors, technical lifetime, operational costs, and observation period. CHP unit start-up costs account for the reduction of technical lifetime of the CHP units, which arises from the mechanical exposure during a start-up procedure.

Table 3. Key parameters of the economic assessment.

Parameter	Unit	Value	Parameter	Unit	Value
Annual Rate of Price Increase			**Technical Lifetime**		
Investment	% p.a.	1.0	Feedstock storage	a	15
Energy	% p.a.	3.0	Hygienization tank	a	15
Substrate	% p.a.	0.5	Feed-in system	a	7.5
Personnel	% p.a.	0.5	Pumps, mixer	a	7.5
Miscellaneous	% p.a.	0.5	Digester	a	15
Interest rate	% p.a.	5.0	Gas storage	a	15
Costs			CHP unit	a	15
Electricity	€ MWh^{-1}	150	Heat storage	a	15
Heat	€ MWh^{-1}	40	Digestate storage	a	15
Personnel	€/h	25	Miscellaneous	a	15
CHP start-up (0.15/0.25 MW)	€	5	**Observation period**	a	15
CHP start-up (0.5/0.75 MW)	€	10			

Four potential modes of plant operation (power generation scenarios) were investigated and compared, which are schematically shown in Figure 3. Scenario CONT assumes continuous power generation (base load) and represents a reference scenario, as the majority of biogas plants in Austria are currently operated as base load power plants. Scenario 12H assumes power generation only occurs by day between 08:00–20:00 by doubling the CHP unit capacity compared to the nominal capacity. Continuous power generation was also assumed in scenarios NEG and POS, whereby participation in the markets for negative (NEG) and positive (POS) secondary control energy reserves was considered. Doubling of the CHP unit capacities was also assumed in scenario POS.

Electricity prices used in the economic assessment were taken from historical data of the EPEX spot market [33] assessing the period of July 2016 to July 2017. An electricity price of 34.8 € MWh^{-1} was considered for scenarios CONT, NEG, and POS, which represents the average spot market price during the assessed period. For scenario 12H a price of 38.3 € MWh^{-1} was assumed, which was the average price between 08:00–20:00 during the assessed period. Data published by the Austrian TSO Austrian Power Grid (APG) [34] and on the internet platform for allocating of control energy reserves [35] was used to determine the control energy reserve activation times. An energy price (remuneration for generated electricity) of 200 € MWh^{-1} was specified for providing positive control energy reserves, while 45 € MWh^{-1} was defined for negative control energy reserves. The average

power price (remuneration for holding power capacities available) that was granted at every weekly tender for control energy reserves was considered in this work. It was assumed that control energy reserves were activated for three minutes whenever they were called off by the TSO.
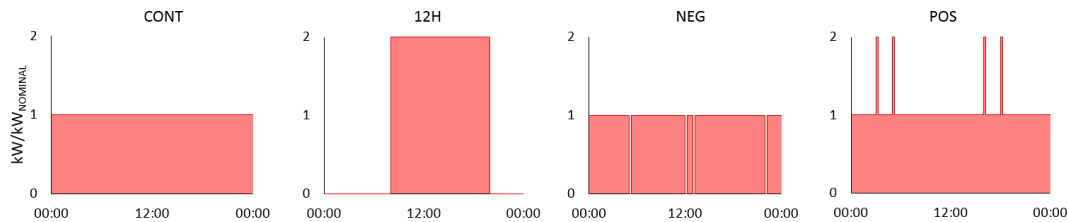

Figure 3. Schematic representation of investigated power generation scenarios.

A heat price of 20 € MWh^{-1} was considered for revenues that are obtained from external heat utilization. In scenario 12H heat is only produced from 08:00 to 20:00 with doubled capacity. This results in a higher share of total produced heat that is used externally and higher heat revenues compared to the other scenarios. However, heat has to be imported in times when the CHP units are not operated and additional heat costs (see Table 3) were taken into account for scenario 12H.

Investment and operational costs surveyed in the course of a biogas plant operator inquiry [30,31] and consultation of plant manufacturers were used in the assessment. A cost function for internal double membrane biogas storages determined by Barchmann et al. [19] was selected for gas storage investment costs. CHP unit general overhaul costs were determined using a cost function stated in Doehler et al. [2]. A general overhaul was assumed to take place after half of the technical lifespan stated in Table 3 if the CHP unit is operated for 8400 full-load hours per year. For scenarios 12H, NEG, and POS, an additional working time requirement of one hour per day was assumed due to flexible plant operation as proposed in Rohrig et al. [36]. Transportation costs of the input materials were included within the substrate costs.

Figure 4 shows biogas plant investment costs calculated for each biogas plant configuration and power generation scenario. Investment costs for scenarios 12H and POS are considerably higher than for scenarios CONT and NEG, mainly due to additional investments in CHP unit and gas storage capacity. Investment costs for biogas plant configurations with MIX and WASTE as input material mixes are higher than configurations considering MAIZE as input material mix, as additional investments in substrate pretreatment units (hygienization) are necessary.
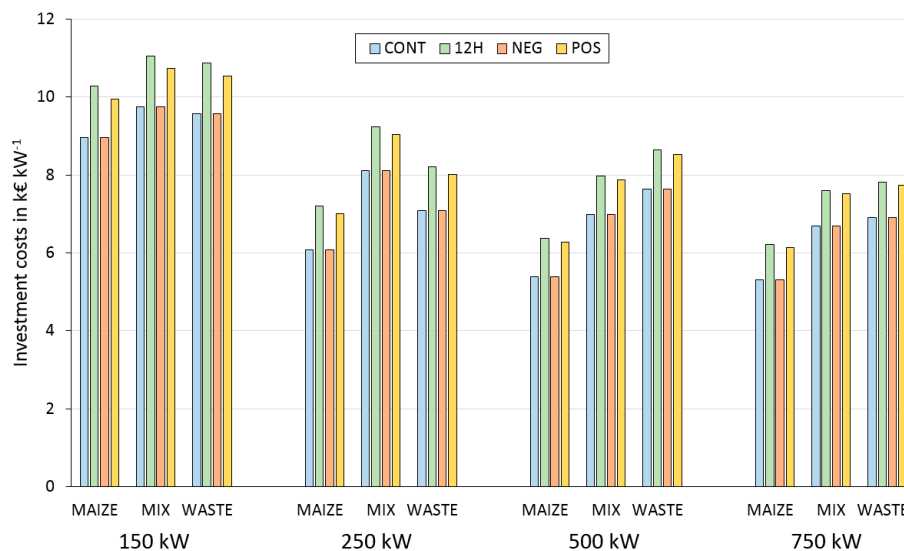

Figure 4. Assumptions about investment costs for investigated scenarios and biogas plant configurations.

2.2. Global Warming Potential Assessment

To include an ecological perspective, the twelve biogas plants configurations were evaluated using a life cycle assessment (LCA). This well-established tool to assess the environmental impact of a product, service, or process is standardized by ISO 14040 and ISO 14044 [37,38]. The four main phases are first conducted in sequence and repeated iteratively as required: goal and scope definition, inventory analysis, impact assessment, and interpretation. The LCA was conducted with the software GaBi version 8.7.0.18 from thinkstep AG to model biogas plant inventories and for the impact assessment.

Defining the goal and setting the scope of the LCA was done at its beginning and adjusted appropriately throughout the assessment. This LCA's primary goal is to evaluate the environmental impact of biogas plant configurations from a GWP perspective, while providing an ecological perspective for the economic assessment. This is achieved by analyzing the influence on the GWP from differences within the described biogas plant configurations shown in Figure 2 and Table 2. As the base case the CONT scenario was chosen and investigated in the LCA. The other scenarios (12H, NEG and POS) don't influence the assessed inventories and therefore yield the same results regarding GWP. However, the CHP units might be operated in partial load if other flexible power generation schedules are considered than the ones investigated in this study. Partial load operation of the CHP unit leads to a reduced electrical efficiency because the engines are usually optimized for full load operation. Therefore, a sensitivity analysis was conducted that varies the thermal and electrical efficiency of the CHP unit to assess the implications of this parameter.

Another sensitivity analysis was similarly conducted for the thermal energy source that was substituted by the excess thermal energy from biogas plants. Finally, the total GWP of the considered biogas plants was compared to conservative electricity sources (electricity grid mix, natural gas, and hard coal) to put the results into perspective. The comparison with natural gas and coal is of particularly interest, as Austria relies on natural gas-fired power plants to meet its electricity demand [39], especially in the winter. In addition, near the beginning of the twenty-first century, Austria became an electricity importing country. The majority of electricity is imported from Germany and the Czech Republic, which both have high shares of coal in their energy mix [40,41].

The scope, described within Figure 5, begins at feedstock supply and cultivation. This includes cultivation and harvesting for energy crops. Farm manure is considered as a waste product from livestock farming and therefore was assumed to have zero emissions from livestock farming. However, it is usually stored in a way where methane emissions are common and therefore, within this LCA, these emissions were considered as avoided GWP where farm manure is not stored but processed within biogas plants. Biogenic waste is considered as a waste product from the food industry and thus was also assumed to have zero emissions. The transportation of these different feedstock types to biogas plants was included in the assessment, as well as the conversion into biogas within biogas plants. Fermentation residue is included as part of the LCA scope by substituting mineral fertilizers (nitrogen, phosphorus, and potassium) while also accounting for the ammonia emissions from the fermentation residue application on the agricultural fields. The combustion of biogas in a CHP unit to yield electricity and heat was inside the scope. The CHP unit supplies the electricity and thermal energy to cover biogas plant demands. The functional unit was set to 1 MWh of electricity fed into the grid and the coproduced thermal energy was substituted for other conventional thermal energy sources.
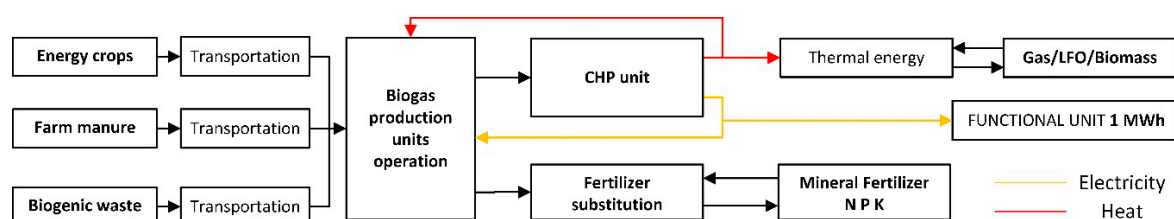

Figure 5. Schematic life cycle assessments (LCA) scope of the biogas plants.

Biogas plant construction and its end-of-life phase were outside the scope of the study. This is justified because of the lack of inventory data on the construction and end-of-life phase of the modeled biogas plants. Additionally, Bachmaier [42] shows that the GWP potential of construction is between 0.002 to 0.004 t CO_2 eq. MWh^{-1} and therefore has a negligible influence when investigating the emissions of CO_2 eq. from biogas plant configurations. However, to compare power generation biogas plants to the electricity grid mix, the natural gas and the hard coal plants, the GWP of plant construction was included using data from Bachmaier [42] because the datasets from the alternatives include the construction of the corresponding plants.

For the inventory analysis of biogas plant, data from the modeled biogas plants, the professional GaBi database (DB version 8.7, service pack 36) from thinkstep AG, a public domain lifecycle and material flow database GEMIS (version 4.95), and various literature sources were used, as shown in Table 4.

Table 4. Key parameters of the life cycle inventory for the global warming potential (GWP) assessment; GUID–Globally Unique Identifier.

Life Cycle Module	Utilized Dataset GUID/Comment	Source
Energy Crops		
Maize silage	{C0BA01BE-CB9C-4835-941B-A0EBBAF505E5}	GEMIS
Grass silage	{49873286-AFB4-4E49-89C3-4A50AEE72F29}	GEMIS
Rye silage	{98501EA1-3B5F-493B-8BD0-33C2F9E812B6}	GEMIS
Catch crops	{98501EA1-3B5F-493B-8BD0-33C2F9E812B6}	GEMIS
Maize straw	Modeled (0 allocation for straw)	GaBi
Farm manure	Literature (CH_4 savings)	Bachmaier [42]
Biogenic waste	0 allocation for waste	Own assumption
Transportation		
Transportation vehicle	{70E7F7B6-666E-48EF-8B29-DB8AF48018CA}	GaBi
Transportation fuel	{99248EE9-3A59-47E4-B1F1-BB79067249BA}	GaBi
Biogas production unit [1]	Common biogas plant settings	Own assumption
Fertilizer substitution		
N mineral fertilizer	{6FF9C0FB-B331-4D9D-BE8C-D11B7EC96DCD}	GEMIS
P mineral fertilizer	{5EE3A45D-E703-4F2F-92C4-AD673866631F}	GEMIS
K mineral fertilizer	{29FD0CE5-8932-47DF-A79C-0FE2909DE802}	GEMIS
Ammonia emissions	Literature	Bachmaier [42]
CHP Unit		
Emissions [2]	Literature	Doehler et al. [2]
Electric & thermal efficiency	Common biogas plant settings	Own assumption
Heat Substitution		
Heat from natural gas	{DB009010-338F-11DD-BD11-0800200C9A66}	GaBi
Heat from light fuel oil	{DB009012-338F-11DD-BD11-0800200C9A66}	GaBi
Heat from wood pellets	{DB009011-338F-11DD-BD11-0800200C9A66}	GaBi

[1] Electricity and thermal energy demand; Substrate demand; Digestate coproduction; Gas leakage; Biogas production.
[2] ($CO2$, CO, $CH4$, NOx, NMHC, NMVOC).

Inventory collection of the feedstock materials was done through literature sources and database inventories. While datasets for maize silage and grass silage were found within GEMIS, no such dataset was available for rye silage and catch crops. Therefore, the similar crop wheat silage was used as a dataset instead for rye silage and catch crops. Maize straw was assumed to have zero emissions allocated from its maize plant cultivation, however the harvesting and field-to-farm transportation was modeled and included with GaBi datasets for agriculture processes. Farm manure, which is normally stored, is utilized within biogas plants. The resulting averted methane emissions were considered for each manure type from Bachmaier [42].

The transportation distance is modeled with an average truck transporter according to the investigated biogas model plants. For biogenic waste and farm manure, the distance was constantly kept at 0.5 km, which is an average distance observed at biogas plants in Austria and in line with Stuermer et al. [43] or Walla and Schneeberger [44]. Typically, the majority of area for substrate production is close to the biogas plant. For the energy crops, the distances were given in respect

to biogas plant size, i.e., 1.0/1.3/2.0/3.0 km in transportation distances for a 150/250/500/750 kW plant, respectively.

The biogas production (electricity demand, thermal energy demand, substrate demand, digestate coproduction, and biogas production) and CHP (electrical and thermal efficiency) units were modeled considering their respective parameters from Table 2 and Figure 2. Gas leakage within the biogas production units was set to 0.33% according to Liebetrau et al. [22], while a leakage of 0.5% was assumed for the CHP unit.

Besides methane, biogas production also yields fermentation residues (digestate). These residues have a fertilization value of nitrogen, phosphor, and potassium and can be applied for crop fertilization. The average contents of these elements within fermentation residues were set according to Wendland and Lichti [45]. Subsequent mineral fertilizers can be replaced and their avoided emissions were calculated from datasets found in GEMIS. However, digestate fertilization tends to have extra ammonia emissions, which were considered in this LCA scope and calculated according to Bachmaier [42] for fertilization of winter wheat and grain maize.

After meeting the thermal energy needs for biogas production, excess thermal energy can be utilized elsewhere and alternative thermal energy conversion can be substituted. Within this inventory, thermal energy generated from burning wood pellets was substituted and the avoided emissions from this alternative thermal energy provision were accounted for in the base case. Preferably energy from biogas as a renewable energy source should substitute a fossil energy resource. Within a sensitivity analysis, alternative sources for thermal energy were varied from wood pellets to natural gas and light fuel oil to investigate the influence of this credit on the LCA results. The inventories for the alternative thermal energy sources are available from the GaBi professional database.

To assess the GWP, the IPCC AR 5 (100 years, excluding biogenic carbon) method was selected for the impact assessment [46]. The GWP is of particular interest for biogas plants because it can quantify the renewable and circular nature of the considered carbon dioxide. Other impact categories were not included, as they were outside the scope of this study. However, eutrophication potential, acidification potential, and water use are relevant impact categories for agricultural processes (e.g., cultivation of energy crops) that need to be considered and were included in other scientific studies of biogas plants. Bacenetti et al. [47] and Lijó et al. [48] have shown the relevance of acidification and eutrophication potentials for biogas plants and the most relevant contributors within these categories were found in the cultivation of the energy crops and the application of digestate for fertilizing agricultural fields. Assessments by Dressler et al. [49] and Provolo et al. [50] also included additional impact categories. Dressler et al. presented results for biogas production from maize and concluded that application of the digester output and emissions from the CHP unit were the most relevant factors in regards to acidification and eutrophication potential. Provolo et al. assessed the GWP and acidification potential of different manure management systems including biogas production. They underlined the importance of including additional impact categories as particular matter production and eutrophication in further works for the purpose of a holistic assessment. Unfortunately, the life cycle inventory of the presented biogas plant setups investigated in this study was insufficient for inclusion of additional impact categories besides GWP due to missing data and consequently they were excluded from this study, as an incomplete life cycle inventory would lead to misleading results.

3. Results

3.1. Economic Assessment

Tables 5 and 6 summarize the results from the economic assessment of the investigated power generation scenarios CONT, 12H, NEG, and POS and the different biogas plant configurations and shows annuities of costs and revenues as well as the total annuity. Results are presented as specific annuities (annuity per electric rated output) for better comparability.

Table 5. Economic assessment results for scenarios CONT and 12H, specific annuities (SA) in € a^{-1} kW^{-1}.

	150 kW			250 kW			500 kW			750 kW		
	MAIZE	**MIX**	**WASTE**	**MAIZE**	**MIX**	**WASTE**	**MAIZE**	**MIX**	**WASTE**	**MAIZE**	**MIX**	**WASTE**
Scenario CONT												
SA of costs (total)	1928	2089	1946	1686	1841	1641	1650	1979	1764	1702	1979	1759
Investment	894	970	952	616	813	713	550	704	767	543	675	696
Operational	292	292	292	225	225	225	222	222	222	222	222	222
Personnel	177	177	177	136	136	136	120	120	120	120	120	120
Substrate	411	497	372	546	504	404	604	779	499	663	809	568
Miscellaneous	153	153	153	163	163	163	155	155	155	153	153	153
SA of revenues (total)	446	446	446	446	446	446	446	446	446	446	446	446
Spot market	263	263	263	263	263	263	263	263	263	263	263	263
Control energy market	0	0	0	0	0	0	0	0	0	0	0	0
Heat	183	183	183	183	183	183	183	183	183	183	183	183
Total SA	−1482	−1643	−1501	−1240	−1395	−1195	−1204	−1533	−1318	−1256	−1533	−1313
Scenario 12H												
SA of costs (total)	2350	2507	2369	2035	2191	1988	1969	2294	2079	2002	2274	2054
Investment	1020	1095	1078	724	920	821	645	799	863	630	762	783
Operational	399	399	399	321	321	321	315	315	315	315	315	315
Personnel	240	240	240	174	174	174	139	139	139	133	133	133
Substrate	411	497	372	546	504	404	604	779	499	663	809	568
Miscellaneous	281	277	281	271	272	269	266	262	262	260	255	255
SA of revenues (total)	533	535	533	528	528	529	517	519	519	498	500	500
Spot market	306	306	306	306	306	306	306	306	306	306	306	306
Control energy market	0	0	0	0	0	0	0	0	0	0	0	0
Heat	228	230	228	223	223	224	212	214	214	192	195	195
Total SA	−1817	−1972	−1836	−1507	−1663	−1459	−1452	−1775	−1560	−1504	−1773	−1553

Table 6. Economic assessment results for scenarios NEG and POS, specific annuities (SA) in € a^{-1} kW^{-1}.

	150 kW			250 kW			500 kW			750 kW		
	MAIZE	**MIX**	**WASTE**	**MAIZE**	**MIX**	**WASTE**	**MAIZE**	**MIX**	**WASTE**	**MAIZE**	**MIX**	**WASTE**
Scenario NEG												
SA of costs (total)	2014	2175	2033	1738	1893	1693	1684	2013	1797	1725	2002	1782
Investment	894	970	952	616	813	713	550	704	767	543	675	696
Operational	292	292	292	225	225	225	222	222	222	222	222	222
Personnel	240	240	240	174	174	174	139	139	139	133	133	133
Substrate	411	497	372	546	504	404	604	779	499	663	809	568
Miscellaneous	177	177	177	178	178	178	170	170	170	164	164	164
SA of revenues (total)	495	495	495	495	495	495	495	495	495	495	495	495
Spot market	263	263	263	263	263	263	263	263	263	263	263	263
Control energy market	49	49	49	49	49	49	49	49	49	49	49	49
Heat	183	183	183	183	183	183	183	183	183	183	183	183
Total SA	−1519	−1680	−1538	−1243	−1398	−1198	−1189	−1518	−1302	−1230	−1507	−1287
Scenario POS												
SA of costs (total)	2231	2393	2250	1933	2088	1888	1871	2200	1985	1904	2181	1961
Investment	989	1064	1047	706	902	803	634	788	852	623	755	776
Operational	399	399	399	321	321	321	315	315	315	315	315	315
Personnel	240	240	240	174	174	174	139	139	139	133	133	133
Substrate	411	497	372	546	504	404	604	779	499	663	809	568
Miscellaneous	193	193	193	187	187	187	179	179	179	170	170	170
SA of revenues (total)	475	475	475	475	475	475	475	475	475	475	475	475
Spot market	261	261	261	261	261	261	261	261	261	261	261	261
Control energy market	31	31	31	31	31	31	31	31	31	31	31	31
Heat	183	183	183	183	183	183	183	183	183	183	183	183
Total SA	−1757	−1918	−1776	−1458	−1614	−1413	−1397	−1726	−1510	−1430	−1707	−1487

Capital and substrate costs represent the highest cost factors for each scenario, followed by the annuity of operational costs. Revenues that are obtained from participating in the market for secondary control energy reserves in scenarios NEG and POS are considerably lower than revenues from the spot market and heat sales. The total annuity is negative for all biogas configurations and scenarios due to the prices at the spot market during the observed period, which were far lower than the electricity generation costs. The average EPEX spot market price was 34.8 € MWh^{-1}, whereas electricity generation costs for Austrian biogas plants typically range from about 200–350 € MWh^{-1} depending on input material composition and plant size [51]. An additional payment (premium) to the electricity market price was calculated for each scenario, which is required to make power generation economically viable (total annuity of 0). The needed premium for each scenario and plant configuration can be seen in Figure 6 and lies in the range of 157.3 € MWh^{-1} (500 kW-NEG-MAIZE) to 260.9 € MWh^{-1} (150 kW-12H-MIX). Within the smaller biogas plants with an electric rated output of 150 kW and 250 kW, the lowest premium is needed for scenario CONT; within the larger plants with the 500 kW and 750 kW scenarios, NEG proved to need the least amount of premium. Biogas plant configurations with a MIX input material composition need considerably higher premiums compared to the other mixes.
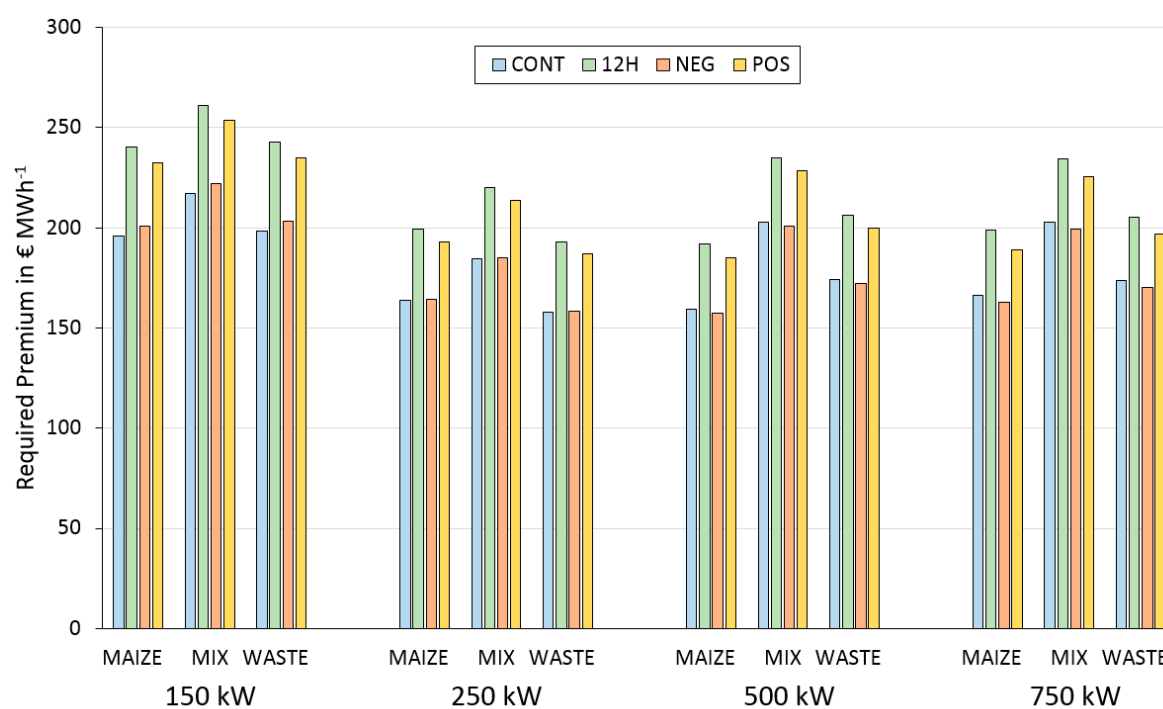

Figure 6. Calculated required premium for investigated scenarios and biogas plant configurations.

3.2. Global Warming Potential Assessment

The GWP results for the functional unit (1 MWh electricity) of the twelve different biogas plant configurations are described in Figure 7. Generally, credits from substituting thermal energy and mineral fertilizer have a negative GWP, as well as the avoided methane emissions from farm manure storage. The biggest GWP arises from the cultivation of the energy crops that are used as feedstock for biogas plants, followed by the combustion of biogas for electricity and heat generation by the CHP unit and the biogas production itself. The transportation of the feedstock materials to biogas plants only account for a small fraction of the total GWP. The total GWP for each investigated plant configuration is given above the stacked bars of Figure 7. Every scenario yields a saving potential except the MAIZE scenarios for the 250, 500, and 750 kW biogas plant setups. The best-case scenario is the 150 kW biogas plant with the WASTE input material composition and the worst-case scenario is the 750 kW biogas plant with the MAIZE input material composition.
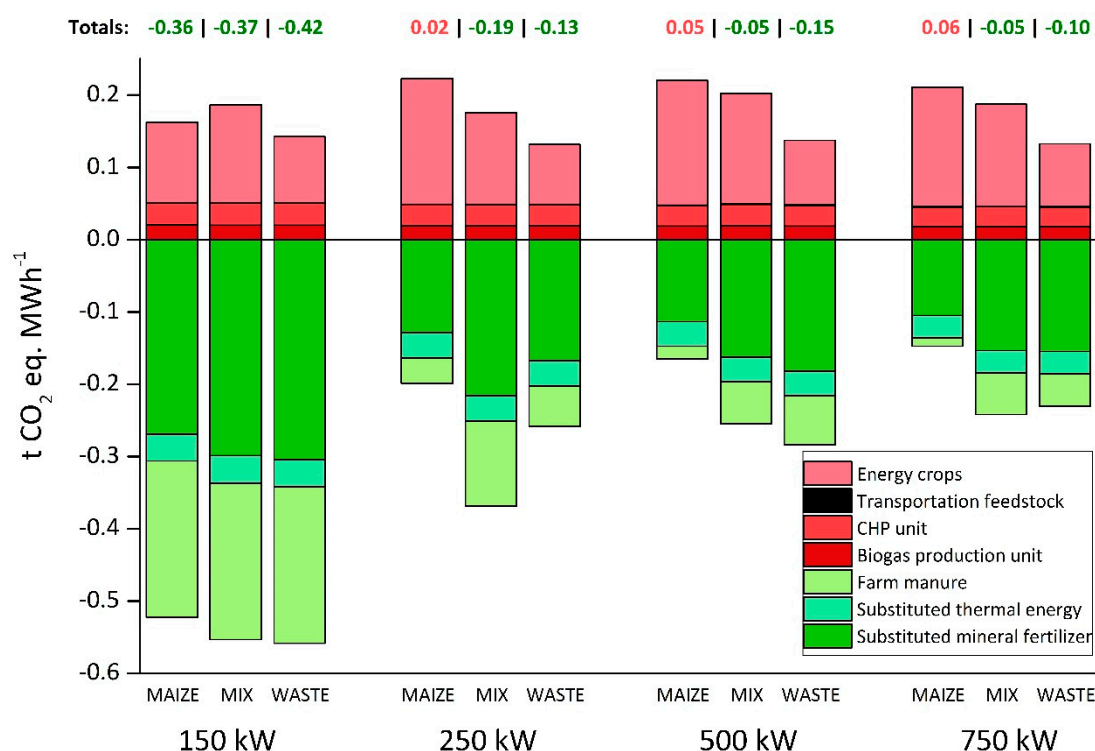
Figure 7. GWP according to IPCC AR5 [46] for the investigated biogas plants configurations.

The sensitivity analysis results, in relation to the base case of the 500 kW plant, are described in Table 7. The absolute changes in GWP are given, reducing or increasing the GHG emissions respectively. Two parameters were varied: the electrical efficiency of the CHP unit and the percentage of heat utilization. The 500 kW plant was selected for the sensitivity analysis because it is the most common size for biogas plants in Austria at this point [31]. Regardless of the size of the biogas plant, the trends resulting from the sensitivity analysis are of a similar nature for the four investigated biogas plant sizes.

Table 7. Results of the sensitivity analysis for the 500 kW plant; change of the absolute GWP impact as a percentage of the base case.

| | Electrical Efficiency of CHP Unit | | | | | |
| | +1% | | | −1% | | |
	MAIZE	**MIX**	**WASTE**	**MAIZE**	**MIX**	**WASTE**
Total	−0.53%	3.90%	2.73%	1.93%	−4.33%	−3.62%
CHP unit	−2.18%	−2.11%	−2.07%	3.13%	3.20%	3.22%
Biogas production units	−2.18%	−2.11%	−2.06%	3.13%	3.24%	3.23%
Energy crops	−2.15%	−2.10%	−2.14%	3.19%	3.21%	3.11%
Feedstock transportation	−2.15%	−2.09%	−2.14%	3.17%	3.21%	3.12%
Substituted mineral fertilizer	2.11%	2.09%	2.09%	−3.17%	−3.20%	−3.13%
Substituted thermal energy	4.80%	4.80%	4.80%	−5.18%	−5.18%	−5.18%
Farm manure	2.13%	2.09%	2.11%	−3.19%	−3.20%	−3.17%
	Percentage of heat utilization					
	+10%			−10%		
	MAIZE	**MIX**	**WASTE**	**MAIZE**	**MIX**	**WASTE**
Total	−9.31%	−9.68%	−3.48%	9.30%	9.68%	3.48%
Substituted thermal energy	−15.16%	−15.16%	−15.16%	15.16%	15.16%	15.16%

Increasing electrical efficiency results in a reduced thermal efficiency and vice versa (a total efficiency of 85% was assumed for all investigated cases). A higher electrical efficiency leads to a

reduced biogas demand and consequently less needed feedstock input, as the functional unit is 1 MWh electricity. In this case, the GWP impact from the CHP unit, biogas production unit, energy crops, and feedstock transportation modules is reduced. Furthermore, less digestate and less avoided manure methane emissions arise, as well as less excess thermal energy to be substituted, resulting in lower GWP saving potentials for the following three modules: substituted mineral fertilizer, substituted thermal energy, and farm manure. However, the opposite effect occurs when electrical efficiency is decreased and thermal efficiency is increased. The total impact from this variation results in absolute differences of 0.5 to 4.3 % in the impact category.

Changing the percentage of heat utilization only affects the substituted thermal energy and leads to a better GWP when more thermal energy is substituted. The decrease or increase of ten percentage points in heat utilization produces an absolute change to the total GWP of 3.5 to 9.7 %, as shown in Table 7.

4. Discussion

The results from the economic assessment revealed that electricity generation with biogas plants is currently not economically viable for the given plant cost structures and market price situation. An appropriate economic framework is necessary for power generation with biogas plants. Feed-in premiums (FIP) are commonly applied in the European region [1] and it is expected that the number of countries with FIP systems for biogas plants will increase in future. The most common premium support schemes for demand-oriented power generation with biogas plants are market premiums, which represents additional payments to the electricity market price. The needed market premium for scenario CONT ranged from 158.1–217.3 € MWh^{-1}, depending on input material composition and plant size. The results from scenario NEG showed that additional revenues, which reduce the needed market premium, can be generated by participating in the market for negative control energy reserves for bigger plants (500 kW and 750 kW). For smaller plants, no additional revenues can be generated, as the provided power capacity is too low to compensate for the additional costs that result from demand-oriented power generation (mainly CHP-unit start-up and personnel costs).

Scenarios 12H and POS require additional investments in plant equipment compared to scenario CONT. Higher investments for doubled CHP unit capacity and electric connection are necessary compared to continuous power generation. Additionally, more biogas and heat storage capacities are necessary in scenario 12H as biogas needs to be stored for twelve hours and to secure a continuous heat output. Higher revenues from the electricity market that are generated due to increased CHP unit capacity are not sufficient to compensate for these additional investments, leading to a higher needed premium. This is because the price spread between peak and off-peak prices at the spot market and that revenues from the secondary control energy market are not high enough. Figure 8 shows the development of the average spot market price in the Austrian spot market EXAA (Energy Exchange Austria) and the development of the ratio of peak (08:00–20:00) and off-peak (20:00–08:00) prices from 2012–2018 [52]. The ratio shows a decreasing trend making market-oriented electricity generation economically less attractive. Additionally, spot prices were at a low level during the period observed in this work (July 2016–July 2017), leading to higher needed premiums.

The importance of demand-oriented power generation and the need for balancing energy is expected to increase in the future, with the increasing implementation of renewable energy sources characterized by fluctuating power output [53]. The demand for balancing energy in Austria rose from 0.73 TWh in 2012 to 1.22 TWh in 2017 [12]. The residual load and control energy reserves in Austria are mainly provided by hydro, pumped storage, and gas power plants [39]. Within the context of a decarbonized future energy system—and as hydro and pumped-storage power plants might not be able to cover the energy needs at all time due to limited capacity and rising energy demand—additional renewable controllable power capacities will be needed, whereby biogas plants can play an important role.
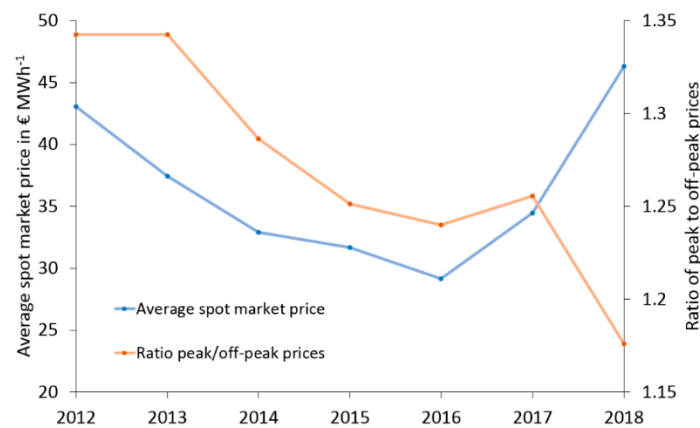
Figure 8. Development of the average spot market price and the ratio of peak and off-peak prices at the EXAA during 2012–2018. Adapted from [52].

Figure 9 shows the results of a sensitivity analysis regarding the effects on the total annuity while increasing different costs and revenues by 10%. Investment costs, operational costs, substrate costs, heat revenue, and the revenue from the electricity market were successively increased and the relative change to the base case is shown representatively for the 500 kW biogas plant as this is the most common plant size in Austria. Investment and operational costs as well as revenues from the electricity market are shown to have the biggest influence on the results.
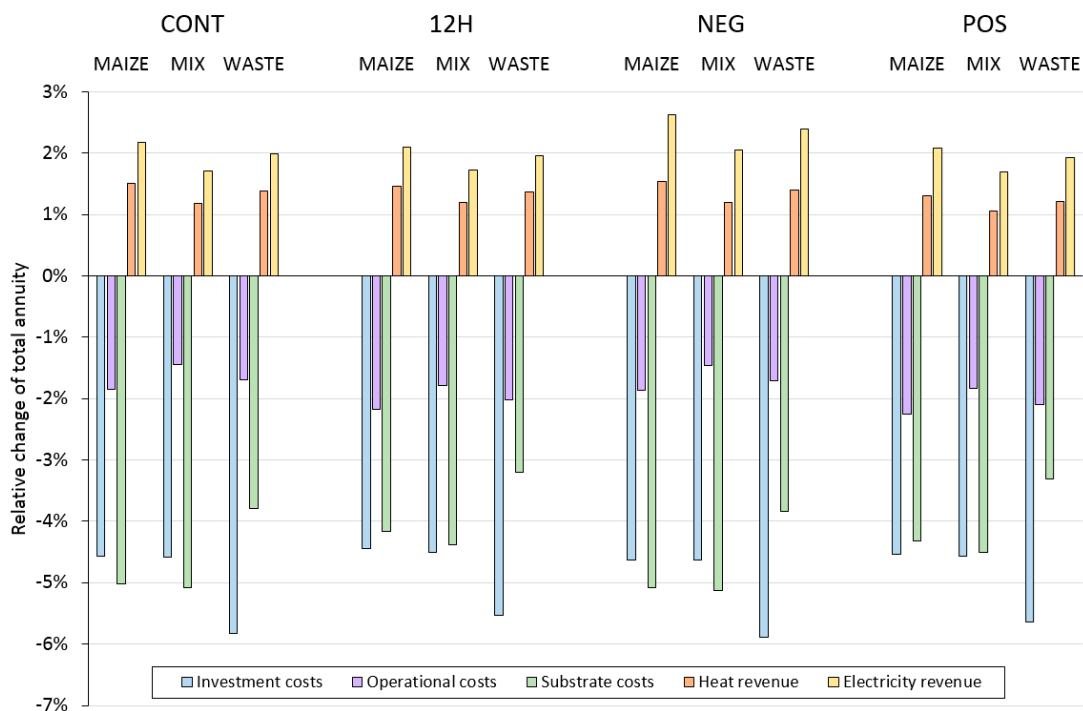
Figure 9. Effects of a 10% increase in investment costs, operational costs, substrate costs, heat revenue and electricity revenue on total annuity for the investigated power generation scenarios of the 500 kW biogas plant.

The GWP assessment showed that the 150 kW biogas plants reach the highest GWP saving potentials. The significantly higher credits originate from the feedstock composition with a low percentage of energy crops and a high share of farm manure, as demonstrated in Figure 2. The feedstock composition WASTE yields the best results within each investigated plant size except for the 250 kW plant. The MAIZE feedstock composition shows the poorest results within each investigated plant size.

This indicates that additional cultivation of feedstock material has a higher environmental impact from a GWP perspective than other assessed input materials. Biogas production has the potential to mitigate GHG emissions by substituting various conventional production and conversion routes for mineral fertilizers and thermal energy. Another advantage is the utilization of farm manure to avoid methane emissions resulting from the storage of manure. Cultivating energy crops has the highest GWP impact in the investigated scenarios. Leakages during biogas production and emissions from the CHP unit are other causes of GWP. Transportation accounts for only a small amount of GWP in the investigated scenarios. For these reasons, utilizing waste streams within biogas plants can be encouraged.

The electrical efficiency parameter variation showed the influence on GWP impacts. When the electrical efficiency is increased, CHP unit emissions are reduced along with the substitution potential of the co-products and the avoided emissions from farm manure. A similar but inverted effect can be observed when decreasing the electrical efficiency: Here, CHP unit emissions are increased together with the substitution potentials and avoiding emissions from farm manure. When maize is the dominant input material, it is of high ecological interest to increase the electrical efficiency. For the other input material compositions—MIX and WASTE—the sensitivity analysis shows that higher GWP savings are obtained by decreasing the electrical efficiency. However, this deduction must be handled with caution, as this would imply using the biogas only for thermal energy substitution and other credits. However, these saving potentials assume that thermal energy is required to meet an already-existing heat demand and can be substituted through this co-product. The same applies for the mineral fertilizer substitution.

Additionally, the functional unit of 1 MWh electricity does not include the use of this type of electrical energy within the considered scope. Electrical energy can be produced from various sources in a similar manner to thermal energy. To put the sensitivity analysis of the electrical efficiency parameter and the overall GWP results into perspective, the best-case and worst-case biogas plant scenario is shown next to three alternative electric energy sources for 1 MWh electricity. The considered sources are the Austrian electricity grid mix, electricity from natural gas, and hard coal power plants, as shown in Figure 10. All biogas plant configurations show a better GWP impact than the considered alternatives.
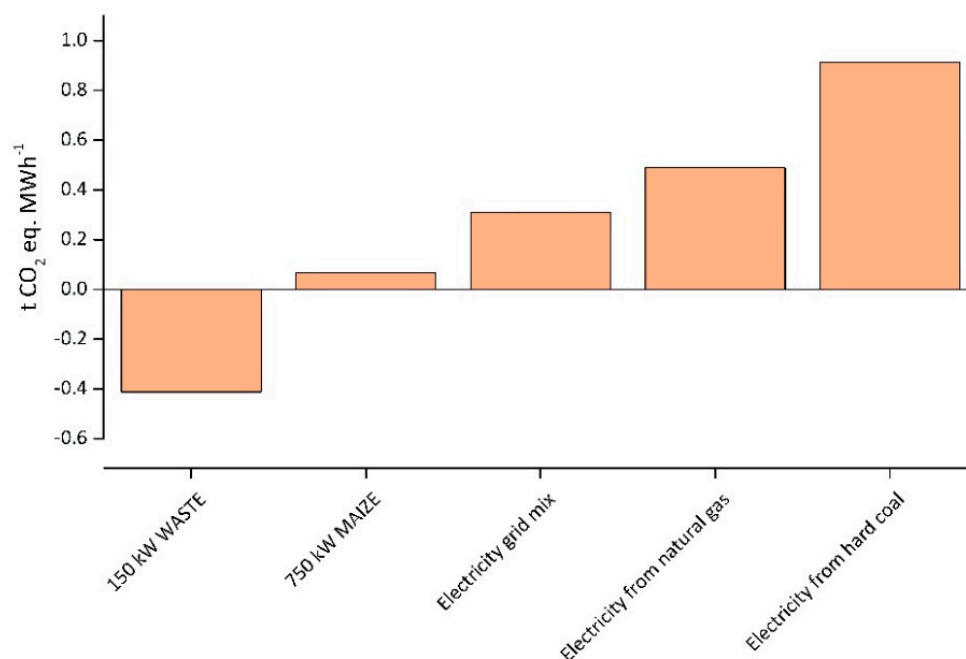

Figure 10. Worst-case and best-case scenario for biogas plant configurations compared to other electrical energy sources.

Substituting thermal energy from wood pellets provides one viable option for heat utilization. However, thermal energy is often also generated from natural gas or light fuel oil. The type of thermal energy source substitution depends on the already-existing local heat supply infrastructure of each specific biogas plant. The calculated results for the biogas plant configurations of these two additional options show a further improvement of the GWP balance, as shown in Figure 11. When substituting fossil thermal energy sources, every scenario results in a GWP saving. The highest GWP saving potential is again visible for 150 kW setups and the best results are achieved when substituting light fuel oil.
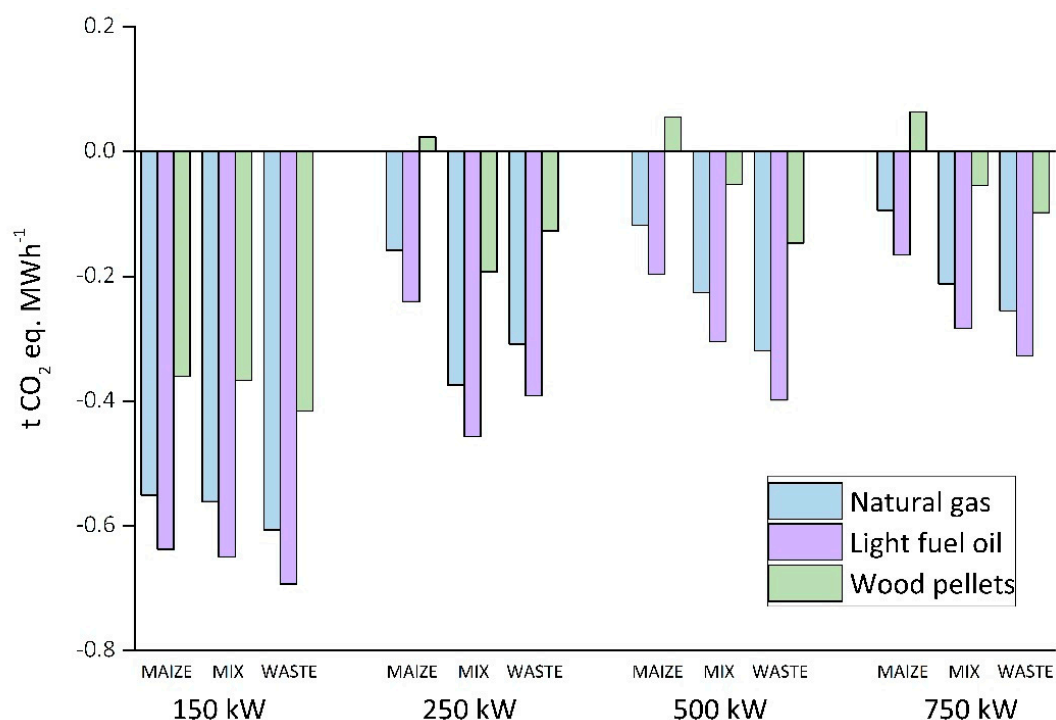

Figure 11. The total GWP impacts of biogas plant base scenarios replacing heat from wood pellets and alternative scenarios replacing thermal energy from light fuel oil and natural gas.

The results from this study were used to calculate GHG mitigation costs by relating the needed premium to the CO_2 eq. saving potential in a scenario where power generation with biogas plants is compared to the Austrian electricity mix and hard coal and natural gas plants. Figure 12 shows the results from this calculation. The results range from 149.5–674.1 € (t CO_2 eq.)$^{-1}$, whereby results from the CONT power generation scenario and base case results from the life cycle assessment were used for the comparison. When flexible power generation scenarios are considered, slightly different results can be expected due to changing CO_2 eq. saving potentials that may occur as the result of different CHP unit efficiencies. These GHG mitigation costs represent break-even prices for CO_2-certificates that are needed to make power generation with the investigated biogas plant configurations economically competitive among hard coal and natural gas plants as well as the electricity grid mix. While CO_2 certificate prices at the time of the study (about 20 € (t CO_2 eq.)$^{-1}$ [54]) are considerably lower than the calculated GHG mitigation cost, certificate costs are expected to approach the calculated GHG mitigation costs in the future as EU climate targets continue to be implemented. In addition, and to put the calculated GHG mitigation costs into perspective, the costs can be compared to the existing Austrian energy tax for fuels. If the tax is recalculated on CO_2 emissions the results show that the prices range from 150.4 to 206.9 € (t CO_2 eq.)$^{-1}$.

Even though the GWP is, within current framework conditions, a very important impact category, future developments will increase the necessity to include other impacts as well. Next to GWP other impact categories (land use, water use, eutrophication, and acidification) should be included for further

environmental assessments and for a more holistic investigation in future works on these biogas plant setups, especially when investigating the cultivation of energy crops (e.g., maize silage).
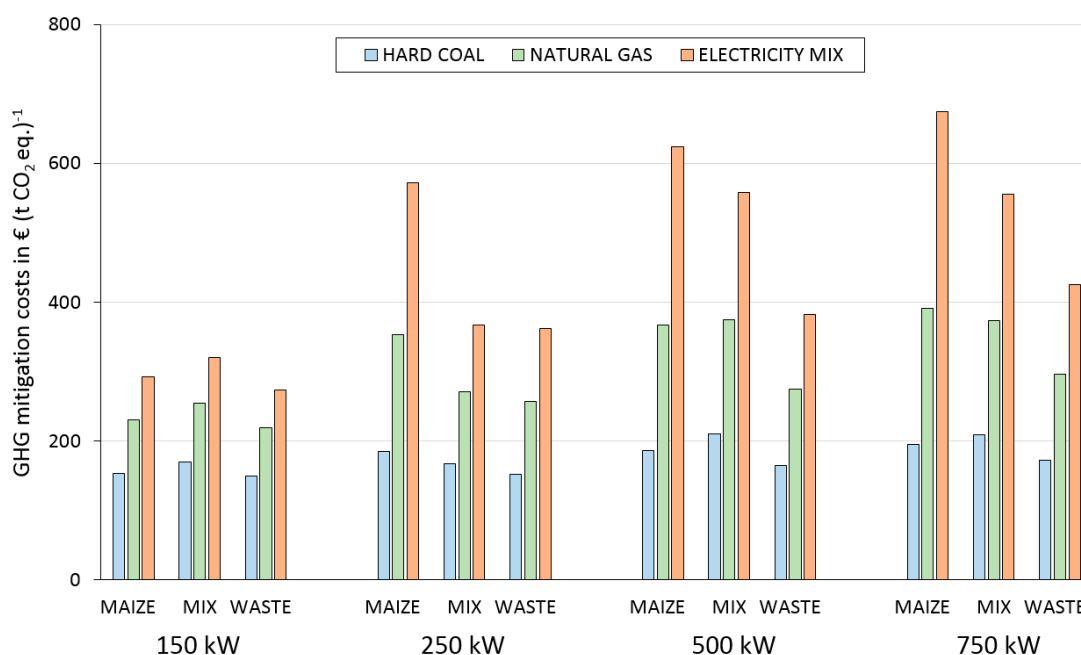

Figure 12. GHG mitigation costs for investigated biogas plant configurations when comparing power generation with biogas plants to power generation with hard coal plants, natural gas plants and the Austrian electricity grid mix.

5. Conclusions

Twelve biogas plant configurations with electric rated outputs ranging from 150–750 kW and different input material compositions of energy crops, farm manure, and biogenic waste were investigated. The economic effects and GWP impacts of power generation were assessed considering four different power generation scenarios that assumed participation in the spot market and the market for secondary control energy reserves. Newly-built plants were considered in the assessments and economic calculations were done using the annuity method. The results revealed that power generation without an appropriate support scheme is not economically viable considering the current electricity market prices. The necessary additional payment (premium) to the electricity spot market price calculated in this work ranged from 158.1–217.3 € MWh^{-1}. The combined premium and electricity spot market price is in the range of the current Austrian feed-in tariff for biogas plants (189.7 € MWh^{-1}, respectively 209.7 € MWh^{-1} for plants with a particularly high heat utilization).

The economic results largely depend on investment and substrate costs. Furthermore, it was shown that additional revenues, which reduce the needed premium, can be generated by participating in the markets for secondary control energy reserves for plants above a certain power capacity. Biogas plants can play an important role for the provision of controllable power capacities, as the balancing power demand is expected to increase with the advancing integration of intermittent power sources in the energy system.

Additionally, LCA and the GWP impact category were used to investigate the environmental impact of biogas plants. The results ranged from –0.42 to 0.06 t CO2 eq. MWh^{-1}, clearly showing that the 150 kW plant configurations yielded the best outcome. Within the input material variation, MAIZE configurations demonstrated the poorest performance for each investigated plant size. A sensitivity analysis of CHP unit electrical efficiency showed that by increasing the efficiency, less GWP occurs from the polluter modules, while the credit from the co-products and emission savings from farm manure processing also decreases. Concerning the co-product of excess thermal energy, if heat from light fuel oil

is substituted instead of heat from wood pellets, the GWP saving potentials are even higher. Compared to conventional electricity sources (electricity grid mix, natural gas, hard coal), electricity from biogas plants showed a better performance within the GWP for all investigated plant configurations.

GHG mitigation costs were calculated by relating the needed premium to the CO_2 eq. saving potential when comparing power generation with biogas plants to hard coal and natural gas power plants and the Austrian electricity grid mix and ranged from 149.5–674.1 € (t CO_2 eq.)$^{-1}$.

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