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BIOGAS PLANT OPTIMIZATION BY INCREASING ITS FLEXIBILITY CONSIDERING UNCERTAIN REVENUES

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Biogas plant optimization by increasing its flexibility considering uncertain revenues

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Abstract

Increasing shares of volatile energy resources like wind and solar energy will require flexibly schedulable energy resources to compensate for their volatility. Biogas plants can produce their energy flexibly and on demand, if their design is adjusted adequately. By doing so, the biogas plant operator has the opportunity to generate more earnings by producing and selling electricity in higher price periods. In order to achieve a flexibly schedulable biogas plant, the design of this plant has to be adjusted to decouple the biogas and electricity production. Therefore, biogas storage possibilities and additional electrical capacity are necessary. The investment decision about the size of the biogas storage and the additional electrical capacity depends on the fluctuation of energy market prices and the availability of governmental subsidies. This work presents an approach supporting investment decisions to increase the flexibility of a biogas plant by installing gas storages and additional electrical capacities under consideration of revenues out of direct marketing at the day-ahead market. In order to support the strategic, long-term investment decisions, an operative plant schedule for the future, considering different plant designs given as investment strategies, using a mixed-integer linear programming (MILP) model in an uncertain environment is optimized. The different designs can be evaluated by calculating the net present value (NPV). Moreover, an analysis concerning current dynamics and uncertainties within spot market prices is executed. Furthermore, the influences concerning the variation of spot market prices compared to the influence of governmental subsidies, in particular, the flexibility premium, are revealed by computational results for a fictional case example, which is based on a biogas plant in southern Germany. In addition, the robustness of the determined solution is analyzed with respect to uncertainties.

1 Introduction

Fossil resources are limited and will eventually run short. Therefore, a changeover in basic economic and ecological thinking is necessary. The renewable energy resources act, or EEG, is the central governmental element in Germany to accomplish this basic changeover in the energy sector. One objective of the German government is to increase the share of energy produced from renewable resources up to 45 % by 2025. To reach this objective, the shares of wind and solar sources will have to be increased. However, the energy generation provided by wind and solar energy is highly volatile. The energy demand is volatile as well. Thus, the issue within an energy system is to balance energy demand and supply. This has to be because of technical reasons. If the energy supply and demand within a grid is not balanced, the grid breaks down. Therefore, other flexibly schedulable energy sources are needed to compensate for the volatility. In relation to the EEG, these resources should not be fossil or nuclear but renewable. Biogas plants, operated flexibly, are a renewable resource that can be used to compensate this volatility with carbon-neutral generation and without using nuclear resources. The advantage of biogas plants is that either the biomass can be stored to produce the biogas more demand oriented, or the produced biogas can be stored to produce the final product electricity demand oriented. The storage of biomass can be used to compensate for long-term volatility, and the storage of biogas is useful to compensate for short-term fluctuations. In contrast, it is more difficult to store electricity.

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If the existing biogas plants are operated flexibly, there will be advantages not only for the energy grid operators, which are responsible for the energy distribution and the maintenance of the grid, the government or the private and commercial energy consumers, but also for the biogas plant operators. As mentioned, the flexible and demand oriented energy production in biogas plants can help to stabilize the power supply in the grid. Furthermore, power plants using fossil resources, which are currently used to compensate the volatility, can be substituted. The great advantage for the biogas plant operators is that they get the opportunity to generate additional revenues in high energy spot market price periods. Moreover, they will be independent of the EEG feed-in tariff, which is part of a governmental strategy to subsidize renewable energy resources. The feed-in tariff guarantees a fixed compensation for all of the produced energy within the first 20 years of plant operation.

As explained previously, biogas plants should be flexibly schedulable in the future to get a demand oriented power generation. Several possible adjustments concerning the biogas plants exist to reach this objective. Within this paper, a novel approach is developed to modify the technical biogas plant design in order to decouple the biogas and electricity production to increase flexibility. The generated power should afterwards be sold through direct marketing at the power exchange EPEX Spot SE. The specific character of this modification is explained in Section 2.2. In brief, it is necessary to build a biogas storage capacity to decouple the biogas and electricity production. Thus, the storage is filled with biogas in times of low electricity prices and used to produce electricity in high price periods. To do so, in addition to the possibility to store biogas, it is necessary to have enough capacity to produce electricity out of the biogas. Hence, as another prerequisite, additional electrical capacity has to be installed. The size of the optimal biogas storage and additional electrical capacity depends on fluctuations in the energy market and thus on the potential to generate as many earnings as possible. A beneficial behavior for biogas plant operators is to produce and sell electricity in high price periods and store it in low price periods. In addition, governmental subsidies offer further incentives to invest in a flexibly schedulable plant. The decision about a specific adjustment of the biogas plant design is a long-term investment decision done by the biogas plant operator. In order to support this strategic, long-term investment decision to generate a robust solution for a risk-averse decision maker, decision support using optimization of an operational plant schedule for the future is given to evaluate the performance of the different plant designs. They can be evaluated by calculating the net present value (NPV) as a key figure using the arising cash flows and the initial investment.

In this work, a novel deterministic optimization approach is described. Therefore, at first, a basic model to optimize the operational plant schedule called OBPP (operational biogas plant problem) is developed. Secondly, this model is extended to support the investment decisions as mentioned (SBPP - strategic biogas plant problem). However, as the spot market prices are varying dynamically over time because of an uncertain behavior of energy demand and supply this variation is analyzed and considered using several scenarios. Therefore, significant sources of uncertainty are analyzed and determined. The examined investment planning problem is based on a real planning problem of a biogas plant operator in southern Germany. Nevertheless, the numerical experiments represent a fictional case, which is similar to the real biogas plant.

The remainder of this paper is organized as follows: In Section 2 an overview of the problem setting is given. Subsequently in Section 3 relevant literature is analyzed. Within Section 4 the deterministic optimization approach is described. Aforementioned, this model is tested using a fictional but close to reality case example in Section 5. Finally, Section 6 summarizes the results and identifies opportunities for extensions or general future research.

2 Problem setting

In Section 2 an overview of the problem setting is given. In particular, an overview of the energy demand in Germany in general, the functionality of biogas plants, the relevant market conditions and especially of the characteristics of direct marketing.

2.1 Energy demand in Germany

As previously mentioned, the electricity production, as well as the electricity demand, are volatile. The behavior of the intraweek electricity demand in Germany, or in other words the load curve, is depicted

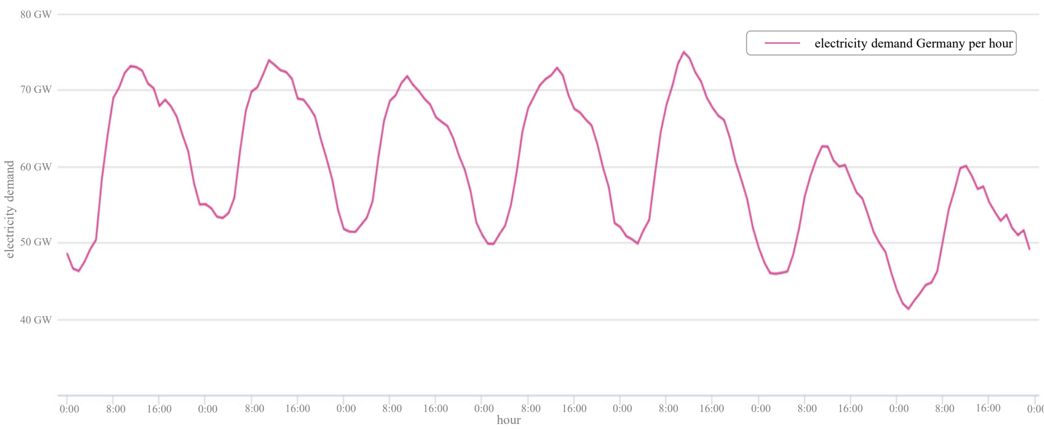

Figure 1: Electricity demand in Germany (Agora Energiewende, 2018)

in Figure 1. The figure is based on data for a typical week from Monday to Sunday in 2018. As demonstrated, the demand is characterized by an intraday and intraweek seasonal pattern. A demand peak during lunchtime on each day characterizes the first one. Additionally, there is a smaller peak or plateau during the afternoon. The intraweek pattern shows that the demand on weekdays from Monday to Friday is rather similar. Nevertheless, the patterns of Saturday and Sunday are very different. In addition to those two patterns, in general, another seasonal pattern can be observed regarding the electricity demand. Typically, the electricity demand in Germany is higher during the winter months than during the summer months. (BDEW Bundesverband der Energie- und Wasserwirtschaft e.V., 2018) To sum up, the electricity load curve in Germany is highly volatile and characterized by three seasonal patterns - intrayear, intraweek and intraday.

As declared, electricity production is volatile as well. The volatility is mostly based on the volatility of the renewable energy sources wind and solar. The production of those two energy sources is only partly controllable. Typical for solar energy is a production peak during lunchtime. Typical for wind power is that the production during the winter months is higher than during the summer months. However, both energy sources are highly volatile in a short-term planning horizon. (Fraunhofer ISE, 2018b)

The major issue within a national electricity power grid is that the electricity demand or consumption has in any time to be equal to the electricity production. Only if production and consumption are (nearly) equal, the power line frequency and the whole grid are stable. In Germany, the power line frequency has to be 50 Hz. There are mainly two technical possibilities to balance electricity production and consumption. Flexibly schedulable power plants are the first possibility. They can be conventional, like natural gas or coal power plants, or renewable, like pumped-storage power plants or biogas plants. The second possibility is import/export from/to neighboring countries. (Fraunhofer ISE, 2018a)

The organizational instrument to balance the electricity production and consumption is the energy exchange EPEX Spot SE. The energy demand and supply is traded in several markets at this energy exchange. Specific characteristics of the markets and the prices are described in Section 2.3. Nevertheless, in brief, the prices at the energy exchange are a result of specific energy demand and supply in a specific period. Depending on the ratio of demand and supply, the prices are high or low and thus volatile. This induces two main consequences. At first, it is necessary to balance electricity demand and supply to stabilize the power grid as explained. Further, the volatility of the prices offers the power plant operators the possibility to generate more earnings by producing and selling electricity in high price periods or in other words in periods, in which the electricity demand is high compared to the uncontrollable part of the electricity supply.

2.2 Biogas plant functionality

Due to uncertain subsidies and changing governmental regulations, optimization strategies for biogas plants concerning flexible power generation and direct marketing become more and more important. Biogas plants provide the opportunity to generate carbon-neutral electricity out of biomass, or in other words renewable resources. There are several types of biogas plants running in the market. The majority

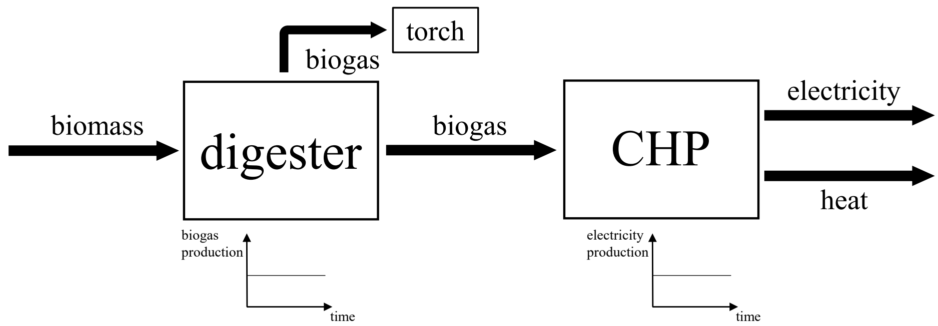

Figure 2: Conventional biogas plant configuration

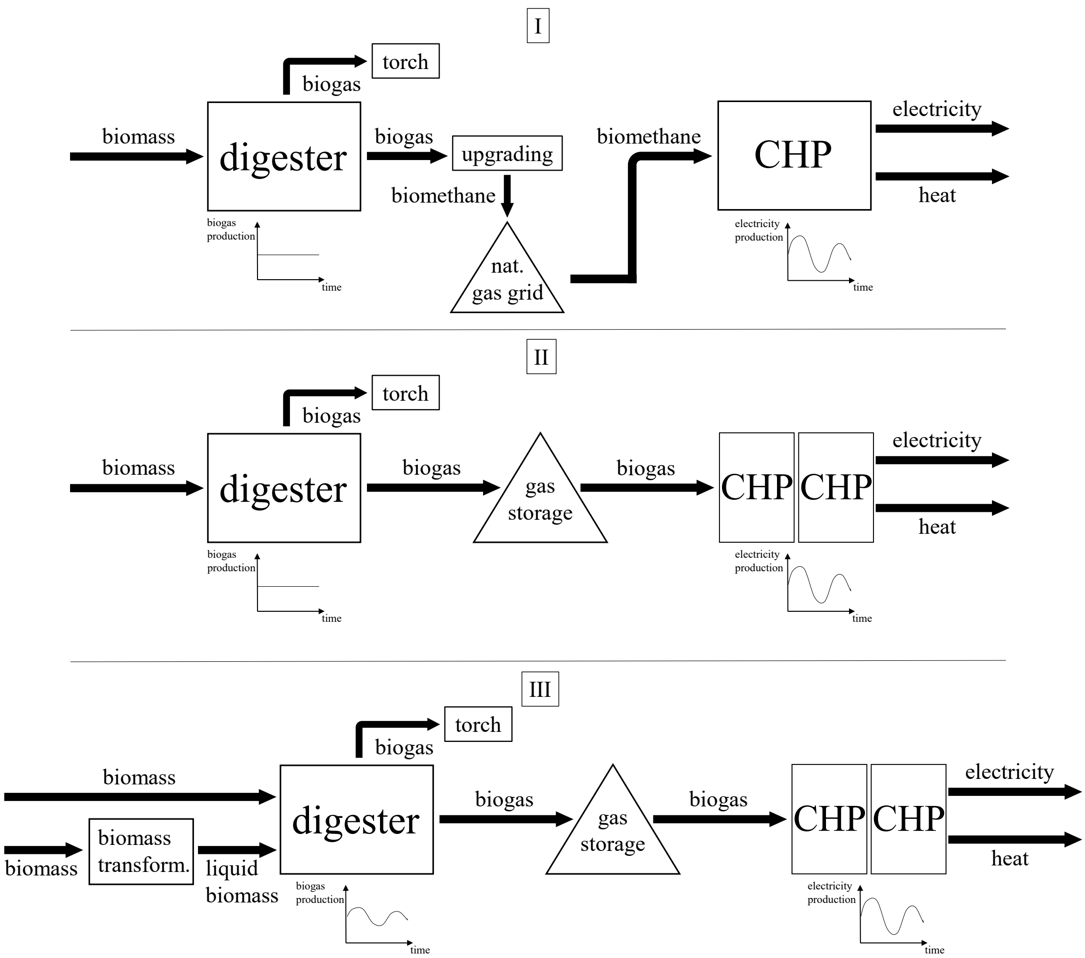

Figure 3: Further biogas plant configurations

of the plants uses the conventional way to produce energy. This conventional biogas plant design is depicted in Figure 2. Here, a digester is used to produce biogas out of substrate through combustion. As substrate, several types of biomass are possible. Common inputs are biowaste, wheat, rye silage, grass silage and maize silage. (Balussou et al. (2014), BiomassV (2016)) Those types of biomass cannot only be used as inputs in biogas plants but also in other utilization pathways of the bioeconomy. Thus, there is a competitive situation on the market of biomass supply. (Fichtner and Meyr, 2017) As depicted in Figure 2 in the chart below the digester, the biogas is produced continuously within the digester. In other words, the biogas production rate over time is fixed. Afterwards, the gas is directly burned in a combined heat and power (CHP) plant to produce electricity. During the combustion process, the by-product heat occurs. Within the CHP plants, several types of engines like gas-Otto engines or dual-fuel engines can be applied. The electricity production is continuous as well within this conventional configuration (represented by the electricity production chart below the CHP). The digester, as well as the CHP plant, are characterized by a specific capacity. As declared, the biogas is produced continuously within the digester. If there occurs a disturbance within the CHP plant(s) or if there is more biogas produced than can be combusted for other reasons, there is the possibility to burn biogas within a torch. Here, no electricity or other products are produced. Accordingly, no revenues are generated. This is just an opportunity to get rid of excess biogas. The main disadvantage of this biogas plant configuration is the inflexibility of the production rates of biogas and electricity. In order to produce the electricity demand oriented, the biogas plant design has to be adjusted. These adjustments cause investments. The resulting biogas plant configurations are explained in the upcoming paragraph. (Lehnert et al., 2011)

Three types of flexible biogas plant configurations are distinguished. These configurations are shown in Figure 3. In the first configuration (type I) the produced biogas is transformed through an upgrade process in biomethane and afterwards injected into the natural gas grid. The natural gas grid builds the infrastructure consisting out of pipelines and storages to supply natural gas to the consumers all over the country. If the biogas is upgraded and injected into the natural gas grid, the gas can be obtained from the grid and burned using CHP plants, but not necessarily at the biogas plant location, or can be used as biofuel. The biomethane can be purchased flexibly out of the natural gas grid. Thus, the electricity production (depicted in Figure 3 by the varying electricity production in the chart) is flexible as well and the biomethane can be burned demand oriented. The natural gas grid itself is used as a gas storage, which is not owned by the biogas plant operator. However, the infrastructure to transform the biogas into biomethane and a connection to the natural gas grid are necessary at the plant. The disadvantage of this approach is that the upgrading of the biogas is complex and expensive. (FNR, Fachagentur Nachwachsende Rohstoffe e. V., 2013) The second configuration (type II) does not use an upgrading process. Here, a gas storage is included between the digester and the CHP plants. Hence, the gas- and electricity productions are decoupled. This means that the biogas production is still continuous but the electricity production is now flexible and thus decoupled. Besides, additional CHP capacity is necessary to increase the flexibility. This flexibility of the electricity production can be used to produce the electricity demand oriented. By doing so higher earnings can be achieved, if the production and sale of the electricity are made in high price periods. In times of low prices, no electricity is produced and the produced biogas is stored in the biogas storage. The flexibility potential of the plant depends on the size of the biogas storage and the CHP plant capacity. Biogas storages, as well as CHP plants, are available in different sizes and technologies. Important is that the size of the storage and the capacity of the CHP plant fit together. Because if, for instance, a lot of CHP plant capacity is installed but only a small biogas storage, there would not be enough available biogas to utilize the capacity of the CHP plants in most of the periods. The difference between type II and type III is that in the third configuration the biogas production within the digester is flexible as well. Therefore, for instance, the substrate has to be transferred into a liquid to influence the digestion process by variable substrate feeding. The advantage of all these three configurations in contrast to the basic configuration is that the electricity production is flexible and can for this reason be demand oriented. This characteristic is necessary for beneficial direct marketing of electricity by generating additional earnings in the energy market. (Hahn et al. (2015), Hahn et al. (2014b), Hahn et al. (2014a), Lehnert et al. (2011))

For all three configurations investments are necessary. In the following, only type II configurations will be examined. The reason is that the effort to reach the other two design configurations is much higher than to build a gas storage and include another CHP plant. For type I, a connection to the natural gas grid is necessary and the upgrading processes are very complex. For type III, the digestion processes in the digester and the biomass structure have to be adjusted. Additionally, another transformation process of

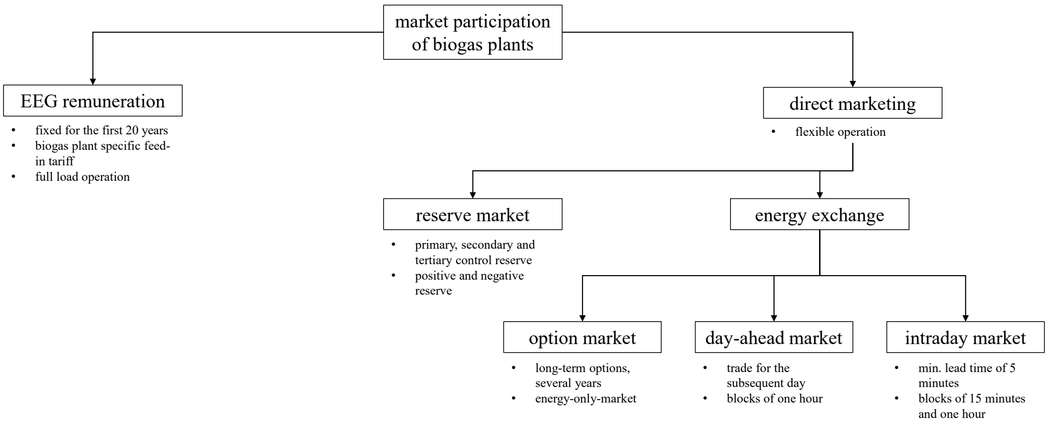

Figure 4: Market participation options of biogas plants

solid biomass into liquid biomass can be necessary. Thus, the type II configuration is easiest to reach, as it is only necessary to build a gas storage and extend the CHP plant capacity. Nevertheless, investments are necessary to build the gas storage, install another CHP plant and adjust other infrastructure components. Additionally, the size of the storage and the maximum capacity of the new CHP plant have to be determined. As explained previously, the benefit of this biogas plant configuration is the possibility to generate more earnings by producing and selling electricity demand oriented in high price periods. Hence, several investment strategies, consisting out of specific biogas storages and aligned CHP plant capacities, have to be assessed based on potential earnings in the energy market.

2.3 Market conditions in the German energy market

The market conditions in the German energy market determine the framework for the biogas plant operator's activities. In general, there are several possibilities for biogas plant operators in Germany to participate in the energy market. The possibilities are regulated in the EEG, which has changed a lot during the last years. The idea of the EEG in the year 2000 was to achieve a sustainable energy supply, decrease carbon emissions and develop energy technologies. (EEG, 2000) The first incentives for a demand oriented energy production were included with the amendment in 2012. Here, the two subsidies market premium and flexibility premium were introduced, which are incentives for a demand oriented energy production using direct marketing. (EEG, 2012) The functionality of those subsidies is explained in detail in Subsection 2.4.1. During the amendments in 2014 and 2017, the structure has changed again. Since 2017, the biogas plant operators have the opportunity to participate within a bidding model to sell their produced energy. (EEG, 2017) As the biogas plant operators have to act according to the EEG version of the time when the plant was put into operation, the following market participation possibilities, demonstrated as well in Figure 4, exist for operators of existing plants.

The first possibility is to take the EEG remuneration, or feed-in tariff, which is fixed for the first 20 years of plant operation and guarantees a fixed compensation per kWh of produced electricity, independent from the realized energy demand. The amount of the feed-in tariff is biogas plant specific because it depends on the used type of biomass, the maximum capacity of the plant and the used CHP technologies. The calculation is regulated in the EEG. (Bundestag, 2011) Here, the biogas plant would be run using the maximum capacity on each day - on full load operation.

Other market participation possibilities require a flexible operation of the biogas plant and are characterized as direct marketing options. If the biogas plant is operated flexibly, the first option would be to participate in one of the three reserve markets. Here, the primary, secondary and tertiary control reserve markets can be distinguished according to their planning horizon. As mentioned in Section 2.1, it is necessary to equalize electricity demand and supply to stabilize the power grid. The reserve markets are used to balance energy production and consumption. In all of the three markets, positive and negative reserve can be offered. Positive reserve means that in case of an unexpected high energy demand this demand is compensated by an increase in energy production. Negative reserve means that in case of an unexpected excess of energy supply the energy production of a plant is decreased. Both strategies are necessary to stabilize the electricity grid by balancing energy demand and supply. In the primary control reserve, the de- or increase of production has to be realized within seconds, within the secondary control reserve within five minutes and in the tertiary control reserve within 15 minutes. (Bundesnetzagentur. Beschlusskammer 6 (2011a), Bundesnetzagentur. Beschlusskammer 6 (2011b), Bundesnetzagentur. Beschlusskammer 6 (2011c))

The second option to participate in the market, if the biogas plant is operated flexibly, is to trade the energy production at the energy exchange EPEX Spot SE. Here, as well several markets exist. The first market is the option market. In this market, long-term options are traded with lead times up to six years. Additionally, this market is called an energy-only market, which means that only the amount of produced energy is compensated and not the reserved capacities as in the previously explained reserve market. The second market at the energy exchange is the day-ahead market. Here, the required energy of the subsequent day is traded in blocks of one hour. On this market, all tradings have to be finished until 12:00 CET of the previous day. This means that an electricity producer, e.g. a biogas plant operator, gives a bid for a specific amount of electricity in a specific hour on the next day for a specific market price on the power exchange. If this bid is accepted by the power exchange, the electricity producer is committed to fulfill his bid on the next day. If the bid is fulfilled, the electricity producer is compensated with the previously determined market price by the power exchange. If not, the electricity producer gets a financial punishment. The third market at the energy exchange is the intraday market. Here, energy in blocks of 15 minutes up to one hour is traded on a short term level. Apart from the shorter lead times, the functionality is similar to that of the day-ahead market. This market is used to minimize energy shortages and surpluses. The lead times can be decreased to five minutes. (Bundestag (2011), EEG (2017)) In the first 20 years of plant operation, the market premium and flexibility premium encourage the biogas plant operators to use direct marketing, reduce the maximum full load operation and thus produce their energy market-oriented and demand-driven. The market premium is a governmental subsidy, which warrants a payment for the plant operators with the amount of the difference between the biogas plant individual feed-in tariff an operator would get and the monthly average market price within the chosen market. Accordingly, there is the certainty for the biogas plant operator that on average at least the EEG feed-in tariff is achieved by choosing direct marketing. (EEG, 2017) The flexibility premium is an incentive for those biogas plant operators which run their plant demand oriented with a flexible schedule and is paid once in a year for the additionally reserved capacity for flexible energy production. Those plants can be used to reduce fluctuations in the power supply and thus to stabilize the voltage of the power grid. (EEG, 2014) (EEG, 2017) The functionality of the market and flexibility premiums is explained in detail in Subsection 2.4.1.

Operators of new plants or plants, which are older than 20 years, have to participate within another bidding model and have the opportunity to get a flexibility surcharge, which is similar to the flexibility premium. (EEG, 2017)

In the remainder, the optimization of biogas plants is based on the circumstances of direct marketing in the spot market, in particular, the day-ahead market. Here, the short-term flexibility potential of a flexibilized biogas plant can be used to generate more revenues than in the other markets. Moreover, most biogas plants are too small to participate in the reserve and option market.

On the spot market, the biogas plant operators have to interact with other market participants. Those participants are governmental institutions, other energy producers, transmission grid operators, the energy exchange as an institution, consumers and service providers. These service providers can help the biogas plant operators to place their produced energy on the market to generate as many revenues as possible. In many cases, several biogas plants are combined to so called virtual power plants (VPPs) by such a service provider. After the combination of the plants, the VPP is treated as a single plant and the total energy is sold together at the spot market.

2.4 Characteristics of direct marketing

Corresponding to the previous explanations, the following optimization approach is based on the market option direct marketing. Thus, the according requirements and subsidies are outlined in Section 2.4.1. The variability and uncertainty in the revenues and in particular the spot market prices are explained in Section 2.4.2.

2.4.1 Requirements and subsidies

As declared in the previous Section 2.3 the basic requirement for a biogas plant operator to participate in direct marketing is to run the biogas plant in a flexible design. Thus, the conventional biogas plant design, depicted in Figure 2, is not appropriate. Instead, one of the further mentioned and in Figure 3 shown designs is necessary.

Aforementioned, infrastructure investments are necessary to reach one of these flexible biogas plant configurations. Hence, there have to be incentives for the biogas plant operators to invest in their plant and produce the electricity demand oriented. One of these incentives is the possibility of generating more revenues in the spot market than taking the feed-in tariff. The revenues, an operator of a flexibly run biogas plant can generate, consist out of the spot market prices and governmental subsidies. Here, the two pertinent subsidies are the market premium and the flexibility premium as already mentioned in Section 2.3. As the prices in the spot market are a result of energy demand and supply, the prices are highly volatile. Accordingly, a beneficial behavior for biogas plant operators is to produce and sell electricity in high price periods.

In order to be entitled to receive the two subsidies, the biogas plant operators have to fulfill several requirements, which are regulated in the current version of the EEG. (EEG, 2017) Here, it is stated that the support through the governmental subsidies starts with the day the biogas plant is put into operation. The requirements for the market premium are as follows: The market premium is only paid for electricity, which is sold through direct marketing. If this is the case, the market premium is paid for a 20-year horizon. The biogas plant has to be flexible and remotely controlled. Thus, a perhaps charged direct marketing service provider is able to regulate the electricity production and feeding into the grid. Hence, the demand oriented electricity production is ensured. Additionally, the flexibility premium is characterized by the following requirements: The flexibility premium is a compensation for the availability of additional capacities within a plant to produce electricity demand oriented. As well as for the market premium, the biogas plant operator has an interest on the flexibility premium if the produced electricity is sold through direct marketing, or in other words, the biogas plant operator does not get the EEG feed-in tariff. Another requirement is that the already installed capacity has to be at least 20 % of the total installed capacity after a capacity extension. The biogas plant has to be run demand oriented according to the technical conditions. A surveyor has to certify that the biogas plant is able to produce electricity demand oriented. The certification in terms of the flexibility premium depends on individual decisions, because there could be more biogas plant specific requirements to fulfill. For this reason, there is still a remaining risk for the biogas plant operator to get approval or not. (EEG (2017), Bundestag (2011))

The idea of the market premium is that it should be ensured that the biogas plant operator achieves at least on average the same payment per kWh through direct marketing as he would achieve through the biogas plant individual feed-in tariff. (EEG, 2017) Thus, the market premium is calculated as given in an example in Table 1.

Table 1: Example market premium

General calculation:	
Market premium =	
biogas plant specific feed-in tariff - average market price per month within the chosen market	
Example:	
Feed-in tariff:	11 ct/kWh
average market price per specific month:	5 ct/kWh
⇒ market premium in this specific month:	6 ct/kWh

The biogas plant specific market premium is the difference between the biogas plant specific feed-in tariff and the average market price within the chosen market. The average market price within the chosen market is calculated retroactively. Hence, the whole market premium is paid monthly retroactively. (EEG, 2017)

The market premium offers an incentive for the biogas plant operators to choose the way of direct marketing in general. Additionally, the flexibility premium offers another incentive to install additional electrical capacities within the plants to increase the potential of flexible production. Thus, the additionally installed flexible capacity is compensated with 130 EUR per kWh once in a year (130 EUR/kWhy).

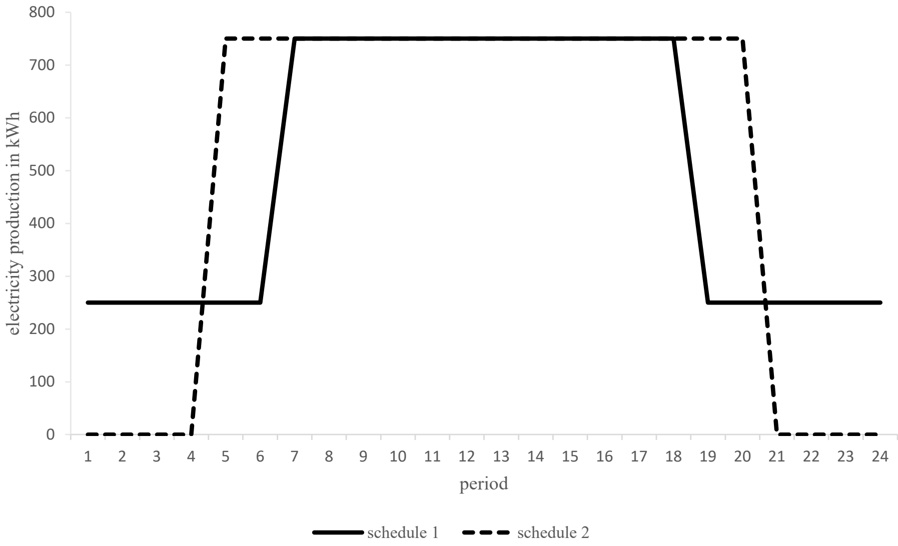

Figure 5: Two possible operational schedules concerning the flexibility premium

The calculation of the flexibility premium is as follows: First, the flexible excess capacity per average hour in a year has to be calculated. Hence, the difference between the installed capacity in total and the already installed capacity, rated with a correction factor of 1.1 for biogas plants, which is defined by the German law, is calculated. The resulting flexible excess capacity for an average hour is compensated with 130 EUR/kWhy. The calculation and payment of the flexibility premium are made retrospectively. (EEG, 2017) For a fictional biogas plant example, the flexibility premium can be calculated as depicted in Table 2.

Table 2: Example flexibility premium

currently installed CHP plant capacity (maximum amount of electricity per hour):	$Cap = 500$ kWh
additionally installed CHP plant capacity (maximum amount of electricity per hour):	$Cap^{add} = 250$ kWh
totally installed CHP plant capacity (maximum amount of electricity per hour):	$Cap^{new} = 750$ kWh
granted flexible excess capacity per hour:	$Flex^{min} = 250$ kWh
maximum amount of electricity on average per hour in a year: $Prod^{max} = Cap^{new}$ - $Flex^{min}$ = 750 - 250 = 500	
granted (*minimum*) flexibility premium per year: $(Cap^{new} - Prod^{max} \cdot 1.1) \cdot 130 =$ $(750 - 500 \cdot 1.1) \cdot 130 = 26{,}000$ EUR	
one possible operational plant schedule (solid in Figure 5): 12 hours maximum amount of electricity per hour 750 kWh 12 hours maximum amount of electricity per hour 250 kWh	
second possible operational plant schedule (dashed in Figure 5): 8 hours maximum amount of electricity per hour 0 kWh 16 hours maximum amount of electricity per hour 750 kWh	

It is not allowed to use the additionally installed capacity continuously. The realized output of the current year has to be lower or equal than the previously realized output per year. If the requirements are met, the flexibility premium can be requested. If the flexibility premium is granted once, there is an entitlement in the premium within the upcoming nine years. Whether the requirements are met

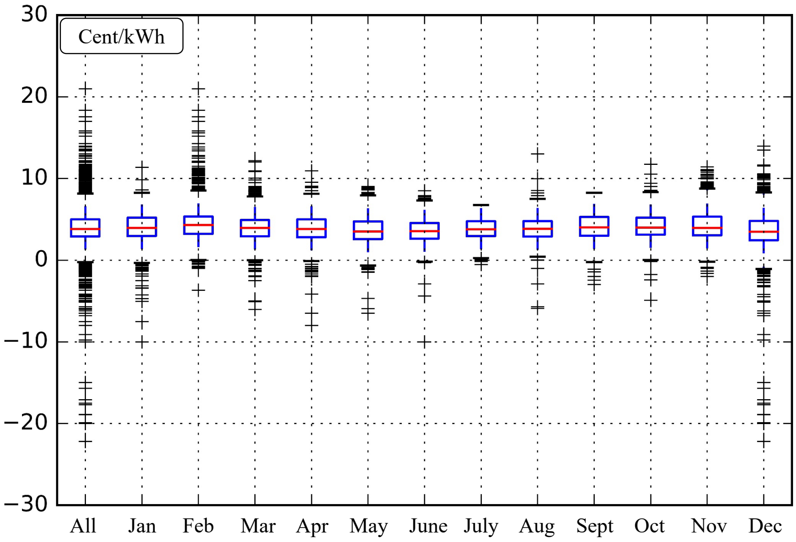

Figure 6: Boxplot of day-ahead spot market prices from 2011-2015 (EPEX Spot, 2018)

or not is verified after each year within this horizon. This important characteristic is expressed by two randomly chosen possible operational schedules within the previously given example and Figure 5. Within the example, the currently installed capacity was assumed as 500 kWh. Therefore, after an increase in electrical capacity, it is prohibited to produce on average more than 500 kW per hour on an average day. Both possible schedules demonstrate that on average exactly 500 kWh electricity is produced but the operational schedule can be very different. These two schedules are just examples of many possible ones. For instance, it is possible as well to produce less electricity than 500 kWh. (EEG, 2017)

2.4.2 Fluctuation of revenues

As described, the participation within direct marketing is characterized by volatilities of prices and revenues. In order to assess the profitability of an energy marketing strategy, it is necessary to analyze the fluctuation within the possible revenues. As the prices at the spot market are a result of specific energy demand and supply, the prices are fluctuating significantly. This fluctuation could even mean that the spot market prices, in contrast to the energy demand, are negative, which means that the power plant operator has to pay for his power supply. One reason for the fluctuation is the energy supply from the renewable sources wind and solar. For example, during the middle of the day, when the energy supply from solar systems is typically high, the spot market prices are lower than in the hours before and after. The fluctuation of the spot market prices is depicted in the boxplot in Figure 6. Here, boxplots for every single month of a year and a boxplot for all data of the spot market prices from the day-ahead market in 2011 to 2015 are depicted. It is possible to interpret these boxplots to get an idea of the price data characteristics like measures of location, the dispersion, the interquartile range or the existence of outliers. As demonstrated, the prices are distributed between -22.1 and 21 $Cent/kWh$. Additionally, it is displayed that many price realizations are outside of the blue boxes, which represent the prices between the first and third quantile. This characteristic presents the variance within the price data. However, the boxplots also show that this variance differs between the individual months. The objective of a flexible plant schedule combined with direct marketing is to produce and sell energy when the spot market price is as high as possible and to store the biogas in times of low prices. In the following, several sources of uncertainties are discussed. Thus, strategic, long-term developments and repetitive, or in other words seasonal, dynamics are distinguished.

Strategic development - Market price development: The first analyzed source is the strategic, long-term development of the spot market prices at the day-ahead market from 2011 to 2015. The development is demonstrated in Table 3. As depicted in the table, the yearly mean of the spot market prices is decreasing through the years. This trend is remarkable because the development of customer electricity prices is totally reverse. The customer prices were rising steadily through these years. (Statistisches Bundesamt, 2017) It is not obvious to give reasons for this decreasing process. One reason might be the decreasing price for crude oil during these years, but there are certainly other influencing factors. For reasons of abstraction, these influencing factors are not analyzed in detail. Most important is to forecast whether this decreasing process will go on in the future or not. Within a study from Schlesinger et al. (2014) the various influencing factors are analyzed. One of the conclusions of this study is that the decreasing of the spot market prices will go on until 2020. From this year on the prices will start increasing. However, it is still uncertain whether this forecast will be correct or not. Hence, this uncertainty should be covered within strategic planning tasks in biogas plants.

Table 3: Long-term development of day-ahead spot market prices from 2011-2015 (EPEX Spot, 2018)

year	mean [Cent/KWh]
2011	5.11
2012	4.26
2013	3.78
2014	3.28
2015	3.16
average 2011-2015	3.92

Strategic development - Governmental subsidies: As described in Section 2.3 and 2.4.1, the achievable revenues for a biogas plant operator using direct marketing consist of the spot market prices and governmental subsidies. Since the revenues at the spot market have been rather low in comparison to, for example, the market premium, it is necessary to evaluate the uncertainty of these revenues as well. The amount of the two subsidies market premium and flexibility premium is declared in the EEG. In the past 17 years since the first version of the EEG, six amendments of the law have been published. This means that on average one EEG version is updated after not even three years. The planning horizon of strategic planning problems is usually several years. Accordingly, the time between two EEG amendments is probably shorter than the considered planning horizon. Nevertheless, the impact of new regulations on existing plants is rather low because existing plants are regulated using the EEG version, which was the current version at the point in time when the plant was built resp. went on stream.

As declared by law, similar to the feed-in tariff, the market premium is fixed for the first 20 years of plant operation. After these years, the operator of a biogas plant has no entitlement on this subsidy. (EEG, 2017) The flexibility premium is fixed, as well. However, only for ten years after application and the first flexible power generation. As a result, the governmental subsidies are rather certain, if they are granted once. (EEG, 2017) Nevertheless, the circumstances for (flexible) biogas plants can change in the future because of changes in the appropriate laws. For this reason, the decision maker has to decide if it is better to make the investment now or later because in the future the subsidies could be higher or lower if the investment is made then. Additionally, there is the risk for the biogas plant operator that the requirements are not fulfilled and especially the flexibility premium is not granted by the surveyor.

Dynamics and seasonalities: As explained previously, uncertainties and repetitive dynamics should be strictly distinguished. As given in Figure 6, there is a seasonal intrayear price fluctuation or dynamic. The average of the prices is noticeably lower in summer than in autumn or winter. Furthermore, the variance differs between specific months. For example in December, the variance is very high compared to for example in July or other months. Moreover, in December an untypically high occurrence of negative outliers exist. One reason for these outliers is that in December there are a lot of holidays and those days have an unusual price pattern which leads to a higher variance within the whole month. In February, the data is characterized by a great number of positive outliers. These characteristics mean that the measures of location and the dispersion but also the skewness differs between the specific months.

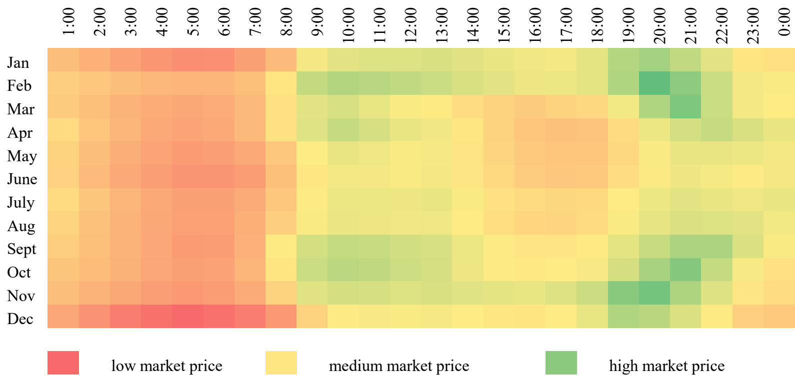

Figure 7: Heatmap of spot market prices per month and hour (EPEX Spot, 2018)

The seasonality during the months of a year is demonstrated in Figure 7 as well. Within the figure, the average of the spot market prices of the day-ahead market from 2011 to 2015 for each month and each time during the day is shown. Low spot market prices are represented by red colors and high prices are represented by green colors. As depicted, the prices during fall, winter and early spring (Sept. - Feb.) are on average, especially by day, higher than during the summer months. Additionally, another seasonality is depicted - an intraday seasonality. Here, the prices are lower during the night, characterized by an increase in the morning, a decrease during lunchtime and another increase during the early evening again. However, the amount of volatility is different within the specific seasons of a year.

The mentioned short-term seasonal price pattern during one day is revealed in Figure 8 as well. The figure shows the mean of the above described price data, specific for each day and each hour of the day. As given, the fluctuation from Monday to Friday is rather similar compared to the fluctuation on Saturday and Sunday, which is more different. From Monday to Friday, there are typically two price peaks, one during the morning and one in the early evening. These peaks can be used to generate high earnings, if a lot of electricity is produced and sold during that time. The two price peaks are caused by the energy demand and the feed-in of electricity produced out of solar power. The energy demand is typically higher during the day than during the night. Thus, the prices during the day should be higher than during the night. However, as the feed-in of solar-based electricity has its peak typically during lunchtime, the energy prices decrease during this part of the day because the energy supply is very high. On the weekend, these peaks are not only lower but also later during the day. On Sunday, the afternoon peak is significantly higher than the peak at lunchtime.

Finally, it can be summarized that the prices at the day-ahead market are characterized by three different seasonal patterns or dynamics. An intrayear, intraweek and intraday pattern. This characteristic should be covered within strategic planning problems in biogas plants to get an appropriate approximation of possible future earnings.

3 Literature

The objective of this work is to solve the planning problem of a real biogas plant in southern Germany as described previously. Biogas plants operated flexibly should be used to compensate differences of energy demand and supply within the power grid to stabilize it. By doing so, the biogas plant operator has the possibility to generate more earnings by producing and selling electricity in times of high price periods. In order to achieve a flexibly schedulable biogas plant, the plant design has to be adjusted to decouple the biogas and electricity production. The starting situation within the real biogas plant is the design of a conventional biogas plant. The design is adjusted to reach a type II configuration. Therefore, a biogas storage and additional electrical capacities are necessary. The investment decision concerning the size of the biogas storage and the additional electrical capacity depends on the fluctuation of the energy market prices and thus the opportunity to generate as high earnings as possible. To asses several investment strategies, consisting out of several possibilities for biogas storages and additional CHP plants, an operational plant schedule based on uncertain energy market prices is optimized. The optimization of the operational schedule with an extraordinary high granularity - on an hourly basis - is necessary, because

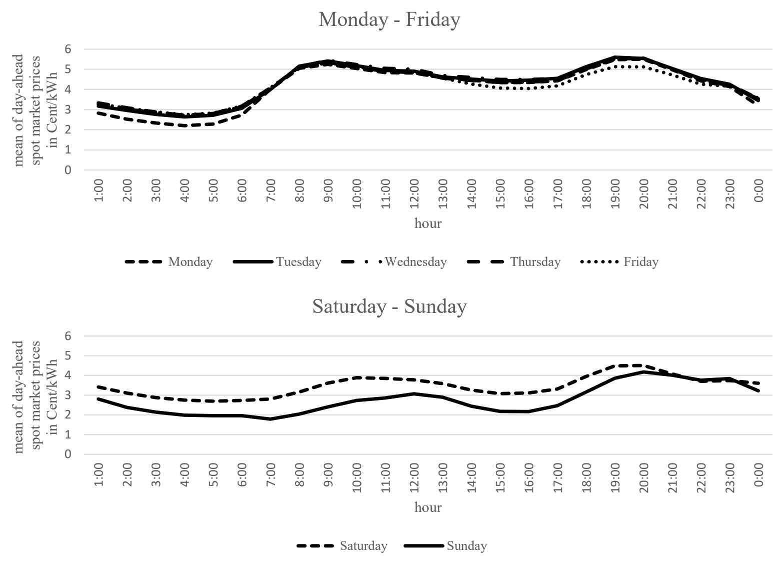

Figure 8: Mean of spot market prices per day and hour (EPEX Spot, 2018)

of the identified sources of uncertainty. An optimization and not only a simulation of the operational schedule is needed, because the scheduling includes revenue-effective decisions, which are crucial for the strategic investment decision. Hence, in the following literature about design and operational plant schedule optimization in biogas plants and related energy sources based on direct marketing and spot market prices is reviewed to ascertain whether appropriate approaches already exist to solve the real case problem as mentioned. The related literature is clustered into six groups. Literature concerning the optimization of biogas plants (BGP), combined heat and power plants (CHP), virtual power plants (VPP) and hydro power plants (Hydro). Additionally, literature about price forecasting (Price) and other literature concerning investment decisions under uncertainty in the general electricity market (Invest.) is distinguished.

In order to define the important field of research in more detail, the Supply Chain Planning Matrix (SCP-Matrix) is used to classify the different planning problems of a biogas plant operator. The adjusted SCP-Matrix for a biogas plant operator is depicted in Figure 9. Here, the different planning problems are covered using typical planning modules of Advanced Planning Systems. (Meyr et al., 2015) From a biogas plant operator's point of view, several planning tasks of the original SCP-Matrix can be neglected. Those planning tasks are colored in grey. Typically, distribution tasks, as well as demand fulfillment tasks, do not play any role for biogas plant operators because they feed in the produced electricity directly to the grid and have typically only one customer. Additionally, as substrate, several types of biomass are possible, which are assumed as available at the plant. Accordingly, purchasing and Material Requirements Planning tasks play a minor role for biogas plant operators. Moreover, the strategic planning problem of adjusting the biogas plant design is solved by optimizing an operational schedule. Hence, mid-term Master Planning tasks are not part of the problem. The planning problems of the current work can be categorized into the long-term Strategic Network Planning (SNP), the mid-/short-term Demand Planning (DP) and the short-term Production Planning and Scheduling (PPS). The biogas plant design as a long-term decision (SNP) is optimized on basis of an idea of uncertain revenues based on uncertain spot market prices (DP) using an optimization of an operational biogas plant schedule (PPS). Distinctive for the current DP-problem is that the specific energy demand determines the market price in combination with the energy supply. Nevertheless, as the total demand in an economy is much greater than the production capacity of one single biogas plant, the energy demand for one plant can be assumed as infinite. Therefore, the prediction of the uncertain spot market prices is the crucial problem.

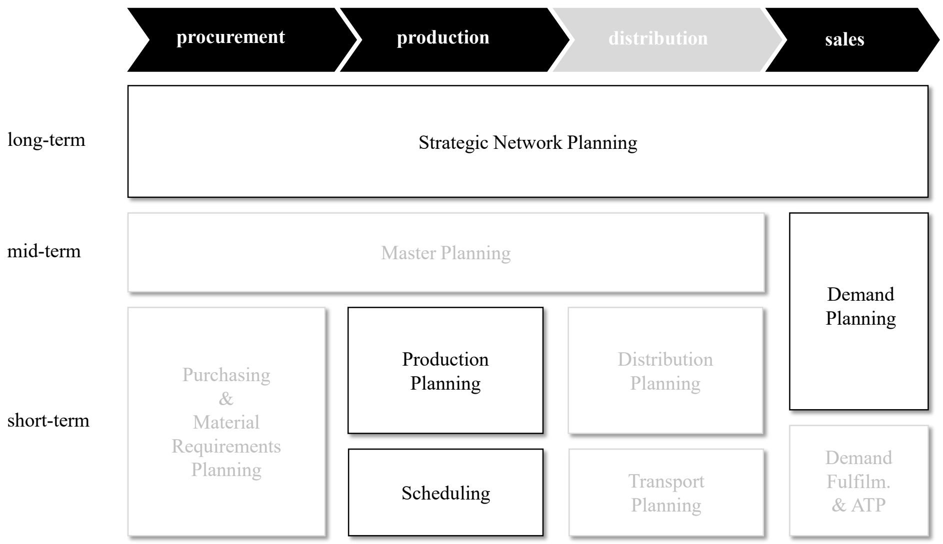

Figure 9: SCP-Matrix for a biogas plant operator using planning modules (see Meyr et al. (2015))

3.1 Related publications

As a first group of literature, existing literature about biogas plant optimization using direct marketing is reviewed. Gohsen and Allelein (2015) have published an approach to optimize the electricity production out of biogas based on a volatile demand. Within their approach, they consider storage capacities but the biogas plant design is given and not changed. They compare different cases of marketing. The first case is taking the feed-in tariff, the second one considers direct marketing and in the third one direct marketing and the flexibility premium are considered. No information about the specific optimization model is included in the publication. Heffels et al. (2012) introduced several business models for direct marketing of electricity from biogas plants using Operations Research models. They distinguish between biogas and biomethane plants, whereas their definition of biomethane plants is as follows: The produced biogas out of the digester is upgraded and injected into the natural gas grid. Afterwards, the gas is used in CHP plants to produce electricity. Moreover, they distinguish between a fixed or demand driven production of electricity. The spot market prices within their model are given as deterministic parameters and since only the operational plant schedule is optimized, no investment decision is made. Besides, as the publication is from 2012, the demonstrated approaches are based on outdated governmental regulations. Additionally, Hochloff and Braun (2014) published a model to optimize the operational biogas plant schedule regarding excess power units and storage capacities. They use the principle of rolling planning to improve their results and distinguish between several energy markets but take the spot market prices as deterministic parameters. Additionally, the results of the generated schedules are compared for a few plant designs. However, the biogas plant design itself is not optimized.

Only one investigated publication deals with the operational optimization of CHP plants. This work is published by Beraldi et al. (2008) and shows an approach for the integrated optimization of production and trading of thermoelectric units or in other words CHP plants. Within this approach, the uncertainty on the day-ahead market is considered in a price taker model. In order to handle the stochasticity in the model, several scenarios are distinguished.

As a third group, publications concerning direct marketing of hydro-power plants are analyzed. Within this review, four representative publications are considered. Additionally, more general information about hydro-power plant optimization can be found in Singh and Singal (2017). The first publication about short term hydro-power scheduling is from Belsnes et al. (2016). Within this work, a stochastic and a deterministic approach are compared on the basis of uncertain electricity prices. The stochastic approach is modeled as a successive linear program. The optimization approach is based on the Norwegian market and thus the legal framework there. Price scenarios, generated using a simulation of stochastic processes to show combinations of fundamental influencing factors, are used as inputs with the same probability. In another publication by Chazarra et al. (2016) the optimal hourly schedule within a weekly scheduling process is examined. They use price scenarios for each hour of a week based on the Spanish market in a price taker model to optimize the operational plant schedule. Fleten and Kristoffersen (2008) deal with the commitments between energy producers and other market participants based on the chosen market regarding an optimization of the short-term planning of a hydro-power plant. They use a stochastic model formulation and scenarios based on time series models to derive a solution for the Norwegian day-ahead market. Another model about short-term hydro-power scheduling is published by García-González et al. (2007). They use a stochastic optimization model with price scenarios. Within this approach, the market prices are exogenous variables and modeled via scenarios. Furthermore, they consider the risk aversion of a decision maker in their approach using the Conditional Value at Risk (CVaR).

In a fourth group of literature, publications concerning investment decisions under uncertainty in the general electricity market are reviewed. Here, Blyth et al. (2007) developed an approach to make investment decisions under risk. Within this approach, regulatory uncertainties concerning for example subsidies are modeled. Even though, no details about the specific modeling are given within the publication. The authors explain a dynamic programming approach to include the risk management of plant operators of coal and gas fired plants or carbon capture and storage (CCS) technology plants. Dynamic programming is used as well by Kumbaroğlu et al. (2008) to evaluate year-by-year investment decisions for energy producers. Here, the price uncertainty is considered using stochastic processes. Additionally, it is assumed that the demand is price sensitive. The optimization approach is based on the legal framework of the Turkish energy market. A real options approach (ROA) is used by Yang et al. (2008) to assess investment alternatives in the energy sector. Governmental regulations are assumed as uncertain within this approach. The objective of the work is to quantify the costs of uncertainty. The ROA is part of a dynamic programming approach to derive a solution for the investment decision. As energy sources gas, coal and nuclear power plants are considered. As the publication is from 2008, the approach is based on outdated legal regulations.

In a further group of literature, publications with a focus on uncertain electricity prices are analyzed. Similar to the group hydro-power planning, only a few representative and typical approaches are explained here. Additionally, more general information about dealing with uncertain electricity prices can be found in Haghi and Tafreshi (2007) and Möst and Keles (2010). Keles et al. (2012) compare and evaluate several models to forecast electricity spot market prices. Within these models, it is possible to include the stochastic behavior of the prices as well as negative prices and price jumps. The forecasted prices are not used as inputs for further calculations or optimizations. In another publication of Keles et al. (2016) the forecasted electricity prices of the day-ahead market are used as inputs for the energy trading. The authors explain that the influencing factors on the prices can be clustered, but as the clustering of these factors has a fundamental influence on the quality of the forecasts, it is still difficult to derive a robust forecast. In order to derive a forecast, artificial neural networks are used. Weron (2006) is dealing with the modeling and forecasting of electricity loads and prices. He describes the legal frameworks in several energy markets, analyzes the characteristics of the time series of loads and prices and compares several forecasting methods. No application of the forecasts is considered. Ziel and Steinert (2016) published a new approach to forecast electricity prices. Within their approach, not the price itself is forecasted but its source - the relationship of the sales and purchase curves. By using the sales and purchase curves the non-linear behavior of the prices, as well as other characteristics of the time series and bidding structures can be modeled. The approach is based on the EPEX market. In an earlier publication Ziel et al. (2015) revealed an econometric model to forecast hourly prices on the EPEX market. In order to derive this forecast, they combine several established methods. Furthermore, changes in the market due to a change in the energy mix are considered. The derived forecasts are not used for further applications.

In a last group of literature, publications considering direct marketing and flexible scheduling in VPPs are analyzed. Similar to the group hydro-power planning, only a few representative and typical approaches are described here. Additionally, more general information about the operational optimization of VPPs can be found in Nosratabadi et al. (2017). A stochastic mixed integer linear programming model for the operational scheduling of VPPs in the Chinese market was published by Ju et al. (2016). The authors consider the robustness of the solution in their published stochastic model and assume a VPP consisting of solar, gas turbine and energy storage systems. To generate a short-term plan, based on the day-ahead market, the uncertain revenues are simulated. The publication of Nojavan and Zare (2013) deals with the optimal bidding strategy of an operator of a VPP in a price taker model. The bidding strategy of the day-ahead market is analyzed. Hence, a short-term planning horizon is regarded. Within the approach, the uncertainty in the prices is considered and risk-averse resp. risk-neutral decision makers are compared. Furthermore, the robustness is considered using a robustness function. Pandžić et al. (2013) are using a stochastic optimization model to build an optimal operational schedule of a VPP consisting of intermittent sources like wind or solar and flexible resources like storages. The approach is based on the EPEX day-ahead and balancing market. Peik-Herfeh et al. (2013) distinguish in their work between several bidding strategies in the day-ahead market by considering uncertain spot market prices. The assumed VPP consists of dispatchable and stochastic units. Within this approach, no market specific subsidies are considered. A two-stage stochastic model is used by Tajeddini et al. (2014) to optimize the short-term operational schedule of a VPP. Within this approach, an expected value model with scenarios is used to derive a solution for a risk averse decision maker. The CVaR is used as a risk measure. The assumed VPP, which produces electricity for the day-ahead market, consists out of a diesel generator, a micro turbine and a battery bank. As a last related publication, the work of Zamani et al. (2016) is reviewed. Within this work, the operational schedule of a large scale VPP is optimized using a stochastic modeling approach. In order to derive a scenario-based decision, scenarios for various stochastic influences are built. Uncertainty in the day-ahead prices, the electrical demand and the power generation are considered. Within the VPP, consisting out of solar, CHP, wind turbine and storage systems, electrical and thermal resources are distinguished.

3.2 Classification scheme and discussion

Table 4 further classifies and summarizes the models described previously. The following attributes and acronyms are used to analyze the related literature in greater detail.

Cluster: The related literature is firstly grouped into the previously explained clusters. Here, publications dealing with biogas plants (BGP), CHP plants (CHP), hydro-power plants (Hydro), investment decisions under uncertainty in the electricity market in general (Invest.), uncertain electricity prices (Price) and virtual power plants (VPP) are distinguished.

Model: Furthermore, the publications are analyzed concerning modeling characteristics. Here, static optimization models (SO.), simulation models (S.), dynamic programming models (DyP) and forecast models (fc.) are distinguished.

Supply Chain Planning (SCP): Additionally, the literature is analyzed in relation to the previously introduced planning tasks of the SCP-Matrix. Thus, the publications are assessed regarding the previously declared three important planning tasks represented by the naming of typical planning modules - Strategic Network Planning (SNP), Demand Planning (DP) and Production Planning and Scheduling (PPS).

Uncertainty: As the uncertainty in spot market prices is a crucial part of problems in the energy market, the consideration of uncertainty within the published models is analyzed as well. Here, deterministic model formulations (det.) and stochastic models (sto.) are distinguished.

Characteristic (charact.): Two more modeling characteristics are analyzed using a further step. Here, it is analyzed if the authors deal with the robustness of their solution (rob.) and which type of risk attitude is considered. Those publications, which consider a risk averse decision maker (risk av.) are marked.

The analysis of the literature leads to the following conclusions:

BGP: Three models for the optimization of biogas plants can be identified. Not one of these models considers an investment decision. Furthermore, the spot market prices are given as exogenous variables and deterministic optimization approaches are used. To the best of our knowledge, there does not exist any publication taking investment decisions and uncertainty into account. Moreover, some of the analyzed publications are based on outdated versions of the EEG. Nevertheless, the authors are dealing with the optimization of an operational biogas plant schedule. Thus, these deterministic models can be used as a part of an optimization approach with the objective to optimize an operational schedule, which is dealing with uncertainty.

CHP: The presented model does not include an investment decision. Indeed, a stochastic model formulation and the risk attitude of the decision maker is considered, but the plant characteristics of a general CHP plant cannot be used for biogas plants without adjustments, although those two energy sources are rather similar. The reason is that a CHP plant, in general, has a one-stage production process. Here combustible material, renewable or conventional, is burned to produce electricity. As demonstrated in Section 2.2 a biogas plant is characterized by a multi-stage production process, in which in a first stage biogas is produced out of substrate. In a second stage, electricity is produced out of biogas using a CHP plant. Hence, the whole system of a biogas plant is much more complex than that of a separate

Table 4: Related literature

		model				SCP			uncertainty		charact.	
	Cluster	SO.	S.	DyP	fc.	SNP	PPS	DP	det.	sto.	rob.	risk av.
Gohsen and Allelein (2015)	BGP	x					x		x			
Heffels et al. (2012)	BGP	x					x		x			
Hochloff and Braun (2014)	BGP	x					x		x			
Beraldi et al. (2008)	CHP	x	x				x	x		x		x
Belsnes et al. (2016)	Hydro	x					x	x	x	x		
Chazarra et al. (2016)	Hydro	x					x	x	x			
Fleten and Kristoffersen (2008)	Hydro	x					x	x		x		
García-González et al. (2007)	Hydro	x					x	x				x
Blyth et al. (2007)	Invest.			x		x						x
Kumbaroğlu et al. (2008)	Invest.			x		x		x		x		x
Yang et al. (2008)	Invest.			x		x						x
Keles et al. (2012)	Price		x		x			x				
Keles et al. (2016)	Price				x			x				
Weron (2006)	Price				x			x				
Ziel and Steinert (2016)	Price		x		x			x				
Ziel et al. (2015)	Price				x			x				
Ju et al. (2016)	VPP	x					x	x		x	x	
Nojavan and Zare (2013)	VPP	x					x	x		x	x	x
Pandžić et al. (2013)	VPP	x					x	x		x		
Peik-Herfeh et al. (2013)	VPP	x					x	x		x		
Tajeddini et al. (2014)	VPP	x					x	x		x		x
Zamani et al. (2016)	VPP	x					x	x		x		
New optimization approach	BGP	x				x	x	x	x	x	x	x

CHP plant. Nonetheless, the results and conclusions of this publication can be helpful to optimize the electricity generation process within a biogas plant.

Hydro: As in the publications of the previously analyzed clusters, not one model for hydro-power plants considers an investment decision. Partly, stochastic formulations are used but the models are based on energy markets in other countries than Germany, hence, on other legal frameworks. Moreover, similar to the models considering CHP plants or VPPs, the plant characteristics are related, as the plants can be run flexibly using preproducts (water, biogas) out of storage. However, the conditions and therefore the restrictions of storing water in a reservoir are different compared to a biogas storage. Apart from the differences in the specific plant characteristics and restrictions regarding the storage, other parts of the published models can be helpful to model and optimize an operational schedule in a biogas plant. The specific modeling of the prices can be used in a similar way for optimizing a biogas plant schedule because in all of the models a plant schedule for hydro power plants, depending on volatile spot market prices, is generated.

Invest.: The three identified models concerning investment decisions in the energy sector are different in contrast to all other considered models. They include an investment decision into the model. However, as they are energy source independent, they do not include a short-term production planning. Moreover, they use dynamic programming and in some of these publications no information about the specific model formulation is given. Furthermore, some of the models are based on outdated legal frameworks. Nevertheless, in contrast to all other considered models, an investment decision is made. For this reason, these ideas of modeling an investment decision in general together with the conclusions for optimizing the operational schedule from other models can be helpful to combine both decisions in one model for a biogas plant design optimization.

Price: The models considered in the cluster "Price" have the advantage that a real demand planning or in particular a price forecast is implemented. Nevertheless, as these forecasts are not used as inputs for further calculations, the models represent only a small part of the optimization problem within a biogas plant. Nevertheless, the conclusions of these publications can be used within an integrated biogas plant optimization approach for instance to produce price forecasts or price scenarios. The role of these forecasts within the later on developed optimization approach is specified in Section 4.1.

VPP: The identified models concerning VPPs do not consider investment decisions. However, all analyzed models use a stochastic model formulation and some of them consider the robustness of the generated solution and the risk attitude of the decision maker as risk averse. Hence, parts of these approaches, especially the modeling of the robustness of a solution and the risk attitude of the decision maker, can be used together with relevant parts from the previously described publications as inputs for biogas plant optimization problems, if the plant characteristics would be adjusted.

To sum up, what is missing in the literature is an approach for the optimization of the design of a biogas plant considering direct marketing and thus uncertain revenues by optimizing an operational plant schedule. Additionally missing is the consideration of the robustness of the generated solution and the assumption of a risk averse decision maker. Risk aversion is a typical risk attitude of biogas plant operators, which are often small farmers. An approach, which is able to do this, is developed in Section 5. Therefore, parts of the previously described publications can be used to model separate subproblems.

4 Solution approach

Within Section 4 the solution approach to the identified strategic planning problem is introduced. Here, at first an overview of the approach is given in Section 4.1. Afterwards, the assumptions of the developed models are explained in Section 4.2. Subsequently, optimization models for the operational (operational biogas plant problem - OBPP, Section 4.3) and strategic planning (strategic biogas plant problem - SBPP, Section 4.4) are presented.

4.1 Overview of the solution approach

As mentioned in the previous section, missing in the literature is an approach for design optimization in a biogas plant considering direct marketing and thus uncertain revenues by optimizing an operational plant schedule. In order to support the investment decision of adjusting the design of a conventional biogas plant into a flexible type II plant considering uncertain revenues, a multi-stage approach is developed. The specific parts of this approach, which is embedded in the legal framework in Germany and considers uncertain influences of the energy market, are illustrated in Figure 10. As depicted, the heart of the approach is a deterministic mixed-integer linear planning (MILP) model for the investment decision called SBPP.

However, before the model is applied, price scenarios for different spot market price forecasts are generated. Therefore, the influencing factors on the spot market prices are analyzed in a first step. Subsequently, the factors with a significant influence are identified. Using these influencing factors and time series decomposition, an expected price development for the future can be generated. However, this expected price is characterized by a forecast error. In order to consider the uncertainty within the expected price, several scenarios are generated. (Section 5.3.1) The idea is to model the risk of not reaching the expected price in a negative way or exceeding this price, by building the best and worst case as extremes and the expected price as an average case. Besides, further scenarios between these extremes are possible. Additionally, further scenarios are generated concerning significant legal conditions, namely the EEG regulations. Here, similar to the price scenarios, extreme scenarios for the development of the legal framework are built. (Section 5.3.2) One scenario, which is used in the determined SBPP model consists of one combination of one price scenario and one EEG scenario. As each scenario for the spot market price and the EEG conditions represents a realization of the appropriate random variables, these scenarios can be used as deterministic input data within the optimization model.

In addition to these scenarios, deterministic input data concerning the plant characteristics is necessary. Here, a finite number of investment alternatives ($j = 1, ..., J$), representing additional biogas storage and CHP plant capacities, is assumed. (Section 5.2)

As Fleischmann and Koberstein (2015) have shown, a strategic design planning problem like an investment decision integrates two planning levels, which are the strategic structural decisions and the mid-term operational ones. In order to optimize the design of a biogas plant, the structural decisions concerning investments are modeled in the SBPP model, while the operational material and financial flows are modeled in the OBPP model. In general, the decisions on the strategic level determine the framework for the operational planning. Additionally, the resulting operational flows are used to assess the investment alternatives in this biogas plant optimization approach. Thus, bilateral connections have

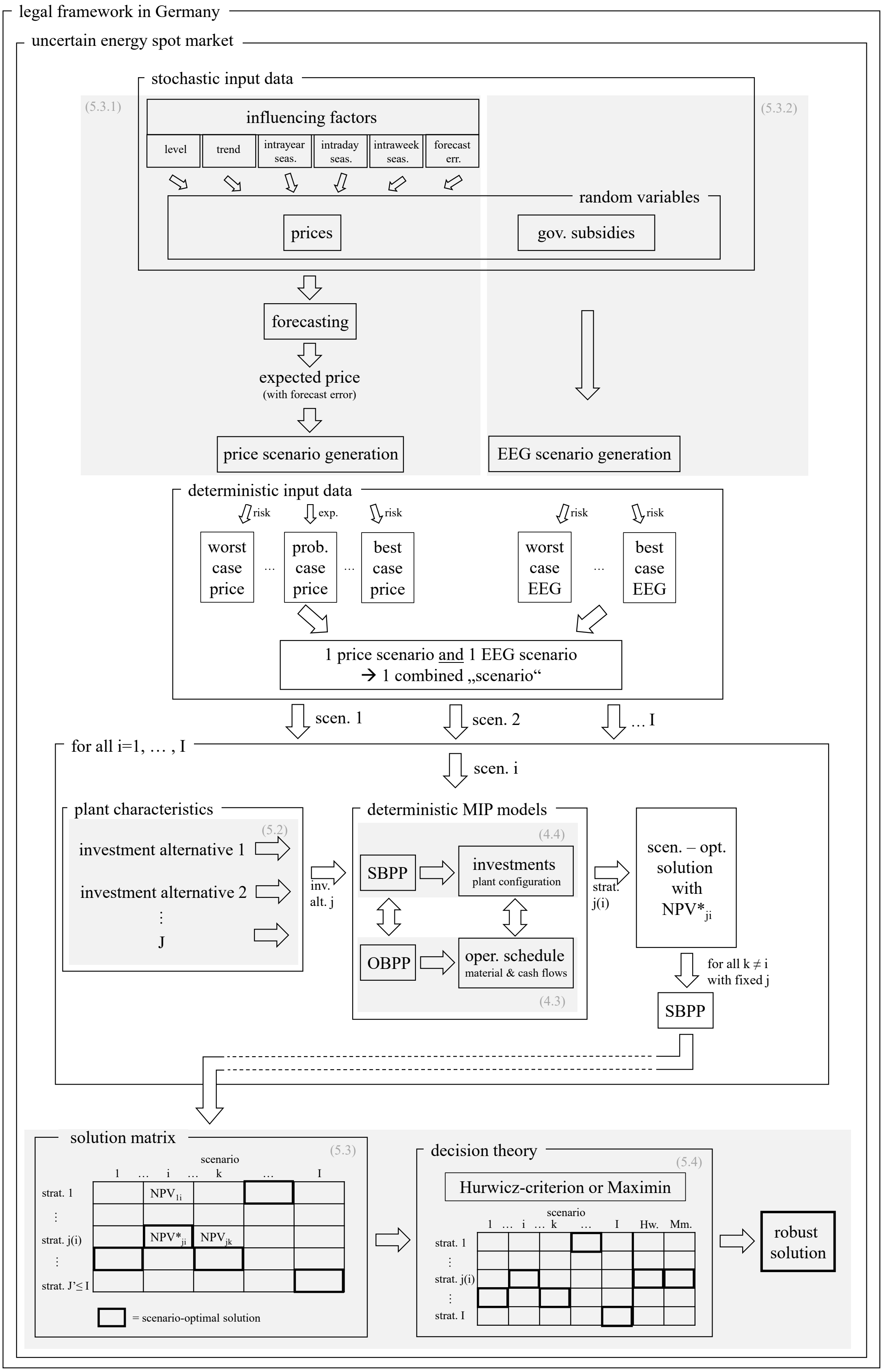

Figure 10: Graphical illustration of the solution approach

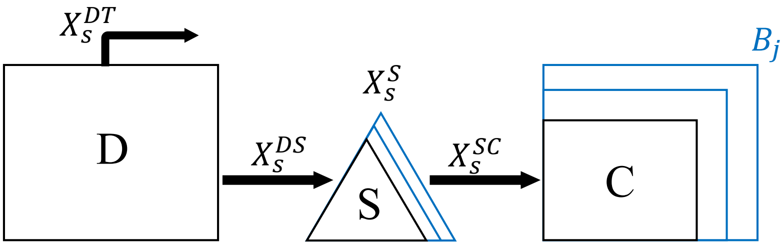

Figure 11: Structural and operational variables

to be considered between the two planning levels. (Fleischmann and Koberstein, 2015) In order to derive the SBPP model, firstly the deterministic linear programming model OBPP, which supports the optimization of an operational schedule of a biogas plant when the structural decision is assumed as having been made is introduced. (Section 4.3) This model can be solved for one specific plant design and one specific scenario to derive the optimal plant schedule for these input data. The OBPP model is the basis of the SBPP model in which operational plant schedules are optimized for several plant designs and several price scenarios. (Section 4.4) Thus, the scenario optimal plant design can be determined. For every scenario i the scenario-optimal investment alternative $j(i)$, which is called a "strategy", and its optimal net present value NPV^*_{ji} are determined. For all strategies, i.e. for all scenario-optimal investment alternatives $j(i)$, the net present value NPV_{jk} of investment alternative $j(i)$ and all other scenarios $k \neq i$ is determined. (By solving the SBPP model with fixed investments $j(i)$ for the input data of scenario k.)

All of the solutions are compared in a solution matrix. (Section 5.4, Table 12) This solution matrix is characterized by one optimal solution per scenario. (i.e. NPV^*_{ji}) Note that different scenarios may point to the same optimal strategy (e.g. scenarios 1 and k of Figure 10 to the same optimal strategy $j(1) = j(k)$), thus resulting in $J' \leq I$ scenario-optimal strategies. In addition, the net present values for non-optimal scenario-strategy combinations are included. (i.e. NPV_{jk}) A robust solution concerning all scenarios should be determined, because some scenario-optimal decisions, for example concerning a high investment, can ruin the biogas plant operator in the event of a worst case scenario. This risk should be avoided. The robust solution is extracted by using the rules of decision theory. As high solution robustness for a risk-averse decision maker should be reached, the decision rules of Hurwicz with a small lambda and the Maximin rule are used. (Section 5.4) (Scholl, 2001; Hurwicz, 1951) Both decision rules are characterized by a great solution robustness. Thus, the determined decisions can be considered as robust. (Scholl, 2001)

4.2 Assumptions concerning OBPP and SBPP

As an Operations Research model is only an abstraction of a real world decision, several assumptions concerning the modeling framework have to be made. The objective of the SBPP model is to determine the optimal investment strategy concerning biogas storages and CHP plant extensions. As declared in Section 2.2, this seams the easiest way to make the plant more flexible. A planning horizon of T periods which is subdivided into $t = 1..., T$ non-overlapping sub-periods is assumed. Only one specific biogas plant, located in Germany, is investigated.

The problem setting is as follows: a conventional biogas plant, which has a steady gas generation in the digester is assumed. As there are no gas storage capacities available within the plant, the power generation is also steady and totally inflexible. The generated power is sold by taking the EEG feed-in tariff. Moreover, as it is required by the German law, the waste heat is used for other processes.

Furthermore, there are several assumptions concerning the chosen marketing channel. As mentioned, there are several possibilities for biogas plant operators in Germany to participate in the energy market. It is assumed that the investigated biogas plant is an already existing plant in Germany, which is less than 20 years in operation. Only direct marketing at the day-ahead market is considered in the optimization approach. Hence, as explained in Section 2.3, it is possible to sell generated power in blocks of one hour the next day. As only one specific biogas plant is considered, an unlimited demand, or in other words a price-taker model, is assumed. The reason is that the energy supply of one biogas plant is very small compared to the total energy demand. Moreover, for the same reason, the amount of produced energy in the considered biogas plant has no impact on the spot market prices. Additionally, the market premium and the flexibility premium are, as offered by the German government in the current EEG and already mentioned in Sections 2.3 and 2.4, considered. For discounting an interest rate of i per period is assumed with $0 < i < 1$.

Concerning the biogas plant, there are several other assumptions. Firstly, it is assumed that the digester produces a steady amount of gas during the hours of a year. After the investment, this gas could be burned directly in the CHP plants, could be stored in a newly installed gas storage or be burned in a torch without generating revenues. As declared in Section 2.2, these are the characteristics of biogas plants with a type II configuration. Secondly, at the beginning of the planning horizon no storage capacities are available, thus the gas storage level is zero. Restrictions concerning the amount and point in time of starts of the CHP plants are not considered.

Within the OBPP model, an already flexibilized type II biogas plant with storage capacities is assumed. Thus, three types of gas flows are resulting, which can exist simultaneously and are depicted in Figure 11. One gas flow from the digester into the gas storage ($X_s^{DS} \geq 0$), one from the digester to the torch ($X_s^{DT} \geq 0$) and one from the storage to the CHP plant(s) ($X_s^{SC} \geq 0$). Additionally, the filling level of the gas storage is included ($X_s^{S} \geq 0$).

Finally, there are some assumptions concerning the characteristic of the investment, which are only considered in the SBPP model. For increasing the flexibility of the biogas plant several possible investment alternatives are distinguished. To increase the flexibility it is necessary to increase the electrical capacity by installing (an) additional CHP plant(s). Here, a finite number of discrete CHP plant capacities is considered. Furthermore, it is necessary to create a possibility to store biogas, which is produced in the digester but not directly burned within the CHP plants or in the torch. For this reason, the gas and power production can be decoupled. Similar to the CHP plant capacity, a finite number of discrete storage capacities is considered. It is assumed that with an increase in the storage size economies of scale concerning the supply costs can be achieved. To install and operate the new technologies it is further necessary to invest in other infrastructure components like the foundation for the storage, gas lines, or a transformer with larger capacity. It is assumed that these infrastructure investments are fixed for all combinations of investment alternatives, but are only made if a storage or an additional CHP plant is installed. Therefore, the compatible combination of a gas storage, a CHP plant extension and further infrastructure components is represented by a (combined overall) investment alternative j with $j = 1, ..., J$. The choice of investment alternatives is then represented by the binary decision variable B_j. For all investments, an expected operation time of DeT periods is assumed. If the planning horizon is shorter than this operation time ($DeT > T$), the terminal value of the total investment is calculated by reducing balance depreciation. The resulting plant design, the operational flow variables, which are the same as in the OBPP model, and the structural investment decision variables are shown in Figure 11.

4.3 Operational biogas plant optimization problem – OBPP

Within the explanations to Figure 10 was specified that an optimized operational biogas plant schedule is used to asses the investment strategy. The OBPP model, which is used to optimize this operational plant schedule, is developed in the upcoming Section. As a basic design for the optimization of an operational schedule, a flexibly schedulable plant is assumed. This means that in the plant additional flexible CHP plant capacity and a biogas storage are implemented. Only if the biogas plant is flexibly schedulable, a direct marketing of the produced energy at the power exchange can be beneficial. Within the optimization process, two characteristic tradeoffs have to be considered during the profit maximization. The first tradeoff is to produce electricity in a current period out of the available biogas or to store the biogas for later periods. This decision depends on the current spot market price and thus the current possible payments, the available capacity in the biogas storage and the expectation regarding future spot market prices and thus the forecasted possible payments. The second tradeoff is to produce electricity in a current period or not to produce, to save up flexible excess capacity. As the flexibility premium compensates the flexible excess capacity, which is the unutilized share of the total capacity, the biogas plant operators have an incentive not to maximize the utilization of the CHP plants. The functionality of the flexibility premium is explained in Sections 2.3 and 2.4. However again in brief, the flexibility premium rewards the flexibility potential of a biogas plant. Hence, if in a biogas plant no electricity is produced in several periods, the remaining capacity on average and thus its flexibility potential increases. Hence, the payments of the flexibility premium increase as well. This decision depends not only on the current spot market price but also on the flexibility premium, which is a governmental subsidy. Managing those two tradeoffs simultaneously is not straightforward.

The optimization of the future operational schedule of the plant gives an idea of possible future cash flows. This information can also be used to assess an investment. The problem setting of the biogas plant is as given in Figure 11, but the decision about the binary variables is assumed as having been made. This means that one investment strategy is already chosen. Accordingly, the biogas plant design is given as flexible type II. As it is shown in Table 5, two different time grids are necessary to model the operational planning problem. Microperiods $s = s, ..., S$, which are given in hours, and macroperiods $t = t, ..., T$, which represent years, are distinguished. This is necessary, because the sales and payments at the spot market occur hourly, but the payments of the flexibility premium depend on the yearly production and are paid once at the end of a year. All microperiods are given by the set Φ. Additionally, the set $\Phi_t \subset \Phi$ is used to determine, which microperiod is in which macroperiod and the set $\Phi_t^* \in \Phi$ denotes the last microperiod of each macroperiod t in the planning horizon.

In order to determine the optimal plant schedule, several data is used. The efficiency a of the installed CHP plant(s) is given as the produced amount of electricity (measured in kWh) per Nm^3 biogas. To fulfill the requirements of the flexibility premium it is important as well to define the previously realized output of the biogas plant Bem^{init} in kWh per macroperiod (kWh/y). Additionally, two different types of variable costs are distinguished. The electricity production costs c^E (EUR/kWh) and the biogas production costs c^G (EUR/Nm^3). The biogas production costs include typical variable costs for the substrate, the fermentation process and personnel. The electricity production costs consist of costs for the combustion process. As the planning problem is capacitated, it is necessary to distinguish capacities for the gas storage Cap^S (Nm^3), and the CHP plants. Here, the formerly installed CHP plant capacity Cap^C (kWh) and the additionally installed CHP plant capacity Cap^{Cadd} (kWh) are differentiated. The distinction between Cap^C and Cap^{Cadd} is not necessary within the OBPP model. However, as this model should be extended later on and this differentiation is necessary then, it is distinguished at this point as well. The steady biogas production rate of the digester is defined as dp (Nm^3/h). For the sold electricity market premiums m_s (EUR/kWh) and spot market prices p_s (EUR/kWh) can be achieved.

The objective of the OBPP model is to maximize the resulting profit. Therefore, the following decision variables have to be optimized. Besides the market premium and the spot market prices, the flexibility premium constitutes an important part of the possible revenues. The granted flexibility premium payments per period s within the planning horizon are represented by $pr_s \geq 0$. The biogas plant operator can decide if the flexibility premium is requested or not, because the possible revenues are linked with the requirements described in Section 2.4.1. The decision is represented by the binary decision variable $Y_t \in \{0, 1\}$, which is 1 if the flexibility premium in macroperiod t is requested and 0 otherwise. Hence, the planning horizon for the operational scheduling model has to be several years and cannot be shorter. This is a special property of the developed approach, because it considers an operational schedule on a more mid-term than the common short-term level.

In order to optimize the operational plant schedule it is necessary to optimize several operational variables. Here, the gas flow from the digester to the torch $X_s^{DT} \geq 0$, the gas flow from the digester to the gas storage $X_s^{DS} \geq 0$, the gas flow from the gas storage to the CHP plants $X_s^{SC} \geq 0$ and the gas storage level $X_s^S \geq 0$ are distinguished.

Table 5: Notation OBPP

Indices	
$s = 1, ..., S$	microperiods, hours (h) in the planning horizon
$t = 1, ..., T$	macroperiods, years (y) in the planning horizon
Sets	
Φ	set of all microperiods
$\Phi_t \subset \Phi$	set of all microperiods in macroperiod t
$\Phi_t^* \in \Phi$	last microperiod in macroperiod t
Parameters	
a	efficiency of the installed CHP plants / produced amount of electricity per Nm^3 biogas in kWh/Nm^3
Bem^{init}	previously realized output per macroperiod kWh/y
c^E	electricity production costs of a specific biogas plant (variable costs) EUR/kWh
c^G	biogas production costs of a specific biogas plant (variable costs) EUR/Nm^3
Cap^S	installed capacity of a gas storage in Nm^3
Cap^C	formerly installed CHP plant capacity (maximum amount of electricity produced in one hour) in kWh
Cap^{Cadd}	additionally installed CHP plant capacity (maximum amount of electricity produced in one hour) in kWh
dp	steady gas production rate of the digester in Nm^3/h
Max^P	sufficiently large number
m_s	market premium in microperiod s in EUR/kWh
p_s	spot market price forecast at the power exchange in the day-ahead market in microperiod s in EUR/kWh
Variables	
$pr_s \geq 0$	granted flexibility premium in microperiod s in EUR paid once in a year (EUR/y)
$X_s^{DT} \geq 0$	gas flow from digester to the torch in microperiod s in Nm^3
$X_s^{DS} \geq 0$	gas flow from digester to the gas storage in microperiod s in Nm^3
$X_s^{SC} \geq 0$	gas flow from the gas storage to the CHP plants in microperiod s in Nm^3
$X_s^S \geq 0$	gas storage level at the end of microperiod s in Nm^3
$Y_t \in \{0, 1\}$	decision variable, 1 if the flexibility premium in macroperiod t is requested, 0 otherwise

4.3.1 Objective function

The objective of the model is to maximize the total profit consisting out of several payments and payouts. Therefore, the objective function consists out of four parts, which are explained in detail later on. In the first part, the spot market payments (SMP_s) are considered. Within the second part, the variable electricity generation payouts ($VEGP_s$) are modeled. The third part represents the realized subsidy payments (RSP_s) based on the flexibility premium. As a last part, the torch payouts (TP_s) are modeled. As all of the four parts represent the payments and payouts per microperiod, they have to be summed up for all microperiods s.

$$Max \quad \sum_s \underbrace{(p_s + m_s) \cdot a \cdot X_s^{SC}}_{SMP_s} - \underbrace{(c^E \cdot a + c^G) \cdot X_s^{SC}}_{VEGP_s} + \underbrace{pr_s}_{RSP_s} - \underbrace{c^G \cdot X_s^{DT}}_{TP_s} \tag{1}$$

The first part of the objective function is represented by the spot market payments (SMP_s). Here, the sum of the spot market price p_s in a specific microperiod s and the market premium m_s is in any microperiod s multiplied with the amount of produced electricity. The amount of produced electricity is given by the gas flow in microperiod s from the biogas storage to the CHP plants X_s^{SC} multiplied with the CHP plant's efficiency. The functionality of the market premium, which is a governmental subsidy, is stated in Subsection 2.4.1.

The second part of the objective function is represented by the variable electricity generation payouts ($VEGP_s$). Here, similar to the spot market payments, the variable electricity production costs per kWh of the specific biogas plant are multiplied with the amount of produced electricity in each microperiod s. The variable electricity production costs per kWh consist of the costs for the used biogas c^G multiplied with the production efficiency of the CHP plants and the costs for the combustion process of biogas into electricity c^E.

The third part of the objective function represents the realized subsidy payments (RSP_s) regarding the flexibility premium. This payment is executed only in the last microperiod s of a specific macroperiod or year t if the biogas operator requests it. The calculation of the granted flexibility premium payment in a microperiod s is explained in detail in Constraints (7a) to (7d).

The fourth part of the objective function represents the costs for using the torch. If it is not beneficial to produce electricity and the biogas storage is completely filled, there is the possibility to burn biogas using the torch. No payments are generated when the biogas is burned through the torch. However, the generation of the biogas causes production costs (c^G). Hence, these costs have to be considered as payouts within the objective function.

4.3.2 Constraints

Plant characteristic

$$dp = X_s^{DS} + X_s^{DT} \qquad \forall s \quad (2)$$

One of the assumptions of the OBPP model is that the digester produces a steady amount of gas during the microperiods because a type II biogas plant is considered. Thus, the biogas production rate cannot be influenced or stopped. This assumption is an abstraction of the real world to avoid the complex modeling of non-linear biogas production rates before and after a stop of the digestion processes. This assumption is modeled in Constraint (2). At this point, the gas flow from the digester into the gas storage (X_s^{DS}) plus the gas flow from the digester to the torch (X_s^{DT}) have to equal the gas production (dp) in each microperiod. As all of the produced biogas is either burned in the torch or filled in the storage and further combusted in the CHP plant(s), Constraint (2) together with $VEGP_s$ and TP_s show that for every Nm^3 of produced biogas at least the biogas production costs c^G have to be paid. Hence, the biogas production costs are not relevant for the decision of the operational biogas plant schedule, because the digestion processes cannot be stopped due to the assumptions. However, this model should be extended later on for the biogas plant design investment decision; for this reason, these costs are considered in the OBPP model as well. In the extended model, those costs are necessary to decide whether the net present value, which will be the objective value in this model, is positive or negative. Nevertheless, they will not influence the operational schedule in the subsequent model.

Capacity restrictions

$$X_s^{SC} \cdot a \leq Cap^C + Cap^{Cadd} \qquad \forall s \quad (3)$$

Constraint (3) ensures that the amount of produced electricity per hour does not exceed the already available capacity plus the additional electrical capacity. The amount of produced electricity is calculated by multiplying the amount of gas flow from the storage to the CHP plants (X_s^{SC}) with the efficiency coefficient (a) of the installed CHP plants.

$$X_s^S \leq Cap^S \qquad \forall s \quad (4)$$

Constraint (4) ensures that the gas storage level (X_s^S) at the end of each microperiod does not exceed the gas storage capacity.

$$\sum_{s \in \Phi_t} a \cdot X_s^{SC} \leq Bem^{init} + (1 - Y_t) \cdot Max^P \qquad \forall t \quad (5)$$

As it is required by the current version of the EEG and already mentioned during the explanations regarding the flexibility premium, it is prohibited that the realized output of the biogas plant in each macroperiod t after an increase in electrical capacity is higher than the previously realized output, if a biogas plant operator requests the flexibility premium. That means, if the flexibility premium is requested, the produced amount of electricity in total in a macroperiod has to be lower than or equal to the realized output in the period before the investment was made. However, the increase in electrical capacity gives the biogas plant operators the opportunity to produce more electricity in beneficial periods. This restriction, modeled in Constraint (5), is used to ensure that the plant operators reserve flexible capacity of their additionally installed electrical capacity. Constraint (5) serves not as a restriction, if the flexibility premium is not requested ($Y_t = 0$). However, the amount of produced electricity is then restricted by the capacity Constraint (3).

$$\sum_{s \in \Phi_t} \frac{a \cdot X_s^{SC}}{|\Phi_t|} \geq \frac{1}{5} \cdot (Cap^C + Cap^{Cadd}) \cdot Y_t \qquad \forall t \quad (6)$$

In addition to the upper bound of the realized output of the biogas plant, there is a lower bound given by the EEG. In any year the biogas plant operator wants to request the flexibility premium, the realized output on average per microperiod s of the biogas plant has to be at least $\frac{1}{5}$ of the installed electrical capacity. Thus, the realized output per year t ($\sum_{s \in \Phi_t} a \cdot X_s^{SC}$) is divided by the assumed number of microperiods in a macroperiod ($|\Phi_t|$) to calculate the realized output on average per microperiod s in a macroperiod t. If the realized output was smaller, the flexibility premium would not be granted for the expired year.

$$pr_s \leq \begin{cases} \left(Cap^C + Cap^{Cadd} - \sum_{s \in \Phi_t} \frac{a \cdot X_s^{SC}}{|\Phi_t|} \cdot 1.1 \right) \cdot 130 & \forall s \in \Phi_t^* \quad (7a) \\ (Cap^C + Cap^{Cadd}) \cdot 0.5 \cdot 130 & \forall s \in \Phi_t^* \quad (7b) \\ Max^P \cdot Y_t & \forall s \in \Phi_t^* \quad (7c) \\ 0 & \forall s \notin \Phi_t^* \quad (7d) \end{cases}$$

The calculation of the granted flexibility premium payment in a microperiod s is explained in Constraints (7a) to (7d). The decision about requesting the flexibility premium or not is modeled using the binary variable Y_t. If the biogas plant operator decides not to request the flexibility premium, the binary variable is set to zero. Accordingly, Constraint (7c) would restrict the premium payment pr_s to zero as well. If the biogas plant operator requests the flexibility premium, the premium payment is, according to Constraint (7c), not restricted. Hence, Constraint (7a) would restrict the premium payment and the flexibility premium payment would be calculated as it is required by the current version of the EEG (EEG, 2017) and modeled in Constraint (7a). The last microperiod in a macroperiod t is given by set Φ_t^*. First, the flexible excess capacity per average microperiod s in a macroperiod t has to be calculated as in Constraint (6). Afterwards, this realized output on average is rated with a correction factor of 1.1 for biogas plants, which is defined by the German legislation, and subtracted from the sum of the installed capacity ($Cap^C + Cap^{Cadd}$). The resulting flexible excess capacity for an average microperiod is compensated with 130 $EUR/kWhy$. Aforementioned, the flexibility premium payment is only executed in the last microperiod of a macroperiod t. Thus, the calculations according to Constraints (7a) to (7c) are only made for those microperiods s which are the last microperiod in a macroperiod. In all other periods, the flexibility premium payments are set to zero. (see (7d)) The flexible excess capacity is restricted to a maximum of the half of the installed electrical capacity by the EEG. This restriction is modeled in Constraint (7b). To understand the function of the flexibility premium it is important to know that it is not allowed to use the additional installed capacity continuously. The realized output of the current year has to be lower or equal than the previously realized output per year as mentioned in Constraint (5). If the requirements are met, the flexibility premium is granted for a ten years horizon. The functionality is explained in detail in Subsection 2.4.1.

Mass balance

$$X_s^S = X_{s-1}^S + X_s^{DS} - X_s^{SC} \qquad \forall s \quad (8)$$

The storage process of produced but not yet burned biogas is modeled in Constraint (8). Here, as usual, the gas storage level (X_s^S) at the end of a microperiod s has to equal the gas storage level of the previous microperiod, plus the gas flow into the gas storage from the digester (X_s^{DS}), minus the gas flow from the gas storage to the CHP plants (X_s^{SC}) in the current microperiod s.

Within the model, material flows and storage levels can only take non-negative real values. Binary variables represent the decisions whether the flexibility premium is requested or not.

4.4 Strategic biogas plant optimization problem – SBPP

As declared, the main objective is to support the investment decision of adjusting the design of a conventional biogas plant into a flexible type II plant considering uncertain revenues. In order to model this decision the previously developed OBPP model for the optimization of an operational plant schedule, described in Section 4.3, has to be extended. Within the SBPP model, the plant design is no longer assumed as having been fixed. Instead, the design should be optimized. As the model to optimize the operational schedule of a biogas plant has been explained in detail in the previous section, only the new and adjusted parts of the model are described in the current one.

In order to model the extensions of the investment decision, further indices, parameters and variables are necessary. The index j is used to distinguish between several possible investment alternatives. Those alternatives consist of a biogas storage with a specific size and a specific CHP plant extension capacity. The known parameters Cap^S and Cap^{Cadd} are adjusted to Cap_j^S and Cap_j^{Cadd} because in the SBPP model they depend on the chosen investment alternative. The aim is to decide which plant design is beneficial. Therefore, the specific total investments are rated with I_j, which are quantity-independent fixed costs that are payed once. Further, if reducing balance depreciation is used to calculate the terminal value of the total investment at the end of the planning horizon, the depreciation rate per year dr_s with $s \in \Phi_t^*$ has to be defined. Moreover, as payments and payouts at different points in time have to be compared and thus discounted, it is necessary to define the discounting interest rate as i. To distinguish between the several investment alternatives the binary variable $B_j \in \{0,1\}$ is used. The variable is 1 if investment alternative and thus strategy j is chosen and 0 otherwise. The known variable Y_t is adjusted to $Y_{j,t} \in \{0,1\}$. Accordingly, the binary decision variable is 1 if the investment strategy j is chosen and the flexibility premium is requested in year t and 0 otherwise. $Y_{j,t}$ models whether the flexibility premium is requested under the condition of an already chosen investment strategy which is represented by B_j. Within the following Subsections 4.4.1 and 4.4.2 the extended model is described.

Table 6: Additional and adjusted notation SBPP

Indices	
$j = 1, ..., J$	discrete investment alternatives
Parameters	
Cap_j^S	installed capacity of a biogas storage in investment alternative j in Nm^3
Cap_j^{Cadd}	additionally installed CHP plant capacity in investment alternative j in kWh
dr_s	decreasing depreciation rate per year t in microperiod $s \in \Phi_t^*$
i	discounting interest rate per microperiod
I_j	total investment for investment alternative j in EUR
Variables	
$B_j \in \{0,1\}$	decision variable, 1 if investment alternative (strategy) j is chosen, 0 otherwise
$NPV \geq 0$	objective value
$Y_{j,t} \in \{0,1\}$	decision variable, 1 if the flexibility premium in macroperiod t is requested and investment alternative (strategy) j is chosen, 0 otherwise

4.4.1 Objective function

In contrast to the previously explained OBPP model, the objective value of the SBPP model is defined as a result of discounted payments and payouts. Thus, the objective value represents the NPV. The understanding of the NPV is similar to common definitions, which are among others given in Huebner (2007). The payments and payouts appear at different points in time. In order to make the investment strategies comparable, the resulting payments and payouts are discounted. Hence, the objective function of the current SBPP model consists out of five parts. The spot market payments (SMP_s), the variable electricity generation payouts ($VEGP_s$), realized subsidy payments (RSP_s) and torch payouts (TP_s) are modeled similar to the OBPP model. For this reason, they are not explained in detail again. The detailed explanations are given in Section 4.3. The only difference is that they have to be discounted using the interest rate i. Additionally, the total loss of value (LOV) is considered in the last part of the objective function.

$$Max \quad NPV =$$
$$\sum_j \sum_s \frac{(p_s + m_s) \cdot a \cdot X_s^{SC} - \ (c^E \cdot a + c^G) \cdot X_s^{SC} + \ pr_s - \ c^G \cdot X_s^{DT}}{(1+i)^s} - \underbrace{\frac{dr_s}{(1+i)^S} \cdot B_j \cdot I_j}_{LOV} \tag{9}$$

The only new part is representing the total LOV of the chosen investment. This loss can be calculated as the discounted sum of all yearly depreciations during the planning horizon. The payout of the initial investment depends on the chosen plant design, which is determined by the structural decision variable B_j. The yearly depreciation is calculated by reducing balance depreciation for the length of the planning horizon as it is given in Equation (9). Here, the yearly depreciation rates are multiplied with the initial investment, depending on the chosen investment strategy, and then discounted. These yearly discounted depreciations are summed up for all years of the planning horizon ($t = t, ..., T$ with $T < DeT$). In order to achieve this, the depreciations, which are defined for each microperiod, are summed up only for the last microperiods in a macroperiod. ($s \in \Phi_t^*$)

4.4.2 Constraints

Constraints (2) and (8) remain the same as in the OBPP model. All other constraints are adjusted or added in contrast to the OBPP model and thus are explained in detail.

Design configuration

$$\sum_j B_j = 1 \tag{10}$$

$$Y_{j,t} \leq B_j \qquad \forall j, t \tag{11}$$

In Constraints (10) and (11) the plant design decision is restricted. It is only permitted to choose one investment strategy or in other words one combination of an additional CHP plant version and one storage version each. Additionally, the two binary variables B_j and and $Y_{j,t}$ have to be connected, because it is only possible to request the flexibility premium subject to an investment strategy j, if the strategy is already chosen.

Capacity restrictions

$$X_s^{SC} \cdot a \leq Cap^C + \sum_j B_j \cdot Cap_j^{Cadd} \qquad \forall s \tag{12}$$

Constraint (12) ensures that the amount of produced electricity per hour does not exceed the already available capacity plus the additional electrical capacity. The additional electrical capacity depends on the chosen investment strategy.

$$X_s^S \leq \sum_j B_j \cdot Cap_j^S \qquad \forall s \quad (13)$$

Constraint (13) ensures that the gas storage level (X_s^S) in each microperiod does not exceed the chosen gas storage capacity. The gas storage capacity depends on the chosen investment strategy.

$$\sum_{s\in\Phi_t} a \cdot X_s^{SC} \leq Bem^{init} + (1 - \sum_j Y_{j,t}) \cdot Max^P \qquad \forall t \quad (14)$$

Constraint (14) is similar to Constraint (5) of the previously explained OBPP model and restricts the realized output to an upper bound. As the decision variable $Y_{j,t}$ now represents the decisions regarding requesting the flexibility premium and the choice of investment strategies, the variables have to be summed up over all investment alternatives j. The remaining parts of the constraint are equal to (5).

$$\sum_{s\in\Phi_t} \frac{a \cdot X_s^{SC}}{|\Phi_t|} \geq \frac{1}{5} \cdot \sum_j \left(Cap^C + Cap_j^{Cadd}\right) \cdot Y_{j,t} \qquad \forall t \quad (15)$$

As mentioned during the explanation of the OBPP model, the realized output of the biogas plant has to be at least $\frac{1}{5}$ of the installed electrical capacity in any year, the biogas plant operator wants to request the flexibility premium. Otherwise, the flexibility premium is not granted for the expired year. The totally installed electrical capacity depends on the chosen investment strategy and is, as well as the decision about requesting the flexibility premium, represented by the binary decision variable $Y_{j,t}$.

$$pr_s \leq \begin{cases} \left(Cap^C + \sum_j B_j \cdot Cap_j^{Cadd} - \sum_{s\in\Phi_t} \frac{a \cdot X_s^{SC}}{|\Phi_t|} \cdot 1.1\right) \cdot 130 & \forall s \in \Phi_t^* \quad (16a) \\ \left(Cap^C + \sum_j B_j \cdot Cap_j^{Cadd}\right) \cdot 0.5 \cdot 130 & \forall s \in \Phi_t^* \quad (16b) \\ \sum_j Max^P \cdot Y_{j,t} & \forall s \in \Phi_t^* \quad (16c) \\ 0 & \forall s \notin \Phi_t^* \quad (16d) \end{cases}$$

The calculation of the yearly flexibility premium payment is similar to Constraints (7a) to (7d) of the previously explained OBPP model. The difference is that in the SBPP model the flexible excess capacity depends on the chosen investment strategy. Hence, the binary decision variable B_j is used to determine which additional electrical capacity is chosen and thereby determines the total excess capacity. Additionally, the definition of the variable $pr_s \geq 0$ has to be adjusted as it depends on the electrical excess capacity. As the possible investment alternatives are all considered implicitly within the calculation of pr_s, no index j is necessary. In Constraint (16c) the binary decision variables $Y_{j,t}$ have to be summed up for all investment alternatives j, because the choices regarding requesting the flexibility premium and investment strategies are considered in $Y_{j,t}$.

Within the model, material flows and storage levels can only take non-negative real values. Binary variables represent the decisions whether an investment strategy j is chosen or not and whether the flexibility premium is requested or not.

5 Application of the deterministic SBPP model in an uncertain environment

In Section 5 the deterministic SBPP model is applied in an uncertain environment as it has been explained in Figure 10. Therefore, the relevant uncertainties are modeled in a first step in Section 5.1. Afterwards, the experimental design is defined in Section 5.2. The effects of uncertainties are analyzed in Section 5.3 before a robust investment decision is made in Section 5.4.

5.1 Modeling uncertainty

As mentioned in Section 2.4, the total revenues a biogas plant operator can generate using direct marketing consist out of several parts. As a first part revenues are generated at the chosen spot market, depending on the spot market prices. It is possible to sell the produced energy on several spot markets simultaneously. Thus, the total spot market revenues consist out of the spot market prices of the chosen markets. The second part are revenues out of subsidies. As explained in Section 2.4.1, it is possible to request two subsidies, if the produced energy is sold through direct marketing – the market premium and the flexibility premium.

For all of those parts of the total revenues, it has to be separately forecasted whether there is relevant uncertainty in the revenues or not, in order to reveal the effect of the uncertainty in a second stage. The characterization of the uncertainties is explained in the upcoming subsections.

5.1.1 Spot market price forecast

The fluctuations and seasonalities within the spot market prices are mentioned in Section 2.4.2. As explained, the spot market prices can be characterized using three different seasonalities, intrayear, intraweek and intraday, and a currently decreasing trend. Using the knowledge of those characteristics, it is assumed that the time series of spot market prices at the day-ahead market for the upcoming five years can be approximated using the following model:

$$p_s = a + b \cdot s + c_s^Y + c_s^W + c_s^D + u_s \tag{17}$$

Within this model p_s is defined as the spot market price in a microperiod s. The model is built using time series decomposition. Hence, a is defined as a level component, b as a trend component and the three remaining parameters c_s^Y, c_s^W, c_s^D characterize the intrayear, intraweek and intraday seasonalities. u_s is defined as the white noise which cannot be forecasted. As one can see, all of the above mentioned characteristics of the spot market prices are covered within (17).

As usual in time series analysis, the component parameters of the forecasting model have to be forecasted. (Makridakis et al., 2010) Hence, the forecast can be wrong because of unexpected future changes in the environment of the energy market. The quality of the forecast, or in other words the forecast error, is represented by the the difference between the real value p_s of a microperiod s and its forecast $\hat{p}_s$ where $\hat{p}_s := \hat{a} + \hat{b} \cdot s + \hat{c}_s^Y + \hat{c}_s^W + \hat{c}_s^D$ and where $\hat{a}, \hat{b}, \hat{c}_s^Y, \hat{c}_s^W$ and $\hat{c}_s^D$ denote the forecasts of the component parameters. In general, it is unrealistic to assume that a forecast without a forecast error can be reached. For this reason, it is important to analyze the effect of a potential forecast error on the decision and the resulting outcome.

As can be seen, all of the component parameter values are uncertain themselves, because every characteristic of the spot market prices can be subject to change separately. For example, it could be possible that the trend component is changing. Although, the current trend is decreasing, it is not completely unlikely that the prices will increase in the future. Keles et al. (2011) distinguish several scenarios for the future energy price development. What all the mentioned scenarios have in common is that the energy prices will increase, thus this could be a future development. As the intrayear and intraweek seasonalities are mainly based on the characteristic of the energy demand, it can be assumed that they will remain similar in the future. This assumption is based on the conclusions that for instance the intrayear seasonality is based on the climatic environment in Germany. The climate will probably not change significantly within the planning horizon of the current model. However, for single years there could be a significant change within the intrayear price seasonality. For example because of extreme

Table 7: Biogas plant specific input data

a	1.52858 kWh/Nm^3				
Bem^{init}	75 % of Cap^C				
c^E	0.02 EUR/kWh				
c^G	0.12 EUR/Nm^3 (=0.08 EUR/kWh)				
Cap^C	1500 kWh				
dp	700 Nm^3/h				
i	2.76 % p.a.				
dr_s	0.30	0.21	0.15	0.10	0.07
s	1	2	3	4	5

weather situations like unusual hot and dry periods in a year. Moreover, the intraweek seasonality is mainly based on the difference in demand between weekdays and weekends because of the reduced industrial production during the weekend. It is unlikely that this behavior will change in the nearer future as well. Moreover, the average level of the spot market prices (a) can be subject to changes as well. For instance, it is possible that the level will be lower in the future because of the ongoing decreasing trend.

5.1.2 Flexibility premium

Apart from the spot market revenues, important parts of the generated total revenues using direct marketing are subsidies. Aforementioned in Section 2.4.1, it is possible to request the market and flexibility premium.

The market premium is not characterized by significant uncertainty. As explained previously, biogas plants are regulated using the EEG version, which was the current version when a biogas plant was put into operation. Hence, the legal framework cannot be changed for existing plants and the operators have the guarantee of a 20-year entitlement on this subsidy. Nevertheless, in a new amendment of the EEG the market premium could be canceled, which affect operators who want to build a new biogas plant. Because of the assumption of only analyzing already built and running plants in this optimization approach, there is no considerable uncertainty regarding the market premium.

Similar to the market premium, the flexibility premium is certain if it is granted once, but only for a 10 years horizon. However, as mentioned in Subsection 2.4.1, there are plenty of requirements to be met to successfully request the flexibility premium. If at least one requirement is not fulfilled, the flexibility premium would not be granted. Hence, the payments of the flexibility premium are subject to uncertainty.

5.2 Experimental design

In order to verify the performance of the developed SBPP model in an uncertain environment a numerical experiment for a fictional but close to reality biogas plant is generated. This biogas plant is less than 20 years in operation. The specific biogas plant characteristics are depicted in Table 7. A rather medium biogas plant with a steady gas production rate of 700 Nm^3/h and a currently installed CHP plant capacity of 1500 kWh is assumed. Furthermore, a rated output of 75 % of the currently installed capacity is presumed. One Nm^3 biogas can be used to produce 1.52858 kWh of electricity. Moreover, the biogas and electricity production costs of the analyzed biogas plant are ascertained with $c^G = 0.08$ EUR/kWh and $c^E = 0.02$ EUR/kWh. For discounting an interest rate of 2.76 % is assumed. (Deutsche Bundesbank, 2017) In order to calculate the terminal value at the end of the planning horizon, reducing balance depreciation with a yearly depreciation rate dr_s with $s \in \Phi_t^*$ is used. As given in Table 7 the yearly depreciation rates start with 30 % in the first year and end up with 7 % in the fifth. This is justified by the reason that machines like CHP plants have a higher loss of value in the first years of operation.

It is explained in Section 4 that several discrete investment alternatives are distinguished within the developed optimization model. For the current calculations, 12 different storage versions and 12 different CHP plant versions are assumed. The specific capacities and the related amount of investments are shown in Table 8. The amount of investments for additional CHP plants is based on the published information by the FNR. (FNR, Fachagentur Nachwachsende Rohstoffe e. V., 2017). The amount of investments for the biogas storages is based on prices from manufacturers. For both investment decisions is assumed that there is an alternative 1, which means that the plant design will not be changed. Furthermore, economies of scale are considered regarding the amount of the investments. In addition to the described investments, a fixed infrastructure investment of 220,000 EUR is considered within the model, if one of the storages and/or CHP plants is installed. As explained, an investment alternative is characterized by a combination of one CHP plant capacity extension and one biogas storage. Accordingly, using 12 different versions each, 144 investment alternatives would be possible. However, since there is additionally assumed that the size of the biogas storage has to be large enough compared to the CHP plant capacity to keep the plant at least two hours running, only 128 possible investment alternatives are remaining. The planning horizon (T) is 5 years. The investments depreciation time (DeT) is 10 years.

The parameters of the previously developed forecasting model (Section 5.1.1) are forecasted from historical data of the day-ahead market prices during the years 2011 to 2014. The character of those prices is explained in Section 2.4. In that section, the prices from 2011 to 2015 are analyzed. In order to forecast and test the necessary parameters using time series decomposition, the available data of five years has to be divided into a learning and a test set. Thus, the years 2011 to 2014 are used as a learning set to find estimators for the parameters. Afterwards, the performance of the estimators in the forecasting function is tested using data from 2015 by calculating the mean squared error (MSE). (Hüttner, 1986) It is possible to model all previously explained characteristics of the spot market prices this way. Nevertheless, a forecasting error appears. The distribution of the resulting forecasting errors is characterized by a normal distribution with an expected value $\mu = 0$ and standard deviation $\sigma = 10.409$. As the expected value of the resulting forecast error is zero, the standard definition of the coefficient of variation $\frac{\sigma}{\mu}$ cannot be applied to express the forecast quality. Thus, we set the forecast error of the previously mentioned price forecast in relation to the mean spot market price instead and denite this key performance indicator as cov. It serves as a percentage measure of forecast quality and of price uncertainty. By doing so, a cov = 0.3291 results. This low value of cov shows a low variation of the forecast errors and emphasizes the good quality of the forecast.

By varying cov, new time series forecasts - for example with a worse forecasting quality expressed by a higher cov - can be simulated. The time series, based on the previously explained optimized estimators, serves, in the remainder, as the *base scenario* to compare several scenario depending outcomes. That means that this time series shows the most probable development of the spot market prices ("probable case" in Figure 10), if there are no market influencing changes in the future. The influence of these changes is included using further scenarios (e.g., best and worst cases in Figure 10) and analyzed in the next section.

5.3 Effects of uncertainties

In order to analyze the effects of the examined uncertainties, several further scenarios are generated. In Section 5.3.1 a varying quality of the spot market price forecasts and varying characteristics of the forecast model's different parameters are simulated. Throughout this section, the "probable case EEG" (see Figure 10) is assumed to hold. At first, the uncertainty regarding the forecast error is modeled using scenarios. Hence, three scenarios are compared to measure the influence of the forecast error. As a first scenario, the original prices of the day-ahead market from 2011 to 2015 are used as input data. This scenario represents the case that a perfect forecast had been made. (cov = 0; "best case" scenario with respect to the forecast quality of spot market prices, see Figure 10) The second scenario represents the base scenario as constructed and explained in Section 5.2. (cov = 0.3291; most probable forecast quality of prices) As a third scenario, the estimators in the forecasting function, which is used to generate the base scenario, are adjusted in a way to increase the forecast error by 90 %. Thus, a very poor forecast is generated. (cov = 0.6251; worst case forecast quality of prices)

Next in Section 5.3.1, the already mentioned uncertainties regarding the specific component parameter values are investigated in some more detail. Therefore, at first, the level component parameter a is varied. Again, the idea is to simulate extreme scenarios like the best and worst case. Hence, the forecast $\hat{a}$ of the price level is in- and decreased by 90 % in order to derive a best and worst scenario. Similar scenarios are derived for the trend component b. Here, a 90 % in- and decrease of the forecast $\hat{b}$ of the trend component is distinguished. As the trend parameter represents a decreasing process, an increase of the trend component represents faster decreasing prices in the planning horizon. Additionally, a switched trend is considered. Therefore, the trend component is decreased through the first years of the planning

Table 8: Investment alternatives

j	Cap_j^S	C_j^{Cadd}	I_j	j	Cap_j^S	C_j^{Cadd}	I_j	j	Cap_j^S	C_j^{Cadd}	I_j
1	0	0	0	44	40	1.5	1507.8	87	40	3.5	2247.7
2	5	0	295	45	45	1.5	1517.8	88	45	3.5	2257.7
3	10	0	359	46	5	2	1530.6	89	10	4	2284.4
4	12	0	370	47	10	2	1594.6	90	12	4	2295.4
5	15	0	390	48	12	2	1605.6	91	15	4	2315.4
6	18	0	410	49	15	2	1625.6	92	18	4	2335.4
7	20	0	420	50	18	2	1645.6	93	20	4	2345.4
8	25	0	440	51	20	2	1655.6	94	25	4	2365.4
9	30	0	455	52	25	2	1675.6	95	30	4	2380.4
10	35	0	470	53	30	2	1690.6	96	35	4	2395.4
11	40	0	480	54	35	2	1705.6	97	40	4	2405.4
12	45	0	490	55	40	2	1715.6	98	45	4	2415.4
13	5	0.5	803.8	56	45	2	1725.6	99	10	4.5	2435.2
14	10	0.5	867.8	57	5	2.5	1720.3	100	12	4.5	2446.2
15	12	0.5	878.8	58	10	2.5	1784.3	101	15	4.5	2466.2
16	15	0.5	898.8	59	12	2.5	1795.3	102	18	4.5	2486.2
17	18	0.5	918.8	60	15	2.5	1815.3	103	20	4.5	2496.2
18	20	0.5	928.8	61	18	2.5	1835.3	104	25	4.5	2516.2
19	25	0.5	948.8	62	20	2.5	1845.3	105	30	4.5	2531.2
20	30	0.5	963.8	63	25	2.5	1865.3	106	35	4.5	2546.2
21	35	0.5	978.8	64	30	2.5	1880.3	107	40	4.5	2556.2
22	40	0.5	988.8	65	35	2.5	1895.3	108	45	4.5	2566.2
23	45	0.5	998.8	66	40	2.5	1905.3	109	10	5	2580
24	5	1	1087.9	67	45	2.5	1915.3	110	12	5	2591
25	10	1	1151.9	68	5	3	1896.7	111	15	5	2611
26	12	1	1162.9	69	10	3	1960.7	112	18	5	2631
27	15	1	1182.9	70	12	3	1971.7	113	20	5	2641
28	18	1	1202.9	71	15	3	1991.7	114	25	5	2661
29	20	1	1212.9	72	18	3	2011.7	115	30	5	2676
30	25	1	1232.9	73	20	3	2021.7	116	35	5	2691
31	30	1	1247.9	74	25	3	2041.7	117	40	5	2701
32	35	1	1262.9	75	30	3	2056.7	118	45	5	2711
33	40	1	1272.9	76	35	3	2071.7	119	10	5.5	2719.7
34	45	1	1282.9	77	40	3	2081.7	120	12	5.5	2730.7
35	5	1.5	1322.8	78	45	3	2091.7	121	15	5.5	2750.7
36	10	1.5	1386.8	79	10	3.5	2126.7	122	18	5.5	2770.7
37	12	1.5	1397.8	80	12	3.5	2137.7	123	20	5.5	2780.7
38	15	1.5	1417.8	81	15	3.5	2157.7	124	25	5.5	2800.7
39	18	1.5	1437.8	82	18	3.5	2177.7	125	30	5.5	2815.7
40	20	1.5	1447.8	83	20	3.5	2187.7	126	35	5.5	2830.7
41	25	1.5	1467.8	84	25	3.5	2207.7	127	40	5.5	2840.7
42	30	1.5	1482.8	85	30	3.5	2222.7	128	45	5.5	2850.7
43	35	1.5	1497.8	86	35	3.5	2237.7				

Cap_j^S in 1000 Nm^3; Cap_j^{Cadd} in 1000 kWh; I_j in 1000 EUR

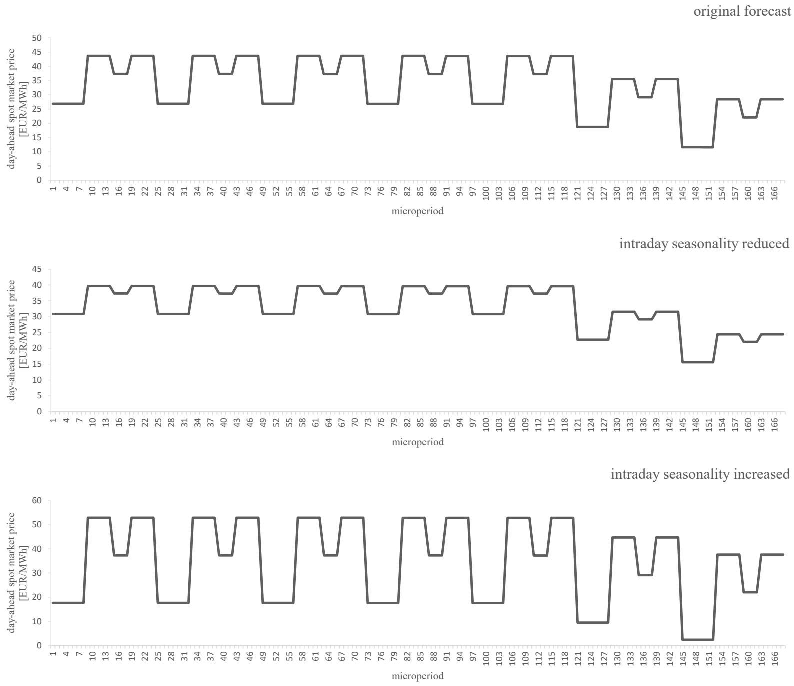

Figure 12: Price scenarios with different intraday seasonalities

horizon and afterwards reversed into an increasing trend. Moreover, the uncertainty in each of the seasonality components is distinguished by a 90 % in- and decrease of the coefficients of variation of the seasonal parameters. The variation of the intraday seasonal parameter is exemplarily depicted in Figure 12. Here, the price curve within an exemplary week (from Monday to Sunday) is simulated for the original forecast and for the reduced resp. increased intraday seasonality. This way of generating scenarios is similar to the idea of Wichmann et al. (2018).

In Section 5.3.2, the influence of the uncertainty regarding the flexibility premium is analyzed. Here, only two scenarios are compared. Firstly, the best case (=base) scenario with granted flexibility premium is considered. Secondly, the same price data is used, but it is assumed that the flexibility premium is not granted. (worst case) Using all these developed scenarios, the effects of the explained uncertainties can be analyzed.

In both subsections, furthermore, the influence of deriving a wrong decision is analyzed. Therefore, at first, the optimal decisions for each scenario have to be determined. (see Section 4.1 and Figure 10) Afterwards, the influence of choosing a wrong investment strategy can be measured. Therefore, the scenario optimal plant configurations are fixed and, combined with the other scenarios, the resulting objective values are calculated. The difference between the scenario optimal solution and the results of the non-optimal scenario plant design combinations demonstrates the influence of a wrong decision.

5.3.1 Spot market price forecast

A numerical study is implemented in Python (2.7) to evaluate the optimization approach. The library Pandas is applied for data analysis. The solver Gurobi (7.5.1) is used together with the Pyomo (5.2) modeling tool interface. Experiments are run on a personal computer operated by Microsoft Windows 10 Professional, using an Intel CPU with 2.49 GHz and 8GB RAM.

First, the effect of the quality of the spot market price forecast is analyzed. As presented in Table 9 the base scenario builds a very accurate forecast because the objective value of the best case scenario with original spot market prices is almost similar to the base scenario. There is only a difference of 0.59 % between the NPV in the base scenario and the scenario with the original prices. If the forecasting error is increased by 90 % there is a difference in the objective values of almost 15 %. Accordingly, it is important to generate an accurate forecast. Therefore, the component parts of the forecasting model should be separately analyzed.

The effects of the uncertainty within the specific components are depicted in Table 9 as well. It can be observed that a variation of the level component's forecast has no influence on the objective value. This is not surprising, because if the level of the spot market prices is higher or lower, the market premium, defined as the difference between the monthly average of the spot market prices and the EEG feed-in tariff, will be adversely lower or higher. Thus, the generated revenues at the spot market consisting out of spot market price and market premium will remain the same. The variation of the trend component $\hat{b}$ shows a rather small percentage effect on the objective value. However, an increase of 0.57 % (switched trend, see Section 5.3) of the NPV corresponds to additional 13,000 EUR for the biogas plant operator, which are often small farmers. Hence, even a small change can be relevant to them. The two scenarios regarding the intraday seasonality variation are leading to reverse effects. If the intraday seasonality is decreased, the objective value is decreased by more than 5 %. In contrast, if the intraday seasonality is increased, the objective value is increased by almost 8 %. Nevertheless, a variation of the intraday seasonality leads to a significant effect on the NPV of the investigated investment decision. The variation of the intraweek seasonality leads to a smaller effect than the intraday seasonality variation. However, the influence is still measurable, but a change within the intraweek seasonality is rather unrealistic as mentioned in Section 5.1. This is valid as well for the probability of a change in the intrayear seasonality. Even though, a reduction of the intrayear seasonality leads to a significant loss of NPV. An increase does not lead to a significant change because the potential biogas storages are too small to influence the long-term electricity production.

Table 9: Effect of forecast error, level, trend and seasonal components on the objective value

forecast error		level		trend		
red.	incr.	red.	incr.	red.	incr.	switch
-0.59 %	-14.66 %	0.00 %	0.00 %	0.23 %	-0.06 %	0.57 %

intraday		intraweek		intrayear	
red.	incr.	red.	incr.	red.	incr.
-5.56 %	7.83 %	-1.02 %	2.00 %	-5.56 %	0.02 %

variation in % compared to base scenario with NPV = 2,362,156 EUR

The effects of deriving a wrong decision are depicted in Table 10, based on a variation of the forecast error. Here, the scenario-optimal investment strategies j are calculated for each scenario. (see Section 4.1 and Figure 10) Thus, three scenario-optimal investment strategies are derived (2, 120, 128). For all of the three scenarios and all of the three investment strategies, the objective value is calculated and the percentage difference to the optimal solution NPV* is measured. It can be concluded that taking the wrong decision, based on an inaccurate price forecast, can lead to a significant loss of NPV. Especially, if the scenario-optimal decision and the made decision are extremely different like investment alternatives 2 and 120. To conclude, it is important to model all significant sources of uncertainty in the spot market prices within scenarios to find a robust solution, because an inaccurate forecast can lead to a significant loss of revenues for the biogas plant operator. The significant influences are the trend, the three seasonalities and the quality of the forecast in general.

Table 10: Effects of wrong decisions - forecast error

		forecast error	
j	base scenario	red.	inc.
120	-	-2.29 %	-7.11 %
128	-1.56 %	-	-7.17 %
2	-5.69 %	-1.59 %	-

variation in % compared to the scen. opt. alt.

5.3.2 Flexibility premium

Apart from the uncertain influences based on the spot market prices, the effect of the flexibility premium on the objective value is investigated. Therefore, the resulting NPV is compared using the best and worst case scenarios - granted and not granted flexibility premium. Compared to the optimal NPV* of the optimal investment strategy j = 120 of the base scenario, assuming to get the flexibility premium, a denial of this grant would lead to a tremendous loss of 88.72 %. Hence, the uncertainty within the flexibility premium determines the major influence on the investment decision compared to the other uncertainty sources.

Similar to the last subsection, effects of deriving a wrong decision are depicted in Table 11, based on granting or not granting of the flexibility premium. Therefore, the optimal decisions are derived for all of the previously mentioned price scenarios concerning the forecast error, level, trend, intraday, intraweek and intrayear seasonality combined with the best and worst case of the flexibility premium. Using these I = 26 scenarios, the following J' = 6 (see Figure 10) scenario optimal investment strategies can be derived: 2, 119, 120, 121, 126, 128. The values in Table 11 are generated using the base scenario for the spot market prices and the two scenarios of a granted or not granted flexibility premium. They show the variation in % of the objective value of a given investment strategy within the base scenario and an EEG-scenario, to the optimal objective value in this price-EEG-scenario combination. The base scenario optimal strategy with a granted flexibility premium is j = 120, resp. j = 2 if the flexibility premium is not granted. The results disclose that the investment decision depends strongly on the (un-)approval of the flexibility premium. If the flexibility premium is granted, typically an investment strategy with a large CHP plant extension and a large biogas storage is chosen. If not, only a small biogas storage should be built and no additionally CHP plant capacity should be installed. (investment strategy 2) Significant losses can be observed if the flexibility premium is granted and a non-optimal decision is derived. If the flexibility premium is not granted, the losses resulting out of non-optimal decisions are tremendous. For this reason, this analysis shows as well that the uncertainty within the flexibility premium determines the major influence on the investment decision.

Table 11: Effects of wrong decisions - flexibility premium

		deviation of NPV	
		granted flex. prem.	not granted flex. prem
j	2	-5.69 %	-
	119	-0.24 %	-85.34 %
	120	-	-85.02 %
	121	-0.01 %	-85.04 %
	126	-0.99 %	-86.34 %
	128	-1.56 %	-87.09 %

NPV*(base scen.; no grant) = NPV*(j = 2) = 1,778,597 EUR
NPV*(base scen.; grant) = NPV*(j = 120) = 2,362,156 EUR

5.4 Robust investment decision under uncertainty

After analyzing the sources of uncertainty and their effect on the optimal investment decision the significant ones are used to derive a robust decision under uncertainty. As explained previously, the accuracy of the forecast as a whole, the trend and seasonal components and the uncertainty of the flexibility premium are identified as significant.

In order to reach the goal of giving decision support for the mentioned investment problem, the developed multi-stage approach, as depicted in Figure 10, is used to derive solutions. The first step, finding and building of sufficient price scenarios, is already finished. Thus, scenario optimal solutions can be generated using the identified significant scenarios and the developed SBPP model. Aforementioned, the significant sources of uncertainties lead to 11 scenarios, because the forecast accuracy is considered implicitly by varying the component parameters concerning trend and seasonality. Using those scenarios, the same six scenario optimal investment strategies as in the last subsection can be derived. For instance, the investment alternative 120 means that a gas storage with capacity 12,000 Nm^3 and additional electrical excess capacity with 5,500 kWh is installed. As the aim is to derive a robust solution concerning all scenarios, the solutions of all scenarios have to be compared. Hence, the determined solutions for the scenario-optimal investment strategies are fixed and the model is solved again for all scenarios and all six gathered plant designs. The results of these calculations are depicted in a solution matrix in Table 12.

Table 12: Scenario optimal results and evaluation using decision theory

		base scenario			trend		intraday		intraweek		intrayear	
		gran. flex. pr.	not gran. flex. pr.	red.	inc.	switch	red.	inc.	red.	inc.	red.	inc.
j	2	30.11	3.88	30.34	29.93	30.89	27.11	30.11	29.35	31.44	30.10	30.13
	119	37.63	-84.78	37.98	37.57	38.42	30.05	37.63	36.59	39.87	37.63	37.65
	120	37.96	-84.44	38.28	37.87	38.75	30.29	37.96	36.56	40.72	37.96	37.98
	121	37.94	-84.46	38.23	37.83	38.73	30.18	37.94	36.00	41.44	37.95	37.97
	126	36.60	-85.81	36.74	36.35	37.39	28.61	36.60	32.74	43.08	36.62	36.62
	128	35.81	-86.59	35.93	35.56	36.61	27.80	35.81	31.81	42.63	35.83	35.83

		flex. premium not granted			flex. premium granted		
		Maximin	Hurwicz $\lambda = 0.2$	Hurwicz $\lambda = 0.4$	Maximin	Hurwicz $\lambda = 0.2$	Hurwicz $\lambda = 0.4$
j	2	3.88	9.39	17.66	27.11	27.97	29.28
	119	-84.78	-59.85	-22.45	30.05	32.02	34.96
	120	-84.44	-59.41	-21.86	30.29	32.37	35.51
	121	-84.46	-59.28	-21.51	30.18	32.44	35.81
	126	-85.81	-60.03	-21.36	28.61	31.50	35.84
	128	-86.59	-60.75	-21.98	27.80	30.77	35.22

deviation in % to EEG feed-in tariff within the planning horizon ($1,712,173$ EUR)

Within Table 12 the percentage deviation of the objective values, depending on the optimized operational biogas plant schedule, the chosen investment strategy and the covered scenario, to the guaranteed EEG feed-in tariff within the planning horizon is depicted. The EEG feed-in tariff represents the unadapted state of the biogas plant, previous to a potential investment decision and thus the conventional plant design without an investment and without direct marketing. Hence, this case is used as a reference strategy in order to normalize the objective values in the solution matrix. The objective value of this reference strategy is $1,712,173$ EUR, thus this strategy is profitable. The given values in Table 12 demonstrate the deviations of the objective values considering a specific investment strategy and scenario to the reference strategy in percent. For instance, the value of 30.11 for the investment strategy 2 considering the scenario with a granted flexibility premium and the base scenario forecast means that the resulting objective value is 30.11% higher as the reference strategy. Hence, additional revenues would be generated. A negative value means that in the specific case fewer revenues are generated than with the reference strategy. Accordingly, an investment and using of direct marketing would not be beneficial compared to the base scenario. However, the objective values of all investigated strategy-scenario combinations are positive, as there are no resulting changes smaller than -100%, which would lead to a negative NPV. For this reason, each of the investment strategies itself is evaluated as beneficial because of the positive NPV. However, if the investment strategies are compared to the reference strategy, the investment alternatives 119, 120, 121, 126 and 128 should not be chosen if the flexibility premium is not granted, because the NPV of the investment strategy is lower as in the reference scenario. Apart from the optimal choices of investment strategies, the results of the numerical experiment show that in every scenario in which the flexibility premium is possible the premium is requested. The influence of the flexibility premium on the results is demonstrated as well in Table 12. As given in the table, the objective values are always higher if the premium is granted than otherwise. Additionally, each of the six investigated investment strategies is beneficial compared to the reference strategy if the flexibility premium is granted. If not, high investments (119, 120, 121, 126, 128) are generally not beneficial compared to the reference scenario.

In the last step of the developed multi-stage approach, a robust solution for a risk averse decision maker is derived. Thus, the rules of decision theory are applied to the results in the solution matrix. Since the generated scenarios are not rated with probabilities, a decision under uncertainty is necessary. Therefore, several decision rules can be applied. However, as Scholl (2001) has revealed in an overview regarding decision theory, only the Maximin rule and the Hurwicz's decision rule lead to great solution robustness. (Scholl (2001), Chap. 4) With the Maximin rule, only the worst scenario for every action (i.e., strategy) is considered. After that, the action is chosen which is best among the worst. Hence, this decision rule represents a strong risk aversion of a very pessimistic decision maker, always expecting the worst, but trying to make the best decision given this assumption. (Scholl, 2001) As depicted in Table 12 the decision tremendously depends on the granting of the flexibility premium. If the flexibility premium is not granted, the investment strategy 2 is chosen. (no CHP plant extension, 5000 Nm^3 biogas storage) If the flexibility premium is granted, the investment alternative 120 should be chosen. (5.500 kWh CHP plant extension, 12000 Nm^3 biogas storage)

As well as the application of the Maximin rule, the adaption of the decision rule of Hurwicz leads to high solution robustness for a risk-averse decision maker. Therefore, a small risk parameter $0 \leq \lambda \leq 1$ has to be assumed. λ can be interpreted as follows: $\lambda = 0$ shows a strong risk aversion (same result as Maximin rule) whereas $\lambda = 1$ means that the decision maker has no aversion against risk.(Scholl, 2001; Hurwicz, 1951) As the aim is to model a risk-averse decision maker, values of $\lambda = 0.2$ and $\lambda = 0.4$ are assumed. Using the decision rule of Hurwicz, a linear combination of the risk parameter λ and the worst, as well as the best scenario solution, is maximized. This leads to the following calculation of the Hurwicz-criterion:

$$\Phi(j) = (1 - \lambda) \cdot min \{NPV_{ji}|i = 1, ..., I\} + \lambda \cdot max \{NPV_{ji}|i = 1, ..., I\} \tag{18}$$

Here j represents the different possible actions of the decision maker (investment strategies), i represents the considered scenarios and NPV_{ji} is defined as the objective value in scenario i with strategy j. (Hurwicz, 1951) The application of the Hurwicz criterion leads to the same results as the Maximin rule, if the flexibility premium is not granted. If the flexibility premium is granted, the optimal decisions using the Maximin rule and the Hurwicz criterion with $\lambda = 0.2$ and $\lambda = 0.4$ are slightly different. However, all of the chosen optimal decisions have in common that the same CHP plant extension of 5.500 kWh is installed. Only the size of the biogas storage is slightly different. As mentioned, an increasing parameter λ represents a decreasing aversion against risk. Accordingly, with decreasing risk aversion a slightly larger biogas storage should be built.

Summarizing the previous results, it should be noted that the decision of the risk averse decision maker depends heavily on the (un-)certainty of the flexibility premium. If the flexibility premium is truly uncertain, the optimal decision would be a minor adjustment of the biogas plant design. If there are realistic chances that the flexibility premium is granted, a high investment using alternatives 120, 121 or 126 would be optimal. Thus, the influence of this subsidy on the decision is tremendous and the decision maker should try to get better information on the chances that his request for the flexibility premium would receive a positive answer. The developed approach can help to show such influences and gives an idea of the resulting consequences.

6 Summary and outlook

In this paper, it was examined how biogas plants operated flexibly can help to balance volatility carbon-neutral and without using nuclear resources within the power grid, if the shares of renewable resources are increased. In order to operate biogas plants flexibly, adjustments of the biogas plant configurations are necessary, which cause investments. Thus, it is investigated how the technical biogas plant design can be modified to increase the flexibility and reach a demand oriented power generation. The generated power should afterwards be sold through direct marketing at the power exchange EPEX Spot SE. Hence, the potential revenues at the spot market are characterized by uncertainty. In order to support this strategic, long-term investment decision and generate a robust solution for a risk-averse decision maker a novel multi-stage approach considering uncertain revenues is presented. The heart of the approach is a novel deterministic MILP model to support the investment decision (SBPP), consisting out of investment decisions concerning biogas storages and additional CHP plant capacities, named investment strategies. However, as the spot market prices are varying dynamically over time these variations, or stochasticity, are considered by simulating several spot market price forecasts using times series decomposition and thus using a deterministic optimization model in an uncertain environment. Therefore, the significant sources of uncertainties were identified and analyzed. The spot market price forecasts are then used to optimize an operational plant schedule. The resulting payments and payouts within the operational plant schedule are used to evaluate the investment strategies.

The numerical experiments reveal that the investment decision depends not only on the development of the spot market prices but also on the governmental subsidies, namely the flexibility and market premium.

In terms of the forecast of spot market prices, it is identified that the forecast accuracy is crucial for the success of an investment strategy. In order to model relevant market developments in the future, it was determined that it is necessary to model trend and seasonal characteristics of the spot market prices. The uncertainty of the flexibility premium determines the choice of doing an investment or not as well. If the flexibility premium is granted, a high investment is chosen in any case of spot market price developments. If not, a small investment is chosen. To conclude, the developed approach gives decision support to a risk-averse biogas plant operator who decides about choosing direct marketing, producing electricity demand driven and thus an adjustment of the biogas plant design. All governmental requirements and regulations of the German energy market are modeled and the possible sources of revenues are distinguished. As well, the resulting payouts are considered. Hence, the long-term investment decision can be supported by optimizing an operational schedule.

Nevertheless, there is potential for further research. As explained in Section 5, the probabilities of the distinguished scenarios should be considered to derive a more detailed solution. In the future, these probabilities could be covered more precisely within the optimization model by applying stochastic variables using probability distributions for market prices and subsidies. Accordingly, all scenarios and all investment alternatives could be considered simultaneously to derive an optimal solution directly. However, this would lead to a stochastic optimization model. In general, more effort in terms of calculation time is necessary to derive an optimal solution for a stochastic model than for a deterministic one.

The decision framework in this paper is characterized by several assumptions. One of these assumptions is the steady gas production rate within the digester. Hence, the resulting biogas plant after the investment is a type II plant. The analysis of the impact of a flexible biogas production rate on the investment decision and thus a type III biogas plant can help to make the developed approach more applicable in practice. With a slightly flexible biogas production, it could be possible to compensate for monthly intrayear fluctuations of the prices. Additionally, it is assumed that only one combination of one gas storage and one additional CHP plant capacity can be chosen. A future model could consider the possibility to combine several CHP plants or biogas storages.

Apart from the mentioned extensions, other extensions could cover the risk attitude of the decision maker using the Conditional Value at Risk, the robustness of the solution using a robustness function, several energy markets apart from the day-ahead market and the marketing of the produced heat as a second product. Moreover, in this paper, the biogas plant is examined independently from other power plants, power storages or power consumers. It could be beneficial to examine the biogas plant design within a network of other market participants in the future. One possible concept to model a biogas plant within the network is to assume the biogas plant as part of a virtual power plant. Here, other flexibility options, for instance, pumped-storage power plants, are considered besides the biogas plant, which can lead to other design decisions.

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