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Patrick Hochloff

Unit commitment and investment valuation of flexible biogas plants in German power markets

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Abstract

Biogas plants contribute a significant share of renewable energy sources (RES) to the electricity system. Most of them are designed to supply constant power generation. In the future biogas plants will most likely become more flexible, scheduling their power generation with respect to market prices. For this purpose power units need extended electrical capacity to convert the continuously produced gas as well as the gas held in storage. When constructing extended capacity at biogas plants, the flexibility premium is the main focus for about 8000 plants which were constructed before August 2014. Additional incomes as a result of selling at higher market prices have been considered, too. However, their relationship to the electrical capacity and storage size of biogas plants was unknown as was the impact on investment valuation.

This work has shown how biogas plants with extended capacity can be analyzed when they are operated in power markets, in particular the power spot market and the control reserve markets. Models on the basis of unit commitment have been developed in order to obtain optimized schedules and financial parameters, such as gross income and net present value (NPV), when biogas plants with extended capacity capitalize on prices in each market. The models developed consider several use cases that describe possible ways of participating in German power markets, switching between static and variable gas supply, providing secondary and tertiary control reserve, and claiming the market and flexibility premium. Mixed integer linear programs (MILP) have been developed for the unit commitment of each use case. The model for the unit commitment of providing control reserve with biogas plants made significant progress compared to the state of the art and has been published in (Hochloff, Braun 2014). There are two ways to make use of this model. First of all, the model could be applied to plan daily schedules for the operation of gas plants located at a gas production site such as biogas plants. Second, it can be applied to analyze the benefits of extending the electrical or storage capacity of gas plants located at a gas production site. The model calculates the optimized gross income of such a gas plant from an expected price curve.

In this work the models have been applied to make an economic analysis of different use cases. For this purpose, a scenario where a new power unit has to be procured, for example, when planning a new plant, or a general overhaul at the end of the engine's lifetime has been considered. This work shows that the gross income and the NPV create a curve with a maximum depending on the extension of the electrical capacity. The optimal electrical capacity at maximum gross income or maximum NPV depends on the available storage capacity and the market prices of the calendar year taken into consideration. For a 12 h storage capacity, it was found that the maximum NPV is obtained at the point when the electrical capacity is extended by 60% with respect to the spot market prices of recent years. There is a significant change to this result when secondary control reserve is provided, too. The model shows that the maximum NPV is reached when there is an extension of the electrical capacity by 90%. However, there is a positive result for extending the electrical capacity with secondary control reserve only if the energy which is reserved for the activation of control reserve is reduced.

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1 Introduction

1.1 Motivation

The past 15 years have witnessed a progressive increase in renewable energy sources (RES) contributing to the German power supply since the RES act (EEG) introduced particular feed-in tariffs for wind, solar, hydro, and biomass power sources. Thus, Germany is a main producer country in the field of biogas power, amassing 29 TWh of the gross power generation of 52.4 TWh in Europe by 2013 (EurObserv'ER 2014). The biogas industry has an estimated 7944 biogas plant installations, of which 7791 are supplied by a local gas source, providing a capacity of about 3859 MW and an annual power generation of 27.55 TWh in Germany by 2014 (German Biogas Association 2014a). A large number of these plants are built with the support of fix feed-in tariffs. Therefore, they are constructed to maximize the yield of electrical energy at a minimum of installed capacity. For this purpose, the size of the power unit corresponds to the continuous biogas production. Flexible membranes cover the digesters, buffering biogas in order to supply the internal combustion engine constantly (DBFZ et al. 2013b). Thus, 50% of the biogas plants generate power throughout 8400 hours a year; the average of the annual operating hours is 8058 h/a (DBFZ 2012); the average of the annual full load hours[1] is 7650 h/a (DBFZ et al. 2013a).

Since 2012 this development has changed in two ways. One change is that the profitability of new biogas plants has been reduced by the amended regulation from 2012 and from 2014 (DBFZ 2014). The annual amount of new biogas plants has decreased from about 1000 in 2009, 2010 and 2011 to about 300 by 2012 and 2013, probably dropping below 100 by 2014 and 2015 (German Biogas Association 2014b). Due to the amended EEG from 28 July 2011, the other change is that biogas plants now aim to provide flexible capacities in the power system.

This amendment designated biogas plants to generate power according to the needs of power markets by a renewed support scheme. It is a reasonable assumption that this change in the support scheme was caused by the RES target for the German power system; determining a minimum of 80% RES share of the German power supply by 2050. Scenarios of the future power supply show that growing shares of wind and solar power will replace more conventional power plants while variably scheduling biomass plants, CHP plants, storages and loads in order to balance supply and demand. In particular, biogas plants that have been upgraded to twice their capacity and generate the same amount of energy are scheduled variably (Uwe Abraham Holzhammer 2015).

This change in the biogas plant's role in the power system was introduced by the market premium and the flexibility premium. The market premium enables RES plants to market their power generation on their own, obtaining variable prices from wholesale power markets. Since August 2014 biogas plants, with an aggregated capacity of 2700 MW, have switched to this way of marketing (IKEM et al. 2014). The flexibility premium

[1] the quantity 'full load hours' is defined by the annual energy generation divided by the installed capacity

was introduced to make biogas plant operators invest in larger power units, or add a second one. Thus, the power unit capacity, over-sized relative to the capacity needed for converting the continuous biogas production, can be operated during higher wholesale market prices. Storage capacities for biogas and heat may be increased. As of January 2014 about 300 biogas plants had claimed the flexibility premium, increasing to 1780 by July 2014 (IKEM et al. 2014).

Marketing biogas plants has been supported by several power trading companies by means of virtual power plants. Virtual power plants are aggregations of controllable distributed energy (CDE) units (Braun, Strauss 2008), (Asmus 2010). They are controlled directly by bidirectional communication. The operator of a commercial aggregation of CDE supplies power markets (Braun, Strauss 2008). The term 'virtual power plant', however, is applied in several contexts, for example, auctioning a slice of the capacity of a power plant for a limited time period (Asmus 2010), (Ausubel, Cramton 2010), (Heredia et al. 2010), or selling an option on power generation against fuel delivery without physical existence of a power plant (Asmus 2010), (Bergschneider et al. 2001). In the context of this work, biogas plants are regarded as being pooled in virtual power plants to supply spot markets and provide control reserve, supported by the market premium.

The flexibility premium however motivated biogas plants' operators to activate decommissioned power units or, rather, to invest in spare power units that were destined for redundancy (Fischbach 2013). Furthermore, a rising number of operators started to claim the flexibility premium until July 2014 because of the EEG amendment due on 1 August 2014, and the uncertainty concerning the flexibility premium. However, a lot of those plants have not extended their capacity; nevertheless, they are able to operate flexibly. Investments in upgrading biogas plants have been obstructed by further regulatory uncertainties concerning the interpretation of the plants’ and generators’ commissioning dates, and the claim on an appropriate feed-in tariff (IKEM et al. 2014).

Valuing investments in extended capacity has been the subject of several studies in recent years. It has been documented that large biogas plants profit more from raising capacity than smaller biogas plants. Additionally, those large biogas plants profit most with the maximal considered capacity; adding 200% on top of the usual capacity (IER 2013). (DBFZ 2015) analyzed upgrading biogas plants by applying static operation schemes that are not optimized to market prices. They pointed to the conflict of marketing power in spot markets and providing control reserve that may emerge by upgrading biogas plants. As biogas plants are used to provide negative control reserve at constant power generation, investing in extended capacity and generating power flexibly without providing control reserve might, from their point of view, be less profitable than this reference, even though a flexibility premium is paid.

However, the influence of designing electrical capacity to increase the plant’s profitability with respect to the market revenues is not well understood. The most significant objection to previous studies is that the characteristics of power market revenues, which depend on a plant's technical ability to exploit market prices, have not been studied sufficiently. Thus, the additional market revenues are not considered sensitively when analyzing the extension of the biogas plant's capacity. The central payment taken in to consideration is the flexibility premium. Further issues have not been examined systematically either, for example, the added value of providing control reserve from upgraded biogas plants; the duration of reserve activation time; the impact of the market premium and the flexibility premium on the unit commitment; and the valuation of investments.

1.2 Objective of work

The increasing number of biogas plants taking part in both wholesale electricity markets and control reserve markets, and the lack of investments in raising flexibility are essential aspects of the current transition of biogas plants' role in the power supply system. It can be reasonably assumed that investments will increase if regulatory uncertainties are clarified or if existing power units reach the end of their lifetime. For this reason, a new method will be needed to estimate the earnings for the investment valuation of biogas plants with extended power and storage capacity. It is therefore the aim of this work to develop a model that enables the appropriate calculation of the revenues in order to improve investigations into the profitability of investments in raising the flexibility of biogas plants. This model should reflect the real economic influences on operating a biogas plant with extended capacity and which is why it should consider the short-term electricity market prices as well as premiums, and especially, the financial incentive of providing control reserve. The central concern of this work is the opportunity for biogas plants in power spot markets and control reserve markets. These markets provide short-term price signals and value flexibility. Market participants profit from supplying different power products and from price differences at different times of the day. They schedule their power plants according to the demand of different power products and variable prices. It is supposed that the flexibility of biogas plants will be capitalized in these markets, too.

Thus, the basic idea is that biogas plants will be capitalized in power markets, using appropriate planning by means of a unit commitment. The development of the unit commitment for biogas plants and its application to value investments via simulations is the central issue throughout this work. This work describes how a mathematical model schedules biogas plants to bid for different power products on the wholesale electricity market and the control reserve markets, aiming at improving the overall maximum profitability. Simulated schedules obtained from this model enable an estimate of the possible revenues for biogas plants from those markets. For this reason, this work aims to develop appropriate models which compute bids to the spot market and control reserve markets with respect to market prices and generation costs and also incorporates the trade-off between these markets in a closed unit commitment. The limited fuel of biogas plants is a central challenge that will be explored in this work. This innovative way of calculating control reserve bids enlarges the unit commitment significantly. For this reason, the solving time, how the solving time can be influenced and the quality of the result will be explored by applying the developed model.

It is supposed that the daily selling of energy to the markets as well as the investment decision is influenced by the premiums paid for the operation of biogas plants. As the development of biogas plants has fallen to below 100 per year since 2014, the focus is on existing plants installed before 1 August 2014. It is therefore the aim of this work to develop a model of the market premium and the flexibility premium in the unit commitment that enables the investigation of their impact on operating a biogas plant and the revenues. The aim is to obtain a description of their influence on the unit commitment, the market revenues and the investment valuation. One basic idea is that when scheduling the plant there is, first of all, a conflict between the market premium and providing control reserve, and then a conflict between the market premium and the flexibility premium. For the purpose of exploring these conflicts, the premiums are modeled within the unit commitment, too. Another basic idea is that the flexibility premium changes the size of the electrical capacity that creates the most value, thus, influencing the investment decision significantly in comparison to one based on market prices and incomes only. The impact of the premiums on the result of the unit commitment must be comprehensible when applying the model to investigate the revenues and the investment valuation. To obtain an elaborate description of the impacts on the valuation of upgrading the biogas plant, the sources of incomes will be considered separately. On the one hand, there are the revenues from power markets, and on the other hand, there are premiums granted by law. Both scenarios, with and without premiums, will be compared to describe the impact on the results.

The assessment of a biogas plant's flexibility is enabled by the calculation of market revenues. Investments in extended capacity of the power generation unit and in storage capacity can be valued according to the possible increase in revenue from the power markets created by the gained flexibility. Varying the size of the installed electrical capacity and the storage volume will shift earnings and investment costs nonlinearly. In order to appropriately deal with the results of simulated earnings from the model, the characteristics of the results will be investigated by applying the developed unit commitment and varying the electrical capacity and size of the storage. This work aims to provide an elaborate description of these characteristics. The central idea is to see the relationship between the size of plant components and the impact on revenues and investment valuation, respectively. For this purpose, the revenues and the investment valuation will be explored by looking at the size of the electrical capacity, the storage, and further influences.

In summary, there are three main objectives for this work:

1. This work will provide an appropriate model to calculate revenues of biogas plants with an extended power unit and storage capacity in order to support the investment decision. The model will be able to be applied to all kinds of gas plants that combust all the gas at the gas production site.

2. Besides calculating revenues from power spot markets with the influence of the German market and flexibility premiums, the model will also consider the control reserve market and the opportunity to bid in both the spot and the control reserve market with respect to the maximum revenues.
3. By applying the developed model this work will show the characteristics of the revenues depending on the size of the flexible capacity and the way of operating biogas plants. Based on incomes from wholesale electricity and control reserve markets an attempt is made to determine the market value of flexibility and its sensitivity. This work will show how the characteristics of component costs and market values result in the investment valuation and how it is influenced by the premiums for biogas plants.

1.3 Approach and structure of work

The general approach to achieve these objectives is shown in Figure 1. There are a couple of research questions to each of the steps of this approach. The content of this work is presented along the research questions that will be treated in the chapters 2 to 5. Therefore, this work falls into six chapters beginning with the introduction above.

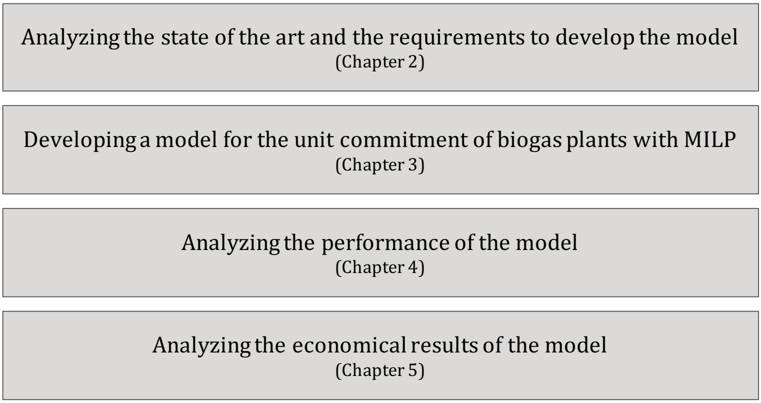

Figure 1: General approach of this work.

Chapter 2 is devoted to the knowledge base and the state-of-the-art technology. The research question for this chapter are given in Table 1.

Table 1: Research questions and content of chapter 2.

Research question	Content
• What are the technical possibilities and the costs of raising the flexibility of biogas plants?	Section 2.1 contains the information regarding the technical requirements and costs of biogas plants.
• What are the German legal requirements for biogas plants to participate in power markets?	Section 2.2 goes on to introduce the regulation for biogas plants participating in markets.
• Which markets and products can be profited from by flexible operation?	Section 2.3 introduces the relevant specifications of the markets and their

	products.
• What technology must be considered when a model for calculating market revenues is developed? • What is the gap between the state of the art and the model need to fulfill the research objective?	Section 2.4 presents the literature review of the unit commitment of CHP plants and analyzes the gap between the state of the art and the model aimed for in this work.

The basic knowledge of mixed-integer linear programming (MILP) is appended in Annex C.

Chapter 3 presents the developed model for the unit commitment of biogas plants. The chapter is organized considering the following questions to the development of innovative part models:

Table 2: Research questions and content of chapter 3.

Research question	Content of chapter 3
• How does a model describe the unit commitment of a biogas plant when it concentrates on the spot market value of the power generation; and when the plant has the opportunity to control and store the biogas production?	Section 3.1 starts with the formulation of the unit commitment problem of a biogas plant as MILP.
• How does a model describe the incentives of the market premium and the flexibility premium within the unit commitment?	Section 3.2 goes on to introduce a model for the revenues from the market premium and the flexibility premium in the objective function and the specific conditions of calculating the amount of this payment.
• How does a model include the opportunity to sell and schedule control reserve in the unit commitment of a biogas plant in addition to the planning of spot market bids? • How does a model consider the limited fuel from the storage and the continuous biogas production when control reserve bids are planned with respect to the energy needed for its activation?	Section 3.3 introduces the revenues from control reserve in the objective function and the model of capacity that can be planned in coordination with the spot market bid and the available energy.
• How must the model be implemented, in particular for rolling planning?	Section 3.4 describes the implementation of the MILP for the rolling unit commitment.

Chapter 4 presents the results of analyzing the implementation of the unit commitment. As the model introduced in chapter 3, especially the part for planning control reserve, extends the models significantly from the state of the art, the run time to solve the model and different methods to reduce the run time are examined along with the research questions in Table 3. This chapter analyzes several approaches of implementing and relaxing the unit commitment problem, concentrating on the excess time period of the rolling unit commitment and relaxations therein, the characteristic curve of power units and strategies using settings of the MILP solver.

Table 3: Research questions and content of chapter 4.

Research question	Content
• How many days have to be considered in the optimization (optimization horizon) of the spot market incomes to obtain an appropriate trade-off between the result of the unit commitment, which is the objective function value (OFV) of a day, and the run time? • As the most varying input parameter, how does the price curve of a day impact the run time?	Section 4.1.1 analyzes the impact of the optimization horizon on the OFV and the run time of an optimization problem that considered scheduling a biogas plant to sell its power generation on the power spot market at maximum revenues (use case A). Furthermore, this section analyzes the run time in consideration of daily price curves from a calendar year.
• How long is the appropriate optimization horizon considering the OFV of a year when the unit commitment is carried out using rolling planning? • Are the differences in the OFV that depend on the optimization horizon influenced by the absolute OFV?	Section 4.1.2 investigates the daily and annual OFV from rolling planning, proceeding from day to day throughout a year. Furthermore, fixed premiums are added to the market prices in order to investigate the change in the result quality depending on the absolute OFV.
• What is the appropriate optimization horizon regarding the trade-off between the maximum OFV and the run time when the complexity of the model is raised by planning control reserve? • How does planning control reserve for biogas plants impact the run time if the model is used for virtual power plants with multiple plants?	Section 4.1.3 extends the unit commitment problem analyzed in the previous section by planning tertiary control reserve (use case B) and investigates the run time and the OFV while varying the optimization horizon. In consideration of making use of the model in virtual power plants, the run time was analyzed for planning multiple plants.
• Can the run time be reduced without loss of OFV by relaxing binary variables in the time overlap (excess time) of the optimization horizon?	Section 4.1.4 investigates the run time and the OFV of the rolling unit commitment of section 4.1.4 (use case B) when binary variables of several hours in the excess time are defined as continuous instead.
• Can the run time be reduced without loss of OFV by merging time intervals in the time overlap (excess time) of the optimization horizon?	Section 4.1.5 investigates the run time and the OFV of the rolling unit commitment of section 4.1.4 (use case B) when the time resolution of a part of the excess time is changed from Δt=1 h to Δt=2 h.
• What is the appropriate optimization horizon for the rolling unit commitment subject to the storage capacity?	Section 4.2.1 repeated the analysis of section 4.1.2 but this time varying the storage horizon and the optimization horizon in order to analyze the financial impact using the annual OFV.
• How many intersections should be used to linearize the characteristic curve in order to minimize run time and the discrepancy of generated power or consumed gas between using the curve and its linearization?	Section 4.2.2 examines the run time, the power generation and the gas consumption of use case B with different linearizations of the characteristic curve.
• Can the run time be significantly reduced by choosing the node-selecting strategy of the MILP solver?	Section 4.3.1 investigates the run time of the unit commitment problem of use case B with different parameter settings

	of the model and different node-selecting strategies offered by the applied MILP solver Cplex Optimization Studio V12.4.
• How can a time limit be used to reduce the run time without much loss in the OFV?	Section 4.3.2 investigates the run time and the OFV of the unit commitment problem of use case B for optimizing single days and the rolling planning with different parameter settings of the model and different time limits.

Chapter 5 focuses on the description and discussion of economic results produced by the model. This section begins with the results of the revenues and the investment valuation of biogas plants in electricity spot markets depending on the electrical capacity and the storage capacity. The section goes on to present the influence of the market premium and the flexibility premium on the unit commitment of biogas plants. It closes with a comprehensive study of biogas plants providing tertiary and secondary control reserve.

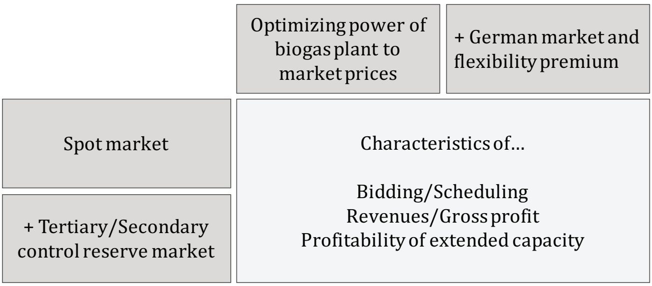

Figure 2: General approach to research questions and content of chapter 5.

Table 4: Research questions and content of chapter 5.

Research question	Content
• How much will the incomes be raised by extending the capacity of the power unit? • Can the investment in extending the capacity of the power unit be profitable?	Section 5.1.1 analyzes the rise of the gross profit of a biogas plant with a gas storage and extended capacity of the power unit from optimally selling its power generation in power spot markets (use case C). Furthermore, this section analyzes by means of the net present value (NPV) whether the investment in the capacity extension could be financed by the additionally generated income from the spot market.
• Is there an impact on the optimal capacity of the power unit with regard to the development of market prices over years?	Section 5.1.2 analyzes the gross income and the profitability of the investment in extended capacity when market prices of different historical calendar years were applied. This section develops a method of determining an optimal power unit size with regard to incomes from several

	years.
• How is the profitability affected when the storage capacity is to be extended, too?	On the basis of the results from section 5.1.1, section 5.1.3 analyzes the profitability of extending the capacity of the power unit when costs of investing in gas and thermal storage are considered, too.
• How does the flexibility premium influence the optimal capacity of the power unit?	Section 5.1.4 continues by taking the flexibility premium into account when the investment in extending capacity and storage is valued on the basis of the results of section 5.1.1 and 5.1.3.
• Is the flexibility premium able to make biogas plants operate flexibly by regulating the biogas production relative to the capacity of the plant? • What fuel price is needed to change to a flexible operation of the biogas plant?	In contrast to section 5.1 that analyzes the flexible power generation of a biogas plant with a constant biogas production, section 5.2 considers a biogas plant which regulates the biogas production (use case D). This section analyzes the optimization of the power generation and gas production with respect to the market and flexibility premium. Section 5.2.1 investigates the impact of the fuel price on the decision of whether the biogas plant is operated constantly at maximum load or the biogas production is reduced so that the plant generates power variably.
• How much flexibility premium must be paid to change to a flexible operation of the biogas plant? • Does the flexibility premium compensate for increasing fuel prices if the plant is operated flexibly?	Section 5.2.2 investigates the influence of the flexibility premium on the biogas production and power generation with use case D. The gross income is analyzed with different fuel prices and flexibility premiums.
• How much and which kind of tertiary control reserve can be offered by a biogas plant with extended capacity? • How much is the gross income raised by additionally providing tertiary control reserve? • Is extending the capacity profitable when the biogas plant is already providing tertiary control reserve?	Section 5.3 includes tertiary control reserve in the optimization that enlarges use case C to use case E. This section analyzes the offered capacity of tertiary control reserve, the change of the gross income and the impact on the value of the investment in extended capacity. As control reserve market prices have changed significantly in recent years, the analysis was carried out with prices from 2009 to 2014.
• How does the market premium influence providing tertiary control reserve, especially when operating at part load?	Section 5.4 analyzes the implications of the market premium on the optimized schedules of products provided for the spot market and the tertiary control reserve market. For this purpose, this section analyzes a modification of use case E that includes the conditions of paying the market premium and thus raises endogenously the costs caused by efficiency losses, and compares the

	results with those from section 5.3.
• How much and which kind of secondary control reserve can be offered by a biogas plant with extended capacity? • How much is the gross income raised by additionally providing secondary control reserve? • Is extending the capacity profitable when the biogas plant is already providing secondary control reserve?	In contrast to section 5.3, section 5.5 analyzes use case F which is use case C enlarged by the provision for secondary control reserve. This section analyzes the offered capacity of secondary control reserve, the change in gross income and the impact on the value of the investment in extended capacity, with prices from 2012 to 2014.
• Does the market premium influence the provision of secondary control reserve?	Section 5.6 analyzes the implications of the market premium on providing secondary control reserve. This section analyzes use case F modified to include the conditions of paying the market premium, and compares the results with those of section 5.5.
• Can the amount of provided secondary control reserve and the incomes be significantly raised by adjusting the amount of energy reserved for activation?	Section 5.7 analyzes the outcome of the developed model of biogas plants providing secondary control reserve when historical data of the length of the activation time are respected in the model. This analysis is carried out in contrast to the analysis of section 5.5 that assumed that activation over the complete time period must be provided.

Chapter 6 concludes this work by summarizing and discussing the results. At first the results from analyzing the unit commitment problem of biogas plants on the spot market and control reserve market are discussed. The section goes on to discuss the economic results of biogas plants with extended capacity on spot markets and the investment valuation. Thereafter, the results of providing optimal tertiary and secondary control reserve are dealt with. The section closes with a discussion of the impact of the market premium and the flexibility premium on the unit commitment and the investment valuation.

2 Biogas plants in electricity markets

2.1 Technology and costs of upgrading biogas plants

This section describes biogas plants' major components needed for flexible operation and the costs thereof. The main operational boundaries and cost functions are used to model technical restrictions in the unit commitment and to value investments.

Biogas plants consist of a digester, biogas storage installations, an internal combustion engine (gas-driven Otto engine or pilot injection gas engine) and a generator. A small group of biogas plants are operated using a gas turbine (DBFZ et al. 2013a). The combination of the engine and generator is called a power unit or CHP unit in the following. Some plants have facilities to prepare the biogas for being fed in to the natural gas grid.

The digester produces a gas mixture containing methane. The methane share is between 50% and 75%, the rest consists of carbon dioxide (25% to 45%), water (2% to 7%), hydrogen sulfide (20 to 20000 ppm), nitrogen (up to 2%), oxygen (up to 2%) and hydrogen (up to 1%) (DBFZ et al. 2013b). The incoming materials are renewable raw materials (81.5% energy content), livestock excrement (13.8%) and waste materials (4.8%) (KTBL 3013). The gas yield of different incoming materials is contained in Table 24 and Table 25, Annex A. The long-term development of the costs of the most frequently used renewable raw materials (Table 25) is shown in Figure 63, Annex A. The fermentation process in the digester is fragile and the challenge is to optimize the process for a stable and continuous operation with maximum output (Cordes + Winterberg, DBFZ 2012). Some research work considers regulating the fermentation and thus also the biogas output (Hahn et al. 2014). The kinetics of biogas fermentation is examined in (Mähnert 2007) (Figure 67, Annex A). Additional biogas is gained by covering the repository of the digestate and this can then finally be used as fertilizer (Cordes + Winterberg, DBFZ 2012).

Engines developed for combusting biogas can be distinguished from engines which combust natural gas. The electrical efficiency of some biogas power units depends on the size of the engine as depicted in Figure 64. The engine works at the minimum of the operating range with 50% of the nominal capacity. This operational state reduces the electrical efficiency by about 8 percentage points and the total efficiency by about 3 percentage points (KTBL 2013). The efficiency loss extracted from data sheets of some biogas plant types is less than 4 percentage points for plant sizes between 500 and 1000 kW and less than 3 percentage points for plant sizes bigger than 1000 kW (Annex A Figure 70). The costs of the power units per nominal electrical power are approximated with the function

$$y = 15648 \cdot x^{-0.5361}$$

in which x is the nominal electrical capacity in kW and y is the specific cost factor in €/kW (ASUE 2011) (compare Annex A Figure 65). The cost of a transformer can be calculated with the function

$$y = 1.12 \cdot (12519 \cdot \ln(x) - 37685)$$

in which x is the nominal electrical capacity in kW and y is the cost in € (IER 2013).

The waste heat of the engine is used for the thermal demand of the fermentation process in the digester (Table 23, Annex A). Additionally, a part of the waste heat is used for the thermal demand of commercial and residential buildings, local and district heating networks and dehydration processes (DBFZ et al. 2013a).

Biogas plants have biogas storage space available within the range of 1 m^3/kW to 2 m^3/kW in ratio to the electric nominal power (Johann Heinrich von Thünen-Institut (vTI) 2009), which corresponds to 2 to 6 hours of the biogas production (KTBL 2013), or even half the daily biogas production (DBFZ 2009). The biogas is held in an internal or external storage space at low pressure, up to 100 mbar depending on the construction. Internal storage space is realized by covering the digester and the digestate repository with flexible gas-proof membranes (DBFZ et al. 2013b). Up to 6300 m^3 internal storage space is available (KTBL 3013). External storage spaces are membrane cushions protected by hard-shelled repositories (DBFZ et al. 2013b). Up to 7000 m^3 external storage space is available (KTBL 3013). Specific safety provisions must be respected for plants that can be charged with 10 t of biogas (12. BImSchV, revised 6/8/2005) which is about 8000 m^3 (KTBL 2013). The specific costs for several storage constructions depending on the storage volume are depicted in Annex A, Figure 66. The functions derived from this figure are presented in, where *x* is the storage volume in m^3 and *y* is the specific cost in €/m^3.

Table 5: Specific cost functions of internal and external biogas storage derived from Figure 66, Annex A.

Internal quarter-of-a-sphere	$y = 3050.7 \cdot x^{-0.618}$
Internal third-of-a-sphere	$y = 6765.9 \cdot x^{-0.663}$
Third-of-a-sphere membrane exchange	$y = 3997.7 \cdot x^{-0.687}$
External three-quarter-of-a-sphere	$y = 3397.9 \cdot x^{-0.585}$

Meteorological influences, such as solar irradiation, cause excess pressure and thus biogas losses. For this reason it has been recommended to keep to a medium storage level (Cordes + Winterberg, DBFZ 2012). To operate biogas storage flexibly, the recommendation is to plan 40% extra volume on top of the calculated volume of dry gas at standard pressure and temperature (DLG 2014). In (Holzhammer et al. 2013) an extra volume of about 68% for internal gas storage spaces and 18% for external storage spaces is stated. Internal storage tanks are confronted with measurement failures that are solved by a buffer volume. In contrast, external storage space need low extra volume because of low measurement failures and gas drying systems (Holzhammer et al. 2013).

2.2 Premiums for biogas plants participating in power markets

The amendment to the EEG which came into force on 1 January 2012 (Bundestag 2011) introduced the optional market participation of RES plants. Plant operators have since had the possibility to market power themselves. This was supported by the market premium. Additionally, the EEG introduced a flexibility premium in order to raise the flexibility of biogas plants. Both the market premium and the flexibility premium are set out in detail below.

The amendment to the EEG which came into force on 1 August 2014 (Bundestag 2014) enforced the intention to integrate RES into the power markets as stated in §2. The market premium has been maintained in this amendment. The flexibility premium as introduced below has been maintained for biogas plants installed before 1 August 2014. However, biogas plants installed since 1 August 2014 only obtain the market premium for the share of power that was generated in a biogas plant according to §47 section 1. The threshold for the average of the annual generated power is half the installed capacity. The share of average power up to half of the installed power is supported by the market premium. The share of the average power exceeding half the installed power does not obtain financial support. Furthermore, the biogas plant's capacity is paid at 40€/kW for 20 years, which is an extra payment for the plant's flexibility according to §53.

2.2.1 Market premium

The market premium supports the sale of generated power on wholesale power markets by compensating for the gap between the static feed-in tariff of the EEG and the income from the markets. For this purpose, the market premium is defined as the difference between the plant's feed-in tariff and the monthly market value of the power generation according to attachment 1 of §34. The monthly market value is determined at the end of the month for each type of RES. As biogas plants of standard design, as well as other biomass or hydro plants, operate constantly, the monthly market value is defined as the mean price of the German spot market on the power exchange EPEX Spot SE.

Furthermore, the market premium respects the thresholds of the feed-in tariff. Several values define thresholds for the average annually generated power. These are 150 kW, 500 kW, 5 MW and 20 MW. The share of the average annually generated power below the threshold is paid by a higher feed-in tariff than the power above.

2.2.2 Flexibility premium

The flexibility premium was introduced to pay biogas plants for a defined excess capacity. Thus, it is an incentive to extend the capacity of the power unit. While the installed capacity of new biogas plants is paid at a rate of 400€/kW for 20 years according to § 53 EEG, a defined excess capacity of biogas plants installed before 1 August 2014 is paid by the flexibility premium introduced in 2012. Those biogas plants can obtain 130€/kW for the excess power according to §54 EEG. Attachment 3 of §54 EEG provides a piecewise definition of the excess power that depends on the installed power P^{max} and the average power P^{use} of the annual power generation. The total amount of payments can be described with

$$\text{flexibility premium payments} = 130€/\mathrm{kW} \cdot \begin{cases} 0, \mathrm{P}^{\mathrm{use}} < 0.2 \cdot \mathrm{P}^{\mathrm{max}} \\ 0.5 \cdot \mathrm{P}^{\mathrm{max}}, 0.2 \cdot \mathrm{P}^{\mathrm{max}} \leq \mathrm{P}^{\mathrm{use}} < 0.5 \cdot \mathrm{P}^{\mathrm{max}} \cdot \mathrm{f}^{-1} \\ \mathrm{P}^{\mathrm{max}} - \mathrm{f} \cdot \mathrm{P}^{\mathrm{use}}, 0.5 \cdot \mathrm{P}^{\mathrm{max}} \cdot \mathrm{f}^{-1} \leq \mathrm{P}^{\mathrm{use}} \end{cases}$$

where f is 1.1 for biogas plants and 1.6 for the prepared biogas which is fed in to the natural gas grid. Figure 3 shows the characteristics of the defined annual payment. The payments of three plant parameters are plotted against the average power based on the annual power generation.

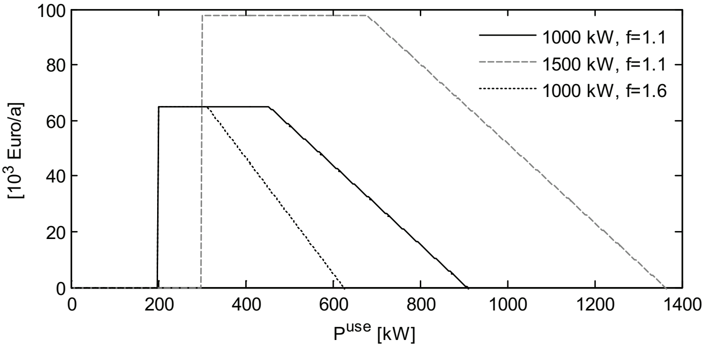

Figure 3: Annual payments from flexibility premium depending on the average power.

2.3 Electricity markets

The power spot markets and the control reserve markets are the most important markets for biogas plants to provide flexibility to the electricity system. This section contains a description of the relevant products and the trading terms.

2.3.1 Spot markets

EPEX SPOT SE operates the power spot markets for the market area of Germany. There are two market segments, the day-ahead market segment and the intraday market segment.

The day-ahead market segment consists of an auction for hourly power products for the 24 hours of the following day. Market participants need to submit their supply and demand into the order book that closes at 12:00 CET. The prices of supply and demand curves are limited to -500€/MWh and 3000€/MWh (EPEX SPOT 2015). The price and volume development of the day-ahead auction is depicted in Annex B Figure 73 and Figure 74.

The intraday market segment consists of an auction and continuous trade. The intraday auction which was launched in December 2014 trades power contracts for the 96 quarters of the hours of the next day (EPEX SPOT 12/9/2014). The order book closes at 15:00 CET. The prices are limited to between -3000€/MWh and 3000€/MWh. The continuous intraday market trades contracts for hours and quarters of hours. The prices of these contracts are limited to between -9999€/MWh and 9999€/MWh. The continuous trading of contracts for hours begins at 15:00 CET and contracts for quarters of hours at 16:00 CET. The trading of each contract closes 45 minutes before delivery (EPEX SPOT 2015)[2]. The frequency of price differences between day-ahead auction and intraday continuous trade is depicted in Annex B Figure 75. Bars show the annual volume of the continuous intraday trade in Figure 76.

2.3.2 Control reserve markets

The four German transmission system operators (TSOs) operate a common market to procure reserves for frequency containment and restoration. The requirements of this ancillary service provided for the TSOs are specified in the annexes D1, D2 and D3 in (VDN 2007). There are three forms of frequency control reserve in Germany, the primary, the secondary and the tertiary control reserve. The TSOs need the primary control reserve to be activated within 30 seconds, the secondary control reserve within 5 minutes and the tertiary control reserve within 15 minutes (VDN 2007).

The control reserve is to be procured by calls for tenders by the TSOs on the basis of the enactment of (Bundesnetzagentur 2007a) for the primary control reserve, (Bundesnetzagentur 2007b) for the secondary control reserve, and (Bundesnetzagentur 2006) for the tertiary control reserve. Every tender contains a bid size and a capacity price. The TSOs accept the tenders with the lowest capacity price in order to meet their demand. Secondary and tertiary control reserve tenders, additionally, contain an energy price. The energy price is a subordinated criterion in accepting tenders. The principle of pay-as-bid is applied, both the payments for provided capacity and activated energy agree with the tender prices (Bundesnetzagentur 2006), (Bundesnetzagentur 2007a), (Bundesnetzagentur 2007b). Table 6 contains a survey of the market rules renewed and released in 2011.

[2] Closure of trading intraday contracts is meanwhile 30 minutes before delivery (EPEX SPOT 2017).

Table 6: Tender rules of primary, secondary and tertiary balancing power products (Bundesnetzagentur 2011a), (Bundesnetzagentur 2011b), (Bundesnetzagentur 2011c).[3]

	Primary	Secondary	Tertiary
Auction time	Tuesdays 15:00 CET	Wednesdays 15:00 CET	Workdays (Mon-Fri) 10:00 CET
Delivery time	Following week	Following week	Following days until next auction day
Tradable products	1 product/week: symmetric positive and negative reserve	4 products/week: positive and negative reserve separated each for peak and off-peak time	12 products/day: positive and negative reserve separated; each for six time slots/day
Product length	24 hours/day for 7 days	Peak time: from 8:00 to 20:00 CET on Mon to Fri Off-peak time: Mon-Fri: from 00:00 to 8:00 and from 20:00 to 24:00 and Sat+Sun from 00:00 to 24:00	4 hours
Product size	Min. 1 MW	Min. 5 MW	Min. 5 MW
Product increment	1 MW	1 MW	1 MW
Product prices	Capacity price	Capacity price and energy price	Capacity price and energy price

Planning the offer of control reserve must reflect its possible activation which needs energy that must be reserved. Especially, the secondary control reserve is much shorter activated than the duration of the product. For this purpose, historical data of the activation signal from the German TSO 50Hertz were analyzed. The activation signal was reduced to one minute mean values in order to approximate the executed activation due to plants' reaction and ramping time. Figure 82 (Annex B) shows the duration of activated secondary control reserve on different amplitudes of the TSO's signal relative to the procured reserve in an hour using the data from every hour in 2012 and 2013, in particular the maximum, the median, the 0.99 percentile and the 0.9995 percentile of the duration. In the following, the maximum duration was used, but from several consecutive hours. Figure 83 (Annex B) shows the maximum durations of secondary control reserve activation relative to the procured reserve in time periods from 1 h to 12 h in 2013. The figure illustrates how raising the considered time period, actually decreased the relative duration of activating a certain amplitude. Up to 168 consecutive hours were considered because of the weekly products of secondary control reserve. Extracting the duration of a certain amplitude depending on the considered number of

[3] The market rules are currently in progress to be redesigned. It is planned that secondary control reserve will be procured in the same manner as tertiary control reserve, however, auction will occur on every day of a week (Bundesnetzagentur 2015).

hours resulted in the data shown in Figure 84 (Annex B), illustrated in comparison with the duration of the full activation throughout the considered time period.

2.4 Unit commitment

Unit commitment is the planning related to the power generation of plants within a period of time in consideration of the costs. The power generation is scheduled some time in advance for discrete, successive time intervals throughout the planning time period. (Carrión, Arroyo 2006) provides a basis for the unit commitment with conventional, thermal plants in mixed-integer linear programming (MILP). Below, the unit commitment is considered for CHP plants that are similar to biogas plants. Furthermore, business cases including the provision of control reserve are considered.

The market returns and cost reductions calculated by unit commitment can be used for the investment valuation. (Henning 1998) and (Sundberg, Henning 2002) show the optimization of the investment in power and heat generation units when considering the minimization of operation costs. (Streckiene et al. 2009) examined the profitability of a heat storage tank operating with a CHP plant on the German power spot market. (Christidis et al. 2012) optimized the size of a heat storage tank endogenously while solving the unit commitment of a CHP plant. (Kavvadias et al. 2010) examined the profitability of several plant configurations to satisfy the power, heat and cooling demand.

2.4.1 Unit commitment of CHP plants

The unit commitment of CHP plants can be modeled as a system that couples components for generating, converting, storing and consuming energy (Ghoudjehbaklou, Püttgen 1987) and (Püttgen, MacGregor 1989). The unit commitment of several CHP plants with heat generation in ratio to the power generation is presented in (Wille-Haussmann et al. 2010). The unit commitment of CHP plants with gas turbines is presented in (Venkatesh, Chankong 1995), (Thorin et al. 2005) and (Weber, Woll 2006; Thorin et al. 2005). The characteristic curve of power units with internal combustion engines are looked at (Gómez-Villalva, Ramos 2003), (Weber, Woll 2006), (Casisi et al. 2009) and (Kavvadias et al. 2010). The unit commitment of CHP plants using steam turbines is presented in (Püttgen, MacGregor 1989) and varies the CHP coefficient within limits. A unit commitment model of a CHP plant with a back-pressure turbine is introduced in (Gardner, Rogers 1997) and (Dvořák, Havel 2012). Modeling the characteristics of extraction condensing turbines for unit commitment is presented in (Venkatesh, Chankong 1995), (Guo et al. 1996), (Lahdelma, Hakonen 2003), (Thorin et al. 2005), (Rong et al. 2006), (Weber, Woll 2006), (Rong, Lahdelma 2007), (Rong et al. 2009), (Dvořák, Havel 2012), (Havel, Šimovič 2013) and (Mohammadi-Ivatloo et al. 2013).

The unit commitment of CHP plants also regards a boiler as an optional heat generator, for example in (Henning 1998), (Rong et al. 2006), (Weber, Woll 2006), (Rong, Lahdelma 2007), (Wille-Haussmann et al. 2010) and (Dvořák, Havel 2012). A heat storage space as an additional component of the CHP plant is presented in (Henning 1998), (Streckiene et al. 2009), (Wille-Haussmann et al. 2010), (Kavvadias et al. 2010) and (Christidis et al. 2012). In (Püttgen, MacGregor 1989) an electrical storage unit is integrated in the CHP plant. The unit commitment of CHP plants that, additionally, have an absorption chiller and an electrical chiller is presented in (Kavvadias et al. 2010).

2.4.2 Unit commitment of CHP operations strategies

Combining CHP units with storage facilities and additional boilers makes CHP plants flexible. Boilers allow the plant to fulfill the heat demand if the CHP plant cannot supply the demanded heat as it is below the minimum operating range or above the maximum thermal capacity. In addition, boilers can provide the demanded heat more efficiently than the CHP plant when power prices are too low. A heat storage unit, furthermore, enables the CHP unit to operate at the point of maximum working efficiency while surplus generated heat is stored. Thus, operation times can be scheduled at times with maximum power prices (Streckiene et al. 2009). The CHP unit and the additional components are scheduled optimally with respect to the operations strategy.

One operational strategy which is presented is the optimization of the CHP plant schedule in order to meet an electrical load and a heat demand (Rong et al. 2006), (Kavvadias et al. 2010) and (Mohammadi-Ivatloo et al. 2013). The market price of power products is not considered in that kind of operation strategy. In contrast, the heat demand and the power prices of the unit commitment of CHP plants are considered in (Püttgen, MacGregor 1989), (Asano et al. 1992), (Venkatesh, Chankong 1995), (Gómez-Villalva, Ramos 2003), (Thorin et al. 2005), (Weber, Woll 2006), (Rong, Lahdelma 2007), (Yusta et al. 2008), (Casisi et al. 2009), (Rong et al. 2009), (Streckiene et al. 2009), (Wille-Haussmann et al. 2010), (Christidis et al. 2012), (Dvořák, Havel 2012) and (Havel, Šimovič 2013). Therein, one operational strategy is the maximization of revenues concerning the power prices as presented in (Streckiene et al. 2009), (Wille-Haussmann et al. 2010), (Dvořák, Havel 2012) and (Havel, Šimovič 2013). Another operational strategy for CHP units is minimizing the cost of the residual load and maximizing the revenues of surplus power while supplying an electrical load (Püttgen, MacGregor 1989), (Asano et al. 1992), (Venkatesh, Chankong 1995), (Gómez-Villalva, Ramos 2003), (Thorin et al. 2005), (Weber, Woll 2006), (Yusta et al. 2008), (Casisi et al. 2009) and (Rong et al. 2009).

In (Thorin et al. 2005) and (Havel, Šimovič 2013) the provision for balancing power is also respected in the unit commitment of power and heat generation.

2.4.3 Unit commitment including control reserve

The provision of control reserve can be part of the unit commitment of a plant. Bidding for control reserve needs to be considered as well as bidding in markets for energy generation. Bidding occurs a week ahead for primary and secondary control reserve and a day ahead for tertiary reserve and spot market offers. Short-term planning for electricity generation can therefore be constrained by being committed to control reserve (Schwarz, Frings 2013). Several different solutions that consider control reserve while scheduling plants and storage have been presented.

(Thorin et al. 2005) and (Havel, Šimovič 2013) present MILP models for the short-term unit commitment of CHP plants under already committed provision of control reserve. The presented MILP in (Drury et al. 2011) optimizes the revenue from energy generation, energy purchase and contingency reserves of a compressed air energy system as a price taker. (Swider 2007) presents a non-linear program to optimize the generation and reserve revenues of a set of coal fired plants, gas fired plants and a pumped hydro storage unit considering strategic bidding in day-ahead control reserve markets.

Plants with limited energy capacity need to be planned with respect to the energy that could be activated to supply control reserve. The software presented in (Schwarz, Frings 2013) plans and tracks the fill level of a pumped-storage hydroelectric plant considering various scenarios in a multiple-stage optimization approach. Another multi-stage algorithm including the unconstrained optimization of a pumped-storage hydroelectric plant is presented in (Lu et al. 2004). A stochastic linear program for a hydroelectric power system with water reservoirs is presented in (Olsson, Soder 2003) optimizing the income from a reserve market under price uncertainty.

CHP systems that are linked to a fixed heat demand gain freedom by having thermal storage and ancillary heat generators, especially by having electrical heating rods that can provide control reserve, too (Spieker et al. 2013). Thermal storage limits need to be integrated in the planning of control reserve in a similar way to pumped-storage hydroelectric plant limits. The activation of positive and negative control reserve is considered in the same way as operation without reserve activation (Wulff 2006). (Wulff 2006) presents MILP that optimizes energy generation revenues with and without reserve activation. The reserve provision and the activation of control reserve are considered therein by previously developed scenarios. The scenario with the highest revenue is selected from an iteration of calculations with different reserve scenarios (Wulff 2006).

2.4.4 Programming approaches for the unit commitment of CHP plants

The unit commitment of CHP plants is realized by linear programming (LP) (Ghoudjehbaklou, Püttgen 1987), (Püttgen, MacGregor 1989) and (Gardner, Rogers 1997). An algorithm for the efficient solution of the linear programming problem of a CHP plant has been developed by (Lahdelma, Hakonen 2003), (Rong et al. 2006) and (Rong, Lahdelma 2007).

Mixed-integer linear programming (MILP) finds the global optimum and fulfills exactly every restriction of a CHP unit commitment problem (Illerhaus, Verstege 1999). The MILP of the CHP unit commitment is presented in (Venkatesh, Chankong 1995), (Illerhaus, Verstege 1999), (Gómez-Villalva, Ramos 2003), (Thorin et al. 2005), (Yusta et al. 2008), (Casisi et al. 2009), (Wille-Haussmann et al. 2010), (Christidis et al. 2012), (Dvořák, Havel 2012) and (Havel, Šimovič 2013). Furthermore, MILP is applied in (Asano et al. 1992) and (Assenmacher et al. 1997).

Further algorithms, not based on LP, have been developed in order to solve the unit commitment problem. The solution of the unit commitment by dynamic programming (DP) was developed in (Rong et al. 2008) and (Rong et al. 2009). (Weber, Woll 2006) developed the unit commitment of CHP plants concerning uncertainties with recursive stochastic optimization that takes place by means of backward induction as DP. Lagrangian Relaxation is applied by (Guo et al. 1996) and (Thorin et al. 2005). (Mohammadi-Ivatloo et al. 2013) developed a particle swarm optimization (PSO) for the unit commitment of a CHP plant.

2.5 Approach to the unit commitment problem of biogas plants

The review of the literature above shows that the unit commitment of plants is a comprehensively treated issue. One basis for this work is modeling power plants and their characteristic curve for the unit commitment. This basis is extended by modeling power plants which offer their power generation on markets. Some studies treat furthermore the issue of providing control reserve, usually at a spinning state. Another basis is the modeling of CHP plants and the generalized approach of combining converters, storages, sources and consumers of energy in a linked system. From this basis, models of CHP plants with thermal storages are more specific developments that provide a basis for this work.

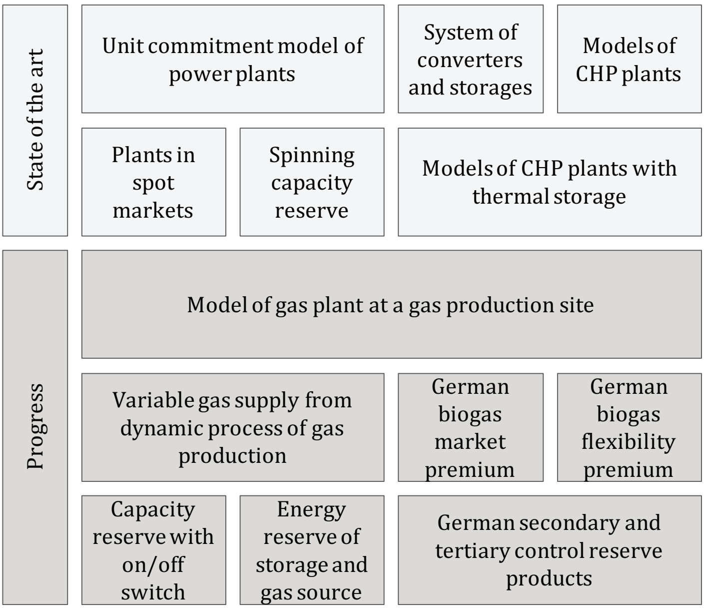

Figure 4: Scheme of the state of the art and the progress both needed for the objectives of this work.

In consideration of the objective of this work, there is a gap of models that can be applied for analyzing the use and success of biogas plants with extended capacity. There is a need of models that give answer to the following questions:

1. How much revenue from the spot market do gas plants gain when they are operated directly at gas production sites such as biogas?
2. How much control reserve market can be offered, when it is, and how much revenues can be gained?
3. How do market and flexibility premium affect the operation of a biogas plant in Germany?

First of all, a model of a gas plant with a continuous gas source that sells its generated power on the spot market is needed. The reviewed literature did not present an appropriate model. However, an initial model can be created easily on the basis of the state-of-the-art technology. As a result, the problem of a biogas plant selling power on spot markets is presented in section 3.1.

Furthermore, the model of the gas plant becomes much more complex when considering premiums and control reserve markets. The models developed for these specific use cases are presented in section 3.2 and 3.3, respectively. The premiums, in particular, are needed for realistic use cases of biogas plants in Germany. They influence the power generation and the level of the gas production, For this reason the premiums need to be implemented in the model of the unit commitment as well as a variable gas production with dynamic characteristics.

In Germany control reserve is a product traded on markets. For this reason bids need to be calculated endogenously in addition to the bids for the spot market. Capacity constraints rule the power unit's power generation and reserve provision at the same time. Biogas plants are able to provide control reserve by switching the plant on and off and, additionally, regulating the power output within the operating range. So capacity constraints should respect both requirements. Furthermore, energy constraints are needed to respect the limitation of fuel from the gas production and storage. Energy constraints are applied to the fuel consumption in case of activated control reserve. The capacity and the energy constraints are to be respected for both secondary and tertiary control reserve, which are determined by constraints of the product specifications.

These models are formulated for mixed-integer linear programming (MILP). MILP is the most common formulation of the optimization problem in the reviewed literature about unit commitment. Commercial software such as CPLEX is usually used to solve the formulated optimization problems. An introduction to MILP and solving algorithms is presented in Annex C. In this work, CPLEX is used to solve the optimization problems, too, as it is the most common software for MILP (Kelso 2015). Recent developments in solving algorithms are presented with CPLEX.

3 Models for the unit commitment problem of biogas plants

This section describes the model developed in this work. The models below describe a mixed-integer linear program (MILP), with

$$\min_{x \in S} c^{\mathrm{T}} x \ , S := \{x | Ax = b, x \geq 0\}$$

where x consists of integer variables $x_1, \ldots, x_r \in \mathbb{N}_0$ and continuous variables $x_{r+1}, \ldots, x_n \in \mathbb{R}_0^+$ (see also Annex C). The models below are described by inequalities, too. Thus, slack variables used to formulate the model in a canonical form are neglected.

Section 3.1 formulates the mathematical model of the unit commitment problem of a biogas plant in spot markets. Section 3.2 presents the models which include the market and the flexibility premium in the unit commitment of a biogas plant. Finally, section 3.3 contains the models that have been developed to plan optimal offers for control reserve markets. The implementation of the MILP for a rolling unit commitment is explained in Annex D, in particular some crucial issues regarding the implementation.

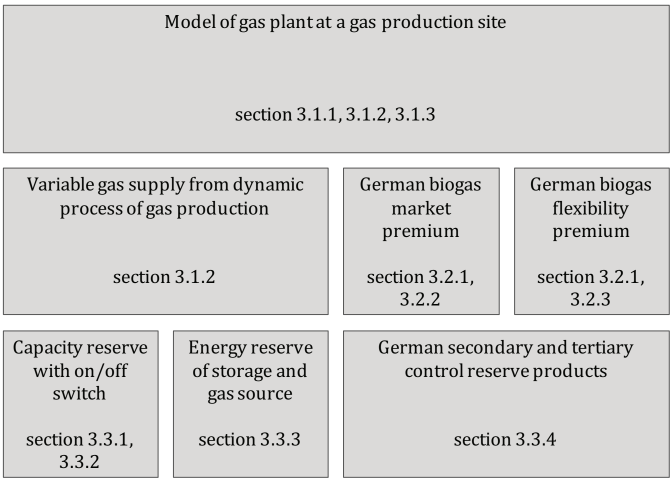

Figure 5: Overview of models developed in this work and organization of chapter 3.

3.1 Model of a gas plant at a gas production site

This section presents the optimization problem that can be applied in use cases considering the biogas plant which is optimizing its power generation for the best gross profit in spot markets. Section 3.1.1 starts by introducing the objective function which defines the gross profit and the corresponding incomes and costs. Section 3.1.2 develops the model of the plant which consists of gas production, a storage unit and power units. Section 3.1.3 develops, in particular, the model of the power unit by adopting state-of-the-art models. This section presents the model for constant efficiency of the power unit, a model considering the characteristic curve with a multiple choice approach and a more efficient model if the linearized consumption curve is convex. A part of the model, in particular Equation 1 to Equation 4, Equation 7 to Equation 11 and Equation 14 to Equation 16 where D was 1, has already been published in (Hochloff, Braun 2014).

3.1.1 Objective function

As did (Havel, Šimovič 2013), (Wille-Haussmann et al. 2010) and (Chang et al. 2004) an objective function is used to maximize the gross income of N plants with respect to spot market prices and costs in the time period T. These techniques are derived from the unit commitment problem as presented in (Carrión, Arroyo 2006). (Chang et al. 2004) stated that market participation just adds maximizing market income to the objective function which minimizes the unit commitment cost so far. So, the difference between the market income and the fuel and start-up costs is maximized.

The objective function (Equation 1) is implemented for biogas plants supplying their power generation to power markets, maximizing the income of power $P_{t,n}^{spot}$ sold at market prices MP_t^{spot}, minimizing the cost of fuel $G_{t,n}^{con.}$ consumed at fuel price c^{fuel}, and the cost c_n^{up} per start-up $s_{t,n}^{up}$.

Equation 1:

$$max\left(\sum_{n=1}^{N}\sum_{t=1}^{T}\left(\Delta t\cdot P_{t,n}^{spot}\cdot MP_t^{spot}-\Delta t\cdot G_{t,n}^{con.}\cdot c^{fuel}-s_{t,n}^{up}\cdot c_n^{up}\right)\right)$$

3.1.2 The plant model

The technical installation of a biogas plant is modeled by three different components which represent the main properties of the biogas plant in terms of its flexibility in power markets. This approach has already been published in (Hochloff, Braun 2014). The optimization problem considers the gas source, the gas storage capacity, and the power units (Figure 6). The power balance of these components is described by Equation 2.

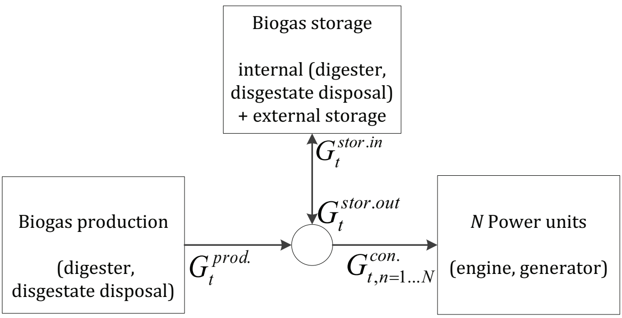

Figure 6: Plant scheme for modeling plant properties and the energy flow.

Equation 2:

$$G_t^{prod.}+G_t^{stor.out}=G_t^{stor.in}+\sum_{n=1}^{N}G_{t,n}^{con.}$$

The gas source is an abstract model of the combined biogas output from the digester and digestate disposal. Gas production is considered either statically, as described by Equation 3, or dynamically within a range, as described by Equation 4. The complex kinetics of fermentation is simplified by maximum differential gas rates per time interval for regulating up (Equation 5) and down (Equation 6) that are derived from (Mähnert 2007).

Equation 3:

$$G_t^{prod.} = G_t^{prod.max}$$

Equation 4:

$$0 \leq G_t^{prod.} \leq G_t^{prod.max}$$

Equation 5:

$$G_t^{prod.} \leq (1 + \epsilon^{up}) \cdot G_{t-1}^{prod.}$$

Equation 6:

$$G_t^{prod.} \geq (1 - \epsilon^{down}) \cdot G_{t-1}^{prod.}$$

The balance of the storage is obtained by Equation 7, keeping incoming and outgoing energy flows in balance with the energy contained. (Wille-Haussmann et al. 2010) presented, for example, this equation for thermal storage respecting losses during charging ($\alpha^{stor.in}$), discharging ($\alpha^{stor.out}$), and storing energy (α^{stor}). Equation 8 is implemented to limit the storage capacity between zero and a maximum available working capacity, as presented by (Kavvadias et al. 2010). The constant S_0, providing an initial storage level, substitutes the variable S_{t-1} in Equation 7 for the first time interval t=1. Optionally, the storage level at the end of the last time interval $S_{t=T}$ is fixed by a constant as described by Equation 9.

Equation 7:

$$S_t = (1 - \alpha^{stor}) \cdot S_{t-1} + \Delta t \cdot \left(\left(1 - \alpha^{stor.in}\right) \cdot G_t^{stor.in} - (1 - \alpha^{stor.out})^{-1} \cdot G_t^{stor.out} \right)$$

Equation 8:

$$0 \leq S_t \leq S^{max}$$

Equation 9:

$$S_{t=T} = S^{end}$$

3.1.3 Electricity generation of the power unit

The power unit is operated within upper and lower boundaries. The binary variable $s_{t,n}^{\mathrm{sp}}$ indicates the power unit spinning. The variable $s_{t,n}^{up}$ indicates the start-up of the power unit by switching to one only when the power unit was running ($s_{t,n}^{\mathrm{sp}} = 1$) after down time ($s_{t,n}^{\mathrm{sp}} = 0$). (Carrión, Arroyo 2006) presented the constraints of Equation 10 and Equation 11 for this purpose.

Equation 10:

$$s_{t,n}^{sp} \cdot P_n^{min} \leq P_{t,n}^{gen.} \leq s_{t,n}^{\text{sp}} \cdot P_n^{max}$$

Equation 11:

$$s_{t,n}^{sp} - s_{t-1,n}^{sp} \leq s_{t,n}^{up}$$

The generated power $P_{t,n}^{gen.}$ is in balance with the power $P_{t,n}^{spot}$ sold, for example, in the spot market and the self-consumed power $P_{t,n}^{self}$ expressed by Equation 12.

Equation 12:

$$P_{t,n}^{gen.} = P_{t,n}^{spot} + P_{t,n}^{self}$$

The generated power $P_{t,n}^{gen.}$ corresponds to fuel consumption $G_{t,n}^{con.}$. Three ways of formulating these relationships are described in the sections below.

3.1.3.1 Modeling constant efficiency

(Wille-Haussmann et al. 2010) and (Kavvadias et al. 2010) simplified the unit commitment of their systems by means of a constant electrical efficiency. Constant electrical efficiency is shown in Equation 13.

Equation 13:

$$G_{t,n}^{con.} \cdot \eta_n^{el.} = P_{t,n}^{\text{gen.}}$$

3.1.3.2 Modeling convex linearized consumption curves

(Carrión, Arroyo 2006) and (Chang et al. 2004) described the linearization of the characteristic curve. They presented a piecewise linearization of the power generation costs, maintaining a convex function (Figure 7).

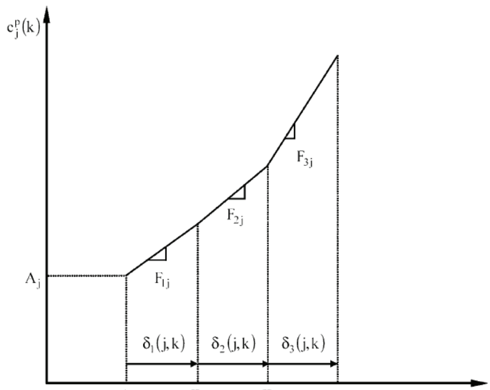

Figure 7: Piecewise linear production costs, extracted from (Carrión, Arroyo 2006)**.**

In a similar way, the fuel consumption, instead of the costs of power unit, is linearized depending on the power generation. The power generation is thereby the sum of the minimum power generation and the power generation of all sections D of the divided operating range (Equation 14). The power generation of each section d is limited by zero and the capacity difference $P_{n,d}^{part,max}$ given in Equation 15. The implemented Equation 16 sum up the fuel consumption instead of the costs, employing the gradient $m_{n,d}$ for each section d. The gradient is defined by

$$m_{n,d} = \frac{\left(G_{n,d}^{max} - G_{n,d}^{min}\right)}{\left(P_{n,d}^{max} - P_{n,d}^{min}\right)}$$

where $G_{n,d}^{max}$ is the fuel consumption at the upper boundary $P_{n,d}^{max}$, and $G_{n,d}^{min}$ is the fuel consumption at the lower boundary $P_{n,d}^{min}$ of power generation in section d.

Equation 14:

$$P_{t,n}^{gen.} = s_{t,n}^{sp} \cdot P_{n}^{min} + \sum_{d=1}^{D} P_{t,n,d}^{part}$$

Equation 15:

$$0 \leq P_{t,n,d}^{part} \leq P_{n,d}^{part,max}$$

Equation 16:

$$G_{t,n}^{con.} = s_{t,n}^{sp} \cdot G_{n}^{min} + \sum_{d=1}^{D} m_{n,d} \cdot P_{t,n,d}^{part}$$

3.1.3.3 Modeling non-convex linearized consumption curves

The linearization of the consumption curve is convex if

$$m_{n,d+1} > m_{n,d} \ \forall \ d \in [1 \ldots D]$$

If this condition is not true, the characteristic curve is to be linearized using a non-convex piecewise approach. (Croxton et al. 2003) and (Vielma et al. 2010) compared different methods such as the multiple choice model, the incremental model and the convex combination model. The multiple choice model is implemented by Equation 17 to Equation 20. The actual power generation $P_{t,n}^{gen.}$ of the biogas plant is the sum of the power generation $P_{t,n,d}^{part}$ in D segments. The boundaries $P_{n,d}^{min}$ and $P_{n,d}^{max}$ limit the power generation $P_{t,n,d}^{part}$ in segment d. Equation 18 enables power generation in segment d if the binary variable $s_{t,n,d}^{sp}$ is one, whereas Equation 19 ensures that only one of the D binary variables is one at the same time. Equation 20 transfers the power generation in segment d to the corresponding gas consumption. Equation 21 forces the variable $s_{t,n}^{up}$ to become one if any binary variable of a segment d is one at t and all zero at t-1.

Equation 17:

$$P_{t,n}^{gen.} = \sum_{d=1}^{D} P_{t,n,d}^{part}$$

Equation 18:

$$s_{t,n,d}^{sp} \cdot P_{n,d}^{min} \leq P_{t,n,d}^{part} \leq s_{t,n,d}^{sp} \cdot P_{n,d}^{max}$$

Equation 19:

$$\sum_{d=1}^{D} s_{t,n,d}^{sp} \leq 1$$

Equation 20:

$$G_{t,n}^{con.} = \sum_{d=1}^{D} \left(s_{t,n,d}^{sp} \cdot G_{n,d}^{0} + m_{n,d} \cdot P_{t,n,d}^{part} \right)$$

Equation 21:

$$\sum_{d=1}^{D} \left(s_{t,n,d}^{sp} - s_{t-1,n,d}^{sp} \right) \leq s_{t,n}^{up}$$

3.2 Models of premiums in the unit commitment

This section develops the models to respect the market premium and the flexibility premium endogenously in the unit commitment. Firstly, section 3.2.1 develops the objective function that contains, additionally, the expected income from both the premiums; the market premium is paid out for the accumulated energy according to thresholds and the flexibility premium is paid out for an excess capacity of the power unit. These payment conditions of the premiums require models that determine the values of the accumulated energy and the excess power. Section 3.2.2 develops the model to determine the accumulated power for the market premium. Section 3.2.3 develops the model to determine the excess power for the flexibility premium.

3.2.1 Objective function

The income of biogas plants from power spot markets is raised by the market premium and the flexibility premium according to Equation 22. Market premiums defined as the difference between the fix tariff $\Psi_{n,l}^{mp}$ and the mean market price of the time period T are paid for the accumulated energy $E_{n,q}^{\mathrm{mp}}$ per threshold q. The flexibility premium Ψ^{flex} is paid for the excess capacity P_{n}^{exc}.

Equation 22:

$$max\left(\sum_{n=1}^{N}\left(\sum_{q=1}^{Q}\left(\left(\Psi_{n,q}^{mp}-\mathrm{T}^{-1}\cdot\sum_{\mathrm{t}=1}^{\mathrm{T}}MP_{t}^{\mathrm{spot}}\right)\cdot E_{n,q}^{\mathrm{mp}}\right)+\Psi^{\mathrm{flex}}\cdot P_{n}^{exc}\right.\right.$$
$$\left.\left.+\sum_{t=1}^{T}\left(\Delta t\cdot P_{t,n}^{spot}\cdot MP_{t}^{spot}-\Delta t\cdot G_{t,n}^{con.}\cdot c^{fuel}-s_{t,n}^{up}\cdot c_{n}^{up}\right)\right)\right)$$

3.2.2 Market premium with thresholds

The market premium for biomass plants includes thresholds above which payments decrease. This relationship between the payment and the premium described a convex linear characteristic, implemented in the objective function Equation 22 which are subject to both the constraints Equation 23 and Equation 24. Equation 23 and Equation 24 limit the power generation $E_{n,q}^{\mathrm{mp}}$ in segment q paid by the difference of the tariff $\Psi_{n,q}^{mp}$ and the mean market price. Equation 23 divides the accumulated power generation of T time intervals into Q or more segments. The convex characteristic of the payment in the objective function ensure that the lower segments are filled first. Equation 24 limits the power generation in each segment according to the thresholds.

Equation 23:

$$\sum_{\mathrm{t}=1}^{\mathrm{T}}P_{t,n}^{gen.}\geq\sum_{q=1}^{Q}E_{n,q}^{mp}$$

Equation 24:

$$0\leq E_{n,q}^{\mathrm{mp}}\leq\sum_{t=1}^{T}\left(P_{n,q}^{\mathrm{upthre}}-P_{n,q}^{\mathrm{lowthre}}\right)$$

3.2.3 Flexibility premium with piecewise definition of excess capacity

The flexibility premium pays the excess power P^{exc} in the objective function (Equation 22). The constant Ψ^{flex} replaces the value 130€/kW contained in the definition of the flexibility premium (section 2.2.2). Equation 25 to Equation 33 define the excess power P^{exc} as well as the segments of the average power P^{use} where the premium is paid, and where not. A multiple choice approach is applied. Four variables represent the average power (P_1^{use}, P_2^{use}, P_3^{use} and P_4^{use}), one of them obtaining a value according to the currently valid segment. Equation 25 calculates the value of average power from the power generation $P_{t,n}^{\mathrm{gen.}}$.

Equation 26 to Equation 29 decide which segment is valid using the binary variables s_1^{flex}, s_2^{flex}, s_3^{flex} or s_4^{flex}. Equation 30 ensures that only one binary variable is true, thus only one segment is valid. Equation 31 to Equation 33 are implemented according to the different functions that define how much capacity can be paid by the premium in each segment. The big-M design[4] of Equation 31 to Equation 33 allows use of the function $\mathrm{P}^{\max} - 1.1 \cdot P_3^{use}$ to limit the excess power in Equation 33, which come into force if s_3^{flex} is true. If segment 1 or 4 are true, Equation 31 reduces the limit of $P_n^{\text{exc.}}$ to zero notwithstanding the limits of both Equation 32 and Equation 33. The binary variable s_2^{flex} being one, limits the excess power to the constant, thus half the installed power.

Equation 25:

$$\sum_{\mathrm{p}=1}^{4} P_p^{use} = \mathrm{T}^{-1} \cdot \sum_{\mathrm{t}=1}^{\mathrm{T}} P_{t,n}^{\text{gen.}}$$

Equation 26:

$$P_1^{use} \leq s_1^{\text{flex}} \cdot 0.2 \cdot P_n^{max}$$

Equation 27:

$$s_2^{\text{flex}} \cdot 0.2 \cdot P_n^{max} \leq P_2^{use} \leq s_2^{\text{flex}} \cdot 0.5 \cdot P_n^{max} \cdot 1.1^{-1}$$

Equation 28:

$$s_3^{flex} \cdot 0.5 \cdot P_n^{max} \cdot 1.1^{-1} \leq P_3^{use} \leq s_3^{flex} \cdot P_n^{max} \cdot 1.1^{-1}$$

Equation 29:

$$s_4^{flex} \cdot P_n^{max} \cdot 1.1^{-1} \leq P_4^{use} \leq s_4^{flex} \cdot P_n^{max}$$

Equation 30:

$$s_1^{flex} + s_2^{flex} + s_3^{flex} + s_4^{flex} = 1$$

Equation 31:

$$P_n^{\text{exc.}} \leq \mathrm{M} \cdot \left(1 - s_1^{flex} - s_4^{flex}\right)$$

Equation 32:

$$P_n^{\text{exc.}} \leq 0.5 \cdot P_n^{max} + \mathrm{M} \cdot \left(1 - s_2^{flex}\right)$$

Equation 33:

$$P_n^{\text{exc.}} \leq P_n^{max} - 1.1 \cdot P_3^{use} + \mathrm{M} \cdot \left(1 - s_3^{flex}\right)$$

3.3 Problem formulation of the unit commitment including control reserve

This section develops the model concerning the planning of control reserve in the unit commitment. A part of the model, in particular Equation 34, Equation 36 to Equation 44, Equation 47 to Equation 51, Equation 56 to Equation 60 where $\xi_{\tau,t,n}^{up}$ and $\xi_{\tau,t,n}^{down}$ was 1, and Equation 69 and Equation 70, has already been published in (Hochloff, Braun 2014). Section 3.3.1 develops the objective functions for two use cases considered in this work. They both add the income from providing control reserve to the objective function but the second use case took the income from the market premium according to section 3.2 into consideration, too. Section 3.3.2 develops the capacity constraints which determine the capacity from the power unit that can be offered on the control reserve market.

[4] A logical condition on inequalities (Kallrath 2002) which is often called the Big-M method is implemented. The constant M is sufficiently big. Thus the constraint is deactivated when M is multiplied by 1 because the constraint is dominated by other constraints where M is multiplied by zero.

Section 3.3.3 develops the energy constraints that consider the available energy from the gas production and storage and thus limit the offer in the control reserve market, too. As all the models are developed with respect to the time interval, section 3.3.4 defines models to determine an equal capacity in all time intervals according to the time slice for which control reserve is procured.

3.3.1 Objective function

The variables of positive and negative control reserve bids per time interval $R_{t,n}^{up}$ and $R_{t,n}^{down}$, respectively, are added to the objective function. The income from control reserve per time interval is described by the income per provided capacity MP_t^{posR} and MP_t^{negR} relative to the time period of the product L^{posR} and L^{negR}. The income per provided capacity contains the capacity price, but it can also contain the income from the energy price for activated control reserve if the energy price is above the marginal costs for activating control reserve. One use case regards the spot market income and the control reserve income according to Equation 34. Another use case includes the market premium according to Equation 35.

Equation 34:

$$max\left(\sum\nolimits_{n=1}^{N}\sum\nolimits_{t=1}^{T}\left(\Delta t\cdot P_{t,n}^{spot}\cdot MP_t^{spot}+R_{t,n}^{up}\cdot MP_t^{posR}/L^{posR}+R_{t,n}^{down}\cdot MP_t^{negR}/L^{negR}\right.\right.$$
$$\left.\left.-\Delta t\cdot G_{t,n}^{con.}\cdot c^{fuel}-s_{t,n}^{up}\cdot c_n^{up}\right)\right)$$

Equation 35:

$$max\left(\sum\nolimits_{n=1}^{N}\left(\sum_{q=1}^{Q}\left(\left(\Psi_{n,q}^{mp}-\mathrm{T}^{-1}\cdot\sum_{\mathrm{t}=1}^{\mathrm{T}}MP_t^{\mathrm{spot}}\right)\cdot E_{n,q}^{\mathrm{mp}}\right)\right.\right.$$
$$\left.\left.+\sum\nolimits_{t=1}^{T}\begin{pmatrix}\Delta t\cdot P_{t,n}^{spot}\cdot MP_t^{spot}+R_{t,n}^{up}\cdot MP_t^{posR}/L^{posR}+R_{t,n}^{down}\cdot MP_t^{negR}/L^{negR}\\-\Delta t\cdot G_{t,n}^{con.}\cdot c^{fuel}-s_{t,n}^{up}\cdot c_n^{up}\end{pmatrix}\right)\right)$$

3.3.2 Control reserve capacity constraints

The control reserve is supplied by regulating the power generation up or down from its current state, which is power generation $P_{t,n}^{gen.}$. Equation 36 (Hochloff, Braun 2014) enables capacity $R_{t,n}^{up}$ to regulate up, in addition to $P_{t,n}^{gen.}$. The sum of both has to be 0 or between the operating limits P_n^{min} and P_n^{max}. If $s_{t,n}^{sp}$ is 0, the binary variable $s_{t,n}^{nsp,up}$ ensures these boundaries are maintained. Equation 37 makes a maximum of one of the binary variables become true. Equation 38 and Equation 39 are used for the non-convex linearization of the characteristic curve.

Equation 36:

$$\left(s_{t,n}^{sp}+s_{t,n}^{nsp,up}\right)\cdot P_n^{min}\leq P_{t,n}^{gen.}+R_{t,n}^{up}\leq\left(s_{t,n}^{sp}+s_{t,n}^{nsp,up}\right)\cdot P_n^{max}$$

Equation 37:

$$s_{t,n}^{sp} + s_{t,n}^{nsp,up} \leq 1$$

Equation 38:

$$\left(\sum_{d=1}^{D} s_{t,n,d}^{sp} + s_{t,n}^{nsp,up}\right) \cdot P_n^{min} \leq P_{t,n}^{gen} + R_{t,n}^{up} \leq \left(\sum_{d=1}^{D} s_{t,n,d}^{sp} + s_{t,n}^{nsp,up}\right) \cdot P_n^{max}$$

Equation 39:

$$\sum_{d=1}^{D} s_{t,n,d}^{sp} + s_{t,n}^{nsp,up} \leq 1$$

Equation 40 enables capacity $R_{t,n}^{down}$ to regulate down from $P_{t,n}^{gen.}$ if the power unit is running. Thus, power generation is reduced to the lower boundary of the operating range or shut down. Providing control reserve by shutting down the power unit is enabled by the binary variable $s_{t,n}^{nsp,down}$set true, so $R_{t,n}^{down}$ is equal to $P_{t,n}^{gen.}$. Equation 41 ensures that $s_{t,n}^{sp}$ is true, too (Equation 41). For the non-convex linearization of the characteristic curve, Equation 42 and Equation 43 are used.

Equation 40:

$$\left(s_{t,n}^{sp} - s_{t,n}^{nsp,down}\right) \cdot P_n^{min} \leq P_{t,n}^{gen.} - R_{t,n}^{down} \leq \left(s_{t,n}^{sp} - s_{t,n}^{nsp,down}\right) \cdot P_n^{max}$$

Equation 41:

$$s_{t,n}^{sp} - s_{t,n}^{nsp,down} \geq 0$$

Equation 42:

$$\left(\sum_{d=1}^{D} s_{t,n,d}^{sp} - s_{t,n}^{nsp,down}\right) \cdot P_n^{min} \leq P_{t,n}^{gen} - R_{t,n}^{down} \leq \left(\sum_{d=1}^{D} s_{t,n,d}^{sp} - s_{t,n}^{nsp,down}\right) \cdot P_n^{max}$$

Equation 43:

$$\sum_{d=1}^{D} s_{t,n,d}^{sp} - s_{t,n}^{nsp,down} \leq 0$$

3.3.3 Control reserve energy constraints

The section above considers the available capacity, whereas this section takes the available fuel into account. The control reserve that increases the power plant output needs a sufficient amount of fuel available when activated. However, the biogas plant's output depends on the storage content and the statically incoming gas. For this reason, the control reserve bid is limited by the energy in terms of the available fuel, too. This limitation on the size of the positive control reserve bid is formulated below.

The central boundary condition formulated by Equation 44 limits the overall plant output in the time period [t...τ] to the storage content before and the gas input during that time period. This constraint is valid for every considerable time period within the planning time. The time period [t...τ] is split by τ'. During the first section from t to τ', the continuous intraday trading is closed and the gas consumed for the output of the biogas plant is defined by $e_{t,\tau,n}$. During the second section from τ'+1 to τ, intraday power contracts can still be traded and the gas consumed for the output of the power plant is defined by $f_{t,\tau,n}$.

Equation 44:

$$S_{t-1} + \Delta t \cdot \sum\nolimits_{t'=t}^{\tau} G_{t'}^{prod.} \geq \Delta t \cdot \sum\nolimits_{n=1}^{N} \left(\sum\nolimits_{t'=t}^{\tau'} e_{t,\tau,n} + \sum\nolimits_{t'=\tau'+1}^{\tau} f_{t,\tau,n} \right)$$

$$\forall\, t, \tau \in [1, T], \tau > t, \tau' > t$$

Equation 44 is implemented for every t and $\tau > t$ within T because the closest time period which implies the endogenous control reserve bid is the most dominant restriction. In contrast, available energy, for example, from the gas production before and after the most dominant time period would relax the limit of the possible control reserve bids. Furthermore, Equation 44 comprises both the time periods containing a block of control reserve bids and the time periods containing several blocks of control reserve bids, which can be consecutive or enclose times without control reserve bids. The variables $e_{t,\tau,n}$ and $f_{t,\tau,n}$ are defined for applying constant efficiency and characteristic curves as described below.

3.3.3.1 Constant efficiency

In time intervals without the possibility of intraday trading, the maximum fuel consumption incorporates the need for the scheduled power generation and the activated control reserve regulating up the power unit. With constant electrical efficiency, $e_{t,n}$ is defined by Equation 45.

Equation 45:

$$e_{t,n} = 1/\eta_n^{el} \cdot \left(P_{t,n}^{gen.} + R_{t,n}^{up}\right)$$

In time intervals with the possibility of intraday trading, the planned generation can be dissolved, and thus the fuel consumption is reduced. However, the power generation and fuel consumption needed to provide down and up regulating control reserve bids, respectively, have to be maintained. Therefore, the fuel consumption $f_{t,n}$ contains the down regulating control reserve instead of the planned power generation.

A first approach is described by Equation 46. As up regulating control reserve bids do not include the minimum fuel consumption if they are offered within the operating range, the minimum fuel consumption G_n^{min} will be added by switching the binary variable $s_{t,n}^{sp,up}$ to true. However, the binary variable $s_{t,n}^{nsp,down,sp,up}$ reduces $f_{t,n}$ by G_n^{min}, planning both up regulating control reserve in the operating range and down regulating control reserve by shutting down the power unit. If down regulating control reserve is offered by shutting down, the minimum fuel consumption is respected by $R_{t,n}^{down}/\eta_n^{el}$. Therefore, the binary variable avoids respecting G_n^{min} twice. Equation 47 to Equation 49 rule $s_{t,n}^{sp,up}$ as true, and Equation 50 to Equation 51 rule $s_{t,n}^{nsp,down,sp,up}$ as true.

Equation 46:

$$f_{t,n} = 1/\eta_n^{el} \cdot \left(R_{t,n}^{up} + R_{t,n}^{down}\right) + \left(s_{t,n}^{sp,up} - s_{t,n}^{nsp,down,sp,up}\right) \cdot G_n^{min}$$

Equation 47:

$$0 \leq R_{t,n}^{up} \leq s_{t,n}^{sp,up} \cdot \left(P_n^{max} - P_n^{min}\right) + s_{t,n}^{nsp,up} \cdot P_n^{max}$$

Equation 48:

$$s_{t,n}^{nsp,up} + s_{t,n}^{sp,up} \leq 1$$

Equation 49:

$$s_{t,n}^{sp} - s_{t,n}^{sp,up} \geq 0$$

Equation 50:

$$s_{t,n}^{nsp,down} - s_{t,n}^{nsp,down,sp,up} \geq 0$$

Equation 51:

$$s_{t,n}^{sp,up} - s_{t,n}^{nsp,down,sp,up} \geq 0$$

Equation 52 describes an improved definition of the maximum fuel consumption after dissolving the planned generation when intraday trading takes place. It includes, explicitly, the minimum fuel consumption G_n^{min} providing down regulating control reserve within the operating range. For this purpose, the binary variable $s_{t,n}^{sp,up/down}$ is introduced. Thus, the variable $f_{t,n}$ will contain the fuel consumption of the complete control reserve bid and the minimum gas consumption G_n^{min} if control reserve is provided within the operating range.

Equation 52:

$$f_{t,n} = 1/\eta_n^{el} \cdot \left(R_{t,n}^{up} + R_{t,n}^{down}\right) + s_{t,n}^{sp,up/down} \cdot G_n^{min}$$

The variable $s_{t,n}^{sp,up/down}$ becomes true if up or down regulation reserve is offered within the operating range as shown by Equation 53. The central idea of this constraint is that either $s_{t,n}^{nsp,up}$ or $s_{t,n}^{nsp,down}$ will be one if up or down regulation is offered by switching the power unit on or off. In this case $s_{t,n}^{sp,up/down}$ is allowed to become one, but Equation 53 is dominated by the limits of the control reserve of Equation 36 to Equation 43. In contrast, the variable $s_{t,n}^{sp,up/down}$ is zero in order to avoid increasing $f_{t,n}$ which is limited by Equation 44, thus reducing the offered control reserve from Equation 52. On the other hand, $s_{t,n}^{sp,up/down}$ will be forced to become one by Equation 53 if up or down regulation reserves are offered in the operating range ($s_{t,n}^{nsp,up} = s_{t,n}^{nsp,down} = 0$).

Equation 53:

$$0 \leq R_{t,n}^{up} + R_{t,n}^{down} \leq s_{t,n}^{sp,up/down} \cdot \left(P_n^{max} - P_n^{min}\right) + s_{t,n}^{nsp,up} \cdot P_n^{max} + s_{t,n}^{nsp,down} \cdot P_n^{max}$$

3.3.3.2 Planning with maximum length of activation

Furthermore, the approach is developed by respecting the duration of reserve activation time. Whereas the equations above incorporate the complete capacity of the control reserve bid throughout each time interval, this section introduces the factors $\xi_{\tau,t,n}^{up}$ and $\xi_{\tau,t,n}^{down}$ to respect an estimated maximum duration of the time in which the control reserve is activated. These factors are defined between zero and one as they are multiplied by Δt in Equation 44.

The central idea of this approach is to reduce the energy needed for activating control reserve in the unit commitment, and thus, to raise the offered amount of control reserve. In contrast to the other variables and coefficients, the factors $\xi_{\tau,t,n}^{up}$ and $\xi_{\tau,t,n}^{down}$ do not depend on the time interval t in the planning time, instead they depend on the currently regarded time period $\tau - (t-1)$ while developing Equation 44 at each time interval t to τ. The reason for distinguishing the factors depending on the time period $\tau - (t-1)$ is that control reserve can mostly be activated in short time periods, however, the share of activated time decreases relative to extending time periods.

Equation 54:

$$e_{t,\tau,n} = G_{t,n}^{con.} + 1/\eta_n^{el} \cdot \xi_{\tau,t,n}^{up} \cdot R_{t,n}^{up}$$

Equation 55:

$$\begin{aligned} f_{t,\tau,n} = 1/\eta_n^{el} \cdot \left(\xi_{\tau,t,n}^{up} \cdot R_{t,n}^{up} + \xi_{\tau,t,n}^{down} \cdot R_{t,n}^{down}\right) \\ + \max\left(\xi_{\tau,t,n}^{up}, \xi_{\tau,t,n}^{down}\right) \cdot s_{t,n}^{sp,up/down} \cdot G_n^{min} \end{aligned}$$

As $s_{t,n}^{sp,up/down}$ considers both directions of activating control reserve within the operating range, the maximum of both coefficients $\xi_{\tau,t,n}^{up}$ and $\xi_{\tau,t,n}^{down}$ is applied.

3.3.3.3 Convex linearization of consumption curve

In consideration of a characteristic curve of the efficiency instead of an efficiency constant, the maximum fuel consumption $e_{t,\tau,n}$ and $f_{t,\tau,n}$ are linearized, too. The linearized fuel consumption variables $e_{t,\tau,n}$ and $f_{t,\tau,n}$, considering the maximum duration of the control reserve activation, are described by Equation 56 to Equation 59 which have been developed following on from the part of this work which has already been published in (Hochloff, Braun 2014). In contrast to the convex linearization of the fuel consumption above, the linearization described below includes only one segment for the operating range, as a convex nature of the model with multiple segments is not proved, or discovered during the experiments.

Equation 56:

$$e_{t,\tau,n} = \left(s_{t,n}^{sp} + \xi_{\tau,t,t}^{up} \cdot s_{t,n}^{nsp,up}\right) \cdot G_n^{min} + m_n \cdot P_{t,n}^{part,e}$$

Equation 57:

$$P_{t,n}^{gen.} + \xi_t^{up} \cdot R_{t,n}^{up} = \left(s_{t,n}^{sp} + \xi_{\tau,t,n}^{up} \cdot s_{t,n}^{nsp,up}\right) \cdot P_n^{min} + P_{t,n}^{part,e}$$

Equation 58:

$$f_{t,\tau,n} = \left(\xi_{\tau,t,n}^{up} \cdot \left(s_{t,n}^{nsp,up} + s_{t,n}^{sp,up} - s_{t,n}^{nsp,down,sp,up}\right) + \xi_{\tau,t,n}^{down} \cdot s_{t,n}^{nsp,down}\right) \cdot G_n^{min} + m_n \cdot P_{t,n}^{part,f}$$

Equation 59:

$$\xi_{\tau,t,n}^{up} \cdot R_{t,n}^{up} + \xi_{\tau,t,n}^{down} \cdot R_{t,n}^{down} = \left(\xi_{\tau,t,n}^{up} \cdot s_{t,n}^{nsp,up} + \xi_{\tau,t,n}^{down} \cdot s_{t,n}^{nsp,down}\right) \cdot P_n^{min} + P_{t,n}^{part,f}$$

The definition of $f_{t,\tau,n}$ according to Equation 52 is modified to Equation 60 in order to consider a linearized characteristic curve.

Equation 60:

$$f_{t,\tau,n} = \left(\xi_{\tau,t,n}^{up} \cdot s_{t,n}^{nsp,up} + \xi_{\tau,t,n}^{down} \cdot s_{t,n}^{nsp,down} + \max\left(\xi_{\tau,t,n}^{up}, \xi_{\tau,t,n}^{down}\right) \cdot s_{t,n}^{sp,up/down}\right) \cdot G_n^{min} + m_n \cdot P_{t,n}^{part,f}$$

3.3.3.4 Non-convex linearization of consumption curve

According to the fuel consumption of power generation, the fuel reserved for activating control reserve is regarded as a non-convex linearization of the characteristic curve. The equations below describe this method of piecewise linearizing the characteristic curve.

Respecting the maximum duration to activate control reserve would lead to a challenging model that distinguishes Equation 63 and Equation 67 for every $\xi_{\tau,t,n}^{up}$ and $\xi_{\tau,t,n}^{down}$ resulting in an increased number of implementations with T^2 if d>1. The reason for that increase is that $P_{t,n,d}^{part,e}$ and $P_{t,n,d}^{part,f}$ would need to be limited by means of the coefficients $\xi_{\tau,t,n}^{up}$ and $\xi_{\tau,t,n}^{down}$ in these constraints in order to apply the right coefficient $m_{n,d}$ in Equation 61 and Equation 65. However, the model is simplified. A simplification can be introduced when $e_{t,\tau,n}$ and $f_{t,\tau,n}$ are overestimated but not underestimated. They are overestimated because the coefficients $\xi_{\tau,t,n}^{up}$ and $\xi_{\tau,t,n}^{down}$ reduce the capacity $P_{t,n,d}^{part,e}$ and $P_{t,n,d}^{part,f}$, thus, they lead to applying segments of operating at lower load and worse efficiency.

Equation 61:

$$e_{t,\tau,n} = \sum_{d=1}^{D}\left(s_{t,n,d}^{part,e} \cdot \xi_{\tau,t,n}^{up} \cdot G_{n,d}^{0} + m_{n,d} \cdot P_{t,n,d}^{part,e}\right)$$

Equation 62:

$$P_{t,n}^{gen.} + \xi_{\tau,t,n}^{up} \cdot R_{t,n}^{up} = \sum_{d=1}^{D} P_{t,n,d}^{part,e}$$

Equation 63:

$$s_{t,n,d}^{part,e} \cdot P_{n,d}^{min} \leq P_{t,n,d}^{part,e} \leq s_{t,n,d}^{part,e} \cdot P_{n,d}^{max}$$

Equation 64:

$$\sum_{d=1}^{D} s_{t,n,d}^{part,e} \leq 1$$

Equation 65:

$$f_{t,\tau,n} = \sum_{d=1}^{D} \left(s_{t,n,d}^{part,f} \cdot \xi_{\tau,t,n}^{up} \cdot G_{n,d}^{0} + m_{n,d} \cdot P_{t,n,d}^{part,f} \right)$$

Equation 66:

$$\xi_{\tau,t,n}^{up} \cdot R_{t,n}^{up} + \xi_{\tau,t,n}^{down} \cdot R_{t,n}^{down} + \max\left(\xi_{\tau,t,n}^{up}. \xi_{\tau,t,n}^{down}\right) \cdot s_{t,n}^{sp,up/down} \cdot P_{n}^{min} = \sum_{d=1}^{D} P_{t,n,d}^{part,f}$$

Equation 67:

$$s_{t,n,d}^{part,f} \cdot P_{n,d}^{min} \leq P_{t,n,d}^{part,f} \leq s_{t,n,d}^{part,f} \cdot P_{n,d}^{max}$$

Equation 68:

$$\sum_{d=1}^{D} s_{t,n,d}^{part,f} \leq 1$$

3.3.4 Constraints of control reserve products

Providing control reserve is constrained by the time and the duration of the products. The variables of the control reserve bid are solved for each time interval t, however, the control reserve products implied multiple time intervals. Furthermore, a valid product can be realized by combining multiple plants. Thus, they can be scheduled individually with respect to capacity and energy constraints, yet interact by creating a common product. The minimum size of a bid is neglected, as a sufficient bid size could easily be achieved by combining several plants. The impact of the minimum bid size on a pool of biogas plants is outside the scope of this work.

3.3.4.1 Tertiary control reserve products

The bid made to the market is the sum of the control reserve provided by each power unit. With regard to K^{posR} and K^{negR} products within the time period T, each of them with L^{posR} and L^{negR} time intervals, the constraint to offer equal capacity in all time intervals of each product is described with Equation 69 and Equation 70.

Equation 69:

$$\sum_{n=1}^{N} R_{t,n}^{up}\,(t = L^{posR} \cdot k + l) = \sum_{n=1}^{N} R_{t,n}^{up}\,(t = L^{posR} \cdot k + l + 1)$$
$$\forall k \in [0, K^{posR} - 1], l \in [1, L^{posR} - 1]$$

Equation 70:

$$\sum_{n=1}^{N} R_{t,n}^{down}\,(t = L^{negR} \cdot k + l) = \sum_{n=1}^{N} R_{t,n}^{down}\,(t = L^{negR} \cdot k + l + 1)$$
$$\forall k \in [0, K^{negR} - 1], l \in [1, L^{negR} - 1]$$

3.3.4.2 Secondary control reserve products

The product constraints of secondary control reserve are formulated in a similar way as those for the tertiary control reserve. However, there is no series of products with equal length as one week contained two products, one for the peak times and one for the off-peak times. Therefore, Equation 71 and Equation 72 are implemented for all time intervals included in L^{peak} and for all time intervals included in $L^{off-peak}$ per week. L^{peak} contains the time intervals t representing time periods from 8.00am to 8.00pm Monday to Friday, and $L^{off-peak} = \{[1 \dots T]\} \setminus L^{peak}$.

Equation 71:

$$\sum_{n=1}^{N} R_{t,n}^{up}\,(t = l) = \sum_{n=1}^{N} R_{t,n}^{up}\,(t = l + 1)$$
$$\forall\, l \in L^{peak} \vee l \in L^{off-peak}$$

Equation 72:

$$\sum_{n=1}^{N} R_{t,n}^{down}\,(t = l) = \sum_{n=1}^{N} R_{t,n}^{down}\,(t = l + 1)$$
$$\forall\, l \in L^{peak} \vee l \in L^{off-peak}$$

4 Unit commitment of biogas plants

This chapter examines how the parameters for implementing the unit commitment problem influence the result. The primary purpose is to provide a context to help understand how best to limit run times and maintain the quality of results. The approach to this analysis is shown in Figure 8.

There is a trade-off between the quality of the result and the run time of solving the MILP. Most of the following analyses dealt with this trade-off. Therefore, the quality was measured by the difference between the objective function value (OFV) of the simulation results with the tested parameters and the OFV of a reference. The OFV was calculated ex-post from the results of the unit commitment with the formula and the constants of the objective function which is the difference between revenues and costs, for example, the OFV of use case B is the sum of incomes from the spot market, positive tertiary reserve market and negative tertiary reserve market minus the start-up and fuel costs. The OFV was calculated from the first 24 hours (Δt=1 h) of the optimization horizon, the remaining hours are called excess time. Thus, the total OFV of the rolling unit commitment is the sum of the OFV of each daily plan throughout the year. As a threshold for the quality criteria, a difference in the OFV of below 0.1% was applied. The reference is defined for each analysis in the respective section.

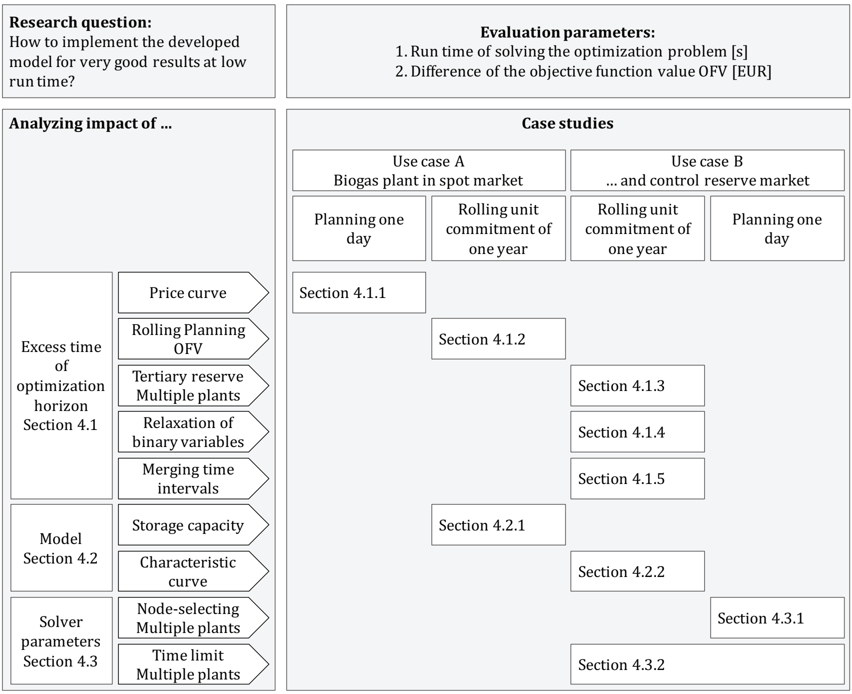

Figure 8: Approach to analyzing the implementation of the model with regard to quality of the result and run time.

The influence of parameters was analyzed step by step beginning with a low complexity biogas plant unit commitment problem (use case A, Table 28 in Annex E) and moving on to the more complex problem of selling control reserve (use case B, Table 29 in Annex E) in addition. A further significant difference between the case studies is the implementation of planning one day at a time, on the one hand and, on the other hand, the implementation of a rolling unit commitment throughout a year. The EPEX Spot SE auction prices from Germany/Austria in 2012 were used for both. Power prices in the excess time of the last days of 2012 were obtained from the 2013 auction prices.

The rolling unit commitment connects the daily planning by means of model input parameters, in particular the state of the power unit and the initial storage level, both obtained from the planning results of the previous day. Thus, the net value of positive and negative differences of the daily OFV appearing throughout the year was taken into account in order to examine the financial impact of the excess time. The initial storage level is set to $S^0 = 0.5 \cdot S^{max}$, and state of the power unit to $s_0^{sp} = 0$ to define the initial conditions for the first day of the rolling unit commitment. In contrast they are set this way for every day when planning single days even if the analysis was carried out by means of the market prices from one year. However, the effects on daily results, for example, the influence of daily price curves from a year on the run time or the OFV difference obtained in one day can be analyzed by the approach to plan only one day.

4.1 Time periods of the rolling planning

A unit commitment problem with a large time period, for example, one year can be solved by rolling planning. The time period of one step of the rolling planning encompasses the actual planning time and some subsequent excess time. However, the excess time lengthens the time period of the optimization problem and thus, the calculation run time. This section presents the results of the investigations which looked at the influence of the excess time on the unit commitment result and calculation run time.

4.1.1 Unit commitment for different time horizons

This section contains the results of examining the influence of optimized time horizons on run times and unit commitment results by means of use case A (Table 28, Annex E). This analysis varied the length of the optimization time horizon from 1 day (T=24) to 50 days (T=1200) and the used price curves. The different lengths of the time horizon were examined by 366 runs of use case A with different historic price curves considering each day of the year as the first day of the simulation. The run time is analyzed before evaluating the influence on the unit commitment result.

Figure 9 plots the mean run time, the 0.99 and 0.01 quantiles, and the median run time from the 366 runs as functions of the number of days in the optimization time horizon. The first finding is, as expected, the exponential increase of the run time. The mean run time was less than 0.15 s and the 0.99-quantile less than 0.5 s for an optimization horizon of one day (24 time intervals) to five days (72 time intervals). With an optimization horizon of ten days (240 time intervals), the mean run time was about 0.5 s and the 0.99-quantile was about 1.0 s. The mean run time increased to 183 s and the 0.99-quantile to 1278 s for an optimization horizon of 50 days (1200 time intervals).

Furthermore, this study found that run times varied hugely. Figure 9 shows that more than 50 per cent of the run times were below the mean value for every number of days except 10. Figure 9 also shows that at least 1 per cent of calculations ran considerably longer, with multiples of the mean value. The reason for the varying run times was the different parameter input in the model which was, in this case, the price curve. An attempt has been made to find a correlation between the price curve and run times (Appendix F).

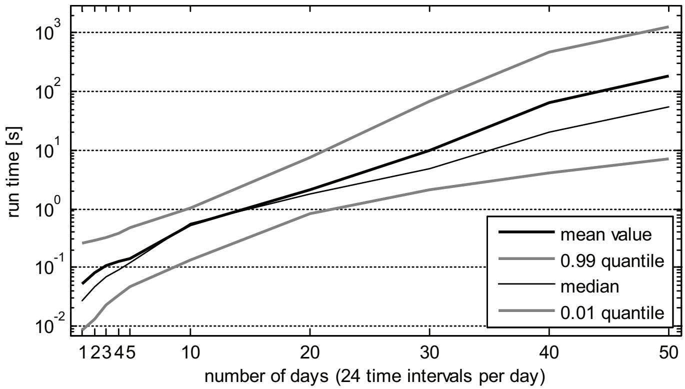

Figure 9: Run times of use case A with different numbers of time intervals.

Figure 10 contains the analysis of the size of the OFV differences on the first day of the optimization horizon which was analyzed concerning the daily rolling planning on the day-ahead spot market. The figure displays, for each optimization horizon, the histograms of relative OFV differences. The relative difference of shorter optimization horizons from the 40-day optimization horizon was used. The histogram was created with centers from -50% to 120%, with increments of 5%.

The figure shows that 82% of the results of the one-day optimization horizon fell short of the result of the 40-day optimization horizon. There was a gap of about 20% in 20.5% of days throughout the year, about 15% in 17.5% of days, 10% in 22.7% of days and 5% in 20.8% of days. There were no differences found in 14% of days in the year. Figure 10 shows, further, that there were no differences on 73% of the days for optimization horizons of two days. The increase of the optimization horizon led to deviations of about -10% on 4% of the days, about -5% on 12% of the days and about 5% on 10% of the days. A further increase of the optimization horizon to three days resulted in a deviating OFV on the first day of about -5% on 4% of the days and 5% on 3% of the days, whereas no deviations were found on 92% of the days. The increase of the optimization horizon to four days raised the share of days without deviations to 98%.

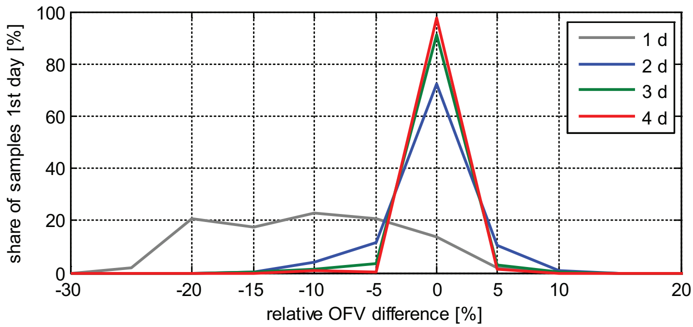

Figure 10: Frequency of differences between unit commitment results (OFV) on the first day of several optimization horizons in ratio to 40-day optimization horizon over period of a year.

These findings from use case A support the expectation that there is a trade-off between the run time and result quality; both affected by the optimization horizon of the unit commitment. The results of this analysis are interpreted with the assumption that results of sufficiently high quality are obtained with an optimization horizon of 40 days. Therefore, the findings below are to be respected when defining time periods:

- The calculation run time rose exponentially in the linear increase of time intervals in the unit commitment.
- The run time varied greatly, depending on the variation of the input data. On a few days, the unit commitment problem was solved in multiples of the mean time. This effect raised for increasing unit commitment problems by lengthening the optimization horizon. Then, a negative correlation coefficient was recognized between the run time and the daily price spreads for optimization horizons longer than a month (compare with Appendix F).
- Increasing the optimization horizon to several days improved the result quality for the planning time which was actually the first day of the optimization horizon. Very small deviations from unit commitment results with much longer time periods were achieved by adding three days to the actual planning time, more days did not affect the result quality.

It was, thus, concluded that the implementation of a four-day optimization horizon could be the proper adjustment for the rolling day-ahead planning. With use case A, an excess time of 3 days, added to the actual planning time, reliably led to very accurate results for the planning time with short calculation run times. However, the findings of these analyses are limited, as the positive and negative differences of the actual planning time were measured in isolation. These differences could be compensated in rolling planning, since unit commitment results of the planning time are linked to results of previous and following planning times. Linking the planning times, for example, in use case A, by respecting the storage level from each of the previous time periods, enlarges the variance of input parameters. Such an examination enables the evaluation of the profitability but not the kind of run time analysis and result accuracy as shown above.

4.1.2 Excess time in the rolling unit commitment

The previous section shows the differences in unit commitment results and run times with increasing time periods for separate days with different price scenarios. It was shown that the result (OFV) of the first day was affected by the total length of the optimization horizon, especially in a time frame of up to four days. Thus, the rolling unit commitment was carried out adding excess time to each planning time. The previous section provides an analysis that supports adjusting the excess time of the rolling unit commitment in consideration of run time and result accuracy. This section adds an evaluation of the excess time's impact on the profit by examining use case A in rolling unit commitment throughout a year. Each planned time period was a day with 24 time intervals and excess time varied within a range from 0 h to 96 h in steps of 12 h. The relative difference in the annual OFV from the one obtained at 96 h excess time was analyzed. In contrast, a relative improvement of the OFV by extending the excess time step by step is shown in Appendix F. Fixed premiums of 50€/MWh, 100€/MWh and 150€/MWh on top of the market prices were introduced in order to investigate the change in the result quality subject to the absolute OFV.

Figure 11 depicts the mean, the 0.95-quantile and the 0.99-quantile of the optimization run times. As expected, the excess time increased the mean run time from 0.04 s at 0 h excess time to 0.13 s at 96 h excess time. However, the run time did not increase monotonously. The 0.95 and the 0.99 quantiles showed a minimum at 36 h excess time.

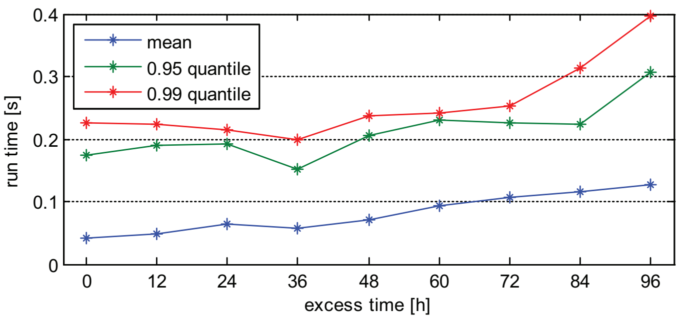

Figure 11: Optimization run times of the rolling unit commitment with use case A and different excess time intervals.

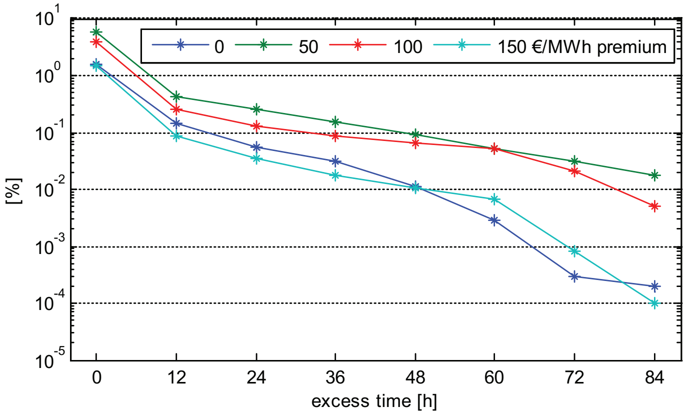

Figure 12: Improvement of the annual OFV depending on the excess time.

Figure 12 shows the relative difference of the annual OFV depending on the excess time and in relation to 96 h excess time. Four cases are presented, three of them containing a premium on the market prices of 50€/MWh, 100€/MWh and 150€/MWh. The figure shows that the difference of the OFV increased monotonously by diminishing the excess time. The relative difference was between 0.0001% and 0.03% at 72 h and 84 h excess time. It rose to a difference of approx. 0.01% to 0.09% at 48 h excess time and approx. 0.03% to 0.25% at 24 h excess time. Eliminating the excess time resulted in a relative difference between 1.5% and 5.8%.

The relative difference depended on the total value of the annual OFV, too. This is shown by the premiums: the total value of the annual OFV was -246 000€ without a premium, -71 000€ for a 50€/MWh premium, 105 000€ for a 100€/MWh premium and 281 000€ for a 150€/MWh premium. Figure 12 shows that high total values of the OFV effected smaller differences than lower total values, a relative difference below 0.1% was achieved at 24 h excess time. In contrast, low total values needed 48 h excess time for a relative difference of the OFV below 0.1%.

The deviations of the annual OFV were quite small in comparison to the results of the previous section which had high deviations of the OFV, up to 20% per day. The reason for this is shown by the daily deviations of the OFV, for example, for 48 h and for 72 h excess time. Figure 13 shows the OFV of each planning time with 48 h and with 72 h excess time deviating from the OFV with 96 h excess time throughout the year. Both positive and negative deviations appeared, as was expected from the results of the previous section. Most of them appeared on consecutive days, thus compensating the positive and negative financial impact within a few days. That means, for example, less power generation on one day led to respectively more power generation on one of the following days. The figure shows further that far fewer deviations occurred for 72 h than for 48 h excess time.

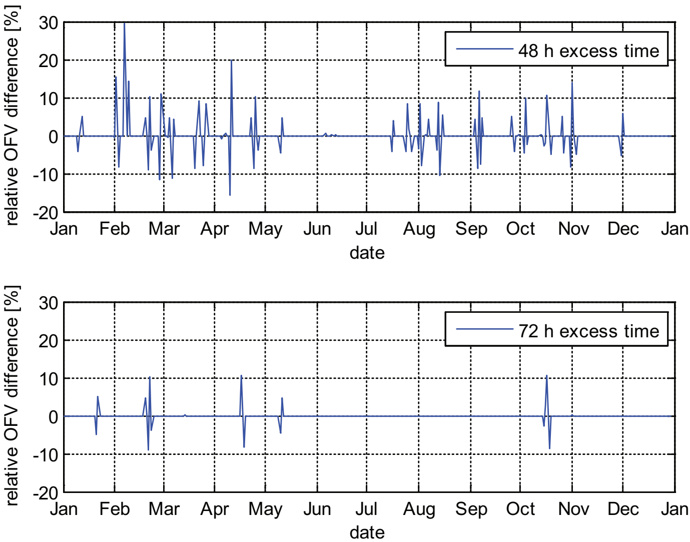

Figure 13: Relative OFV differences per day of planning with 48 h and 72 h to planning with 96 h excess time.

It can be concluded that the implementation of excess time improves the result of the unit commitment. The annual financial effect is below 10%, yet on a single day the effect can account for about 20%. The largest improvement in the result is achieved if a small excess time of about 12 h is incorporated. More excess time had much less impact on the result, nevertheless, it improved the result. Whereas 12 h excess time made an effect of between 1% and 10%, further excess time made an effect between 0.01% and 1%. Extending the excess time to beyond 24 h results in financial improvements below 0.1%. The achieved improvement of the result is paid by increasing run time. Use case A incorporated very small run times, even with several days excess time, but the financial impact for more than 24 h excess time was negligible.

4.1.3 Excess time intervals for tertiary reserve planning

Bidding for tertiary control reserve increases the complexity of the optimization problem. Thus, this section analyzes the impact of the excess time on the unit commitment result and especially on the run time. The focus is on the run time because the developed model will be applied for the unit commitment in virtual power plants. For this reason the analysis was extended by considering multiple plants in the unit commitment. The excess time was varied from 0 h to 96 h.

Figure 14 shows the curve of the result quality depending on the excess time. The result quality was measured by the relative difference of the annual OFV at several excess times from the result with four days excess time (96 h). Increasing excess time from 0 h to 72 h, the relative OFV difference diminished exponentially. The relative difference was reduced from 1.6% at 0 h to 0.05% at 24 h, further to 0.007% at 48 h and finally to 0.0005% at 72 h excess time. That result corresponds to the expectation derived from the results shown in Figure 12.

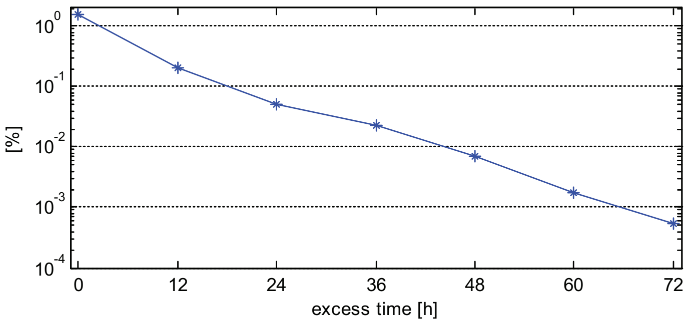

Figure 14: Relative differences of the annual OFV from the rolling unit commitment of use case B depending on the number of excess time intervals (Δt=1 h).

A difference in the results was expected from the run time as the complexity of use case B exceeds complexity of use case A. The mean run time of use case B with one, two and three plants is presented in Figure 15. The mean run time increased exponentially from 0.15 s at 0 h to 25.3 s at 96 h excess time. In contrast the mean run time of use case A rose from 0.04 s to 0.13 s in the same range of excess time.

Adding plants with the same use case B to the unit commitment problem raised the complexity, resulting in an excessive increase of run time. The mean run time with two plants rose from 0.65 s at 0 h to 38.2 s at 48 h excess time. The mean run time with three plants rose from 2.8 s at 0 h to 40.6 s at 24 h excess time.

The run time is plotted against the relative differences in the OFV in Figure 16 in which the data are displayed as the reference. On the one hand the figure shows that the run time increased significantly when the excess time was extended from 24 h, but the relative differences in the OFV, thereby, was not decreased much. On the other hand, the run time was decreased significantly by reducing the excess time below 24 h.

It can be concluded that the quality of results is sufficient with 24 h excess time, as the difference from results with much more excess time, such as 96 h, was only 0.05%, and thus, the mean run time can be kept at 0.5 s without losing more than 0.1% profit. However, considering a pool in the unit commitment results in quickly increasing run times. Planning and supplying control reserve jointly in a pool is inevitable as distributed plants can only exceed the minimum bid size collectively. Further options to relax the optimization problem in order to save run time are examined below.

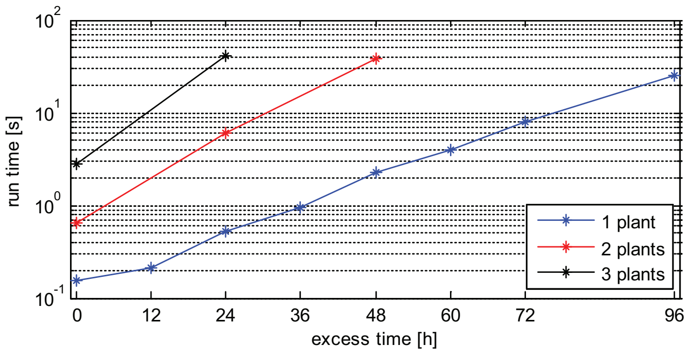

Figure 15: Mean run times of the day-ahead rolling unit commitment of use case B depending on the number of excess time intervals with different numbers of biogas plants.

4.1.4 Relaxing binary variables of the excess time

The previous sections show that increasing excess time periods improves the result of the rolling unit commitment, and it also raises the run time exponentially because of the additional binary variables. The OFV, however, was finally obtained only from the actual planning time. For this reason, binary variables need to remain binary at least in the planning time. However, excess time considers the market development after the actual planning time which is why an attempt was made to save run time and maintain result quality by relaxing the binary variables of the excess time. Those variables, that had been defined binary for each time interval, were defined binary and continuous depending on the represented time interval.

The analysis was carried out by means of use case B planning bids from a biogas plant for power spot and tertiary reserve markets. For the excess time, the binary variables stayed binary for a number of time intervals at the beginning of the excess time and were defined continuous for the remaining time intervals. Thus, the total number of binary variables was constant with the increasing numbers of excess time intervals. In various investigations, all excess time variables were set continuous, or they were defined binary for the first 4 to the first 32 time intervals.

The most effective results are presented in Figure 16. The figure shows the run times plotted against the relative OFV difference from the OFV with 96 h excess time. The reference curve is obtained from the unit commitment without the relaxation of binary variables and excess times from zero to 72 h. Against this reference, the figure shows that remaining binary variables in the first 8 h of 24 h excess time, and 32 h of 48 h excess time decreased the run time while the relative OFV difference was equal or even less. The OFV difference was approx. 0.052% at 24 h excess time and still about 0.053% due to the relaxing of the binary variables in the last 16 time intervals which means the binary variables were retained in the first 8 time intervals of the excess time. This relaxation reduced the run time from 0.52 s to 0.43 s. Furthermore, the OFV difference was 0.007% at 48 h excess time and still 0.0055%, due to relaxing the binary variables in the last 16 time intervals, which means the binary variables were retained in the first 32 time intervals of the excess time. This relaxation reduced the run time from 2.31 s to 1.43 s.

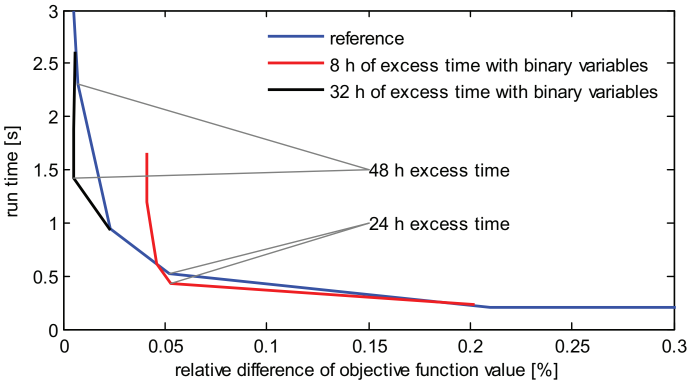

Figure 16: Mean run time against relative OFV differences of use case B: reference curve from reducing excess time and curves from relaxing binary variables while keeping binary variables in 8 h and 32 h in the excess time.

Finally, relaxing binary variables to continuous variables was found to be an adequate option to reduce the run time while keeping the quality of the unit commitment result. This effect was achieved with a few combinations of excess time and intervals without relaxation. As a minimum the binary variables of the first 8 h of a 24 h excess time needed to be kept in order to achieve the same quality of result as that without relaxation, that means all binary variables in the 24 h excess time were kept. The same effect was noticed at 48 h excess time and binary variables kept in 32 h of the excess time. With use case B, both these observations might lead to the assumption that, generally, the last 16 h of the excess time are less important than the rest of the excess time. These 16 h still have to be considered, but only as continuous variables. In contrast, relaxing more than the last 16 h of the excess time resulted in reduced quality, without an effective reduction of run time. For example, relaxing the last 28 h of a 48 h-excess time (binary variables of 20 intervals kept) increased the OFV difference to the same level obtained by a 36 h-excess time but the mean run time of 1.16 s was still higher than the 0.95 s of the 36 h-excess time.

It can be concluded that relaxing binary variables in the excess time is a successful way to relax the optimization problem within limits. The run time was reduced while the unit commitment result maintained the same quality if the last 16 h or less of the excess time were relaxed. Further relaxations reduced the run time but at a loss of result quality.

4.1.5 Relaxation by merging excess time intervals

This section deals with a further attempt to raise the run time and maintain the unit commitment result by introducing measures to relax the excess time. For the same reason as in the previous section about relaxed binary variables, it was assumed that measures to relax excess time variables marginally influence the unit commitment result in the planning time. This section relaxes optimization problems by merging time intervals in the excess time by increasing the time interval from Δt=1 h to Δt=2 h, resulting in half the number of variables, especially binary variables, in that part of the excess time. Several tactics, including varying excess time and number of merged time intervals, were examined in consideration of the run time and the unit commitment results. The total excess time varied between 12 h and 96 h and the non-relaxed time intervals after the planning time varied between zero and 32 (number of time intervals that stayed Δt=1 h). The reference of the examination was the unit commitment with its according excess times and all excess time intervals covering a time period of an hour.

The results of the remaining 8 h of 24 h excess time, and 32 h of 48 h excess time without any relaxation are presented in Figure 17. The figure shows the run times plotted against the relative OFV difference from the OFV with 96 h excess time. The reference curve is obtained from the unit commitment without the relaxation of binary variables and excess times from zero to 72 h. Against this reference, the figure shows that keeping a 1 h time interval in the first 8 h of 24 h excess time, and 32 h of 48 h excess time decreased the run time. However the relative OFV difference increased as a result of this relaxation. Keeping 8 time intervals of 24 h excess time at Δt=1 h increased the OFV difference from 0.052% to 0.088% while the run time decreased from 0.52 s to 0.34 s. Keeping 32 time intervals of 48 h excess time at Δt=1 h increased the OFV difference from 0.007% to 0.017% while the run time decreased from 2.31 s to 1.57 s.

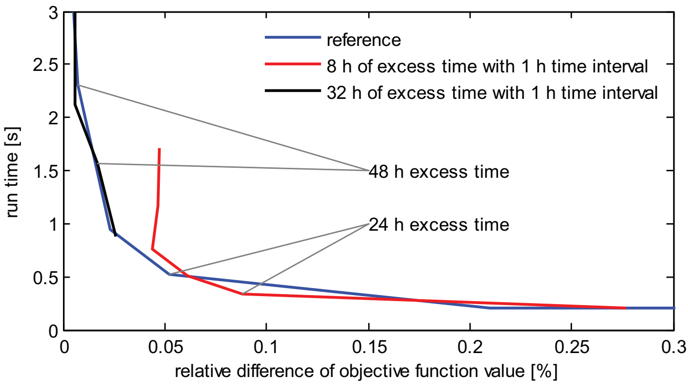

Figure 17: Mean run time against relative OFV differences in use case B: reference curve from reducing excess time and curves from merging excess time intervals to Δt=2 h while maintaining 8 h and 32 h with Δt=1 h.

In contrast to relaxing binary variables in the excess time, there was no relaxation of the optimization problem without loss of result quality. Merging time intervals in the excess time reduced the mean run time very effectively, however, a loss of result quality was suffered in every analysis. Merging time intervals reduces the run time more than relaxing binary variables when the first 8 time intervals of a 24 h excess time are not relaxed, but it is not so for the first 32 time intervals of a 48 h excess time. Reducing the excess time, however, had a higher impact on the run time but also on the result quality. Therefore, merging time intervals was a suitable tactic to reduce the run time rather than reducing the excess time as less result quality was lost. For example, the relative OFV difference at 24 h excess time was raised from 0.052% to 0.137% while the run time was reduced from 0.52 s to 0.27 s by increasing the time interval to 2 h in the complete excess time. In contrast, reducing the excess time to 12 h raised the relative OFV difference to 0.21% and reduced the run time to 0.21 s. So, the gain in run time from merging the intervals is, in terms of the loss of the OFV difference, better than what is gained by reducing the excess time.

4.2 Impact from the model

4.2.1 Excess time depending on the storage horizon

The plant design set by use case A contained a storage horizon of 12 h that was dedicated to one recharging and discharging cycle per day. The storage horizon was defined symmetrically considering both the ratio of storage capacity to continuous gas supply, and the ratio of storage capacity to the extension of the power unit capacity. The storage dimensions in use case A enabled a continuous gas supply of about 12 hours to be held and the discharge of the storage unit within 12 hours while generating electricity. While generating electricity at full load, the power unit consumed the storage content and, additionally, the continuous gas supply. This section varies the storage horizon in order to analyze its impact on the accuracy depending on the excess time. This investigation analyzed the financial impact of the annual OFV, varying the storage horizon between 12 h and 10 days. The corresponding storage sizes in MWh are indicated in Table 7. The excess time was varied between 24 h and 60 days for each storage horizon.

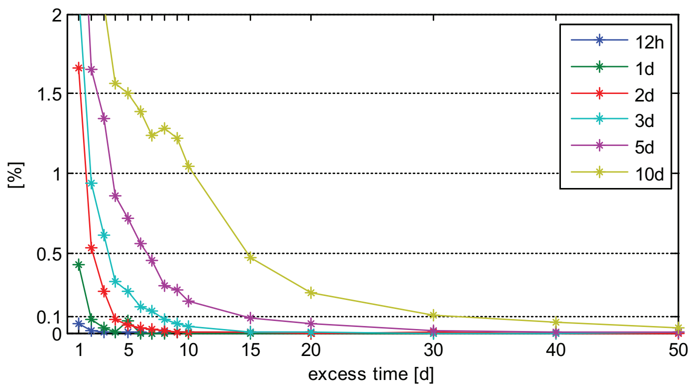

Figure 18: Relative difference of the annual OFV depending on the excess time of the rolling planning for different storage horizons from 12 h to 10 d.

Figure 18 shows for each storage horizon the relative difference between the annual OFV and the result with the longest excess time. As expected, the relative OFV difference increased if the storage capacity was raised. Additional excess time reduced the relative OFV difference. As a benchmark, a relative difference of less than 0.1% was chosen. Table 7 contains the storage horizons and the corresponding excess time causing a relative OFV difference below 0.1%.

Table 7: Storage horizon in days and MWh and excess time in days at relative OFV difference below 0.1%

Storage [d]	0.5	1	2	3	5	10
Storage [MWh]	11.57	23.13	46.27	69.4	115.7	231.3
Excess time [d]	1	2	4	8	15	40

Furthermore, it was observed that the run time depended on the storage horizon as well as the optimization horizon. Figure 19 shows the mean run time of the unit commitment of use case A with different storage horizons depending on the excess time. The run time increased exponentially, as was expected from the results of section 4.1.1. However, the run times of small storage units can be much higher than the run times of large storage units at the same optimization horizon. For example, the mean run time of 12 h storage horizon increased exponentially from 0.06 s with 1 d excess time to 0.5 s with 9 d excess time and further to 10 s with 30 d excess time. In contrast, the mean run time of the 48 h-storage horizon increased from 0.05 s with 1 d excess time to 0.44 s with 30 d excess time. The run time difference of larger storage capacities from the 2 d-horizon was not as much as between the 12 h, 24 h and 48 h-storage horizons. For example, the mean run time of the 10 d-storage horizon was 0.31 s with 30 d excess time.

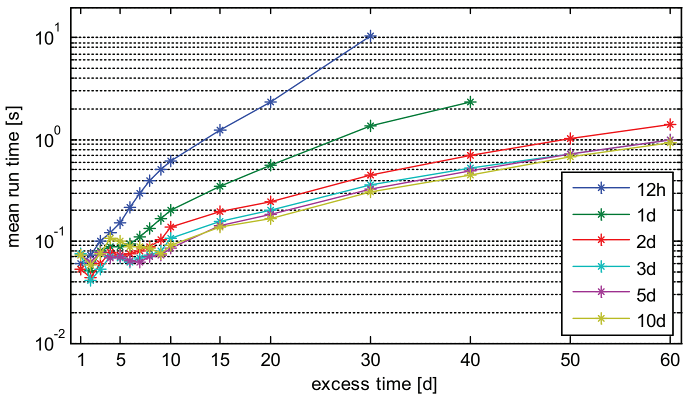

Figure 19: Mean calculation run time of use case A with different storage horizons depending on the optimization time horizon.

It can be concluded that the storage horizon had an impact on defining adequate excess time in order to analyze use cases by rolling unit commitment. The analysis of use case A has shown that a unit commitment with large storage horizons of more than a day should be carried out with at least double that amount of excess time in order to achieve the most profitable results. It has been shown that too much excess time does not harm the quality of the result but it raises the run time unnecessarily. The rise in the run time of a unit commitment with a 2 d-storage horizon or more is not as critical as with smaller storage horizons. Thus, small storage horizons of a day or below should be analyzed with a maximum 2 d excess time in order to achieve very profitable results with a minimum run time.

4.2.2 Relaxation of the power unit model

This section deals with variations on modeling the power unit and focuses on two aspects: the approximation of the real fuel consumption behavior at part load and how to model the characteristic curve. The objective is to identify well-suited models with short run times. However, exact data about efficiency losses were very difficult to obtain. Useful data can be drawn from data sheets of biogas and natural gas CHP units and often contain electrical and thermal efficiency values at 50%, 75% and 100% load. Further linearizations of the characteristic curve needed more detailed data of the characteristic curve. The characteristic curve was reconstructed using a second grade curve fit. This reconstruction was then linearized into three and four segments. Interpolations and the reconstruction of the characteristic curve using a 2nd grade curve fit based on data sheet information are shown in Table 8 and Figure 20, where p is the relative load and η_{el} the electrical efficiency.

Table 8: Relative load and electrical efficiency from data sheet, 2nd grade curve fit and piecewise interpolations with 3 and 4 segments

Data sheet	Relative load	$p = 0.5, 0.75, 1$
	El. efficiency	$\eta_{el} = 0.381, 0.404, 0.415$
2nd grade curve fit		$\eta_{el}(p) = -0.096p^2 + 0.212p + 0.299$
3 segments	Relative load	$p = 0.5, 0.6667, 0.8333, 1$
	El. efficiency	$\eta_{el} = 0.381, 0.3977, 0.409, 0.415$
4 segments	Relative load	$p = 0.5, 0.625, 0.75, 0.875, 1$
	El. efficiency	$\eta_{el} = 0.381, 0.394, 0.404, 0.411, 0.415$

The consumption curve was not convex for all linearizations depicted in Figure 20. For this reason, the examination of use case B was carried out with the non-convex piecewise linearization approach. The results were compared to the result of a convex piecewise linearization approach with one segment and to the result of a constant efficiency unit model that neglected efficiency loss at part load. These piecewise linearizations of the characteristic curve were examined by means of use case B which is described in Table 29 (Annex E) for all three different approaches which consider the electrical efficiency.

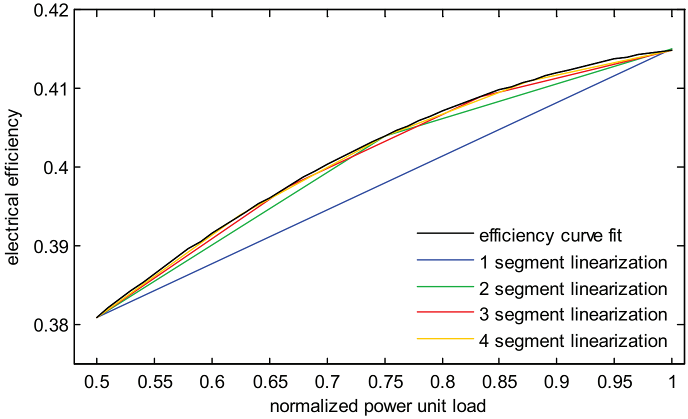

Figure 20: Characteristic curve of electrical efficiency and linearizations with one to four segments.

The mean run times of those implementations are shown in Figure 21. The shortest run time was achieved by modeling constant electrical efficiency of a power unit. The mean run time was between 0.24 s for 24 h excess time and 1.6 s for 72 h excess time. The run time of models with linearized consumption curves increased. However, the model of convex linearized consumption curves was more efficient, with mean run times ranging from 0.52 s at 24 h to 8 s at 72 h excess time. The model of non-convex consumption curves increased the mean run times to 0.63 s at 24 h and 9.7 s at 72 h excess time. Increasing the number of segments that approximate the consumption curve raised the run time. For example, the mean run time was raised to 0.41 s for four segments and 24 h excess time and to 51.8 s for three segments and 72 h excess time.

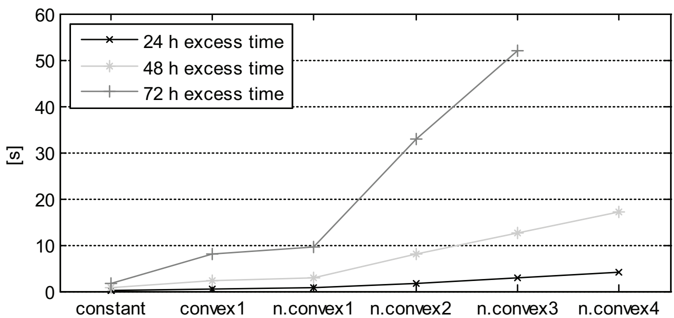

Figure 21: Mean run times of use case B implemented by constant fuel consumption, one to four segments of consumption curve, convex and non-convex piecewise linearization and 24 h, 48 h and 72 h excess times.

The approximation of the characteristic curve influenced the unit commitment results to the same extent as the fuel consumption deviated. The unit commitment results are shown by duration curves in Figure 22. The duration curves show how many hours of a year at full load and at part load resulted from the implementations of use case B. The unit commitment with constant electrical efficiency resulted in scheduling power generation to about 1882 h at part load. Considering the efficiency losses of linearization with one segment reduced the number of part load hours to 723 h for the convex curve model and to 679 h for the non-convex curve model. Modeling the characteristic curve more exactly with four segments increased, in turn, the number of part load hours to 925 h.

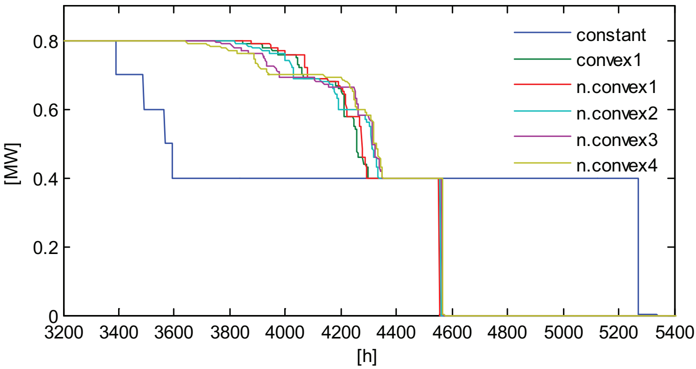

Figure 22: Duration curve of use case B with constant efficiency, convex and non-convex characteristic curve linearization and different numbers of segments approximating the characteristic curve.

Table 9 shows the resulting failure of the different characteristic curve approximations. The planned gas consumption from the unit commitment was compared to the calculated gas consumption using the values from the efficiency curve which fit the planned power generation. Table 9 contains the sum of the planned power generation, the difference between actual and planned gas consumption and the mean efficiency resulting from unit commitment and exact calculation. The unit commitment with constant efficiency underestimated the gas consumption at part load resulting in a difference of approx. 151 MWh/a. The linearizations of the characteristic curve shown in Figure 20 overestimated the gas consumption. The resulting fuel demand failures were about 1.3 MWh/a for the non-convex model with one segment and 1.35 MWh/a for the convex one and diminished to 0.23 MWh/a for four segments of the characteristic curve.

Table 9: Annual power generation and difference between planned and actual gas consumption from unit commitment of use case B with constant efficiency, convex and non-convex characteristic curve linearization and different numbers of segments approximating the characteristic curve.

	constant	convex1	n.convex1	n.convex2	n.convex3	n.convex4
Power generation [MWh/a]	3511.2	3497.25	3498.19	3498.29	3498.36	3498.51
Mean efficiency: unit commitment	0.415	0.41335	0.41346	0.41347	0.41348	0.41350
Mean efficiency: characteristic curve	0.40773	0.41342	0.41353	0.41351	0.41350	0.41351
Planned minus actual gas consumption [MWh/a]	- 150.76	1.35	1.30	0.80	0.42	0.23

It can be concluded that the efficiency losses at part load need to be considered by at least one segment of piecewise linearization of the characteristic curve. Neglecting efficiency losses results in large deviations from the schedule, the calculated fuel consumption, and the fuel consumption costs. Increasing the number of segments approximating the characteristic curve reduces the deviations and enables an exact calculation of unit commitment at part load. However, the run time of calculating the unit commitment increases as non-convex consumption curves need extra binary variables for each segment while the gained reduction from deviations is small. Considering one segment of piecewise linearized characteristic curve seems to be sufficient.

4.3 MIP-solving parameters

The software Cplex Optimization Studio V12.4 offers various opportunities to parameterize the process of solving an optimization problem. Cplex offers two major algorithms to solve mixed-integer programming (MIP), the branch-and-cut algorithm (default setting) and a dynamic search algorithm that is not considered in the following. Furthermore, opportunities are offered to influence the search strategy, especially the node and the variable selecting strategy, and to set abort criteria such as tolerances and limits.

The selection of nodes and variables is an important part of the branch-and-bound search in MIP (Kallrath 2002). The node-selecting strategies used by the software are examined in the following in consideration of the run time to solve specific problems in this work. The default setting of the variable selecting strategy is an automatic strategy adjustment. During the process of branching Cplex chooses the rule most adapted to the optimization problem and the progress (IBM). Therefore, the node-selecting strategy was examined, but not the variable-selecting strategy.

Limits can be set to abort the calculation, for example, when the size of the tree memory or the time taken to search for the mixed integer solution hits a defined value. Tolerances can be set to abort the calculation, for example, when the OFV of the current solution reaches a defined difference from the solution of the linear relaxation. Limits and tolerances need to be used carefully as they affect the result of the optimization.

The use of limits and tolerances needs to be integrated into a strategy adapted to the specific problem. In this case, the rolling unit commitment exerts a lot of single optimizations that are solved quickly in most cases, but some calculations extend the run time enormously as shown above. For this reason, a limit, especially a time limit that affects only these optimization runs, is more effective than a tolerance that affects every optimization run. Knowledge about these rare very high run times may help to find effective time limits, with negligible impact on the annual OFV. Time limits are to be used restrictively, for example, at the third quartile of run times, which means 75% of the run times are below that limit, as aborting at a time limit causes an impact on the OFV.

4.3.1 MIP node-selecting strategy

The software Cplex Optimization Studio V12.4 presents the user with the following node-selecting strategies:

- Depth first (DF)
- Best bound (BB), default
- Best estimate (BE)
- Alternative best estimate (ABE)

The run times of these strategies were analyzed by means of use case B, varying the number of plants, the length of excess time and the price curve. Each combination of node-selecting strategy, length of the excess time and number of plants was examined by 366 runs of use case B with different historic price curves considering each day of the year as the first day of the simulation. Thus, a distribution of run times was obtained for each combination of node-selecting strategy, length of the excess time and number of plants. The investigation was carried out at first with one plant (N=1) and an optimization horizon of T=48 time intervals (Δt=1 h). The optimization problem was changed by increasing the optimized time horizon to T=72 and T=96 and separately the number of power units to N=2 and N=3.

The resulting distribution of the run times for the different branch-and-bound strategies is depicted in boxplots (box-and-whisker plots) in Figure 23 and Figure 24. The whiskers cover about 97% to 99% of the results. Extremely high values were treated as outliers. The ABE-strategy achieved the minimum mean run time of 0.67 s at T=48, 2.40 s at T=72, and 7.16 s for one plant, 5.62 s for two plants and 52.96 s for three plants when T=96. The longest run time was needed by the DF strategy. Focusing on the third quartile of the run times, the BB, BE and ABE strategy achieved the minimum values.

Figure 23 shows the run times of use case B for one plant, varying the optimization time horizons T and search strategies. The third quartile of the run times at T=48 was 0.93 s with the DF strategy, 0.9 s with the BB strategy, 0.89 s with the BE strategy and 0.89 s with the ABE strategy. At an optimization horizon of T=72, the third quartile was 3.2 s with the DF strategy, 3.0 s with the BB and the BE strategy and 3.1 s for the ABE strategy. An optimization horizon of T=96 accomplished the third quartile in 8.4 s with the DF strategy, 8.1 s with the BB strategy, 8.2 s with the BE strategy and 7.8 s with the ABE strategy.

Figure 24 shows the run times of use case B with two and three plants (T=48). The third quartile of the unit commitments' run times with two plants was 6.0 s with the DF strategy, 5.9 s with the BB strategy, 6.1 s with the BE strategy and 5.9 s with the ABE strategy. The unit commitment with three plants had run times in the third quartile which increased to 53.3 s with the DF strategy, 44.3 s with the BB strategy, 38.6 s with the BE strategy and 46.6 s with the ABE strategy.

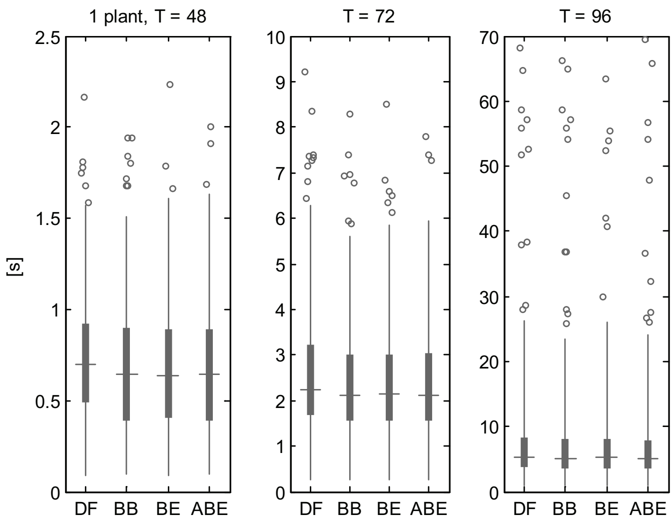

Figure 23: Run times of use case B with several daily price scenarios and one plant for optimization horizons T=48, T=72 and T=96 and several node-selecting strategies in the branch-and-bound-search.

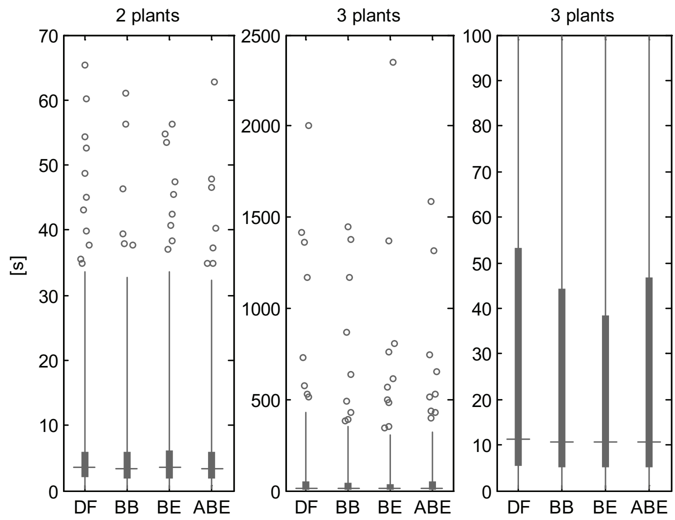

Figure 24: Run times of use case B with several daily price scenarios for two and three plants, optimization horizon of T=48 and several node-selecting strategies in the branch-and-bound-search.

Even though the ABE strategy was the fastest considering the mean run time, the BB and especially the BE strategy could be advantageous because 75% of the optimization runs are concluded in a shorter time. The effect is particularly considerable for larger problems, especially with several plants, because the run times of the remaining 25% increase greatly, to a multiple of the mean run time. A time limit, for example, near the third quartile, would then abort those remaining 25% of optimization runs and influence their results. It can be concluded that combining a node-selecting strategy with a time limit is preferred with the BB and the BE-strategy for two and three plants, respectively, as the time limit could be set to a shorter time than with other strategies whilst affecting the optimization results less. The impact on the results with time limits is investigated below.

4.3.2 MIP time limit

Time limits make the MIP solving algorithm abort if it exceeds the specified time to find the optimal solution. When solving is aborted at the time limit, a feasible solution is found but not the optimal solution that could be found when there is no time limit. Thus, the result is affected by time limits. The previous section shows that the run time of some calculations rose enormously in comparison to the rest. If only these calculations are aborted by time limits, the mean run time could be reduced significantly. Therefore, a time limit seems to be the most successful way of reducing the mean run time effectively, and there is only a small impact on the result quality.

In the following, different time limits and their influence on the result quality were examined. The investigation was carried out considering the run time results of the previous section for use case B with two and with three plants and an optimized horizon of T=48 time intervals ($\Delta t = 1$ h). For the analysis of two plants, the BB-strategy was selected. The time limits were set to 6 s, 10 s, 20 s and 30 s. For examining three plants, the BE-strategy was selected. The time limits were set to 40 s, 100 s and 200 s. Figure 25 shows the run times of two and three plants in a histogram with logarithmic centers. The lines indicate the time limits investigated down to a run near the third quartile (6 s for two plants and 40 s for three plants).

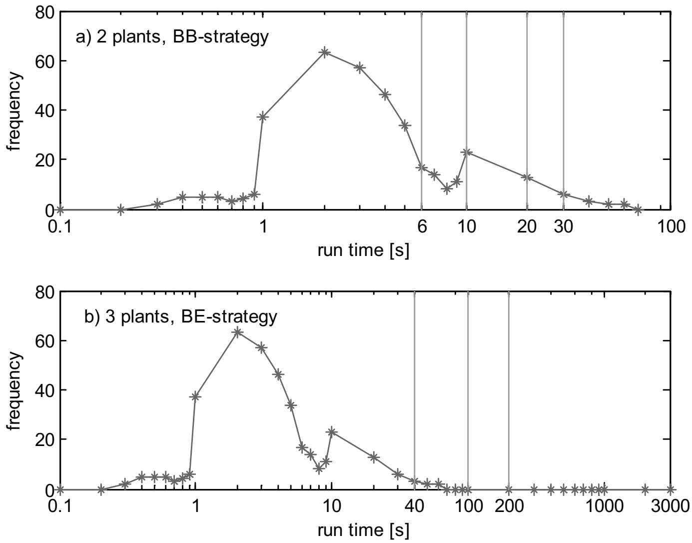

Figure 25: Histogram of run times for the unit commitment of use case B with a) two plants and b) three plants without a time limit; vertical lines indicating time limits.

The impact on the result was examined by way of the OFV. Two approaches were selected to evaluate the impact on the OFV. The first approach emphasized the reduction of the OFV (in case of maximizing the objective function) of single days. Starting with each day of a year and the corresponding price curves, the optimization for every scenario was carried out with and without time limits. The second approach evaluated the influence of a time limit on the annual result. That required a rolling unit commitment that was calculated with and without time limits. In contrast to optimizing single days, the results of the rolling unit commitment cannot be used for the comparison of results from each day as time limits change the solution and, thus, the starting conditions such as storage level for the optimization of the next time period. Vice versa, different starting conditions change the time needed for solving the optimization problem as shown in Figure 26, in the difference between the run times of both approaches throughout the year. Figure 26a) for two plants with the BB node-selecting strategy, and Figure 26b) for three plants with the BE strategy. Differences between the run times were observed due to different start conditions on the same day. For example, Figure 26a) shows that the difference increased to 60 s. For example, the peak of the daily run times from the rolling unit commitment emerged on October 13 at 115 s while the run time of separate daily scenarios was 57 s on that day. Figure 26b) shows that the difference between the run times increased to 800 s.

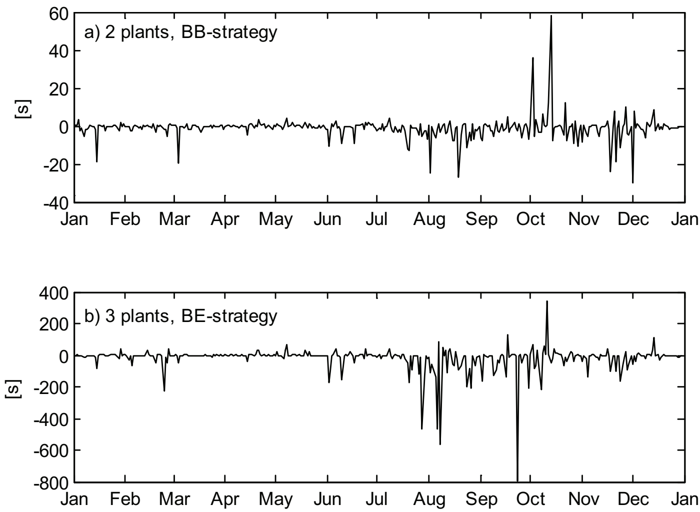

Figure 26: Difference in run times from rolling planning and separate daily scenarios from the unit commitment of use case B with a) two plants and b) three plants without time limit.

The mean run times of both approaches are contained in Table 10 for the unit commitment of two plants and of three plants in Table 11. The mean run times and the relative OFV differences resulting from introducing a time limit are also presented. The mean run times were reduced considerably by limiting the run time to the third quartile of the run times without a limit. Table 10 shows that the mean run time was reduced by up to 37.3% in the separate scenarios and by up to 33.1% in the rolling unit commitment when there was a time limit of 6 s. The impact of the rolling unit commitment with two plants on the OFV was approx. 0.0135%. Table 11 shows a reduction in the mean run time of approx. 68.5% in the separate scenarios and of approx. 58.3% in the rolling unit commitment with a time limit of 40 s. The impact on the OFV of the rolling unit commitment with three plants was approx. 0.0058%.

Table 10: Time limits and mean calculation run times of the unit commitment of use case B with two plants.

Time limit [s]	-	30	20	10	6
Mean run time [s]: - separate scenarios	5,78	5,44	5,07	4,34	3,65
Mean run time [s]: - rolling unit commitment	4,70	4,21	4,04	3,55	3,15
Relative OFV difference [%]: - rolling unit commitment	-	0.0004	0.0012	0.0027	0.0135

Table 11: Time limits and mean calculation run times of the unit commitment of use case B with three plants.

Time limit [s]	-	200	100	40
Mean run time [s]: - separate scenarios	56,2	37,8	29,6	17,7
Mean run time [s]: - rolling unit commitment	37,3	25,7	21,9	15,5
Relative OFV difference [%]: - rolling unit commitment	-	0.0003	0.0011	0.0058

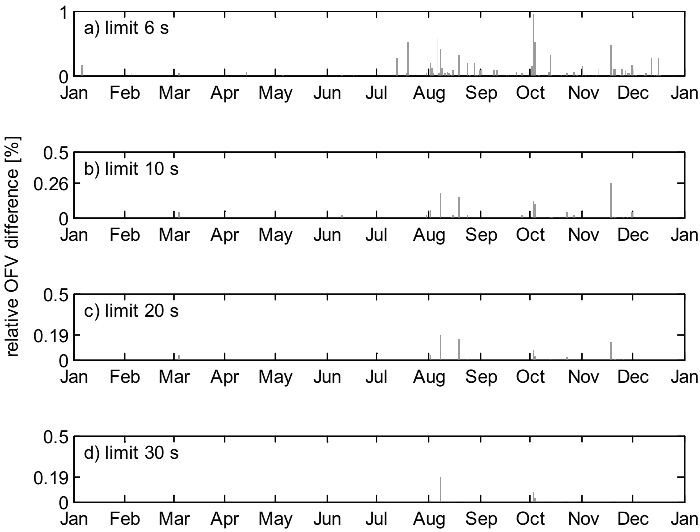

Figure 27: Relative OFV difference of time limited unit commitment solution of use case B with two plants from solution without time limit depending on the scenario start date.

While the annual OFV differences were analyzed with the rolling unit commitment, the daily OFV differences were analyzed with the separate daily scenarios. The impact of time limits on the daily OFV of separate scenarios is shown in Figure 27 (two plants) and Figure 28 (three plants). The bars show the relative difference of the OFV with a time limit from the OFV without a time limit. Figure 27 shows that a time limit of 6 s resulted in a maximum daily OFV difference of approx. 0.95%. Limiting the run time to 10 s, 20 s and 30 s produced maximum daily OFV differences of approx. 0.26%, 0.19% and 0.19%, respectively. Figure 28 shows that limiting the run time of the unit commitment with three plants to 40 s, 100 s, and 200 s resulted in maximum OFV reductions of about 0.3%, 0.12%, and 0.025%, respectively.

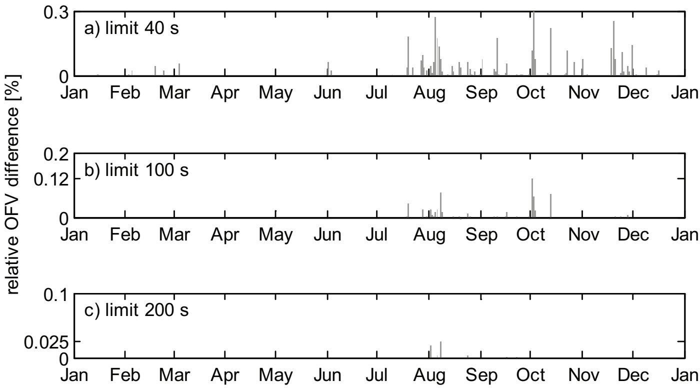

Figure 28: Relative OFV difference of time limited unit commitment solution of use case B with three plants from solution without time limit depending on the scenario start date.

Even time limits set near to the third quartile of the run times, affecting 25% of optimization calculations throughout a year, cause very small losses in the annual financial result. There are three potential reasons for that small impact. First, about 75% of the daily optimizations throughout a year are not affected by the time limit. Second, imperfect results on one day could cause better results on the following days because of differences in using the storage capacity as shown in section 4.1.2. Third, the results obtained at the moment of aborting are already close to a perfect result such as can be obtained without a time limit as shown above by the analysis of separate daily scenarios. It can be concluded that time limits are well-suited to controlling the run time. In combination with the appropriate node-selecting strategy, time limits could be set up to the third quartile of run times, while the annual unit commitment result is reduced less than 0.1% and the daily unit commitment result less than 1%. However, an adequate time limit must be found in respect to the size of the optimization problem.

4.4 Summary of findings of the unit commitment including tertiary control reserve

This section concludes the analysis of the performance of the MILP which schedules the bids for the spot market and tertiary control reserve market. At first, optimizing the biogas plant for a day on the spot market was examined with market prices from one year, but without rolling planning. This examination guaranteed that the findings varied due to the market prices only, and not to handover values, linking the daily optimizations from a year for rolling planning.

One important result found in this investigation is the huge impact of used market prices and the optimization horizon on the time needed for solving the MILP. However, there was no correlation found between the run time and the spot market prices when considering planning time horizons shorter than 10 days. Increasing this time horizon to 30 and 40 days raised the correlation between the run time and the average daily price spread within the planning period. It is interpreted with caution that a decreasing spread of prices leads to increasing run times. Further work may explore the relationship between the structure of prices and the run time of solving the MILP.

Comparing the daily results of the unit commitment of different optimization horizons, this investigation showed that an optimization horizon of 72 h with respect to the daily planning provides very good results for the first 24 hours. This means that they are not improved significantly by increasing the optimization horizon. Even an optimization horizon of 48 h provides quite good results, reducing the run time of solving the optimization problem. A significant improvement in run time can be observed, and the result is far better than the result obtained by a 24 h optimization horizon.

Furthermore, the analysis of the rolling unit commitment of the biogas plant optimized with respect to spot market prices throughout a year showed that the annual result improved up to 5% as a result of increasing the optimization horizon from 24 h to 36 h. Increasing the optimization horizon from 36 h to 48 h increased the annual financial result less than 0.2%. Thus, a second important finding is that 48 h and, even more so, 72 h are robust optimization horizons that can be used to examine a rolling unit commitment of daily planning. However, this result is limited to biogas plants with a 12 h storage capacity. It was found that increasing the storage capacity requires much larger optimization horizons to keep the incremental improvement of the financial result below 0.1% when increasing the storage horizon in steps of 12 h. The small incremental improvement of the annual result by increasing the optimization horizon was found by including the optimization of tertiary control reserve bids, too. Therefore, these results are applied to analyze further use cases.

Further investigations with regard to the optimization time horizon were carried out focusing on the excess time after the actually planned day. An attempt was made to relax the problem, reducing the run time of solving the MILP while keeping the quality of the result. A successful approach is relaxing the binary variables in the excess time by replacing them with continuous variables defined between 0 and 1 instead. The results of this analysis showed that the binary variables of excess time up to 16 h from the end of the optimization horizon can be relaxed, keeping the quality of the annual result, reducing the mean run time by 17.3% at the 48 h optimization horizon and 38.1% at the 72 h one. There are limitations in consideration of these findings as the number of relaxed variables was increased in steps of 4 h. Furthermore, the optimization horizon was increased in steps of 12 h in this analysis. Further work is required to elaborate the relationship of relaxing binary variables in the excess time of the optimization horizon in rolling planning. Despite these limitations, the success of this approach is a relevant result and can be applied for the unit commitment of biogas plants in order to reduce the run time.

In addition to the time period that is forecasted in the unit commitment of the power unit, the model of the power unit itself was analyzed. The crucial issue analyzed in this work is the linearization of the characteristic curve. Constant efficiency and the piecewise linearization in a number of segments varying from one to four were regarded. The results described above demonstrated that the linearization in one segment resulted in an operational scheme with the least number of hours at part load, and vice versa, the maximum number of hours at full load. Increasing the number of segments decreased the number of hours the power unit operated at full load because efficiency losses were valued more precisely. Comparing the approximated gas consumption from planning with the exactly calculated gas consumption by means of the characteristic curve showed that the annual accumulated error is small. The linearization in one segment overestimated the annual gas consumption by approx. 1.35 MWh, whereas the continuous gas production was 1.25 MW. A very different operational scheme resulted from the unit commitment considering a constant efficiency of the power unit resulting in a large number of hours that the power unit operated at part load. That caused an underestimation of the annual gas consumption of approx. 150 MWh while planning. However, interpreting the large number of hours the power unit operated at part load needs to respect the start-up costs which were still incorporated in the unit commitment.

Finally, the application of different node-selecting strategies was analyzed and combined with time limits. The software CPLEX offered four different settings for the selection of nodes, the depth first search, the best bound search (default), the best estimate search, and the alternative best estimate search. The run times were analyzed for five different settings, varying the number of biogas plants and the optimization horizon. The third quartile of the run times was used to rank strategies because, depending on the market prices, run times of single daily optimizations rose greatly. The results described above demonstrated that the best bound search and the best estimate search perform best for most of the settings. The depth first search and the alternative best estimate search achieved a comparable result each for one of the settings. The third quartile was furthermore used to define restricted time limits. Thus, 75% of the daily optimizations throughout a year were not affected by the time limit. This time limit was analyzed for two settings, one with two plants and one with three plants. The results of this analysis demonstrated that the mean run time was reduced by 33% and 58%, respectively, whereas the accumulated optimization result of the complete year was hardly influenced at 0.0135% and 0.0058%, respectively. Further work is required to explore the impact on the result in relation to the time limit. Future work could provide data which elaborate the trade-off between the quality of the result and run time savings. The time limit has to be identified individually for each problem. On the basis of the findings of this work, the search for an appropriate time limit should mirror the fact that the impact on the annual result is very small with a time limit at the third quartile of the optimizations' run times. The third quartile or any limit above with less impact on the result can be found easily by increasing the time limit from a small initial time limit and counting the optimization runs that hit the time limit.

5 Optimized income and evaluation of extended capacity

The power generation of gas plants situated at local gas sources, such as biogas plants, is typically tied to a constantly maintained gas supply. However, these plants can optimize their revenues by means of extended power unit capacity and gas storage capacity scheduled according to variable market prices. For short-term products with variable prices the spot market, the tertiary reserve market and the secondary reserve market were taken into account. Furthermore, it was assumed that capitalizing market prices and financing extended capacity are impacted by the market premium and the flexibility premium. This section shows the results of the model developed for analyzing the market revenues in different use cases depending on the size of extended power unit and storage capacities. The approach to this investigation is shown in Figure 29.

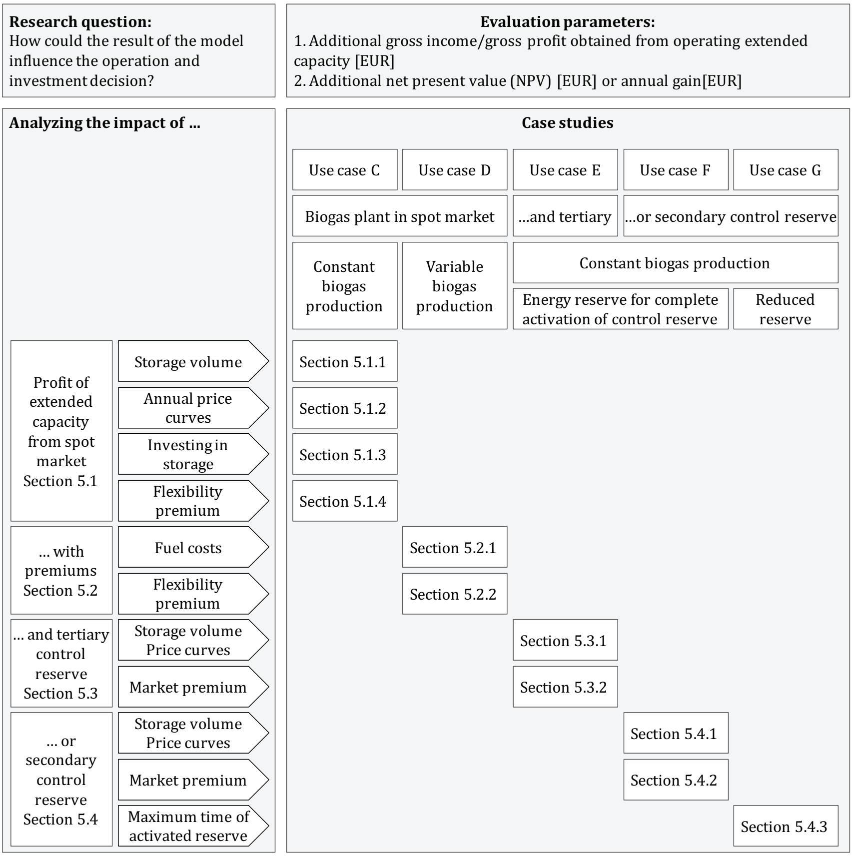

Figure 29: Approach to analyzing the results of the model with regard to operation and financial outcome.

Every use case, except for use case D, treated the biogas plant as having a constant biogas output of 1.25 MW which corresponds to a constant electricity generation of

0.5 MW from a power unit with an electrical efficiency of 40%[5]. Furthermore, each analysis regarded plant availability to be 91%. The self-consumption was neglected as it was assumed that the consumed power was purchased via a constant retail tariff and the produced power was contracted to a trading company transferring to the wholesale market. On this basis, the extension of the electrical capacity of the power unit was analyzed with regard to the influence on power generation and the created income as well as on financing the extended capacity in the different use cases. Vice versa, use case D investigated how the market and the flexibility premium would affect the biogas and power production of the plant if the biogas production was variable.

Table 12: Terms and relations used for valuing investments in extended capacity (left-hand), and origin of values applied (right-hand).

Income	*Spot market, control reserve market, premiums*
- Variable operation costs	*Fuel costs, start-up costs*
= Gross income	*Objective function value (OFV) x 91%*
- Reference gross income	*[Reference income - reference costs] x 91%*
= Additional gross income	
- Extra fix operation costs	*Extra insurance, maintenance*
= Additional cash flow	
Present value of the additional cash flow	*10 year life expectancy, 7% interest rate (WACC)*
- Investment costs	*Power unit and transformer >500 kW, storage*
+ Reference investment costs	*Power unit and transformer 500 kW*
= Additional Net Present Value (NPV)	
Additional cash flow	
- annuity of investment costs	*10 year life expectancy, 7% interest rate (WACC)*
+ annuity of reference investment costs	*10 year life expectancy, 7% interest rate (WACC)*
= Additional annual result (annuity)	

The gross profit, also called gross income, which is a direct output from the model was analyzed. Furthermore, the costs of the investment were respected to show how the results of the model influence the investment decision. For this reason, the net present value (NPV) or the annuity (annual gain, annual result) of the extra investment in the extension of the electrical capacity were analyzed. The NPV shows the created value and if the NPV was larger than 0, an investment would make a profit. The investment at the most NPV is to be preferred (Becker 2009). The internal rate of return (IRR) showing

[5] The electrical efficiency of power units larger than 500 kW ranges between 40% and 43% (compare with Figure 64 and Figure 68). The indicated curve of electrical efficiency in Figure 64 presumes an increase in efficiency when the electrical capacity is raised but the samples of power units larger than 500 kW do not confirm this trend. As there is no inherent increase, the electrical efficiency was considered constant in every examination.

the profitability of the invested capital is presented in sections 5.1.1 and 5.1.4 in order to compare it with the NPV and to analyze different influences on the investment decision. However the IRR is not used to evaluate all results in this chapter, as the interpretation of the IRR is not clear (Kruschwitz 2011). All financial parameters were analyzed in contrast to the reference, which is the 500 kW power unit. Table 12 shows the steps and data used for calculating the financial parameters. The formulas for calculating the NPV, the annual gain and the IRR are presented in Annex G.

The gross income was obtained from the OFV that contained the revenues from selling the generated power on spot markets and the capacity on control reserve markets as well as the variable operation costs. A factor of 91% respects the annual availability as availability was not considered in the unit commitment. The reference was defined for each use case. In order to analyze the investment in extending the electrical capacity, the gross income of the reference consisted of the incomes and costs when a 500 kW power unit is operated constantly throughout the year at 91% availability. When analyzing use case C, the incomes of the reference were obtained from the spot market and, additionally, the incomes from providing negative control reserve when analyzing the use cases E, F and G. In order to evaluate the opportunities in control reserve markets when a biogas plant with extended capacity is operated, the gross income of use case C was used as reference (compare with Figure 30).

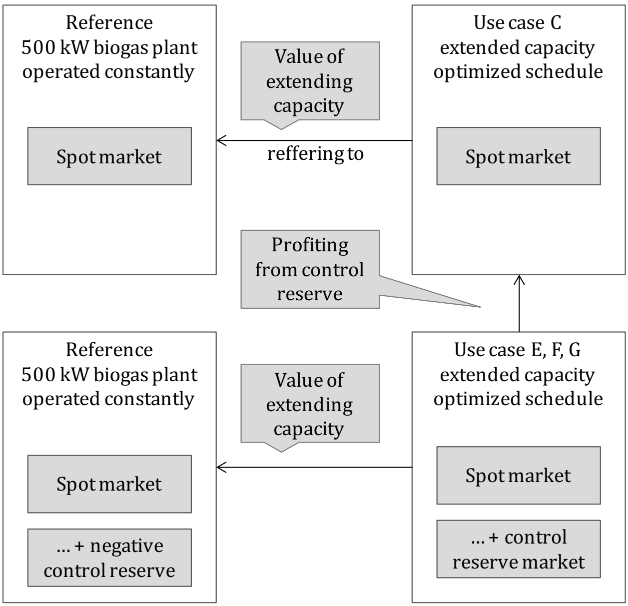

Figure 30: Scheme of references used in the analysis of use cases E, F, and G depending on the interpretation of results.

The additional cash flow was obtained from the additional gross income and the fixed operation costs arising from installing extended capacity. These fixed operation costs were additional insurance costs and maintenance costs. Insurance costs were respected with 0.5% per year and maintenance costs with 1.5% per year of the investment in extended capacity. Extra maintenance costs as a result of the flexible operation of the power unit were respected with 1% per year of the investment in extended capacity. It was assumed that these fixed operation costs were constant for a life expectancy of ten years.

The scenario in this work considered purchasing a larger power unit instead of the 500 kW power unit regarded as the reference. The investment costs of the reference capacity and its gross income were removed while valuing the investment. The NPV, the additional annual gain and the IRR were calculated using the additional cash flow, the investment costs and the investment costs of the reference. Neither other incomes nor costs of the biogas plants, nor taxes were considered. Capital costs and returns were respected by a weighted average of capital costs (WACC). Furthermore, it was assumed that biogas storage capacity is available. If not, the effect on valuing the investment is analyzed in section 5.1.3. The investment in the power unit, the transformer and the gas storage capacity was calculated by applying the cost functions from (ASUE 2011), (IER 2013) and (DLG 2014) presented in section 2.1, and the cost function from (Schulz, Brandstätt 2013) was used for thermal storages.

5.1 Biogas plants with extended capacity on the spot market

This section presents the results of analyzing biogas plants' optimized participation in the spot market. The analysis focused on maximizing the financial result of biogas plants with respect to volatile power spot prices; the market premium and the flexibility premium were disregarded at first. The optimization model of the biogas plant required a constant biogas supply from the digester, gas storage capacity and a power unit with extended capacity. Modeling a constant biogas supply allowed the market premium to be neglected as the supplied gas has to be converted to power even though marginal costs are higher than average market prices[6].

First of all, the increase in gross income and the impact on valuing the investment in extended electrical capacity was examined depending on the power unit and storage size (section 5.1.1). Secondly, the impact of the calendar year and its power spot prices from EPEX was investigated (section 5.1.2). Thirdly, it was assumed that the investment includes storage capacity and several construction types were analyzed (section 5.1.3). Finally, the influence of the flexibility premium on valuing the investment in extended capacity and on determining the optimal electrical capacity was analyzed (section 5.1.4).

[6] Corn silage is the most widely used incoming renewable raw material (Table 25). Its costs of about 0.35€/m^3 methane yield (Figure 63) correspond to 35.1€/MWh fuel costs at a calorific value of 35.89 MJ/m^3. With an electrical efficiency of 42 %, the costs of the electrical output are at least 83.6€/MWh. Electric self-consumption of 8 % raises the minimum market price level to 91€/MWh in order to benefit. The long-term course of spot market prices show that prices higher than 90€/MWh occur rarely. Biogas production in the digester cannot be launched economically at these market prices. Even lower costs of 0.25€/m^3, as observed in 2009, need a market price of 65€/MWh to benefit.

5.1.1 Optimizing spot market incomes of a biogas plant with extended electrical capacity

This section shows the results of optimizing a biogas plant's gross income on the power spot market by using the unit commitment as described in use case C (Table 30, Appendix E). The market prices were obtained from the EPEX Spot SE auction market in Germany/Austria from 2013. The impact of the electrical capacity and the gas storage capacity on the gross income and on valuing the investment was analyzed. For this reason, the electrical capacity was varied between 600 kW and 9 MW. The storage capacity was varied between 4 h and 48 h.

The additional gross income, the additional NPV and the IRR were investigated. Furthermore, the storage charge and discharge times were analyzed. The storage capacity in hours is the time needed to fill the storage with the constantly produced biogas. Vice versa, the gas storage is discharged by the extended capacity of the power unit when a notional partitioning of the power unit's capacity is undertaken, and the reference capacity consumes the constant biogas production. The storage discharge time is the time needed by the excess capacity to consume the complete contents of one storage container, indicating the size of the storage capacity in ratio to the extended capacity.

The optimization of the biogas plant resulted in schedules for the power unit and the storage level. The schedule defined operation times and therein the operating point. A section of a week from such a schedule is shown in Figure 95 to Figure 97 (Annex H). These figures show that the electricity generation took place in times with high prices (Figure 94, Annex H) by storing the constant biogas supply in the in between times. The gross income was expected to increase, in contrast to constant electricity generation.

Figure 31 shows this additional gross income as a difference of the optimized gross income from the gross income with constant electricity generation. The gross income depended on the sizes of the power unit and the storage. The additional gross income has been plotted as curves of each size of the storage capacity depending on the nominal electrical capacity of the power unit. The curves lying upon each other without intersecting show that expanding the storage capacity increased the gross income. In contrast, increasing the power unit size resulted in a maximum additional gross income. The additional gross income reached the maximum and then declined as the power unit size increased, even dropping to negative additional gross income. The maximum point shifted towards larger power units when the storage capacity was extended.

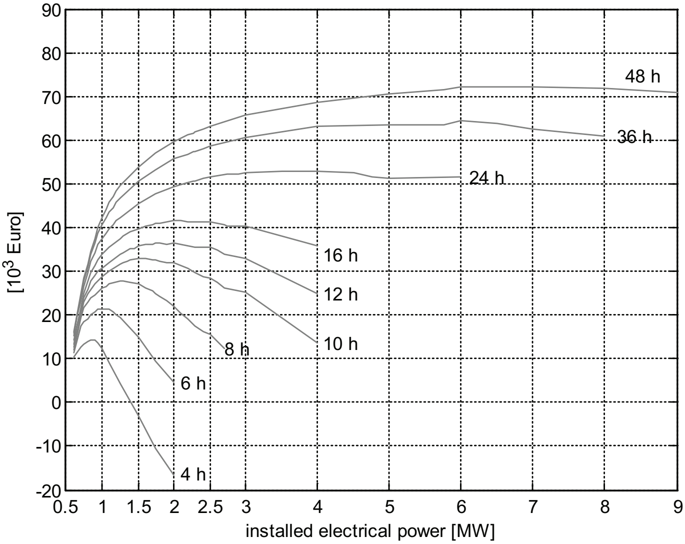

Figure 31: Additional gross income (difference between OFV and reference) of use case C (biogas plant on spot market) depending on the installed electrical power for different storage capacities.

The power unit and storage sizes of these maximums are recorded in Table 13 as is the capacity factor and the discharge time. The capacity factor was the nominal power in ratio to the reference power of 0.5 MW. The discharge time was the storage capacity in ratio to the extended capacity that in turn was the difference between the power unit capacity and the reference capacity.

Table 13: Maximum positions (nominal power) of OFV curves at equal storage horizons, capacity increase related to 0.5 MW and storage discharge time due to extended capacity.

Storage capacity (charge time) [h]	Storage capacity [MWh]	Nominal power [MW]	Capacity factor [-]	Discharge time [h]
4	5	0.9	1.8	5
6	7.5	1	2	6
8	10	1.25	2.5	5.33
10	12.5	1.5	3	5
12	15	2	4	4
16	20	2	4	5.33
24	30	4	8	3.43
36	45	6	12	3.27
48	60	6	12	4.36

The charge and discharge times are synonymic to the off and on times of the power unit, respectively. The ratio of charge and discharge times expressed the maximum capitalization of market prices with respect to plant restrictions. The results show that short discharge times seemed to be optimal as the power was generated and sold at times with the highest prices. For this reason, increasing the power unit size raised the gross income at first. However, the power unit was forced to run when the storage level reached maximum capacity. Even operating at the minimum level of operation consumed more than the constant gas supply at a capacity factor of more than 2. Thus, the larger the electrical capacity, the more irrespective of market prices the discharging of the gas storage units occurred. This resulted in a peak and then a decrease in gross income as the electrical capacity was increased further.

In summary, the mixed-integer behavior of power units and the efficiency losses at part load prevent an unlimited increase of gross income by increasing the power unit size at a gas source. Extending the storage capacity shifts the maximum gross income towards larger electrical capacities. These gross income maximums occur in a range from 0.9 MW to 6 MW for storage capacities between 4 h to 48 h (Table 13).

For the purpose of valuing the investment in extended electrical capacity, fixed operation costs and investment costs were considered. Figure 32 shows the internal rate of return (IRR) and the net present value (NPV) as curves plotted for several storage sizes depending on the installed electrical power. The NPV was calculated with an exemplary discount rate of 7% and a lifetime of ten years. At a nominal electrical capacity of 600 kW the IRR was between 32% and 56% for 4 h and 48 h storage capacity, respectively. The IRR decreased with increasing nominal electric power. The IRR fell to below zero at an installed capacity of more than 900 kW for 4 h storage capacity and more than 4.5 MW for 48 h storage capacity. The NPV was between 39 200€ for 4 h storage capacity and 81 400€ for 48 h storage capacity at an installed capacity of 600 kW. The NPV rose to its maximum for every storage size except for the 4 h storage capacity. The maxima and the corresponding power unit sizes are given in Table 14. By further increasing nominal electric power the NPV dropped below zero at more than 800 kW for 4 h storage capacity and more than 2.9 MW for 48 h storage capacity, respectively.

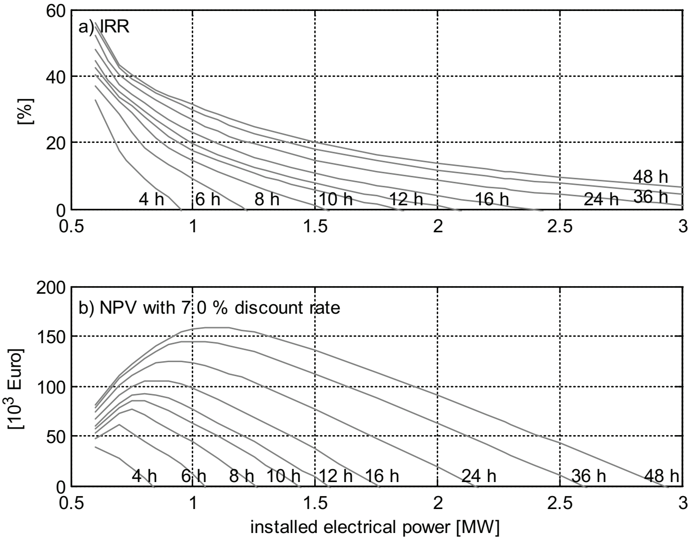

Figure 32: Valuation of installed electrical power by (a) IRR and (b) NPV at 7% discount rate and ten year returns at 2013 power prices for use case C (biogas plant on the spot market) with several storage capacities.

Table 14: Optimal power unit size at maximum NPV for different storage horizons.

Storage horizon [h]	4	6	8	10	12	16	24	36	48
Power unit [kW]	600*	700	750	800	800	850	900	1000	1100
NPV [10^3 €]	39.2	60.9	76.6	84.9	92.4	105.5	125.3	144.8	159.0

*lower boundary of examined range

The smallest extension of the power unit gave the highest internal rate of return. Thus, the invested capital for minimally extended capacity is more efficient than for large extensions of the capacity. Such an investment could yield a profit as long as the IRR exceeds the required minimum rate of return. However, small investments which create low values could have a higher IRR than a larger project with a larger amount of value created (Agar 2005). This can be observed in the presented results. The amount of value created rose when the capacity was increased to a maximum of the NPV. However, different amounts of capital invested are hard to compare using the NPV (Becker 2009). The computed NPV in Figure 32 neglected this issue of different amounts of invested capital. This makes the investment decisions individual depending on an investor's funds. If funds are limited and more than one investment to extend capacity at biogas plants can be undertaken, it is more efficient to allocate funds for different projects with less extended capacity in consideration of the IRR. If funds are not limited or debt is raised, the value created by each project could be maximized by orienting investments to maximum NPV.

5.1.2 Impact of spot market prices

The previous section shows how sizing the power and storage units influenced the investment valuation of extended capacity. That was shown by a price scenario of historical power spot prices from the EPEX in 2013. As prices have significantly changed since launching the power spot market (compare with Figure 73, Annex B), the impact of price scenarios on the investment valuation was investigated. The spot market prices from 2001 to 2014 from the EPEX and EEX power auctions for the German/Austrian market area were used.

The additional gross income was presented along with the additional annual result and the most profitable electrical capacity from each year. Furthermore, the most profitable electrical capacity was analyzed with respect to the spot market revenues in several years with different prices. Thus, the sensitivity of the gross income in each year was respected. In order to cancel out the influence of single years with extreme prices, the result of several years was additionally analyzed repeatedly skipping one year, two years, three years and four years.

Figure 33 shows, on the one hand, the monthly additional revenues from the unit commitment of a biogas plant with a 0.85 MW power unit and 12 h-storage capacity, and on the other hand, the monthly average of the daily difference between peak prices (from 8.00 to 20.00) and base prices (from 00.00 to 24.00) from January 2001 to December 2014.

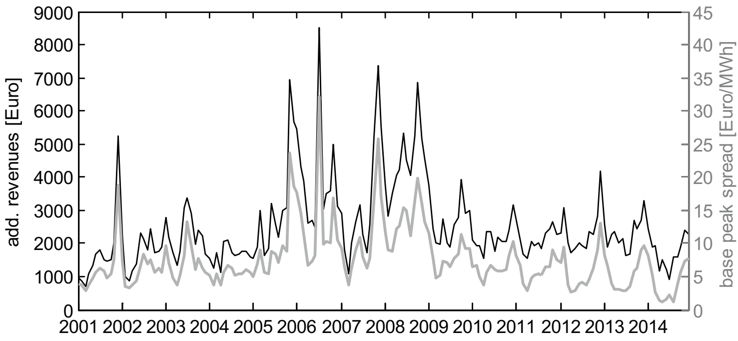

Figure 33: Monthly additional revenues from unit commitment of use case C with a 0.85 MW power unit and 12 h-storage capacity (left axis) and monthly average of daily differences between base and peak power spot prices (base prices from 00.00 to 24.00 and peak prices from 8.00 to 20.00, right axis).

The additional gross income from the unit commitment of use case C and 12 h-storage capacity in different calendar years is shown in Figure 34. The figure plots the additional gross income as curves of each calendar year between 2001 and 2014 depending on the power unit size. The additional gross income was generated by capitalizing on the price differences of hourly spot market prices. For the analysis of this additional gross income, the gross income of the reference operating scheme was deducted from the gross income obtained by means of the unit commitment. Figure 34 shows that the most additional gross income was obtained from the power spot prices in 2008 and the least additional gross income from the power spot prices in 2001 and 2004. Furthermore, the intersections of the curves show that low extended capacity profited more, for example, from prices in 2009 than from prices in 2005 and 2007, whilst large capacity extensions profited significantly more in 2005 and 2007 than in 2009. An additional profit was calculated by deducting fixed annual costs and a ten-year annuity of the investment in extended capacity at 7% interest rate from the additional gross income. This additional profit, which is equivalent to the NPV, is shown in Figure 35.

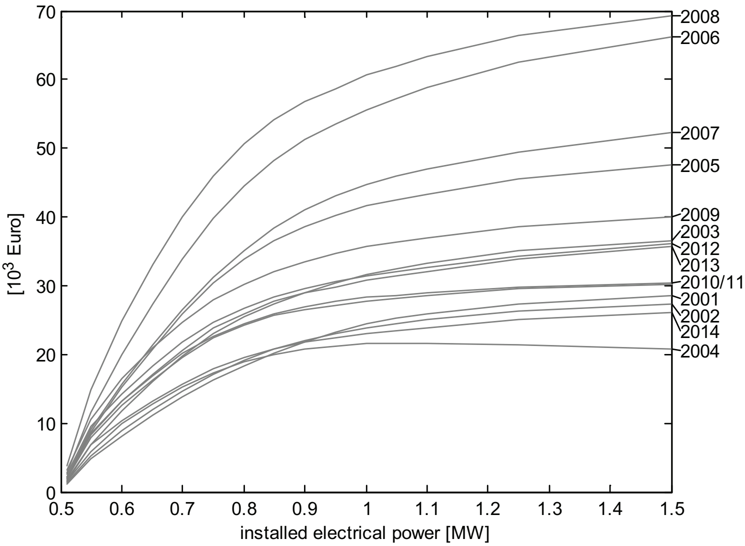

Figure 34: Additional gross income (difference between OFV and reference) of use case C (biogas plant on spot market) depending on the installed electrical power for price scenarios from each calendar year.

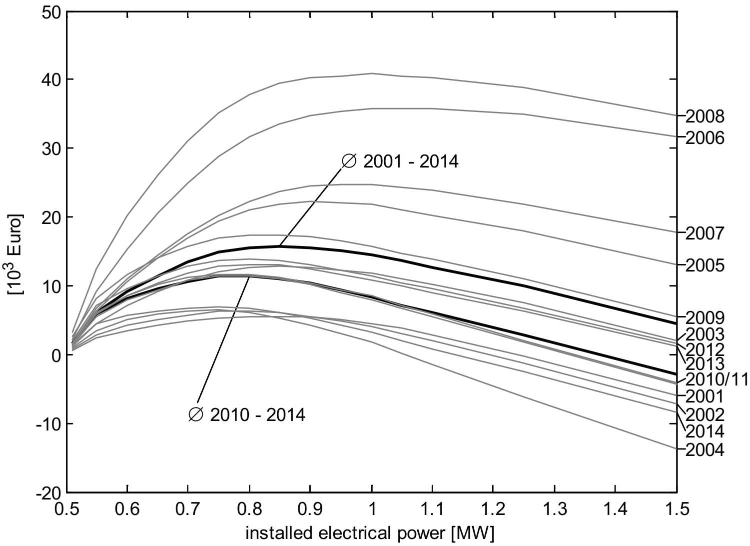

Figure 35: Additional annual profit from investment in extended capacity for use case C (biogas plant on spot market) with 12 h-storage capacity depending on the installed electrical power.

The additional profit varied according to the additional gross income. Furthermore, the curves evolved maximums that would indicate most profitable power unit sizes as observed in Figure 32. However, the maximums emerged with different power unit sizes for each calendar year. The maximum profits and the corresponding power unit sizes are presented in Table 15.

Table 15: Power unit size at maximum profits in each calendar year.

Year	Power unit [kW]	Profit [10^3 €]	Year	Power unit [kW]	Profit [10^3 €]
2001	850	5.5	2008	1000	40.8
2002	800	6.3	2009	850	17.4
2003	850	12.8	2010	750	11.7
2004	750	6.4	2011	750	11.4
2005	900	22.2	2012	800	13.9
2006	1050	35.8	2013	800	13.2
2007	950	24.8	2014	750	6.9

The results show that the valuation of the investment is influenced heavily by the historical price scenario which is used to determine market incomes. In consideration of the years 2010 to 2014, investing in 0.75 MW to 0.8 MW power units, with an extension of the capacity by a factor of 1.5 to 1.6, would have been optimal. However, considering the steep increase of additional profit on the left-hand side of the maximum and in contrast the flat decrease on the right-hand side led to the assumption that larger power units profit more if power spot prices, such as from 2005 to 2008, arise during the lifetime of the power unit. Therefore, the sum of profits from several years was analyzed. Taking every calendar year into account, the most profitable power unit size was 850 kW with a capacity factor of 1.7. The robustness of this result was tested by repeatedly skipping one year, two years, three years and four years while looking for the most profitable power unit size in the sum of profit curves from 2001 to 2014. Skipping one calendar year of this sum, the most profitable power unit size was again 850 kW. Skipping two calendar years of the sum of annual profits resulted in the most profitable power unit size of 850 kW except when 2006 and 2007 are excluded which results in a 800 kW power unit. Skipping three consecutive calendar years resulted in 850 kW being the most profitable power unit size too, except when 2005 to 2007 and 2006 to 2008 are excluded which resulted in 800 kW. Repeatedly skipping four consecutive calendar years resulted in 850 kW five times, 800 kW three times and 900 kW three times. The 900 kW power unit was the most profitable if four calendar years from 2009 and later were skipped from the sum of annual profits.

It can be concluded that sizing the power unit needs to consider price scenarios from several years as the annual power spot prices have an impact on the market incomes created by capitalizing price differences. The example of a biogas plant with 12 h-storage capacity and a constant biogas supply of 500 kW electrical equivalent showed that power unit sizes between 750 kW and 1050 kW were most successful when considering one calendar year. Considering the profits of several years resulted very clearly in a power unit size of 850 kW and a capacity factor of 1.7, respectively. That was more than the most profitable sizes of 750 kW and 800 kW in recent years but raised opportunities to profit from price scenarios such as from 2005 to 2008.

5.1.3 Valuing the investment in storage capacity

The investigations above assumed existing biogas storage facilities with different capacities. The costs of storage capacity were not respected while valuing the investment in extended capacity of the power unit. Gaining more flexibility in a biogas plant may however include investments in storage capacities such as gas storage or thermal storage. Such additional investments reduce the NPV by the amount of further investment costs, and the curves in Figure 32 shift vertically as there is no further impact on the cash flow. For this reason, the results of section 3.1.1 were used to analyze whether the biogas storage could be financed if it was not already in existence.

Different building for biogas storage facilities were considered; the internal quarter-of-a-sphere storage, the internal third-of-a-sphere storage, the internal third-of-a-sphere storage created by exchanging the membrane and the external three-quarter-of-a-sphere. Due to the humidity and temperature of the gas the volume of the internal storage was considered with an extra 40%, the external storage with an extra 18% and the third-of-a-sphere storage with an extra 68% (DLG 2014), (Holzhammer et al. 2013).

The analyzed NPV considered an investment in installing the complete storage capacity, i.e. there was no storage capacity before which is now used in addition to the new storage capacity. Installation prices for storage volumes of more than 8000 m^3 have not been reported yet. It was assumed that an extrapolation of specific cost curves would not be realistic as larger storage volumes must respect tighter legal restriction than introduced above. Therefore, the NPV is shown up to a storage capacity of 24 h, which is equivalent[7] to a volume of about 8100 m³ including an extra volume of 40%.

Furthermore, the investment in thermal storage container was considered since interrupting the operation of the internal combustion engine might interrupt the supply of heat to the digester. Thermal storage is needed to maintain the temperature of the biogas production if there are neither sufficient insulation of the digester nor alternative heat supply. For dimensioning the thermal storage it was assumed that a maximum of 25% of the produced heat is needed for the digester heating. The temperature spread between inlet and return was assumed to 20 K. The analyzed NPV considers the investment in thermal storage only.

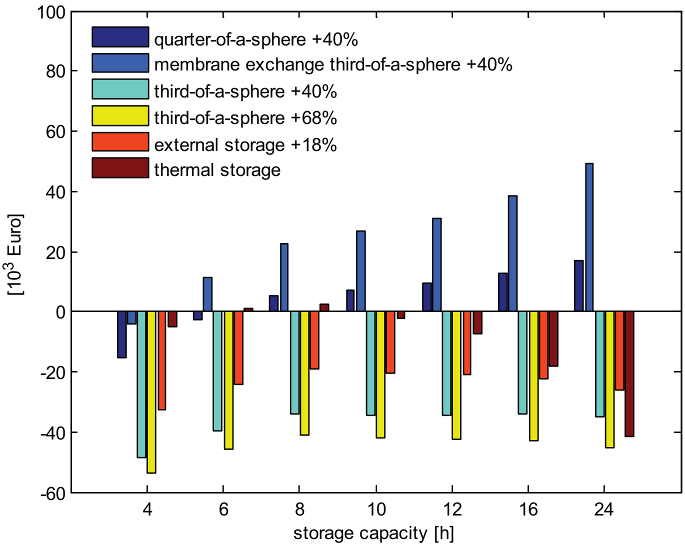

Figure 36: NPV of investing in extended capacity (refer to Table 14) and different storage facilities depending on the storage capacity.

Figure 36 shows the reduced NPV for different storage sizes and the corresponding power unit size from Table 14. Even though the maxima of the NPV curves (refer to Table 14) were used to include an investment in storage capacity, the resulting NPV was only positive for exchanging the membrane to create third-of-a-sphere storage when the capacity is larger than 6 h or quarter-of-a-sphere storage when the capacity is larger

[7] The net calorific value of methane of 35.89 MJ/m³ was used and the methane share of the biogas was assumed to 52%. During off-times of the power unit, the energy inlet per hour into the gas storage was modeled at 1.25 MWh.

than 8 h. The positive NPV was 11 500€ for a 6 h-storage capacity and rose to 49 000€ for a 24 h-storage capacity which was retained by creating storage capacity through the exchange of the membrane of the third-of-a-sphere storage. Building quarter-of-a-sphere storage resulted in a positive NPV of 5 400€ for an 8 h-storage capacity rising to 17 000€ for a 24 h-storage capacity. Additionally, a positive NPV between 1 100€ and 2 600€ was obtained for investing in thermal storage with storage capacity between 6 h and 8 h.

It can be concluded that investing in storage capacity may wipe out any profits arising from the gain in flexibility. Storage capacity could be installed at low cost and remain a positive valued investment, if more than 8 h storage capacity were achieved by a quarter-of-a-sphere storage or more than 6 h storage capacity by the exchange of the membrane of a third-of-a-sphere- storage. The need for thermal storage to maintain the temperature in the digester when the power unit is turned down would lead to negative valuations of the investment. These results show the worst case scenario when the whole storage capacity has to be installed whereas section 5.1.1 and 5.1.2 showed the best case scenario when the entire gas storage capacity is already installed.

5.1.4 The influence of the flexibility premium on the investment valuation

Financing extended capacity of power units and storage facilities is supported by the flexibility premium that was introduced in 2012. Although the flexibility premium was replaced in 2014, it is still the most influential factor in upgrading biogas plants that are constructed before August 2014 and a large number of biogas plant owners are still allowed to claim the premium or have claimed it first before August 2014 without investing in extended capacity yet.

The flexibility premium is scaled according to the installed power and the annual power generation. Its impact on valuing the investment was analyzed. Accordingly, the annual payment of the flexibility premium was determined and added to the gross income of the results of section 5.1.1 and 5.1.3. First, the impact of the flexibility premium on the gross income, NPV and IRR from the investigation in section 5.1.1 was analyzed depending on the electrical capacity. Second, the NPV was analyzed depending on the storage capacity, taking the investment in a third-of-a-sphere internal biogas storage container (68% extra volume with respect to humidity and temperature) into account. The resulting impact of the flexibility premium on valuing the investment in extended capacity is shown in Figure 37 depending on the electrical capacity.

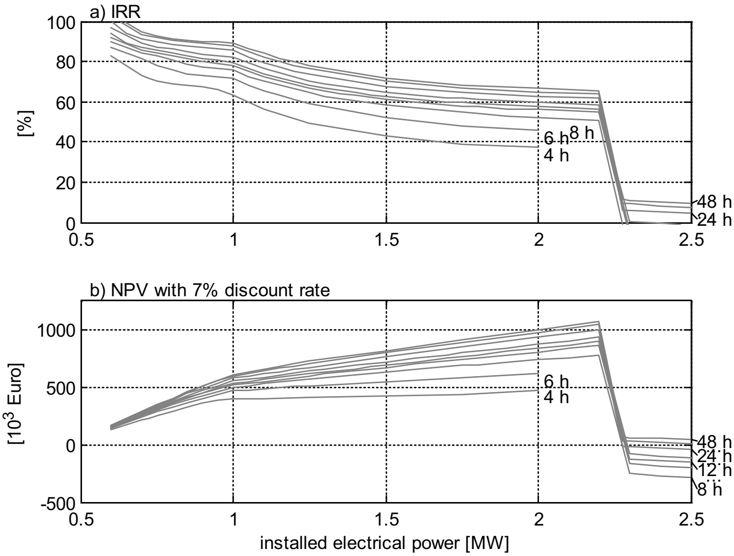

Figure 37 Valuation of nominal electric power increase via IRR (a) and NPV with a discount rate of 7% (b) of use case C (biogas plant on spot market) plus accounting for the flexibility premium for different storage capacities.

The IRR increased significantly to a range of between 83% (4 h storage) and 104% (48 h storage) at an electrical capacity of 600 kW. Increasing the installed electrical capacity to 2.2 MW reduced the IRR to a range of between 51% (8 h storage) and 65% (48 h storage). The IRR dropped below zero except for very large storage capacities as the electrical capacity exceeded 2.2 MW. The 48 h storage retained an IRR of approx. 11%.

The NPV was between 132 000€ (4 h storage) and 172 800€ (48 h storage) at 600 kW electrical capacity. Raising the electrical capacity to 1 MW, increased this range of the NPV to between 403 700€ and 612 200€, respectively. Furthermore, raising the capacity to 2.2 MW increased the NPV to its maximum, ranging between 779 800€ (8 h storage) and 1 075 500€ (48 h storage). Raising the capacity beyond 2.2 MW, the NPV dropped to -249 500€ and 60 800€ for the 8 h-storage and 48 h-storage, respectively. This is due to the fact that the flexibility premium was rejected for larger capacities.

The flexibility premium raised the NPV significantly, however, there was a steep fall between 2.2 MW and 2.3 MW because the premium is not paid if the electrical capacity is used below 20% of the annual average (compare with Figure 3). Therefore, the presented scaling of the NPV depended on the annual use of the electrical capacity rather than on the dimension of the extended capacity. The steep fall of the premium indicated that there is a risk of losing the claim to the premium in an accounting period. Plant outages that reduce the annual availability to below the considered 91% would shift the steep fall of the NPV towards lower electrical capacity. The default of the complete flexibility premium decreases the NPV. For example, if the flexibility premium of 143 000€ at an installed electrical capacity of 2.2 MW was not paid in the first year, the NPV, presented in Figure 37, would decrease by 133 640€ and failure in year ten would decrease the NPV by 72 690€. Thus, the NPV would be still positive in this scenario if the premium failed in more than one year. Further aspects of this discussion are: outages could be compensated by increasing the biogas production, as far as is possible, within the accounting period; and the plant's availability could be raised above the considered 91% by scheduling maintenance into times of low market prices.

With the support of the flexibility premium storage facilities can be financed, too. Figure 38 presents the NPV including the flexibility premium and the costs of third-of-a-sphere storage depending on the storage capacity. The NPV is plotted as curves of equal electrical capacity. The NPV of plants with an electrical capacity of more than 1.25 MW rose monotonously for the larger storage capacities of up to 48 h. A steep increase in the NPV was gained by increasing the storage capacity up to 10 h. Electrical capacities below 1 MW had a maximum NPV below 48 h storage capacity. The 1 MW NPV curve was very flat between 12 h and 48 h with a maximum of 409 800€ at 24 h storage capacity. The 750 kW NPV curve had its maximum of 188 400€ at 8 h storage capacity. The 600 kW NPV curve fell monotonously from 38 900€ at 4 h to -5000€ at 24 h storage capacity and larger. The reason for the decreasing NPV was the small additional income gained by increasing the storage capacity in contrast to the increasing costs of storage. Large electrical capacities were not affected in the same way because they profit more from the additional gross income created by means of larger storage capacities.

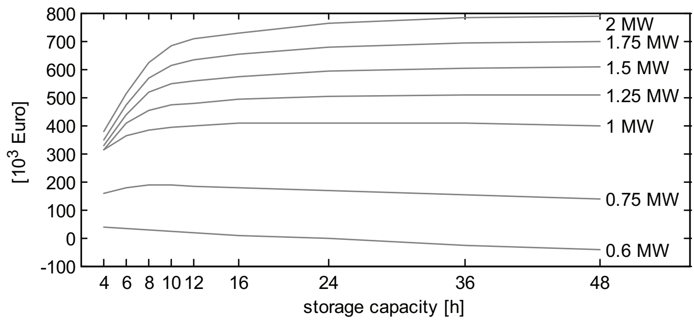

Figure 38: NPV of third-of-a-sphere storage investment (68% extra volume) on top of the extended power and grid connection depending on the storage capacity in hours.

The valuation of the investment in extended electrical capacity and biogas storage facilities was changed significantly by the flexibility premium. In contrast to the results of valuing the investment presented in Figure 32 and the yellow bars in Figure 36, this examination has shown that nearly every electrical capacity up to 2.2 MW, which enlarges the reference capacity by a factor of 4.4, and additionally, nearly every storage capacity can be financed by the flexibility premium. The maximum NPV was obtained by the maximum that was still paid by the flexibility premium, an electrical capacity of

2.2 MW, and is regardless of the market returns of each plant design. The flexibility premium formula even allows 2.5 MW if the plant runs constantly throughout the year. However, that cannot be achieved with respect to the plant's availability which was put at 91% in this analysis.

5.2 Optimizing biogas production based on market prices and premiums

The previous section shows how a biogas plant consisting of a fixed biogas production, gas storage and a power unit can be used most profitably with respect to variable market prices, increasing revenues depending on the electrical capacity and the gas storage. The flexibility premium could support such a scenario by developing additional gas storage and power unit capacities. Another scenario is that a biogas plant reduces the biogas production level in consideration of both the market premium and the flexibility premium. This scenario could be implemented without any investment in extended capacity. Then, the optimal adjustment of the gas production level must be found with respect to the opposing influences of both, the market premium and the flexibility premium; the former set incentives for producing as much power as possible and the latter for reducing the use of the electrical capacity. This examination analyzed whether a biogas plant would reduce its annual power generation in order to operate variably with respect to hourly power prices.

This investigation was carried out by means of use case D (Table 31, Annex E) that included the payment conditions of the market and flexibility premiums in the unit commitment. Furthermore, the biogas production was variable in order to be solved endogenously by the optimized economic decision. Simple kinetics of the biogas production, derived from (Mähnert 2007) (Figure 67, Annex A) were modeled in use case D. The gross income was analyzed according to the unit commitment and the premiums calculated using data from the annual schedules.

5.2.1 Optimal biogas production depending on fuel costs

The first investigation into the behavior of biogas production was carried out by varying the fuel costs from 35€/MWh to 70€/MWh. As the market premium includes thresholds that depend on the annual average capacity used, different power unit sizes from 350 kW to 2000 kW were examined. A part of the following results were already shown in (Hochloff 2014), in particular results shown in Figure 40.

It was found that the adjustment of biogas production depends strongly on the fuel costs. For example, results shown in Figure 39 display the hourly biogas production of a 1 MW biogas plant for three different fuel costs in comparison to the course of the daily average spot market prices. The variable biogas production was limited to 2.5 MW according to the electrical efficiency of 40%. The results show that fuel costs of 35€/MWh made the biogas plant produce electricity at full load throughout most of the year. Raising the fuel costs to 50€/MWh resulted in several sporadic reductions of the biogas production, especially, when the baseload price decreased or daily spreads of high and low prices increased. The biogas production schedule switched from sporadic reductions to weekly cycles at fuel costs of 55€/MWh. The annual utilization factor of the biogas plant was decreased from 89% to 52%. Further increasing the fuel costs to 70€/MWh reduced this utilization factor to 44%.

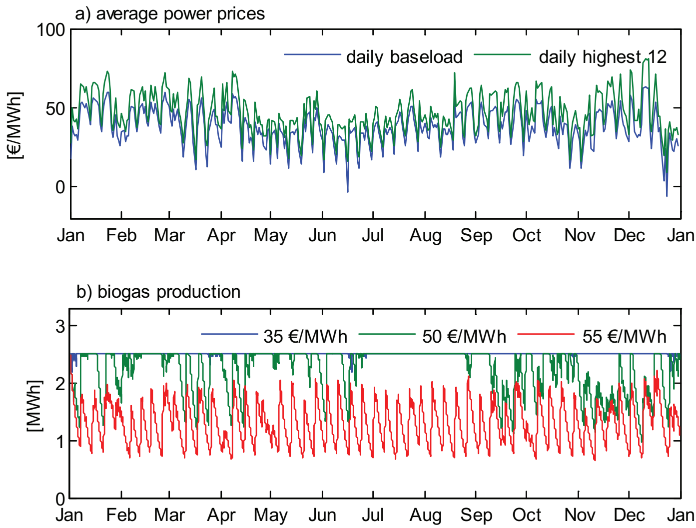

Figure 39: Daily average power prices (a) and hourly biogas production from unit commitment (b) with a 1 MW power unit and a 15 MWh biogas storage facility for different fuel costs, curves from 1/1/2013 to 12/31/2013.

The financial result is depicted in Figure 40. It shows the change in the gross income and in particular the costs and incomes in contrast to fixed power generation at full load throughout the year depending on the fuel costs. Figure 40a) presents the change in the gross income of different power unit sizes and 12 h biogas storage. The gross income of plants between 750 kW and 2 MW increased when fuel costs were raised to more than 50€/MWh. The reduction of biogas production at fuel costs below 50€/MWh did not influence the gross income significantly. The revenues of biogas plants between 350 kW and 500 kW increased when the fuel costs were raised to more than 60€/MWh. The reason for the difference between power units which are smaller than 500 kW and those which are larger is the payment of market premium, which is reduced from the 500 kW threshold of the annual average power. Power generation exceeding the annual average power of 500 kW was paid at the lowest tariff of 150€/MWh, and the power generation between an average of 150 kW and 500 kW was paid at 173€/MWh. The market price had to exceed the difference between the market premium, the flexibility premium and the marginal costs of power generation which were, for example, 125€/MWh based on fuel costs of 50€/MWh and the electrical efficiency of 40%. So, power generation on the low tariff was initially affected by increasing fuel costs, as this difference was less frequently compensated by market prices. Further increasing the fuel costs to above

60€/MWh, meant power generation on the second pay scale level of 173€/MWh was affected more often, too, but not as often as the generation on the low pay level.

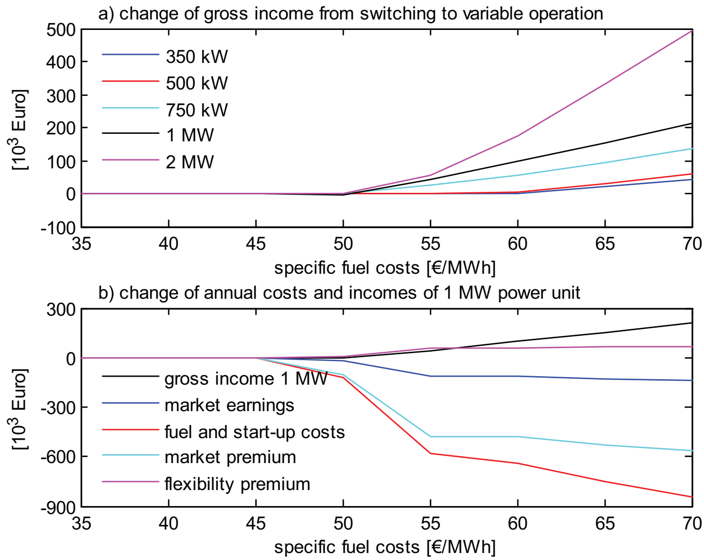

Figure 40: Change in revenues of different plant sizes (a) and change of cash flow positions of a 1 MW power unit (b) by adjusting the biogas production and the utilization of a 15 MWh biogas storage facility.

Furthermore, the effect of increasing the gross income in contrast to the constant power generation at full load is explained by Figure 40b) which displays the change in costs and incomes of the 1 MW power unit. An initial reduction of the fuel costs and the market premium, each of more than 100 000€, was observed at fuel costs of 50€/MWh. The spot market earnings were reduced to approx. 18 600€. A flexibility premium of 2700€ was obtained. As a result, the gross income was about 4700€ below the reference. While the market premium and the fuel costs were reduced by 9.5% and 10.8%, respectively, the spot market earnings were reduced by 5.6% due to the reduction in power generation.

Increasing the fuel costs to 55€/MWh increased the impact on costs and incomes and significantly raised the gross income to 43 000€ above the reference. The fuel costs were reduced by 100 000€ more than the income from the market premium. The market earnings were reduced by 113 700€ and the payments from the flexibility premium increased by 56 000€. While fuel costs decreased by 47.9%, the market premium only fell by 42.4% and the market incomes by 34.4%.

Further increasing the fuel costs to 70€/MWh raised the gross income by 214 100€ above the reference. Fuel cost savings rose 287 900€ more than market premiums. Fuel costs were reduced by 55.3% and the market premium by 49.9%. Market earnings decreased by 41.9% to a difference of 138 800€ against the reference and the payments of the flexibility premium rose to 65 000€.

The biggest effect was gained by increasing the fuel costs from 50€/MWh to 55€/MWh where the biogas production switched from sporadic reductions to weekly cycles. The relative reduction in fuel costs was greater than the relative reduction in the market premium and the market earnings. Even though the annual fuel costs decreased more than the market premium, and the market earnings for further increasing the specific fuel costs, the additional reduction of the costs corresponded to the additional reduction of the incomes, except of the flexibility premium.

For fuel costs of 55€/MWh, the resulting gross income would be negative without the flexibility premium. However, the weight of the flexibility premium was reduced when the fuel costs increased further. The gross income which is gained in comparison to the reference would be positive without the flexibility premium for fuel prices of 60€/MWh and more.

It can be concluded that the premiums paid for generating power and providing extended capacity have a significant influence on the way a plant operates. However, this influence depends strongly on the fuel costs. While optimizing the gross income by adjusting the plant's operation, the market premium and the flexibility premium control the moment the fuel costs initiate change in the way a plant operates. It was shown that the thresholds for paying different rates of the market premium separate small from large plants and their ability to switch to a more flexible plant operation according to market prices. Furthermore, it was shown that the flexibility premium makes a positive financial result at the moment the switch is made while its influence is lost for higher fuel costs. Therefore, it can be concluded that the flexibility premium only moves the value of the specific fuel costs that initiates a switch to flexible operation.

5.2.2 Sensitivity of the flexibility premium on the biogas plant operation

The previous section focused on the influence of premiums on the biogas plant operation depending on fuel costs. The results have shown that there was a small price range wherein the plant operation scheme switched from constant operation at full load to variable operation. This price range was influenced by payments of the market premium and the flexibility premium. As the flexibility premium is the legal mechanism introduced to evolve flexible biogas plants, this section examines further the impact of the flexibility premium on the price range whereby this switching to the flexible operation scheme occurs.

This analysis was also carried out with use case D, the number of time intervals T was set to 120. A 1 MW biogas plant with a storage capacity of about 12 h was examined. The flexibility premium was varied between 0€/kW and 390€/kW. The influence of the flexibility premium was examined considering biogas fuel costs of about 40€/MWh, 45€/MWh, 50€/MWh and 55€/MWh.

Figure 41 shows the resulting impact of different rates of the flexibility premium on the additional gross income depending on the fuel costs. The reference was again the constant power generation at full load at each fuel cost. The curves dropped to below zero before the additional gross income increased. This effect was caused by an over-estimation of the anticipated flexibility premium in the unit commitment. The payment was expected during the short-term unit commitment but not confirmed at the annual analysis of the resulting schedule. This error increased in size when the rate of the flexibility premium was raised. It is neglected for the further analysis of the results. At each of the fuel costs with negative results it is assumed that constant operation at full load is still more profitable.

The results show that switching to variable operation without any flexibility premium raised the gross income at fuel costs of more than 55€/MWh. Introducing and increasing the flexibility premium decreased the point of the fuel costs at which the gross income started to rise due to switching to the variable operation. A flexibility premium between 100€/kW and 170€/kW increased the gross income when fuel costs ranged between 50€/MWh and 52€/MWh. Raising the flexibility premium of 130€/kW by a factor of two and three decreased the fuel costs when switching to variable operation to 47€/MWh and 42€/MWh, respectively.

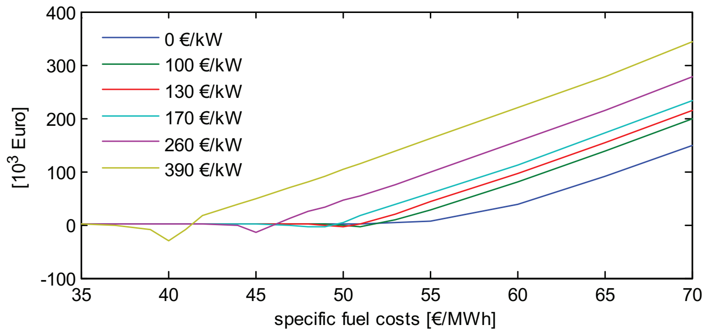

Figure 41: Additional gross income against constant operation of a 1 MW power unit by optimizing biogas production and power generation to variable power prices and different rates of the flexibility premium depending on the fuel costs.

These results show that the flexibility premium supports changes to the operation scheme of a biogas plant. However, in consideration of current fuel costs of about 35€/MWh, the flexibility premium would have to be raised many times over in order to achieve this effect. In contrast, plants that have to calculate higher fuel costs might profit from developing their plant to produce biogas and generate power variably with respect to market prices.

This leads to the question, whether variable plant operation and the payment of a flexibility premium could compensate increasing fuel costs. The influence on the gross income is shown in Figure 42 and it distinguishes the marginal specific fuel costs at which the plant is still profitable. The reference was not constant operation anymore but optimized operation without a flexibility premium at each of the marginal fuel costs. So, the blue curve, representing the flexibility premium of 0€/kW passed zero at marginal fuel costs. Decreasing the fuel costs increased the gross income, and vice versa increasing the fuel costs decreased the gross income. The additional gross income with a flexibility premium had to be at least zero to remain profitable while raising the fuel costs from the marginal ones. That was not found in Figure 42a) which presents the influence on the gross income at marginal fuel costs of 40€/MWh. Figure 42b) shows that the highest considered flexibility premium of 390€/kW compensated increasing fuel costs from 45€/MWh to 50€/MWh. Figure 42c) shows that a flexibility premium of 260€/kW compensated the increase in fuel costs from 50€/MWh to 55€/MWh, whereas a flexibility premium of 390€/kW compensated the increase up to 60€/MWh. Figure 42d) shows that a flexibility premium of 130€/kW and 260€/kW compensated increasing fuel costs from 55€/MWh to 60€/MWh and 65€/MWh, respectively.

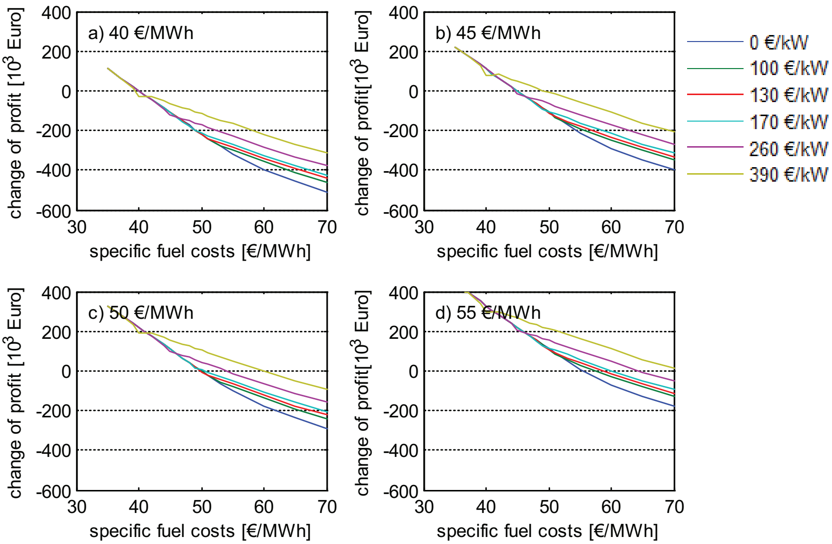

Figure 42: Impact on optimized gross income (use case D) from changing fuel costs against four examples of marginal fuel costs and different rates of the flexibility premium.

These results show that the flexible plant operation with lower average biogas production and the support of the flexibility premium can compensate increases in fuel costs within a small range. The current flexibility premium of 130€/kW compensates an increase of about 5€/MWh but only from a threshold of profitability of 55€/MWh. Higher increases or with a threshold of profitability at lower specific fuel costs can only be compensated with higher flexibility premium levels.

It can be concluded that the flexibility premium can support the conversion of a biogas plant but it has to be adjusted to the fuel costs. On the one hand, the flexibility premium becomes ineffective if its rate is too small in ratio to the fuel costs. On the other hand, it is not needed if the fuel costs are too high because biogas plants could switch from constant to variable operation at fuel costs larger than 55€/MWh in order to raise the gross income. The current rate of 130€/kW reduces the point of the fuel costs at which the conversion would take place without the flexibility premium by only 5€/MWh. However, this range of fuel costs between 50€/MWh and 55€/MWh is significantly more than average fuel costs of about 35€/MWh today.

Furthermore, the flexibility premium does not compensate increasing fuel costs by reducing the power generation and operating variably with regard to power prices. This compensation would be possible at an increase from 55€/MWh to 60€/MWh where a flexibility premium would not be needed for transforming the type of operation.

Therefore, this section analyzed two separate tasks that should be covered by the flexibility premium. The flexibility premium could either replace the reduction in gross income at constant fuel costs when the plant's output decreases as a result of switching from constant to variable operation or it could balance increasing fuel costs by adjusting the variable operation.

5.3 Biogas plants with extended capacity on the spot and tertiary control reserve market

The previous sections show how prices on power spot markets can be capitalized on by biogas plants with extended capacity. However, the revenues can be increased using a biogas plant's ability to supply several products in different markets, in particular control reserve and power generation. The profitability of the extended capacity and the impact of the flexibility premium has been discussed in (Hochloff, Braun 2014). Therein, we studied the additional revenues of four plant settings optimized with respect to market prices of both the power spot market and the tertiary control reserve market. This section shows the profitability of biogas plants with extended capacity depending on the electrical capacity.

The analysis was carried out with use case E (Table 32, Annex E), without market premium in section 5.3.1 and with market premium in section 5.3.2. Use case E extended use case C by adding the equations for bidding for tertiary control reserve products. The biogas plant parameters were the same as in use case C. The prices of tertiary control reserve were obtained from the German TSOs' control reserve market (www.regelleistung.net). As the control reserve is procured in a pay-as-bid market, there are many prices for each product in every product's time interval. The weighted average of the capacity prices of tertiary control reserve was applied as in (Spieker et al. 2013). The resulting time series of weighted averages of the accepted bid's capacity prices are depicted in Figure 79, Annex B. Energy price returns from control reserve activations are thereby assumed to be marginal costs.

The influence of the electrical capacity and the storage size on the additional gross income and the additional annual result was analyzed. The gross income was analyzed against two references, the first being a biogas plant without extended capacity but providing negative control reserve at constant power generation (compare with Figure 30). That showed the effect of investing in excess capacity. Therefore, valuing the investment using the additional annual result was analyzed with this reference. On the other hand, using the results from section 5.1.2, the investigation of use case C, as the second reference showed the advantage of providing additional tertiary control reserve. To analyze the financial result in several calendar years, power and control reserve prices were varied according to the market data from 2009 to 2014.

5.3.1 Optimizing incomes from the tertiary control reserve and spot market

This section shows how additional revenues are created and the profitability of extended capacity improves when supplying tertiary control reserve in addition to selling power on the spot market. Furthermore, how much positive and negative control reserve is offered in the tertiary control reserve market is also analyzed. The storage capacity was varied from 8 h to 48 h, and the electrical capacity from 0.6 MW to 2 MW.

Figure 43a) shows the additional gross income in comparison to the first reference, the constant operation with negative control reserve provision. The additional gross income was between 9000€ and 10 700€ at an installed capacity of 600 kW. Increasing the installed capacity to 2 MW raised the additional gross income to between 9800€ and 51 100€. However, a maximum of 19 200€ and 27 000€ was reached for 8 h and 12 h storage capacity, respectively.

This results in an NPV as shown in Figure 43b). As shown in Figure 32, without control reserve, the NPV peaked and then diminished. However, the NPV of the investment in extended capacity was much lower when tertiary control reserve is taken into account. The values and positions of the maxima are contained in Table 16. The positions were almost the same as in Table 14, except for the maximum of the 12 h storage curve. The difference in their NPV maxima were 38 200€ for the 8 h storage curve and 62 400€ for the 48 h storage curve.

Table 16: Optimal power unit size at maximum profit margin for different storage horizons.

Storage horizon [h]	8	12	16	24	36	48
Power unit [kW]	750	750	850	900	1000	1100
NPV [10^3 €]	38.4	50.9	59.7	72.8	88.9	96.6

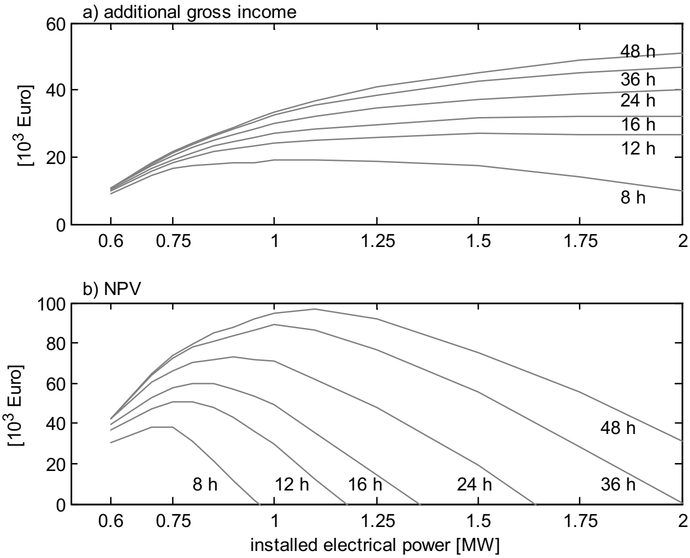

Figure 43: Additional gross income (a) and NPV of extended capacity (b) of use case E in contrast to constant operation including negative control reserve for different storage sizes depending on the electrical capacity.

This decrease in the NPV is caused by the increase in reference revenues which incorporate negative tertiary control reserve incomes throughout the year. The revenues from flexible operation and selling on the spot and tertiary control reserve market increased in comparison to both references. Whereas Figure 43a) shows the difference between gross income and the first reference, constant power generation and negative tertiary control reserve provision, Figure 44 compares the gross income to use case C representing flexible biogas plant operation optimized to spot market prices without providing control reserve.

Figure 44 shows the OFV difference between use case E and use case C results depending on the power unit and gas storage capacity. The maximum additional revenue of 19 600€ is achieved for biogas plants with the smallest considered power unit size of 0.6 MW and a biogas storage capacity of 8 h. The additional revenues decrease to 17 300€ when the biogas storage capacity increases to 48 h. The increase in power unit size to 2 MW leads to the lowest observed additional revenue of 10 600€ at 8 h storage capacity. The majority of the calculated power unit-biogas storage size combinations are green, light-green and turquoise planes in Figure 44 which show an increase between 14 000€ and 16 000€.

Even though providing tertiary control reserve raised the revenues, the NPV of investing in extended capacity was lower than without providing control reserve as the reference revenues increased. Furthermore, the increase in NPV to its maximum was not as steep as in the results with tertiary control reserve. For example, the difference between the NPV at 600 kW and 900 kW was approx. 30 000€ with the provision of control reserve and approx. 50 000€ without the provision of control reserve.

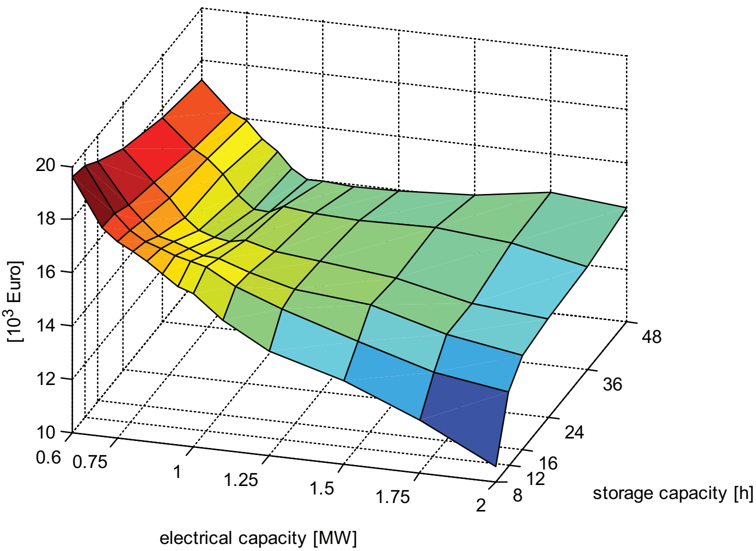

Figure 44: Additional gross income from tertiary control reserve (use case E) against optimized spot market incomes only (use case C) depending on the electrical capacity and storage capacity.

The results in Figure 44 show that the highest additional revenues when providing tertiary control reserve were achieved with the lowest electrical capacity. Such low capacities achieve hardly any additional value on spot markets (Figure 31) and profit more from providing tertiary control reserve. Table 17 shows that the annual amount of capacity that provides tertiary reserve and the revenues thereof are larger for low-capacity plants than for high-capacity ones. Increasing the installed capacity decreased the revenues from tertiary control reserve. However, the increase in revenues from the spot market was larger than the loss of revenues from tertiary control reserve with respect to Figure 43a).

Providing tertiary control reserve with a flexible biogas plant raised the gross income, yet, the increase depended heavily on the year. The additional gross income viewed against optimized incomes from just the spot market is shown in Figure 45. As already illustrated in (Hochloff, Braun 2014), the additional revenues from participating in control reserve markets with biogas plants dropped from 2009 to 2010. However, Figure 45 shows that the additional gross income increased in 2013 and diminished in 2014.

Table 17: Annual provided positive and negative tertiary control reserve (accumulated offers) and revenues depending on power unit and storage capacity, results from use case E.

	8 h	12 h	24 h
0.6 MW	+R: 32.7 MW | 121€ -R: 988 MW | 23 730€	+R: 53.6 MW | 171€ -R: 989 MW | 23 720€	+R: 95.5 MW | 289€ -R: 1008 MW | 23 548€
0,75 MW	+R: 49.5 MW | 228€ -R: 885 MW | 22 398€	+R: 88.5 MW | 370€ -R: 901 MW | 22 445€	+R: 153 MW | 609€ -R: 915 MW | 22 517€
1 MW	+R: 92 MW | 733€ -R: 737 MW | 21 177€	+R: 124 MW | 908€ -R: 791 MW | 21 596€	+R: 204 MW | 1182€ -R: 814 MW | 21 435€
1.5 MW	+R: 98 MW | 958€ -R: 509 MW | 19 332€	+R: 180 MW | 1282€ -R: 595 MW | 19 740€	+R: 304 MW | 2299€ -R: 634 MW | 20 248€
2 MW	+R: 8 MW | 60€ -R: 399 MW | 17 551€	+R: 209 MW | 1452€ -R: 467 MW | 18 780€	+R: 321 MW | 2576€ -R: 552 MW | 19 453€

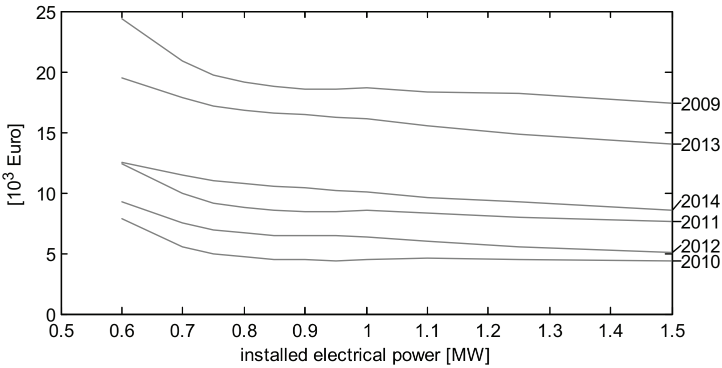

Figure 45: Additional gross income from tertiary control reserve (use case E) viewed against optimized income from just the spot market (use case C) depending on the electrical capacity in different calendar years (12 h storage).

In conclusion, providing tertiary control reserve raises the gross income and plants with little extended capacity profit much more from this additional source of income than plants with large extensions. The total income for this effect is, however, considered with caution as control reserve prices and the resulting income may change significantly every year (compare Annex B Figure 79). In order to value the investment in extended capacity, the reference is then the constantly operating biogas plant which provides tertiary control reserve. For this reason, the NPV is reduced in comparison to the NPV obtained from the revenues from just the spot market. As well as considering just the spot market, the range of a profitable investment in extended capacity grows when the storage capacity is increased. The maximum NPV is also achieved at an electrical capacity between 750 kW and 1100 kW depending on a storage capacity between 8 h and 48 h.

5.3.2 Implications of market premium on providing tertiary control reserve

The previous section considered the planning of spot market and control reserve bids without any premiums. While planning the schedule for bids at full load and part load, the reduction of the power unit's electrical efficiency according to its characteristic curve was taken into account. The trade-off was made by accounting for efficiency losses, control reserve prices and spot market prices. However, a lower power-generation output as a result of efficiency loss, would also mean a lower market premium. Thus, this section analyzed the implications of the market premium on the optimized schedules of products provided to the spot market and the tertiary reserve market. For this reason, the conditions of paying the market premium were modeled endogenously.

The analysis was carried out using use case E with the modification for analyzing the market premium (Table 32, Annex E). The implication of the market premium on bidding for tertiary control reserve was analyzed depending on the electrical capacity of the power unit. Therefore, the electrical capacity was varied between 600 kW and 2 MW. In order to compare influences from the storage capacity, it was set to 12 h and to 24 h. Implications of the market premium were analyzed by comparing these results with the results of section 5.3.1, use case E without the market premium and then adding the market premium to these results, too.

The resulting impact on the schedule of the power unit is shown by the duration curves of a 1 MW power unit with 12 h storage in Figure 46. The unit commitment without considering the market premium resulted in 3616 h at full load and 1050 h at part load, thereof 439 h at minimum load. Considering the market premium in the unit commitment resulted in 4345 h at full load and 43 h at part load. The duration curves show that the result of planning was significantly shifted towards more operational hours at full load and fewer at part load.

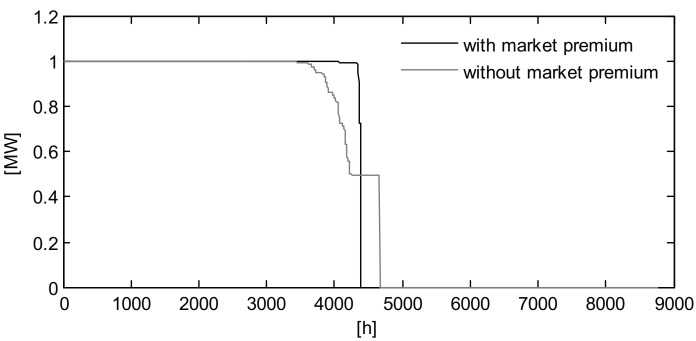

Figure 46: Duration curves of a 0.5 MW biogas plant with a 1 MW power unit and a 12 h-storage capacity scheduled for spot and tertiary control reserve market with/without market premium.

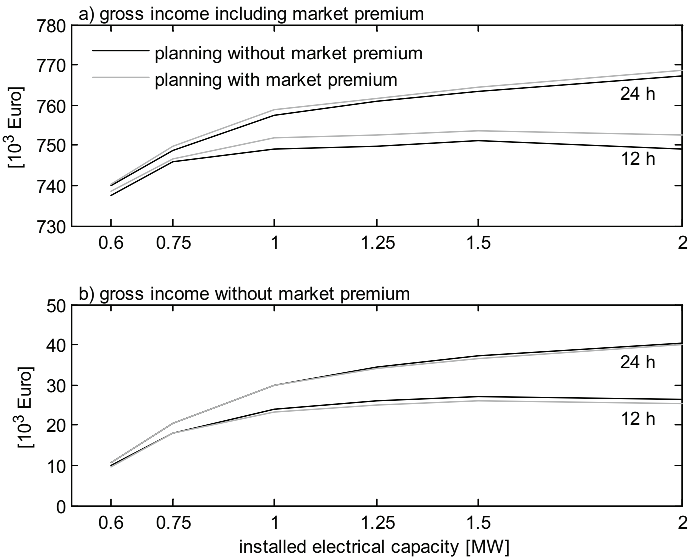

Figure 47: Additional gross income without market premium in use case E (biogas plant on spot and tertiary control reserve market) from planning with and without the market premium in the unit commitment depending on the installed electrical capacity for 12 h and 24 h-storage capacities.

This shift in planning resulted in a change on the gross income. On the one hand, the overall gross income including the market premium was influenced, and on the other hand, the market revenues and the variable costs were influenced. Figure 47 presents both the impact on the gross income including the market premium and the impact on variable costs and revenues without the market premium. The reference for each was constant power generation providing negative tertiary control reserve throughout the year. The impact is shown by curves plotting the result of both, planning with and without the market premium, depending on the power unit size for 12 h and 24 h-storage capacities.

Figure 47a) shows the impact on the gross income including the market premium. As expected, the gross income resulting from the unit commitment including the market premium was larger than the gross income without considering the market premium endogenously. The difference between the 12 h-storage curves was approx. 1000€ for small electrical capacities of up to 0.75 MW. The difference rose to approx. 3000€ for electrical capacities between 1 MW and 2 MW with a maximum difference of 3300€ at 2 MW. The maximum difference of the 24 h storage curves was 1400€ at 2 MW electrical capacity. Figure 47b) shows the impact on the gross income without market premium, i.e. only the market revenues and the variable costs. The maximum difference of approx. 1200€ was observed for a 2 MW power unit with a 12 h-storage capacity. Considering

24 h storage, the maximum difference was approx. 500€ at an electrical capacity of 1.5 MW.

Furthermore, the annual accumulated bids for control reserve were analyzed. Table 18 contains these accumulated bids for both unit commitments, with and without market premium. A systematic shift of positive or negative control reserve offers was not observed. Positive reserve bids increased (for example 0.75 MW and 1.5 MW with 12 h and 1 MW to 2 MW with 24 h) and decreased as well when the market premium was considered in the unit commitment. Negative reserve bids also increased (for example 1.5 MW and 2 MW with 24 h) but predominantly decreased.

Table 18: Annual amount of provided positive and negative tertiary control reserve (accumulated offers) of use case E with and without market premium.

	12h		24h	
	With market premium	Without market premium	With market premium	Without market premium
0.6 MW	+R: 50.8 MW -R: 986.7 MW	+R: 53.6 MW -R: 989 MW	+R: 90.9 MW -R: 1008 MW	+R: 95.5 MW -R: 1008 MW
0,75 MW	+R: 91.6 MW -R: 897.8 MW	+R: 88.5 MW -R: 901 MW	+R: 150 MW -R: 914 MW	+R: 153 MW -R: 915 MW
1 MW	+R: 121 MW -R: 789 MW	+R: 124 MW -R: 791 MW	+R: 218 MW -R: 815 MW	+R: 204 MW -R: 814 MW
1.5 MW	+R: 202 MW -R: 544 MW	+R: 180 MW -R: 595 MW	+R: 326 MW -R: 612 MW	+R: 304 MW -R: 634 MW
2 MW	+R: 198 MW -R: 437 MW	+R: 209 MW -R: 467 MW	+R: 330 MW -R: 556 MW	+R: 321 MW -R: 552 MW

It can be concluded that the impact on the schedule from considering the market premium is significant. Part load is systematically avoided as efficiency losses lead to lower payments of the market premium. However, there is hardly any impact on the resulting annual gross income when considering the market revenues and costs. Nevertheless, it is recommended that the market premium should be considered, too, as the loss of gross income due to the market premium can amount to more than 3000€ for 12 h storage.

5.4 Biogas plants with extended capacity on the spot and secondary control reserve market

In an analogous manner to that of examining the impact of tertiary control reserve, this investigation considered secondary control reserve. Secondary control reserve was planned in a joint optimization of bidding offers to both, the spot market and the secondary control reserve market. Secondary control reserve products mean less flexibility than tertiary control reserve due to the fact that there are four products per week: the negative and positive control reserve for the peak times and the off-peak times. Therefore, the amount of annual bids and the way of scheduling in combination with the power generation was analyzed for some striking examples of power unit sizes.

The gross income was analyzed, again comparing it to two references, where the reference incorporating constantly provided negative control reserve considered secondary control reserve here. Section 5.4.1 investigated the gross income and the annual result when the biogas plant bids in the spot and secondary reserve market and section 5.4.2, then, investigated the impact of the market premium. Both analyses, with and without market premium, were carried out with use case F (Table 33, Annex E). Furthermore, section 5.4.3 made an attempt to increase the bids, especially for positive control reserve, by reducing the reserve for the energy requirement of activating control reserve. Instead of providing energy for activation during the complete time of each product, the historical activation time maximums were taken into consideration. This investigation was carried out with use case G (Table 34, Annex E).

Use case F and G extended use case C by adding the equations for bidding for secondary control reserve products. The biogas plant parameters were the same as in use case C. The prices for providing secondary control reserve were obtained from the German TSOs' control reserve market (www.regelleistung.net). As the control reserve is procured in a pay-as-bid market, the weighted average of the capacity prices of secondary control reserve was applied. The resulting time series of weighted averages of the accepted bid's capacity prices are depicted in Figure 77, Annex B. Energy price returns from control reserve activations are thereby assumed to be marginal costs.

5.4.1 Optimizing incomes from the secondary control reserve and spot market

Bidding for secondary control reserve was analyzed depending on the electrical capacity. One analysis was carried out with two different storage sizes (12 h and 24 h), and one analysis varied the price according to data from between 2012 and 2014.

As a result, Figure 48 shows schedules of weekly secondary control reserve offers throughout a year (an example of the schedule of bids within a time period of two weeks is shown in Annex H, Figure 98). Figure 48a) presents the offers of the 0.6 MW power unit with 12 h storage for peak times, and on the other hand, Figure 48b) presents offers for off-peak times. The results from the optimization show that the 0.6 MW power unit offered negative control reserve at maximum, or near maximum, capacity at peak times. At off-peak times the power unit offered negative control reserve at a capacity between 0.43 MW and 0.45 MW in most weeks. In 20 weeks of the year negative reserve for off-peak times was offered with a capacity of 0.3 MW, which was both capacity at the lower boundary of the operating range and the same size of the operating range itself. In some weeks the offers at peak time decreased; in one week in June it even went down to 0.3 MW. Vice versa, the offers then increased to 0.5 MW in off-peak periods, in particular in July and August, and even to 0.54 MW in this week in June.

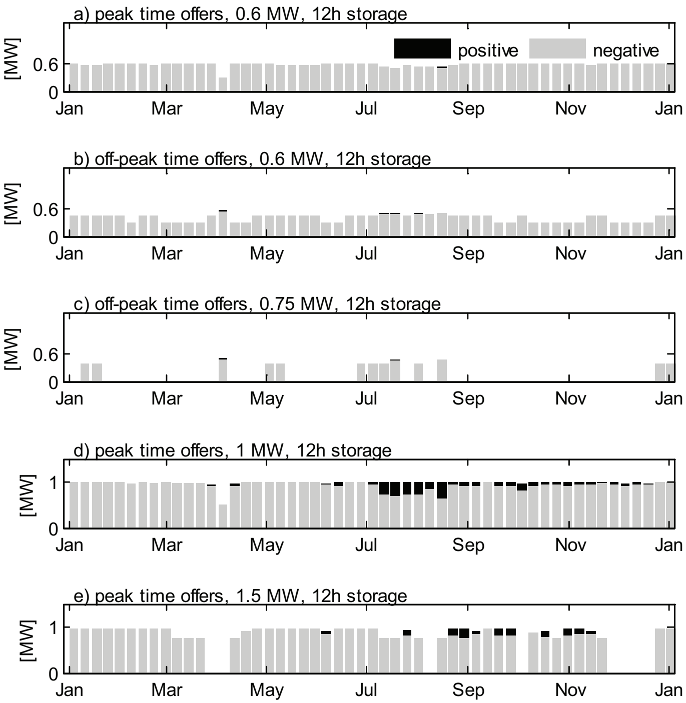

Figure 48: Weekly secondary control reserve offers for peak and off-peak times with different combinations of unit size and storage capacity.

Figure 48c) shows 13 weekly negative control reserve offers of the 750 kW power unit for off-peak times. This illustrates that negative control reserve at off-peak times diminishes as a result of increasing power unit capacity. There were no offers found in off-peak periods for capacities larger than 0.75 MW.

The positive control reserve offers of the 0.6 MW and the 0.75 MW power units were very small but they became more significant in July and August when a 1 MW power unit was used as presented in Figure 48d). The 1 MW power plant offered negative control reserve at maximum capacity in peak times almost the whole year, whereby the negative control reserve offers were significantly lower in July and August only.

Further increasing the power unit size reduced the number of weeks with negative control reserve bids at peak times to 45 as shown by the 1.5 MW power unit in Figure 48e). The negative reserve bids do not exceed 1 MW because the power unit cannot raise the power generation beyond 1 MW for 12 h as there is no more fuel when the complete biogas production from the off-peak time, which is held in the storage, is then consumed at the peak time. The result for those 45 weeks shows that running at part load in order to create a secondary reserve offer was more valuable than generating power at full load. Vice versa, in the remaining 8 weeks, it was more valuable to generate power at full load during peak prices and to renounce secondary reserve offers.

The gross income from the power spot market and secondary reserve market was obtained from the OFV of use case F. The additional gross income was considered against two references. The first being the selling of power on the spot market and negative secondary reserve at constant power generation which showed the additional value of extended capacity. The second being the optimized power generation of flexible biogas plants sold at spot markets which showed the additional value of bidding for secondary control reserve. Figure 49 shows the additional gross income against both references depending on the power unit size of biogas plants with storage capacities of 12 h and 24 h in 2013. Figure 49a) shows the additional gross income against supplying power and secondary reserve at constant power generation. Figure 49b) shows the additional gross income against use case C, the optimized gross income on the spot market only (compare with Figure 31).

These results show that increasing the electrical capacity from 0.5 MW to 0.6 MW raised the gross income to approx. 2400€ (12 h storage) and 3400€ (24 h storage). Considering a flexible plant with 0.6 MW, providing secondary control reserve, the gross income rose to approx. 35 600€ (12 h storage) and 34 600€ (24 h storage). Further increasing the power unit size raised the additional gross income to a maximum of 15 500€ at 1 MW (12 h storage) and of approx. 22 800€ at 1.05 MW (24 h storage). However, the additional gross income gained from providing secondary control reserve with flexible plants decreased at first to a minimum of approx. 27 900€ (12 h storage) and 27 200€ (24 h storage) at 0,75 MW. Furthermore, these curves show a second peak of approx. 31 500€ at 0.95 MW (12 h storage) and 30 500€ at 1.05 MW (24 h storage).

The results from 2012 to 2014 are presented in Figure 50. Similar to the result of 2013, the additional gross income rose to 700€ (2012) and to 3900€ (2014) after the installation of a power unit of 600 kW instead of 500 kW. Installing a 1 MW power unit raised the additional gross income to a maximum of approx. 5500€ at 0.95 MW (2012) and 15 100€ at 1 MW (2014). In 2014 increasing the electrical capacity to 1.5 MW reduced the additional gross income to 11 500€. In 2012 the additional gross income was negative between 1.25 MW and 1.5 MW. In 2012 and 2014 the additional gross income after providing secondary control reserve with a flexible plant (Figure 50b) led to significantly different results in comparison to 2013. In 2012 the additional gross income decreased monotonously from 33 200€ at 0.6 MW to 8700€ at 1.5 MW. In 2014 the most additional gross income of approx. 13 300€ was achieved by the 0.6 MW power unit, and another peak of approx. 12 300€ was at 0.95 MW. The minimum additional gross income of approx. 11 700€ was found at 0.7 MW. Increasing the power unit size to 1.5 MW reduced the additional gross income to approx. 5200€.

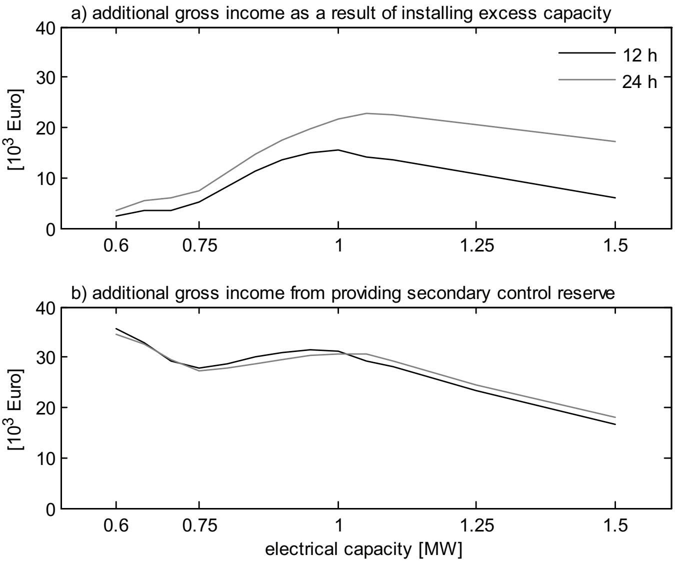

Figure 49: Additional gross income (2013) of use case F, a) against constant operation providing secondary control reserve, and b) against use case C depending on the electrical capacity for 12 h and 24 h storage.

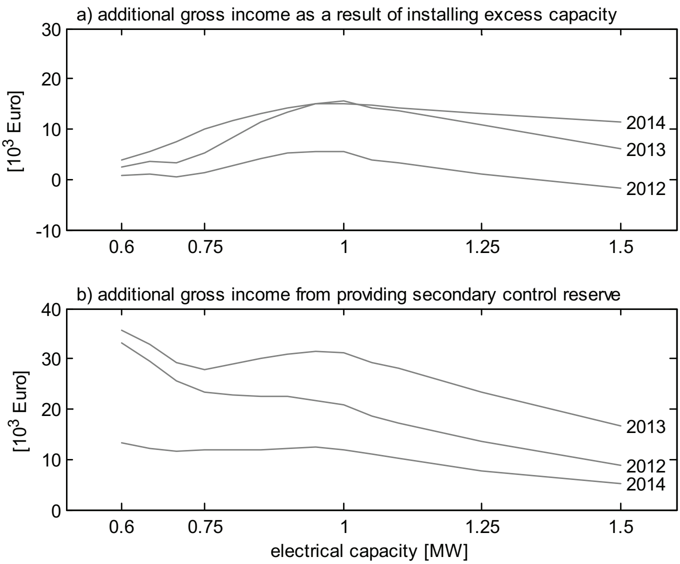

Figure 50: Additional gross income of use case F (12 h storage) from 2012 to 2014, a) against constant operation providing secondary control reserve, and b) against use case C depending on the electrical capacity.

The explanation of these results is twofold; product prices and the amount of products that can be offered. For example, the secondary control reserve incomes and the sum of positive and negative reserve bids of 53 weeks in 2013 of four power unit sizes and two storage sizes are contained in Table 19.

Table 19: Annual amount of provided positive and negative secondary control reserve (accumulated weekly capacity offers) in 2013 and revenues depending on power unit and storage capacity, results from use case F.

	12h	24h
0.6 MW	+R: 0.2 MW | 170€ -R: 51.4 MW | 48 266€	+R: 1.3 MW | 975€ -R: 52.0 MW | 48 816€
0.75 MW	+R: 0.2 MW | 123€ -R: 42.7 MW | 36 111€	+R: 0.6 MW | 453€ -R: 41.4 MW | 35 458€
1 MW	+R: 3.0 MW | 2290€ -R: 48.9 MW | 38 826€	+R: 2.2 MW | 1746€ -R: 50.8 MW | 39 928€
1.5 MW	+R: 1.3 MW | 1047€ -R: 39.3 MW | 33 085€	+R: 5.2 MW | 4085€ -R: 41.7 MW | 35 512€

Table 20: Annual amount of provided negative secondary control reserve (accumulated weekly capacity offers) in peak times and off-peak times in 2012, 2013 and 2014, results from use case F.

	2012	2013	2014
0.6 MW	-R peak: 26.5 MW -R off-peak: 22.1 MW	-R peak: 30.6 MW -R off-peak: 20.8 MW	-R peak: 29.7 MW -R off-peak: 13.1 MW
0.75 MW	-R peak: 29.5 MW -R off-peak: 11.7 MW	-R peak: 37.6 MW -R off-peak: 5.1 MW	-R peak: 38.4 MW -R off-peak: 1.2 MW
1 MW	-R peak: 43.7 MW -R off-peak: 3.6 MW	-R peak: 48.9 MW -R off-peak: 0 MW	-R peak: 37.7 MW -R off-peak: 0 MW
1.5 MW	-R peak: 36.4 MW -R off-peak: 0 MW	-R peak: 39.3 MW -R off-peak: 0 MW	-R peak: 14.5 MW -R off-peak: 0 MW

The 0.6 MW power unit provided very low flexibility that could be capitalized on in spot markets while biogas of an equivalent of 0.5 MW was supplied constantly. However, plants with such small extended capacities gained most from providing negative control reserve. The power unit usually operated at full power (0.6 MW) throughout the peak time, and the fuel still sufficed for operating the power unit at part load throughout the off-peak time. Therefore, negative control reserve was provided similar to the reference, the 0.5 MW power unit, throughout the operational time (Figure 48a and b). The amount annual provided for control reserve and the income thereof reduced in comparison to the reference. However, the incomes relative to the length and capacity of offered control reserve rose by 3.4% using the prices from 2013. That year the biogas plant gained most from secondary reserve revenues because peak time negative secondary control reserve prices were highest. In contrast, the lowest negative secondary control reserve prices were observed in 2014. Furthermore, the biogas plant provided significantly less negative control reserve in off-peak times in 2014. In 13 weeks of the year 2014 the 0.6 MW power unit did not offer control reserve at off-peak times. Instead,

power generation was concentrated on obtaining the highest prices in these off-peak times.

When the power unit size was increased to 0.75 MW, providing secondary control reserve decreased the additional gross income in 2012 and 2013. This was caused by the lower amount of provided control reserve, although the provided control reserve at peak times increased. However, the control reserve offers for off-peak times decreased much more because biogas production could not supply both full load at peak times and part load at off-peak times. In 2013 and 2014 the power unit was operated at full load (0.75 MW) throughout the peak time, consuming the fuel that would be needed to provide negative control reserve at off-peak times. In 2012 less control reserve was provided at peak times in order to raise the offers for off-peak times as those prices were very high. For this reason the plant offered negative control reserve for peak times with a capacity of up to 0.54 MW in 23 weeks between May and October and 3 weeks in January and February. In 16 weeks of the year 2012 negative control reserve was offered for off-peak times as well as for peak times.

Increasing the power unit size from 0.75 MW to 1 MW meant providing secondary control reserve raised the additional gross income in 2013 but not in 2012 and 2014. In 2013 the control reserve incomes grew due to the increased amount of provided control reserve. Although the 1 MW power unit provided nearly the same accumulated capacity of weekly negative control reserve bids as the 0.6 MW power unit, the incomes were still smaller than those of the 0.6 MW power unit. The reason for this is the difference in negative secondary control reserve prices between peak times and off-peak times (compare with Annex B Table 26 and Figure 77). On the other hand, the negative control reserve prices in off-peak times were not high enough to make the 1 MW power unit produce power continuously during the off-peak time as that would lead to a higher loss in income from the spot market. Regarding the duration of the peak and off-peak products, the relative income of secondary control reserve rose by 14.7% against the reference. In 2012 the secondary control reserve incomes of the 1 MW power unit suffered more from this price difference as prices for off-peak times were higher than in 2013 and prices for peak times were lower than in 2013. In 2014 the amount of provided negative control reserve of the 1 MW power unit was kept at the same level as for the 0.75 MW power unit. Therefore, increasing the power unit size from 0.75 MW to 1 MW did not influence the added value of providing secondary control reserve in 2012 and in 2014.

Increasing the power unit size from 1 MW to 1.5 MW reduced the additional gross income in comparison to both references. The reason for this was the decline of control reserve incomes because the 1.5 MW power unit supplied significantly less negative control reserve than the 1 MW power unit. In 2013, for example, the control reserve bids of the 1.5 MW unit occurred at peak times, operating at part load in 32 of the 53 weeks. However, in the other 21 weeks in 2013, the 1.5 MW power unit profited more from hourly spot market price spreads than from negative control reserve provided at fixed peak times. As the bids for secondary control reserve were concentrated in those 32 weeks, the relative incomes rose by 39.4% against the reference with respect to the duration of products at peak times and off-peak times.

Comparing the 0.75 MW power unit with the 1.5 MW power unit in 2012 and in 2013, the accumulated capacity of weekly secondary control reserve bids was nearly the same. However, providing secondary control reserve with an already flexible plant was more profitable with the 0.75 MW power unit than with the 1.5 MW power unit due to lower control reserve prices at peak times (compare with Annex B Table 26). That made a difference in the negative control reserve incomes of approx. 15 500€ in 2012 and 3000€ in 2013. In 2013 the incomes decreased less because of higher prices at peak times and lower prices at off-peak times than in 2012. These differences in control reserve incomes combined with the differences of spot market incomes, which increased by 19 300€ in 2012 and by 8900€ in 2013, and the corresponding costs resulted in an additional gross income for the 1.5 MW power unit that was about 3100€ lower and about 900€ higher than those of the 0.75 MW power unit in 2012 and 2013, respectively.

Based on these additional gross income results, the impact of secondary control reserve on valuing the investment in extended capacity is presented in Figure 51. It shows the annual result having deducted fixed operation costs and the annuity of the extended capacity's investment costs from the additional gross income which were presented in Figure 49a) and Figure 50a).

In contrast to the results of valuing the investment in extended capacity above, the annual result of the 12 h storage capacity was entirely negative for every examined power unit size in 2013. The best results occurred around the two peaks of approx. -1800€ at 0.6 MW and -3000€ at 0.9 MW. There was a minimum of approx. -5700€ at 0.75 MW between these peaks, and increasing the electrical capacity to above 0.9 MW decreased the annual result further. However, the annual result of the 24 h storage capacity was positive between 0.9 MW and 1.05 MW around the maximum of approx. 1600€ at 0.95 MW. A second peak of approx. -900€ occurred at 0.6 MW and a minimum of approx. -3600€ at 0.75 MW.

The annual result for 2012 was significantly weaker because of the low additional gross income. In contrast to the annual result in 2013, there was not a second peak, the maximum of approx. -3900€ occurred at 0.6 MW. Further increasing the electrical capacity mean the annual result decreased monotonously. In 2014 the annual result was negative, too. The annual result ranged between -700€ at 0.6 MW and -1700€ at 0.85 MW. Further increasing the electrical capacity decreased the annual result.

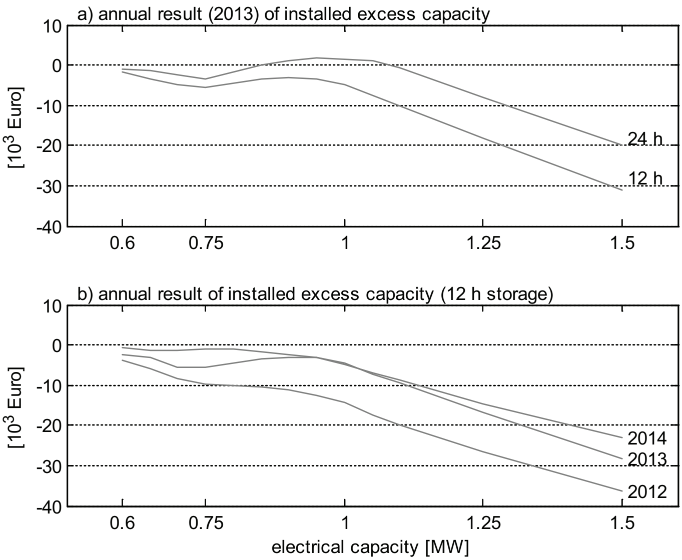

Figure 51: Annual result of extended capacity investment with use case E (biogas plant on spot and secondary control reserve market) for a) 12 h and 24 h storage capacities in 2013 and b) for 12 h storage capacity from 2012 to 2014 depending on the electrical capacity of the power unit.

It can be concluded that investing in extended capacity is not profitable if the biogas plant is already providing secondary control reserve. Only plants with existing large storage capacities of at least 24 h can profit from such an investment. The plants with smaller storage capacities such as 12 h create too little additional gross income to finance this investment. The first reason for this is that a constantly operated biogas plant without extended capacity already increases its profit by providing secondary control reserve during its runtime. However, the income from secondary control reserve is reduced during the flexible operating modus because of the price difference between peak and off-peak times. The significantly higher negative control reserve prices at off-peak times raise the benchmark for measures that lead to fewer offers of negative control reserve at off-peak times. On the other hand, the prices are not so wide apart that biogas plants operate at maximum power at off-peak times throughout the year. That would lead to higher losses from selling the produced power at lower spot market prices. The second reason is that providing secondary control reserve makes the biogas plant less flexible in terms of matching the best prices on the spot market. The spot market incomes are significantly smaller than when secondary control reserve is not provided because the four weekly reserve products must be provided completely or not at all. Nevertheless, for a biogas plant with extended capacity providing both secondary control reserve and power optimized to get the best prices is more profitable than running constantly or optimizing to get best prices on one or other of the markets.

Furthermore, these effects lead to better results when investing in minimal capacity extensions than for investing in large capacity extensions. The smallest investment in extending the 0.5 MW capacity to 0.6 MW (factor 1.2) was preferred by most of the scenarios. In 2013 larger extensions, ranging from 0.9 MW (factor 1.8) to 1 MW (factor 2), were very close to the result of the 0.6 MW power unit and even more successful if the storage capacity was raised. This valuation resulted from negative secondary control reserve prices at peak times that were far closer to the prices at off-peak times than in 2012 and 2014 (compare with Table 26 in Annex B). Annual prices influence the results heavily. The 2012 results showed that the annual financial result worsened as the investment in extended capacity increased. Additionally, the off-peak time prices in 2012 were higher than in 2013, so the resulting valuation was lower. In contrast, the results in 2014 show that a valuation close to zero is obtained for the extended capacity between 0.6 MW and 0.8 MW when negative reserve prices dropped. Decreasing prices reduce the impact of the secondary control reserve on the valuation of the investment in excess capacity.

5.4.2 Implications of premiums on providing secondary control reserve

The previous section shows the impact on the gross income and the valuation of investments in extended capacity after optimizing offers for the power spot markets and the secondary control reserve market. The gross income did not consider the market premium and the investment valuation did not consider the flexibility premium. As secondary control reserve can be provided while operating in part load, this section analyzes the influence of the market premium on the result of the unit commitment, in particular on the scheduling and the financial parameters. Furthermore, this section analyzes the influence of the flexibility premium on the value of extending the electrical capacity.

Figure 52 presents the duration curve of the resulting schedule of a 1 MW power unit with 12 h storage capacity from unit commitment with and without the market premium. The market premium increased the number of full load hours from 2168 h to 3318 h. Besides that it also marginally increased the annual aggregated negative reserve offers from 49.8 MW to 50.6 MW, whereas the aggregated positive reserve offers decreased from 1.7 MW to 0.2 MW. The market premium raised the value of power generation, thus avoiding power generation at part load as a consequence.

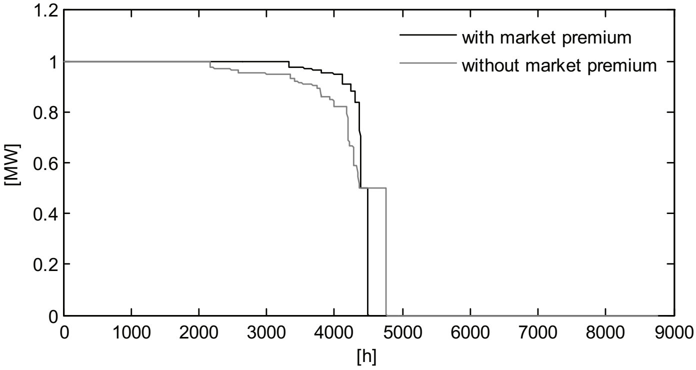

Figure 52: Duration curves of a 0.5 MW biogas plant with a 1 MW power unit and 12 h storage capacity scheduled for spot and secondary control reserve markets with/without market premium.

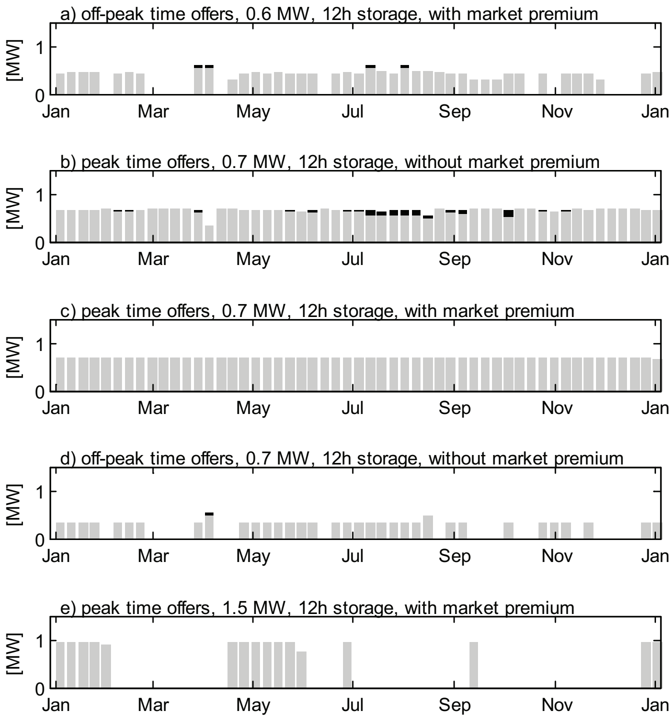

Figure 53: Weekly secondary control reserve offers at peak and off-peak times (2013) with different combinations of unit sizes and storage capacities, with and without market premium.

Figure 53 shows, for example, weekly bids for secondary control reserve over the period of a year resulting from the unit commitment of use case F with and without market premium. Figure 53a) shows that the 0.6 MW power unit reduced the number of weeks with bids at off-peak time as a result of the market premium (compare with Figure 48b). What is more, the 0.7 MW power unit offered secondary control reserve at off-peak time only in one week as a result of the market premium, whereas Figure 53d) shows 34 weeks in which bids were made for the same product from the unit commitment without market premium. In contrast, the market premium raised the bids of small capacity plants at peak times. Thus, they offered negative secondary control reserve at peak times at full load almost throughout the year. For example, Figure 53b) shows the bids for peak times of the 0.7 MW power unit without market premium, and Figure 53c) shows the bids for the same time considering the market premium in the unit commitment. This effect was observed for all capacities up to 1 MW.

Further increasing the power unit's capacity, however, diminished the number of weeks with bids for secondary control reserve at peak times. The number of weeks with secondary control reserve bids from plants with electrical capacities larger than 1 MW decreased as negative control reserve could not be provided at full load. For example, the resulting bids of the 1.5 MW power unit at peak times is presented in Figure 53e). There were 16 weeks with control reserve bids for peak times, whereas the number of weeks with bids for peak times was 32 when the unit commitment without market premium was considered (compare with Figure 48e).

The financial results are presented in Figure 54. It shows the impact on the gross income depending on the electrical capacity of the power unit. Figure 54a) shows the impact on the gross income after installing extended capacity. The reference was providing negative secondary control reserve while operating constantly, and it included the market premium. The figure compares this impact on the gross income with the impact on the income when there is no market premium, which can be seen in the curve of Figure 49a). Figure 54a) shows that the additional gross income with the market premium was lower than without it and even negative from 0.6 MW to 0.7 MW and from 1.2 MW to 1.5 MW. The maximum additional gross income of 12 400€ was achieved at 0.95 MW.

The reason for the negative impact on the gross income was the reduced power generation in ratio to the reference, which was constant power generation of a 0.5 MW power unit. The reduction in power generation was caused by efficiency losses as a result of the plant operating at part load at off-peak times (small capacities) and peak times (large capacities) to be able to provide control reserve. That being said, power generation when considering the market premium was larger than without it and these efficiency losses led to a smaller and even negative impact on the gross income because of the reduced payments from the market premium. In a lot of weeks providing control reserve in off-peak times (small capacities) and in peak times (large capacities), accepting the efficiency losses and the corresponding market premium, was more profitable than operating only at full load, which was the unit commitment solution for the remaining weeks. Nevertheless, the very small and the very large capacities made losses against the reference, which profited from the market premium without any efficiency losses and from providing constant negative control reserve at peak and at off-peak times.

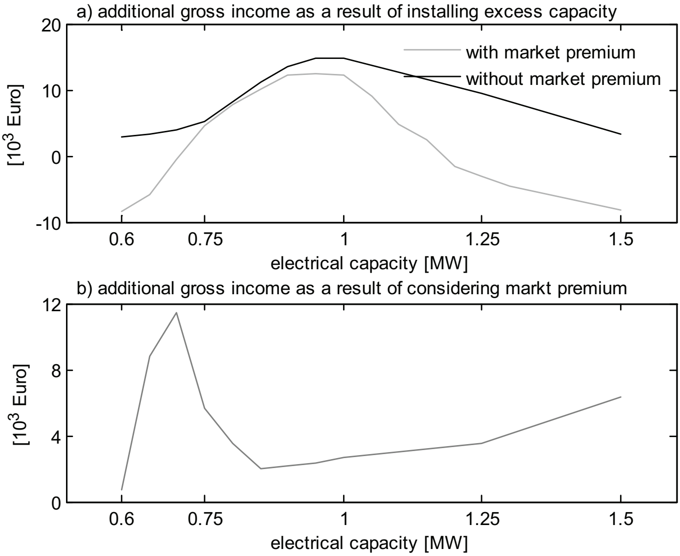

Figure 54: Additional revenues (2013) as difference of the OFV of optimized revenues for the spot and secondary control reserve market and the reference revenues (a) and the increase of revenues by endogenously considered market premium (b) of biogas plants with a 12 h storage capacity depending on the electrical capacity.

The influence of the market premium considered endogenously in the unit commitment on the gross income is presented in Figure 54b). It shows the difference in the gross income from considering the market premium in the unit commitment on the one hand, and on the other hand, adding the market premium to the unit commitment result afterwards. Modeling the market premium in the unit commitment raised the gross income for every considered power unit capacity. The gross income was raised by approx. 760€ at 0.6 MW, 11 500€ at 0.7 MW, 2000€ at 0.85 MW and 6400€ at 1.5 MW. The reason for these differences is that electrical capacities of about 0.7 MW as well as large capacities of about 1.5 MW were scheduled with a lot of operational hours at part load and these were reorganized when considering the market premium. However, as a small capacity 0.6 MW provided too little excess capacity to avoid part load efficiently without large losses from secondary control reserve at off-peak times. The 1 MW power unit, in turn, generated power predominantly at peak times at full load with and without considering the market premium.

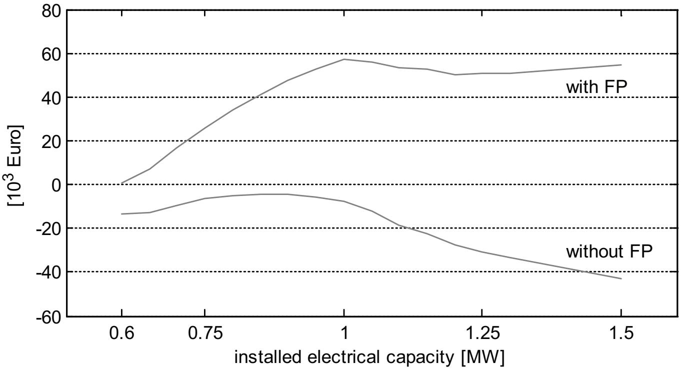

Figure 55: Annual result (2013) of nominal electric power increase of a biogas plant supplying spot and secondary control reserve market in consideration of the market premium (use case E) and the flexibility premium.

Furthermore, the annual result is presented in Figure 55 depending on the power unit size with and without including the flexibility premium. The annual result of investing in extended power was calculated by using the additional gross income above which resulted from planning a biogas plant with respect to secondary control reserve prices, power spot market prices and the market premium. As expected, with regard to the annual result presented in Figure 51a) and the new curve of additional gross income presented in Figure 54a), the annual result was still negative when the flexibility premium was not considered. The flexibility premium raised the annual result in a positive manner: it was approx. 600€ at 0.6 MW and increased to 57 400€ when the electrical capacity was increased to 1 MW. Further increasing the electrical capacity to 1.2 MW reduced the annual result to 50 300€, and increasing it to 1.5 MW raised the annual result again to 54 700€.

The flexibility premium's influence increased when the power unit's electrical capacity was increased. In contrast to the premium’s influence when no secondary control reserve was provided, a peak in the annual result emerged at 1 MW. This was caused by the steep reduction in the additional gross income between 1 MW and 1.2 MW that was not compensated for completely by payments of the flexibility premium. The additional gross income decreased smoothly between 1.25 MW and 1.5 MW. This smaller decrease in income was superposed by the flexibility premium so that the annual result increased again. The claim on the flexibility premium is limited to a maximum power unit size in ratio to the power generation. For this reason the extrapolated annual result will fall for power unit sizes larger than 2.3 MW.

This analysis has shown that the market premium and the flexibility premium have a significant influence on the unit commitment and the investment valuation, respectively. As the market premium is paid for generated power, efficiency losses are weighted more heavily against market incomes, even leading to a negative impact on the gross income.

Therefore, it can be concluded that generating power and, thus, spot market products are preferred to control reserve products provided at part load. It has been shown that this is more profitable as a result of the market premium, and it is especially so when the market premium is modeled in the unit commitment. However, there is still a trade-off in terms of market prices as results have shown that control reserve offers at part load do occur. Furthermore, the reference, providing secondary control reserve while operating constantly, is more profitable than upgrading the biogas plant. Considering upgraded plants with increased capacity, one more reason for the reference being more profitable is that they cannot increase the control reserve bid because the available fuel limits the bids according to the constraints applied in this analysis. However, the flexibility premium altered everything in terms of valuing the investment in extended capacity. The flexibility premium makes upgrading biogas plants profitable, even if the additional gross income is negative.

5.4.3 Secondary control reserve with adjusted energy reserve

Planning the schedule must reflect the possible activation of secondary control reserve which needs energy that must be reserved. Respecting Equation 44, these energy reserves limit the control reserve that can be provided to the market as the available energy of the biogas plant is limited. A restrictive estimation of the energy needed for activating control reserve, which is adjusted to historical data, could replace the assumption above, that activation over the complete time period must be provided. Thus, the amount of control reserve bids provided to the market might be raised.

Use case G applied the data from Figure 84 (Annex B) to determine the factors $\xi^{up}_{\tau-t,1}$ and $\xi^{down}_{\tau-t,1}$ in Equation 44. For this purpose, the illustrated maximum minutes were divided by the number of minutes of each considered time period $(\tau - t)$. Different levels of the activation signal's amplitude in ratio to the procured reserve were examined, in particular activations of at least 10%, 30%, 50% and 90% of the procured reserve. The examination considered several electrical power unit capacities from 0.6 MW to 1.5 MW at a biogas plant with 12 h storage capacity.

As a result, selected schedules of negative and positive control reserve bids for peak and off-peak times are presented in Figure 56, Figure 57 and Figure 58. Figure 56 shows the schedules based on more than 10% energy being retained for reserve activation while optimizing secondary reserve bids. Small power unit capacities profited from scheduling more bids at off-peak times than planning energy at full activation (Figure 48). Furthermore, the result contained more provision of positive control reserve as a result of running at part load. These bids rose to maximum capacity by decreasing the energy reserve and increasing the level of activation to 50% and more of the reserve energy.

Figure 57 shows how the 1 MW power unit profited from adjusting the energy reserve for the activation of more than 30% of the TSOs' reserve and more than 50%. Whereas there was nearly no difference between the reserves for full activation and those adjusted to the energy need for activating more than 30% of the TSOs' reserve, scheduling with respect to an energy need for activating more than 50% of their reserves shows positive control reserve bids of 0.5 MW at off-peak times. These bids were not increased by further decreasing the energy reserve in consideration of an increased level of activating TSOs' reserve. This is because the positive reserve was offered from both the power unit being off and running at half capacity. Biogas produced at weekends made the power unit run at off-peak time, resulting in positive control reserve bids that had to be able to be provided in both states, off and running at part load.

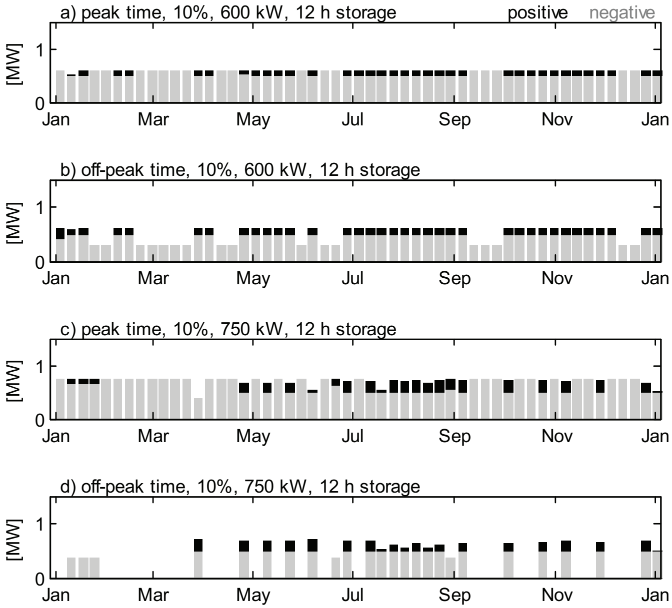

Figure 56: Weekly secondary control reserve bids for peak and off-peak times with energy reserves for more than 10% reserve activation of the 0.6 MW and the 0.75 MW power unit.

Figure 58 shows the schedules of the 1.5 MW power unit planned with energy reserves for activating 50% and 90% of TSOs' reserve. It shows that the number of weeks offering negative control reserve at peak times was raised to 50 and 52, respectively, and positive control reserve was combined with those bids in most weeks. Furthermore, the number of bids for positive control reserve based on half the electrical capacity at off-peak times increased significantly from 15 to 49 by decreasing the reserved energy from the 50% to the 90% reserve activation level.

This different way of bidding had a significant impact on the gross income as shown in Figure 59. It presents the additional gross income against the same two references as in

Figure 49 and Figure 50. The curves, plotted against the power unit capacity, differ in the energy reserved for activations: more than 10%, 30%, 50% and 90% of the procured reserve and full activation throughout the provided time. As a result of decreasing the reserved energy, a small impact was observed for small power unit capacities, rising significantly for the 50% and the 90% curve due to the increase in electrical capacity. However, an influence on the gross income was also seen at small electrical capacities by reducing the reserved energy to the 10% threshold and the 30% one of the activation signal, which was diminishing as the electrical capacity increased. The gross income rose by 2600€ at 0.6 MW. By increasing the electrical capacity to 1 MW, the gross income rose by 1300€ (30% curve), 10 100€ (50% curve) and 11 000€ (90% curve). Furthermore, raising the electrical capacity to 1.5 MW, meant the gross income rose by 1700€ (30% curve), 12 900€ (50% curve) and 29 300€ (90% curve).

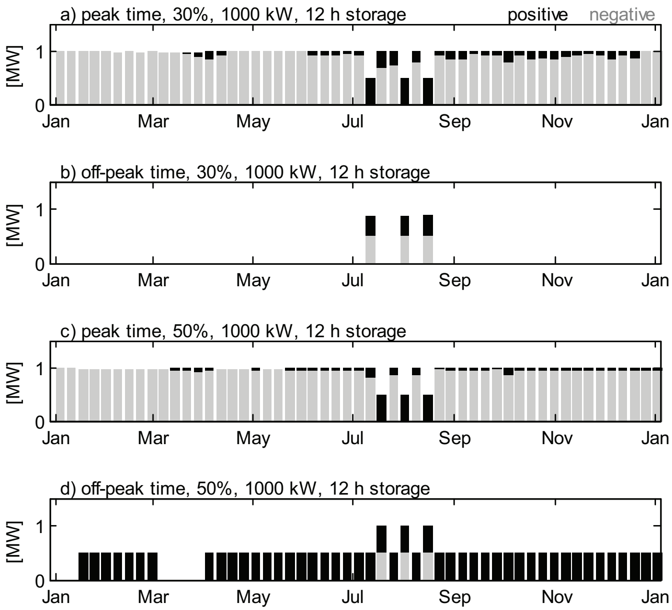

Figure 57: Weekly secondary control reserve bids for peak and off-peak times with energy reserves for more than 30% and more than 50% reserve activation of the 1 MW power unit.

The effect on the gross income in turn influenced the valuation of the investment in extended capacity. The annual result is presented in Figure 60. Due to the additionally offered secondary control reserve, investing in extended capacity became rather profitable. Reducing the reserved energy to the maximum needed for activations of more than 30% of the procured reserve, the valuation was slightly positive between

0.65 MW and 0.85 MW. The 50% and the 90% curve were positive up to an electrical capacity of 1.05 MW and 1.5 MW, respectively, with a maximum of 5400€ and 6500€ at 0.95 MW.

It can be concluded that this method of bidding raises the income so that financing the investment in extended capacity is enabled. However, only a limited range of extended capacities can be financed and those depend heavily on the reserved energy for activations and thus the income from the amount of provided control reserve. In particular, large capacities between 0.8 MW and 1 MW profit from the income of additionally provided control reserve by reducing the reserved energy for their activation. Smaller capacities may profit, too, but the effect is small and it cannot be pushed up by increasing the level of activation, and thus, reducing the reserved energy.

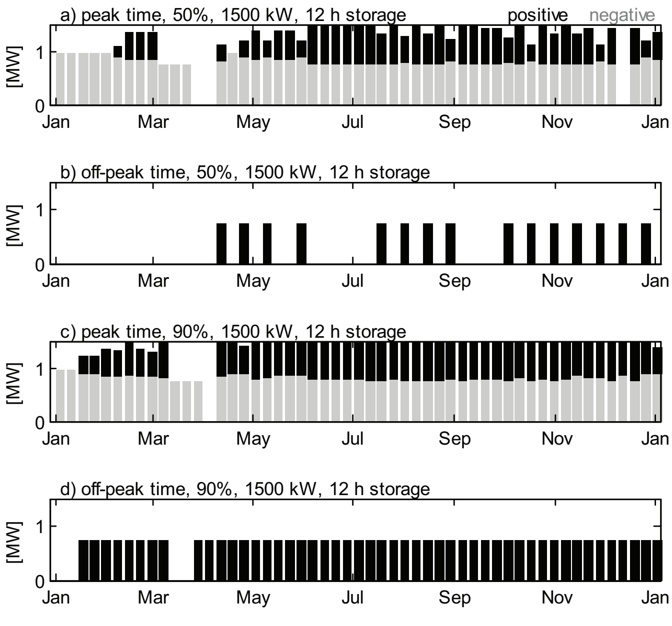

Figure 58: Weekly secondary control reserve bids for peak and off-peak times with energy reserves for more than 50% and more than 90% reserve activation of the 1.5 MW power unit.

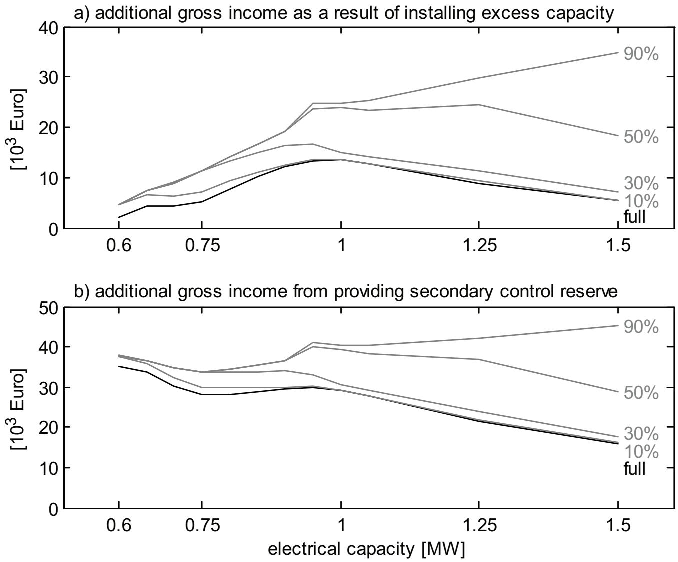

Figure 59: Additional gross income of use case G with reserved energy for more than 10%, 30%, 50% and 90% reserve activations, a) against constant operation providing secondary control reserve, and b) against use case C depending on the electrical capacity.

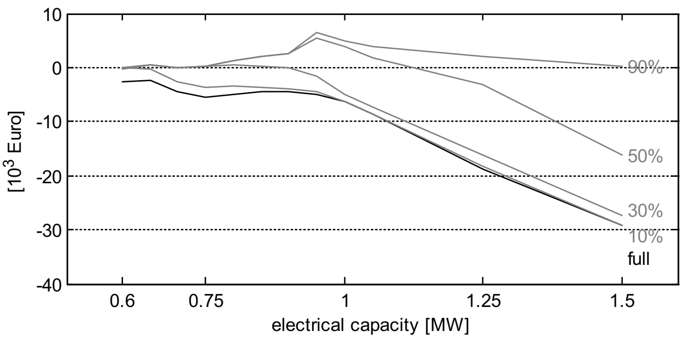

Figure 60: Annual result of extended capacity investment with use case G with reserved energy for more than 10%, 30%, 50% and 90% reserve activations depending on the electrical capacity.

5.5 Summary of economical findings

The following sections summarize the findings above. Section 5.5.1 focuses on the findings of analyzed use cases considering biogas plants participating in spot markets. Section 5.5.2 concentrates on the findings from analyzing the participation of biogas plants in secondary and tertiary control reserve markets in addition to the spot market. Section 5.5.3 highlights findings from analyzing the impact of the market and the flexibility premium on the market participation.

5.5.1 Findings of biogas plants with extended capacity on spot markets

The results of the analysis of biogas plants on the power spot market demonstrated that biogas plants can generate significant additional revenues by exploiting hourly price differences. In 2013, for example, to finance the costs of creating extended capacity in the power unit, the additional gross income of a biogas plant with 12 h storage is between 13 000€ (0.6 MW) and the maximum of 36 000€ (1.75 MW). Extensions of the electrical capacity can be profitable even at biogas plants with very small biogas storage capacity. Data suggest that small storage capacities enable only profitable investments in small extensions of the capacity, whereas large storage capacities enable a large range of profitable extensions of the electrical capacity. From each storage size emerges an electrical capacity that creates the most NPV, ranging from an extension of the electrical capacity of 20% at 4 h storage to 120% at 48 h storage.

One important finding was that the 500 kW capacity of a biogas plant with 12 h storage is most profitably extended with an additional 350 kW (factor 1.7) regarding several historical years of hourly spot market prices. This result is especially robust because different years (from 2001 to 2014) were taken into account, leading predominantly to the same capacity or a small difference. While extrapolating the power prices of recent years from 2010 onwards, data suggest a preference towards smaller extensions of 50% to 60% on top of the reference capacity.

The results demonstrated, furthermore, that the investment in storage capacity is not predominantly financed by the additional gross income. This is only possible if inexpensive technologies and measures, for example, the quarter-of-a-sphere storage, or exchanging the membrane of a third-of-a-sphere storage, suffice to create storage capacity of at least 6 h to 8 h.

To my knowledge, this work provides the first demonstration of additional market revenues of a biogas plant obtained from MILP, strictly depending on the electrical capacity and the storage capacity. Increasing the electrical capacity of a biogas plant is thus considered with a focus on its opportunities in the power market.

However, biogas plants are engineered very individually. Creating extended capacity, and in particular, the costs of upgrading a biogas plant will vary distinctly. Various cases could be considered, varying technical parameters, operational and investment costs, financial conditions, and plant designs with different constraints, technical options and compositions of components. These aspects of engineering a plant have not been considered. Instead, this work focuses on the market opportunities in different use cases and the implications of plant component dimensions on the success in markets and the possibility of financing the extension of the capacity.

A scenario where a new power unit has been planned, is not a very typical use case today. New biogas plants are hardly planned in Germany. Upgrading existing plants with a second power unit occurs more often, however, that was not considered in this work. Instead, the results of this work can be applied when power units have to be replaced at the end of their lifetime. Thousands of biogas plants have been built in Germany since the introduction of financial support by law. Insights and models from this work may be used to estimate incomes depending on component sizes while engineering and procuring the power unit. As this work assumed a biogas plant to be a price-taker in power markets, the results can easily be transferred to biogas plants with a smaller or larger biogas supply, considering the electrical capacity of the power unit in ratio to the reference instead of the total capacity. Furthermore, the results of this work can be transferred to power markets abroad and to other technical sources of continuously produced gas, for example, from waste or from treatment plants. The results can be used to plan new distributed plants if similar hourly prices are obtained for the generated power.

5.5.2 Findings of extended capacity in control reserve markets

In addition to the spot market, control reserve markets and their product prices have been considered while optimizing the schedule and the bids for these markets. The results described above indicate that this additional possibility of generating income raises the additional gross income effectively. One important finding was that small capacities profit more from providing control reserve than large capacities as presented in Table 21, summarizing the results described above.

Table 21: Increase in gross income due to provision of control reserve for flexible biogas plants with 12 h storage depending on the electrical capacity.

Year	Tertiary (1.5 MW ... 0.6 MW)	Secondary (1.5 MW ... 0.6 MW)
2012	5000€ ... 9000€	9000€ ... 33 000€
2013	14000€ ... 19 000€	14 000€ ... 36 000€
2014	8000€ ... 13 000€	5000€ ... 13 000€

This result is surprising because one would assume that large capacities could provide more control reserve than small capacities and thus earn more income. However, a strong constraint was applied that limited the control reserve bids to the available fuel in order to satisfy the activation of this control reserve for the whole time it is provided. Therefore, large capacities profit more from exploiting spot market prices than from providing control reserve and, in contrast, small capacities provide more control reserve per year. Furthermore, they operate for many more hours to consume the same amount of biogas and can, therefore, provide negative control reserve during higher control reserve prices, too. A second important finding was that the impact on the gross incomes varied significantly depending on the considered year. The financial result from participating in control reserve markets can vary up to a factor of 3, depending on the considered capacity and year. This is an effective illustration of how fluctuating control reserve prices influence the analysis of the market integration of flexible biogas plants.

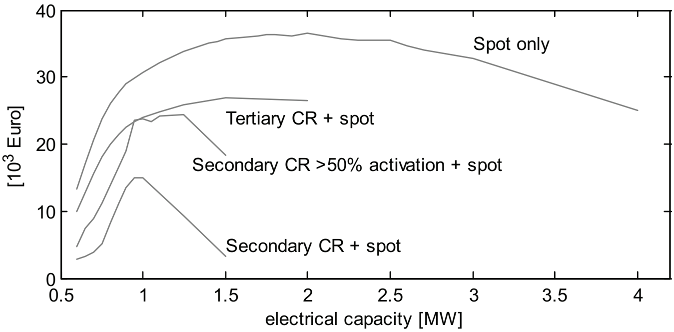

Figure 61: Additional gross income (2013) against each reference depending on the electrical capacity.

With respect to the effect of installing extended capacity, the reference, which the results have to be compared with, included the incomes from negative control reserve throughout the constant operating time, too. Respecting this reference, the additional gross income as a result of installing extended capacity was between 10 000€ (0.6 MW) and a maximum of 27 000€ (1.5 MW), and between 3000€ (0.6 MW) and a maximum of 15 000€ (0.95 MW ... 1 MW) for providing secondary reserve in 2013. The results of this work demonstrated that providing control reserve in addition to supplying the spot market decreases the additional gross income, even though, the total gross income rose as shown in Table 21. This result might be surprising, yet, it can be explained easily by the increased figures for the reference. Furthermore, the maximum additional gross income shifted towards smaller capacities as presented in Table 22 because small capacities gain more from providing control reserve. Both effects occurred more with secondary control reserve than with tertiary control reserve for the reasons below:

- Providing secondary control reserve included approx. 1000 hours more at part load than providing tertiary control reserve considering, for example, the 1 MW power unit in 2013. Thus, providing secondary control reserve caused more efficiency losses than tertiary control reserve.
- In comparison with the reference the annual provision of secondary control reserve decreases more than the annual provision of tertiary control reserve with respect to the duration of the products.
- The income from tertiary control reserve in ratio to the provided amount is higher in comparison with the reference than the relative income from secondary control reserve. Increasing the electrical capacity raises this effect.

These reasons cause, furthermore, that the peak of the additional gross income from providing secondary control reserve is much more visible, whereas the peaks arising from supplying both the spot market only and providing tertiary control reserve in addition are flatter.

Table 22: Maximum additional gross income due to the installation of extended capacity at a biogas plant with 12 h storage.

Year	Spot only		Spot + Tertiary		Spot + Secondary	
2012	37 000€	1.75 MW	29 000€	1.5 MW	5500€	0.95 MW
2013	36 000€	1.75 MW	27 000€	1.5 MW	15 000€	1 MW
2014	26 000€	1.75 MW	19 000€	1.5 MW	15 000€	1 MW

The change in the additional gross income has significant effects on valuing the investment in extended capacity. Figure 62 shows the annual result of a biogas plant with 12 h storage in 2013, comparing the results from the spot market only and in combination with the secondary and the tertiary control reserve market, respectively. In view of respecting control reserve incomes in the reference of the additional gross income, providing control reserve reduces the annual result, even though the overall gross income increases. The annual result is positive up to an electrical capacity of 1.5 MW with a maximum at 0.75 MW. These findings demonstrated that the additional gross income from supplying the spot market optimally can finance extensions of more than 1 MW on a 0.5 MW original capacity. Tertiary control reserve reduces the annual result, and thus, an extension of the capacity by 0.6 MW can be financed by the additional gross income. Also, the maximum annual result is obtained at an electrical capacity of 750 kW. Providing secondary control reserve leads to negative results. Moreover, a local minimum of the annual result occurs at an electrical capacity of 750 kW. However, this minimum is not confirmed in consideration of the annual result from other years (compare with Figure 51).

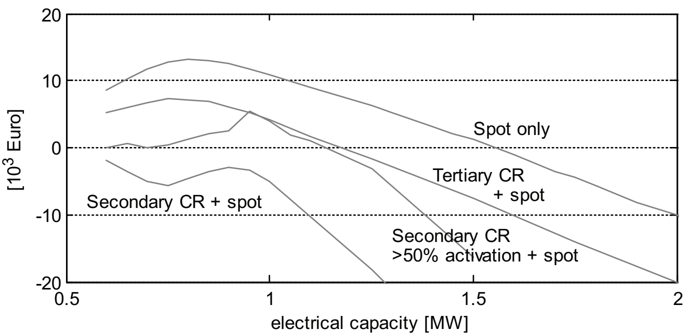

Figure 62: Annual result (2013) against each reference depending on the electrical capacity.

From this result it cannot be interpreted that a flexible plant supplying the spot market only should not enter the control reserve market as the financing of the extended capacity might be harmed. In contrast, providing control reserve creates additional income in this scenario as presented in Table 21. Instead it should be interpreted that, depending on the control reserve market and the size of the power unit, a biogas plant already providing control reserve should not invest in extended capacity.

These results are obtained by applying very strict constraints with respect to the energy needed to activate control reserve. When full activation over the whole time period of the product is considered, the available fuel limits the capacity which can be provided as control reserve. The maximum energy requirement, obtained from analyzing activation signal data from the secondary control reserve, relaxes the limits of providing control reserve, and thus raises the income. Activating the plant depends on the energy price of the bid and the amplitude of TSO's activation signal. Figure 61 shows that the gross income will rise if the planned energy need is adjusted to activating more than 50% of TSO's procured reserve. This additional gross income causes a positive annual result at an electrical capacity between 0.65 MW and 1.1 MW. The maximum annual result occurs at an electrical capacity of 0.95 MW.

These findings broaden the understanding of investing in extended capacity in consideration of providing control reserve. As control reserve can be provided by both flexibly and constantly operated biogas plants, providing control reserve has to be considered independently of investing in extended capacity while the change in its market revenues must be respected. Furthermore, it is an effective illustration of the influence of estimating the activated energy need on bidding for control reserve and the income it generates. In particular, the maximum duration of activations in consecutive hours at certain amplitudes of the activation signal was used in this analysis, indicating the energy need in every period of consecutive hours analyzed endogenously.

However, some caution should be taken in generalizing these conclusions. First, exact numbers of activated minutes from historical data were employed to respect the energy need while planning the offers. This restrictive estimation incorporates the risk of failing to meet the TSO's requirement to fulfill completely the demanded activation. In this respect, reducing the provided energy for activating control reserve can be considered crucial in general, however, data show that significant reductions can be made, and yet the control reserve requirements can still be fulfilled. Second, while varying the plant's activation level depending on the amplitude of the TSO's signal, it was assumed that every bid is located at the same place on the TSO's merit order list regardless of costs and energy prices for its activation. As energy prices of control reserve fluctuate strongly, the place on the merit order list cannot be planned exactly in practice. Furthermore, the investigation includes the limitation that varying the level of activation considers the incomes from the control reserve bids' capacity prices, but not the incomes from their energy prices. Within this limitation, the results indicate the effect of the increased amount of provided control reserve.

These findings may serve as a basis for further study into the implications of bidding for control reserve and reducing the provided energy for its activation. So far, the results show that a significant effect on the financial result can be achieved due to such reductions. In this manner, investments in extended capacity become profitable, although secondary reserve is provided with and without upgrading the plant. The optimal size of the electrical capacity can be planned with regard to these results. However, these results should be considered with the reminder that prices from different years influence the annual result heavily, depending on the electrical capacity. The results are not as robust as the results of considering the spot market only.

5.5.3 Findings of the market premium and the flexibility premium

The findings described above demonstrated the influence of premiums on operating and investing in four cases:

- Spot market with fixed biogas production: impact of the flexibility premium on financing extended electrical capacity and storage capacity
- Spot market with variable biogas production: impact of the market premium and the flexibility premium on operating the biogas plant
- Tertiary control reserve and spot market: impact of the market premium and the flexibility premium on operating the biogas plant
- Secondary control reserve and spot market: impact of the market premium on operating the plant, and impact of the flexibility premium on financing extended capacity

The results of this investigation demonstrated that the market premium affects the operation of a biogas plant considerably, for example, when considering the number of hours operating at full load and part load. The number of operational hours at full load of a 1 MW power unit rose by 700 h for providing tertiary control reserve and 1150 h for providing secondary control reserve. A significant impact on the financial result, however, was only recognized for providing secondary control reserve when electrical capacities were much smaller or much larger than 1 MW. For such power unit sizes this is explained by the large number of operational hours at part load, resulting from the unit commitment to provide secondary control reserve, which diminishes by respecting the market premium endogenously. In particular, the effect on the gross income is negative in comparison with the reference (a constantly operated biogas plant with a 0.5 MW power unit providing negative control reserve and is being paid the market premium). The financial result of installing extended capacity, which is already negative in the case of providing secondary control reserve without market premium, is decreased significantly at electrical capacities smaller than 0.75 MW and larger than 1 MW, whereas it hardly decreases in the range between. These findings are limited to biogas plants upgraded from 0.5 MW as they incorporate payment thresholds for different rates of the market premium. For this reason, the results can hardly be transferred to smaller or larger references. However, these findings might be useful to evaluate generally the implications of efficiency losses at part load as a result of providing control reserve.

The flexibility premium influences the financial result in various respects. In line with the premium's purpose, the financial result increases significantly, and it is even positive in the case of providing secondary control reserve. So, further upgrading costs can be financed, for example, storage capacity. Another important finding is that the maximum financial result shifted towards much larger electrical capacity, more than four times that of the reference capacity. From providing secondary control reserve emerges an additional local maximum at 1 MW, double the reference capacity. The demonstrated impact on the financial result which depends on the electrical capacity is an effective illustration of stimulating investment using the flexibility premium. However, the results described above demonstrated that extended capacity can be financed by the additional market revenues. The results did not allow for insights into the effects of further upgrading costs. This issue will need further investigation as upgrading costs are individual to each biogas plant. Nevertheless, these results may serve as a basis for further investigation to support specifically upgrading costs. Furthermore, one can assume that investing in electrical capacity near to the threshold where the flexibility premium is paid is most profitable. This result needs to be interpreted with caution as this threshold is not static and does not depend on the installed capacity, but rather on the annual power generation as illustrated in Figure 3. This is respected by an average factor of the plant's annual availability incorporated in the results. However, outages exceeding the calculated availability can cause a menacing collapse of the annual result. Furthermore, investing in such large electrical capacities is not robust in consideration of regulatory changes as power market prices and investment costs stimulate far smaller extended capacity.

Both the market premium and the flexibility premium influence the operation of a biogas plant if biogas production is considered variably. Instead of keeping it static, variable biogas production is adjusted with respect to its costs and the plant's incomes. The results described above demonstrate that a reduced gas operation, varying dynamically in weekly cycles, is stimulated if gas production costs exceed 55€/MWh - regarding its heating value. The flexibility premium shifts this point to 50€/MWh, as the flexibility premium remunerates less power generation of a plant. On the other hand, the results indicate that the flexibility premium is hardly able to compensate increasing fuel costs in general, except in a small range from 55€/MWh to 60€/MWh. This result is to be treated with caution as current average fuel costs are assumed to be about 35€/MWh. However, these findings can be applied to help plan biogas plants in challenging markets with high variable costs. The findings reported in this investigation broaden the understanding of operating a biogas plant in the German power market, interacting with several decision-making influences, for instance, the power market prices, the fuel costs, the market premium and the flexibility premium. The flexibility premium can hardly be applied to stimulate the flexible operation of a biogas plants as long as biogas production can be increased to maximize the use of the power unit. Maximizing power generation is supported by the market premium, which decreases the marginal costs of power generation at a biogas plant. A multiple of the flexibility premium would be required in order to counteract the market premium's effect and switch to flexible plant operation at current fuel costs. This is not recommended as the flexibility premium's purpose is to cover upgrading costs of a biogas plant.

6 Conclusion

This work shows how biogas plants with extended capacity can be analyzed when they participate in power markets, in particular the power spot market and the control reserve markets. A model is developed in order to obtain optimized schedules and financial parameters just as gross income and net present value when biogas plants with extended capacity capitalize on prices in each market. Those schedules that are calculated by maximizing the gross income, which is the difference between incomes and costs of the products, show the optimized operation of biogas plants in different markets with expected price curves. The gross income can be determined depending on the electrical capacity of the power unit. Thus, the results of the model which was developed can be applied when planning a new plant, or during a general overhaul and, thus, used to improve the information available when making investment decisions. The model can show to what extent the extended capacity can be financed by the revenues gained, in contrast to the reference which is the constant operation of a power unit at full load.

There are different ways of participating in power markets as biogas plants can provide control reserve and may claim premiums for their power generation. As a result, there are incomes from different origins that can be exploited in various manners and influence the daily decision on how to operate the plant. Therefore, the developed model respects several use cases that describe possible ways of participating in German power markets, switching between static and variable gas supply, providing secondary and tertiary control reserve, and claiming the market and flexibility premium. Making daily decisions about how to operate the biogas plant with respect to various incomes and costs and a planning time period of several hours or days needs an appropriate unit commitment. Mixed integer linear programs (MILP) have been developed for the unit commitment of each use case. The model for the unit commitment of providing control reserve with biogas plants makes significant progress against the state-of-the-art technology and has already been published in (Hochloff, Braun 2014). The first results from this model were published in (Hochloff 2013) and (Hochloff, Holzhammer 2013). In this work the model has been developed further from (Hochloff, Braun 2014) by regarding the secondary control reserve market, and especially by reducing the energy which is reserved for the activation of control reserve in order to enlarge the amount of provided control reserve. Furthermore, this work presents models to consider the market premium and the flexibility premium within the unit commitment. Results from a use case that regards the variable power and gas generation as well as market and flexibility premium were published in (Hochloff 2014).

In this work results from the model were analyzed, too. The implemented MILPs, solved with CPLEX, were applied to simulate the unit commitment throughout a year by rolling planning. Two kinds of investigations were carried out: an analysis of the time to solve the MILP and the trade-off from saving run time with regard to the result, and an analysis of the financial parameters, in particular the gross income and the net present value, obtained from the simulated results of the model.

Firstly, solving the MILPs which included bidding for tertiary control reserve was examined, as bidding for control reserve massively extended the state-of-the-art unit commitment problem. Several attempts were made to relax the model and limit the run time of solving the MILPs. The influence on the result and the run time was analyzed. It is shown that the run time varies greatly throughout a year because of the price data used each day. A time limit that aborts the process of searching for the best solution of the MILP in 25% of the days from one year effectively reduces the mean run time by 30% to 60%. The analysis of the rolling unit commitment shows that the result of these days is affected by up to 1%, but the annual result is affected by less than 0.02%. Relaxing binary variables in the excess time of the optimization horizon regarded in the rolling unit commitment is a further strategy to save run time. For a 48 h optimization horizon, it is shown that keeping the binary variables in 8 h directly after the actual 24 h planning time and relaxing the binary variables in the remaining 16 h reduces the run time effectively by 17% without loss in the solved value of the objective function in the planning time.

Secondly, the results from the model in different use cases were analyzed with an economic focus. The use cases comprised: participating in power spot markets, in combination with tertiary or secondary control reserve, with and without taking the market and the flexibility premium into account. The results were used to calculate an additional gross income in contrast to the gross income of the reference. Thus, the cash flow generated by employing extended capacity was determined and furthermore used to value the investment. The net present value (NPV) and the equivalent annual result of upgrading the plant were presented. The economic analysis of the use cases in this work focuses on a biogas plant with one power unit, originating from a scenario where a new power unit has to be procured, for example, when planning a new plant, or a general overhaul at the end of the engine's lifetime. It is shown that the gross income and the NPV create a curve with a maximum depending on the extension of the electrical capacity. The optimal electrical capacity at the maximum gross income or the maximum NPV depends on the available storage capacity and the market prices of a calendar year. For a 12 h storage capacity it has been found that the maximum NPV, with respect to the spot market prices of recent years, is obtained at the point when the electrical capacity is extended by 60%. A significantly different result is obtained when secondary control reserve is provided, too. The model shows that the maximum NPV shifts towards 90% extension of the electrical capacity. The flexibility premium, however, shows the most impact on the result of the model. It dominates the result as the maximum NPV shifts towards the maximum payed out by the flexibility premium.

The model developed in this work is based on the principles of unit commitment and there are two ways to make use of it. First of all, the model can be applied to plan daily schedules for the operation of gas plants located at a gas production site such as biogas plants. The model can be applied to several power units at one gas production site as well as for several gas productions sites and the corresponding power units. Several geographically distributed plants are usually combined by power trading companies in virtual power plants to sell power generation and control reserve together. So, the model can be applied to optimize the bids from a virtual power plant in power spot and control reserve markets. Multiple plants can be optimized by the model at the same time in order to create collective products of several hours such as control reserve. However, the run time of solving the MILP increases greatly. Therefore, strategies need to be developed in order to keep the run time within an acceptable time frame, for example, making use of time limits, or creating small pools of gas plants that are either optimized one by one or represent all the distributed plants of the virtual power plant.

The model can, secondly, be applied to analyze the benefits from extending the electrical or the storage capacity of gas plants located at a gas production site. The model calculates the optimized gross income of such a gas plant from an expected price curve. The gross income is represented in the objective function of the model. Thus, the model returns the maximum market incomes minus the marginal costs. The obtained gross income enables the electrical capacity that generates the most NPV to be found and to analyze influences such as different price scenarios or technical parameters, for example the storage capacity. In the same manner the installation of thermal storage at biomass plants with steam turbines has been analyzed by means of a further development from this work (Hoffstede et al. 2015). Furthermore, the impact of different schemes of taxes and levies on operating a CHP plant with thermal storage and electrical heating rods has been analyzed (Gerhardt et al. 2014).

Further work may include new use cases such as providing ancillary services to the distribution grids, for example, by means of products procured by DSO and TSO on new markets for flexible capacity at certain nodes of the grid. This work provides a basis for above mentioned use cases because generating power with regard to variable prices and providing capacity for an ancillary service, which, in this work, is control reserve procured by the TSO, are modeled to do both at the same time. Ancillary services in distribution grids can be supplied by distributed energy resources, for example biogas plants, in virtual power plants and active distribution grids (Braun, Strauss 2008), (Stetz 2013). For example, scheduled CHP plants brought together in a virtual power plant that are affected by needs for regulation from the distribution grid are analyzed in (Marten et al. 2013) by means of the implemented model from this work. A further example is the model implemented in the same simulation framework that showed how the power consumption of households with photovoltaic panels and batteries can be influenced by tariffs with regard to the consumption peaks (Schreiber et al. 2015). Such investigations show that use cases to provide ancillary services in distribution grids should be elaborated in the further development of models analyzing the unit commitment of distributed plants.

Nomenclature

Abbreviations

CHP	combined heat and power
DA	day-ahead
DSO	distribution system operator
EEG	'Erneuerbare-Energien-Gesetz'
ID	intraday
IRR	internal rate of return
LP	linear program/programming
MILP	mixed-integer linear program/programming
MIP	mixed-integer program/programming
NPV	net present value
OFV	objective function value
PV	present value
RES	renewable energy sources
TSO	transmission system operator
WACC	weighted average of capital costs

Parameters

D	number of segments of the linearization of characteristic curves
K^{posR}, K^{negR}	number of tertiary control reserve products within T
L^{posR}, L^{negR}	number of time intervals of tertiary control reserve product
$L^{peak}, L^{off-peak}$	time intervals of peak time and off-peak time, respectively
N	number of power units
Q	number of thresholds of energy paid by the market premium
T	number of time intervals
τ	time intervals indicating the end of a sub time period within T

Subscripts

d	index of number of linearization intervals within D
k	subscript of number of products within K^{posR}, K^{negR}
l	subscript of time interval within the product length L^{posR}, L^{negR}
n	index of the power unit within N
p	index of the range of the average power generated
q	index of threshold within Q
t	index of the time interval within T

Continuous Variables

$E_{n,q}^{mp}$	energy produced up to threshold q [MWh]
$e_{t,\tau,n}$	fuel needed for power generation and up regulating reserve [MW]
$f_{t,\tau,n}$	fuel needed for providing up and down regulating reserve [MW]
$G_t^{prod.}$	gas produced [MW]
$G_t^{stor.out}$	gas storage discharge [MW]
$G_t^{stor.in}$	gas storage charge (MW]
$G_{t,n}^{con.}$	fuel consumption of power unit [MW]
P_n^{exc}	excess capacity of power unit, paid by flexibility premium [MW]
$P_{t,n}^{gen.}$	generation of the power unit [MW]
$P_{t,n}^{self}$	power consumed by technical units of the plant [MW]
$P_{t,n}^{spot}$	power offered to the spot market [MW]
$P_{t,n,d}^{part}$	power generation related to segment d [MW]
$P_{t,n,d}^{part,e}, P_{t,n,d}^{part,f}$	power related to segment d calculated for $e_{t,\tau,n}$ and $f_{t,\tau,n}$ [MW]
$\mathrm{P}_{\mathrm{p}}^{\mathrm{use}}$	average power generated within the period [1...T] [MW]
$R_{t,n}^{up}$	up regulating capacity offered to control reserve market [MW]
$R_{t,n}^{down}$	down regulating capacity offered to control reserve market [MW]
S_t	gas storage level [MWh]

$s_{t,n}^{up}$	indicating start-up time of the power unit, virtual binary variable

Binary variables

$s_{t,n}^{sp}$	indicating power unit in spinning state
$s_{t,n}^{sp,up}$	indicating up regulating reserve provided from spinning state
$s_{t,n}^{sp,up/down}$	indicating up or down regulating reserve provided within operating range
$s_{t,n}^{nsp,up}$	indicating up regulating reserve provided from non-spinning state
$s_{t,n}^{nsp,down}$	indicating provision of down regulating reserve to non-spinning state
$s_{t,n}^{nsp,down,sp,up}$	indicating both $s_{t,n}^{nsp,down}$ and $s_{t,n}^{sp,up}$ at the same time
s_{p}^{flex}	indicating the range of the average power produced

Constants

c^{fuel}	fuel cost of power unit [€/MWh]
c^{up}	start-up cost of power unit [€/start]
$G_{n,d}^{min}$	fuel consumption at the lower boundary of segment *d* [MW]
$G_{n,d}^{max}$	fuel consumption at the upper boundary of segment *d* [MW]
$G_{t}^{prod.max}$	maximum produced gas [MW]
$G_{n,d}^{0}$	offset of segment d in function of fuel consumption [MW]
$m_{n,d}$	gradient of fuel consumed per power generated in segment d
MP_{t}^{spot}	market price from spot market [€/MWh]
MP_{t}^{posR}	price bid for positive control reserve [€/MW]
MP_{t}^{negR}	price bid for negative control reserve [€/MW]
P_{n}^{min}	lower boundary of the operating range [MW]
P_{n}^{max}	upper boundary of the operating range [MW]
$P_{n,d}^{part.max}$	maximum of partial power generation of segment d [MW]
$P_{n,q}^{lowthre}$	exceeded threshold of power range *q* paid by use of $\Psi_{n,q}^{mp}$ [MW]

$P_{n,q}^{upthre}$	threshold of power range q paid by use of $\Psi_{n,q}^{mp}$ [MW]
S_0	storage level before first time interval of the period [1...T] [MWh]
S^{end}	storage level at the end of the period [1...T] [MWh]
S^{max}	maximum gas storage capacity [MWh]
Δt	length of time interval [h]
α^{stor}	rate of loss while storing
$\alpha^{stor.in}, \alpha^{stor.out}$	rate of loss during charging and discharging
$\epsilon^{up}, \epsilon^{down}$	maximum rate of up and down regulating the gas production
$\eta_n^{el.}$	electrical efficiency of the power unit
$\Psi_{n,q}^{mp}$	fixed feed-in tariff [€]
Ψ^{flex}	flexibility premium [€/MW]
$\xi_{\tau,t,n}^{up}, \xi_{\tau,t,n}^{down}$	share of maximum activated minutes per time interval of up and down regulating reserve

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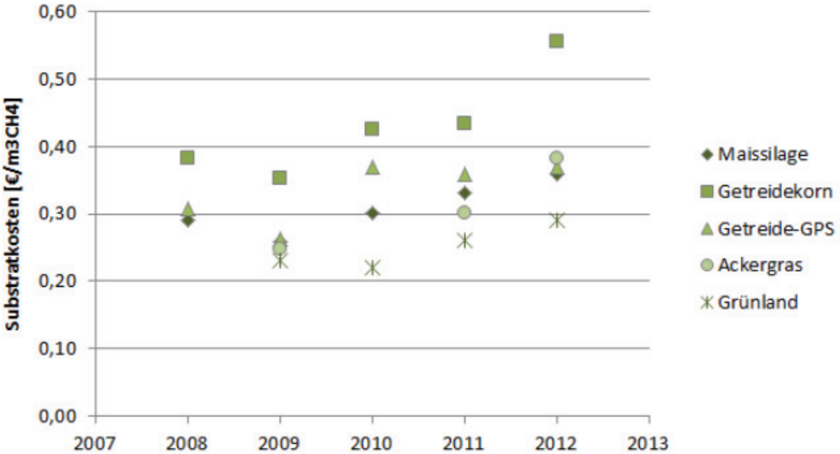
Annex A Biogas plant parameters



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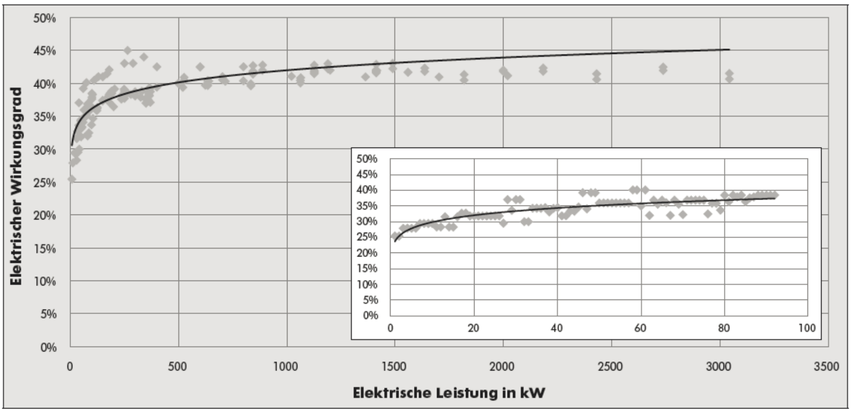

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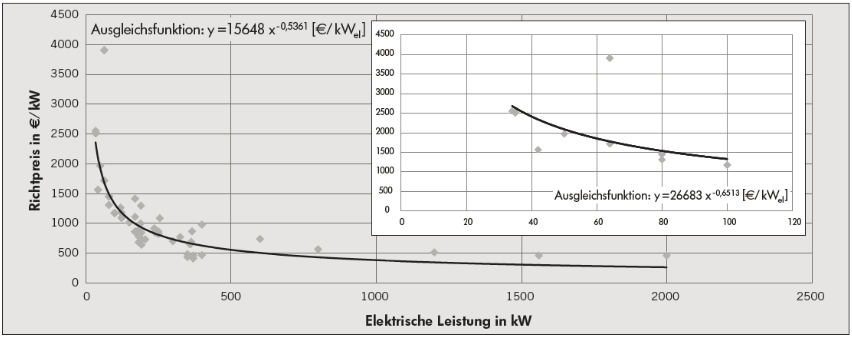

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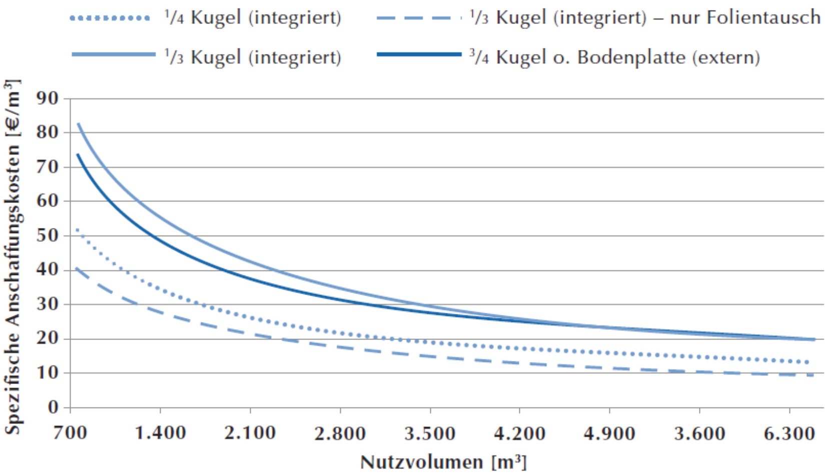

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Table 23: Average electrical and thermal demand of biogas plants in ratio to the generation (DBFZ et al. 2013a).

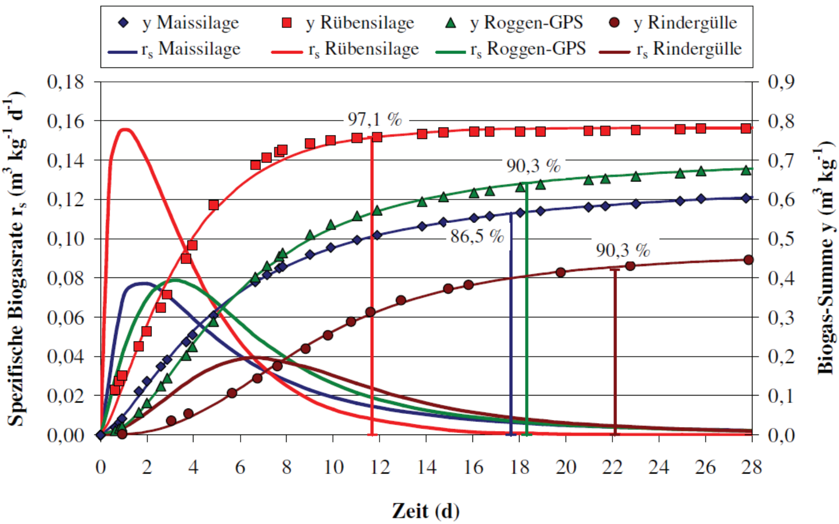
Electric nominal power	Electric self consumption	Thermal self consumption
≤ 70 kW	10 %	60,5 %
> 70 kW ∧ ≤ 150 kW	6,9 %	38,4 %
> 150 kW ∧ ≤ 500 kW	7,2 %	26,1 %
> 500 kW ∧ ≤ 1000 kW	7,9 %	20,5 %
> 1000 kW	8,7 %	13,9 %
All	7,5 %	26,5 %

Table 24: Fermentation gas yield from excrements (dry organic mass) (KTBL 3013).

Raw material	Biogas yield [m^3/kg]	Methane share [%]	Methane yield [m^3/kg]
Poultry manure	0.5	55	0.28
Cow dung	0.45	55	0.25
Cow liquid manure	0.38	55	0.21
Swine liquid manure	0.42	60	0.25

Table 25: Number of uses of and fermentation gas yield from renewable raw materials (dry organic mass) (KTBL 3013).

Raw material	Number of uses [%] (energy content)	Biogas yield [m^3/kg]	Methane share [%]	Methane yield [m^3/kg]
Fodder beet silage	2	0.7	52	0.36
Whole crop silage	7	0.62	53	0.33
Kernel	4	0.73	52	0.38
Grass silage	10	0.6	53	0.32
Corn silage	75	0.65	52	0.34



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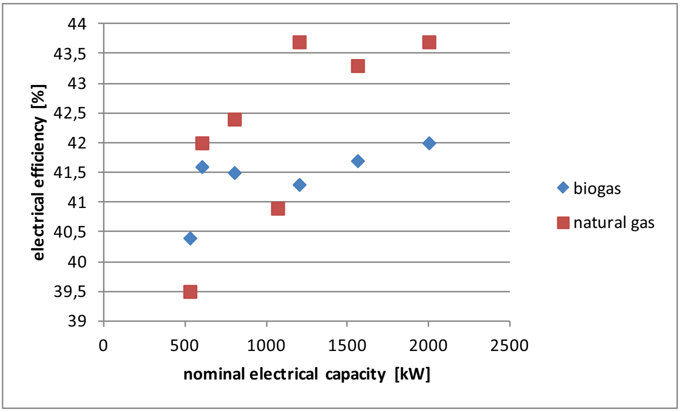
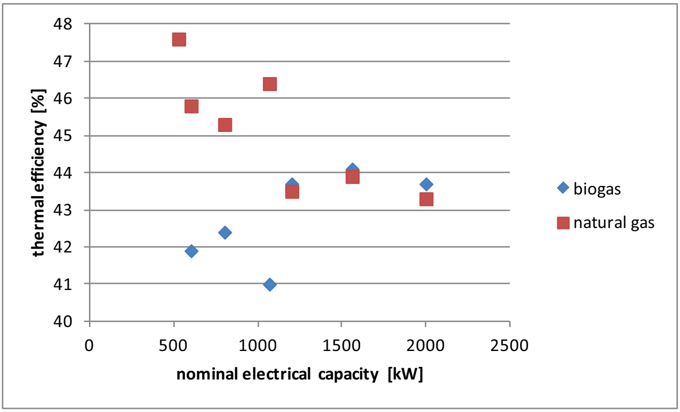


Figure 68: Electrical efficiency of biogas and natural gas plants depending on electrical capacity.



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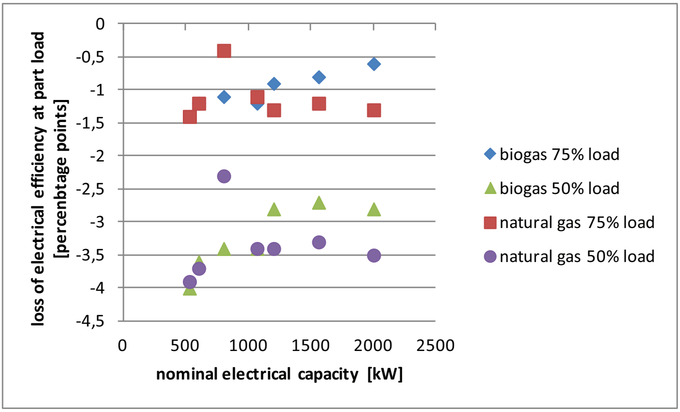

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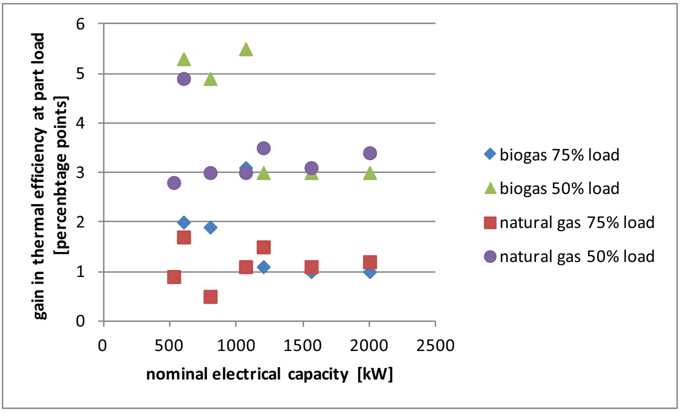

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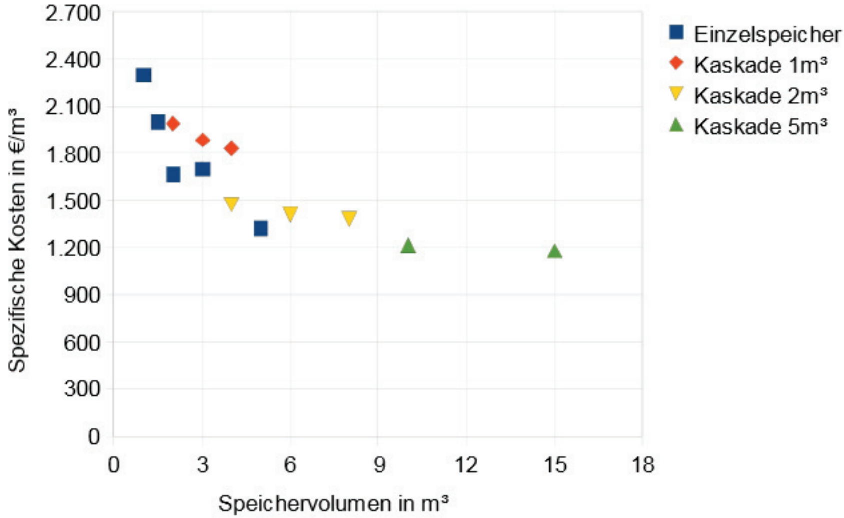

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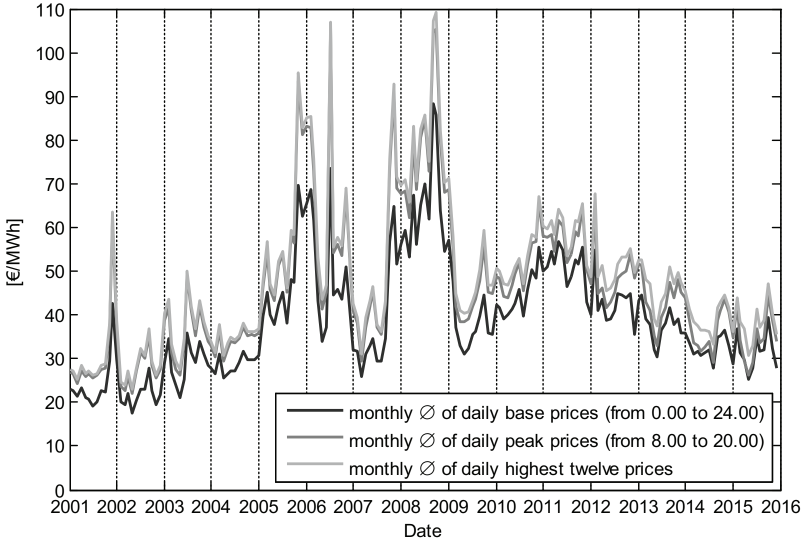
Annex B Spot and control reserve market prices



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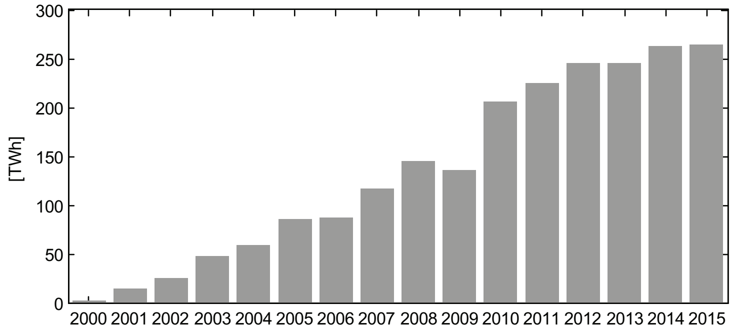

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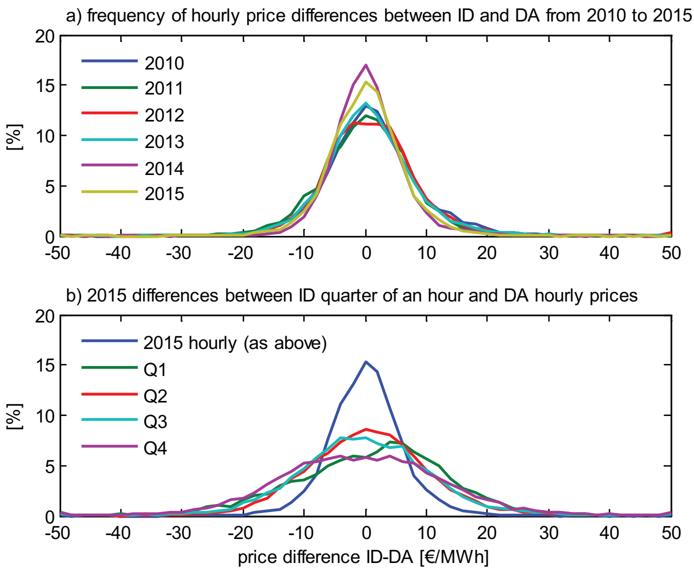

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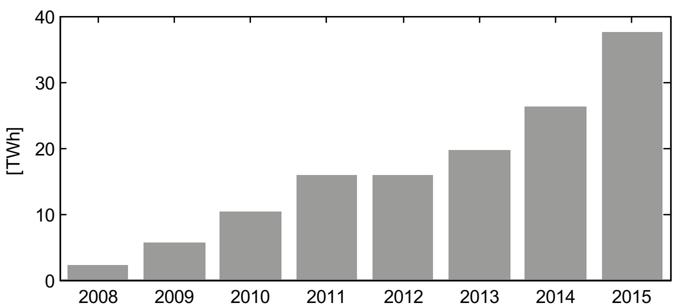

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Table 26: Annual average of secondary reserve capacity prices from the weekly weighted average.

	2012	2013	2014	2015
Negative reserve peak time	570€/MW	797€/MW	324€/MW	104€/MW
Negative reserve off-peak time	1432€/MW	1194€/MW	531€/MW	290€/MW
Positive reserve peak time	106€/MW	559€/MW	469€/MW	352€/MW
Positive reserve off-peak time	316€/MW	761€/MW	809€/MW	607€/MW

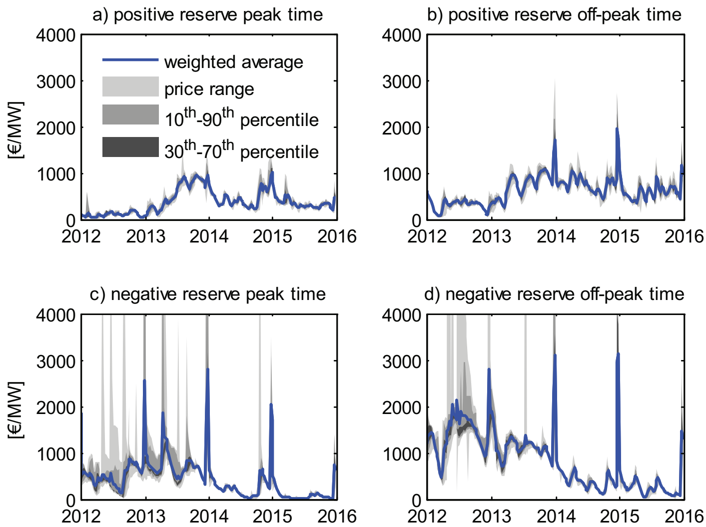
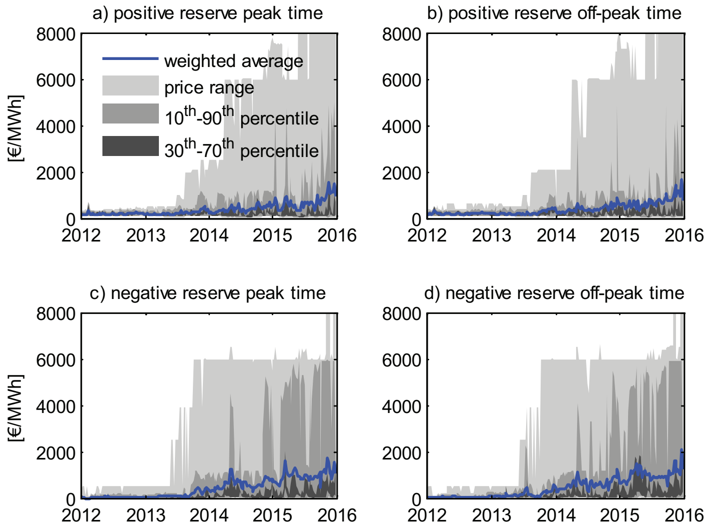


Figure 77: Capacity prices of secondary control reserve products from Jan. 2012 to Dec. 2015.



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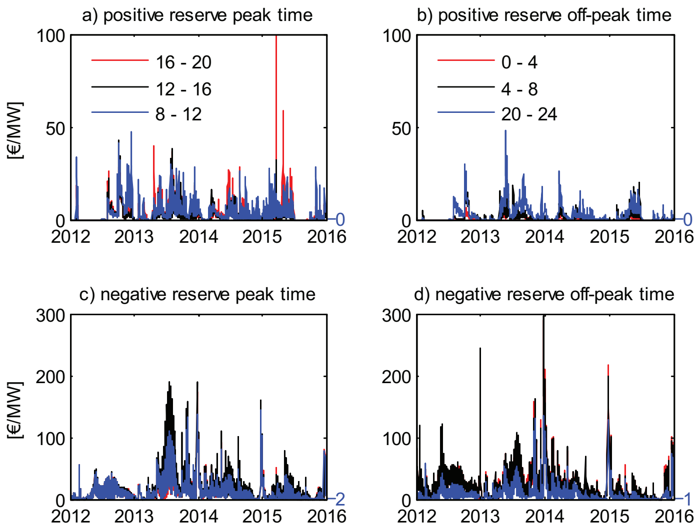

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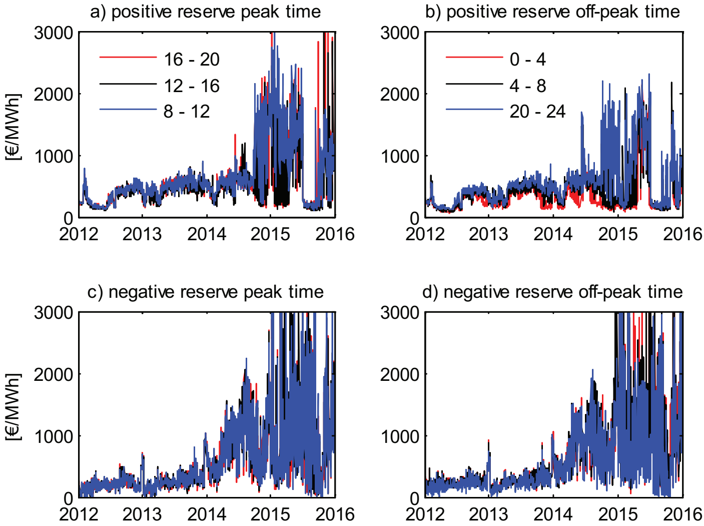
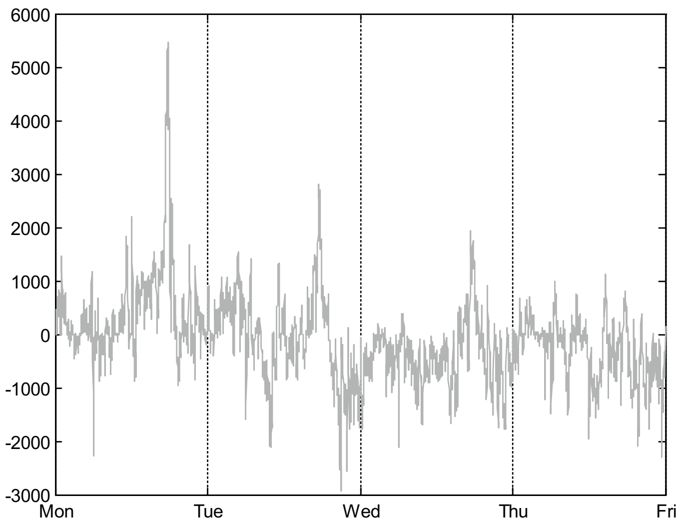


Figure 80: Mean energy prices of tertiary control reserve products from Jan. 2012 to Dec. 2015.



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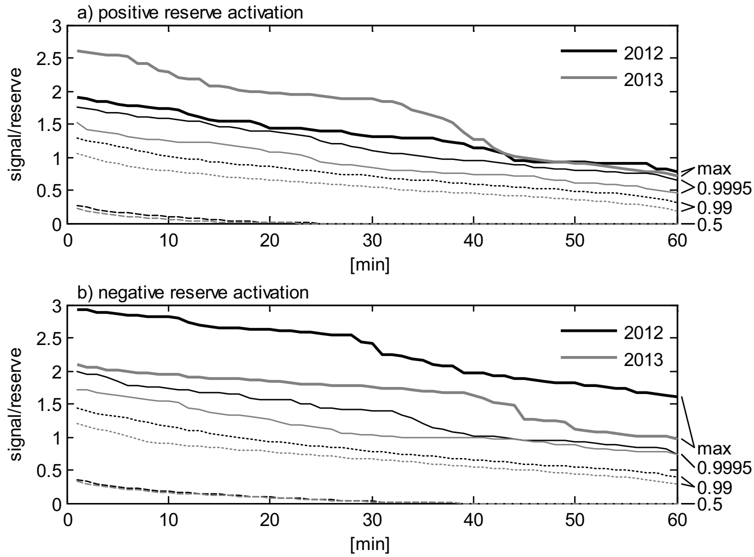

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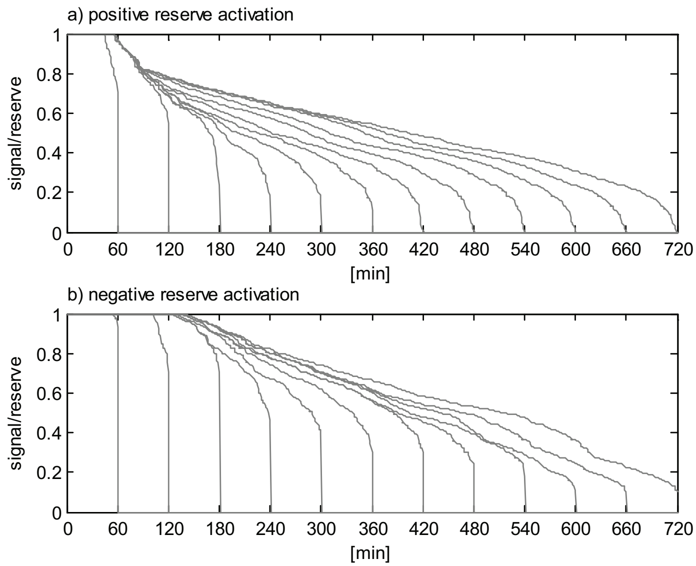

Figure 83: Maximum duration of secondary control reserve activation in time periods from one to twelve hours based on the mean value of every minute of the 2013 activation signal data in ratio to the procured reserve.

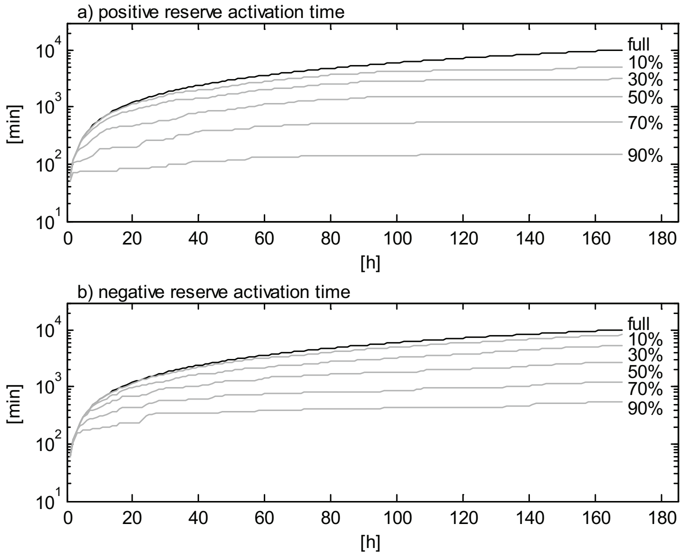

Figure 84: Maximum minutes of the 2013 secondary reserve activation signal (mean values per minute) at defined amplitudes in ratio to the procured reserve depending on the number of consecutive hours (grey) and the minutes of assumed full activation (black).

Annex C Basics of mixed integer linear programming

The review of the literature (section 2.4) shows that mixed-integer linear programming is very often used to solve the unit commitment problem. Mixed-integer programming, as well as linear programming, is used in the field of operations research, encompassing methods and algorithms of economic planning and decision making (Domschke, Drexl 2011).

Mixed-integer linear programming is described in the form

$$\min_{x \in S} c^{\mathrm{T}} x \ , S := \{x | Ax = b, x \geq 0\}$$

with integer variables $x_1, \ldots, x_r \in \mathbb{N}_0$ and continuous variables $x_{r+1}, \ldots, x_n \in \mathbb{R}_0^+$. Inequations are realized by excess and slack variables (Kallrath 2002).

Exact algorithms find the optimal solution (Kallrath 2002) and there are exact algorithms, such as branch-and-bound, cutting plane methods or branch-and-cut to solve mixed-integer linear programming. This section introduces the general functionality of these algorithms. Introduced first is an essential part of these algorithms which is the solution of relaxed problems by linear programming (Wolsey 1998).

Linear programming and simplex algorithm

Economic planning problems with multiple, feasible solutions need a criterion for the best solution. Furthermore, they need a procedure to find this best solution. Linear programming is a method for this kind of economic analysis. Along with the simplex algorithm (Kallrath 2002) it was developed by George B. Dantzig in 1947 (Dorfman et al. 1987, c1958). Further algorithms to solve linear programs are the family of interior-point methods that were developed first by L.G. Khachian in 1979 (Dantzig, Thapa 1997) and by Narendra Karmakar in 1984 (Kallrath 2002). Figure 85 illustrates the principles of the simplex and the interior-point method to solve a linear program with two variables.

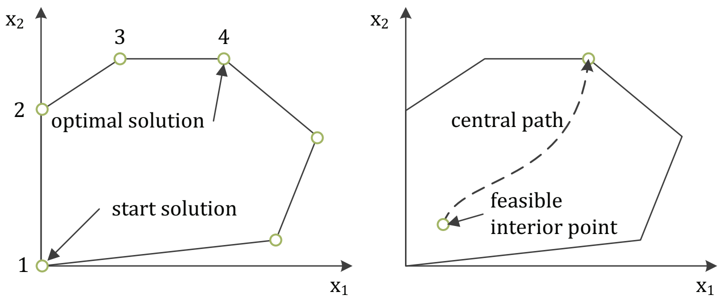

Figure 85: Illustration of simplex (left) and interior-point method (right) (Kallrath 2002)**.**

The principle of the simplex method is to move along the boundary from one extreme point (vertex) to the next (Dantzig, Thapa 1997). On the other hand, the interior-point method iterates towards the optimal solution through the interior of the boundaries of the feasible solutions (Dantzig, Thapa 1997).

The simplex method consists of two phases. A feasible start solution is determined in the first phase. The optimal solution of the linear program is sought in the second phase. Both phases employ the simplex algorithm (Dantzig, Thapa 1997). The simplex algorithm starts with a linear program in standard form that is converted to a feasible canonical form. Every equation contains a variable that does not appear in the other equations. These variables that appear only in one equation are referred to the basic variables x_B, the other variables are the non-basic variables x_N. The linear program has the form

$$\begin{aligned}&(-z) + 0x_B + \bar{c}^T x_N = -\bar{z}_0\\ &Ix_B + \bar{A}x_N = \bar{b}\end{aligned}$$

with the basic feasible solution $x_B = \bar{b} \geq 0, x_N = 0$ and $z = \bar{z}_0$ (Dantzig, Thapa 1997).

An iteration of pivoting launches from this basic feasible solution. Each iteration of the algorithmic steps ends with the selection of the pivot element $\bar{a}_{rs}$ if the algorithm does not abort. As long as the algorithm continues, $\bar{z}_0$ decreases with every new pivot $\bar{a}_{rs}$. The algorithmic steps (in case of minimizing the objective function) are described in Table 27.

Table 27: Steps of simplex algorithm according to (Dantzig, Thapa 1997), (Williams 1993) **and** (Domschke, Drexl 2011).

1.	Find $s = \text{argmin}_j\, \bar{c}_j$, Return $\bar{c}_s = \min_j \bar{c}_j$	The pivot variable x_s with the index *s* is sought from the non-basic variables x_N. It is the variable that reduces most (in case of minimization) the value of the solution z in the objective row, so $\bar{c}_s = \min_j \bar{c}_j$. If there are no more $\bar{c}_s \geq 0$, the optimal solution is found and the algorithm aborts.
2.	Stop if $\bar{c}_s \geq 0$	
3.	If $\bar{c}_s < 0$ return x_s	
4.	Stop if every $\bar{a}_{is} \leq 0$ for $i = 1, \dots, m$	The solution z is unbounded if there is no restriction on raising the value of x_s in $x_{B,i} = \bar{b}_i - \bar{a}_{is}x_s\ \forall\ i = 1, \dots, m$ as all variables *x* are non-negative. $z = \bar{z}_0 + \bar{c}_s x_s$ leads then to $z \to -\infty$ while $x_s \to \infty$. There is no optimal solution and the algorithm aborts.
5.	Find $\bar{x}_s = \frac{\bar{b}_r}{a_{rs}} = \min_{\{i\mid\bar{a}_{is}>0\}} \frac{\bar{b}_i}{\bar{a}_{is}}$ Return $\bar{a}_{rs}$ and $x_{B,r}$	The equation that limits the smallest increase of the non-negative x_s is sought. This equation with the index *r* is the pivot equation.
6.	Pivot on $\bar{a}_{rs}$	A new basic feasible solution is determined by the elimination of x_s in all rows (except of row r). x_s becomes a basic variable in the next iteration and $x_{B,r}$ becomes a non-basic variable.

Branch-and-bound

If the space of feasible variable values S of the optimization problem P contains integers, the problem needs to be solved by an enumeration tree. The enumeration tree is built up of subproblems P_k that are the nodes of the tree. A subproblem P_k can be created with S_k from the decomposition of $S = S_1 \cup \ldots \cup S_K$ for $k = 1, \ldots, K$ and their solutions $z^k = max\{cx : x \in S_k\}$ (in case of a maximization problem). However, the complete enumeration of a tree calculating the solution of every subproblem is impossible because of the combinatorial explosion. For this reason, an implicit enumeration is exercised with bounds z that enable one to prune branches of the enumeration tree (Wolsey 1998).

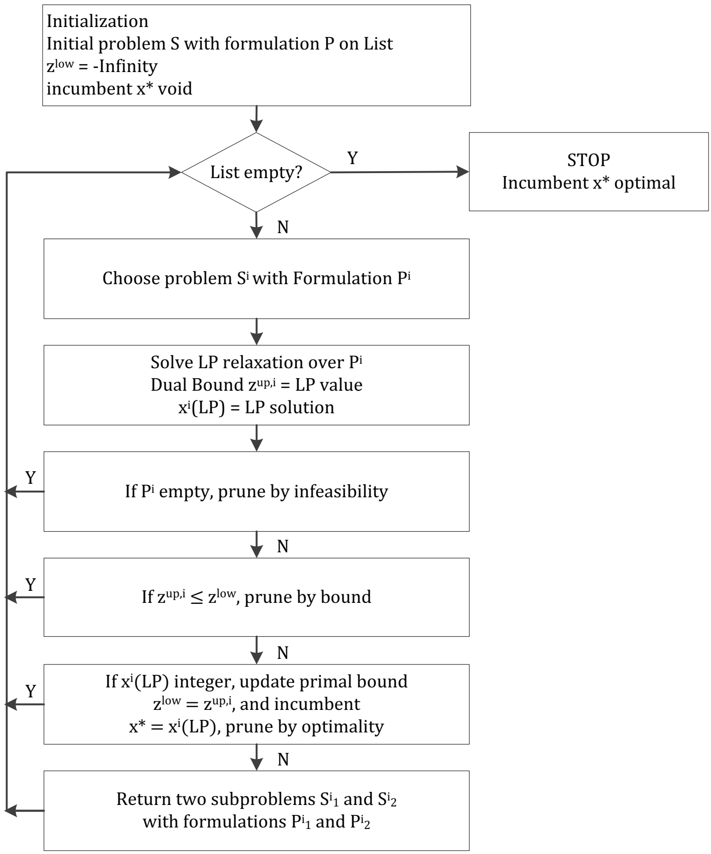

Figure 86: Branch-and-bound algorithm (Wolsey 1998).

The flow-chart in Figure 86 describes the steps of the LP-based branch-and-bound algorithm (Wolsey 1998). These algorithmic steps are carried out at the initial node or any chosen node of the tree. The steps begin by solving the LP relaxation of the problem P or any subproblem P_k. The solution of the LP relaxation of the subproblem P_k is used as the upper dual bound $z^{up,k}$ of the node. That means there will be no better result in any subsidiary branch from that node. Lower bounds are obtained from the solution of a subproblem P_k, if all designated integer variables obtain integer values ($x^k \in S$). The comparison of the upper and lower bounds enables the pruning of nodes (Wolsey 1998), (Williams 1993). Three tests are carried out that enable pruning and avoid further branching from this node (Wolsey 1998), (Kallrath 2002):

- The subproblem P_k is infeasible due to the new constraint obtained by branching on a designated integer variable (Williams 1993). The node will be pruned by infeasibility (Wolsey 1998).
- The upper bound $z^{up,k}$ of the subproblem is smaller than or equal to the incumbent lower bound (Williams 1993), (Wolsey 1998). As LP relaxation of P_k does not exceed the incumbent best solution with $x^* \in S$, even more further branching does not lead to a better solution (Williams 1993), (Kallrath 2002). The node will be pruned by bound (Wolsey 1998).
- The variable values of the solution are feasible with respect to the allowed solution space ($x^k \in S$). The lower bound $z^{low,k}$ and the incumbent solution x^* are updated in comparison with the new solution (Wolsey 1998), (Williams 1993) and (Kallrath 2002). The node will be pruned by optimality (Wolsey 1998).

If there is no reason to prune the node, at least two subproblems will be returned. The branching variable must be chosen. The branching variable is selected from the variables that are designated to be integers but solved fractionally at the LP relaxation. For this variable, two boundaries are introduced that split the feasible range of this variable in to two subsidiary LP relaxations. Thus, two subproblems are created by adding new boundaries to the problem. The next feasible integer values above and below the fractional solution value are taken as the lower and upper boundary, respectively (Kallrath 2002), (Williams 1993) and (Wolsey 1998). If there are no more active nodes, the incumbent x^* is the optimal solution (Wolsey 1998).

Node selection and branching

While proceeding with the branch-and-bound algorithm, a new variable for branching or a new node for further investigation must be chosen. The selection of nodes or variables has a large effect on the velocity of solving the model (Williams 1993).

After solving the LP relaxation of the problem P or a subproblem P_k, a variable that is solved fractionally but designated to be an integer must be selected for further branching if there is no reason to prune. Branching is the method of splitting the problem into two or more subproblems. Branching has a very significant impact on the size of the search tree and the speed of solving the problem, and every examined rule implemented in IBM's MIP-solving software CPLEX 12.5, combining several rules in 'hybrid branching', contributes to raising the performance (Achterberg, Wunderling 2013). Furthermore, there is no proof that one strategy is better. The performance of a strategy for a specific optimization problem is to be found computationally (Fügenschuh, Martin 2005). The core of branching is scoring the integer variables that have been solved fractionally by the LP-relaxation. Several rules of scoring have been introduced: the 'most infeasible branching', 'pseudocost branching', 'strong branching', and combinations such as, 'hybrid strong/pseudocost branching' and 'pseudocost branching with strong branching initialization'. (Achterberg et al. 2005) introduced 'reliability branching' developed from 'pseudocost branching with strong branching initialization'. Furthermore, they found that the branching rules interrelate by parameters introduced by each of them. Varying these parameters conducts one from one rule to another. They have shown that 'pseudocost branching' leads to 'strong branching' via 'reliability branching', increasing the reliability factor from 0 to ∞, or via 'hybrid strong/pseudocost branching', increasing the depth factor from 0 to ∞. Both paths enable the variation of the look-ahead parameter. The 'strong branching' becomes 'full strong branching' since the look-ahead parameter is ∞. Based on this insight, they conducted a performance study, with the findings that 'reliability branching' performs best.

Selecting nodes has two goals: firstly, finding a good, feasible solution that improves the primal bound, and secondly, improving the global dual bound. To reach the first goal the strategy 'depth first search' is used, and for the second goal the strategy 'best first search'. The strategy 'best estimate search' is a variant of 'best first search'. Both can be combined with 'depth first search', and are then called 'best first search with plunging' and 'best estimate search with plunging' (Achterberg 2007). Furthermore, the 'breadth first search' is presented in the review of (Morrison et al. 2016), however, it is not being applied to branch-and-bound because pruning rules will not be exploited. (Kallrath 2002) subsumed 'best first search' and 'best estimate search' in the category of 'breadth first strategies'. (Morrison et al. 2016) also presented the 'cyclic best-first search' that is a combination of 'best first search' and 'depth first search'.

- 'Depth first search': This strategy proceeds at first with one subproblem of the current node. If a node is pruned, an unprocessed subproblem of the same superior node will be processed. If all nodes are pruned, the search backtracks to a superior node with unprocessed subproblems to proceed on them. 'Depth first search' has, therefore, the advantages that, firstly, it is focused on finding a feasible solution, secondly, the next LP relaxation that takes place is changed with minimum effort, and thirdly, it does not take up much memory (Achterberg 2007).
- 'Breadth first strategy': This strategy first investigates every subproblem at the same level and then moves on to the next subsidiary level. That generates a lot of active nodes. According to (Kallrath 2002), there are several rules regarding the selection of the next node to be processed and they are introduced below.

- 'Best first search': This strategy chooses the subproblem with the best dual bound in order to proceed. There are several unprocessed nodes which are stored at the same time in a priority queue. 'Best first search' improves the global dual bound quickly, processing a minimum number of nodes (Achterberg 2007). It is supposed that the subsidiary nodes possess good dual bounds as well. A feasible solution that is found in that branch could provide a new primal bound (Kallrath 2002).
- 'Best estimate search': This strategy aims to find good solutions by incorporating information about the dual bound and the integrality of the LP solution in an estimated value for each node. There are two different rules to calculate an estimation, yet, one of these performs better than the other. The better performing rule estimates the influence on the objective function value by employing the pseudocost values of the variables. These pseudocosts are applied to the distance, to the nearest integer, of the variables solved in the node's LP relaxation (Achterberg 2007).

Cutting planes

Cutting planes are a technique used to solve MIPs. A cutting plane is a constraint added to the linear program, relaxing the integral variables, after solving and finding that that the solution does not fit all integral requirements. For example, the following algorithms are used to find good, new constraints as cutting planes: the 'Gomory integer cut', the 'Gomory mixed integer cut', the 'mixed-integer-rounding cut', the 'lift-and-project cut', 'knapsack inequalities', 'flow cover inequalities', 'set packing inequalities' and 'lifted inequalities' (Fügenschuh, Martin 2005). Cutting planes substantially raise the performance of solving MIPs (Achterberg, Wunderling 2013). The rule with the most improvement is the 'mixed integer rounding' (MIR), whereby it was found that essential improvements were gained only with MIR and 'Gomory cuts' and also, with less impact, the 'knapsack cover cuts'(Achterberg, Wunderling 2013).

Mathematical descriptions of the cutting planes are presented in the review of (Fügenschuh, Martin 2005). The cutting planes are introduced into the problem by adding new inequalities. A valid 'mixed integer cut' is obtained by

$$\sum_{i=1}^{p}\left(\lfloor a_i \rfloor + \frac{max\big(0, f(a_i) - f(b)\big)}{1 - f(b)}\right)x_i - \frac{1}{1 - f(b)}y \leq \lfloor b \rfloor$$

where a_i is the coefficient of the integer variables in the subset $N^1 = \{i \in \{1, \ldots, n\}: f(a_i) \leq f(b)\}$ from the mixed integer set $X = \{(x, y) \in \mathbb{Z}_+^p \times \mathbb{R}_+: a^T x - y \leq b\}$ and the function $f(\alpha) \coloneqq \alpha - \lfloor \alpha \rfloor$ for $\alpha \in \mathbb{R}$ (Fügenschuh, Martin 2005).

The 'Gomory integer cut' is added by a constraint that is set by analyzing the solved LP relaxation of the problem. A basic variable x_i for which $i \in B$ that has obtained a fractional solution from the LP relaxation is chosen. This variable may be applied to the 'Gomory integer cut' by implementing the inequality

$$x_i + \sum_{j \in N} \lfloor \bar{a}_{ij} \rfloor x_j \leq \lfloor \bar{b}_i \rfloor$$

where $\bar{a}_{ij} = A_{i \cdot}{}^{-1} A_{\cdot j}$ and $\bar{b}_i = A_{i \cdot}{}^{-1}$ with $j \in N$ which is the set of nonbasic variables (Fügenschuh, Martin 2005)[8].

The 'Gomory mixed integer cut', applied if the problem consists of p integer and n continuous variables, is more complicated than rounding down $\bar{b}_i$ as described above, as it could cut off feasible solutions. Therefore, the 'Gomory mixed integer cut' is described for problems with $n > p$ by the inequality

$$\sum_{\substack{j \in N, j \leq p \\ f(\bar{a}_{ij}) \leq f(\bar{b}_i)}} f(\bar{a}_{ij}) x_j + \sum_{\substack{j \in N, j \leq p \\ f(\bar{a}_{ij}) > f(\bar{b}_i)}} \frac{f(\bar{b}_i)\left(1 - f(\bar{a}_{ij})\right)}{1 - f(\bar{b}_i)} x_j +$$

$$\sum_{j \in N^+, j > p} \bar{a}_j x_j - \sum_{j \in N^-, j > p} \frac{f(\bar{b}_i)}{1 - f(\bar{b}_i)} \bar{a}_j x_j \geq f(\bar{b}_i)$$

where $N^+ = \{j \in N : \bar{a}_{ij} \geq 0\}$, and $N^- = N \backslash N^+$ (Fügenschuh, Martin 2005).

Branch-and-cut

The software CPLEX applied in this work uses the branch-and-cut algorithm, whereas cutting planes had been introduced in version 3.0 in 1994 (Achterberg, Wunderling 2013). The branch-and-cut algorithm combines the branch-and-bound algorithm with the advantages of the cutting plane method (Kallrath 2002).

The method of cutting planes solves linear integer or mixed integer programs. The purpose of this method is to add valid inequalities to the formulation of the problem (Wolsey 1998). The cutting plane method begins with the solution of the LP relaxation. The feasible space of solutions is then reduced by additional linear inequalities (Kallrath 2002). Cutting planes can be added a priori to a problem that is then solved by branch-and-bound. On the other hand algorithms can be used to define a family of valid inequalities, such as Gomory's fractional cutting plane method that applies the Chvátal-Gomory procedure to construct valid inequalities (Wolsey 1998). A review of cutting plane algorithms used by general MIP solvers and their mathematical formulation is contained in (Fügenschuh, Martin 2005).

[8] Ax corresponds to $Ix_B + \bar{A}x_N$ and b to $\bar{b}$ introduced above

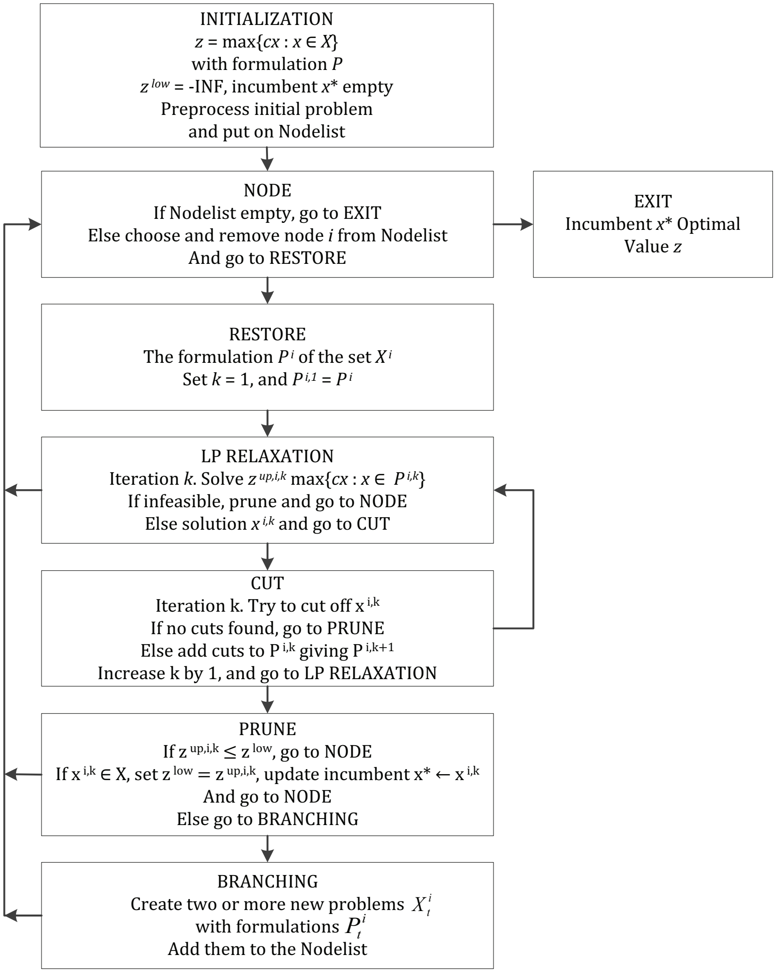

Figure 87: Branch-and-cut algorithm (Wolsey 1998).

This approach is to introduce cutting planes to solve the branch-and-bound tree. The algorithm employs cutting planes from a pool and then generate branches. Additionally, the branch-and-cut algorithm executes various further operations before re-optimizing at each node to achieve tight dual bounds. This is the major difference to the branch-and-bound algorithm that re-optimizes quickly at each node (Wolsey 1998). The flowchart in Figure 87 shows the basic steps of the branch-and-cut algorithm according to (Wolsey 1998).

The introduction of cutting planes to the branch-and-bound algorithm is one technique to improve the performance of solving MIP. Further techniques focus on branching and presolving combined with branch-and-cut to improve the performance. Furthermore, primal heuristics are applied to find feasible solutions quickly. (Achterberg, Wunderling 2013) shows the improved performance of the software CPLEX version 12.5 as a result of the implementation of new developments in branching, cutting planes, presolving and the use of primal heuristics.

One task, and formerly the main one, of presolving is to obtain an efficient MIP, especially if it is generated from an algebraic model as in this work. The development of presolving techniques since version 2.1 in 1993 has improved the performance of solving MIPs as presented in (Achterberg, Wunderling 2013). Several techniques are applied with different purposes and impacts on the performance. Primal reductions reduce the size of the problem or tighten the LP relaxation raising most meaningfully the performance of solving MIPs. Further significant performance increases are achieved by dual reductions and probing. Dual reductions reduce the problem, for example, dominated constraints, keeping at least one optimal solution. Probing initiates a solution of binary variables that is valid considering the constraints and extracts information in order to strengthen the LP relaxation. Furthermore, applying presolving techniques at nodes and conducting restarts at the root node with already globally fixed variables raises the performance significantly (Achterberg, Wunderling 2013). (Gamrath et al. 2015) found that in particular real supply chain management problems profit from presolving, by reducing the solving time to almost 50% by means of three presolving techniques.

Primal heuristics are introduced in order to find feasible solutions and to reduce the number of subtrees quickly. Furthermore, good solutions can be provided quickly to the user of MIP, without proof of its optimality. There are 'starting heuristics' that are applied to find feasible solutions from the solved LP-relaxation. These feasible solutions are then processed further by 'improvement heuristics'. So-called 'before-LP heuristics', which even run before the LP-relaxation, are implemented in CPLEX, and from version 12.2 onwards they have run parallel to the solution of the root LP relaxation (Achterberg, Wunderling 2013).

Annex D Implementation of the rolling unit commitment

Modeling framework for the rolling unit commitment

The simulation was implemented in Matlab, in the so-called framework RedSim (Renewable Energy Dispatch Simulation) which is an object-oriented program to calculate optimal plant schedules from a rolling unit commitment. RedSim provides a modular environment to generate a MILP of a defined setting of several power units and a business case that is to be optimized. To solve the MILP, RedSim uses the Matlab API of IBM ILOG CPLEX Optimization Studio. This work applied the versions 12.2 and 12.4.

This work defined plants consisting of several components, constraints applied for control reserve only, product constraints and premium constraints. The plant components and different parts of the business case have been implemented in separate classes. That enabled alternative use cases to be analyzed easily, for example, by multiplying the number of plants, adding the provision of control reserve, or obtaining a premium.

Furthermore, RedSim was applied in the studies of (Schreiber, Hochloff 2013), (Marten et al. 2013), (Hochloff, Braun 2014), (Hoffstede et al. 2015) and (Schreiber et al. 2015).

The rolling planning of time fractions reduced the number of variables in the optimization problem, which meant a fewer time intervals. As each time fraction was solved separately, the dependencies from the time intervals before and after each time fraction were considered. Dependencies between time intervals were implemented by several restrictions just as Equation 7, Equation 11 and Equation 44.

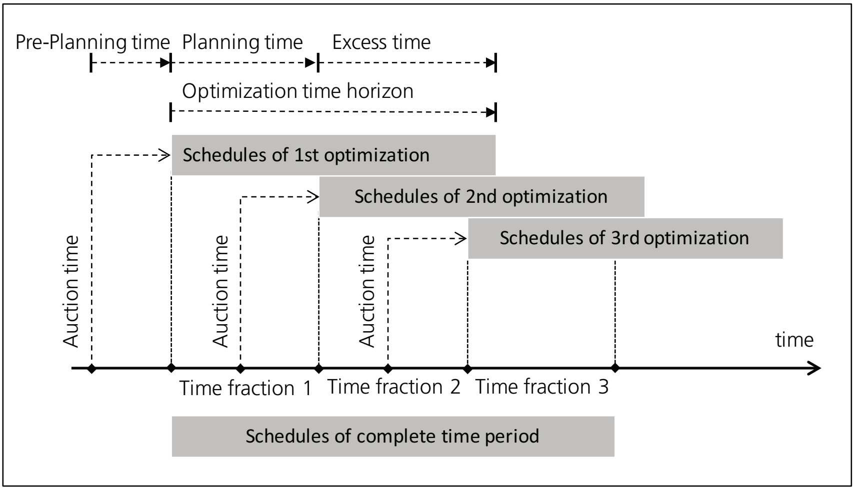

Figure 88: Scheme of a time period of a unit commitment problem divided into four time fractions each with excess time in order to solve sequentially.

Equation 7 and Equation 11 contained initial values representing S_0 and $s_{0,n}^{sp}$ for the indices $t-1$ while implementing these equations at $t=1$. These initial values have been obtained from the corresponding time interval in the schedule solved for the previous time fraction. For this reason, the unit commitments of time fractions were carried out sequentially.

Furthermore, these equations depended on the time period after the current time fraction. This influence can be dealt with by considering excess time in addition to the actual planning time (Figure 88). The unit commitment problem with excess time contains variables and the corresponding constraints for surplus time intervals. Thus, the optimization time horizon T exceeds the actual planning time. The solution of the variables within the excess time is not considered in the final analysis of the objective function value (OFV) as the solution of variables in the excess time was updated by solving the next time fraction.

Respecting control reserve during the lead time

Planning control reserve included Equation 44 that limited the control reserve bed between t and τ to the storage content in t-1 and the produced gas. For this purpose, Equation 44 was implemented for every time interval t=[1...T-1] and each time τ>t. An initial storage content S_0 was regarded instead of the variable S_{t-1} for t=1 and every time τ=[2...T] (compare with Figure 89: line 7, 8 and 9). So, Equation 73 expressed at least one valid implementation of Equation 44.

Equation 73:

$$S_0 \geq \Delta t \cdot \sum_{n=1}^{N} \left(\sum_{t'=1}^{\tau'} e_{t',n} + \sum_{t'=\tau'+1}^{\tau} f_{t',n} \right) - \Delta t \cdot \sum_{t'=1}^{\tau} G_{t',n}^{prod.} \quad \forall\, \tau \in [1, T]$$

Furthermore, the lead time was taken in to account since in the spot market and control market auctions there are several time intervals before the first time interval t=1 (Figure 89). In this lead time the planned control reserve could be activated and thus change the initial storage content S_0. For this reason a fictitious storage content S_0^* was calculated that respected the lead time by applying Equation 44. The extended time period with T* intervals defined the time period from the time of the auction until the last optimization time interval T. The lead time contained the time intervals t*. The additional constraints that needed to be respected are described by Equation 74 (compare with Figure 89: line 1 to 6).

Equation 74:

$$S_{t^*-1} \geq \Delta t \cdot \sum_{n=1}^{N} \left(\sum_{t''=t^*}^{\tau''} e_{t'',\tau,n} + \sum_{t''=\tau''+1}^{\tau} f_{t'',\tau,n} \right) - \Delta t \cdot \sum_{t''=t^*}^{\tau} G_{t'',n}^{prod.}$$
$$\forall\, t^* \in [1, T^* - T], \tau \in [T^* - T + 1, T^*]$$

The variables in the lead time intervals t^* were already solved in the planning. Therefore, they were respected exogenously, thus creating the fictive storage content S_0^* defined by Equation 74. Summarizing the variables and constants of the lead time to S_0^* resulted in Equation 74 being limited to several constant values (compare with Equation 74: lines 1 to 6). Therefore, Equation 74 returned the minimum value of possible solutions of S_0^* .

Equation 75:

$$S_0^* = min\left\{ \begin{matrix} S_{t^*-1} - \Delta t \cdot \sum_{n=1}^{N}\left(\sum_{t''=t^*}^{\tau''} e_{t'',n} + \sum_{t''=\tau''+1}^{T^*-T} f_{t'',n}\right) + \Delta t \cdot \sum_{t''=t^*}^{T^*-T} G_{t',n}^{prod.} \\ \forall\, t^* \in [1, T^* - T] \end{matrix} \right\}$$

Assuming that τ'' is at least one time interval before t=1 (compare with Figure 89: lines 1 to 6), respecting the lead time through S_0^* resulted in Equation 76 that was implemented in addition to Equation 74 while developing Equation 44 for t=1.

Equation 76:

$$S_0^* \geq \Delta t \cdot \sum_{n=1}^{N} \sum_{t'=1}^{\tau} \left(f_{t',n} - G_{t',n}^{prod.}\right) \;\; \forall\, \tau \in [1, T]$$

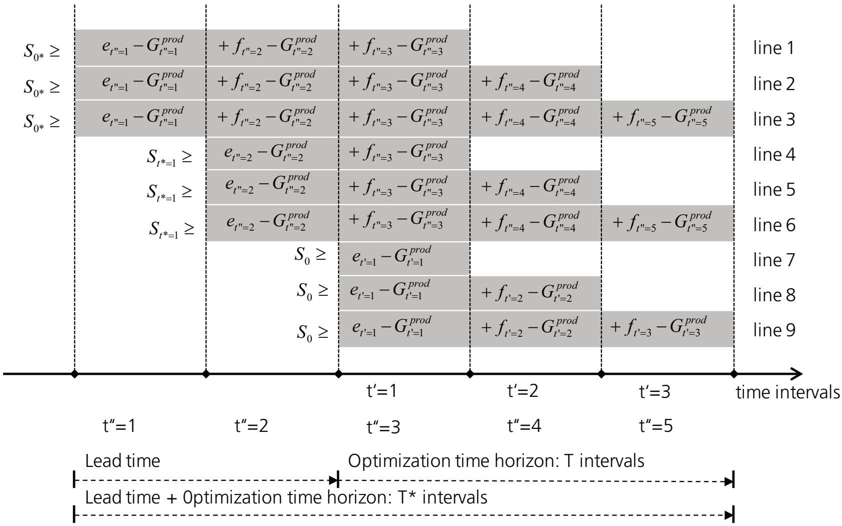

Figure 89: Illustration of implementations of Equation 73 and Equation 74.

Annex E Use case definitions

Table 28: Implemented equations, common parameters and constants of use case A.

	Use case A Biogas plant supplying the spot market, with static biogas input, extended capacity, and storage
System	Intel Core i7-2620M, 2,7 GHz Cplex Optimization Studio 12.2
Implemented Equations	Objective function: Equation 1 Gas supply and gas balance: Equation 2, Equation 3 Gas storage: Equation 7, Equation 8, Equation 9, , Power generation: Equation 10, Equation 11, Equation 12, Equation 14, Equation 15, Equation 16
Parameters	N=1 D=1 T=24, 48, 72, 96, 120, 240, 480, 720, 960, 1200
Constants	$\Delta t = 1\ h$ $G_t^{prod.max} = 0.9639\ MW$ $\alpha^{stor} = \alpha^{stor,in} = \alpha^{stor,out} = 0$ $P_1^{max} = 0.8\ MW$ $P_1^{min} = 0.5\ \cdot P_1^{max}$ $P_{1,1}^{part.max} = P_1^{max} - P_1^{min}$ $G_1^{min} = 1.0499\ MW$ $m_1 = 2.1946$ $S^{max} = 11.5663\ MWh$ $S^{end} = 0.5 \cdot S^{max}$ $c^{fuel} = 50€/MWh$ $c^{start} = 8€/start$

Table 29: Implemented equations, parameters and constants values of use cases B.

	Use case B Biogas plant supplying the spot market and the tertiary control reserve market, with static biogas input, extended capacity, and storage		
	Constant efficiency	Convex linearization	Non-convex linearization
System	Intel Core i7-2620M, 2,7 GHz Cplex Optimization Studio 12.2		
Equations	Objective function: Equation 1 Gas supply and gas balance: Equation 2, Equation 3 Gas storage: Equation 7, Equation 8, Equation 9 Product constraints: Equation 69, Equation 70		
	Power generation: Equation 10, Equation 11, Equation 12, Equation 13 Control reserve capacity constraints: Equation 36, Equation 37, Equation 40, Equation 41, Control reserve energy constraints: Equation 44, Equation 45, Equation 46, Equation 47, Equation 48, Equation 49, Equation 50, Equation 51	Power generation: Equation 10, Equation 11, Equation 12, Equation 14, Equation 15, Equation 16 Control reserve capacity constraints: Equation 36, Equation 37, Equation 40, Equation 41, Control reserve energy constraints: Equation 44, Equation 47, Equation 48, Equation 49, Equation 50, Equation 51, Equation 56, Equation 57, Equation 58, Equation 59	Power generation: Equation 10, Equation 11, Equation 12, Equation 17, Equation 18, Equation 19, Equation 20, Equation 21 Control reserve capacity constraints: Equation 38, Equation 39, Equation 42, Equation 43 Control reserve energy constraints: Equation 44, Equation 61, Equation 62, Equation 63, Equation 64, Equation 65, Equation 66, Equation 67, Equation 68
Parameters	N=1 T=48, 72, 96 $L^{posR} = L^{negR} = 4$ $K^{posR} = K^{negR} = 12, 18, 24$	N=1, 2, 3 D=1 T=24, 36, 48, 60, 72, 84, 96, 120 $L^{posR} = L^{negR} = 4$ $K^{posR} = K^{negR} = 6, 9, 12, 15, 18, 21, 24, 30$	N=1 D=1, 2, 3, 4 T=48, 72, 96 $L^{posR} = L^{negR} = 4$ $K^{posR} = K^{negR} = 12, 18, 24$

<table>
<tr><td rowspan="5">Constants</td><td colspan="6">$\Delta t = 1\ h$
$G_t^{prod.max} = 0.9639\ MW$
$\alpha^{stor} = \alpha^{stor,in} = \alpha^{stor,out} = 0$
$S^{max} = 11.5663\ MWh$
$S^{end} = 0.5 \cdot S^{max}$
$c^{fuel} = 50€/MWh$
$c^{start} = 8€$</td></tr>
<tr><td colspan="2">$P_1^{max} = 0.8\ MW$
$P_1^{min} = 0.4\ MW$
$\eta_{el} = 0.415$</td><td colspan="2">$P_{[1,2,3]}^{max} = 0.8\ MW$
$P_{[1,2,3]}^{min} = 0.4\ MW$
$P_{[1,2,3]}^{part.max} = 0.4\ MW$
$G_{[1,2,3]}^{min} = 1.0499\ MW$
$m_{[1,2,3]} = 2.1946$
$\xi_{\tau-t,[1,2,3]}^{up}$
$= \xi_{\tau-t,[1,2,3]}^{down} = 1$</td><td colspan="2">$\xi_{\tau-t,n}^{up} = \xi_{\tau-t,n}^{down} = 1$</td></tr>
<tr><td colspan="6">Non-convex linearization:</td></tr>
<tr><td colspan="3">For D=1:
$P_{1,1}^{min} = 0.4\ MW$
$P_{1,1}^{max} = 0.8\ MW$
$G_1^0 = 1.0499\ MW$
$m_1 = 2.1946$</td><td colspan="3">For D=2:
$P_{1,1}^{min} = 0.4\ MW$
$P_{1,1}^{max} = P_{1,2}^{min} = 0.6\ MW$
$P_{1,2}^{max} = 0.8\ MW$
$G_{1,1}^0 = 0.1793\ MW$
$G_{1,2}^0 = 0.1575\ MW$
$m_1 = 2.1764$
$m_2 = 2.2128$</td></tr>
<tr><td colspan="3">For D=3:
$P_{1,1}^{min} = 0.4\ MW$
$P_{1,1}^{max} = P_{1,2}^{min} = 0.5334\ MW$
$P_{1,2}^{max} = P_{1,3}^{min} = 0.6666\ MW$
$P_{1,3}^{max} = 0.8\ MW$
$G_{1,1}^0 = 0.176\ MW$
$G_{1,2}^0 = 0.1858\ MW$
$G_{1,3}^0 = 0.1414\ MW$
$m_1 = 2.1847$
$m_2 = 2.1663$
$m_3 = 2.2329$</td><td colspan="3">For D=4:
$P_{1,1}^{min} = 0.4\ MW$
$P_{1,1}^{max} = P_{1,2}^{min} = 0.5\ MW$
$P_{1,2}^{max} = P_{1,3}^{min} = 0.6\ MW$
$P_{1,3}^{max} = P_{1,4}^{min} = 0.7\ MW$
$P_{1,4}^{max} = 0.8\ MW$
$G_{1,1}^0 = 0.1732\ MW$
$G_{1,2}^0 = 0.1885\ MW$
$G_{1,3}^0 = 0.1771\ MW$
$G_{1,4}^0 = 0.1313\ MW$
$m_1 = 2.1917$
$m_2 = 2.1611$
$m_3 = 2.1801$
$m_4 = 2.2455$</td></tr>
</table>

Table 30: Implemented equations, parameters and constants of use case C.

	Use case C Biogas plant supplying the spot market, with static biogas input, extended capacity, and storage
System	Intel Core i7-2620M, 2,7 GHz Cplex Optimization Studio 12.4
Implemented Equations	Objective function: Equation 1 Gas supply and gas balance: Equation 2, Equation 3 Gas storage: Equation 7, Equation 8, Equation 9 Power generation: Equation 10, Equation 11, Equation 12, Equation 14, Equation 15, Equation 16
Parameters	N=1 D=1 $T = \begin{cases} 120, S^{hor.} < 24\ h \\ 240, S^{hor.} \geq 24\ h \end{cases}$
Constants	$\Delta t = 1\ h$ $G_t^{prod.max} = 1.25\ MW$ $\alpha^{stor} = \alpha^{stor,in} = \alpha^{stor,out} = 0$ $P_1^{max} = 0.6 \dots 9\ MW$ $P_1^{min} = 0.5\ \cdot P_1^{max}$ $P_{1,1}^{part.max} = P_1^{max} - P_1^{min}$ $G_{1,1}^{min} = G_1^{min} = P_1^{min}/0.37$ $G_{1,1}^{max} = P_1^{max}/0.4$ $m_1 = 2.1978022$ $S^{max} = 4 \dots 48\ h \cdot\ G_t^{prod.max}$ $S^{end} = 0.5 \cdot S^{max}$ $c^{fuel} = 35€/MWh$ $c^{start} = 10€/MW \cdot P_1^{max}$

Table 31: Implemented equations, parameters and constants of use case D.

	Use case D Biogas plant supplying the spot market, obtaining market premium and flexibility premium, with variable biogas input and storage
System	Intel Core i7-2620M, 2,7 GHz Cplex Optimization Studio 12.4
Implemented Equations	Objective function: Equation 22 Gas supply and gas balance: Equation 2, Equation 4, Equation 5, Equation 6 Gas storage: Equation 7, Equation 8, Equation 9 Power generation: Equation 10, Equation 11, Equation 12, Equation 14, Equation 15, Equation 16 Market premium: Equation 25, Equation 26 Flexibility premium: Equation 27, Equation 28, Equation 29, Equation 30, Equation 31, Equation 32, Equation 33, Equation 34, Equation 35
Parameters	N=1 D=1 $T = \begin{cases} 168, P_1^{max} \leq 1\ MW \\ 72, P_1^{max} \geq 1.25\ MW \end{cases}$ $Q = 3$
Constants	$\Delta t = 1\ h$ $G_t^{prod.max} = P_1^{max}/0.4$ $\epsilon^{up} = 0.0417$ $\epsilon^{down} = 0.007$ $\alpha^{stor} = \alpha^{stor,in} = \alpha^{stor,out} = 0$ $P_1^{max} = 0.5\ MW \dots 2\ MW$ $P_1^{min} = 0.5\ \cdot P_1^{max}$ $P_{1,1}^{part.max} = P_1^{max} - P_1^{min}$ $G_{1,1}^{min} = G_1^{min} = P_1^{min}/0.37$ $G_{1,1}^{max} = P_1^{max}/0.4$ $m_1 = 2.1978022$ $S^{max} = 12\ h \cdot\ G_t^{prod.max}$ $S^{end} = 0.5 \cdot S^{max}$ $c^{fuel} = 35 \dots 70€/MWh$ $c^{start} = 10€/MW \cdot P_1^{max}$ $\Psi_{1,[1,2,3]}^{mp} = [203, 173, 150]€/MWh$ $\mathrm{P}_{1,[1,2,3]}^{mp} = [0.15, 0.5, 5]\ MW$ $\Psi^{\mathrm{flex}} = 0 \dots 390\ €/\mathrm{kW}$

Table 32: Implemented equations, parameters and constants of use case E.

	Use case E Biogas plant supplying the spot market and the tertiary control reserve market, with static biogas input, extended capacity, and storage	
	Without market premium	With market premium
System	Intel Core i7-2620M, 2,7 GHz Cplex Optimization Studio 12.4	
Implemented Equations	Objective function: Equation 34	Objective function: Equation 35 Market premium: Equation 25, Equation 26
	Gas supply and gas balance: Equation 2, Equation 3 Gas storage: Equation 7, Equation 8, Equation 9 Power generation: Equation 10, Equation 11, Equation 12, Equation 14, Equation 15, Equation 16 Control reserve capacity constraints: Equation 36, Equation 37, Equation 40, Equation 41 Control reserve energy constraints: Equation 44, Equation 47, Equation 48, Equation 49, Equation 50, Equation 51, Equation 56, Equation 57, Equation 58, Equation 59 Product constraints: Equation 69, Equation 70	
Parameters	N=1 D=1 T=72 $L^{posR} = L^{negR} = 4$ $K^{posR} = K^{negR} = 18$	
	Time limit 60 s and node select strategy "best estimate" for $P_1^{max} \geq 1.75\ MW$	Q=3
Constants	$\Delta t = 1\ h$ $G_t^{prod.max} = 1.25\ MW$ $\alpha^{stor} = \alpha^{stor,in} = \alpha^{stor,out} = 0$ $P_1^{max} = 0.6 \ldots 2\ MW$ $P_1^{min} = 0.5\ \cdot P_1^{max}$ $P_{1,1}^{part.max} = P_1^{max} - P_1^{min}$ $G_{1,1}^{min} = G_1^{min} = P_1^{min}/0.37$ $G_{1,1}^{max} = P_1^{max}/0.4$ $m_1 = 2.1978022$ $S^{max} = 8 \ldots 48\ h \cdot\ G_t^{prod.max}$ $S^{end} = 0.5 \cdot S^{max}$ $c^{fuel} = 35€/MWh$ $c^{start} = 10€/MW \cdot P_1^{max}$ $\xi_{\tau-t,1}^{up} = \xi_{\tau-t,1}^{down} = 1$	
		$\Psi_{1,[1,2,3]}^{mp} = [203, 173, 150]\ €/MWh$ $\mathrm{P}_{1,[1,2,3]}^{mp} = [0.15, 0.5, 5]\ MW$

Table 33: Implemented equations, parameters and constants of use case F.

Characterization	Use case F Biogas plant supplying the spot market and the secondary control reserve market, with static biogas input, extended capacity, and storage	
	Without market premium	With market premium
System	2 Intel XEON X5660, 2.8 GHz Cplex Optimization Studio 12.2	
Equations	Objective function: Equation 34	Objective function: Equation 35 Market premium: Equation 25, Equation 26
	Gas supply and gas balance: Equation 2, Equation 3 Gas storage: Equation 7, Equation 8, Equation 9 Power generation: Equation 10, Equation 11, Equation 12, Equation 14, Equation 15, Equation 16 Control reserve capacity constraints: Equation 36, Equation 37, Equation 40, Equation 41 Up and down regulation energy reserve: Equation 44, Equation 53, Equation 56, Equation 57, Equation 58, Equation 60 Product constraints: Equation 71, Equation 72	
Parameters	N=1 D=1 T=168 Time limit 600 s	
		Q=3
Constants	$\Delta t = 1\,h$ $G_t^{prod.max} = 1.25\,MW$ $\alpha^{stor} = \alpha^{stor,in} = \alpha^{stor,out} = 0$ $P_1^{max} = 0.6 \ldots 1.5\,MW$ $P_1^{min} = 0.5 \cdot P_1^{max}$ $P_{1,1}^{part.max} = P_1^{max} - P_1^{min}$ $G_{1,1}^{min} = G_1^{min} = P_1^{min}/0.37$ $G_{1,1}^{max} = P_1^{max}/0.4$ $m_1 = 2.1978022$ $S^{max} = 12 \ldots 24\,h \cdot G_t^{prod.max}$ $S^{end} = 0.5 \cdot S^{max}$ $c^{fuel} = 35€/MWh$ $c^{start} = 10€/MW \cdot P_1^{max}$ $\xi_{\tau-t,1}^{up} = \xi_{\tau-t,1}^{down} = 1$	
		$\Psi_{1,[1,2,3]}^{mp} = [203, 173, 150]\,€/MWh$ $\mathrm{P}_{1,[1,2,3]}^{mp} = [0.15, 0.5, 5]\,MW$

Table 34: Implemented equations, parameters and constants of use case G.

Characterization	Use case G Biogas plant supplying the spot market and the secondary control reserve market considering a reduced energy reserve for activating control reserve, with static biogas input, extended capacity, and storage
System	2 Intel XEON X5660, 2.8 GHz Cplex Optimization Studio 12.2
	Objective function: Equation 34 Gas supply and gas balance: Equation 2, Equation 3 Gas storage: Equation 7, Equation 8, Equation 9 Power generation: Equation 10, Equation 11, Equation 12, Equation 14, Equation 15, Equation 16 Control reserve capacity constraints: Equation 36, Equation 37, Equation 40, Equation 41 Up and down regulation energy reserve: Equation 44, Equation 53, Equation 54, Equation 55 Product constraints: Equation 71, Equation 72
Parameters	N=1 D=1 T=168 Time limit 600 s
Constants	$\Delta t = 1\ h$ $G_t^{prod.max} = 1.25\ MW$ $\alpha^{stor} = \alpha^{stor,in} = \alpha^{stor,out} = 0$ $P_1^{max} = 0.6 \dots 1.5\ MW$ $P_1^{min} = 0.5 \cdot P_1^{max}$ $P_{1,1}^{part.max} = P_1^{max} - P_1^{min}$ $G_{1,1}^{min} = G_1^{min} = P_1^{min}/0.37$ $G_{1,1}^{max} = P_1^{max}/0.4$ $m_1 = 2.1978022$ $S^{max} = 12 \dots 24\ h \cdot G_t^{prod.max}$ $S^{end} = 0.5 \cdot S^{max}$ $c^{fuel} = 35€/MWh$ $c^{start} = 10€/MW \cdot P_1^{max}$

Appendix F Additional investigations to chapter 4

Analysis of correlation from price curve and run time (section 4.1.1)

Figure 90 plots the run times and the corresponding market price spreads for time horizons of 2 days to 40 days as a function of the start date of prices used. The spread was used as a descriptive indicator of the market prices which were the only data being varied in the optimizations of the same time horizon. The price spreads in Figure 11 are the mean values of the daily 12 h spreads for each optimization horizon. The 12 h spread is the mean difference of the 12 highest prices from each day and the 12 lowest prices. The figure shows that there is suggestive evidence of an association between run times and market spreads, especially for optimization horizons longer than 10 days. The correlation coefficients were 0.29 for a 2-day optimization horizon, -0.16 for a 10-day one, -0.25 for a 20–day one, -0.34 for a 30–day one and -0.42 for a 40–day one. Highlighting the results with a 40-day optimization horizon, it has been found that average price differences below 28€/MWh cause a run time of at least 38 s. Almost every run time longer than 38 s was found at a mean price spread below 33€/MWh. However, long run times of more than 38 s were also found at mean price differences between 43€/MWh and 45€/MWh.

There were no consistent patterns of association between run times and price spreads. Nevertheless, these findings support the idea that very low price spreads cause increasing run times.

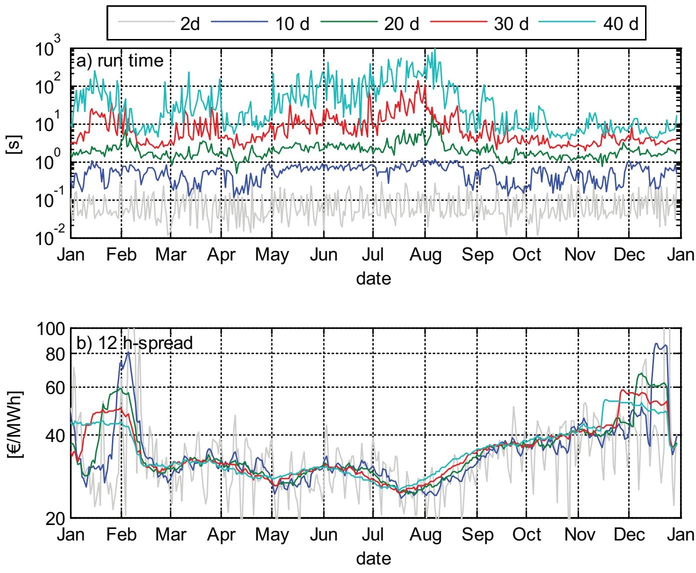

Figure 90: Run times of use case A with optimization horizons of 10, 20, 30, 40 and 50 days, depicted for the first day of the optimization horizon.

Differences in the OFV of each day from the optimization horizon (section 4.1.1)

The following results relate to the influence of the optimization horizon on the unit commitment results. The unit commitment results were analyzed by means of the objective function value (OFV). This investigation considered the OFV of full days (sum of 24 time intervals). Therein, the differences between daily OFVs were examined in order to indicate the optimization horizons influence on unit commitment results. The daily OFV of the unit commitment results starting on 01/25/2012 with several horizons, ranging from one day to 40 days, are depicted in Figure 91.

This result illustrates that most daily OFVs are identical even when they are calculated with different optimization horizons. Differences occur in the latter period when comparing the daily OFV of a shorter with a longer optimization horizon.

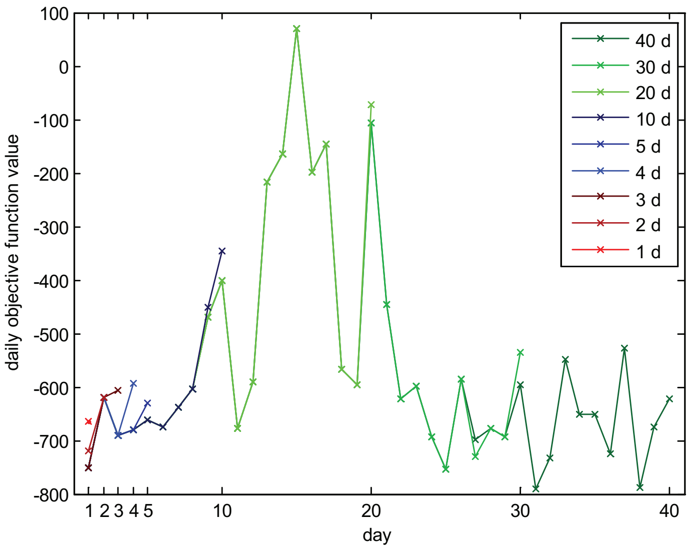

Figure 91: Daily OFV of unit commitment results of use case A on 01/25/2012 with optimization horizons from one day to 40 days.

Figure 92 contains a more elaborate analysis of OFV differences in which every unit commitment result from the whole year is contained. The figure presents the share of unit commitments for which the daily OFV differed from that of the 40-day optimization horizon. These shares of unit commitment deviations are plotted as functions of the time of each optimization horizon, with daily intervals. The curves distinguish different planning horizons for the unit commitment. The figure shows that the OFV of the last day of the optimization horizon differed in about 86% of runs. The OFV of the second-to-last day differed in 29% to 33% of runs and the OFV of the third-to-last day in 12% to

16% of runs throughout the year. The daily OFV of the fourth-to-last day and earlier differed in below 10% of all runs.

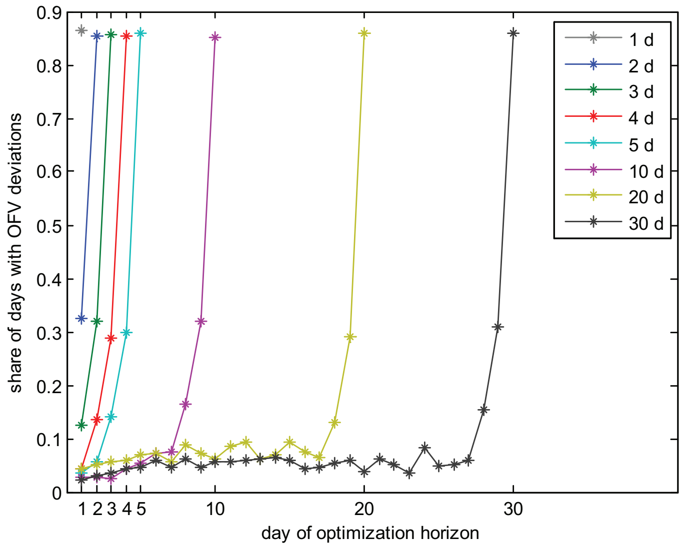

Figure 92: Share of runs with daily OFV differing from the 40-day optimization horizon results depending on the number of day within the optimization horizon.

Improvement of the annual result by extending the excess time (section 4.1.2)

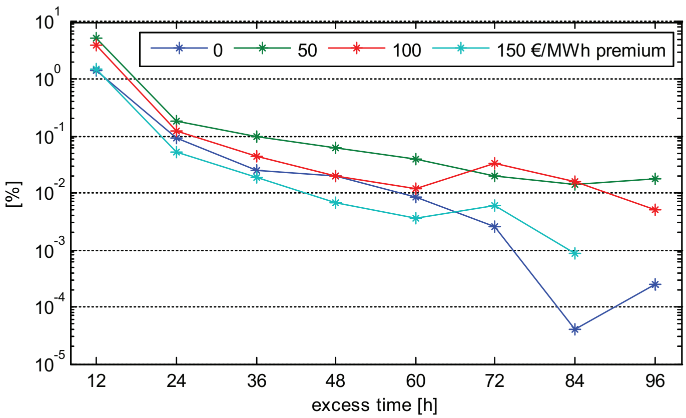

Figure 93: Relative improvement of the annual objective function value (OFV) from unit commitment depending on the excess time regarded for daily planning.

The relative improvement of the annual result of the unit commitment by increasing the excess time is shown in Figure 93. Four cases are presented, three of them containing a premium on the market prices of 50€/MWh, 100€/MWh and 150€/MWh. The figure shows the relative improvement of the OFV by increasing the excess time step-by-step. The OFV was increased between 1.4% and 5.1% by introducing an excess time of 12 h. Further increases of the excess time resulted in much less improvement. Raising the excess time from 12 h to 24 h increased the OFV from 0.05% to 0.18%. Each further increment raised the OFV in a magnitude between 0.001% and 0.1% up to 72 h and less from 72 h up to 96 h excess time.

Annex G Formulas of financial parameters

The net present value NPV is calculated by

$$NPV = \sum_{t=0}^{T} z_t (1+i)^{-t}$$

where z is the cash flow, i the interest and T the planned time horizon of the investment (Kruschwitz 2011). While the analysis of chapter 5 uses z_t for t=[1...T] from the unit commitment results according to Table 12, z_0 is the investment cost with $z_0<0$. If the annual gain is considered constant, it is equivalent to the NPV because of

$$\Delta C = \frac{i \cdot (1+i)^T}{(1+i)^T - 1} \cdot NPV$$

where ΔC is the annual gain, or so-called annuity, i the interest and T the planned time horizon of the investment (Kruschwitz 2011). As the present value PV of the annual gain is

$$PV = \sum_{t=1}^{T} z_t (1+i)^{-t}$$

which is

$$PV = z_t \cdot \frac{i \cdot (1+i)^T}{(1+i)^T - 1}$$

for constant z_t in t=[1...T] (Kruschwitz 2011) and z_0 the investment cost, the annual gain ΔC in Table 12 is calculated by the sum of the cash flow and the annuity of investment

$$\Delta C = z_t + z_0 \cdot \frac{i \cdot (1+i)^T}{(1+i)^T - 1}$$

where $z_0 < 0$. The internal rate of return (IRR) is the interest where the NPV becomes zero:

$$\sum_{t=0}^{T} z_t (1+i)^{-t} = 0$$

The IRR has to be calculated iteratively (Kruschwitz 2011).

Annex H Load curves from unit commitment

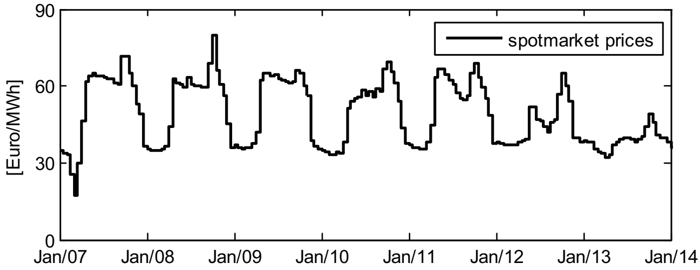

Figure 94: Spot market prices from 7-13 January 2013.

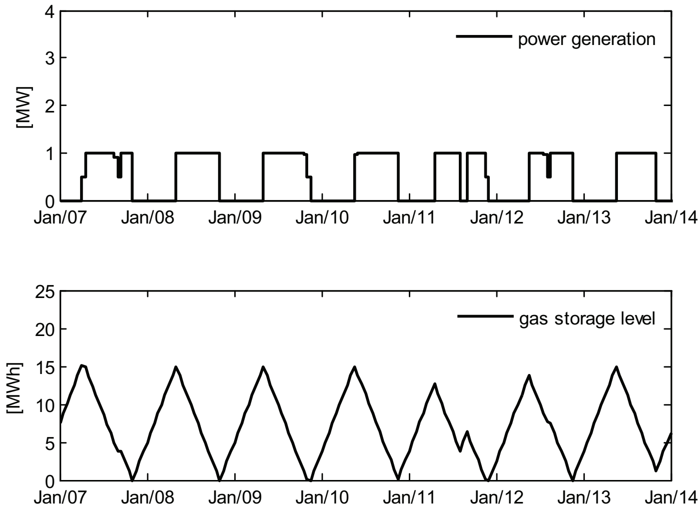

Figure 95: Schedule of optimized power generation of a biogas plant with extended capacity (factor 2) and storage capacity of 12 h.

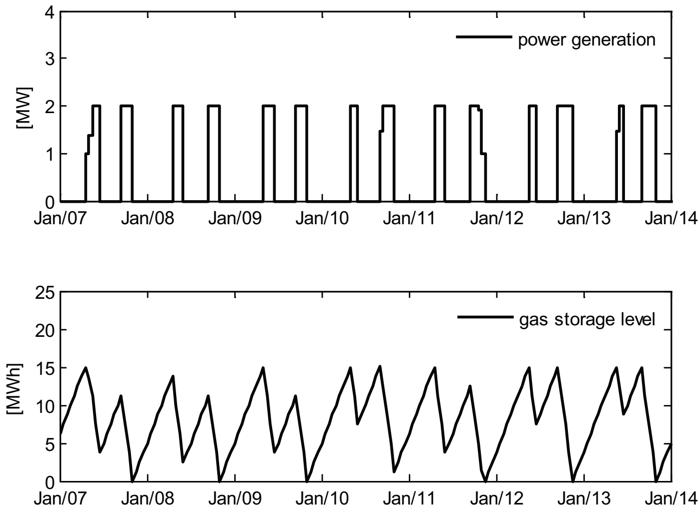

Figure 96: Schedule of optimized power generation of a biogas plant with extended capacity (factor 4) and storage capacity of 12 h.

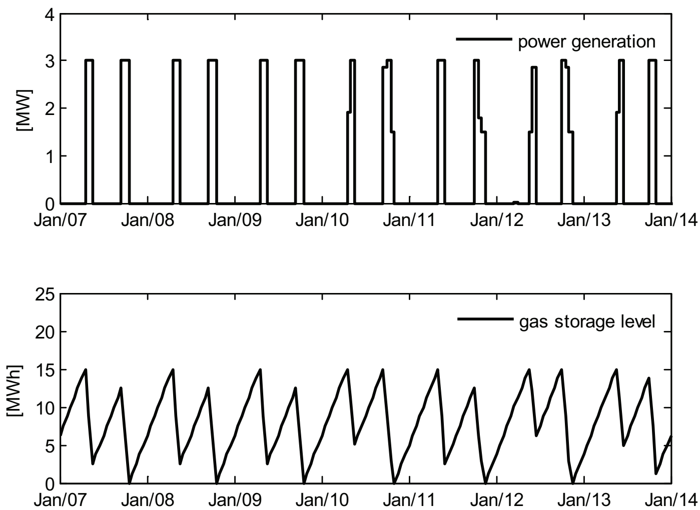

Figure 97: Schedule of optimized power generation of a biogas plant with extended capacity (factor 6) and storage capacity of 12 h.

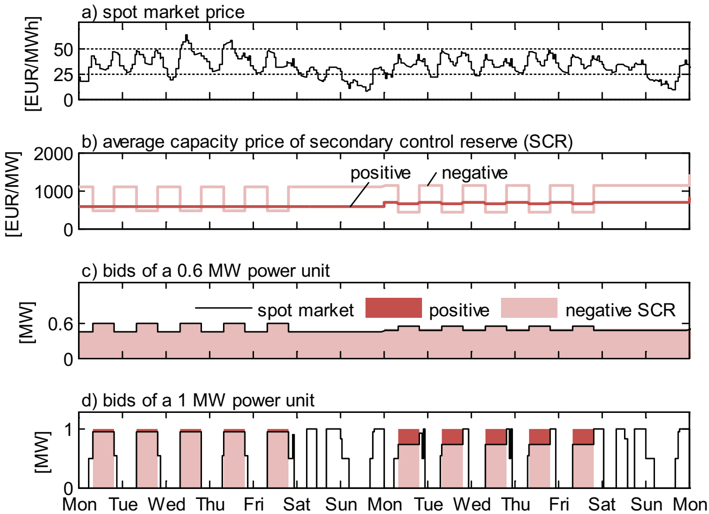

Figure 98: Schedule of optimized bids in the spot and secondary control reserve market of biogas plants with an electrical capacity of 0.6 MW and 1 MW and a 12 h storage capacity from 1-14 July 2013.

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Biogas plants become more flexible, scheduling their power generation with respect to market prices. For this purpose the electrical capacity of power units is extended to convert the continuously produced gas as well as the gas held in storage. This work has shown how gas plants with extended capacity located at a gas production site can be analyzed on the basis of unit commitment. Mixed integer linear programs (MILP) have been developed for the unit commitment of such plants in different use cases. The models developed consider gas plants at a gas production site participating in German power markets, switching between static and variable gas supply, providing secondary and tertiary control reserve, and claiming the German market and flexibility premium. The models can be applied to plan daily schedules for the operation of these gas plants. Furthermore, the models can be applied to analyze the benefits of extending the electrical or storage capacity of gas plants located at a gas production site. The models calculate the optimized gross income that can be applied as cash flow for determining the net present value (NPV) of investments in extended electrical and storage capacity.

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