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„Gas Power Plants in the Context of the Energy Transition in Germany and Austria
-
Assessing Future Prospects using a Mixed Integer Linear Programming Approach“

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Moritz Herrmann

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Moritz Herrmann

Moritz Herrmann

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1 Introduction

In 2008 the responsible committees of the Verbund and its subsidiary, the VERBUND-Austrian Thermal Power GmbH, have authorized the construction of the Mellach gas power plant. Only two years after it started operation in 2011 the current situation and the economic outlook for the plant are devastating. The company publicly declared that it considers shutting down the plant. The case of Mellach is exemplary for the problems, energy providers are currently facing. On a company level this problem may look like an issue of little relevance for politics and society. From a wider perspective it does not.

In many European countries, governments have set up regulatory frameworks to promote renewable energy. While the instruments vary throughout countries they all have the same goal: An increase in the share of energy supplied by renewable sources. Gas power plants combine certain features which make them a well suited technology to complement renewable energy sources. Fast start-up times and relatively low CO2 emissions make gas power plants superior to most other conventional energy sources.

This master thesis aims to analyze how the business environment for gas power plants in Germany and Austria has changed during the last years and examines future perspectives. For this purpose a fundamental model is set up. The model solves a unit commitment problem for the gas power plant in Mellach. With this model the profitability can be examined for the past years as well as for the future periods, using forecasts about the major cost factors and electricity prices.

The thesis is organized as follows. The second chapter outlines the basics of electricity markets. In the third chapter the mixed integer linear programming model is set up. The results of the model for the years 2008 to 2012 are given in chapter 4. Chapter 5 analyzes the future prospects for gas power plants. Scenarios about the major cost factors and electricity prices are determined and the results for the projected profitability until the year 2019 are outlined. Chapter 6 concludes the thesis.

2 General Outline of Electricity Markets

Electricity markets have several characteristics which crucially distinguish them from other markets. These characteristics make analyses of such markets particularly complex. This chapter is devoted to the general structure and the special characteristics of electricity markets. It will outline the organization of the market as well as features and anomalies on the supply and on the demand side.

2.1 Market Organization

In the process of liberalization in Europe, all European countries have undergone a change to liberalized electricity markets (Ockenfels et al. 2008, 11). Before the liberalization reforms electricity markets were represented by regulated utilities which acted as monopolists, controlling the generation as well as the transmission of electricity. This market layout did not promote competition, neither at the generators level, nor at the retailing level. Governments regulated the monopolies by setting price limits according to the average costs of the provision of electricity. End users were served by local distribution companies which could only buy electricity from the monopolistic generators. With the liberalization of the electricity markets, these monopolies were split up. The fundamental difference between the liberalized electricity markets and the formerly regulated utilities is the unbundling of generation and transmission (Murray 2009, 6). While the transmission services are still run by local monopolies all generators are granted a non-discriminatory access to the transmission network. Another innovation was the liberalization of the retailer choice of end users. These modifications introduced competition between generators and between retailers as well (Brunekreeft and Twelemann 2004, 3).

Through the liberalization of electricity markets, the organization of trading has changed as well. There are two trading models which have emerged in liberalized markets. One possibility of organizing electricity trade is given by the pool model. With this model participants in the market are obliged to trade the entire electricity via the pool. For this purpose generators make bids about the volume of electricity they want to supply at the next day and the respective price they are asking for. After generators have handed in their bids, a computer algorithm chooses the optimal schedule for the power plant complex that minimizes the total costs and satisfies the demand.

The second model is the so called exchange model (or multi-market) model. The difference to the pool model is that, although there is a central auction over exchanges, it is not mandatory to trade over this exchange. Participants have the possibility to engage in bilateral trading in a non-standardized form. For all trading deals made beneath the exchange, volumes have to be announced to the system operator. Although it is not mandatory to sell electricity over the exchange, prices observed there act as a reference price for bilateral trading as well. (Ockenfels et al. 2008, 6 and14; Murray 2009, 30).

2.2 Market Participants

Electricity markets can be divided into four broad parts: Generation, transmission, distribution and retailing.

Generation

Generators produce electric energy either from conventional fuels, such as coal, gas or nuclear, or from renewable energy sources, such as wind and solar. Produced electricity is then sold on exchanges like the EEX or via bilateral contracts. Bilateral trading can take place between generators and retailers or directly between generators and end users.

Transmission

Electricity produced by the generators need to be transported to end users via an electricity grid. For long distance transmission high voltage grid are used, whereas the distribution of electricity in urban areas is carried out with lower voltage grids. The transmission and distribution is generally carried out by monopolies. In Germany there are 4 regional transmission system operators (TSOs), namely amprion, TransnetBW, 50Hertz and Tennet TSO. In Austria transmission is carried out by the nationwide monopoly APG. All these TSOs are regulated by the governments which also sets the prices for the transmission services. The reason to have monopolies in place arises from the non-storability-feature of electricity and the resulting need to balance supply and demand at all times. Another argument in favor of monopolistic transmission operators is the high investment costs for building the transmission network. The TSOs are responsible to ensure that the system works stable, secure and safe. They operate the high voltage network ranging from 110 kV to 380 kV (Murray 2009, 21).

Distribution

Distribution system operators (DSOs) operate the networks which transmits electricity from the high voltage grid to the end users. The voltage range of their networks is between 240 V to around 132 kV (Murray 2009, 22). Like TSOs, DSOs have to guarantee non-discriminatory access to all network users. For the distribution service the DSO can charge a usage fee which set by the regulator as in the case of transmission.

Retailing

Retailing is done by several different market participants. On the one hand retailing firms can be a combination of generators and retailers, partly selling their own generated electricity directly to customers and partly buying electricity on the spot market to meet the demand of their customers. On the other hand firms can rely totally on buying all electricity on the spot market or via bilateral trading and sell it to end users. The latter can therefore be seen as intermediaries between generators and customers.

2.3 Special Characteristics of Electricity Markets

The first and probably most unusual feature of electricity markets is that supply and demand have to be balanced at any point in time. This comes from the fact that electricity cannot be stored (at least not in a sufficient scale to balance supply and demand) and that electricity networks break down if there is either more demand than supply or more supply than demand. If such situations occur and the difference is sufficiently large, power outages are the result.

Another anomaly is concerned with the emergence of prices. Electricity is a perfectly homogeneous product which can be produced by several different technologies. Each of these technologies has different marginal costs of producing the same good. A widely used concept to model the determination of spot electricity prices is the merit order. Figure 2.1

shows the merit order for Germany as of 17.11.2010. It only shows conventional plants and their respective costs.

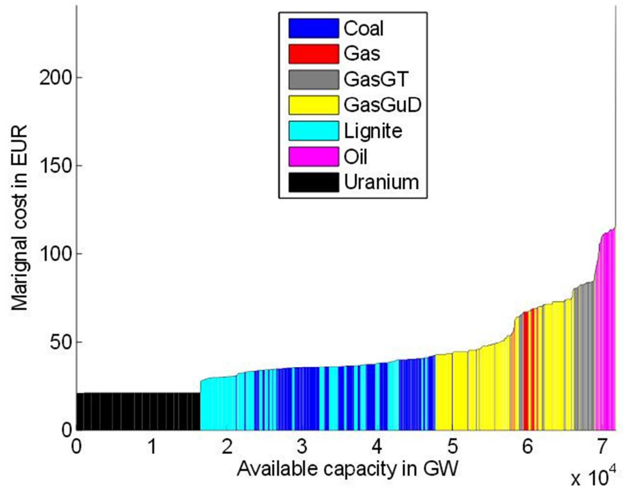

Fig. 2.1: Merit Order for Germany. Without Renewable Energy Sources. Source: Wozabal et al. 2013

The merit order ranks all power producing utilities according to their marginal costs. The result is an increasing step function, starting with low marginal cost utilities on the left side, e.g. nuclear plants and closing with the highest marginal cost utilities on the right side, e.g. oil plants. The function increases with the marginal costs of the technology. (Graf et al. 2013, 19). The marginal costs of a utility are not only dependent on its technology but also on the efficiency with which it can produce electricity out of its input fuel. The efficiency of utilities varies also within technologies where, for example, older plants normally have a lower efficiency, and thus higher marginal costs than newer utilities. This explains the increasing slope of the merit order within technologies.

Renewable energy sources are neglected in this illustration. They have marginal costs close to zero and would therefore be located at the left end of the merit order. However, the supply of these sources cannot be controlled as it is dependent on the availability of external factors such as wind power or sunlight. Moreover, supply from renewable energy utilities are treated preferentially in the sense that electricity produced by these utilities has to be fed in into the grid whenever available and generators are granted a fixed payment for the supplied renewable electricity. In cases in which renewable energy is available, the entire merit order therefore shifts to the right.

The ranking of the utilities which is the basis for the merit order is not only a helpful graphical tool but can also be used to determine the supply curve for electricity as it shows the relationship between the quantity and the price. Chapter 3.1 will have a closer look on the importance of the merit order for the price formation process.

Another crucial characteristic is the structure between generators, retailers and end consumers. Generators sell their produced electricity either on the spot market, via bilateral trading or act as retailers, supplying end consumers directly. On the other hand end consumers can be served by retailers which entirely buy electricity on the spot market or via bilateral trading and sell it to their customers. While spot market prices react to demand and supply on an hourly basis, end consumers are offered contracts in which their kWh-prices of electricity are fixed on a certain level for a certain period (till the retailer announces and conducts a price change). This results in a low elasticity of demand as consumers therefore do not have incentives to react on spot market fluctuations and for instance reduce their usage of electricity during times of high demand and resulting high prices, e.g. by using the washing machine at night, when prices are low. Figure 2.2 shows the average hourly electricity prices on the EPEX Spot market and the average hourly load in Germany and Austria in 2012. The term load is defined as “the hourly average active power absorbed by all installations connected to the transmission network or to the distribution network” (entsoe 2013a, 1). Alternatively it can be described as “the power consumed by the network including (+) the network losses but excluding (-) the consumption for pumped storage and excluding (-) the consumption of generating auxiliaries.” (entsoe 2013a, 1). Although the load is therefore not exactly equal to the demand it will be used as a proxy for the electricity demand hereafter.

The average daily pattern of electricity spot prices for each hour of the day, presented in figure 2.2, shows two peaks, one in the morning at around 9 a.m. and one in the evening at around 8 p.m. At night, prices are at their minimum. Figure 2.3 illustrates the average daily pattern of the load in Germany in 2012. It shows a similar pattern as the hourly electricity prices with two peaks, one at around 12 a.m., one at around 7 p.m. and low demand during the night.

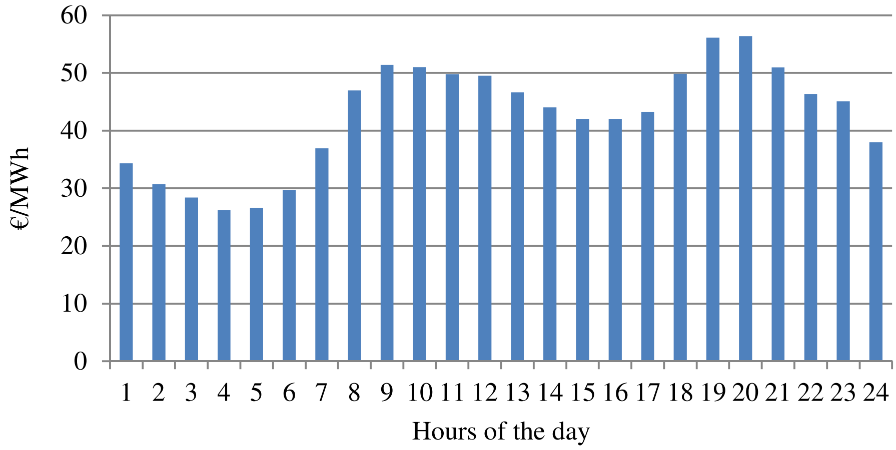

Fig. 2.2: Average Daily Pattern of EPEX Spot Prices in 2012. Source: EEX

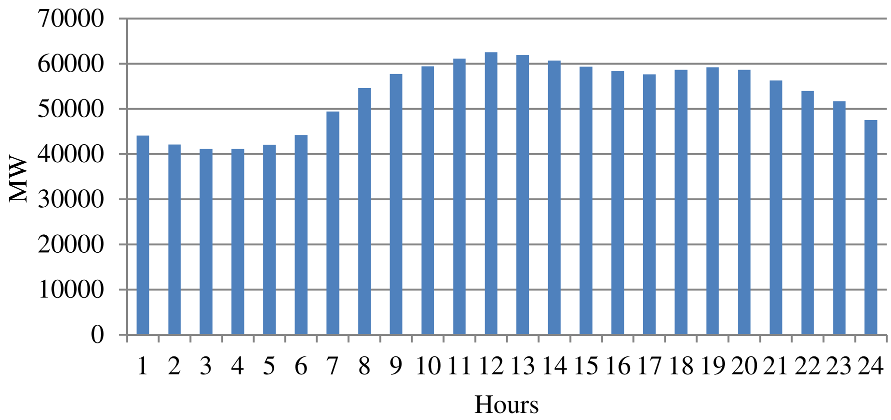

Fig. 2.3: Average Daily Pattern of Load in Germany 2012. Source: entsoe (2013b)

Fixed-price contracts arose because metering the electricity consumption is generally not done on a real-time level. Mostly customers do not have electricity meters which report the real-time consumption to their supplier but the supplier has to, physically, go to the customers and read their meters in certain time intervals. One possibility to incentivize customers to react on price signals form the spot market is the installation of smart meters. Such devices report the consumption of customers in short intervals to the retailers. With this additional information new forms of contracts between retailers and customers would be possible, where the kWh-prices could be variable, dependent on the hour of the day or directly dependent on the current electricity spot price.

The absence of real-time metering, together with the non-storability feature of electricity leads to the daily recurrent electricity price pattern. Introducing spot price dependent electricity contracts together with a comprehensive usage of smart meters and a possibility of storing electricity, the pattern of electricity prices and the load should diminish. Customers should rationally use arbitrage possibilities by buying electricity at low price hours, store it and consume it at peak price hours. This should lead to a smoother pattern of both, the prices and the load. Regarding the load, a smooth daily pattern, combined with a smooth yearly pattern would have the advantage that it could reduce the generating capacity needed to satisfy the demand during all hours of the year.

Another important feature arises from the special role that electricity plays in modern societies. Security of supply of electricity is of high importance for modern societies. The consequences of an absence of electricity on economic activity, on security aspects but also on transportation systems, bureaucratic affairs and much more everyday activities make the reliability of electricity supply a highly important matter which is of general interest to the society.

3 Profit Maximization Model - The Unit Commitment Problem

This chapter builds the core of this thesis. As described above the aim of the thesis is to evaluate the profitability of gas power plants. For this purpose a mixed integer linear programming model is set up which optimizes the dispatch of the analyzed plant. In the case of power plants such problems are also called unit commitment problems. The intention of the unit commitment problem is to build up a model that determines the optimal schedule of a power unit, given data about the cost factors, electricity prices and constraints regarding the operation of the unit. Power plants can consist of several different power producing units which can be operated independently from each other. Therefore the decision about the optimal schedule is concerned with the commitment of units rather than power plants. The optimal schedule determines at which points in time the unit is started up, at which points in time it is shut down and how much capacity of the unit is utilized when it is in operation. The model comprises electricity prices, variable costs and fixed costs. Fixed costs describe cost factors which do not vary with the generation level but arise in full extent if the operator decides to operate the unit over a certain year. In contrast to fixed costs, variable costs vary with the generation level and are only incurred if the unit is in operation. The objective of the model is to maximize the profit generated by the power plant. Please note that in this context the term profit differs from the accounting term, book profit, which also accounts for depreciation and capital costs.

For the scheduling problem presented in this thesis the power plant Mellach is considered. It is a combined cycle gas turbine plant, called CCGT. CCGTs are gas turbines which use the heat accompanied with the electricity generation to produce steam that is used as a fuel for a steam engine. Therefore the otherwise lost heat energy is transformed into electric power which increases the efficiency of such plants compared to regular gas turbines. The plant is located in Mellach, Styria in Austria. It was built between 2009 and 2011 by the VERBUND Thermal Power GmbH & Co KG which belongs to the Verbund AG. The total capacity is 832 MW_E divided into two units (Verbund 2013).

The decision to analyze the gas power plant in Mellach has several reasons. A very interesting fact about Mellach is that it was only built recently which makes it a perfect object of study. Gas power plants differ widely in their efficiency for reasons of age. As this thesis wants to address questions about the future of gas power, a modern gas plant with an up-to-date technology is chosen. Another interesting feature about Mellach is that it started operation only recently but that the Verbund AG already discusses about shutting it down (Der Standard 2013). This makes an analysis of the market environments in 2008 (the time when the construction was authorized), in mid-2013 (when the further operation of the plant was questioned) and future periods especially interesting.

Compared to coal fired plants, gas power plants are an especially good option if the goal of politics is to reduce greenhouse gas emissions and on the other hand promote conventional energy sources to complement the intermittent renewable energy production. One of the big advantages of gas plants over coal fired plants is the minor emissions of greenhouse gas in the generation process. Combined with the fast start-up times, gas power plants seem to be the more favorable option compared to coal fired plants. Nevertheless gas power plants struggle and operators in Germany and Austria claim that the prevalent market conditions do not allow a profitable operation (Manager Magazin Online 2013). In the following, these problems will be addressed and the concerns raised will be reviewed.

The first part of this chapter will give an overview over the electricity spot market and describe the price data used for the calculations. The second part outlines the variable and the fixed cost factors. In the third part constraints and special features concerning the production process of the power plant will be discussed. The last part presents the profit maximization model, combining all the formerly discussed parts.

3.1 Electricity Prices

3.1.1 The EPEX Spot Market

In the following, the general organization and the price formation process on the EPEX spot market will be outlined.

The EPEX Spot SE is an exchange on which electric power can be traded. It is a company under the legal form of a Societas Europaea. It offers the possibility to trade electricity on the day-ahead market or on the intraday market. Data about the hourly spot prices are taken from the day-ahead auction market. In the following the term spot market is used as a synonym for the day-ahead auction market.

The day-ahead auction is organized as a sealed bid, uniform price auction. An auction is said to be a sealed bid auction if there is only one bidding round which ensures that participants do not get any feedback on the behavior of other participants. Figuratively speaking, every participant of the auction hands in a sealed envelope containing his bid. After all envelopes are handed in, the auctioneer opens them and determines which bidder has won the auction. This mechanism ensures that participants cannot react on bids handed in by other participants. In addition the day-ahead auction is characterized by a uniform price mechanism. Here every unit is sold or bought at the same price (at a particular point in time).

Having outlined the general structure of a sealed bid, uniform price auction the special case of the EPEX day-ahead auction will be described below.

All registered members at the EPEX Spot SE can make offers about the quantity of electric power they want to supply at each hour of the next day and respectively the price at which they want to sell it. The price is given in € per MWh_E and the quantity in MW_E, each with one decimal digit respectively. The subscript E in MWh_E and MW_E indicates that electrical megawatt hours are meant. The minimum allowed price is -3000 € per MWh_E, the maximum price is 3000 € MWh_E. The possibility of negative prices is a special characteristic of electricity markets. Power plants have substantial start-up and shut-down costs. For this reason shutting down a plant only for a short period of time can be less profitable than keeping it turned on and sell the power for negative prices. In such situations the marginal costs of the plant are negative. An intuitive explanation for the existence of negative prices on an electric power exchange in specific times is therefore the following: Although, producing an additional unit of electric power during the next hour is associated with additional losses, shutting down the plant induces even higher losses due to the high start-up costs that have to be incurred when starting up the plant again. Recall that in a standard market situation without start-up or shut-down costs, a supplier who faces negative marginal costs in a certain period would stop the production till marginal costs are at least equal to zero again (Ockenfels et al. 2008, 39).

Members can choose to either make orders for every individual hour of the next day or make so called block orders. Here specific hours are aggregated into a block. There are several standardized blocks from which bidders can choose from. Examples for such block orders are: Baseload (0:00 a.m.-12:00 p.m.), Peakload (08:00 a.m.-08:00 p.m.), Morning (06:00 a.m.-10:00 a.m.), Night (00:00 a.m.-06:00 a.m.). Beside the predefined options, bidders can also define custom-built blocks. Bids can be made 24 hours per day and up to 45 days before the delivery day. At 12:00 a.m. the order book closes and no further bids for the next day are accepted.

At 12:00 a.m. all submitted bids are collected. In order to construct demand and supply curves a branch-and-bound algorithm is used. Block orders can only be executed fully or rejected fully, called the “All-or-None” condition. This condition makes it necessary to use an algorithm to find the optimal solution. Would there only be hourly orders, supply and demand curves could be found in a straightforward way.

The search algorithm uses two steps. In the first step the “All-or-None” condition is relaxed and therefore block orders are treated like hourly orders, with the exception that the price is constant over the respective hours. In the second step, the “All-or-None” condition becomes a binding constraint. The algorithm then tries to find a feasible solution where all block orders are either executed fully or rejected fully. The results of these calculations are linearly interpolated supply and demand curves. Determining the intersections of these curves gives the market clearing prices for every individual hour. The results of the auction are published at the same day, as soon as possible from 12:40 pm. (Ockenfels et al. 2008, 9 ; EPEX 2013b,7)

For the scheduling problem, it is assumed that there is perfect competition in the spot market. Consequently all market participants are price takers. This assumption is crucial for the analysis as it removes strategical behavior. How could startegical behavior look like?

Assume that there are only two types of plants: identical base load and identical peak load plants, representing facilities with low and high marginal costs respectively. Further assume that at the analyzed moment in time all base load plants are in operation and are producing just enough electricity to serve the current demand. Recall that in this situation profits for the firms are zero as the spot market price is characterized by the marginal cost of the last plant that is needed to exactly satisfy the current demand. In this case every producer has the incentive to cut back his electricity production from the base load plants and therefore shifting the intersection of the demand and the merit order (supply) curve to the right. In this new situation, the price will be equal to the marginal costs of the peak load plants, granting profits out of the sale of electricity generated by the base load plants.
The assumption of perfect competition, and therefore the absence of strategic behavior, is also in line with Graf and Wozabal (2011). They use a conjectural variations model to test whether energy producers abuse their market power. The analysis considers price data of the EPEX spot market of the years 2007-2010 and yields no evidence for a misuse of market power.

For the model the EPEX spot market data is taken in hourly resolution and is denoted by

$$p_t \dots EPEX\ price\ in\ \frac{€}{MWh}\ in\ hour\ t, \qquad t \in T.$$

3.2 Cost factors

Cost factors can be either variable of fixed. Variable cost factors are gas costs, CO2 allowances costs, variable operation and management costs, grid use fees and start-up costs. Fixed costs included in the model are fixed operation and management costs. In the following these cost factors will be explained in detail.

3.2.1 Variable Costs

3.2.1.1 Gas Costs

Costs arising due to the input of gas are the major factor in the profitability analysis of a gas-fired power plant. The profitability of these plants heavily depends on the level of the gas prices. There are basically two possible sources of supply generators can choose from. On the one hand operators can obtain gas via long term contracts with gas suppliers. With such contracts the purchase price of gas is indexed to the price of oil and a basket of refined oil products. Firms are very discreet with data about the terms of these long term contracts. This makes it hard to obtain information about prices for gas traded over such contracts. The only reliable source about long term contract gas prices is the so called BAFA import price for natural gas, called BAFA price henceforth. This price is published by the Federal Office of Economics and Export Control (BAFA) on a monthly basis. It measures the prices of gas imported from neighboring countries into Germany (BAFA 2011). The BAFA price is denoted by

$$cgBAFA_t \ldots BAFA\, price\ in\ €/MWh\ \ at\ hour\ t, \qquad t \in T.$$

On the other hand a generator can buy gas on hubs where spot market trading is possible. Although there are several hubs in Germany and Austria prices from the Net Connect Germany Hub (NCG) are taken as, with respect to the total traded volume, it is the biggest spot trading place in Germany and Austria. The NCG prices are denoted by:

$$cgNCG_t \ldots price\ at\ the\ NCG\ hub\ in\ €/MWh\, at\ hour\ t, \qquad t \in T.$$

Figure 3.1 shows the evolution of the BAFA price from 2007 to 2012 and prices on some European gas hubs. Here we see that all hubs follow more or less a similar pattern whereas the BAFA price is mostly higher than the hub prices.

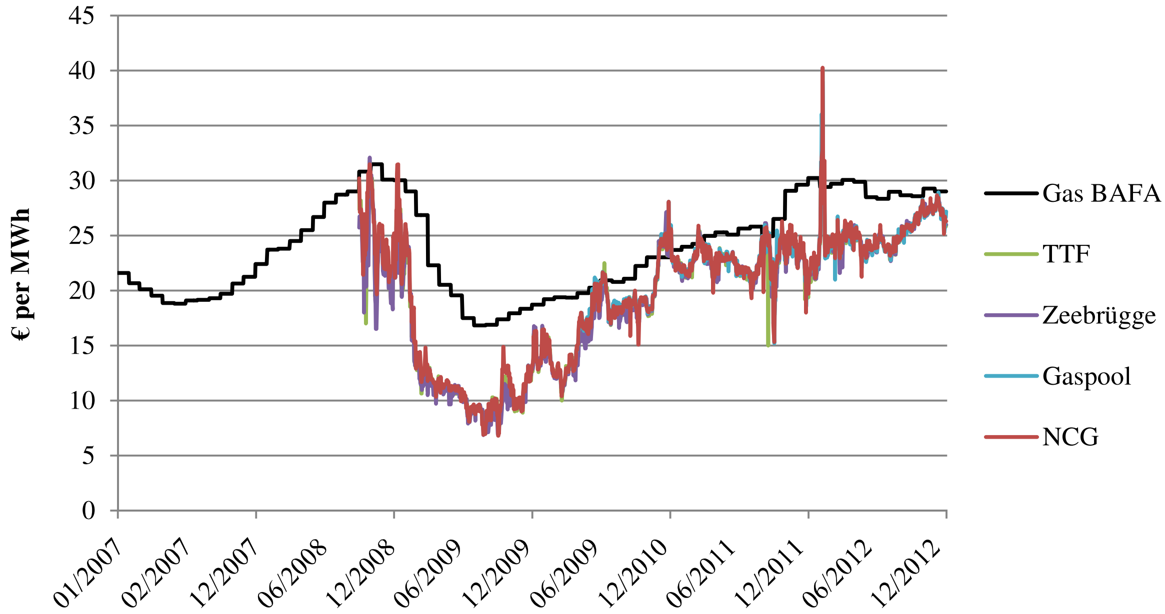

Fig. 3.1: Evolution of BAFA Gas Prices and European Gas Hub Prices 2007-2012. Source: NCG (2013) and BAFA (2013)

3.2.1.2 CO2 Allowance Prices

For every ton of CO2 emissions, a power plant operator has to either own or buy an emission right, called allowance. Such allowances authorize the owner to emit CO2 and are issued over the EU Emissions Trading System (EU ETS). This system works as a so called cap and trade system where the regulator sets an upper limit to greenhouse gases by issuing only a limited number of rights to emit to firms. Each firm is granted a limited amount of allowances according to Europe-wide allocation rules. Firms can then either use their allowances for their own use or sell them (DEHSt 2013). Trading of allowances can be done over the counter or over exchanges such as the EEX. One allowance allows the owner to emit one ton of CO2 and can be used only once. Every year the overall emission cap is reduced by 1.74%. This gives firms the incentive to decrease their emissions as they otherwise have to buy additional allowances.

The first phase of the EU ETS started in 2005 and covered the years 2005-2007. This phase was characterized by low allowance prices as the estimations about the needs of firms were too high (European Commission 2013a). The second phase covered the years 2008-2012. Figure 3.2 shows the evolution of the allowances prices for the years 2007 till 2012. This phase was characterized by a sharp increase in the allowance price in the beginning and a gradually decrease of the prices from mid-2011 to the end of 2012. The third phase started in 2013 and ranges till 2020. One difference to the other phases is that power generators do not get any allowances issued for free anymore but have to buy them on the market. However, allowance prices are rather low at the moment with around 4 € per ton[1] compared to above 16 € in the middle of 2011.

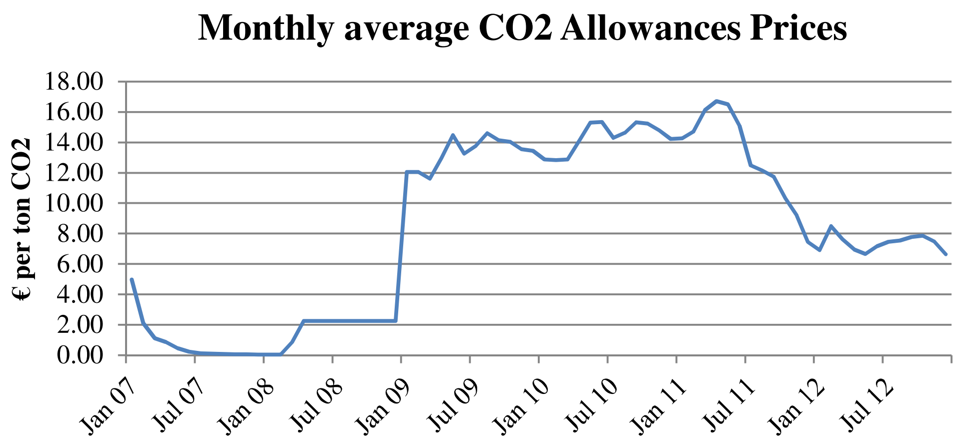

Fig. 3.2: Monthly average CO2 Allowances Prices. Source: EEX

For the calculations in this thesis it is assumed that firms have to buy all allowances on the market. Furthermore it is assumed that firms do not strategically buy allowances but constantly buy them at the exchange, according to their current emissions. The price of one CO2 allowance at hour t is given by:

$$cPERMIT_t \ldots price\ of\ one\ ton\ CO2\ in \frac{€}{ton\ CO2}\ at\ hour\ t, \qquad t \in T.$$

For the determination of the current emissions, the amount of used gas, measured in MWh_G, is taken. For 1 MWh_G of gas burned in the production process, CO2 emissions in the amount

[1] At 16.08.2013 source: http://www.eex.com/de/Marktdaten/Handelsdaten/Emissionsrechte

of 0.18483 tons of CO2 are emitted (DECC 2012). In the following the emission costs will be captured via the gas input. The costs for emission allowance at hour t for the usage of one MWh_G of gas is given by

$$cCO2_t = 0.18483 \times cPERMIT_t \quad \forall\, t \in T. \tag{1}$$

The total gas costs include both the costs of the used gas and the costs for the CO2 allowances. Therefore the total costs for gas at hour t are given by

$$cGAS_t = GI_t(x_t) \times (cgNCG_t + cCO2_t)\,, \tag{2}$$

for gas bought at the NCG hub, and

$$cGAS_t = GI_t(x_t) \times (cgBAFA_t + cCO2_t)\,, \tag{3}$$

for the case where gas is bought with the BAFA price. $GI_t(x_t)$ denotes the gas input at hour t dependent on the generation level x_t.

3.2.1.3 Gas Grid-Use Fees

Gas grid-use fees have to be paid by the operator of the plant for using the grid. These fees are set according to federal law. For the calculation not all fees are taken into account, but only the grid-use fees. Other fees like metering fees or grid-entry fees are not included in the model. Every end-consumer who receives gas via the gas grid has to pay fees to the respective grid operator. These grid-use fees are divided into the “demand rate” (Leistungspreis) and the “energy rate” (Arbeitspreis).

The yearly **energy rate** (ER) is determined by taking the sum of all gas consumed by the customer and multiplying it with the respective energy rate. The energy rate again is divided into different zones. In contrast to the demand rate the energy rate is characterized by a degressive tariff, where every zone beneath the final zone has to be passed. The term degressive means that zones representing small consumption levels have higher rates than high-consumption zones.

Consumption MWh_G/year	Energy rate €/MWh_G	Demand rate €/MWh_G/hour
0 – 5.000	2,089	4320
5.000,001 – 10.000	1,726	4320
10.000,001 – 100.000	1,201	4320
100.000,001 – 200.000	0,446	4320
200.000,001 – 900.000	0,443	4320
from 900.000,001	0,430	4320

Table 3.1: Energy and Demand Rates. Source: Gas-Systemnutzungsentgelte-Verordnung-2013

In order to model the energy rate, a piecewise function has to be constructed. In the following an approach for such a piecewise cost function will be presented. The piecewise function approach is based on Carrión and Arroyo (2006). Figure 3.3 shows the main idea of the approach. Let $b \in [1, \ldots, 6]$ denote the zone in which the operator of the unit is in, s_b the consumed amount of gas in zone b and er_b the energy rate in this zone. $b = 1$ represents the zone with the lowest consumption and the highest energy rate, while $b = 6$ represents the zone with the highest consumption and the lowest energy rate. Zones 2 to 6 are characterized by an upper limit, L_b, and a lower limit, L_{b-1}. For zone $b = 6$ the upper limit is the maximum consumption in one year. This limit would be reached if the unit is in operation every hour of the year. The lower limit for the zone $b = 1$ is zero. Table 3.1 shows the zones and how they are defined.

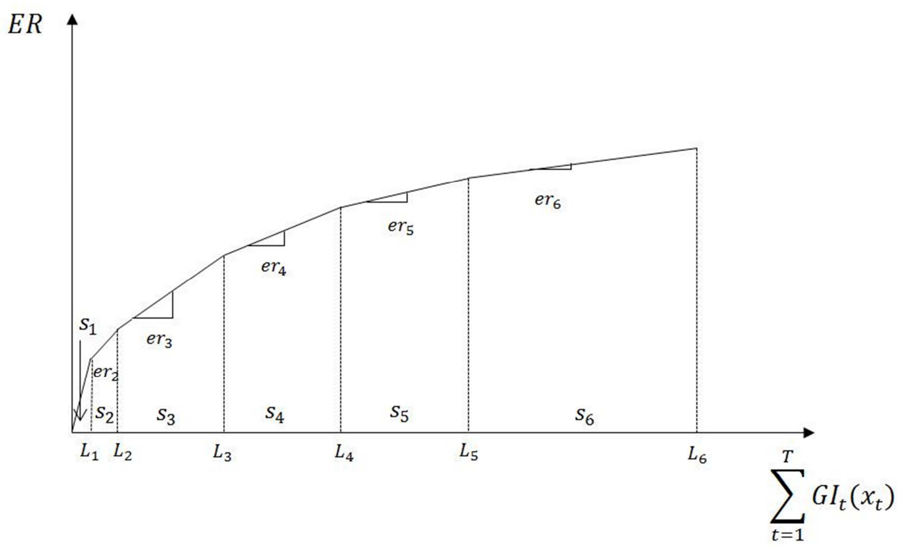

Fig. 3.3: Piecewise Energy rate Function. See Carrión and Arroyo (2006)

To set up the constraints for the piecewise energy rate function, binary variables have to be included, stating in which zone the gas consumption is. These binary variables are denoted by α_b, where α_b is 1 when the consumption of gas exceeds the limit L_{b-1} and is 0 otherwise. The constraints for the piecewise energy rate function are given by:

$$ER = \sum_{b=1}^{6} (s_b \times er_b) \, , \tag{4}$$

$$0 \leq s_1 \leq L_1 \, , \tag{5}$$

$$0 \leq s_b \leq \alpha_b \, (L_b - L_{b-1}) \;\; \forall \, b = 2, \ldots, 6 \, . \tag{6}$$

(5) and (6) ensure that the consumption in zone s_b does not exceed the upper and lower limits of the respective zone. (7) ensures that consumption in a specific zone can only take place if there was consumption in the zone before as well. With (8) and (9) consumption in zone b is only possible if the maximum consumption took place in the previous zone $b-1$.

$$\alpha_b - \alpha_{b-1} \leq 0 \quad \forall \, b = 2, \ldots, 6 \, , \tag{7}$$

$$s_1 \geq \alpha_2 \, L_1 \tag{8}$$

$$s_b \geq \alpha_{b+1} \, (L_b - L_{b-1}) \quad \forall \, b = 2, \ldots, 5 \, , \tag{9}$$

$$\sum_{b=1}^{6} s_b = \sum_{t=1}^{T} GI_t(x_t) \, . \tag{10}$$

Equation (10) ensures that the sum of the consumption in all zones equals the total consumption.

While the energy rate is concerned with the total amount of consumed gas, the **demand rate (DR)** is concerned with the maximum amount of gas a consumer uses in any hour of a month. Table 4.1 shows the yearly demand rate. In contrast to the energy rate, the demand rate is constant for each consumption zone. Note that the demand rates given in table 4.1 are yearly rates. The Monthly rate is given by one twelfth of the yearly rate.

The exact fee is calculated as follows. For every month, the hour with the maximal consumption is taken and multiplied with 1/12 of the demand rate. In any case the demand rate is at least 20% of the maximum announced consumption limit of the end consumer. The maximum consumption limit has to be announced by the end consumer in advance of the year and is valid throughout this year. It is assumed that this limit is the required amount of gas the unit needs to operate at full capacity. In the case of the power plant Mellach the maximum electric output per unit is 416 MWh_E. Divided by the efficiency at this level, the maximal consumption of gas per hour is $416MWh_E/0.59 = 705.08MWh_G$ of gas, denoted by $\overline{GI_{t_m}(x_{t_m})}$. The monthly demand rate is given by the monthly maximum consumption at any hour but has to be equal or greater than 20% of the maximal announced consumption.

The total yearly demand rate is hence the sum of the monthly demand rates.

$$dr_m = \max\left[\max\left(GI_{t_m}(x_{t_m})\right), 0.2 \times \overline{GI_{t_m}(x_{t_m})}\right] \quad \forall\, t_m \in T_m \tag{11}$$

$$DR = \sum_{m=1}^{12} dr_m \tag{12}$$

Where T_m represents the hours of the month m and DR the rates set by the Austrian energy regulator, called E-Control.

Total grid costs are thus given by

$$cGRID = ER + DR \tag{13}$$

3.2.1.4 Start-Up Costs

Start-up costs arise if the unit is leaving the idle state and moves to a state in which it is in operation. There are three different start-up types which depend on the hours the unit was in the idle state: Cold starts, warm start and hot starts. For simplicity it is assumed that there is only one start-up type. This renders, accounting for the hours of the unit in the idle state before being started up unnecessary and simplifies the model. Arroyo and Conejo (2000) model the start-up cost as a stairwise function which depends on the hours the unit has been switched off. In this thesis the start-up cost will be covered with a fixed value of c_{start}. This value is assumed to be 13,000 € (Troy et al. 2008) for each of the two units of the power plant Mellach.

$$c_{start} \ldots start\ up\ cost.\ 13{,}000\ €\ per\ start\ up\ process$$

The binary variable y_t captures if the unit is started up at hour t. Therefore the start-up costs at hour t are given by

$$cSTART_t = y_t \times c_{start} \tag{14}$$

3.2.1.5 Variable O&M Costs

As classified by eia (2013) operation and maintenance costs (referred to as O&M costs) can be separated into variable and fixed O&M costs. Both cost factors will be discussed separately. O&M costs include cost factors which arise due to the operation and the maintenance of the unit. They include staff costs, material costs, administrative expenditures, communication and insurance and the costs for consumables (NETL 2011 and Murray 2009). Variable O&M costs depend on the generation level. Raw water, waste disposal expenses, chemicals and consumable materials and supplies are the major contributors for this cost factor (eia 2013, 6-3).

$$OM_{var} \ldots variable\ O\&M\ costs\ in\ €/MWh_E$$

$$OM_{var} = 2.52\ €/MWh_E\text{[2]} \tag{15}$$

The yearly variable O&M costs are thus given by the sum of the generated electricity multiplied with the variable O&M costs per MWh_E.

$$cOM_{var} = OM_{var} \sum_{t=1}^{T} x_t \tag{16}$$

[2] Source: eia 2013, 6

3.2.2 Fixed Costs

Fixed costs do not vary with the generation level. Even when the unit is not operated these costs are incurred. In this model fixed costs will be captured by the fixed O&M costs. These fixed costs are dependent on the maximum capacity of the unit. Thus they are measured in € per MW. Examples for such costs are staff and administration costs, preventive maintenance operations and equipment rentals (eia 2013, 6-3).

$$OM_{fix} \dots fixed\ O\&M\ costs\ in\ \frac{€}{MW}\ ,$$

$$OM_{fix} = 11{,}868.73 \frac{€}{MW} / year^{3}\ . \tag{17}$$

The yearly fixed O&M costs for one power unit are given by

$$cOM_{fix} = OM_{fix}\ \times 416, \tag{18}$$

where 416 is the maximum capacity of one unit of the Mellach power plant.

Summarizing all operation and maintenance costs by merging (16) and (18), the total O&M costs for one power unit per year are given by

$$cOM_{total} = cOM_{fix} + cOM_{var} \tag{19}$$

3.2.3 Constraints and Special Features

3.2.3.1 Minimum/Maximum Capacity

The operation of a power unit is possible only within a range of generation levels. The upper limit represents the maximum power the unit can potentially produce, which is equal to the total capacity of the unit. It is denoted by$\overline{X}$. The lower limit is characterized by the lowest possible generation level of the unit and is denoted by $\underline{X}$. The power plant in Mellach has two units, each with a capacity of 416 MW_E and a minimum generation level of 100 MW_E

[3] Source: eia 2013, 6

(Tauschitz and Hochfellner 2005). Therefore the constraint for each unit regarding the range of generation levels is:

$$100 = \underline{X} \leq x \leq \overline{X} = 416 \qquad (20)$$

3.2.3.2 Efficiency Curve

It is important to distinguish between different variable cost factors to properly account for each of them. Although the O&M costs are determined by the produced electricity, the costs for natural gas and CO2 allowances vary only with the required amount of gas needed to produce the current electric power. Therefore the model needs to give information about the electric output and the corresponding input of gas for every hour.

The efficiency of a gas power unit measures the ratio of the input of energy (in the form of gas) and the output of energy (in the form of electric power). The efficiency of a unit crucially depends on how much output is currently produced compared to its potential maximum output. If the unit produces close to its maximum capacity, the efficiency is highest whereas a generation level close to the minimum power output is accompanied with a low efficiency.

This relationship is not linear in reality. Figure 3.4 graphically shows how such an efficiency curve could look like in reality and how it is linearized for the calculations in this thesis.

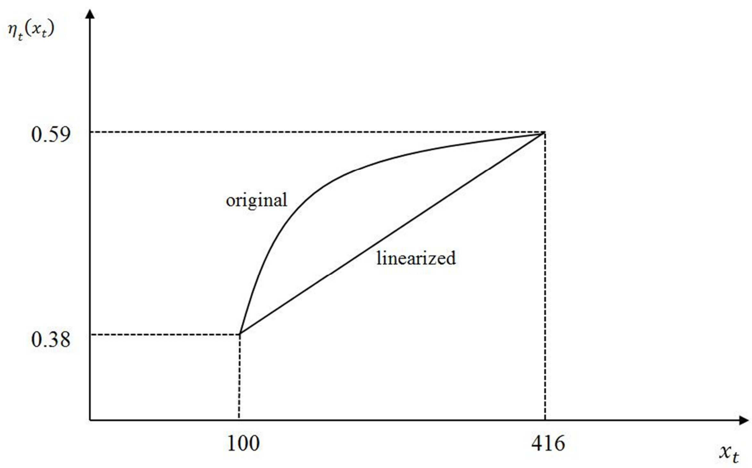

Fig. 3.4: Source: Own illustration based on Murray (2009, 47), Valdes et al. (2004)

Linearization ensures that the optimization problem remains linear. Otherwise the programming and the computational effort would grow substantially. Therefore it is assumed that the efficiency curve is represented by a linear function. The efficiency of the unit at maximum capacity is $\overline{\eta}$ = 59% (Verbund 2013) whereas the efficiency at minimum capacity is $\underline{\eta}$ = 38% (Tauschitz and Hochfellner 2005). Let $\eta_t(x_t)$ be the efficiency of a unit at hour t, dependend on the current electric power output, x_t.

There are several ways to implement the efficiency into the model. In the following, three approaches will be discussed.

1) One way to account for the efficiency is to consider the efficiency directly in the objective function by multiplying the reciprocal efficiency with the generation level x_t. This multiplication yields the corresponding needed input of gas and the costs for the emitted amount of CO2. Note that the efficiency depends on the current generation level. Therefore a linear efficiency function has to be formulated which represents the relationship between the generation level and the respective efficiency. The efficiency at two generation levels are known, for $\overline{X}$ and $\underline{X}$, therefore the slope, b, and the intersection, a, of the linear efficiency function $\eta_t(x_t)$ can be derived as follows:

$$\eta_t(x_t) = a + b \times x_t \ , \tag{21}$$

$$b = \frac{\overline{\eta} - \underline{\eta}}{\overline{X} - \underline{X}} \ , \tag{22}$$

$$a = \underline{\eta} - \underline{X} \times b \ . \tag{23}$$

In the objective function the variable costs, including the respective efficiency, could then be included as follows

$$\left(\frac{1}{\eta_t(x_t)} \times x_t\right) \times (cgNCG_t + cCO2_t) \ . \tag{24}$$

Inserting (21) into (24) yields:

$$\left(\frac{1}{(\underline{\eta} - \underline{X} \times b) + \left(\frac{\overline{\eta} - \underline{\eta}}{\overline{X} - \underline{X}}\right) \times x_t} \times x_t\right) \times (cgNCG_t + cCO2_t)\,. \tag{25}$$

From (24) and (25) we see that this term is not linear. $\eta_t(x_t)$ depends on x_t and has to be multiplied by x_t to get the needed amount of gas to produce x_t. As we aim for a linear model set up, this approach of capturing the efficiency is not chosen.

2) The second possibility, and the one chosen for the model, is to describe the efficiency as the required amount of gas to produce a certain level of electric power. The result is a function which describes the input of gas depending on the generation level of the unit. Figure 3.5 shows the relationship between the generation level x_t and the required amount of gas for the respective generation level, $GI_t(x_t) = \frac{x_t}{\eta(x_t)}$.

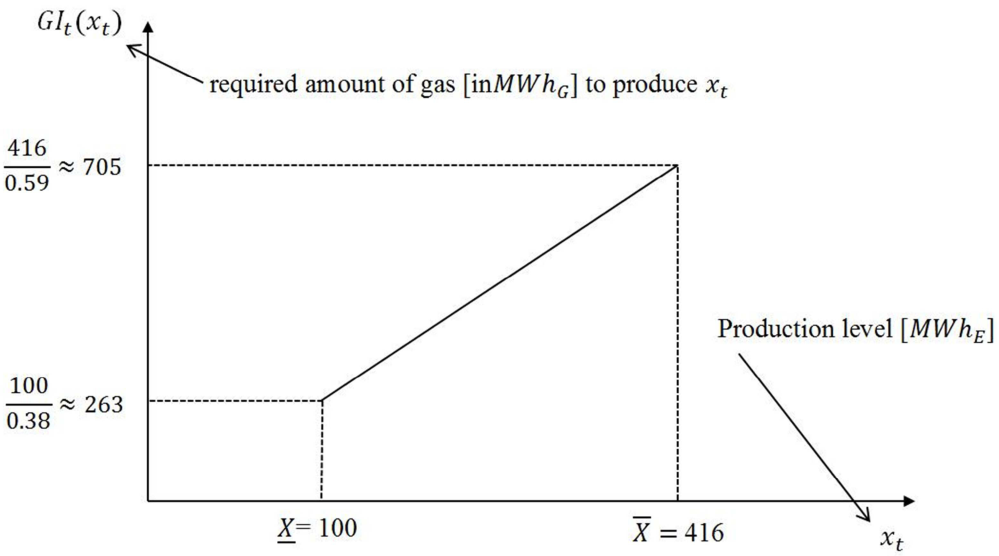

Fig. 3.5; Linear Gas Input Function.

Again it is necessary to derive the equation of this linear input function, denoted by $GI_t(x_t)$. As in the previous approach the linear efficiency function is set up in the standard form. To ensure that in cases in which the unit is in the idle state the gas input is zero, a binary variable denoted by v_t has to be included. If the unit is in operation, v_t is equal to one, if the unit is in the idle state v_t is equal to zero.

$$GI_t(x_t) = v_t\, a + b \times\, x_t\ , \tag{26}$$

$$b = \frac{\left(\frac{\overline{X}}{\overline{\eta}} - \frac{\underline{X}}{\underline{\eta}}\right)}{\overline{X} - \underline{X}}\ , \tag{27}$$

$$a = \frac{\underline{X}}{\underline{\eta}} - \underline{X}\ \times b\ . \tag{28}$$

Inserting (27) and (28) in (26) yields

$$GI_t(x_t) = v_t\left(\frac{\underline{X}}{\underline{\eta}} - \underline{X}\ \times \frac{\left(\frac{\overline{X}}{\overline{\eta}} - \frac{\underline{X}}{\underline{\eta}}\right)}{\overline{X} - \underline{X}}\right) + \frac{\left(\frac{\overline{X}}{\overline{\eta}} - \frac{\underline{X}}{\underline{\eta}}\right)}{\overline{X} - \underline{X}} \times\ x_t\ . \tag{29}$$

Having defined the gas input function, $GI_t(x_t)$, equations (2) and (3), which capture the total gas costs, are now fully defined. In the objective the gas costs are captured with the term:

$$cGAS_t = GI_t(x_t) * (cgNCG_t + cCO2_t)\,, \tag{30}$$

for the case when NCG gas prices are considered, or

$$cGAS_t = GI_t(x_t) * (cgBAFA_t + cCO2_t)\,, \tag{31}$$

for the case when BAFA gas prices are considered.

By using this approach to capture the efficiency, the model is kept linear, as only the term $GI_t(x_t)$ contains x_t.

3) There is one other method which is similar to the last approach as it is also captures the efficiency via the consumed gas. For this purpose the non-linear variable cost curve is approximated with multiple linear functions. The last approach can be seen as a basic version of the one described in this section as it also approximates the non-linear function with a linear function but only uses single function. The approach

described here is more precise in the approximation. Arroyo and Conejo (2000) describe such a piecewise linear curve. Figure 3.6 shows the basic idea.

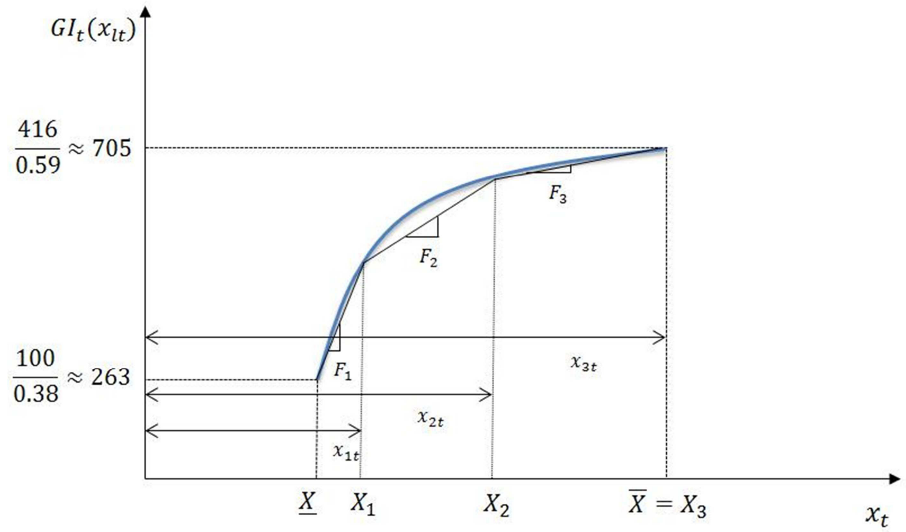

Fig. 3.6: Piecewise Approximation of the Variable Cost Function

In a first step the range between the minimum power output and the maximum power output of the unit has to be divided into blocks, denoted by $l \in L$, where L is the number of blocks. Blocks are characterized by an upper limit X_l and respectively by a distinctive slope, F_l, of the gas input function. This slope represents the reciprocal efficiency within the respective block. Figure 3.6 shows an example where the non-linear curve is divided into 3 blocks. If the power output exceeds the upper limit of block l, X_l, production moves to the next block, $l+1$ with the new slope F_{l+1}.

If this approach is chosen, the variable capturing the generation level at each hour, x_t, has to be extended with an index l which comprises the information about the block in which the production process is currently in. x_{lt} denotes the power output at hour t when the unit operates in block l. As in the case of the energy rate, binary variables have to be included to define the different blocks. The binary variables are denoted by y_{lt}. At each point in time the production process can only be in one block. This is ensured by the constraint (32).

$$\sum_{l=1}^{L} y_{lt} \leq 1\,. \qquad \forall\, l \in L \tag{32}$$

If the production at hour t is in block l, the sum of all y_{lt} has to be equal to one and the generation level is x_{lt}. When the generation level is in the range of block l at hour t, the efficiency for the total production process is the same, therefore the gas consumption at this hour is given by:

$$GI_t(x_{lt}) = \sum_{l=1}^{L} x_{lt}\, F_l \tag{33}$$

It is important to mention that in difference to the piecewise function for the energy rate, where all zones with lower consumption levels have to be passed, in the approach described here, the slope of the curve (reciprocal efficiency) of the respective block applies for the total production at the respective hour.

The following constraints set up the piecewise linearization.

$$y_{1t}\, \underline{X} \leq\; x_{1t} \leq\; y_{1t}\, X_1 \tag{34}$$

$$y_{lt}\, X_{l-1} \leq\; x_{lt} \leq\; y_{lt}\, X_l \quad \forall\, l \in [2, \dots, L] \tag{35}$$

The inequalities (34) and (35) assure that the production in each block does not exceed it limits and that the binary variables linked to the respective block.

3.3 Model set up

The objective of the owner of a gas power plant is to maximize the profit from selling electricity either on the spot market or via bilateral trading. Spot market prices act as reference prices for bilateral trading between generators and end consumers as well. For the model in this thesis it is assumed that generators sell all their electricity only over the spot market and do not trade in futures or forward markets.

On the one hand, revenues are generated by selling produced electricity, on the other hand owning the plant, starting it up and running it induces costs to the owner. The owner therefore wants to find a schedule for the units of the plant with which the operation is carried out in the optimal way.

For the profit maximization model a mixed integer linear programming approach is used. The notation is as follows:

t	Time index in hours $t \in T$
T	Number of hours per year
m	Indicates the month $m = 1 \dots 12$
p_t	EPEX price in $€/MWh_E$ at hour t
x_t	Electric power output in MWh_E at hour t
v_t unit	0/1 variable which is equal to 1 if the unit is in operation at hour t and 0 if is in the idle state
y_t hour	0/1 variable which is equal to 1 if the unit is started up at the beginning of t and 0 otherwise
$cSTART_t$	Start-up costs at hour t in € per start-up process.
$cgNCG_t$	daily reference price of natural gas at the NCG hub in $€/MWh_G$ at hour t
$cgBAFA_t$	BAFA price of natural gas in $€/MWh_G$ at hour t
$cPERMIT_t$	Emission allowance price for 1 ton CO2 in $€/ton\ CO2$ in hour t
$cCO2_t$	Emission allowance costs at hour t when consuming one MWh_G of gas
$cGAS_t$	Total costs for the gas input at hour t
$GI_{t_m}(x_{t_m})$	Gas input at hour t dependent on the power output
DR	Yearly demand rate (Leistungspreis) in €

dr_m	Demand rate for month m in €
ER	Energy rate (Arbeitspreis) in $€/MWh_G$
b	Respective zone for the calculation of the energy rate
er_b	Energy rate in zone b
s_b	Consumed amount of gas in zone b in MWh_G
L_b	Upper limits of zone b
α_b	0/1 variable which is equal to 1 if total consumption of gas exceeds limit L_{b-1}
$cGRID$	Total grid costs in € per year
$\overline{X}$	Maximum capacity of the unit in MW_E
$\underline{X}$	Minimum power output of the unit inMW_E
$\overline{\eta}$	Efficiency at maximum capacity. $\overline{\eta}$ = 59%
$\underline{\eta}$	Efficiency at minimum power output. $\underline{\eta}$ = 38%
OM_{var}	Variable O&M costs in $€/MWh_E$
OM_{fix}	Fixed O&M costs $€/MW$ per year
cOM_{total}	Total O&M costs per year in €

The objective function for one year is given by:

$$\max \quad \sum_{t=1}^{T}[x_t \times p_t] - \sum_{t=1}^{T} cGAS_t - cOM_{total} - cGRID - \sum_{t=1}^{T} cSTART_t \quad \forall\, t \in T. \qquad (36)$$

Accurately the objective is given by:

$$\max \sum_{t=1}^{T} [x_t \times p_t]$$

$$-\sum_{t=1}^{T} \left(\left(v_t \times \left(\frac{\underline{X}}{\underline{\eta}} - \underline{X} \times \frac{\left(\frac{\overline{X}}{\overline{\eta}} - \frac{\underline{X}}{\underline{\eta}} \right)}{\overline{X} - \underline{X}} \right) + \frac{\left(\frac{\overline{X}}{\overline{\eta}} - \frac{\underline{X}}{\underline{\eta}} \right)}{\overline{X} - \underline{X}} \times x_t \right) \times (cgNCG_t + cCO2_t) \right)$$

$$-OM_{var} \times \sum_{t=1}^{T} x_t - 416 \times OM_{fix}$$

$$-\sum_{b=1}^{6} (s_b \times er_b) - \sum_{m=1}^{12} \max \left[\max \left(GI_{t_m}(x_{t_m}) \right), 0.2 \times \overline{GI_{t_m}(x_{t_m})} \right]$$

$$-\sum_{t=1}^{T} y_t \times c_{start} \ .$$

$$\forall\, t \in T, \qquad \forall\, b \in [1, \dots, 6], \qquad \forall\, m \in [1, \dots, 12]$$

subject to:

Output and start-up constraints:

$$v_t\, \underline{X} \le x_t \le v_t\, \overline{X} \tag{37}$$

$$y_t \ge 0 \tag{38}$$

$$v_t - v_{t-1} \le y_t \tag{39}$$

Constraints for the energy rate:

$$ER = \sum_{b=1}^{6} (s_b * er_b) , \tag{40}$$

$$0 \leq s_1 \leq L_1 , \tag{41}$$

$$0 \leq s_b \leq \alpha_b (L_b - L_{b-1}) \ \forall b = 2, \ldots ,6 . \tag{42}$$

$$\alpha_b - \alpha_{b-1} \leq 0 \quad \forall b = 2, \ldots ,6 , \tag{43}$$

$$s_1 \geq \alpha_2 L_1 \tag{44}$$

$$s_b \geq \alpha_{b+1} (L_b - L_{b-1}) \quad \forall b = 2, \ldots ,5 , \tag{45}$$

$$\sum_{b=1}^{6} s_b = \sum_{t=1}^{T} GI_t(x_t). \tag{46}$$

The objective function gives the profit for one unit with a capacity of 416 MW_E for one year. As described above, the power plant Mellach has two identical units, each with a capacity of 416 MW_E. The results for the profitability are the same for both units. As mentioned above it is assumed that firms are price takers and cannot change the price on the spot market with additional supplied electricity. Therefore the optimization results are valid for both units and the profit for the plant Mellach is simply two times the profit of one unit. The calculations are implemented in MATLAB R2012a using the YALMIP toolbox (Löfberg 2004) and solved with the GUROBI solver (Gurobi Optimization, Inc 2013).

4 Historical Results

In the previous chapter the profit maximization model for the power plant in Mellach has been outlined. This chapter gives the results for the profits of the power plant Mellach for the years 2008 to 2012. Note that the results are given for both units of the plant.

Although the power plant Mellach was completed and started operation in 2011 the process of planning and construction took place years before that. In Mai 2008 the responsible committees of the Verbund AG authorized the construction of the Mellach plant (Verbund 2008). Before the investment decision, the prevalent situation and the outlooks must have been promising to lead the firm to invest in the gas power plant, if rational behavior is assumed. Data about future contracts traded in the year 2008 suggest the view that the outlook for power plants was encouraging when the investment decision was made. Figure 4.1 shows the prices of yearly baseload futures contracts traded in 2008 for the years 2009 to 2012 as well as the realized spot prices for these years. In 2008 yearly baseload future contracts for the years 2009 to 2012 were traded with settlement prices between 69€ and 71€ per MWh_E on the EEX exchange. The expectations underlying these trades did not come true. For the years 2009 to 2012 the realized average yearly spot prices ranged between 38€ and 51€.

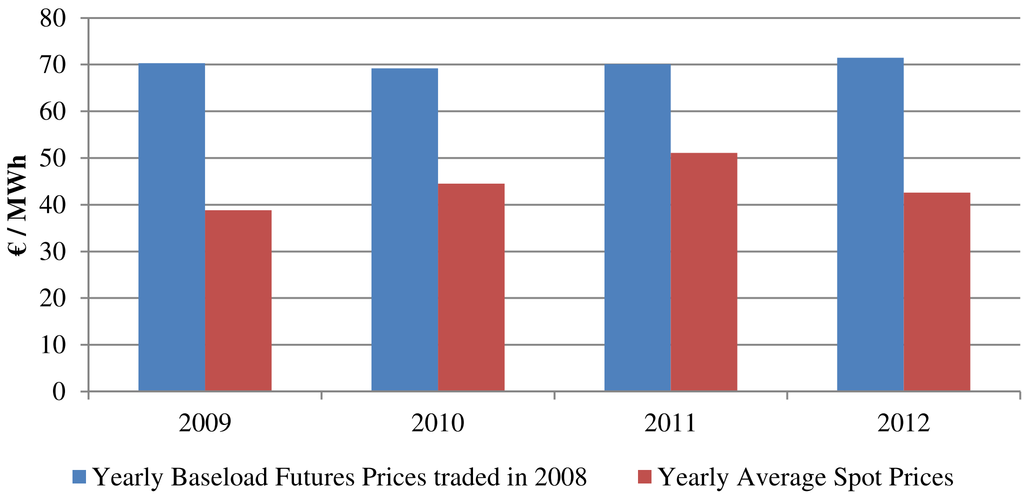

Fig. 4.1; Comparison of Futures Contract Prices traded in 2008 and Realized Spot Prices. Source: EEX

As the construction of the Mellach plant was not finished until 2011, the calculations for the years 2008 to 2011 are only hypothetical. They are aimed to show how the profitability of gas power plants evolved due to the changed economic environment between the investment decision and the completion of the plant.

4.1 Results

Table 4.1 and table 4.2 show the results of the profit maximization model for the years 2008 to 2012. Table 4.1 gives the results for the case where it is assumed that the plant operator has bought gas entirely over the NCG hub, while table 4.2 shows the result with BAFA gas prices as the input source. Figure 4.3 highlights the evolution of the cost factors over the analyzed years.

For both the NCG and the BAFA case, profits are high in 2008 but decline rapidly afterwards. In both cases, profits in 2012 are lowest and even negative for the BAFA scenario. Another finding is the decrease in operating hours from 2008 to 2012. This suggests that the frequency of peak hours, where electricity prices are especially high and the operation of gas power plants is profitable, have decreases sufficiently. Figure 4.2 shows the price duration curves (PDC) for the years 2008 to 2012. The PDC is a graphical tool to illustrate the fundamental structure of prices occurred in a given year. For the analysis it can be interesting to analyze at how much hours, prices exceeded a certain threshold. The PDC is a useful tool to illustrate this. To construct the PDC, prices occurred during the year are sorted in a descending order. In order to examine changes in the profitability of the power plant, information about both prices and cost factors have to be included in the analysis. Figure 4.3 shows the evolution of the cost factors and the electricity spot price from 2008 to 2012. The following analysis of the results refers to figure 4.2 and figure 4.3 to explain the profitability results.

The high profits in 2008 are mainly driven by the high electricity prices. The PDC for 2008 shows that electricity prices were substantially higher in almost all hours of the year than in later years. Although gas prices are at a high level as well, high electricity prices together with low CO2 allowances prices allowed a profitable operation in almost 85 % of the hours. In 2009 the average gas prices declined by about 50% for NCG gas and 22% for BAFA gas compared to the average level in 2008. Nevertheless yearly average electricity prices decreased by about 40% as well. Together with an increase of the CO2 allowances prices, profits declined substantially for both gas input cases in 2009. Table 4.1 shows that although the produced electricity in the NCG case is similar in 2008 and 2009, revenues as well as the costs for gas are only 50% of the level of 2008. If we compare the PDCs for 2008 and 2009 the remarkable decline in revenues can be explained. In 2008, electricity prices were sufficiently higher than in 2009 for all hours. The cheaper input prices of gas could not compensate for this loss in revenues and therefore profits declined by more than 50%. Another interesting finding for the year 2009 is the huge difference in the profits as well as in the operating hours between the NCG and the BAFA case. While in the NCG case the operating hours in 2009 are only slightly lower than in 2008, the operating hour in the BAFA case decrease by more than 50% compared to 2008. The profit maximization model for the power plant starts up the plant only at hours in which the electricity price is sufficiently high to cover the gas, CO2 allowances, O&M, grid use and the start-up costs. NCG gas prices in 2009 were on average 12€ per MWh_E and in the BAFA case 21€ per MWh_E. The higher BAFA gas prices reduced the number of hours in which a profitable operation was possible by more than 60% compared to the NCG case.

The years 2010 and 2011 were characterized by a steady increase of gas prices as well as electricity prices and a rather constant price for CO2 allowances. Profits in the NCG case declined less than in the BAFA case while operating hours and the generated revenues remained rather constant. In the year 2012 profits in the NCG case are barely positive and in the BAFA case the plant even made a loss of about 6 million €. While electricity prices declined constantly gas costs for both cases increased steadily. The only positive development for the profits was the declining CO2 allowances price. However, their impact on the profitability is rather low compared to gas prices or the level of electricity prices.

Nevertheless, CO2 allowances prices are relevant not only for gas power plants but also for other conventional power plants which could have in impact on the level of electricity prices as well. Low CO2 allowances prices are beneficial for gas plants but are overproportionally beneficial for coal fired plants. The production of 1 MWh_E of electricity with a coal fired plant produces nearly twice as much CO2 emissions than the production of 1 MWh_E with a gas fired plant. If CO2 allowances prices decrease, coal fired plants can be more economical than gas fired plants. In the merit order, coal plants move to the left side of the gas plants and decrease the average prices. Beneath the growing share of renewable energy production, this could partially explain the decreased electricity price. The effect of a growing share of renewables on the electricity prices will be outlined in detail in chapter 5.2.

	2008	2009	2010	2011	2012
Revenues	442,401,732	257,375,941	286,768,407	315,377,382	147,495,756
Gas Costs	257,566,414	123,829,758	173,000,368	216,822,044	109,361,459
CO2 Costs	3,370,673	25,250,958	26,609,271	23,520,078	5,927,833
Commodity Rate	4,610,495	4,574,444	4,523,288	4,287,166	2,048,942
Demand Rate	6,091,932	6,091,932	6,091,932	6,091,932	6,091,932
variable O&M	15,224,066	15,051,174	14,935,012	14,153,953	6,427,714
fixed O&M	9,874,783	9,874,783	9,874,783	9,874,783	9,874,783
Start-up Costs	4,108,000	2,886,000	3,380,000	4,628,000	5,798,000
Profit	141,918,626	69,816,892	48,353,753	35,999,425	1,965,094
Production (MWh)	6,050,448	5,972,688	5,926,592	5,616,648	2,550,680
Operating Hours	7,377	7,478	7,257	6,788	3,068
Number of Start-Ups	158	111	130	178	223

Table 4.1: Profit maximization model Results with NCG Gas Prices as Input

	2008	2009	2010	2011	2012
Revenues	418,925,084	126,587,349	235,946,281	240,892,638	50,783,425
Gas Costs	252,891,806	78,268,149	145,192,956	173,207,997	36,840,785
CO2 Costs	3,017,539	10,135,707	20,649,690	17,895,424	1,739,832
Commodity Rate	4,246,932	1,918,401	3,549,275	3,149,735	728,565
Demand Rate	6,091,932	5,137,370	6,091,932	5,773,745	3,864,621
variable O&M	13,998,681	5,971,332	11,599,500	10,233,619	1,886,976
fixed O&M	9,874,783	9,874,783	9,874,783	9,874,783	9,874,783
Start-up Costs	4,888,000	4,992,000	5,330,000	5,512,000	1,950,000
Profit	123,915,410	10,289,607	33,658,145	15,245,335	-6,102,138
Production (MWh)	5,555,032	2,369,576	4,602,976	4,060,960	748,800
Operating Hours	6,758	2,864	5,578	4,884	900
Number of Start-Ups	188	192	205	212	75

Table 4.2: Profit maximization model Results with BAFA Gas Prices as Input

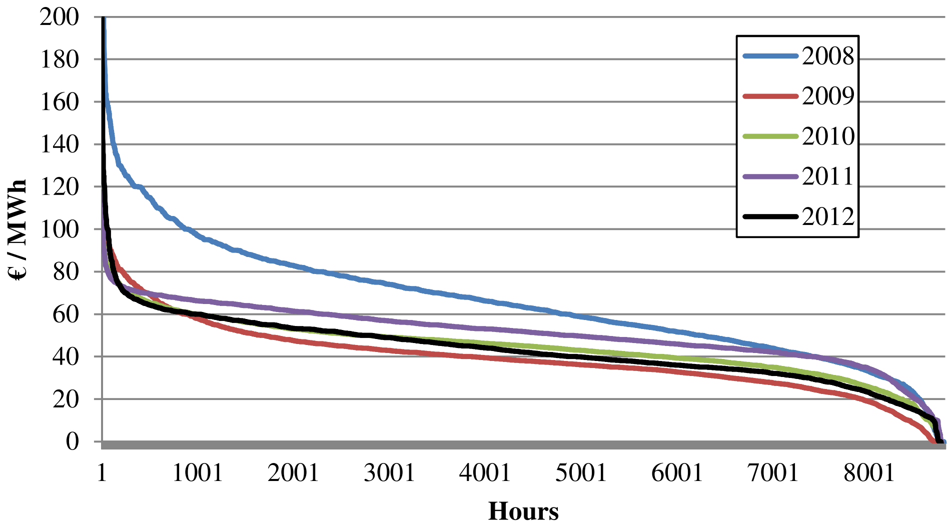

Fig. 4.2: Price Duration Curve for the Years 2008-2012. Source: EEX

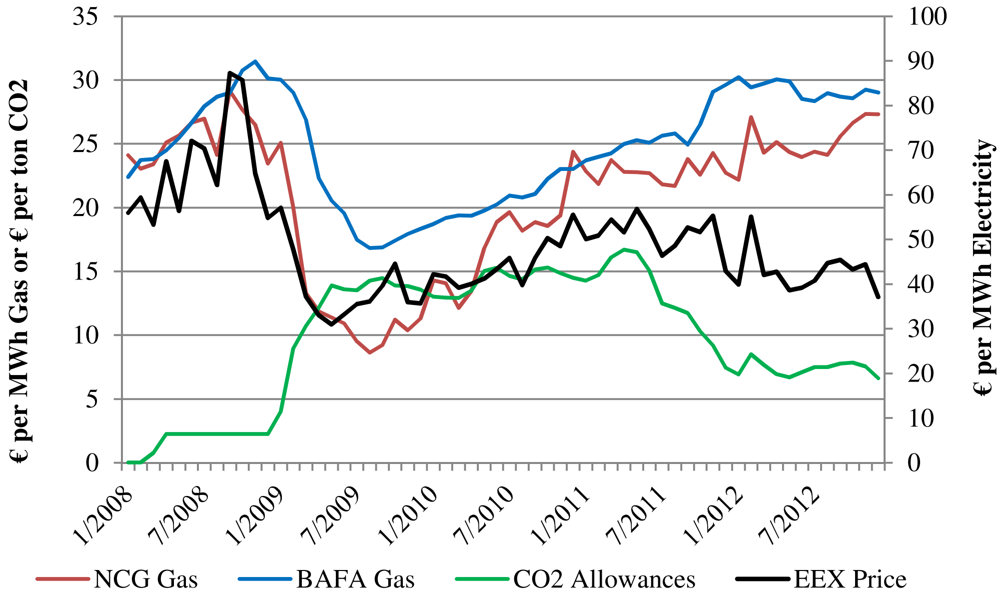

Fig. 4.3: Evolution of Cost Factors and Electricity Spot Prices from 2008 to 2012: Source: EEX, NCG (2013) and BAFA (2013)

The historical results are in line with the concerns of plant operators about the economically problematic situation of the gas plants. If capital costs and depreciation would be accounted for as well, the situation would be even worse. With investment costs of 550 million € and an expected lifetime of 30 years (eia 2013), the depreciation is around 18 million € per year. For the BAFA case not even this costs could be covered in 2011 and 2012.

5 Future Outlook

After having analyzed the current situation and the evolution of historical profits, this chapter discusses future projections about gas costs, CO2 allowances costs and electricity prices. For each component three scenarios will be formulated, namely a base scenario, a high price scenario and a low price scenario. Taking these scenarios as the basis, the future profitability of the plant will be analyzed. The high and low price scenarios deviate from the base scenario by 5% each year in an exponential way. The calculation is the same for the gas, the CO2 and the electricity scenarios and is given by:

$$LOW_y = BASE_y \times (1.05)^y \qquad \forall\ y\ \in\ [1, \dots, 6]\,, \tag{47}$$

for the low price scenarios, and

$$HIGH_y = BASE_y \times (1.05)^y \qquad \forall\ y\ \in\ [1, \dots, 6], \tag{48}$$

for the high price scenarios. LOW_y denotes the price of the low price scenario for year, y, and $HIGH_y$ the price of the low price scenario for year y. $BASE_y$ represents the price of the base scenario for the year y. For the year 2014, $y = 1$ while $t = 6$ for the year 2019.

5.1 Cost Factor Projections

5.1.1 Gas Prices

This paragraph will examine the developments in the natural gas market and their possible consequences on gas prices. The mentioned developments in the gas market are the appearance of gas hubs on which spot trading takes place and the possible effect of shale gas extraction combined with liquefied natural gas (LNG) trading. These issues are interlinked and therefore a separated analysis of each of them is not appropriate. Starting with a short historical review of gas pricing the following paragraph gives an overview of the current problems and challenges in the natural gas market.

5.1.1.1 A Short Historical Review of Gas Pricing

The history of gas pricing in Europe began with the discovery of natural gas at the Slochteren field in Groningen, Netherlands, and the North Sea in the late 1950s by the Dutch. Before this discovery gas trade in Europe was only marginal. The Pricing regime in place was called Netback Pricing. To determine the price paid at the Dutch border, the market value of gas in each destination country was determined. From the respective market value, costs of transportation, overheads and a profit margin were deducted to calculate the price paid at the border for each customer country. As this led to different prices for different customer countries at the Dutch border, contracts contained destination clauses in order to eliminate arbitrage possibilities for countries with more remote destinations and therefore lower purchase prices.

In the following decades gas was also supplied from Russia, Algeria and Norway. Trade was carried out through long term contracts (LTCs) with a duration of about 20-30 years. In order for suppliers to ensure that the high investment costs for the transmission infrastructure, namely pipelines, can be recovered such contracts typically have clauses that specify the minimum annual quantity that has to be purchased by the customer. Such clauses are called “Take-or-Pay” clauses. The “Take-or-Pay” level is normally around 80-90 percent. Another special feature of LTCs is oil-indexation. With this concept the price of gas is linked to the price level of oil products, such as gasoil and heavy fuel oil. Additionally, LTCs normally contain price review clauses. With these clauses each party has the right to request renegotiations at prespecified dates (Melling 2010, 20).

The emergence of spot markets for natural gas in Europe began in the mid-1990s. The first exchange for natural gas was the National Balancing Point (NBP) in the UK. In the following years more hubs emerged throughout Europe. The most important ones are the Zeebrugge Platform /ZEE) in Belgium, the Title Transfer Facility (TTF) in the Netherlands, the Gas Exchange Point (PEG) in France, the Gaspool (GPL) and Net Connect Germany (NCG) in Germany, the Single Balancing Point (CDG) in Spain and the Central European Gas Hub in Austria.

Gas Price Scenarios

The emergence of spot gas market created a new possibility for consumers to buy gas with distinct prices. Figure 5.1 shows that the prices at European hubs have been lower than the BAFA prices almost always. Such a situation leads to problems for importers which purchase their gas over LTCs and producers alike. The observed spot prices act as a reference for both the end consumers, but also for the importers of gas. Importers will ask for renegotiations as their customers request lower prices as well. In the last years gas importers therefore renegotiated the prices for their oil-indexed contracts with producers (Reuters 2013; ICIS 2012).

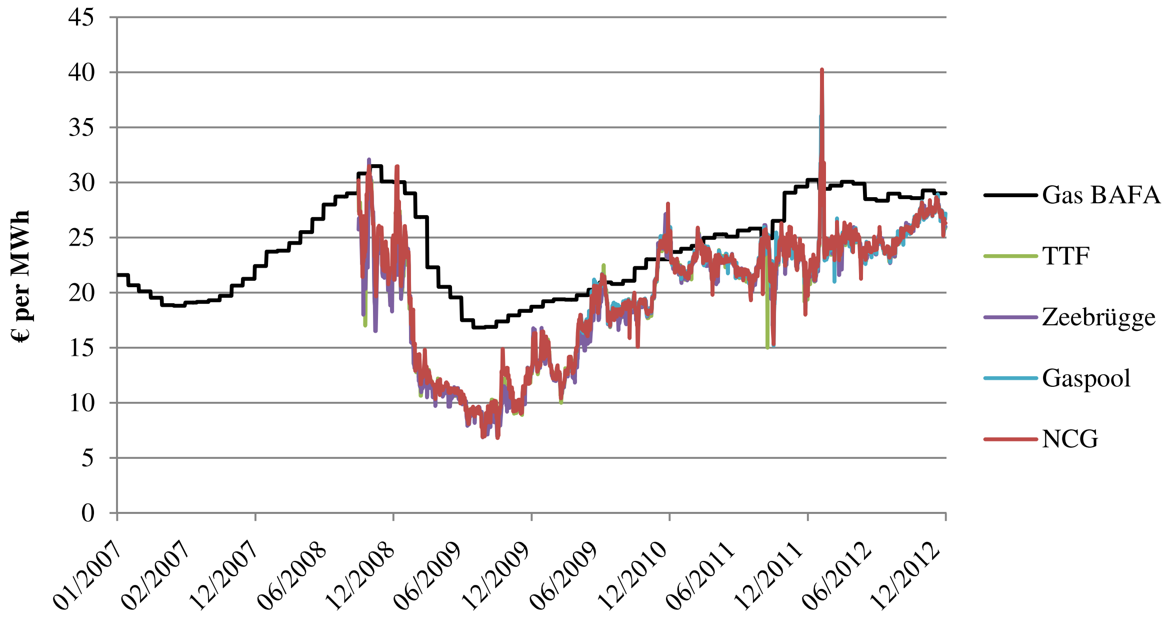

Fig. 5.1: Evolution of BAFA Gas Prices and European Gas Hub Prices 2007-2012. Source: NCG (2013) and BAFA (2013)

Another issue that has to be addressed is the extraction of shale gas which takes place on a big scale in the United States at present. Together with the evolution of LNG transportation facilities this could lead to a potential new source of supply. Figure 5.2 shows the evolution of gas prices in Japan, the U.S, in Germany and at the NBP in the UK. Around 2009 especially between Japan, Germany and the UK on the one side and the US on the other side, prices start to diverge substantially.

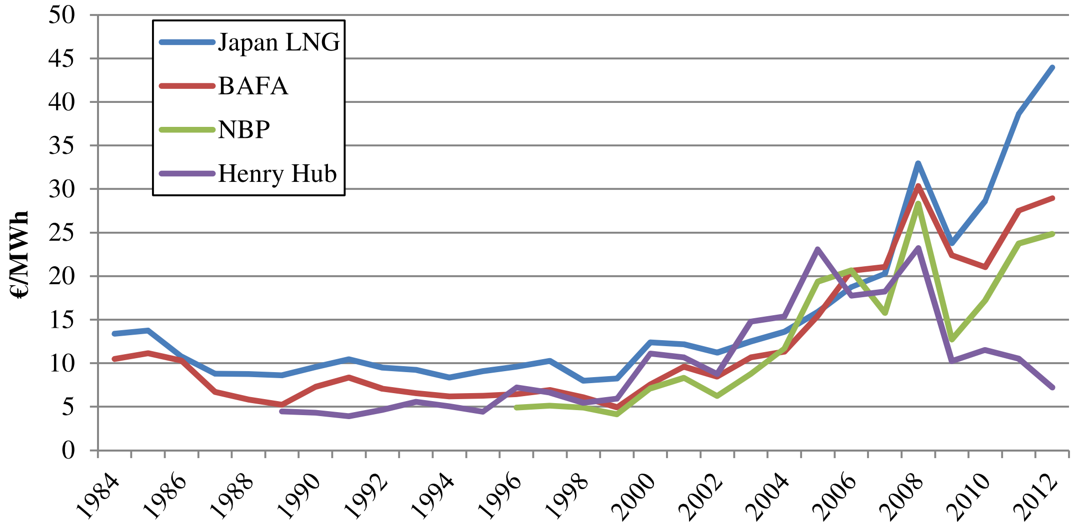

Fig. 5.2: Major Gas Reference Prices 1984-2012. Source: BP (2013)

Dehnavi et al. (2013) argue that such large differences of prices cannot prevail for a long period of time. Their calculations show that even when accounting for transport costs, arbitrage would still be possible between Japan and the US as well as between the UK and the US after 2008. In their analysis they suggest that neither investment related constraints nor contract restrictions or LNG capacity constraints can explain the huge missing arbitrage between the markets.

The base scenario, denoted by "Gas Base", is characterized by futures contracts prices for gas from the NCG hub. Information about these contracts is obtained from the homepage of the EEX exchange. Yearly futures are traded with delivery periods till the end of 2016. The prices for the years 2017 to 2019 are taken from World Bank forecasts (World Bank 2013). Table 5.1 shows the futures prices until 2016 and the prices forecasts up to 2019.

Year	NCG[1]	World Bank [2]
2014	25.56	25.93
2015	26.01	24.57
2016	25.30	24.02
2017		23.48
2018		22.93
2019		22.38

[1] Future prices in €/MWh_G
[2] Price forecasts in €/MWh_G

Table 5.1: Gas Future Contracts and Projections: Source: EEX (Assessed on 22.08.2013), World Bank (2013)

For the low price scenario ("Gas-5%") it is assumed that the shale gas, extracted in the US will be transported to Europe using the LNG technology and therefore promoting arbitrage between the two markets. This new source of supply will decrease the price at the German and Austrian hubs. In Addition to the LNG imports from the US, a transition away from long term contracts to hub-based trading takes place, enabling gas consumers to benefit from the low prices at the gas hubs.

The high price scenario ("Gas+5%") assumes that the US restricts the export of gas to keep domestic prices low. Arbitrage however, takes place between Europe and Japan, thereby increasing the gas price level in Europe. Figure 5.3 shows the three gas price scenarios.

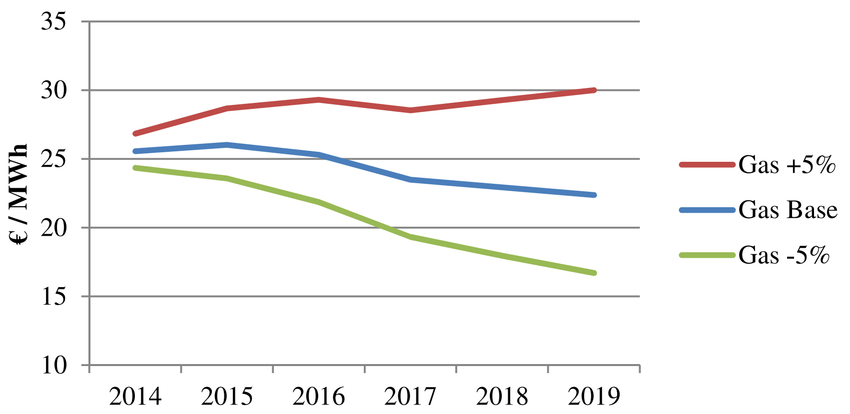

Fig. 5.3: Gas Price Scenarios

5.1.2 CO2 Allowances Prices

The market for CO2 allowances is currently characterized by low prices, compared to past levels. The base scenario is represented by futures contracts for CO2 allowances, traded on the EEX exchange. The base scenario is denoted by "CO2 Base". Opposed to the gas futures market, CO2 allowances futures are available till 2019 at the homepage of the EEX. Table 5.2 shows the futures prices until 2019.

Year	CO2 Allowances Price*
2014	4.51
2015	4.68
2016	4.89
2017	5.10
2018	5.33
2019	5.59
*in € per ton CO2	

Table 5.2: CO2 Allowances Futures till 2019. Source: EEX. Assessed on 22.08.2013

To increase prices again, there are attempts to postpone the auctioning of 900 million allowances, which should actually be auctioned during the years 2013-2015, to later years (European Commission 2013b). By increasing the scarcity in the market, allowances prices should increase in theory. However a final decision about the proposal has not been made at the time of writing this thesis. The high price scenario ("CO2+5%") assumes that the proposal will be accepted and allowances will be withheld from the market. On the other hand, the low price scenario ("CO2-5%") assumes that the proposal will be rejected and the prices will decline compared to the base scenario. Figure 5.4 show the CO2 allowance price scenarios.

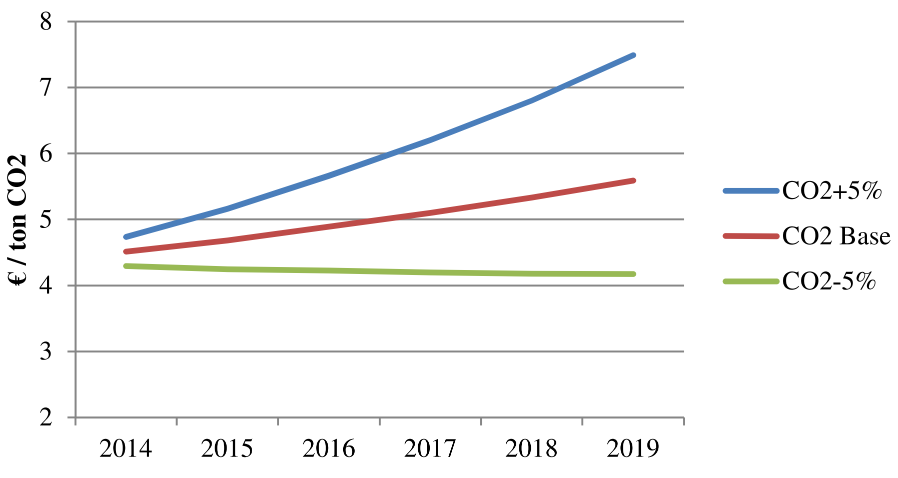

Fig. 5.4: CO2 Allowances Price Scenarios

5.2 Electricity Price Projections

This subchapter will have a closer look on the possible development of spot electricity prices. Within the projections of the input factors for the model, the electricity price forecasts are the most complicated factor among them. For the costs projections the average value over one year is applicable to be included into the profit maximization model. For electricity price projections the mean is not a good forecast to be included. It is especially important here to distinguish between the average spot price and the variance of prices. As explained before, gas-fired power plants are mostly peaking power plants. As they are mostly operated during peak hours a higher average spot electricity price does not necessarily result in higher revenues for these plants. The intuition behind this counterintuitive finding can be outlined by a simple example, where the prices of gas and CO2 allowances are assumed to be constant in all periods.

Let us have a look on a simple example in which the average electricity spot price is 45€ and the price fluctuates between 35€ and 55€. Furthermore, the trigger price for a gas-fired power plant to operate profitable is assumed to be 50€. In times of prices above 50€ the plant will be in operation, and creates revenues. As stated above there will be some points in time where the plant can and will operate profitably.
If we now consider another scenario in which the average spot price is 47.50€ and the fluctuation is in the range of 45 and 50, we see the importance of the price variance. As there are no points in time where the trigger price of 50€ is exceeded, the plant will never run and will therefore never earn revenues although the average price is higher than in the first case. This highly simplified example shows the importance of distinguishing between the development of the average electricity price and the development of the variance of spot electricity prices in the future. Due to the problems addressed above, using projections about the average electricity exchange price will not yield satisfying results of the profit maximization model for gas powered plants.

5.2.1 Average Prices

The existing literature about the impact of wind and solar energy on the average electricity prices mostly agrees that a growing share of these sources reduce the price level. Through their low marginal costs, renewable energy generation facilities replace conventional power plants with high fuels costs. This changes the merit order of the respective market. In times when the demand can be satisfied by renewable energy sources, costs will be on a low level. An increase in renewable energy capacity increases the number of hours when such situations occur and should theoretically decrease the average prices.

Sensfuß et al. (2008) analyze the merit-order effect of wind generation in Germany, which they define as the effect of renewable energy supply on prices due to the change of the merit-order. They examine electricity spot market prices and data about renewable energy supply for the years 2001 and 2004-2006. Their results suggest a reduction of the average prices due to the infeed from renewable energy sources between 1.7€/MWh_E in the year 2001 where 24.3 TWh renewable energy were supplied and 7.83€/MWh_E in 2006 where the renewable energy supply was 52.2 TWh. Traber and Kemfert (2011) use a fundamental model to analyze the impact of increased wind energy supply on the electricity spot market price in Germany. Their results also suggest a decrease of spot market prices due to a higher share of renewable energy infeed. Figure 5.5 shows the development of electricity spot prices and the share of renewable energy on the total electricity consumption in Germany for the years 2008 to 2012. For the period from 2008 to the end of 2010 there is no obvious correlation between the share of renewables and the electricity prices. Nevertheless, the strong increase of the renewable energy share in 2011 and 2012, accompanied by a steady decline of electricity prices supports the findings of Sensfuß et al. (2008) and Traber and Kemfert (2011).

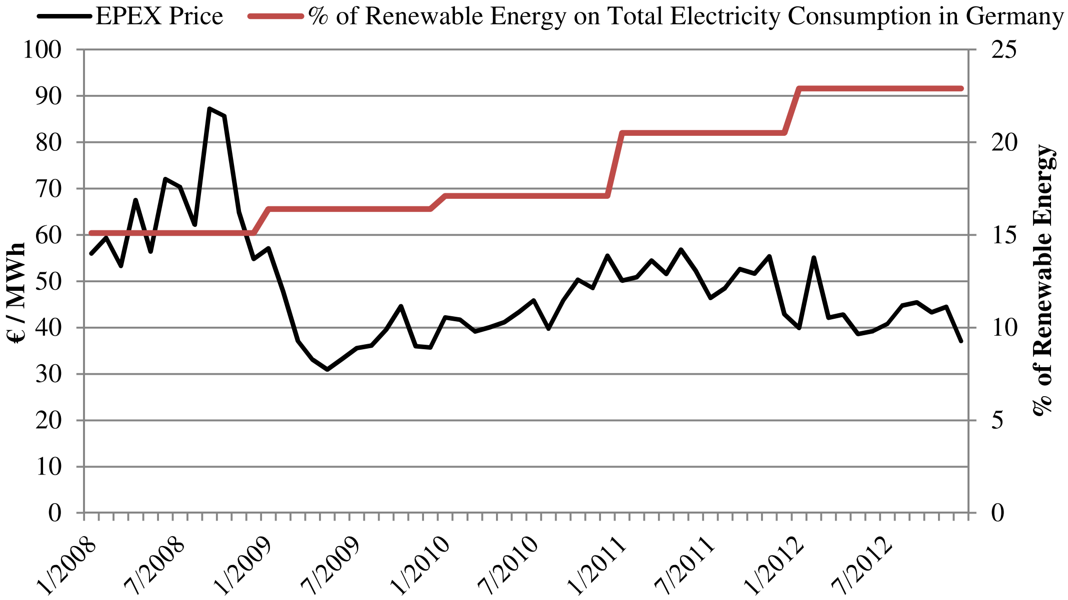

Fig. 5.5: Comparison between EPEX Prices and the Share of Renewable Infeed. Source: EEX, BMU (2013)

5.2.2 Price Volatility

Concerning the influence of a growing share of renewable energy on the price volatility of electricity spot prices, the opinions in the literature are rather divided. Whereas the majority of authors hold the view that an increasing share of renewable energy will lead to a higher volatility of prices, there are also some authors, claiming the contrary.

Graf et al. (2013) suggest that an increasing share of renewable energy has two effects on the price variance. The first effect is closely related to the shape of the supply function. In their framework they assume that the supply curve is a convex function and that renewable energy sources have lower marginal costs than conventional plants. Therefore an increasing share of renewable energy shifts the supply curve to the right. Equivalently this can also be seen as a shift of the demand curve to left, if the feed-in of renewable energy is subtracted from the actual demand. Either way, the result is that the intersection of supply and demand moves to the left. As the supply curve is assumed to be a convex function, the new intersection of supply and demand is located in a section of the supply curve where the slope is flatter than in the section it was located before. As pointed out above demand for electricity varies within days and also over the year which can be characterized by some distribution of the residual demand. This implies that the intersection of supply and demand changes constantly, causing volatility of electricity prices in the first place. In the case of more renewable energy and the intersection in the flat area of the supply curve a lower price variance should be the result.

The second effect is concerned with the distribution of the residual demand. As renewable energy generation is supply-dependent, the residual demand depends not only on demand patterns of consumers but also on the supply of renewable sources. A higher feed-in of renewable energy can therefore broaden the distribution of the residual demand and lead to a higher price variance (Graf et al. 2013).

However, there are other studies that suggest a volatility increasing effect of a higher share of renewable energy. Green and Vasilakos (2010) project that with an increase of wind generation in Great Britain the volatility of electricity prices will increase as well. Woo et al (2011) analyze the effect of an increase in wind generation on the variance and the average level of spot market prices in Texas. The study estimates a regression model on the basis of 15-min data about spot prices, wind generation output and other factors for the years 2007 to 2010. Their results suggest that wind power is indeed negatively correlated with the spot price level and positively correlated with the spot price variance.

5.2.3 Forecasting Procedures

There are several different approaches to forecast electricity prices. The choice of the approach depends mainly on the period that has to be forecasted. Feinberg and Genethliou (2005) divide forecasts in to three categories. Short-term forecasts range from one hour to one week, medium-term forecasts from one week to one year and long-term forecasts are used for periods exceeding one year.

For each purpose there are numerous forecasting methods. An extensive literature review of all these techniques is beyond the scope of this thesis. In the following subchapters a small selection of forecasting techniques will be discussed. The general structure of fundamental models and two statistical models will be outlined.

5.2.3.1 Fundamental Models

One possibility to forecast electricity prices are fundamental models. These models try to reproduce the fundamental structure of the electricity market. For this purpose production costs and constraints of generation facilities are included in the model. With this information the demand for electricity is matched with the supply to obtain equilibrium spot market prices. The scope of fundamental models depends crucially on the level of accuracy of the modeling of the generation facilities (Coulon 2009, 18).

One crucial assumption often made in fundamental models in the electricity market is that markets are characterized by perfect competition. If this is the case, a cost minimizing approach results in spot prices that would have been set by a benevolent social planer. With such models a merit order can be constructed and be matched with the current demand to obtain market prices. In order to forecast prices it is necessary to build projections about the development of the demand level as well about supply side factors. Beneath other determinants, the demand level depends crucially on weather conditions and the economic situation. If winters are especially cold or cloudy demand will be high. An economic recession on the other hand will normally lower electricity demand.

On the supply side factors, influencing the merit order have to be projected. Input prices, the structure of the energy mix but also weather conditions have to be accounted for. A growing share of renewable energy on the total electricity generation or the nuclear phase-out plans of the German government have strong impacts on the merit order and have to be taken into account when using fundamental models to project prices. Including predictions about the demand side and the supply side factors, such models can match the expected demand and supply in future hours.

In chapter 3 the difficulties of modeling power plants have been outlined. Start-up costs, changing efficiencies with regard to the generation level, and other factors have to be considered. A fundamental model, aimed at thoroughly reproduce all generating facilities, is confronted with additional challenges. One problem for fundamental models is the way how hydro storages should be treated, as they do not incur fuel costs when producing electricity but when they pump water. In this case the water can be regarded as having a value itself. (Coulon 2009, 18).

Such models can also be used to analyze if firms abuse their market power. Weigt and Hirschhausen (2008) compare their results obtained from a fundamental cost minimization model with the observed prices in the German electricity market. For the year 2006 they find that observed prices are significantly higher than their model would suggest and conclude that the market did not work perfectly competitive within this period.

5.2.3.2 Statistical Models

5.2.3.2.1 Time series analysis

The first part of this chapter gives an overview over the basic idea of times series analysis. In the second part the derivation of SARIMA models will be outlined and their applicability will be discussed.

Examples for time series data are hourly stock exchange prices, data about the yearly GDP of a country, daily weather temperature or spot prices of electricity which we will examine here. Time series are data with the special feature that for every time unit, there is only one observation, or realization available. Although many realizations could have taken place at every observed point in time, only one actually did. In this sense the sample for the stochastic process at time t only exists of one observation. In the case of temperature data for a certain area, several different temperature values could have been realized at a specific day. However, the measured temperature at this day is the only observation. In contrast to time series analysis, samples in traditional statistics normally consist of many observations of a random stochastic variable (Neusser 2011, 9).

The objective of time series analysis is therefore to set up a model that specifies the distribution of the underlying time series and to identify patterns in the data. The main idea is that the analyzed data has some internal structure like seasonal cycles or an observable trend (Feinberg and Genethliou 2005, 277). In the case of electricity spot market prices such patterns are the daily pathway of prices, shown in figure 2.2, and a typical yearly trend with higher prices in winter than in summer months. The yearly pattern is shown in figure 5.6. For the evolution of the prices over several years the situation is not as clear as for the daily or yearly pattern. Figure 5.4 shows the evolution of the EPEX Prices from 2007 to 2012. The rapid growth in 2007 and the peak in 2008 were followed by a decline of more than 50% in 2009. Since 2011 prices gradually decrease again.

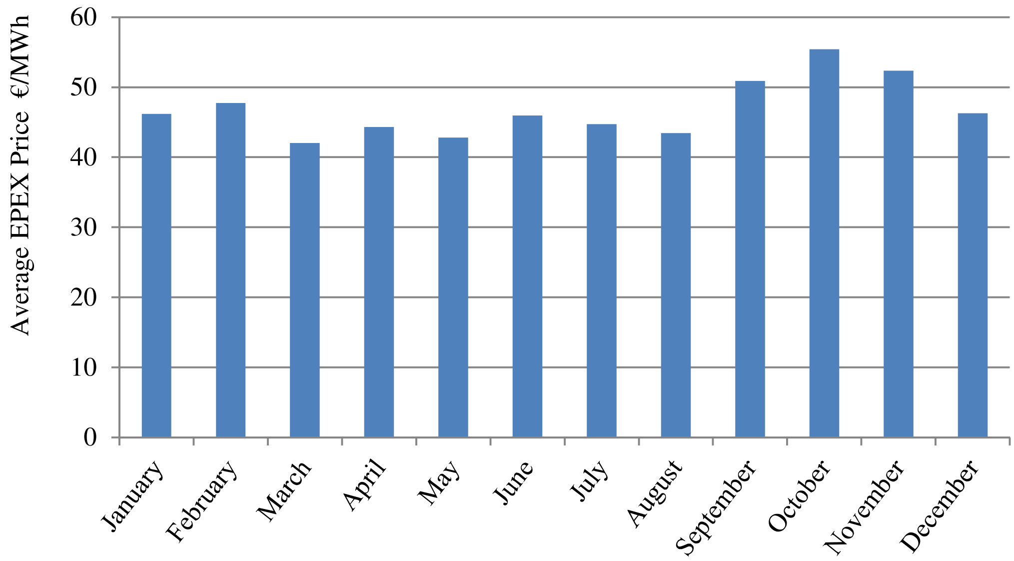

Fig. 5.6: Average Yearly Pattern of EPEX Prices. Source: EEX

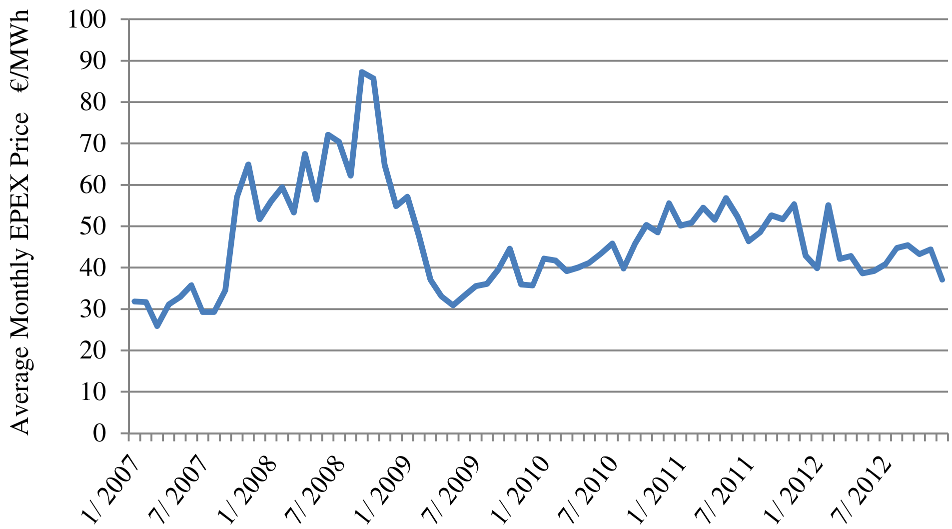

Fig. 5.7:Average Monthly EPEX Prices 2007-2012. Source: EEX

There are two major problems with time series data which lead to the concept of stationarity. First of all, time series data mostly only illustrate a limited period of the past. In our example the time series is limited to hourly data from 2007 to 2012. Secondly it is not possible to, ex post generate more observations for bygone points in time. It is therefore crucial for the analysis that patterns of the observed period do not change through time (Neusser 2011, 9). The concept of staionarity ensures that this condition is ensured. A stochastic process is called (second-order) stationary if its mean and its variance do not change through time and the autocovariance depends only on the lag k. This means that whatever period of the stochastic process is observed, the properties are identical. Let z_t be an observation at hour t of a random variable Z_t. In this case a (second-order) stationary process is characterized by:

$$\mathbb{E}\, z_t = \mu\, constant\,,$$

$$\mathbb{V}ar(z_t) < \infty\,,$$

$$Cov[z_t, z_{t+k}] = \mathbb{E}\,[(z_t - \mu)(z_{t+k} - \mu)]\,.$$

(Chatfield 2000, 34; Neusser 2011,11)

The time series data of the electricity prices clearly does not satisfy these conditions. Figure 5.6 and 5.7 show that the mean is not constant over the observed period. Such non-stationary processes can be converted into stationary processes by differentiating the series till the conditions for stationarity are satisfied.

Seasonal ARIMA model (SARIMA)

Time series forecasting is mostly used for short-term forecasting**,** ranging from one hour to one week. One example on how time series models are used to predict next-day electricity prices is given in Contreras et al. (2003). They apply a SARIMA model for the Spanish and Californian market. The average forecasting errors of their model is between 5% and 10%. Seasonal ARIMA model stands for seasonal autoregressive integrated moving average model. In this context "integrated" means that such models can be applied for non-stationary models through differentiation of the original data set.

Hyndman and Khandakar (2008) describe an automatic forecasting algorithm that has been implemented in the "forecast" package in R. The forecast package can automatically predict the parameters for of a SARIMA model. The standard notation is as follows:

$$SARIMA\,(p, d, q)(P, D, Q)_m\,.$$

The first term (p, d, q) represents the non-seasonal part while the term (P, D, Q) gives the seasonal part of the model. m represents the number of periods per season. (Hyndman and Athanasopoulos 2013, Section 8/9).
To understand the idea of SARIMA models it is necessary to first explain autoregressive models (AR) and moving average models (MA) as SARIMA models are a combination of these two.

Autoregressive model

Autoregressive models, referred to as AR(p) models, use linear combinations of the observations of the time series examined to forecast future values. Such a linear combination is given in (49):

$$z_t = \phi_1 z_{t-1} + \phi_2 z_{t-2} + \cdots + \phi_p z_{t-p} + e_t \,. \tag{49}$$

Equation (49) represents an AR(p) process, which is sum of the past p obervations, weighted with the factor ϕ_p plus a white noise process with $\mathbb{E}(e_t) = 0$ and $\mathbb{V}ar(Z_t) = \sigma_Z^2$. An AR(1) process with $\phi_1 = 1$ would then result in a random walk process where z_t is given by $z_t = z_{t-1} + e_t$ (Hyndman and Athanasopoulos 2013, Section 8/3; Chatfield 2000, 44).

This model can also be described by using a backshift notation. For this reason the backshift operator B is used. In the literature this operator is sometimes also referred to as lag operator. If B^1 is operated on z_t it shifts back the data for one period. If it is operated p times on z_t (denoted by B^p) the data is shifted back p periods. Following the backshift notation equation (49) can also be written as:

$$\left(1 - \phi_1 B^1 - \cdots - \phi_p B^p\right) z_t = e_t \,. \tag{50}$$

Moving average model

In comparison to autoregressive models a moving average model, referred to as MA(q) model, is a weighted sum of the last q weighted white noise random disturbances e_t.

$$z_t = e_t + \theta_1 e_{t-1} + \theta_2 e_{t-2} + \cdots + \theta_q e_{t-q} \,. \tag{51}$$

Using the backshift notation introduced above, the moving average model can be expressed by

$$(1 - \theta_1 B^1 + \cdots + \theta_1 B^q)\, e_t = z_t \tag{52}$$

By combining AR(p) and MA(q) models, together with differentiation of the underlying time series, non-seasonal $ARIMA\ (p, d, q)$ models can be constructed, where d represents the degree of differencing used to make the time series stationary. By capturing seasonality as well, $SARIMA\ (p, d, q)(P, D, Q)_m$ models can be created. The uppercase letters, (P, D, Q), describe the seasonal part of the model and m represents the number of periods per season. If for example quarterly data is analyzed $m = 4$. Using the backshift notation, a $SARIMA\ (p, d, q)(P, D, Q)_m$ can be written as

$$\begin{aligned}\left(1 - \phi_1 B^1 - \cdots - \phi_p B^p\right)(1 - \Phi_1 B^m - \cdots - \Phi_1 B^{Pm})(1 - B)^d (1 - B^m)^D z_t \\ = (1 + \theta_1 B^1 + \cdots + \theta_1 B^q)\left(1 + \Phi_1 B^m + \cdots + \Phi_Q B^{Qm}\right) e_t\,.\end{aligned}$$

On the left side of the equality the first term describes the non-seasonal AR(p) process and the second term the seasonal AR(p) process. The third and fourth term on the left side represent the non-seasonal and seasonal differences respectively. The terms on the right side show the non-seasonal and the seasonal moving average process.

5.2.3.2.2 Hourly Price Forward Curve Model (HPFC Model)

The second statistical approach to predict electricity prices is the HPFC model. Although it is not a statistical model in the classical sense, it uses information about the historical pattern of prices for the prediction rather than fundamental information. Therefore it is described as a statistical model here. In comparison to the already described forecasting methods, the HPFC model is the most qualified approach for the aim of this thesis. Constructing a fundamental model to forecast prices is beyond the scope of this thesis. As mentioned above, SARIMA models are only qualified for short-term predictions and are thus not used here. The advantage of the HPFC model is that it can be used for long-term forecasts and is therefore chosen.

The model described here is based on Fleten and Lemming (2003). The main idea of this approach is to use information from futures or forward contracts about prices in future periods and combine them with a bottom-up model, containing patterns of historical prices. By combining these information an hourly price forward curve (HPFC) will be constructed which gives hourly forecasts of the electricity price.

The basis of the HPFC model is the idea that future or forward contracts contain important information about average prices in the future. One difference between the two forms of contracts is that forwards are not standardized and are traded over the counter, whereas futures contracts are standardized products that are traded on exchanges. Another difference regards the payment procedure. As forwards are private trading arrangements between two parties the organization of the settlement is not standardized and may vary from contract to contract. For futures contracts however the settlement is a standardized procedure and is called clearing. The settlement is conducted by clearing houses, which act as trustees and is carried out on a daily basis.

On the homepage of the EEX data about futures for electricity is publicly available. All futures data used for the analysis in this thesis is entirely from this source. The used futures contracts are shown in the Appendix. As forward contracts are traded over the counter, data is rather scarce and is therefore neglected in the calculations.

With a future contract the buyer and the seller agree to buy or, respectively, sell a certain quantity of power over a certain period in the future (EEX 2012). In contrast to other commodities, future contracts for electric power are characterized by a delivery of a certain flow of energy over a certain period. For other commodities the delivery normally takes place only at one point in time where the total contracted volume is delivered (Fleten and Lemming 2003, 413).

The EEX offers several different contract types which differ in the length of the delivery period, the date at which the delivery period begins and hours covered per day. The available options are:

- Phelix Base Week Future
- Phelix Peak Week Future
- Phelix Base Year/Quarter/Month Future

- Phelix Peak Year/Quarter/Month Future
- Phelix Off-Peak Year/Quarter/Month Future

The delivery period is a weak, a month, a quarter or one year respectively. Base futures cover all hours of the day, while peak futures comprise only the hours from 8 a.m. to 8 p.m. from Monday to Friday and off-peak futures cover the night hours from 0 a.m. to 8 a.m. and 8 p.m. to 12 p.m. from Monday to Friday as well as the all hours of the weekend. The power volume per hour is 1 MW_E for all contract types, meaning that a base week future contract for example has a contract volume of *1 MW_E x 7 days x 24 h/day = 168* MWh_E. The price, to be paid by the buyer of the future, is denominated in € per MWh_E and is constant over the whole delivery period (EEX 2012, 5). For the HPFC model in this thesis, all contract types are considered.

Figure 5.8 shows the settlement prices of all available base future contracts from the 32[nd] week of 2013 to the end of 2019 as of the 26.07.2013. At the short end there are several overlapping contracts available. For January 2014 for example, there are 3 contracts, namely a monthly, a quarterly and a yearly future. For the long end only yearly futures are traded. Figure 5.5 shows two basic patterns. Firstly, yearly contracts do not exhibit large differences among the years. As yearly future contracts represent the expected yearly average price, a price change reflects the expectation that the overall price level will increase of decrease. Secondly, contracts with shorter delivery periods exhibit higher fluctuations among contracts of the same period type. Quarterly contracts show a clear pattern. For the last and the first quarter of the year contracts are traded with significantly higher prices than the contracts for the second and third quarter of the year, reflecting the difference in the spot price level between the summer and winter season (see Figure 5.6). For monthly and weekly contracts the fluctuation is high as well, although the underlying reasons are not as obvious as for the quarterly contracts.

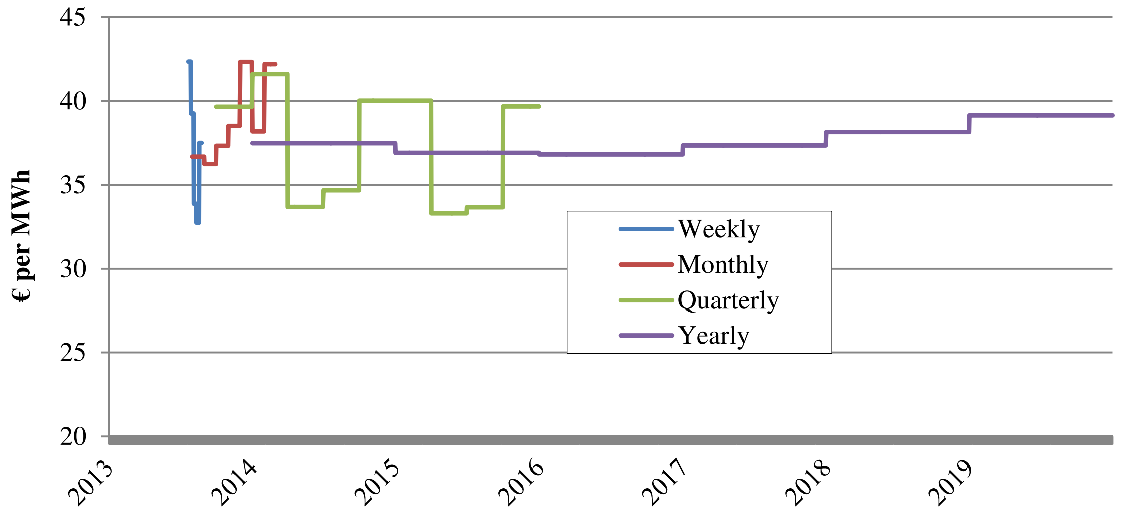

Fig. 5.8: Baseload Futures Settlement Prices. Source: EEX (Assessed on 26.07.2013)

Figure 5.9 shows futures curves for base, peak and off-peak contracts until the year 2019. Overlapping contracts within the same type of contracts (base, peak and off-peak) are not shown in this figure. In the cases where multiple contracts are available, the one with the shorter delivery period is drawn in the graph to simplify the illustration.

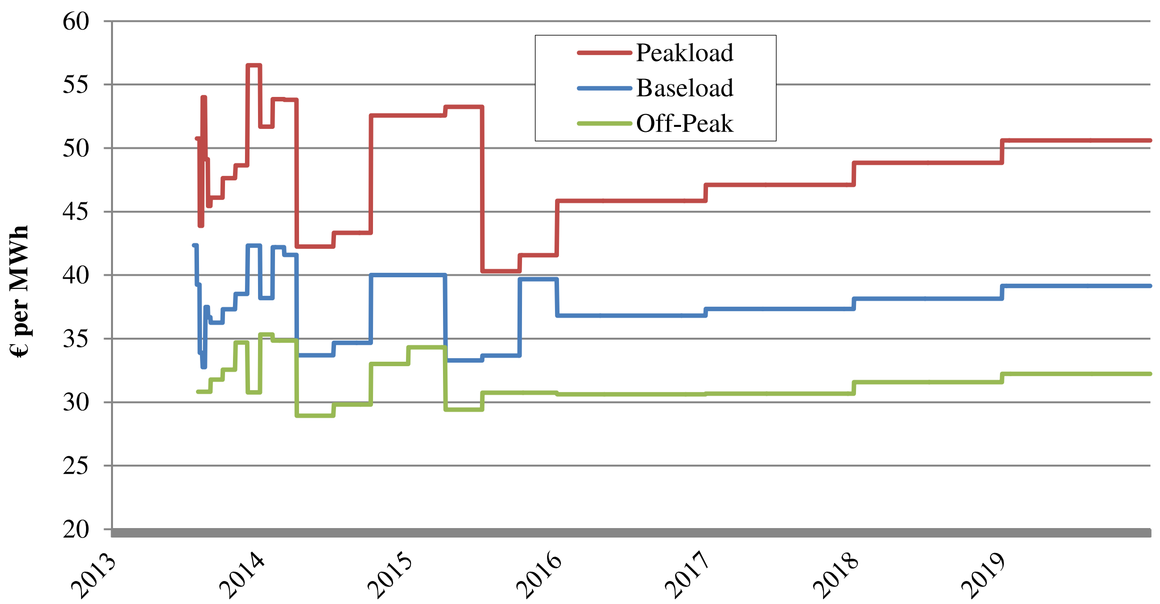

Fig. 5.9: Future Contracts Settlement Prices. Source: EEX (Assessed on 26.07.2013)

To assess the profitability of gas power plants in the future, hourly price forecasts are needed. These forecasts can then be used as input data for the profit maximization model of the plant. In a first step it is therefore necessary to analyze the relationship between future contracts and the hourly prices forecasted with the HPFC model. As the result of the forecasting procedure is a portfolio of hourly prices, it is necessary to divide every future contract into a portfolio of multiple contracts, each with a delivery period of 1 hour and 1 MWh_E. In the following ζ denotes the set of all contracts observed in the market and r denotes a specific contract out of the set ζ. The set of contracts contains of base, peak and off-peak contracts with a weekly, monthly, quarterly or yearly delivery period.

The aim of this model is to forecast hourly prices. Future contracts however have a constant price over a certain period. Therefore these contracts are split up in several hypothetical hourly contracts with price f_t. The result of the model will be a set of forecasts of hourly prices f_t.

Let T_{1r} be first hour of the delivery period of the original future contract, T_{2r} the last hour and $[T_{1r},\ T_{2r}]$ the delivery period. The price of such a contract is given by $F(T_{1r}, T_{2r})$ in € per MWh_E. The relationship between the original contract price and the hourly contracts prices is given in (53).

$$F(T_{1r}, T_{2r}) = \frac{1}{T_{2r} - T_{1r} + 1} \sum_{t=T_{1r}}^{T_{2r}} f_t\ ;\ \ \forall r \in \zeta\ . \tag{53}$$

Equation (53) shows that the average price of the hourly future contracts portfolio has to be equal to the contract price of the original future contract.

The necessary price information about the futures contracts for the construction of the HPFC are the best bid and the best ask prices. The best ask price is the lowest offer for a specific future contract of a seller which was not accepted by any buyer. The intuition behind the best ask price is that anyone who wants to buy such a specific future contract has to pay this price to get it. The second price is the best bid which is, analogously, the highest offer of a buyer to buy a specific future contract which was not accepted by any seller. The best bid and the best ask constrain the average price of the portfolio of hourly contracts. We can therefore rewrite (53) to

$$F(T_{1r}, T_{2r})_{bid} \leq \frac{1}{T_{2r} - T_{1r} + 1} \sum_{t=T_{1r}}^{T_{2r}} f_t \leq F(T_{1r}, T_{2r})_{ask} \quad \forall r \in \zeta \ , \tag{54}$$

where $F(T_1, T_2)_{bid}$ is the best bid price and $F(T_1, T_2)_{ask}$ is the best ask price of a future contract. For the model to be solvable there must not be any arbitrage opportunities among overlapping contracts (Fleten and Lemming 2013, 416).

After having discussed the relationship between the bid and ask prices of the futures contracts and the HPFC, it will now be analyzed how the price pattern over the year can be included in the model. This is especially important for the long end of the price forward curve as there are only yearly futures sold in the market with a constant delivery price throughout the year.

The seasonal variation is included into the model via a bottom-up model. For this purpose the historical average spot prices for every hour of the year are calculated and used as a prediction for the pattern of prices for future years. Let B_t be the average price at hour t considering the past years. For the calculation of the average hourly prices, B_t, electricity spot prices of the years 2007 to 2012 are used. B_t is calculated as follows:

$$B_t = \frac{\sum_{y=2007}^{2012} b_{t,y}}{Y} \quad \forall \, y \in [2007, \dots 2012], \qquad \forall \, t \in T \ , \tag{55}$$

where Y represents the number of years included for the calculation of B_t and $b_{t,y}$ is the electricity price at hour t in year y. For the calculation of B_t for leap years, non-leap years were extended for the hours of February 29, by using the average prices of the previous and the following day.

To construct the HPFC an optimization model is constructed which minimizes the difference between the bottom up forecasts B_t and the forecasted hourly prices f_t under the constraints that the average forecasted prices are in the bid/ask spread of the respective futures contracts.

$$\min \sum_{t=1}^{T} (f_t - B_t)^2 + \lambda \sum_{t=2}^{T-1} (f_{t-1} - 2f_t \; + \; f_{t+1})^2 \tag{56}$$

Subject to

$$F(T_{1r}, T_{2r})_{bid} \; \leq \frac{1}{T_{2r} - T_{1r} + 1} \sum_{t=T_{1r}}^{T_{2r}} f_t \; ; \quad \forall r \in \zeta \tag{57}$$

$$F(T_{1r}, T_{2r})_{ask} \; \geq \frac{1}{T_{2r} - T_{1r} + 1} \sum_{t=T_{1r}}^{T_{2r}} f_t \, ; \quad \forall r \in \zeta \tag{58}$$

The notation is as follows:

B_t:	bottom-up forecast for the hour t
ζ:	set of future contract products
T_{1r} :	first hour of delivery period of product r out of the set of products ζ
T_{2r} :	last hour of delivery period of product r out of the set of products ζ
$F(T_{1r}, T_{2r})_{bid}$:	bid price for product r
$F(T_{1r}, T_{2r})_{ask}$:	ask price for product r
λ :	weight on the smoothing term
f_t :	forward price prediction for the hour t,

The first term of the objective function minimizes the squared differences between the bottom-up forecast and the predicted price for the hour t. By taking squared differences the price forecasts, f_t, are fitted to the historical price pattern and are adjusted to the level of future contract prices by the constraints.

The second term is a smoothing term which is weighted by the factor λ. This term ensures that differences from one hour to the next hour are in an acceptable range. This is especially important to prevent large jumps of the prediction at the transitions from one future contract to another. Quarterly future contracts for summer months have substantially lower prices than quarterly future contracts for winter months. Peak contracts as well have substantially lower prices than off-peak contracts. Without a smoothing term there would be large price jumps between the last hour of one contract and the first hour of the next contract (Fleten and

Lemming 2003, 417). Smoothing is especially important in the context of peak and off-peak contracts. Whenever such contracts are available they are included in the model. Nevertheless the observable contracts at the EEX exchange are not arbitrage free in all cases. In such cases contracts which could be reproduced by shorter term contracts were eliminated (e.g. a quarter contract can be reproduced by the three monthly contracts). In cases in which base, peak and off-peak contracts with the same delivery period and arbitrage possibilities among them were available, the baseload contract was not considered. The reason for this is that the combination of a peak and an off-peak contract contains more information about the underlying pattern of prices than a baseload contract does.

Figure 5.10 shows the forecasted hourly prices with different smoothing factors, the quarterly base, peak and off-peak futures contract settlement prices and the bottom up forecasts (denoted by B in the figure) for the period from Saturday, 29.03.2014, to Thursday, 03.04.2014. This period is chosen as it shows the transition from the first quarter to the second quarter of 2014. For all futures contract types, the price level decreases significantly at this transition. The results for the HPFC forecasts are plotted for two different smoothing factors, namely for $\lambda = 2$ and for $\lambda = 20$.

Figure 5.10 shows the tradeoff between a high smoothing factor and a low smoothing factor. For the case with $\lambda = 20$ we see that at the transition from the 31.03.2014 to the 01.04.2014 prices do not drop as rapidly as with the case of $\lambda = 2$. As mentioned above the smoothing factor should prevent large price jumps of the HPFC forecasts. On the other hand a high smoothing factor decreases the extent to which the HPFC forecasts reproduces the pattern of the bottom up forecasts. As we see in figure 5.10 the high smoothing factor limits the development of peak hours of the HPFC forecasts, while the lower smoothing factor allows prices to reach higher levels. For the profitability of gas power plants, the occurrence of peak hours with high prices is of great importance. The HPFC forecasts, used as input for the profitability forecasts, are therefore calculated with the smoothing factor $\lambda = 2$.

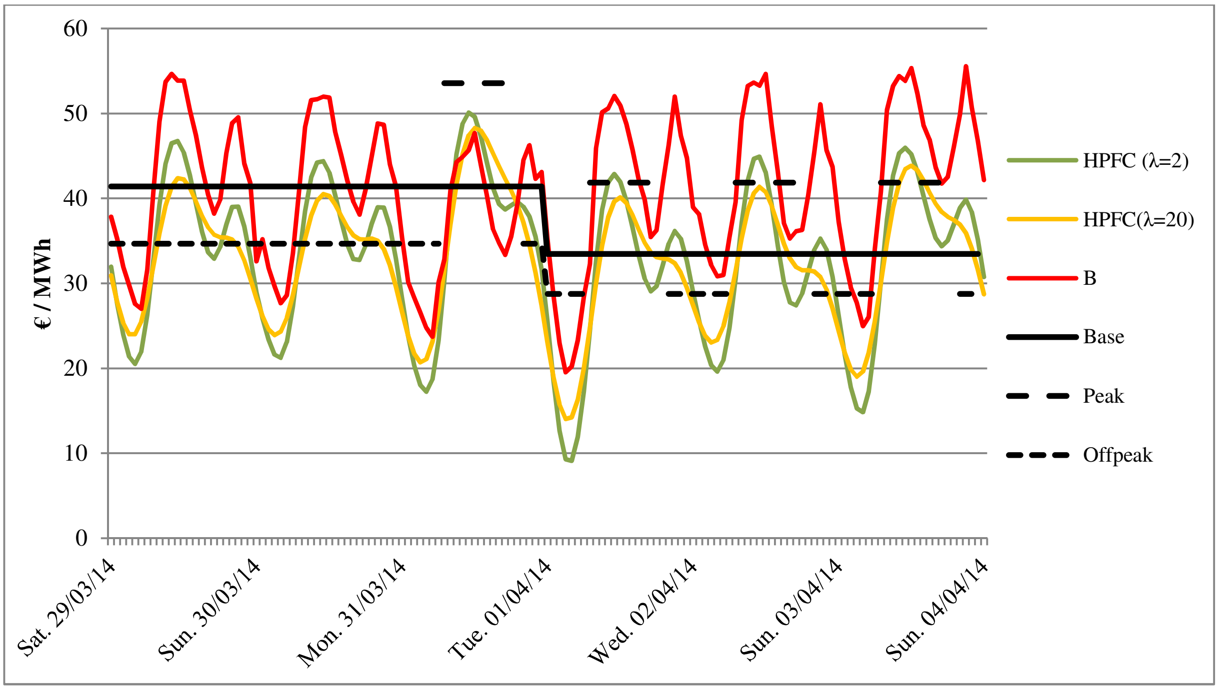

Fig. 5.10: HPFC Forecasts and Futures Contracts

Electricity Price Scenarios

Opposed to the scenarios for gas and CO2 allowances prices, which are characterized by a single price valid for each hour of the respective year, the electricity price scenarios are given by the fluctuating HPFC forecasts. These forecasts are built, using the model by Fleten and Lemming (2003) described above. Although the HPFC prices vary throughout the year, the average price per year is determined by the available futures contract prices. The calculation of the high and low price scenarios is equivalent to the scenarios for the gas prices and CO2 allowances prices.

<u>Base scenario:</u>

The base scenario uses futures contracts prices for electricity, obtained from the EEX platform at the 26.07.2013. The basic idea is that these future contracts represent the expectations of participants about future price. This scenario will be denoted by “EPEX Base”.

High Price Scenario

Different fundamental changes in the industry could lead to higher electricity prices in future years. One possible reason for an increase of electricity price could be a change in the structure of the conventional power plant complex accompanied by a change of the merit order. Figure 2.1 shows that on the left side of the merit order nuclear plants are ranked. They are characterized by low marginal costs and normally generate electricity in almost all hours of the year. In Germany concerns about the security of nuclear power plants gave rise to debates about the future of such plants. In consequence, the German government decided to phase out all nuclear power plants gradually until the end of 2022. The phase out of nuclear power plants will, ceteris paribus, shifts the merit order to the left. In this new situation, prices should be higher in theory as plants with higher marginal costs would have to satisfy the demand.

Another possible explanation for higher electricity prices is concerned with the cost factors of conventional power plants. An increase in fuel costs or CO2 allowances prices for conventional power plants leads to higher marginal costs and could increase electricity prices as well. The high price scenario is denoted by “EPEX+5%”.

Low Price Scenarios

For this scenario it is assumed that through a growing supply of renewable energy, electricity prices decrease more than expected by the buyers of future contracts. In addition a positive implementation and execution of the energy efficiency directive of the European Commission is anticipated. The aim of this directive is to improve the energy efficiency in order to reduce the consumption of primary energy by 20% until 2020 compared to projections for the year 2020 without any reduction measures (European Commission 2012). Such a decrease in demand should, ceteris paribus, shift the intersection of the residual demand and the merit order curve to the left, accompanied by a lower electricity price. Furthermore it is assumed that the reduction in generating capacity due to the nuclear phase-out in Germany is completely offset by new thermal power plants. As these plants have higher marginal costs than nuclear power plants the merit order changes as well. The effect of this substitution should increase spot prices. It is therefore assumed that through the growing supply of renewable energy sources, the hours in which these thermal power plants operate is reduced sufficiently to offset the price increasing effect of the substitution. The low price scenario is denoted by “Price–5%“.

Figure 5.11 shows the three scenarios for the electricity spot prices. Note that due to graphical reasons, the electricity prices in figure 5.11 are average values of the spot prices. The HPFC forecasts used for the calculations fluctuate as shown in figure 5.10.

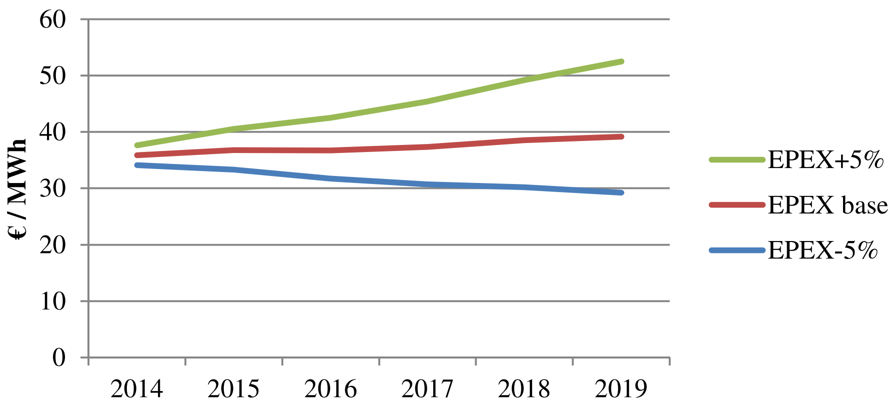

Fig. 5.11: Electricity Price Scenarios

5.3 Forecasted Profitability Results

With the scenarios developed in the previous subchapters, the projected profitability of the gas power plant in Mellach is calculated for the years 2014 to 2019, using the profit maximization model described in chapter 3. Note that the results are given for the entire power plant and not for a single turbine. For each year the projected profitability for all combinations of the scenario are determined. The results of the calculations as well as a graphical illustration of the underlying scenarios are shown in table 5.3.

We see that from 2014 to 2015 the plant incurs losses in all possible combinations of the scenarios. In these years the plant cannot even cover its fixed costs. In 2016 the situation improves. For the low gas price scenario together with the base and high electricity price scenario the plant makes profits.

Considering the high electricity price scenario for the years 2018 and 2019 the plant works profitable even for the worst cases regarding the CO2 allowances and gas costs. For the year 2019 profits for the best case (EPEX+5%, CO2-5% and Gas-5%) are approximately equal to the calculated profits for the year 2008 shown in table 4.1 and table 4.2.

		2014			2015			2016		
		EPEX-5%	EPEX Base	EPEX+5%	EPEX-5%	EPEX Base	EPEX+5%	EPEX-5%	EPEX Base	EPEX+5%
Gas+5%	CO2+5%	-11,649,762	-10,474,821	-8,588,471	-12,148,468	-11,166,681	-6,598,443	-12,148,468	-11,170,476	-5,416,135
	CO2 Base	-11,624,312	-10,442,201	-8,524,148	-12,148,468	-11,091,174	-6,450,747	-12,148,468	-11,088,013	-5,137,322
	CO2–5%	-11,600,075	-10,410,970	-8,462,760	-12,148,468	-11,019,890	-6,315,994	-12,148,468	-11,015,911	-4,888,268
Gas Base	CO2+5%	-10,770,983	-9,141,378	-6,366,712	-11,742,501	-7,937,099	-533,814	-11,776,310	-7,611,299	5,366,072
	CO2 Base	-10,738,673	-9,090,068	-6,286,547	-11,685,651	-7,796,571	-262,422	-11,709,410	-7,404,194	5,935,979
	CO2–5%	-10,708,101	-9,041,173	-6,210,024	-11,624,611	-7,668,186	-11,799	-11,649,047	-7,212,606	6,434,389
Gas–5%	CO2+5%	-9,623,602	-7,159,549	-3,534,720	-9,115,567	-2,949,791	7,911,653	-9,185,192	511,070	22,029,545
	CO2 Base	-9,574,266	-7,080,196	-3,428,586	-8,987,166	-2,712,593	8,270,758	-9,029,297	977,791	22,870,565
	CO2–5%	-9,526,957	-7,004,529	-3,325,994	-8,865,531	-2,495,099	8,598,233	-8,891,738	1,386,772	23,631,136
		2017			2018			2019		
		EPEX-5%	EPEX Base	EPEX+5%	EPEX-5%	EPEX Base	EPEX+5%	EPEX-5%	EPEX Base	EPEX+5%
Gas+5%	CO2+5%	-12,148,468	-10,303,941	2,408,451	-12,148,468	-10,260,543	9,443,070	-12,148,468	-10,137,515	19,101,672
	CO2 Base	-12,148,468	-10,149,918	3,022,474	-12,148,468	-10,052,362	10,556,083	-12,148,468	-9,890,444	20,747,747
	CO2–5%	-12,148,468	-10,018,094	3,538,959	-12,148,468	-9,883,817	11,444,104	-12,148,468	-9,688,095	22,015,712
Gas Base	CO2+5%	-11,385,746	-2,905,460	25,122,883	-11,593,048	406,536	45,616,085	-11,685,578	5,025,628	69,677,767
	CO2 Base	-11,256,597	-2,376,396	26,373,816	-11,430,830	1,269,605	47,719,898	-11,490,056	6,464,979	72,660,093
	CO2–5%	-11,147,698	-1,927,233	27,418,347	-11,290,647	1,967,486	49,389,810	-11,330,920	7,576,561	74,918,728
Gas–5%	CO2+5%	-6,741,629	13,454,108	55,811,497	-5,605,701	25,268,933	89,759,083	-4,133,107	38,842,488	124,786,028
	CO2 Base	-6,320,508	14,559,754	57,549,644	-4,906,072	27,240,988	92,553,223	-3,094,602	41,712,025	128,680,795
	CO2–5%	-5,963,805	15,485,948	58,992,525	-4,336,802	28,831,918	94,765,030	-2,267,288	43,900,073	131,610,205

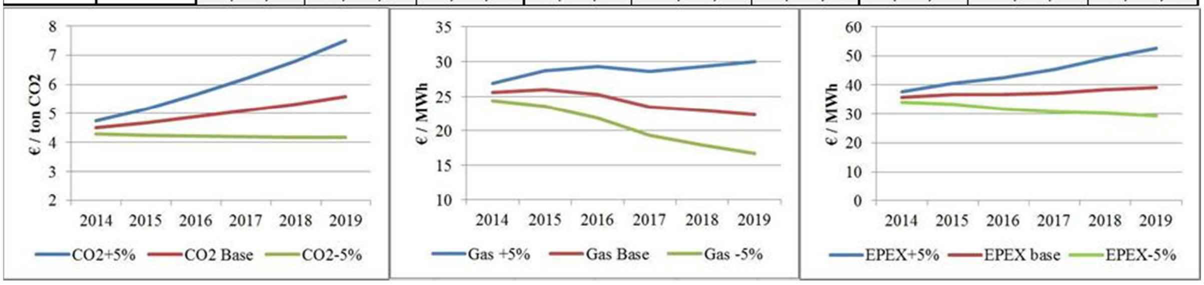

Table 5.3: Projected Profits in of the power plant Mellach for the Years 2013-2019. (€ per year)

Although the situation seems to improve in the end of the decade, profits are still low compared to 2008 for most combinations of the scenarios. Another crucial finding is that considering the base scenarios of input prices as well as the electricity price scenario, the plant makes losses for each year until 2017 and small profits in 2018 and 2019. However, the profits made in 2018 and 2019 do not even cover the depreciation of the plant for one year. This is a rather pessimistic result for gas plant operators as it suggests that with the expectations contained in futures contract prices and projections from the World Bank, gas power plants will make losses until the end of the decade.

5.4 Capacity Markets – A Possible Solution?

The previous chapter showed that prospects look rather pessimistic for gas power plants for the period until 2019. If electricity prices evolve as suggested by the futures market gas prices have to decrease substantially in order for gas power plants to operate profitable. As mentioned above gas power plants are well suited to complement the steadily growing share of renewable energy due to their relatively low investment costs, CO2 emissions and start-up costs. However generators will be reluctant to invest in new gas power plants if prospects do not improve. Furthermore already built gas power plants could be phased out by generators. Keep in mind that when accounting for depreciation as well losses in the year 2012 were around € 20 million in the calculations for the power plant in Mellach.

One possibility to encourage investment in new generating capacity is the introduction of capacity markets. Arguments in favor of such markets are mostly concerned with supply security issues. This aspect was not treated in this thesis. Nevertheless capacity markets could be a possible solution for the problems outlined in the last chapter. The basic idea of capacity markets is to assign a market value for the security of supply and create a market that allows power plant owners to sell their generating capacity in response for a certain payment. In return they have to supply electricity on the market whenever scarcity hours occur and the capacities are needed. This creates a new source of income to generators owning conventional power plants (Tietjen 2012).

There are several different approaches on how to design such capacity markets. On the one hand, capacity markets can be organized by a price based mechanism. In Spain such a price based mechanism is in place, called pagos por capacidad. With this mechanism the regulator determines the required amount of capacity. The regulator then offers fixed payments for newly built or, environmentally, upgraded power plants for a period of 10 years. If requirements for new capacities are high, payments are high as well, whereas payments decrease if demand for new capacity is low (Süßenbacher et al. 2011). Through the payments, the regulator determines the amount of built capacity in this mechanism.

On the other hand capacity markets can be organized in a way in which the regulator does not set the prices for the required capacity but the amount of capacity that retailers and generators need to have available. Retailers and generators need to be able to serve the demand of their customers at every point in time. They can build their own capacity or buy the respective amount on exchanges. Such a mechanism is used in the market for the US states Pennsylvania, New Jersey and Maryland at the east cost of the US for example (Süßenbacher et al. 2011).

Each of the mechanisms provides additional income sources for owners of conventional plants. Moreover predictability of revenues is enhanced as well. This could help to improve the future profitability of conventional, and especially gas power plants. However capacity markets are severe intervention into the market. Regulatory imperfections, as well as the influence of interest groups can result in bad economically and socially imperfect outcomes.

6 Conclusion

The aim of this thesis was to assess the situation of gas power plants in Austria and Germany. The basis for the analysis is the case study of the Mellach power plant. By considering the specifications of this gas power plant the development of the profitability for such plants was examined. Chapter two gave a general description of the electricity market. The market organization, the participants and some special features of the electricity market were discussed.

The third chapter builds the core of the thesis. It describes the profit maximization model with which the analysis of the profitability is carried out. For this purpose a unit commitment model for the Mellach power plant was set up. The relevant cost factors, such as gas, CO2 allowances, grid-use, start-up and O&M costs, as well as the efficiency curve and the constraints regarding the capacity were described. The third part of the chapter set up the profit maximization model.

Using the results of the profit maximization model for historical year from 2008 to 2012, chapter four shows how the profitability of gas power plants has evolved over this period. The results suggest that at the time of the investment decision in 2008 the outlook as well as the prevalent business environment was promising, allowing gas power plant owners to make substantial profits. After 2009 however, electricity prices did not develop as suggested by future contracts traded in 2008. Electricity prices decreased, while gas prices increased steadily. The result of these developments was a substantial decrease of profits until 2012. Beginning at a level of over 100 million € in 2008, profits declined over time, and ended up to be close to zero in the year 2012.

In chapter 5 the future outlook of gas power plants was addressed. In the first part of the chapter scenarios for the cost factors were developed. The second part gave an overview over forecasting procedures for electricity prices. In this context, fundamental and statistical models were discussed and electricity price forecasts conducted.

With data about future contracts till the year 2019 hourly prices were forecasted, using the HPFC model described by Fleten and Lemming (2003). With the hourly forecasts, projections about the profitability were developed by considering all possible combinations of the scenarios about gas, CO_2 allowances and electricity prices. The results suggest that only if electricity prices rise substantially gas power plants are able to run operate profitable in the future. One possible solution to increase investment in new gas power plants and keep already built plants in operation could be the creation of a capacity market. This would give gas power plants the chance to generate additional revenues. However the design of the capacity market is vulnerable to create oversupply and lead to economically wrong incentives.

Appendix

		Base	Peak	Offpeak			Base	Peak	Offpeak
Weekly	KW32	33,75	44,50		Quarterly	4/13	39,35	51,95	32,50
		32,50	42,00				39,20	51,90	32,00
	KW33	33,00	41,50			1/14	41,45	53,90	34,95
		32,00	39,00				41,35	53,25	34,40
	KW34	38,05	50,50			2/14	33,60	42,40	29,25
		36,75	47,50				33,30	41,30	28,25
	Aug 13	35,80	45,90	30,85		3/14	34,75	43,55	30,10
		35,55	45,30	29,85			34,40	42,60	29,10
Monthly	Sep 13	37,00	47,20	31,85		4/14	40,00	52,85	33,65
		36,70	46,90	30,85			39,65	51,90	31,65
	Oct 14	38,25	48,35	32,85		1/15	41,50	54,75	
		38,00	48,20	31,35			40,60	51,75	
	Nov 14	43,25	56,20	35,40		2/15	34,30	41,80	
		42,10	54,85	33,40			32,30	38,80	
	Dec 14	38,15	51,50	31,10	Yearly	2014	37,39	48.00	
		37,00	51,35	29,10			37,25	47.65	
	Jan 14	43,20	55,35			2015	36,75	46.40	
		41,20	52,35				36,65	45.85	
						2016	36,70	45.95	
							36,60	45.25	
						2017	37,35		
							37,25		
						2018	38,55		
							38,30		
						2019	39,15		

Table 0.1: Futures Contracts (as of 26.07.2013). Source: EEX

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Abstract

The aim of this thesis is the analysis of the profitability of gas power plants in Germany and Austria. The basis for the analysis is the case study of the Mellach power plant. In 2008 the responsible committees of the Verbund AG and its subsidiary, the VERBUND-Austrian Thermal Power GmbH, have authorized the construction of the Mellach gas power plant. Only two years after it started operation in 2011 the current situation and the economic outlook for the plant are devastating. The company publicly declared that it considers shutting down the plant. The case of Mellach is exemplary for the problems, gas power plant owners are currently facing.

In many European countries, governments have set up regulatory frameworks to promote renewable energy. While the instruments vary throughout countries, they all have the same goal: An increase in the share of energy supplied by renewable sources. Gas power plants combine certain features which make them a well suited technology to complement renewable energy sources. Fast start-up times and relatively low CO2 emissions make gas power plants superior to most other conventional energy sources.

The basis of the analysis of the profitability is a fundamental profit maximization model for the exemplary power plant in Mellach. The model solves the unit commitment problem for the plant using a mixed integer linear programming approach. Cost factors like gas and CO2 allowances prices, electricity prices as well as technical constraints of the power plant are included in the model as well.

With the profit maximization model, the historical development of the profits as well as future prospects of the profitability are calculated. In order to obtain results for future periods, scenarios about gas, CO2 and electricity prices are determined. The thesis gives an overview over fundamental and statistical forecasting procedures for electricity prices. Using an hourly price forward curve model, electricity prices are forecasted until 2019. These forecasts are used to construct scenarios for electricity prices. Together with the scenarios for the cost factors prospects about the profitability of gas power plants are analyzed.

The results suggest that the situation for gas power plants was good at the time of the investment decision for the construction of the gas power plant in Mellach. However, profits decrease substantially till the year 2012. The future prospects are pessimistic as well. If input

costs and electricity prices take the path, suggested by the most likely scenarios, power plants will not generate revenues large enough to cover all costs. Only a strong increase in electricity prices or a substantial decrease in gas prices could make gas power plants profitable in the future.

Abstract - German

Ziel der vorliegenden Arbeit ist die Untersuchung der Profitabilität von Gaskraftwerken in Österreich und Deutschland sowohl in der Vergangenheit als auch in zukünftigen Jahren. Durch die Energiewende wächst der Anteil erneuerbarer Energien an der Stromerzeugung von Jahr zu Jahr. Zusammen mit dem Atomausstieg verändert diese Entwicklung die Energieerzeugungsstruktur grundlegend. Ein größerer Anteil dargebotsabhängiger erneuerbarer Energien wie Wind- oder Sonnenenergie bringt neue Herausforderungen mit sich. Ausgangspunkt der Arbeit ist die Annahme, dass Gaskraftwerke diesen Herausforderungen besser gewachsen sind als andere Energieerzeugungstechniken. Durch einen, relativ zu anderen fossilen Energieträgern, niedrigen CO2 Ausstoß, niedrige Investitionskosten sowie die Möglichkeit schneller Anfahrvorgänge sind Gaskraftwerke eine sehr gute Ergänzung der erneuerbaren Energien. Jedoch lässt das aktuelle wirtschaftliche Umfeld keinen profitablen Betrieb dieser Kraftwerke zu.

Als aktuelles Beispiel wird die Entwicklung der Profitabilität des Gas- und Dampfkraftwerkes in Mellach untersucht. Die VERBUND-Austrian Thermal Power GmbH traf im Jahr 2008 die Investitionsentscheidung für dieses Kraftwerk. Nach der Fertigstellung im Jahr 2011 und nur 2 Jahren Betrieb sind die Zukunftsaussichten derart schlecht, dass die Verbund AG öffentlich über eine Schließung nachdenkt. In dieser Arbeit werden die Entwicklungen des wirtschaftlichen Umfelds die zu dieser Situation geführt haben untersucht. Des weiteren wird anhand von Szenarien über die Entwicklung der Kostenfaktoren sowohl als auch der Elektrizitätspreise ein Ausblick auf die zukünftigen Profitabilitätschancen für Gaskraftwerke gegeben.

Die Basis der Analyse bildet ein gemischt ganzzahliges Optimierungsmodell, welches einen optimalen Kraftwerkseinsatzplan für das Gaskraftwerk in Mellach errechnet. Die Ergebnisse des Models zeigen deutlich, dass zum Zeitpunkt der Investitionsentscheidung im Jahr 2008 die Profitabilität von Gaskraftwerke auf einem hohen Niveau war. Bis zum Jahr 2012 verschlechterte sich die Situation jedoch zunehmend, so dass viele Gaskraftwerkseigentümer heute einen profitablen Betrieb in Frage stellen. Anhand der erstellten Szenarien wird des weiteren die Entwicklung bis zum Jahr 2019 untersucht. Hier zeigt sich deutlich, dass nur bei einem starken Anstieg der Elektrizitätspreise oder einem stark verringerten Gaspreis Gewinne erzielt werden können.

CURRICULUM VITAE

NAME	**MORITZ HERRMANN**

AUSBILDUNG

seit 10/2010	STUDIUM DER BETRIEBSWIRTSCHAFTSLEHRE AN DER UNIVERSITÄT WIEN
10/2007 – 08/2010	STUDIUM DER VOLKSWIRTSCHAFTSLEHRE AN DER UNIVERSITÄT WIEN
09/1997 – 06/2006	EV. FIRSTWALD-GYMNASIUM MÖSSINGEN Abschluss: Allgemeine Hochschulreife
09/1993 – 07/1997	GRUNDSCHULE BODELSHAUSEN