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To what extent do spot and forward natural gas and coal prices explain the month-ahead forward electricity price in the PHELIX market?

How forward electricity prices are formed and how Renewable Energy Sources alter price formation.

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Abstract

This thesis aims to address the effect of spot and future natural gas and coal prices on the forward price of electricity. The analysis concerns the PHELIX forward market between June 2011 and March 2016, regarding the main power exchange in Germany, Austria and Luxembourg, the NCG natural gas hub and coal market at Richards Bay, South Africa. We find forward natural gas prices to strongly positively influence the forward electricity price with a negative quadratic term, attributable to switching to marginally less expensive plants. Interestingly, the influence of forward gas prices on forward power prices disappears from June 2014 to March 2016, as a result of the *Energiewende*. Spot coal prices rather than forward coal prices affect power prices in a positive way, attributed to a delay between delivery and use of coal. The increasingly fluctuating behavior of the merit order curve could also explain the absence of a type of power plants in explaining forward power prices, since they might never be the last plant on the merit order curve. Furthermore, historical averages of the number of sunshine hours strongly negatively affects the forward power prices via decreasing industrial and consumer demand and increasing photovoltaic feed-in supply. Ultimately, no conclusion about the validity of a no-arbitrage equation between current spot and forward power prices could be drawn, although it might become decreasingly valid on the rise of Renewable Energy Sources.

Contents

1 Introduction

Two developments affected electricity markets significantly in recent years: the liberalization of energy markets and the rapid rise of Renewable Energy Sources (RES). The former gave rise to the abolition of cost-based price regulation and purely financial markets trading long-term contracts coupled to the spot price of electricity, which allowed producers and consumers to hedge against risks of fluctuating prices. The latter affects the decisions of the supply side of electricity prices, since RESs possess the property of being very volatile in supply and total non-storability. There is neither a storable commodity or a way to efficiently store electricity for most renewables, whereas most conventional power is generated by a depletable (non-renewable) natural commodity that can be stored and hence allows for electricity production to be postponed [Redl et al., 2009, Marchenko, 2007]. The rapid increase in the generation capacity of renewables (mostly solar power, wind power, and power from biomass) in Germany is referred to as the *Energiewende*.

When a producer decides to postpone electricity production, the surplus of electricity to be produced at a later instance can be sold directly in a forward market. Moreover, the producer can also decide to sell the electricity at a later time on a spot market, which has a short time-to-delivery. The wedge between the expected spot price and the future price, both referring to delivery after a period of length T could be explained by a risk premium, see section [2.2]. Moreover, a model including storage costs and storage benefits (the convenience yield) could explain the wedge between future contract prices and the current spot price, see section [2.2]. The decision to produce when and to sell in which market depends on the considerations of the electricity producers.

For many RESs (such as wind and solar) there is no (efficient) facility for postponing power production and expected future conditions have to be really extreme to make power storage profitable. Therefore, pricing models concerning storage costs generally do not apply to a power market dominated by these power generators. However, the commodities for hydro-power and biomass can be stored by allowing the water level to increase and to store organic material, respectively.

In classical power markets, dominated by thermal energy (mostly by nuclear fission, gas turbines, lignite and hard coal plants), one expects storage costs to cause forward prices to exceed spot prices when storage is, since high storage costs decreases the willingness to postpone production. If the capacity of storage are low and costs are high, this might not be valid. For thermal electricity sources, the marginal cost of electricity production is primarily determined by the cost of the fuels used and the price of emission allowances [Redl et al., 2009]. For forward power prices, it can be also argued that current commodity prices could affect this relation, when storage is possible and producers make production decisions about various time periods before the forward delivery period.

The main subject to be covered in this thesis is how month-ahead forward prices of electricity can be explained from prices in the underlying commodities and whether spot or forward prices explain forward power prices. This thesis contributes to existing literature on price formation in forward power markets by extending the analysis to the month ahead regime, which is more susceptible to short term supply and demand shocks. Furthermore, the analysis of the aforementioned no-arbitrage relation between forward and current spot prices is extended to a market area lacking large scale hydropower storage. Ultimately, the current and future impact of the *Energiewende* on the merit order and price formation is strongly emphasized.

The lack of efficient storage possibilities makes it hard to postpone production, leading to the hypothesis forward prices of power are most affected by forward power prices of coal and natural gas. Moreover, since producers mind the opportunity (economic) cost of the materials used and not the purchasing cost, we expect current prices of energy generating commodities not to affect future electricity prices. If agents are forming rational expectations, one would expect the future electricity price not to affect the future price. Moreover, the cost of forward emission allowance contracts also contributes to the expected future marginal costs of thermal power production and is hence expected to affect. Due to the short time to delivery, also anticipated demand and supply shocks are expected to affect forward spot price formation via the expected future spot price.

Essential to forward contracts are the way forward prices are formed and how supply decisions, the possibility of energy carrier storage and expected future spot prices affect forward price formation. Chapter 2 will deal with the theory of forward price formation and expected spot price formation, the supply curve for power and producer considerations. Chapter 3 will discuss the methods employed to research the variables their influence on forward prices. Chapter 4 will introduce the data used to employ these methods and chapter 5 will state the results found. Finally, chapter 6 concludes, compares to literature, provides methodological improvements.

2 Theory

2.1 Power markets

Power markets can be subdivided in two major vertically integrated markets. The first is the wholesale market, on which producers trade energy with resellers, often referred to as Distribution System Operators (DSO's). The second market is the retail market, where DSOs sell power contracts to households and industries, mostly for constant prices for longer periods [Bundesnetzagentur, 2015]. Another important party in trading power is the Transmission System Operator (TSO), which accommodates the transport of power and monitors that there always is a balance between supply and demand and to prevent power lines to get overloaded.

Within the wholesale power markets, multiple contracts for power are quoted, referring to different times-to-delivery of energy. The price for delivery of electricity at a particular future time period agreed upon beforehand is usually referred to as the future or forward price. Generally, the future contracts are not referring to physical delivery, but are solely financial contracts. The combination of holding on to a purely financial future obligation to sell and selling physically on the spot market ensures a price for physical future delivery to producers. Hence, such a combination has identical payoff in both the commodity as in cash compared to a physical future contract. The spot price for short term delivery is usually significantly affected by physical constraints. This is one of the reasons the day ahead price instead of the intraday price is understood as the spot price at European energy exchanges and academic literature [Botterud et al., 2010]. The forward contracts are characterized by different delivery period durations (weeks, months, years) and different times-to-delivery (weeks to years). These contracts are quoted for delivery over a particular period with a flat load profile, which means that the total power delivered is constant over the delivery period.

Electricity spot prices are very volatile which is a risk to producers and users of electricity. Electricity markets have unique properties such as non-storability, uncertain and inelastic short run demand and a steep supply function [Deng and Oren, 2006]. Producers and (industrial) users can hedge the price risk by ensuring themselves of a reasonable price and hence avoid financial distress by involving in a forward conract.

In understanding the future and forward markets it is important to understand the difference between future and forward contracts in the field of finance [Hillier et al., 2012, Botterud et al., 2010]. Forward contracts include the financial obligation of the holder to purchase a particular commodity after a period T, where the initial time is t. The difference between the future price and reference spot price is the only cash flow and occurs after a period T over the period of delivery. In future contracts, a contract exists of N periods and in every period the difference between the current and the previous period is paid from the contract seller to the contract buyer. If the difference is negative, cash flows go the other way. This process is referred to as marking-to-market. The advantage of these schemes is that since small amounts are involved, the sudden burden on liquidity is generally limited. On the other hand, forward contracts do not require liquidity until the time of delivery. In this article, these two are both included in the term "forward contracts", since the agreement price of these two are the same when interest rates are constant [Hull, 2006].

However, not all power is traded in official exchanges. Bilateral Over-The-Counter (OTC) contracts are rather common [Hildmann et al., 2015] and future contracts can be stated over every period possible with any load profile possible, instead of pre-specified contracts with limited contract conditions. A disadvantage of OTC markets is that contract have to be settled with a single counter-party, which could be troublesome if the counter-party ends up in insolvency.

Sometimes no single forward contract of a kind is traded. However, the exchanges still quote a price, which is referred to as the settlement price. The settlement price is the best guess the exchange house makes based on the last trades and the level of the spot price. This is an acknowledged figure, since it is used to determine margin requirements for accounts in future contracts trading [Investopedia, 2016].

2.2 Price formation

Botterud et al. [2010] poses and discusses two forward contract pricing theories for commodities, tailored to the characteristics of the electricity markets. To simplify the models below, it is assumed that the time to delivery T is much larger than the period of delivery (the load period), which is acknowledged as a single cash flow at t+T.

Another important note to make is that these models actually describe the forward price for a single commodity. In our case, forward contracts for power are considered. If power plants are able to instantly convert energy carriers to power, these models apply to forward power contracts as well. This assumption might be reasonable, especially since many natural gas and coal-fired plants do not run on full capacity often and are able to increase production (see [Berger, 2014], appendix B).

The first pricing model describes the forward price of a commodity as a function of the current power spot price and the costs and benefits attributed to storing resources that are able to generate energy. These three factors are:

- Foregone interest (proxied by the risk free interest rate, assuming agents do not want to bear external financial risk)
- Convenience yield of holding a commodity
- Cost of warehousing

The interest is foregone when commodities are purchased if the wealth could have been used to earn a return somewhere else. This also holds for purely financial contracts, since one should obey to certain liquidity requirements and cash can't be deployed to create a risky return. The convenience yield of holding a commodity arises due to the advantage of physically possessing a commodity opposed to holding a future obligation to produce energy. An example of convenience yield could be to be able to meet a sudden positive jump in demand associated to high market clearing prices, which creates an opportunity to create value. The cost of warehousing is rather straightforward, since it refers to the costs inferred due to storage, such as the rent of storage facilities or the chemical degeneration of the commodities.

For a commodity that can be stored for a long time, one can specify a no-arbitrage relationship between the price of a forward contract and the current spot price [Hull, 2006]. The future price $F_{t,T}$ agreed to at time t describes the obligation of the seller to deliver power after a period T. The risk free rate is denoted by r_T, the convenience yield by y_T and the costs of physical storage are denoted by u_T. Note that the time-dependency is already covered by the exponential terms, since these are total rates over a period T. By continuous discounting, the forward price is given by:

$$F_{t,T} = S_t \mathrm{e}^{r_T + u_T - y_T} \tag{1}$$

When this equation is satisfied, no riskless profits can be made by buying an energy carrier on the spot market and storing the energy carrier and selling it on the forward market. Two regimes can be distinguished: if the future price exceeds the spot price, $F_{t,T} > S_t$ (backwardation) and if the spot price exceeds the future price, $F_{t,T} < S_t$ (contango). Botterud et al. [2010] find evidence for contango in the Nord Pool market between 2005 and 2008.

An important connotation to this model is that most RESs are electricity generators that are not using depletable resources for power production. Hence, the marginal costs of these sources of electricity is fairly low, causing these renewables to be the first on the merit order (see section [2.3]). This implies that if - according to the merit order, see section [2.3] - renewables such as wind and solar can generate power, they will. The current tendency of more RES capacity causes the characteristics of the energy market to change non-accordingly to a theory involving storage costs and benefits [Hildmann et al., 2015]. The validity of this model with respect to the possibility of storage will be discussed in section [2.4].

Another theory describes the price of the obligation committed at t to buy at T as a function of the expected spot price at time $t+T$ and the risk faced by the buyer of the future contract. The risk premium ρ_T is given as the difference between the required rate of return for holding a future contract, i_T, and the risk free rate r_T over a period T. Note that the time-dependency is already covered by the exponential terms, since these are total rates over a period T. The relation between future prices and future expected spot prices by a risk premium is given by Botterud et al. [2010]:

$$F_{t,T} = E_t(S_{t+T})\mathrm{e}^{-i_T+r_T} \tag{2}$$

Equation 2 states the future price to be the expected future spot price discounted by the risk premium. In the limit $T \to 0$ the future and expected spot price are identical and the exponential term becomes 1, which leads to a necessary arbitrage condition. If agents are risk-neutral but do make unsystematic expectation errors, there is no risk premium and the difference between realized spot prices and future prices one period before is a random error term ($\hat{e}_t$) with mean zero [Redl et al., 2009]:

$$F_{t,T} = E_t(S_{t+T}) = S_{t+T} + \hat{e}_t \tag{3}$$

Which states the price of a future with delivery after a period T agreed upon at time t is equal to the expected (the expectation is formed in t) spot price after a period T. Botterud et al. [2010] find evidence of a negative risk premium and they explain the premium by a difference a risk aversion between buyers and sellers of the contract.

2.3 Merit order of the PHELIX market

When considering power prices in a specific geographic area, it is important to consider the merit order, which is the hierarchy of the supply curve in terms of the marginal costs of the power plants. Different power plants face different marginal production costs and all plants with marginal costs below the market price will be operational assuming a perfectly competitive setting. The market price will therefore equal the marginal costs of the last plant ordered to operate.

From figure 1, one sees the German power market is characterized by a large share of renewables and a large share of inexpensive (hard coal, lignite, nuclear) and expensive (natural gas and oil) thermal energy sources. Figure 1 also shows e.g. a much higher share of nuclear and lignite in production then in installed capacity, attributable to the moderate marginal costs. The lower the marginal costs, the higher the number of full load hours due to the merit order.

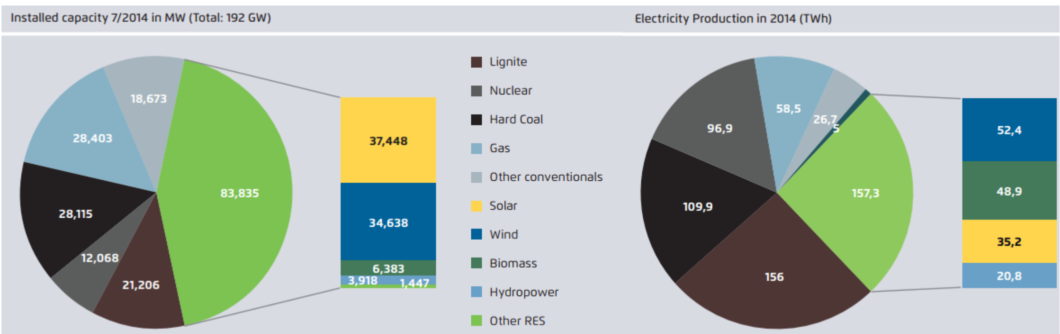

Figure 1
Share of power source in total energy capacity (in July 2014) and production (over 2014) in Germany, per type of energy carrier [Energiewende, 2015].

The merit order curve for the PHELIX spot market in 2009 is specified in figure 2, including the hourly volumes demanded over that year. Since demand is very inelastic and the supply curve is steep (heavily increasing marginal costs), prices tend to be very volatile [Hildmann et al., 2015]. Since the marginal costs of the last plant set to work, the marginal costs of the plants covered by the histogram in figure 2 hence determined day-ahead market prices in 2009.

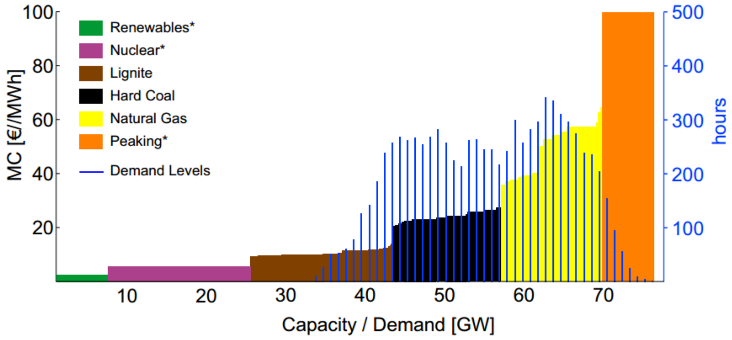

Figure 2
Estimate of the merit order curve of the German electricity market in 2009. The blue histograms note the volume demanded per hour in 2009. This figure shows which type of plant is most often the last one in the merit order to be put to work, which were often coal- and natural gas-fired plants [Pehle et al., 2011].

However, the merit order is subject to continuous change. Commodity prices and prices of emission allowances change continuously and an increasing share of renewables causes the supply curve to oscillate left and rightwards over the day and over the year, since their feed-in fluctuates. As mentioned before, the current trend towards more renewable power is clearly visible in figure 3. We observe a very strong increase in total renewable energy capacity and production, attributable to the increasing share of power production by onshore and offshore wind mills and photovoltaic cells. These developments are driven by both subsidies and decreases in generation costs [Hildmann et al., 2015]. If the back-up capacity for renewables is decreasing and since these back-up plants are characterized by much higher costs, prices are inherently becoming more volatile from hour to hour.

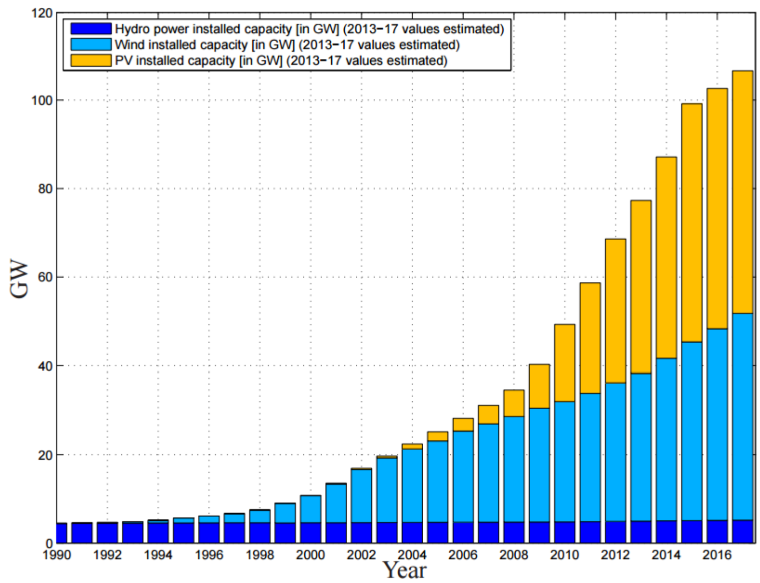

Figure 3
Realized (1990-2012) and projected (2013-2017) production capacity of renewable energy in the German energy market in GW [Hildmann et al., 2015].

Spot prices of wholesale markets are affected by supply and demand, which are subject to continuous change. The demand for power is periodic on many scales due to the periodicity of human and industrial life cycles. One can observe yearly, weekly and daily periodicity in the demand for electricity and combined with a much more rigid supply, prices will be positively related to increases in demand. The largest component of supply side periodicity can be attributed to RESs, since their supply volume depends on weather conditions. The increase causes supply to be more uncertain, leading to volatile prices and looming market unbalances. This urged market exchange to even start last minute markets [NordPool, 2016].

Since demand and supply differ periodically over the day with predominant peaks and lows, generally two regimes are distinguished in both exchanges and academic literature. The *base load* contains all 24 hours of the day, whereas the *peak load* contains the hours between 8 AM and 8 PM, excluding weekends [IWR, 2016].

2.4 Price formation and storage model validity

Since the share of renewables increases rapidly in the German power market, many conventional power plants will be shut down, reducing storage possibilities for commodities able to generate power. When storage costs of electricity or a commodity which can generate it become really high, the storage cost model of equation 1 will fail to hold [Bessembinder and Lemmon, 2002]. When the power production capacity of a market area consists mainly of renewables without storable commodities, there is little efficient opportunity to store. No agent will store electricity very inefficiently and rather purchase a forward contract and pay the risk premium to the counter party for not being hedged. Therefore, the relation between spot prices and forward prices of equation 1 is expected to disappear when storage is impossible.

Bessembinder and Lemmon [2002] do not consider the case of neither electricity storage or power-generating commodity storage since they judge it to be non-economical. However, Botterud et al. [2010] show the net convenience yield[1] to depend on hydro reservoir levels in the Nord Pool market, implying efficient storage of an underlying commodity which can be converted to power. A similar mechanism could be also deployed in power plants making use of a storable commodity close to the end of the merit order curve, such as hard coal and natural gas.

In practice, techniques such as Pumped Hydroelectricity Storage (PHS) are deployed actively (with a closed cycle efficiency[2] up to 80% [Yang, 2012]) for short term storage to reap profits at high demand periods. A compelling advantage of such systems is that the efficiency is almost not time-related, since most of the power is lost in the conversion of electrical energy to gravitational energy and in the opposite process. Hence, forward contracts with longer times-to-delivery face relatively less storage costs compared to the variability (risk) of these contracts and on the longer run, storage might be attractive as well. However, PHS requires either natural endowments such as large up-hill lakes also suitable for hydro power (as in the Nord Pool market) or very high investments [Yang, 2012].

Although storage might be inefficient, in extreme conditions, when expected future spot prices are sufficiently high and risk premia are sufficiently low, storage of power becomes a profitable activity and subsequently the no-arbitrage relation specified in equation 1 still holds. Whether the storage model holds will be addressed in section [4.2], when considering the net convenience yield.

However, the risk premium model of equation 2 will still be limiting, since that equation only requires a market for forward contracts where expectations about future spot prices are formed and the possibility of storage of cash to purchase on a later spot market.

2.5 Forward price formation and expected spot price formation

The main consideration of this thesis is whether forward prices of natural gas and coal or current spot prices of natural gas and coal explain forward electricity prices. Moreover, it is researched to what extent and in what way these commodity prices and other factors affect the forward price of electricity. If the storage model does hold, decisions about forward power supply could depend on previous (spot) prices of power. Irregardless whether the storage model holds, the model of

[1]The net convenience yield is the yield from physically holding a commodity. For explanation about how to deduce it, see section [4.2].

[2]Closed cycle efficiency is the amount of power regenerated after first pumping water up and then bringing it down to generate power.

equation 2 will govern forward price formation. Therefore, the formation of expected spot prices is essential to understand forward price formation in power markets.

If a power generating commodity is storable, it is possible to postpone power generation or to purchase more than the plant can process with the installed capacity. The market price of power at the time of actual generation should *not* depend on the cost base of the current commodities in stock. Since these commodities already have been purchased, this is a sunk cost and the economic cost of using that coal is equal to the opportunity cost of purchasing new coal to refill the stock of coal, since that would yield an identical situation in a new time period. If this new time period has similar prospects to the previous period, one would expect forward electricity prices to depend on the short run marginal cost of producing electricity in the future period. If the future period is not identical, a producer might also care about forward prices of hard coal and gas of longer time-to-delivery, since the prospect of high replacement cost after t+T might cause the producer not to produce in t+T or to purchase more in t+T. However, if producers do not replace their stock, the similarities between these two time periods might be small especially when market prices are expected to decrease continuously (which is the case in the German market due to an increasing share of RESs).

In designing a model that is able to explain forward prices, also current spot prices of power might be considered. If agents are not rational, but form expectations about future prices adaptively, current spot prices might be able to affect forward power prices. However, not only the current spot price might affect the forward price, but also previous spot prices could if the price expectations are based on a longer range of previous spot prices [Redl et al., 2009]. If some variable affecting forward prices is omitted, but is correlated with spot prices, spot prices might occur significant in explaining forward prices whereas they might not be. An example of such a variable would be a period of strong industrial power demand due to increased temporary government spending, which can last over several months and affect spot prices.

Redl et al. [2009] suggest also to use quadratic terms for natural gas and coal prices to model forward power prices. When the marginal cost of coal-fired plants raises to very high levels, they might not be put to use and marginally less expensive plants will. This could lead to insensitivity of power prices to coal prices when coal prices raise substantially. Redl et al. [2009] find significant negative quadratic estimators of coal forwards in explaining the forward price, corroborating their intuitive explanation. Since gas-fired plants are operational for less time, an increasing share of renewables might have decreased the influence of, via a lower utilization rate over time (see appendix B). Hence, the increase of the amount of renewables might have reduced the effect of forward gas prices on forward power prices.

Since power production from hard coal and natural gas also produces CO_2, producers are required to buy emission allowances accordingly to the emissions they produce. Therefore, the price of emission allowances contributes to the marginal production costs for coal- and gas-fired power plants, possibly increasing market prices.

Next to marginal production costs influencing the expected spot price, also the risk premium affects the pricing of forward contracts (see equation 2). The risk premium on short run forward contracts was found to be generally negative and volatile by Botterud et al. [2010]. Testing the explanatory power of the risk premium on forward contracts and the determination of the risk premium is beyond the scope of this thesis.

However, in estimating a model one has to take both other supply and demand side factors into accont. Two supply side factors affecting expected spot prices in $t + T$ are wind power and solar power feed-in. Wind power feed-in can be proxied by wind speeds (W_{t+T}) and solar power feed-in by the number of sunshine hours (S_{t+T}). Since the forward contract period in this thesis is month-ahead for a month-long delivery, monthly averaged wind speeds and sunshine hours for month $t+T$ might explain the expected feed-in of energy from wind over the delivery period. Since weather predictions have very limited predictive power over 14 days [Stern and Davidson, 2015], half-month to one and a half-month forecast is best estimated by the historical monthly average.

If wind speeds are higher, wind power feed-in is higher causing market prices to drop. Solar power feed-in also strongly correlates to temperature, which also affects the demand side of the power market. More hours of sun and higher temperatures decrease demand for lighting and heat, decreasing market prices. Moreover, holidays tend to be in the summer period characterized by many sun hours. Therefore, demand from industry and consumers decreases leading to lower power prices. However, since this term might include many effects, higher order terms might be significant.

Since gas-fired plants are operational for less time, an increasing share of renewables might have decreased the influence of, via a lower utilization rate over time (see appendix B). Hence, the increase of the amount of renewables might have reduced the effect of forward gas prices on forward power prices.

3 Methodology

Exploring the influence of power generating commodity prices on forward power prices, one could estimate models which regress the forward contract price on spot and forward contract prices of commodities as natural gas and coal. One expects forward contract prices of commodities to affect forward contracts for electricity if producers only mind the replacement cost of the commodities and there are no other demand and supply shocks, as explained in section [2.2] and [2.5]. The model equation with parameters $\beta_1 ... \beta_3$ can be estimated by Ordinary Least Squares (OLS):

$$F_{e,t,T} = \beta_1 + \beta_2 F_{c,t,T} + \beta_3 F_{g,t,T} + \hat{e}_t \tag{4}$$

In equation 4, 'P' denotes spot prices and 'F' denotes forward prices, whereas 'e', 'g' and 'c' in subscript refer to power, gas and coal prices, respectively. For future prices, the first time t in subscript denotes the agreement date, whereas the second time T denotes the time-to-delivery. The length of the period of delivery and the load profile are not specified in the notation above.

The estimator β_1 is the autonomous price of electricity, independent of the independent variables. The estimators β_2 and β_3 reflect the increase in the future electricity price caused by a 1 unit increase in commodity forward price.

We expect β_1 to be 0 if there are no other power generators in this idealized model and there are no demand shocks in the power market. Moreover, β_2 and β_3 are expected to be positive and of the magnitude of their relative market share, since these increase the marginal costs of power production and hence the market price one-to-one, assuming perfect competition.

As discussed in section [2.5], the idealized case of equation 4 might not hold. If we assume that agents are not rational and that price expectations might be formed adaptively, also the current spot price should be included in our model specification. However, not only the current spot price might affect the forward price, but also previous spot prices could if the price formation behavior is adaptive.

Furthermore, spot prices of commodities might affect forward power prices if producers care about the cost base of their power generating commodities in stock. If this relation is valid, this might indicate efficient storage of commodities that generate power. For hard coal this is more likely, since physical storage is more convenient than for natural gas. Moreover, Germany has a pipeline connection for natural gas[Bundesnetzagentur, 2015], which eases on-time delivery.

When natural gas and coal prices increase substantially, other power plants might become less expensive and natural gas plants are switched off, not further increasing upward pressure on power prices (see section [2.3]). Hence, quadratic terms for future commodity prices might be able to capture this effect.

Furthermore, there are more demand and supply shocks present in real power markets affecting expected spot prices, such as seasonal fluctuations in wind and solar power generation, which are able to affect the formation of expected spot prices. Moreover, varying temperatures, holiday periods and month-by-month varying industrial demand could be able to explain demand side forces affecting prices. These should not be the actual values in $t + T$, but the expectation at t, since the actual values are not known when the forward price is quoted.

A model capturing the previous effects can be specified in a regression model:

$$\begin{aligned} F_{e,t,T} = \beta_1 + \beta_2 P_{e,t} + \beta_3 P_{e,t-1} + \beta_4 P_{c,t} + \beta_5 P_{c,t-1} + \beta_6 F_{c,t,T} + \beta_7 \left(F_{c,t,T}\right)^2 + \beta_8 P_{g,t} + \beta_9 F_{g,t,T} + \\ \beta_{10} \left(F_{g,t,T}\right)^2 + \beta_{11} E_t W_{t+T} + \beta_{12} E_t S_{t+T} + \beta_{13} \left(I_t \cdot F_{g,t,T}\right) + \beta_{14} F_{ghg,t,T} + \hat{e}_t \end{aligned} \tag{5}$$

Here, $E_t x_\tau$ notes the value expected at t of the variable x at τ. $E_t W_{t+T}$ notes the expected average wind speed in Northern Germany at $t+T$ and $E_t S_{t+T}$ notes the expected number of hours of sun in Middle Germany at $t+T$.

From the theory of section [2.4], we expect the coefficient β_1 to be zero, since there is no autonomous price of forwards. The coefficients β_2 and β_3 are expected to be 0 when agents are rational and no important variables are omitted. However, we expect price expectations to be adaptive and hence β_2 and β_3 are expected to be positive. Moreover, we expect the coefficients β_6 and β_9 to be positive, since we expect forward natural gas and coal prices to positively influence the forward electricity price through the expected future spot prices. Since we expect substitution of coal- and natural gas-fired plants if their forward price becomes large, we expect β_7 and β_{10} to be negative. β_4, β_5 and β_8 are expected to be zero, since these costs are sunk at the moment production has to be decided on. However, if agents use these prices to form expectations about future replacement costs or to postpone production in an earlier time period, we expect these three coefficients to be positively affecting forward prices. β_{11} is expected to be negative, since higher wind speeds lead to higher wind power feed-in, which puts a downward pressure on future prices. β_{12} is expected to be negative, since more sun hours lead to higher solar power feed-in from photovoltaics and lower power demand, which both puts a downward pressure on future prices[3]. Ultimately, β_{13} is expected to be negative, since the usually positive effect of forward gas prices on forward power prices is lower if the share of renewables is higher, since gas-fired plants are less often the last plant set to work. β_{14} is expected to be positive, since an increase in forward emission allowances price increases the short run marginal costs of production, which increases expected future spot prices.

[3]Future in this context does not refer to a forward contract, but to any price relating to power delivery in $t + T$

4 Data

4.1 Data summary

The geographic region of interest for the power data is the EPEX SPOT (previously referred to EEX in literature) power market operating in middle Europe (Germany, Switzerland, Austria, France, and Luxembourg). The mother company EEX also manages an exchange for natural gas (NCG) and coal contracts (Richards bay forwards). The EPEX SPOT area is subdivided in three markets. The analysis of this thesis will consider forward contracts at the PHELIX power market, comprised of Germany, Austria and Luxembourg. The characterizing analysis in this chapter will predominantly concern Germany, since it covers largest part of the market area.

The forward contracts traded at PHELIX are purely financial contracts in which the pay-off to contractors is based on the spot price at the time of 'delivery'. However, in combination with selling on the spot market at the time of delivery, a producer is able to hedge the risk of a changing power price (see section [2.2]).

The power grid of the German power market is an internationally integrated one, as seen in figure 4. Hence, not only German supply and demand factors affect market prices, but foreign factors will influence the PHELIX market as well. Some countries both export to and import from Germany (figure 4). A compelling explanation lies in the nature of the German electricity market. Due to the increased share of RESs (predominantly solar and wind) in recent years, the daytime supply significantly exceeds the nighttime supply [Berger, 2014]. Although daytime market prices in France are (slightly) higher than in Germany, France still exports power to Germany. In the night, the excess of inexpensive nuclear power from France is exported to the German market to undercut the use of marginally expensive gas turbines.

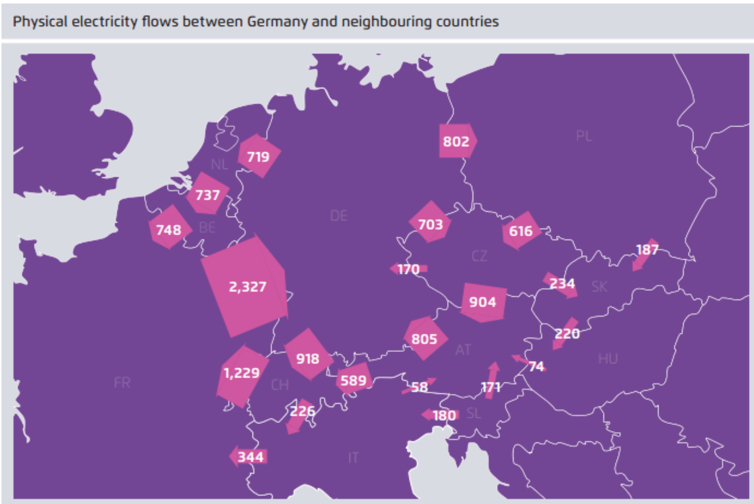

Figure 4
Electricity imports to and exports from Germany over 2014 in TWh [Energiewende, 2015].

Although total power use in Germany dropped continuously from 2011 to 2014 [Bundesnetzagentur, 2015], the total amount of energy traded at the PHELIX exchange increased over recent years. Hence, the OTC market (and other local exchanges) has become smaller with respect to the main exchange [Bundesnetzagentur, 2015].

Currently, most of RES energy is already traded over the PHELIX exchange [Hildmann et al., 2015]. Hildmann et al. [2015] suggest that if the PHELIX market would gain more market share, the merit order effect of increasing volatility (see section [2.3]) would be reduced, since the supply elasticity will be reduced if relatively more conventional energy is traded at the grid. A small shock in demand leads to less volatile prices, reducing the risk faced by users and producers.

The data to conduct the research proposed in section [3.1] involves:

- Spot price data: from the PHELIX day-ahead power market, daily frequency, quoted in Euro per MWh, base prices, obtained from EEX. Symbolized by $P_{e,t}$.
- Forward contract price data: from the PHELIX market with a flat load profile and a month-ahead delivery for a month-long delivery, daily frequency, quoted in Euro per MWh, base prices, obtained from EEX. Symbolized by $F_{e,t,T}$.
- Spot price data of coal: at the Richards Bay API2 hub CIF[4] (South Africa), daily frequency, quoted in US Dollar per short ton, obtained from EEX. Symbolized in Euro per short ton by $P_{c,t}$.
  Factually, there is no spot market for coal since it cannot be withdrawn from an integrated network such as possible for natural gas and electricity almost instantaneously. A substantial time difference arises between arrival and the possibility to actually use the coal for power production. Especially on the month-ahead regime, forward prices at the time of delivery might not explain the opportunity cost of filling the coal stock at the plant site.
- Future price data of coal: at the Richards Bay API2 hub CIF (South Africa) with a month-ahead delivery for a month-long delivery, daily frequency, quoted in US Dollar per short ton, obtained from EEX. Symbolized in Euro per short ton by $F_{c,t,T}$.
- Spot price data of natural gas: at the NCG market (Germany), daily frequency, quoted in Euro per MWh, obtained from EEX. Symbolized by $P_{g,t}$.
- Forward price data of natural gas: at the NCG market (Germany) with a month-ahead delivery for a month-long delivery, daily frequency, quoted in Euro per MWh. Symbolized by $F_{g,t,T}$.
- Exchange rate data between US Dollar and Euro, daily frequency (to convert USD prices to EUR prices) [GoogleFinance, 2016].
- Wind speed data: monthly averages of 2000 to 2008, from Hamburg (Germany), specified in (rounded) m/s [Weather and Climate, 2016]. Symbolized as the expectation at t for period $t + T$ by E_tW_{t+T}.
- Suntime data: monthly averages of sunshine duration in Woerzburg (Germany), and specified in hours, obtained from [Climatemps, 2016]. Symbolized as the expectation at t for period $t + T$ by E_tS_{t+T}.
- Emission Allowances data: at the EEX environmental market, daily frequency, quoted in Euro per ton of carbondioxide [EEX, 2016]. Symbolized by $F_{ghg,t,T}$
- Share of renewables data: artificial variable symbolized by I_t
  Since no recent data regarding the share of renewables in power production was available, an artificial variable I_t was created, which takes value 0 from June 2011 to May 2014 and value 1 form June 2014 to March 2016 grasping the increasing share of renewables over time. This variable could be used to be an interacting variable with the forward gas price and hence grasp the effect of natural gas-fired plants becoming redundant, diminishing the natural gas price its effect on forward power prices.

The data could be formatted in several ways, depending on the averaging period for the data, from a single day to the entire month of interest. An advantage of averaging over a period as long as possible is that short run supply and demand shocks have less influence on the data, which could significantly affect the relation between e.g. the expected future spot price and the forward price of power. This is especially true if the storage no-arbitrage equation does not hold, since no sudden extra supply can be created which could mitigate the price effect of a sudden increase in demand. However, one can not average over a longer period than the first day of delivery is reached, which would be one month in this case.

[4]Cost, Insurance and Freight: the seller delivers the products at the port of destination.

A disadvantage of a large averaging period for month-ahead forward contracts is that on the last days of the month regarded, the forward contract already includes delivery in a few days. Therefore, accurate forecasts of weather, industrial demand and power plant downtimes might dominate price formation on such time scales.

The first data format consisted of one particular day of the month its spot and month-ahead future prices for flat load delivery in the upcoming month. The month ahead forward contract was chosen, since the temporal difference between the spot period and future period is not to large to study the effect of commodity prices on the forward electricity price. The time period considered is from June 2011 till March 2016 with a monthly frequency, leading up to 58 observations. All spot prices are quoted on the 15th day of the month, the 14th if the 15th is a saturday and the 16th if the 15th is a sunday.

However, without averaging, the data was very sensitive to shocks in both explanatory and dependent variables leading to non-sensible results with large standard errors. The second data format was designed to mitigate this problem. For forward contracts, prices were averaged over the 5 week days closest around the 15th of every month and for spot prices the average was taken over the 12th to the 18th of every month. The time period of data format one also applied to this data format.

Moreover, the third data format was obtained by averaging over 28 days (20 days for forward contracts) around the 15th of every month. A multiple of the number of weeks was considered, to prevent having more weekend days in some month with respect to others, since demand is generally lower on weekend days. This approach could not been taken of the emission data, since data could not be easily accessed and still consisted of weekly averages. Both the second and third data format are used for the data characterization of next section and the estimations in the next chapter.

4.2 Descriptive Statistics

The data as described in the previous section can be summarized by looking at the time series of the prices of the coal, natural gas and power spot and forward prices in figure 6.

The results of figure 6 show the time series of spot and future prices of coal, gas and power from June 2011 till March 2011. For the third data format an interesting observation is the continuous downward trend in all of the variables. This could indicate a causal relation leading the power prices to drop due to a drop in fuel costs, although it could also be attributed to different developments on both the demand and supply side of the power markets. This will be subjects to the tests of section [5.1]. Every plot (**a), b), c)**) shows both the spot price (day ahead for power, for aforementioned reasons) and the forward power price. The electricity price shows a strong seasonal behavior, attributable to the seasonal demand from households and industry. This is illustrated in Appendix D.

Table 1
Data summary of coal, natural gas and power prices, including the correlations between the respective coal and future price data for monthly averaged values.

	Type of energy carrier		
	Coal [EUR/short ton]	Gas [EUR/MWh]	Power [EUR/MWh]
Spot price mean	80.296	22.775	37.601
Standard deviation spot price	20.887	3.928	8.008
Future price mean	80.382	22.896	38.436
Standard deviation forward prices	21.037	3.848	9.038
R^2 between spot and forward price	0.996	0.977	0.887

Table 1 summarizes the main data statistics. The spot and forward prices averages of all three commodities are close to each other and are strongly correlated, especially for coal and natural gas. Rewriting equation 1, leads to the following expression for net convenience yield:

$$CV_t = \ln\left(\frac{P_{e,t}}{F_{e,t,T}}\right) \tag{6}$$

A net convenience yield larger than zero implies backwardation, whereas a net convenience yield smaller than zero implies contango if efficient storage is possible. Botterud et al. [2010] find evidence for contango (see section [2.2]) in 6-week forward contracts in the Nord Pool market between 2005 and 2008. In our case, there is some evidence for contango in figure 5. The value of the monthly net convenience yield is -0.0179 with a standard deviation of -0.0210. However, this does not proof the validity of 1, since a negative market premium and constant spot prices would also indicate forward prices being higher than current spot prices.

6.

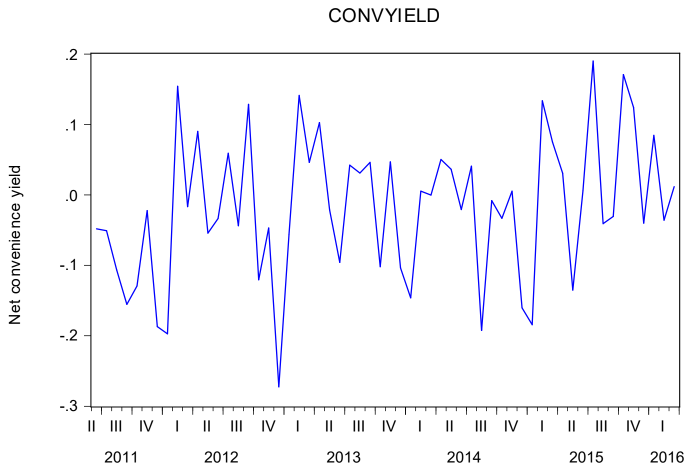

Figure 5
Monthly convenience yield from March 2011 to June 2016 on the PHELIX market, calculated by equation 6.

Storage by filling natural hydro reservoirs as performed in the Nord Pool market region is rather inexpensive and the cost of storage increase when hydro levels rise till unacceptable levels. The yearly periodicity of rainfall causes storage costs to differ over the year [Botterud et al., 2010]. In the EEX region, power from hydro is very limited and the storage capacity might hence be too small for the storage model to show yearly periodicity. Hence, no proof of the validity of the storage model can be deduced in a similar way for the PHELIX market.

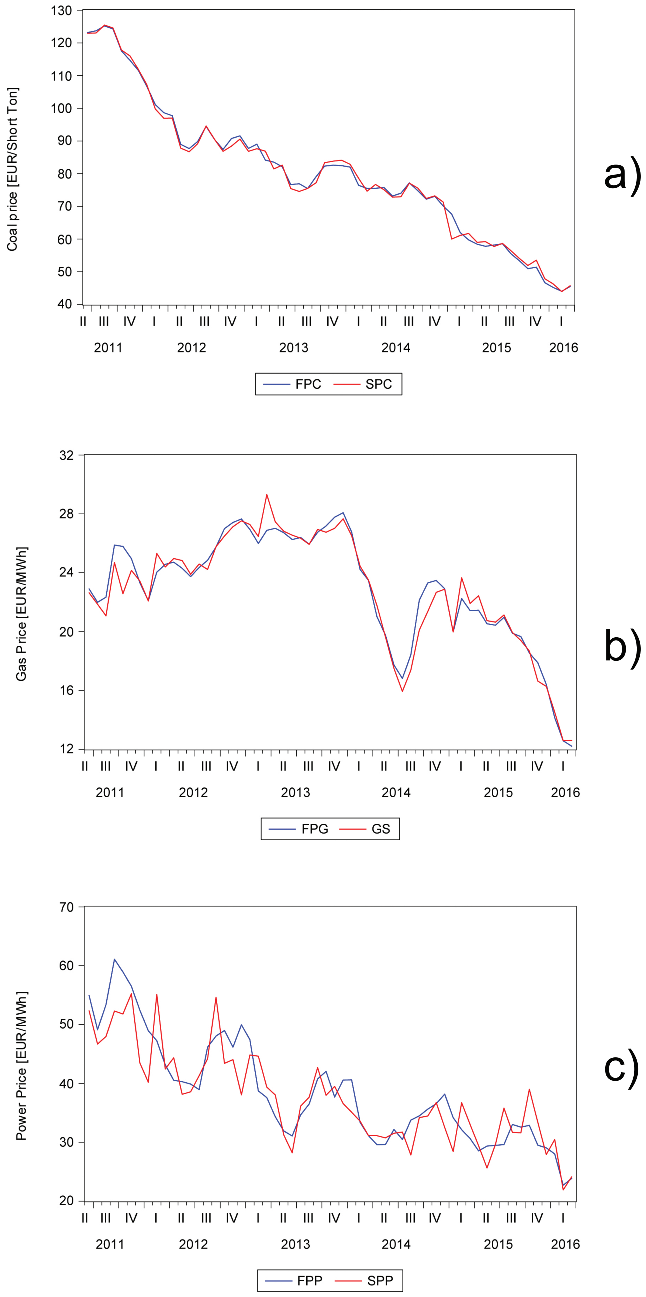

Figure 6
Time series with monthly frequency from June 2011 till March 2016 for the third data format of a) spot (SPC) and future (FPC) coal price, b) spot(GS) and future (FPG) and c) spot (SPP) and future (FPP) electricity price. Note the units for the coal prices, which are quoted in euro per short ton. A short ton is equal to 907 kg.

5 Model Results

5.1 Model setup

Using the second data format from section [4.1], the model of equation 4 showed to have an incorrect functional form by the Ramsey RESET test. Hence, the data was formatted into a log-log model which was als not able to withstand the RESET test, the null of no specifation error was rejected at a 10% significance level. Moreover, multicollinearity might be a problem due to the high correlations between the spot and forward price of coal and natural gas. Near multicollinearity is not a condition violating the assumptions of the Ordinary Least Squares (OLS) approach. However, it can increase standard errors, causing significant relationships to appear to be insignificant [Carter-Hill et al., 2008]. Hence, it is important to mitigate multicollinearity. The assessment will be given after the estimation results.

All variables used also showed all to be non-stationary, Augmented Dickey-Fuller (ADF) tests showed those were all integrated of order 1 (**I(1)**) [Carter-Hill et al., 2008]. Moreover, since all variables are integrated of order 1, there was no cointegration (residual auxiliary regression: t-stat = -6.298) and the functional form was insufficient, a first-differences model was necessary to avoid spurious regressions [Engle and Granger, 1987]. Another advantage of this first-differences model was that it mitigated collinearity. The previously highest R^2 value between spot and forward coal prices reduced to 0.85.

In the subsequent model, the null of the RESET test of no specification error could not be rejected at a 5% level. Besides, the Durbin-Watson statistic shows to be 2.1566, which implies that serial correlation is not a problem in this model [Carter-Hill et al., 2008]. Moreover, the null of no heteroscadasticity could not be rejected with a p-value of 0.5952 from a Breusch-Pagan test without and 0.6288 from a white test with z-variables [Carter-Hill et al., 2008].

For the third model, the estimation results were significantly different. As for the second data format, the functional form was found to be insufficient by the RESET test, leading up to a log-log model. All variables were **I(1)** and the estimations were not co-integrated (residual auxiliary regression: t-stat = -5.498). As mentioned in section [2.5], an important consideration is to add are higher order and lag terms and supply and demand factors affecting expected spot prices that could improve the model. However, simply adding terms will always improve the explanatory of the model, but won't improve the predictive power of the coefficients.

5.2 Model selection

With the Akaike Information Criterion (AIC), one is able to select the relatively best model from a set of model specifications. The trade-off considered in the AIC metric is that between goodness-of-fit of the model and the complexity of the model. The higher the AIC value with respect to the lowest AIC value attainable, the lower the probability this model is the best model [Yamaoka et al., 1978]. Table 2 shows several functional forms and their corresponding AIC values, R^2 and adjusted R^2. The rationale for the variables added can be found in section [2.5].

From table 2 and from the p-values of particular coefficients in the regressions belonging to these, we can deduce several characteristics. The addition of spot prices of natural gas and coal improves the model, just as the addition of spot prices of power and a single lag in power spot prices. Also the addition of two lag terms of coal spot prices improved the model. A forward emission allowances term did improve the model as well. No quadratic terms in natural gas and coal forward contracts were able to improve the model any further.

Several suggestions for other variables were done in section [2.5]. The wind speed term did not improve the model. Moreover, the sunshine term improved the model significantly, as well as the square of it. Ultimately, an interaction between the forward gas price and the variable I_t was able to lower the AIC as well.

For the third data format, no lag terms of power spot prices improved the model. Moreover, no lag term of the power spot price was able to improve the model. Moreover, the coal forward price was also insignificant and the coal spot price coefficient was somewhat significant and positive. No lags and no squared terms of the coal spot price were able to improve the model. Also in this

Table 2
Model selection criterion (AIC) for several time-lagged explanatory variables and quadratic terms, with dependent variable $\Delta \ln(F_{e,t,T})$. The first twelve modes are estimated using the second data format, whereas the last is estimated using the third data format.

Explanatory variables[a]	AIC	R^2	R^2_{Adj}
$F_{g,t,T}$, $F_{c,t,T}$	-2.11	0.141	0.110
$F_{g,t,T}$, $F_{c,t,T}$, $P_{g,t}$, $P_{c,t}$	-2.14	0.222	0.218
$P_{e,t}$, $P_{g,t}$, $P_{c,t}$, $F_{g,t,T}$, $F_{c,t,T}$	-2.19	0.288	0.218
$P_{e,t}$, $P_{g,t}$, $P_{c,t}$, $F_{g,t,T}$, $F^2_{g,t,T}$, $F_{c,t,T}$	-2.16	0.289	0.204
$P_{e,t}$, $P_{g,t}$, $P_{c,t}$, $F_{g,t,T}$, $F_{c,t,T}$, $F^2_{c,t,T}$	-2.16	0.289	0.203
$P_{e,t}$, $P_{e,t-1}$, $P_{g,t}$, $P_{c,t}$, $F_{g,t,T}$, $F_{c,t,T}$	-2.20	0.311	0.227
$P_{e,t}$, $P_{e,t-1}$, $P_{e,t-2}$, $P_{g,t}$, $P_{c,t}$, $F_{g,t,T}$, $F_{c,t,T}$	-2.17	0.320	0.218
$P_{e,t}$, $P_{e,t-1}$, $F_{g,t,T}$, $F_{c,t,T}$	-2.17	0.239	0.179
$P_{e,t}$, $P_{e,t-1}$, $F_{g,t,T}$, $P_{c,t}$	-2.16	0.235	0.176
$P_{e,t}$, $P_{e,t-1}$, $F_{g,t,T}$, $P_{g,t}$, $P_{c,t}$, $P_{c,t-1}$, $P_{c,t-2}$	-2.23	0.357	0.261
$P_{e,t}$, $P_{e,t-1}$, $F_{g,t,T}$, $P_{g,t}$, $P_{c,t-1}$, $P_{c,t-2}$, $F_{c,t,T}$	-2.26	0.399	0.295
$P_{e,t}$, $F_{g,t,T}$, $I_t \cdot F_{g,t,T}$, $P_{c,t}$, $P_{c,t-1}$, $P_{c,t-2}$, $F_{ghg,t,T}$, $E_t\left(S_{t+T}\right)$, $\left(E_t\left(S_{t+T}\right)\right)^2$	-2.52	0.556	0.466
$P_{e,t}$, $F_{g,t,T}$, $(\mathrm{F}_{g,t,T}{}^2$,$\mathrm{I}_t \cdot F_{g,t,T}$, $P_{c,t}$, $F_{ghg,t,T}$, $(E_t S_{t+T})$, $\left(E_t\left(S_{t+T}\right)\right)^2$	-2.71	0.561	0.486

[a] All variables are in differences of their logarithm, e.g. '$P_{e,t}$' is $\Delta \ln(P_{e,t})$, except 'I_t'

data format, forward gas prices improved the model, whereas spot prices of natural gas did not. Surprisingly, a term proxying wind power feed-in was not able to explain the forward power price, possibly due to the roughly data, rounded to integer m/s. As expected, also for the third data format sunshine hours term did improve the model, just as the interaction term with the forward natural gas price grasping the increase in renewables over the time period.

The results of the three final models discussed in this paragraph will be considered in the following paragraph. So far, most emphasis was on the second data format. The following paragraph will mostly discuss the third data format, since it was found to be the most consistent one showing the highest AIC criterion.

5.3 Final model estimations

The three last models of section [5.2] are explicitly specified in Appendix C, since these are lengthy. The coefficients of the estimation and the important diagnostics of the model of equations 7, 8 and 9 can be found in table 3.

The interpretation of a first differences logarithmic model is not straightforward. Ceteris paribus, a coefficient of +0.6711 for the coefficent β_9 in model I of equation 7 implies that if the ratio of the explanatory variable and value of the explanatory variable a period before increases with 1 percent, then the ratio of the dependent variable and value of the dependent variable a period before increases with 0.6711 percent. This is illustrated in Appendix A.

The nonzero intercept term of model II and III is odd, since this would mean a negative price change and positive price change if no of the other variables changes, respectively. An explanation for this could be that the functional form was not best. The RESET test showed up to 10% significance that functional form might be suboptimal. However, the intercept values found are rather small compared to the coefficients.

The coefficients of table 3 implicate several conclusions. The current and previous power spot price significantly affect the forward power price in a positive way in model I. This could indicate adaptive expectation formation by agents on the power markets, but it could also be attributed to missing demand side variables. Model II checks for this and still shows that power spot prices affect forward prices, but not that significant as before. The significance of the lag term of spot prices disappears in the second model.

Furthermore, the forward natural gas price shows a strong positive relation to the forward power price (coefficient equals 0.48), as expected from the producer decision to sell at a particular power price. The equilibrium forward price will increase as the forward natural gas price increases. Moreover, the spot price of gas shows an unexpected negative coefficient. In the model II this significance disappears.

The coefficient for both coal prices has opposite sign. If the forward and spot coal price were used in the model solely, they failed to be significant every time, indicating no influence of coal prices on forward prices. Moreover, both lag term coefficients (β_1 and β_2) are positive, indicating that forward power prices do depend positively on previous prices of coal to form expectations about future marginal costs. The negative coefficient for forward coal prices disappears in model II.

As expected, also the emission allowances prices significantly affects the forward power price. The effect of the forward gas price on the forward power price disappears completely due to an increased share of renewables as suggested in section [2.5]. The coefficient β_6 and β_7 of equation 9 are of similar magnitude (close to 0.5) and opposite sign, implying a positive effect from June 2011 to May 2014 and no effect thereafter. The sunshine term is hard to interpret, since it grasps many effects (see section [2.5], appendix D). The linear term implies a decrease in power price due to decreased demand from industry and households and increased solar power feed-in. However, the coefficient of the quadratic sunshine term implies that this effect is non-linear and decreases, to increase since the quadratic term is negative.

For the third model, the results were similar to that of the second model. However, the influence of lag terms of the coal spot price did not show up. This implied that coal prices only affect the forward price of power via the spot price ($\beta_3 = 0.2684$), although it was close to insignificance. Another deviation from model II is that the quadratic term of gas forward price was significant, corroborating the hypothesis that gas-fired plants are replaced with cheaper plants of other kind when natural gas prices rise substantially.

However, the result that the future coal price does not affect the forward electricity price is unexpected, since hard coal contributes to a significant part of power production in germany (see section [2.3]). If all coal plants are at full capacity the entire year, as long as the marginal costs do not exceed that of natural gas, the coal prices are not expected to affect the power prices in a competitive market. If the coal plants are in full use, these are not the last on the merit order and hence not determining market prices. However, a quick calculation from figure 1 shows that less than 50% of maximal production from coal plants is actually produced, opposed to more than 90 % for nuclear plants in 2004. A part of the explanation may lie in the aforementioned delay between coal delivery and use in coal-fired plants, which is reflected in the relatively large positive but not significant coefficient of coal spot price in model III.

An explanation requiring more research to test is that of strong intraday changes of RES feed-in. If feed-in is high, supply meets demand such that no coal plant is enabled. If feed-in is low, supply meets demand such that all coal plants are enabled and the marginal costs of marginally more expensive plants determine market prices. Hence, also power prices for future delivery and longer load profiles are independent of coal prices (as long as they do not become too large), since such a plant would never be the last on the merit order. However, figure 7 suggests that in 2014 coal plant still switched a lot between 0 and 100%, indicating that it was often the last type of plant to be switched on according to the merit order.

Those results might hint that this periodic effect of the merit order also plays a role on the seasonal time scale, since in some months it might be expected that coal-fired plants are the last to set to work and in other months it might be expected natural gas-fired plants are the last to set to work due to periodic renewables feed-in. However, this is beyond the scope of this thesis.

Table 3
Estimation results for the regression analysis of the model specified in equations 7, 8 and 9 for dependent variable$\Delta \ln(F_{e,t,T})$.

Explanatory variable[a]	I	II	III
Intercept	0.0028	-0.0272*	0.0029*
	(0.23)	(-2.08)	(4.49)
$\Delta \ln(P_{e,t})$	0.1611*	0.0889***	0.0874***
	(2.55)	(1.57)	(1.47)
$\Delta \ln(P_{e,t-1})$	0.0923**		
	(1.85)		
$\Delta \ln(F_{c,t,T})$	-0.9226*		
	(-2.64)		
$\Delta \ln(P_{c,t})$	1.0520*	0.2817***	0.2684***
	(3.05)	(1.53)	(1.39)
$\Delta \ln(P_{c,t-1})$	0.2408***	0.2022	
	(1.10)	(1.19)	
$\Delta \ln(P_{c,t-2})$	0.4926*	0.2880***	
	(2.18)	(1.47)	
$\Delta \ln(P_{g,t})$	-0.4101*		
	(-2.13)		
$\Delta \ln(F_{g,t,T})$	0.6711*	0.4375*	0.48*
	(3.68)	(2.40)	(2.44)
$(\Delta \ln(F_{g,t,T}))^2$			-1.905***
			(-1.55)
$I_t \cdot \Delta \ln(F_{g,t,T})$		-0.5262*	-0.5505*
		(-2.50)	(-3.12)
$\Delta \ln \left(F_{ghg,t,T}\right)$		0.1118*	0.1130*
		(2.21)	(2.22)
$\Delta \ln \left(E_t \left(S_{t+T}\right)\right)$		-0.0632*	-0.0596*
		(-2.89)	(-2.77)
$\left(\Delta \ln \left(E_t \left(S_{t+T}\right)\right)\right)^2$		0.1855*	0.2146*
		(3.50)	(3.64)
R^2	0.3998	0.5564	0.5611
Observations	54	54	56
Autocorrelation (DW, p-value)	2.0542	2.4030	2.2197
Functional Form (RESET, p-value)	0.1313	0.0770	0.0722
Heteroskedasticity (B-P-G χ^2, p-value)	0.7521	0.7121	0.7322

[a] t-statistics are given between brackets
All results are presented with HAC standard errors (Newey-West)
*, **, ***: significant up to the 5, 10, 20% level respectively

6 Conclusion

This paper addressed to how and to which extent both spot and forward natural gas and coal rices affect the forward base load price of electricity in the PHELIX market region from June 2011 to March 2016. After several data formats and functional form specifications of regression models model, the best explaining, although not of perfect functional form, was found.

The hypothesis that forward power prices can be explained from forward coal prices and forward gas prices and not other prices of these commodities was not confirmed fully. Forward coal prices showed to have no explanatory power of forward power prices, whereas spot prices of coal did. This was attributed to the delay between the delivery date of coal and the ready for use date for coal, which might imply efficient storage of power generating commodities. However, the coal spot price effect was weak and close to insignificant and eventually no spot price price lag terms showed to have explanatory power. The strongly hourly fluctuating feed-in from renewables may as well cause the coal plants to not be the last plant to put to work (due to the shift of the merit order curve), but either less expensive and more expensive plants will throughout the day.

Gas forward prices did explain forward power prices, whereas spot prices did not. Moreover, the suspicion that strong increases in forward natural gas prices do not pass through into forward power prices was confirmed by the regression results. Ultimately, the suspicion raised by low utilization rates of gas-fired plants that the influence of forward gas prices on forward power prices changed over time was tested by using a dummy interaction variable, which switched from 0 to 1 after May 2014. Although the variable used did not include information about renewables itself, it showed the effective coefficient for the first and the second time period to be different. This was strong evidence for the decreasing effect of forward gas prices on forward power prices, eventually leading to a shut down of gas-fired plants.

Moreover, electricity spot prices showed to explain forward prices, leading to the conclusion that agents form price expectations adaptively. Moreover, the influence of spot prices is found to be higher in year-ahead forward contracts then in month-ahead contracts (for year-ahead, see [Redl et al., 2009]). This indicates that agents rely more on month-ahead forward prices then on year-ahead forward prices to form expectations about forward cost of production. A rationale for this might be the ability to forecast certain demand and supply factors, some of them discussed subsequently.

Seasonal averages for sunshine hours and wind speeds were used to resemble the supply factors that are expected to affect expected future spot prices and hence forward power prices. However, the forward price for the next month with a flat load profile traded on the last day of the month will already contain short run estimates of, say, the next two weeks (typical to weather predictions) of these variables. This might not only apply to the supply side, but also to demand from industry and households, due to e.g. expected temperature. Therefore, it is not alienating that the explanatory power of commodity and emission allowance prices of month-ahead forward contracts is less than for year-ahead forward contracts. Whereas [Redl et al., 2009] find an R^2 of 0.75, the model in chapter 5 only finds an R^2 of 0.56. This can be understood from the short turn anticipated demand and supply shocks that would not occur when prices are formed over longer periods.

Another explanation could be that natural gas and coal are not explaining prices as good as before due to the increase of renewables. A higher share of renewables might have caused gas- and coal-fired plants to be less often the last plant set to work according to the merit order. Hence, adding prices of lignite, a somewhat marginally less expensive type of power generator on the merit order, might improve the explanatory power of the model. Since day-ahead prices in the period of interest were sometimes negative, subsidized plants were the last expected to set to work.

An obvious improvement of the data could be achieved by combining the emission allowances costs and commodity costs into the short run marginal cost of producing power with that commodity. To conduct this research, one would need the plant efficiency and the conversion of coal to mass of CO_2. This would lead to a better estimation of the coefficients for short run costs for natural gas- and coal-fired plants. Moreover, for month-ahead forwards it turned out to be difficult to find the 'right-in-time' price for coal price to explain forward prices of power, contrary to research performed on year-ahead forwards [Redl et al., 2009]. Another improvement in explaining month-ahead forward contracts would be to involve monthly expectations of demand, anomalous of the seasonal fluctuations proxied by temperatures.

An inherent disadvantage to investigating month-ahead forward contracts is the vulnerability when averaging over both a small time period and large time periods. Although averaging over a month-long period would also involve expectations over the order of days, this seemed to yield better models than averages over a single week.

A small part of this thesis was considering to what extent renewables affect the no-arbitrage relation of equation 1 and to what extent the storage no-arbitrage relation is valid. The equation is essential to the relation between forward prices and current spot prices and hence affects price formation. The influence of spot prices of coal on forward power prices might indicate storability, but that does not conclude the validity of equation 1. Redl et al. [2009] find that in the Nord Pool market the effect of skewness on risk premia disappears if efficient storage is possible, since power price peaks can be anticipated by converting gravitational energy to power close to instantly. If the share of increasing renewables keeps increasing, ignoring public interventions, existing natural gas and coal plants will close since these are the least expensive. This would decrease the storage possibilities further, making the validity of equation 1 less likely.

The data showed some evidence for contango, although the nature of no periodically changing storage costs (specific to hydro reservoirs) made it impossible to validate or falsify the storage cost model for the PHELIX market region.

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Appendices

A Interpretation of functional form

The interpretation given in section [5.3x] will be illustrated by rewriting the regression model specified in equation 7, using $\beta_1 + K = K$, where K is an arbitrary constant and $\beta_9 = 0.6711$:

$$\Delta \ln(F_{e,t,T}) = \beta_1 + \beta_9 \Delta \ln(F_{g,t,T}) + K$$

$$\ln(F_{e,t,T}) - \ln(F_{e,t-1,T-1}) = \beta_1 + \beta_9 \left(\ln(F_{g,t,T}) - \ln(F_{g,t-1,T-1})\right)$$

$$\ln\left(\frac{F_{e,t,T}}{F_{e,t-1,T-1}}\right) = \beta_1 + \beta_2 \ln\left(\frac{F_{g,t,T}}{F_{g,t-1,T-1}}\right) + K$$

$$\ln\left(\frac{F_{e,t,T}}{F_{e,t-1,T-1}}\right) = \beta_1 + \beta_2 \ln\left(\frac{F_{g,t,T}}{F_{g,t-1,T-1}}\right) + K$$

$$\left(\frac{F_{e,t,T}}{F_{e,t-1,T-1}}\right) = \mathrm{e}^{\beta_1 + K} \cdot \mathrm{e}^{\ln\left(\frac{F_{g,t,T}}{F_{g,t-1,T-1}}\right)^{0.6711}} = \mathrm{e}^{\beta_1 + K} \cdot \left(\frac{F_{g,t,T}}{F_{g,t-1,T-1}}\right)^{0.6711}$$

Where K notes all other terms considered to be constant. A 1% increase in the ratio forward gas price/forward gas price a month before leads to an increase of 0.6711 % in the ratio forward power price/forward power price a month before. The interpretation is the sign of the coefficients is similar to that of a usual log-log model, although we are basically discussing increases in increases.

B Utilization rate of power plants

Since not all power plants are set to work simultaneously, one can specify how many times which percentage of capacity is utilized by specific power plants. An intuitive illustration of the utilization of power plants can be illustrated in figure 7. This figure shows the percentage of installed capacity of a specific kind of plant set to use in the year 2014.

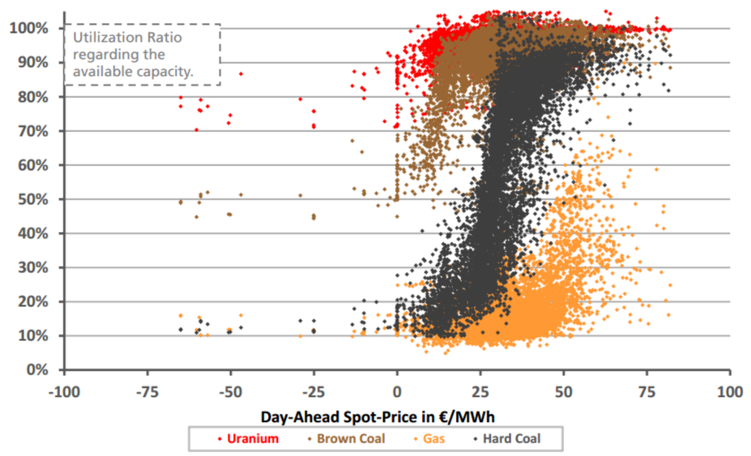

Figure 7
Utilization rates per hour in Germany in 2014, separated per type of power plant [Berger, 2014].

However, from figure 7, we can conclude that in practice the merit order does not consist of ordered sections of types of power plants. Although almost no coal-fired plants is set to work, the percentage of gas-fired plants does not become zero. Another interpretation is the rigidity of some plants, which implies there is a cost associated to fully stopping a plant due to the physical process on the time scale of the day. This argument is corroborated by the nonzero utilization ratios for the equilibria in figure 7.

C Model equations

This appendix will list the three model specifications estimated in section [5.3]. The first two are estimated with data format two, whereas the last one is estimated with data format three.

Simple model without any other demand and supply factors, referred to as Model I:

$$\begin{aligned}\Delta\ln(F_{e,t,T}) = \beta_1 + \beta_2\Delta\ln(P_{e,t}) + \beta_3\Delta\ln(P_{e,t-1}) + \beta_4\Delta\ln(F_{c,t,T}) + \beta_5\Delta\ln(P_{c,t}) + \\ \beta_6\Delta\ln(P_{c,t-1}) + \beta_7\Delta\ln(P_{c,t-2}) + \beta_8\Delta\ln(P_{g,t}) + \beta_9\Delta\ln(F_{g,t,T})\end{aligned} \quad (7)$$

Model including other demand and supply factors, referred to as Model II:

$$\begin{aligned}\Delta\ln(F_{e,t,T}) = \beta_1 + \beta_2\Delta\ln(P_{e,t}) + \beta_3\Delta\ln(P_{c,t}) + \\ \beta_4\Delta\ln(P_{c,t-1}) + \beta_5\Delta\ln(P_{c,t-2}) + \beta_6\Delta\ln(F_{g,t,T}) + \beta_7\left(I_t\cdot\Delta\ln(F_{g,t,T})\right) + \\ \beta_8\left(\Delta\ln F_{ghg,t,T}\right) + \beta_9\left(E_tS_{t+T}\right) + \beta_{10}\left(E_t\left(S_{t+T}\right)\right)^2\end{aligned} \quad (8)$$

Model including demand and supply factors, using monthly averaging of the third data format, referred to as Model III:

$$\begin{aligned}\Delta\ln(F_{e,t,T}) = \beta_1 + \beta_2\Delta\ln(P_{e,t}) + \beta_3\Delta\ln(P_{c,t}) + \\ + \beta_4\Delta\ln(F_{g,t,T}) + \beta_5\Delta\ln(F_{g,t,T})^2 + \beta_6\left(I_t\cdot\Delta\ln(F_{g,t,T})\right) + \\ \beta_7\left(\Delta\ln F_{ghg,t,T}\right) + \beta_8\left(E_tS_{t+T}\right) + \beta_9\left(E_t\left(S_{t+T}\right)\right)^2\end{aligned} \quad (9)$$

D Influence of sunshine hours on forward power prices

This appendix shows how sunshine hours explain the seasonal periodicity in power prices with the data of chapter 4. Figure 8 shows the time series of sunshine and the forward power price. The forward price is negatively correlated with the number of hours of sunshine. Section [2.5] explains several key pathways which enforce this relation.

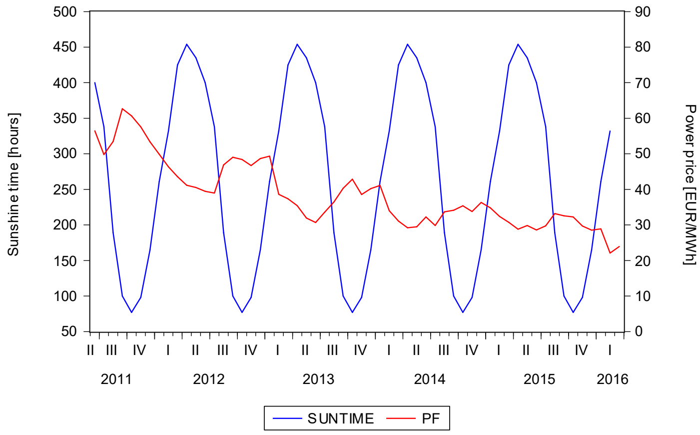

Figure 8
Time series of both the forward power price and the historical monthly average of the number of sunshine hours. These two variables appear to be negatively correlated, $R^2 = 0.205$ **[Berger, 2014].**