PRICING AND RISK PREMIA IN GERMAN ELECTRICITY MARKETS

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1 Introduction

1.1 Motivation

> *"Initially, it was all about increasing the share of renewables. Now we've got to look at the system as a whole and keep an eye on costs—renewables have to take on greater responsibility."*
>
> *Brigitte Zypries, Economy Minister of Germany (CEW, 2017)*

The increasing share of renewable energy sources (RES) in the energy mix of Germany that Brigitte Zypries refers to is supported by the Renewable Energy Act (REA). Introduced in 2000, the REA fosters the integration of renewable energies into a competitive energy market. To this end, producers of electricity from RES receive guaranteed subsidies that are paid by the consumers via a REA-levy. After the Fukushima Daiichi nuclear accident in 2011, the German government decided on a stepwise nuclear phase-out by 2022 as a part of the so-called "energy transition." As a consequence, nuclear production capacities have to be replaced to guarantee security of supply. To fulfill national climate protection goals, which require a target share of renewable energies in domestic energy consumption of 30% in 2020 and 50% in 2050, the majority of these missing capacities has to be replaced with RES (von Hirschhausen, 2014).

At the end of 2016, the total installed power plant capacity in Germany was about 197 gigawatts (GW). Approximately 52% of these availabilities stem from RES (103 GW). Among them, the potential capacity of wind energy (onshore and offshore) is about 50 GW and is about 41 GW for solar energy. The remaining installed nuclear power plants account for 11% of the total availability (Fraunhofer ISE, 2018).

Figure 1-1 depicts the distribution of generated electricity across the different energy sources for the years 2006 to 2016. In 2006, RES contributed about 11% to the gross electricity generation in Germany. Ten years later, RES account for nearly 30% of the total generation of 651 terawatt hours (TWh). Obviously, their share on actual generation differs from their share on installed capacities because the actual output from RES is very sensitive to changes in weather.

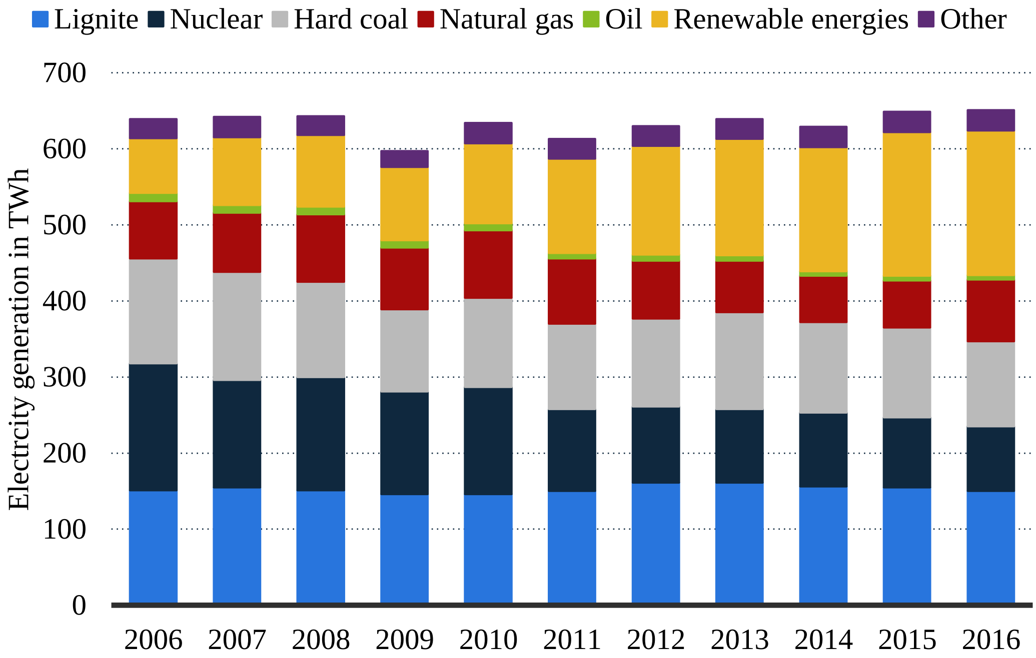

Figure 1-1: Gross electricity generation in Germany from 2006 to 2016
Source: Statista (2018), modified

Besides the growth in installed capacities of RES, the process of European energy market liberalization led to an increase in trading activities on electricity spot markets. The unbundling of generation and sales departments incentivized electricity firms to participate in power exchanges to get higher profits (Hagemann, 2015a).

This dissertation focuses on pricing and risk premia in electricity markets and addresses three specific topics related to the German market zone. The first two studies investigate research questions related to the German day-ahead electricity market, whereas the third study focuses on the intraday electricity market. To this end, this thesis applies econometric methods to get better insight into price building on wholesale markets.

Since the beginning of 2010, electricity generated under the REA in Germany has to be traded on power exchanges. As a result, the supply of RES significantly influences the price formation. The response of consumers to changes in prices is especially important for taxation policies. So far, a price elasticity of electricity demand in Germany is only reported for the residential or total electricity demand (Lee and Lee, 2010; Schulte and Heindl, 2017). Corresponding estimates for power exchanges are examined for the Californian, the Norwegian and the Dutch day-ahead electricity markets (Earle, 2000; Johnsen, 2001; Lijesen, 2007). Hence, the first research question to be answered in this thesis is:

> *What is the price elasticity of demand in the German day-ahead electricity market?*

Replication is important for reliability and confidence in research findings (Reed and Alm, 2015). Chang and Li (2015) report that only half of the research published in 13 highly ranked economics journals can be replicated. A replication may, therefore, ask whether the old results hold if newer data are added and/or methods are brought up to date (Clemens, 2015). The second empirical study of this dissertation contributes to the literature as a replication study on energy economics.

Since electricity cannot be stored economically, risk management plays an important role for producers and retailers. Because of price and/or demand risks, a risk premium, defined as the difference between the forward price and the expected spot price, is often observed in short-term electricity markets (Bessembinder and Lemmon, 2002;

Redl et al., 2009). Viehmann (2011) empirically examined the presence of risk premia in the German day-ahead market, confirming that risk premia are paid in periods of low demand and positive risk premia are paid during peak hours.

The second empirical study in this dissertation replicates the study by Viehmann (2011). Besides the replication, it makes the following contributions to the literature. First, it extends the original analysis with data of preceding years. Second, it investigates the impact of the introduction of negative electricity prices on risk premia. Negative price bids for the German market were first introduced in September 2008 at the German day-ahead market. Hence, the second research question to be answered in this thesis is:

> *Does the German day-ahead electricity market exhibit risk premia? What is the impact of negative electricity prices on risk premia?*

Given the complexity of electricity markets, prices can depend on other factors than market fundamentals such as changes in supply and demand. Asymmetric information between participants in electricity markets may distort the formation of a competitive price, too (von der Fehr, 2013). The role of private information is investigated in studies for the German day-ahead market, in which participants have an incentive to withhold capacities to increase the market price (Weigt and von Hirschhausen, 2008; Bergler et al., 2017). Variations of the subsequent German intraday price from the day-ahead price, however, are only analyzed from a fundamental perspective (Hagemann, 2015b; Pape et al., 2016). Hence, the third research question to be answered in this thesis is:

> *What is the impact of private and public information about unplanned power plant outages on German intraday electricity prices?*

The remainder of this dissertation is structured as follows. Chapter 2 provides an introduction to the German electricity market. Chapters 3, 4 and 5 are empirical studies related to the German day-ahead and intraday markets and can be read as autonomous papers. The main findings, possible policy options, study limitations and future research avenues are presented in Chapter 6.

1.2 Overview

In the following, I give a brief summary of the studies discussed in this dissertation. Every chapter can be read as an autonomous paper and is related to the German electricity market. I wrote Chapter 2 and Chapter 4, whereas Chapter 3 is an extension of a co-authored paper. Chapter 5 is based on a co-authored paper, too.

Chapter 2: Introduction to the German electricity market

Chapter 2 provides an introduction to the German electricity market. It follows the structure by Graeber (2014) and discusses the technical background of electricity trading and gives an overview of the price building mechanism on wholesale markets. The chapter introduces the framework of the German day-ahead and intraday markets, which is important for the studies investigated in Chapters 3, 4 and 5, respectively.

Furthermore, this chapter discusses the model by Bessembinder and Lemmon (2002), which is the standard theoretical model to explain the formation of risk premia in electricity markets and gives an overview of related empirical studies for German markets. Chapter 4 empirically analyzes the impact of negative electricity prices on risk premia in the German day-ahead market.

Chapter 3: Price elasticity of demand in the German day-ahead electricity market

Chapter 3 is based on a short paper titled "Price elasticity of demand in the EPEX spot market for electricity—New empirical evidence," co-authored with Prof. Dr. Werner Bönte, Dr. Sebastian Nielen and Dr. Torben Engelmeyer, and published in *Economics Letters* (2015, Vol. 135, pp. 5-8).[1]

This paper estimates the price elasticity of demand in the European Power Exchange (EPEX) day-ahead market for electricity in Germany. It argues that an institutional change in the year 2010 enables use of average hourly wind speed as an instrumental variable for hourly spot market prices to deal with potential endogeneity problems. The average price elasticity of demand covering the years 2010 to 2014 is about –0.43, and the results point to a decline in its absolute value over time.

Using volumes traded on the day-ahead market instead of load implies that the estimates do not represent the price elasticity of total electricity demand, but rather the price elasticity of demand in the day-ahead market. Future research might use the calculated elasticities to investigate market power in the German day-ahead market (Borenstein et al., 1999).

[1] Available here: https://doi.org/10.1016/j.econlet.2015.07.007.
An earlier version of this paper was presented at the 14th IAEE European Energy Conference in Rome. The authors are grateful for participants' comments and for the helpful suggestions of one anonymous referee from *Economics Letters*.

Chapter 4: Risk premia in the German day-ahead electricity market revisited: The impact of negative prices

Chapter 4 is based on a paper titled “Risk premia in the German day-ahead electricity market revisited: The impact of negative prices,” published in *Energy Economics* (2018) as a part of the special issue on “Replication in Energy Economics.”[2]

This paper replicates Viehmann's (2011) study that investigated risk premia in the German day-ahead electricity market from October 2005 to September 2008. While estimated sizes of risk premia can be replicated, this paper does not reproduce respective standard errors, leading to remarkable differences between the reported significance levels. An extension with data of preceding years points to further differences with respect to size and statistical significance. In addition, this paper analyzes the impact of negative prices on risk premia. Negative electricity prices were introduced in 2008 at the EPEX and in 2013 at the Energy Exchange Austria (EXAA). The results of an econometric analysis suggest that the introduction of negative prices has led to a decrease in risk premia compared to the period of a positive price regime.

While Viehmann (2011) conjectured that this might be the case, he was unable to empirically test this because the analysis was based on data comprised of only positive prices. These new results also have implications for theoretical research because Bessembinder and Lemmon's (2002) model does not consider the existence of negative prices.

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[2] Available here: https://doi.org/10.1016/j.eneco.2018.01.020.
Earlier versions of this paper were presented at the 39th IAEE International Conference in Bergen and the 11th BIEE Research Conference in Oxford. The author is grateful for participants’ comments and for the helpful suggestions of three anonymous referees from *Energy Economics*.

Chapter 5: Asymmetric information in the German intraday electricity market

Chapter 5 is based on a paper titled "Asymmetric information in the German intraday electricity market," co-authored with Andreas Maier. This paper is currently under review in *Energy Economics* (revise and resubmit).[3]

This paper investigates how private and public information about unplanned power plant outages impact intraday electricity prices in Germany. It uses data from the EPEX day-ahead and continuous intraday markets as well as market messages concerning unscheduled power plant non-usabilities from the European Energy Exchange (EEX) transparency platform. The results of an econometric analysis suggest that private and public information about unplanned power plant outages have a significant positive effect on the intraday price.

Furthermore, this paper shows that a reduction of the lead time on the intraday market enhances the possibilities of traders reacting to unplanned non-usabilities: an increased impact of private information on the electricity price is observed. The results also confirm an asymmetric impact of private and public information on the intraday price after the lead time reduction on the power exchange. The findings contradict the main objectives of the Regulation on Wholesale Energy Market Integrity and Transparency (REMIT), which stipulates that the possession of private information must not have an impact on electricity prices.

[3] Earlier versions of this paper were presented at the Young Energy Economists and Engineers Seminar 2017 in Nuremberg, the 40th IAEE International Conference in Singapore and the 36th USAEE/IAEE North American Conference in Washington, D.C. The authors are grateful for participants' comments and for the helpful suggestions of two anonymous referees from *Energy Economics*. An earlier version of this paper was awarded a student cash prize ($500) at the 36th USAEE/IAEE North American Conference.

2 Introduction to the German electricity market

This chapter introduces the German electricity market to build the theoretical framework for the thesis. It describes the technical background of electricity trading as well as the principles of price building. Furthermore, the functioning and interdependencies between the forward, day-ahead and intraday markets are discussed. Finally, this chapter provides an introduction to the theory of risk premia in electricity markets and an overview of empirical studies for Germany.

2.1 Technical background

Electricity as a commodity has special properties such as immateriality, homogeneity and non-storability. In addition, the transport of electricity is network-linked. In Germany, the four transmission system operators (TSO), 50Hertz, Amprion, TenneT and TransnetBW, are responsible for the reliable functioning of the power grid within their control area and for balancing electricity transactions between market participants (NEP, 2015).

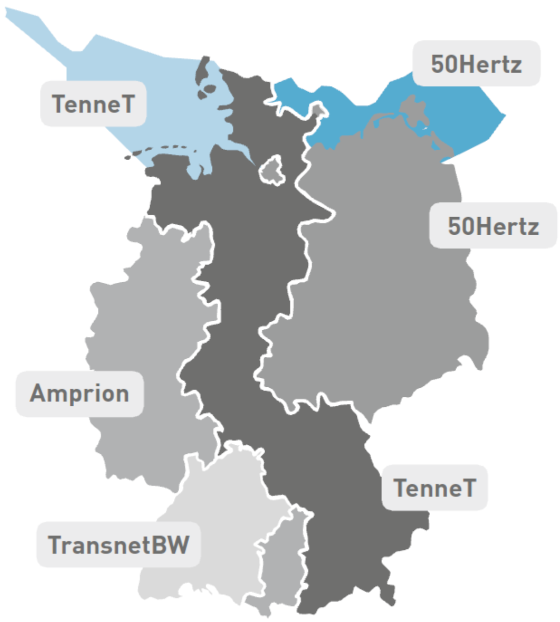

Figure 2-1: Control areas in Germany
Source: NEP (2015)

Due to the homogenous character of electricity, the physical flow of a distinct amount of energy is not traceable. For that reason, TSOs organize trading between market participants within a balancing group and distinguish between feed-ins and feed-outs. Feed-ins can be generation within the control area or electricity imports from other control areas; feed-outs are consumption in the control area or exports. All incoming and outgoing flows in a control area are measured by the TSOs or the local distribution system operators (DSO). If a certain amount of electricity is sold by market participants, the corresponding quantity on the balancing group is considered a feed-out, and on the corresponding balancing group of the buyer, it is considered a feed-in. Both market participants have to communicate the trading business to the respective TSO. Each balance sheet of a balancing group must correspond to inputs and withdrawals. Consequently, deviations may occur on the supply and/or demand side. An operator of a fossil-fueled power plant, for instance, may produce less electricity than expected because of an unplanned power plant outage. Other reasons for deviations in the balancing group could be forecast errors of the feed-in from RES or intermittent electricity demand. To adjust for these differences between incoming and outgoing flows, the balancing group manager has to use positive or negative control energy that is provided by the TSO. Table 2-1 presents an example for a balancing group. Since feed-outs exceed feed-ins, positive control energy has to be activated (Graeber, 2014).

Table 2-1: Sample balancing group of a market participant

Feed-in (MWh)		Feed-out (MWh)	
Power plant X	115.31	Consumption S	1.35
Power plant Y	42.12	Consumption T	11.20
Buy Z	10.00	Sell U	90.00
Positive control energy	5.12	Sell V	70.00
Total	172.55	Total	172.55

Source: Graeber (2014), modified

2.2 Control energy

Due to the large number of balancing groups within a control area, deviations can be partly compensated for between the market participants. However, due to unforeseen events, supply and demand are never exactly in equilibrium. To balance out these differences, a TSO uses control energy. The required amount of control energy corresponds exactly to the balance of the control energy of all balancing groups. If the sum of the generation is smaller than the consumption, positive control energy is used. Conversely, if the generation is greater than the consumption, negative control energy is used. Positive control energy is usually provided by increasing the production of a power plant or activating reserve capacities, and negative control energy by reducing its production or increasing electricity demand (Graeber, 2014).

Technically, an imbalance in the market can be detected by a deviation of the electricity grid frequency from the target size of 50 Hz. The frequency increases with an oversupply and decreases with an undersupply of electricity. Deviations can occur both on the demand side (e.g., by meteorological influences or inaccuracies in the load forecasts) and on the supply side (e.g., by power plant failures or forecast errors of RES). To provide sufficient positive or negative control energy, power plants must always be ready to reduce or increase their production (Consentec, 2014).

In case of a deviation of the frequency, a call of control energy takes place immediately. For this purpose, primary control reserve is activated. It is maintained in large thermal power plants across the entire European interconnected grid and used in a decentralized and fully automatic manner depending on the grid frequency. The primary control reserve is organized so that it can immediately replace the outage of three large power plants at any time. The secondary control reserve is instantly activated by the TSO in the control area of which the imbalance exists. Similarly, the tertiary control reserve is activated by the TSO if a disturbance exists for a long time. The price for the usage of control energy is determined via an auction mechanism and depends on the actual amount of the deviation. Because of the possibility to bid at negative prices for secondary and tertiary control reserves, the final balancing energy price can also be negative (Consentec, 2014).

2.3 Price building

Pricing on electricity spot markets is often described by the merit order model in the literature. In the short term, it is assumed that demand is price inelastic due to fixed-price tariffs on the retail markets. The supply curve is assumed to depend on the short-term marginal costs of the power plants, such as fuel costs and costs for CO_2 certificates. Accordingly, the supply curve represents an array of all power plants with rising marginal costs, the so-called merit order. The market-clearing price results from the marginal costs of the last of the power plants used to serve the demand. The fluctuations of the electricity price are thus mainly explained by changes in demand with respect to a constant power plant supply. Consequently, seasonality such as prices differences between weekdays and weekends can be analyzed with the merit order model (Graeber, 2014).

However, modeled electricity prices may differ from those observed in reality. The reason is that the merit order model neglects the intertemporal relationships that are important for a power plant dispatch. For example, in addition to fuel costs, start-up and shutdown costs must be taken into account. In a situation with a large but short decline in demand, it is therefore often not economically reasonable for a power plant operator to shut down the generator. The short-term marginal costs are thus below the fuel costs during off-peak demand and may be even negative (Fanone et al., 2013; Graeber, 2014).

Power plant operators producing with RES have lower marginal costs than operators of fossil-fueled power plants. Consequently, hydropower, wind and photovoltaic would be prioritized in the merit order if these generators offer their capacities under competitive conditions. The feed-in of RES shifts the position of conventional power generators with higher marginal costs in the merit order to the right as depicted in Figure 2-2. As long as demand remains constant, the market price decreases. This impact is known as the merit order effect (Sensfuß et al., 2008; Zweifel et al., 2017).

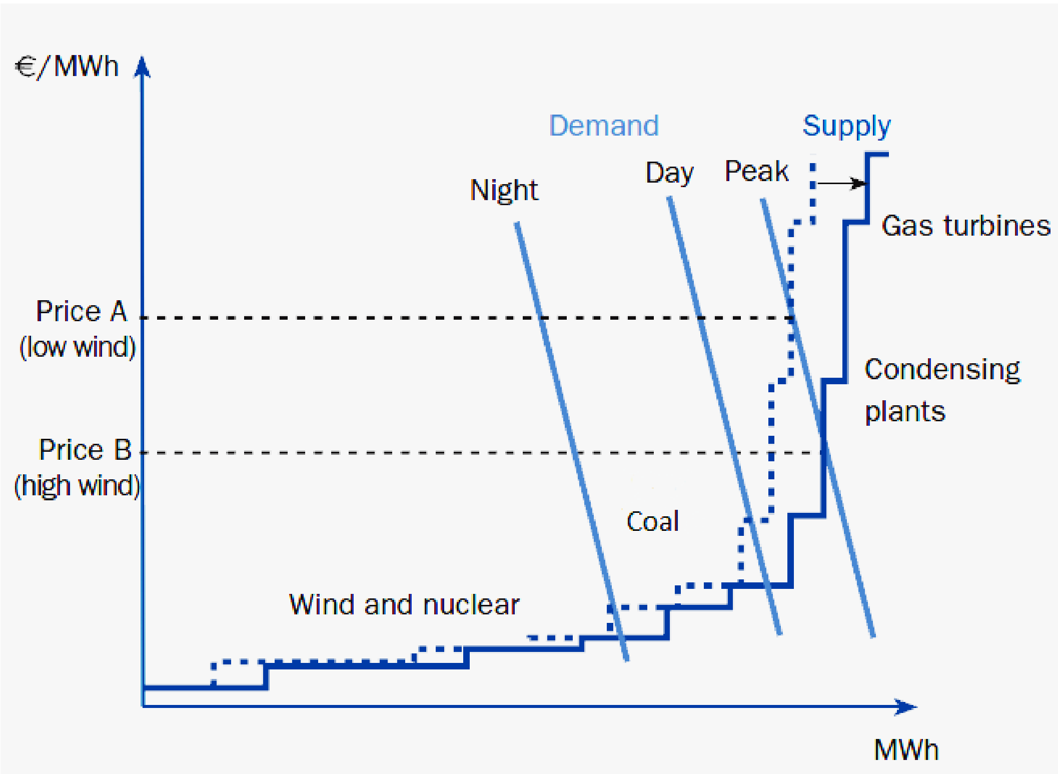

Figure 2-2: Merit order effect in the electricity spot market
Source: Krohn et al. (2009), modified

2.4 Markets

Trading with electricity on wholesale markets can be either exchange-based or settled over the counter (OTC). OTC trading is often carried out bilaterally or through organized trading platforms and brokers. Due to the low regulation and standardization, a high degree of flexibility and a large variety of delivery contracts are possible. However, OTC markets are often non-transparent and entail high transaction risks for the participants. In contrast, a power exchange offers trading at a high degree of transparency and with low transaction risks, but trading is restricted to frequently requested contracts. The most important wholesale markets are discussed in the following sections: forward, day-ahead and intraday markets (Graeber, 2014).

2.4.1 Forward market

Electricity with a long-term delivery horizon is traded on the forward market. On this market, power generators can hedge their production, and electricity distributors may obtain electricity in advance to provide consumers with price guarantees. Pricing on a forward market is determined by expectations of future spot market prices, which mainly depend on prices for primary energy sources. The shape of the forward price curve can be categorized in backwardation and contango. Backwardation describes a situation in which the current spot price is higher than the forward price. The market has a contango structure when forward prices exceed spot prices (Benth et al., 2008).

An exchange-based forward market in Germany is organized by the European Energy Exchange (EEX) in Leipzig. It offers continuous trading of futures[4] with delivery periods of one calendar week, one calendar month, one quarter and one calendar year. Futures can be traded with the delivery structure base as well as peak. Base means the

[4] Forward contracts, bought on power exchanges, are called futures.

constant delivery of a quantity of electricity over the entire delivery period, while peak means only the delivery during the periods of high consumption on weekdays. Because of the fixed base or peak contract structure, the EEX future market is less suitable for trading with electricity from intermittent RES (Graeber, 2014; EEX, 2018).

2.4.2 Day-ahead market

On the day-ahead market, electricity contracts are traded with next-day delivery. Exchange-based trading for the German market area is possible at the Energy Exchange Austria (EXAA) in Vienna and the European Power Exchange (EPEX) in Paris. The EPEX, which is the largest power exchange in Central Europe, is a joint venture between EEX and the French power exchange Powernext. The day-ahead market is designed as a unit price auction market in which participants can bid until 12 pm for contracts that involve the supply of electricity on the following day. Subsequently, EPEX will calculate a uniform market equilibrium price for each hour of the next day. In addition to single-hour bids, it is also possible to submit block bids that include several hourly contracts (EPEX SPOT SE, 2018a).

Figure 2-3 displays the aggregated buy and sell curves of the uniform day-ahead price for the electricity delivery period on November 18, 2016 from 01:00 to 02:00. In this example, the market price is –12.10 €/MWh, implying that producers are willing to pay for selling electricity on the spot market. Due to a higher feed-in from RES in a period of low demand, even subsequent contracts were traded at negative prices of –10.00 €/MWh for the contract from 02:00 to 03:00 and –0.01 €/MWh for the contract from 03:00 to 04:00, respectively.

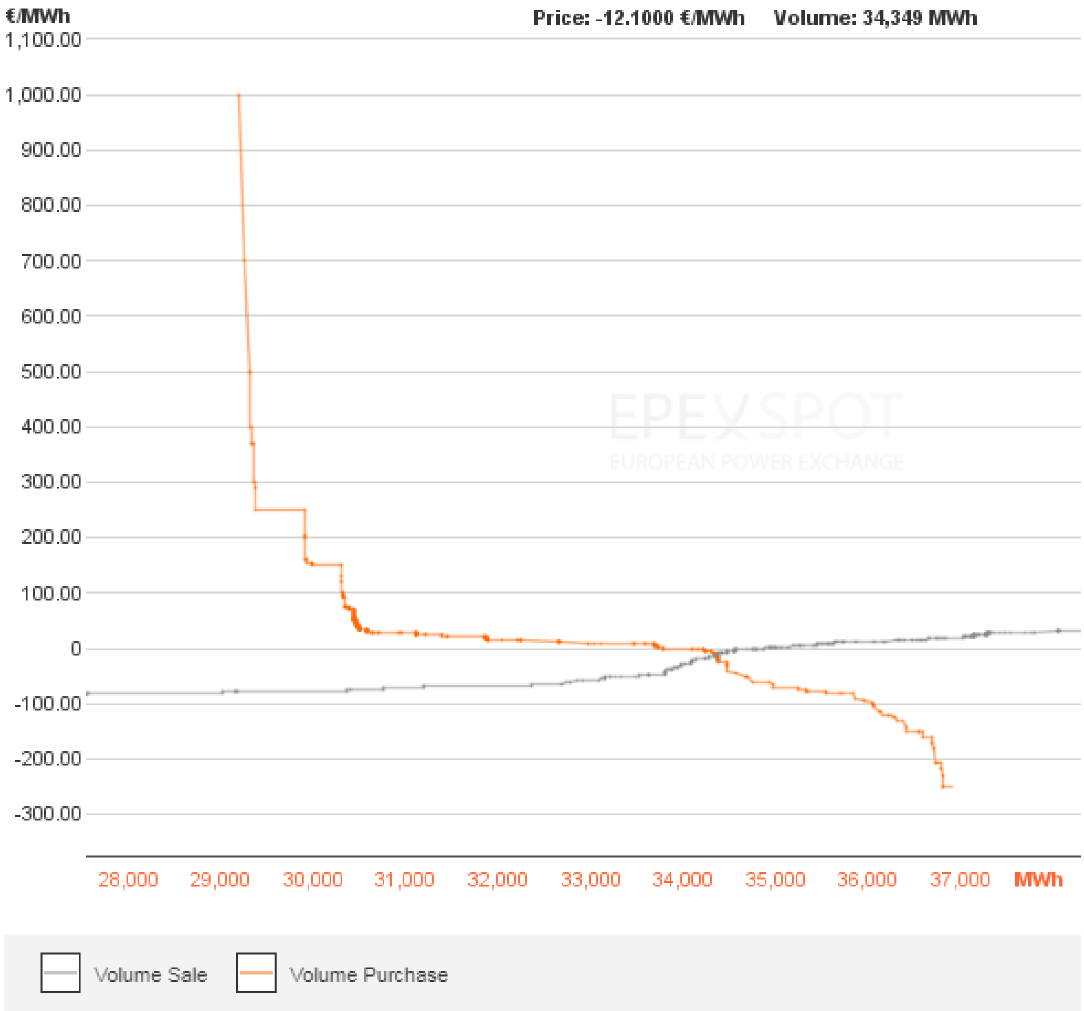

Figure 2-3: Market-clearing price in the EPEX day-ahead market
Source: EPEX SPOT SE (2018a)

The design of the day-ahead market enables trading with electricity produced from RES, since reliable generation forecasts are available one day in advance. However, significant deviations in actual production may occur due to the feed-in from intermittent energy sources. Demand on the day-ahead market does not represent end-user demand, but that of wholesale market participants such as retailers with their own electricity production. Depending on the market price, it may be more rational to produce electricity themselves or to buy in the market (Graeber, 2014).

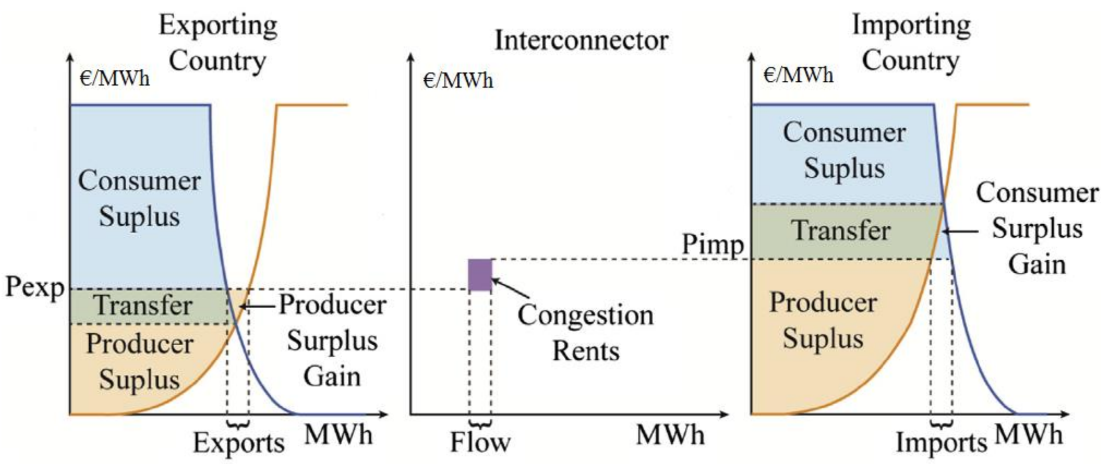

Figure 2-4: Social welfare with market coupling
Source: Ochoa and van Ackere (2015), modified

One additional feature of the day-ahead market is the coupling of several European market areas through a market coupling mechanism. The aim is welfare-optimized cross-border electricity trading against the background of the restriction of cross-border transport capacities. The most important step toward an European market integration took place in 2014, when price coupling in north-western Europe was introduced and further extended in 2015. As a result, the area covers 19 countries, representing about 85% of European electricity consumption. The market coupling mechanism accesses the bids of all involved electricity exchanges and the available transport capacities and calculates welfare-optimal electricity flows between the market areas (EPEX SPOT SE, 2018b).

As Figure 2-4 shows, social welfare with market coupling is calculated as the sum of the producer, consumer and interconnector surpluses. In the short term, a cross-border electricity trade increases the price in the exporting country and decreases the price in the importing country. This leads to surplus transfers between consumers and producers within both countries. The interconnector gains a congestion rent if electricity prices diverge (Ochoa and van Ackere, 2015).

2.4.3 Intraday market

To enable market participants to react on deviations in the power plant production scheme, the EPEX organizes a continuous intraday market subsequent to the day-ahead market. Electricity contracts can be traded on the same day up to 30 minutes before delivery. A market coupling mechanism, as in the day-ahead market, does not exist for the intraday market. However, the exchange framework allows cross-border transactions between the German, Austrian, French and Swiss market areas (EPEX SPOT SE, 2018c).

Similar to on the day-ahead market, pricing on the intraday market can be explained by the merit order model. However, the number of participants and thus liquidity on the intraday market is significantly lower than on the day-ahead market. Especially at night and on weekends, only a few traders are active. The total trading volume on the German continuous intraday market was about 4 TWh in December 2016, which is below 20% of the volume on the day-ahead market. As a result, the supply curve on the intraday market is steeper than on the day-ahead market (Pape et al, 2016).

Since fossil-fueled power plants require some lead time before activation, the potential liquidity on the intraday market decreases as the delivery horizon comes closer. Because of the possibility to trade until 30 minutes before delivery, the intraday market is suitable for balancing out forecast errors of RES, forecast errors in consumption and deviations in the power plant generation (e.g., unplanned power plant outages). However, the largest part of electricity produced through RES is still traded on the day-ahead market (Graeber, 2014).

Figure 2-5: Prices on the EPEX continuous intraday market

Figure 2-5 depicts an example for different electricity spot prices. It summarizes prices for the hourly product 15:00-16:00 on the German continuous intraday market at October 24, 2016. The volume weighted average price is 57.28 €/MWh and takes into account the first trade at around 23:00 on October 23 and the last trade at around 14:30 on October 24. In total, 633 trades took place during this time frame. The day-ahead price is 46.09 €/MWh and therefore, on average, is lower than intraday prices. Possible price drivers could be an overestimation of the feed-in from RES or unscheduled power plant non-usabilities.

2.5 Risk premia in electricity markets

In electricity markets, sellers and buyers are exposed to cost risks and revenue risks. Market participants have the possibility to hedge these risks by trading long-term contracts to close positions or by trading on short-term spot markets (Zweifel et al., 2017). The difference between the forward price F and the expected spot price S is defined as the ex ante risk premium RP [5]:

$$RP_c = F_{c,t} - E_t[S_{c,t+1}], \tag{2.1}$$

where c stands for the hourly contract at time t. To avoid wrong forecasts of the future spot price, the ex post approach with realized data is often used in the empirical literature (Haugom and Ullrich, 2012):

$$\begin{aligned} RP_c &= F_{c,t} - S_{c,t+1} \\ &= F_{c,t} - E_t[S_{c,t+1}] + E_t[S_{c,t+1}] - S_{c,t+1}. \end{aligned} \tag{2.2}$$

[5] The risk premium is also known as "forward premium" in the literature.

Assuming random noise for the forecast error, it follows that evidence of a nonzero ex post premium is also evidence of a nonzero ex ante premium. The risk premium tends to be positive when the forward price is higher than the spot price and vice versa. The standard theoretical reference for the formation of a risk premium in electricity markets is Bessembinder and Lemmon's (2002) equilibrium model. The model takes into account the non-storable character of electricity and the convexity of producer's cost function and explains the risk premium as an interplay between producer's and retailer's hedging pressure. It assumes that N_P power producers and N_R power retailers trade electricity in a competitive spot market in which power demand in the immediate future can be forecasted with precision. According to the model, each producer Pi has the following total cost function TC_i:

$$TC_i = F + \frac{a}{c}\left(Q_{P_i}\right)^c, \tag{2.3}$$

where F are fixed costs, a is a variable cost parameter, Q is the output and c is a constant with $c >= 2$. This cost function implies that marginal costs increase with output. Thus, it reflects a typical electricity industry with different production technologies and fuel sources such as nuclear, coal, oil and natural gas. The profit of producer π_{Pi} is defined as:

$$\pi_{Pi} = P_W Q_{Pi}^W + P_F Q_{Pi}^F - F - \frac{a}{c}\left(Q_{P_i}\right)^c, \tag{2.4}$$

where P_W denotes the spot price, ${Q_{Pi}}^W$ the quantity sold by producer i in the spot market and ${Q_{Pi}}^F$ the quantity bought or sold in the forward market at the fixed price P_F. Each producer's physical production Q_{Pi} is consequently the sum of its quantities sold on the spot and forward markets (${Q_{Pi}}^W + {Q_{Pi}}^F$).

The retailer R_j can buy or sell electricity forward and buys on the spot market the difference between realized retail demand and their forward trades. Consequently, the profit of retailer π_{Rj} is defined as:

$$\pi_{Rj} = P_R Q_{Rj} + P_F Q_{Rj}^F - P_W \left(Q_{Rj} + Q_{Rj}^F \right), \tag{2.5}$$

where P_R denotes the fixed retail price, Q_{Rj} the realized retail demand and $Q_{Rj}{}^F$ the quantity traded on the forward market. Note that $Q_{Rj}{}^F$ is negative if the retailer buys electricity forward. The first derivative of Equation (2.4) with respect to $Q_{Pi}{}^W$ yields the quantity sold by one producer in the spot market:

$$Q_{Pi}^W = \left(\frac{P_W}{a} \right)^x - Q_{Pi}^F \,, \tag{2.6}$$

where x is $1/(c - 1)$. Since total producer supply Q_P (= N_p ($Q_{Pi}{}^W + Q_{Pi}{}^F$)) must equal total retail demand Q^D (= $\sum_{j=1}^{N_R} Q_{R_j}$), the market-clearing spot price P_W can be expressed as:

$$P_W = a \left(\frac{Q^D}{N_P} \right)^{c-1} , \tag{2.7}$$

where N_p is the number of producers. Substituting Equation (2.7) in Equation (2.6) yields each producer's sales in the spot market:

$$Q_{Pi}^W = \frac{Q^D}{N_P} - Q_{Pi}^F \,. \tag{2.8}$$

To determine the optimal forward quantities by the producers and retailers, Bessembinder and Lemmon (2002) consider the respective profits first in the absence of any forward positions. This implies that $Q_{Pi}{}^{F}$ and $Q_{Rj}{}^{F}$ are set as zero, which leads to the profits ρ_{Pi} and ρ_{Rj}:

$$\rho_{Pi} = P_W\left(\frac{Q^D}{N_P}\right) - F - \frac{a}{c}\left(\frac{Q^D}{N_P}\right)^c, \tag{2.9}$$

and

$$\rho_{Rj} = P_R Q_{Rj} - P_W Q_{Rj} \tag{2.10}$$

Following Anderson and Danthine (1980) as well as Hirshleifer and Subramanyam (1993), the optimal forward position for producers and retailers is given by:

$$Q^F_{(P,R)i} = \frac{P_F - E(P_W)}{AVar(P_W)} + \frac{Cov(\rho_{(P,R)i}, P_W)}{Var(P_W)}, \tag{2.11}$$

where A is a measure for the volatility risk of the market participant.[6] The first term on the right-hand side of Equation (2.11) can be interpreted as the amount of bought/sold forward contracts to speculate on the difference between the forward and the expected spot price. The second term on the right-hand side of Equation (2.11) reflects participant's risks that the forward market can potentially hedge. The profit of producers depends on the generation costs and the revenues from sales to the retailers, whereas the profit of retailers depends on the costs of acquiring electricity and the revenues from sales to customers. Since producer's revenues equal retailer's costs, the equilibrium forward price depends on the variability in retail revenues and in production costs.

[6] For the sake of simplicity, Bessembinder and Lemmon (2002) argue that both market participants are equally concerned with risk. Using heterogeneous risk coefficients impacts only the magnitude, but not the sign of the risk premium.

The covariance in Equation (2.11) is calculated for producers and retailers, respectively:

$$Cov(\rho_{Pi}, P_W) = Cov(a\left(\frac{Q^D}{N_p}\right)^c - F - \frac{a}{c}\left(\frac{Q^D}{N_p}\right)^c, P_W)$$
$$= \frac{1}{a^x} Cov(P_W^{x+1}, P_W) - \frac{1}{ca^x} Cov(P_W^{x+1}, P_W). \tag{2.12}$$

Analogous, the covariance between retailer's profits and the spot price can be expressed as:

$$Cov(\rho_{Rj}, P_W) = Cov(P_R Q_{Rj} - P_W Q_{Rj}, P_W)$$
$$= P_R Cov\big(Q_{Rj}, P_W\big) - Cov\big(P_W Q_{Rj}, P_W\big). \tag{2.13}$$

Substituting Equations (2.12) and (2.13) accordingly in Equation (2.11) yields forward demand for the producers:

$$Q_{Pi}^F = \frac{P_F - E(P_W)}{AVar(P_W)} + \frac{1}{a^x}\left(1 - \frac{1}{c}\right)\frac{Cov(P_W^{x+1}, P_W)}{Var(P_W)}, \tag{2.14}$$

and forward demand for the retailers:

$$Q_{Rj}^F = \frac{P_F - E(P_W)}{AVar(P_W)} + P_R \frac{Cov(Q_{Rj}, P_W)}{Var(P_W)} - \frac{Cov\big(P_W Q_{Rj}, P_W\big)}{Var(P_W)}. \tag{2.15}$$

The equilibrium forward price is derived from adding the sum of the optimal forward positions of all producers N_P and retailers N_R:

$$\sum_{i=1}^{N_P} Q_{Pi}^F + \sum_{j=1}^{N_R} Q_{Rj}^F = 0 \tag{2.16}$$

Substituting $Q_{Pi}{}^{F}$ by Equation (2.14) and $Q_{Rj}{}^{F}$ by Equation (2.15) and solving after P_F, the forward price can be formulated as:

$$P_F = E(P_W) - \frac{N_P A}{(N_R + N_P)ca^x}\left[cP_R Cov(P_W^x, P_W) - Cov(P_W^{x+1}, P_W)\right]. \tag{2.17}$$

The forward price converges to the expected spot price if the number of firms in the industry ($N_R + N_P$) goes to infinity or if risk is irrelevant to the industry ($A = 0$). Using second-order Taylor series expansions, Bessembinder and Lemmon (2002) rewrite Equation (2.17) as:

$$P_F - E(P_W) = \alpha Var(P_W) + \gamma Skew(P_W), \tag{2.18}$$

where α and γ are represented as follows:

$$\alpha \equiv \frac{N_P(x+1)A}{(N_R + N_P)ca^x}\left([E(P_W)]^x - P_R[E(P_W)]^{x-1}\right) \tag{2.19}$$

$$\gamma \equiv \frac{N_P(x+1)A}{2(N_R + N_P)ca^x}\left(x[E(P_W)]^{x-1} - (x-1)P_R[E(P_W)]^{x-2}\right). \tag{2.20}$$

To induce risk-averse retailers N_R to enter the industry, the fixed retail price P_R must exceed the expected spot price, which results in $\alpha < 0$ and $\gamma > 0$. Consequently, the model leads to the relationship in which the risk premium is negatively related in the variance of the spot price distribution and upward biased when the price skewness of the spot price distribution is large.

This result can be explained because spot prices are positively related with demand, profits of retailers are increasing in demand and profits of retailers are decreasing in prices. An increase in spot price variance will increase the number of high demand realizations and therefore increase the profit of retailers, since the effect of higher demand-induced revenues outweighs the negative effect of higher demand-induced spot prices, on average. However, the increase in variance will also increase the number of low demand realizations and has a negative impact on retailer's profits. Consequently, retailers have an incentive to hedge this risk by selling electricity forward, resulting in lower forward prices (van Koten, 2016).

A higher spot price skewness implies a higher probability of price spikes. As a result, retailer's profits are affected negatively. Therefore, retailers prefer to hedge against this risk by buying more electricity in the forward market, resulting in higher forward prices. Taking everything into consideration, the risk premium represents a compensation for bearing price and/or demand risks. Using simulations based on Equation (2.17) and Equation (2.18), Bessembinder and Lemmon (2002) derive four hypotheses with respect to the equilibrium risk premium.[7]

Hypothesis 1: The equilibrium risk premium decreases in the anticipated variance of spot prices, ceteris paribus.

Hypothesis 2: The equilibrium risk premium increases in the anticipated skewness of spot prices, ceteris paribus.

Hypothesis 3: The equilibrium risk premium is convex, initially decreasing and then increasing, in the variability of power demand, ceteris paribus.

Hypothesis 4: The equilibrium risk premium increases in expected power demand, ceteris paribus.

[7] Van Koten (2016) is able to replicate Hypotheses 3 and 4, but not Hypotheses 1 and 2. However, further simulations support an adjustment of Bessembinder and Lemmon's (2002) model with flexible retail tariffs instead of the assumption of a fixed retail tariff.

Hypotheses 1, 2 and 4 build the theoretical framework for many empirical studies and are either supported or not supported. For instance, Longstaff and Wang’s (2004) study for the PJM market confirms that risk premia are negatively related to the variance of spot prices and positively related to the skewness of spot prices. However, Haugom and Ullrich (2012) revisit the PJM market, and their results point to highly unstable or even opposite signs for variance and skewness.

Empirical studies examining risk premia in German electricity markets follow the methodological approach by Longstaff and Wang (2004). They can be subdivided into studies that calculate the risk premium exactly as the difference between forward/future and spot prices and studies in which the price of a spot market is compared with the price of a subsequent spot market.

Redl et al. (2009) investigate the price formation in the EEX future market and discuss the relevance of forecast errors of supply- and demand-side shocks. Comparing prices of month-ahead futures with monthly average day-ahead prices, the study presents evidence for a positive mean risk premium and confirms Bessembinder and Lemmon's (2002) hypothesis that the skewness of spot prices plays an important role for the risk assessment of market participants. However, the results do not provide evidence for a negative influence of the variability in spot prices, but for a positive impact on the risk premium.

Redl and Bunn (2013) extend the study by Redl et al. (2009) and analyze further determinants of the risk premium besides the variance and skewness of the spot prices. The authors conclude that the electricity risk premium is a rather complex function of fundamental and behavioral components such as fossil fuel prices, market conduct and unexpected changes in supply and demand.

Fleten et al. (2015) investigate the presence of an "overnight risk premium" (i.e., the first difference of the daily forward price) for quarterly, monthly and yearly futures on the EEX future market. Their findings point to a decrease in risk premia over time as the respective future contracts approach the delivery ("front") period. Including the variance and skewness of EPEX day-ahead prices as explanatory variables in the regression, the results also present evidence that the overnight risk premium is negatively related to the variability of spot prices and positively related to the skewness of spot prices.

Daskalakis and Markellos (2009) analyze whether the initiation of the European Union Emissions Trading Scheme has an impact on the pricing of electricity forward. Using daily prices of the EPEX day-ahead and the subsequent EPEX continuous intraday market, their results point to a positive relationship between carbon allowance returns and risk premia. This conjecture is driven by substantial uncertainties about the carbon market. To hedge against unexpected price changes of carbon allowances, sellers of forward contracts may require a "carbon risk premium." Furthermore, Daskalakis and Markellos (2009) present evidence for the presence of a negative and statistically significant mean risk premium on the German electricity market.

Viehmann (2011) analyzes risk premia in Germany using data of the EXAA and EPEX day-ahead market from October 2005 to September 2008. Since auction results on the EXAA are published two hours in advance, a corresponding price for an electricity contract on the EXAA can be interpreted as a forward (price), whereas its price on the EPEX is the respective spot (price). The results of the empirical investigation suggest that market participants are willing to pay significant negative risk premia in periods of low demand and positive risk premia during peak hours, which aligns with Hypothesis 4 of the model by Bessembinder and Lemmon (2002).

Table 2-2: Overview of empirical studies for German electricity markets

Study	Data used
Redl et al. (2009)	EEX futures and EPEX day-ahead
Redl and Bunn (2013)	EEX futures and EPEX day-ahead
Fleten et al. (2015)	EEX futures and EPEX day-ahead
Daskalakis and Markellos (2009)	EPEX day-ahead and EPEX intraday
Viehmann (2011)	EXAA day-ahead and EPEX day-ahead

Chapter 4 of this dissertation replicates Viehmann's (2011) study and extends the empirical analysis to previous years, when electricity prices had to be positive. Furthermore, it addresses the impact of negative prices on risk premia. Negative price bids for the German market were first introduced on September 1, 2008, at the EPEX and on October 15, 2013, at the EXAA.

3 Price elasticity of demand in the German day-ahead electricity market

3.1 Introduction

At the beginning of the year 2010, the electricity market in Germany experienced a remarkable institutional change. Since January 1st 2010, German transmission system operators are required to trade energy produced under the Renewable Energy Act (REA) on spot markets. Producers of electricity from renewable energy sources (RES) receive a fixed feed-in tariff for each kilowatt hour produced, which network operators sell directly over power exchanges. As a result, the supply of RES significantly influences the price formation on spot markets.

This paper quantifies the price elasticity of electricity demand in the European Power Exchange (EPEX) day-ahead market for Germany. We argue that due to the institutional change at the beginning of 2010, wind speed has become a suitable instrumental variable for the price on this market. This is not the first study quantifying the price elasticity of demand using data of day-ahead spot markets and employing an instrumental variable approach. Lijesen (2007) uses the lagged price as an instrumental variable for the clearing price. As in our study, Graf and Wozabal (2013) also use price data of the EPEX day-ahead market. However, they use prices for primary energy and emission rights as instrumental variables for the market price. Their results (Table 5, p. 957) point to a statistically insignificant or even positive relationship between spot price and load. Our results indicate a negative and statistically significant relationship between spot prices and traded volumes.

This paper is organized as follows. The following section reviews the literature with respect to estimation methods of price elasticity of electricity demand. Section 3.3

explains the EPEX day-ahead market for electricity and discusses the effects of RES on the price formation. Section 3.4 presents the methodology and the estimation results. Section 3.5 concludes.

3.2 Literature review

Empirical studies on price elasticity of electricity demand differ in the type of estimation approaches. The economic standard is conducting an ordinary least squares (OLS) estimation from a loglinear model, since the estimated coefficients can be directly interpreted as elasticities. Several studies implement an autoregressive distributive lag (ARDL) framework to estimate short- and long-run elasticities of residential electricity demand (Narayan and Smyth, 2005; Halicioglu, 2007).

Kamerschen and Porter (2004) estimate price elasticities for the residential and industrial sector as well as for the total demand in the U.S. from 1973-1998. They use a three-stage least square (3SLS) estimation approach on different versions of a simultaneous supply and demand model. The results suggest higher values for households (–0.85 to –0.94) and more inelastic figures for industrial (–0.34 to –0.55) and total electricity demand (–0.13 to –0.55).

Alberini et al. (2011) analyze residential demand for electricity in the U.S. using generalized least squares (GLS) regressions over the period 1997-2007. To test the robustness of the estimation, the authors use the instruments' state-level electricity price and lagged price for the average electricity price faced by the residential customers. The obtained elasticities of about –0.67 to –0.86 suggest some potential for pricing policies in contrast to prior studies.

Schulte and Heindl (2017) investigate price and income elasticities of residential electricity and heating demand in Germany from 1993 to 2008 by applying a quadratic expenditure system. Their results suggest a price elasticity for electricity of –0.43.

The price elasticity of electricity demand on spot markets, however, is rarely discussed in the literature. Earle (2000) calculates the demand responsiveness on the California Power Exchange day-ahead market directly at the respective market-clearing price and quantity. The results suggest that the price elasticity of electricity is elastic in 27% of trading hours, but in more than 50% of hours, it is less than –0.10.

Johnsen (2001) adopts a full information maximum likelihood procedure to estimate price responsiveness of the Norwegian electricity day-ahead market from 1994 to 1995. Since the local electricity sector is mainly hydro-based, expectations of future weather conditions play an important role. Changes in temperature or snowfall may heavily influence the dispatch of water storages, which are able to cover about 75% of the annual generation. Therefore, market supply can be associated with the producer's current valuation of storage levels. The obtained elasticities derived from weekly data lie between –0.05 to –0.35.

Lijesen (2007) estimates price elasticity of demand on the Dutch day-ahead electricity market with a loglinear model. To avoid endogeneity problems, a 2SLS approach is used with lagged price as an instrumental variable for price. Electricity demand is proxied by the total system load (i.e., consumption) on an hourly basis. The results point to an inelastic value of –0.03 during peak load periods in 2003.

Graf and Wozabal (2013) investigate competitiveness of the EPEX day-ahead market in Germany with a conjectural variations approach and a fundamental market model. They find evidence that the spot market was competitive from 2007 to 2010. To estimate the marginal impact of price on quantity, the authors use prices for primary energy and emission rights as instrumental variables for the market price. However, their results point also to a statistically insignificant or even positive relationship between spot price and load, which indicates that prices for primary energy and emission rights might not be suitable instrumental variables for the day-ahead price.

3.3 Identification strategy

In the past decade, electricity from RES has become more important in Germany due to the support by the REA. The electricity generated from wind turbines, for instance, is fed into the grid of the closest distribution system operator (DSO), which pays a specified feed-in tariff. Next, the network operator provides the electricity completely to an upstream transmission system operator (TSO) and in turn receives the feed-in tariff back.

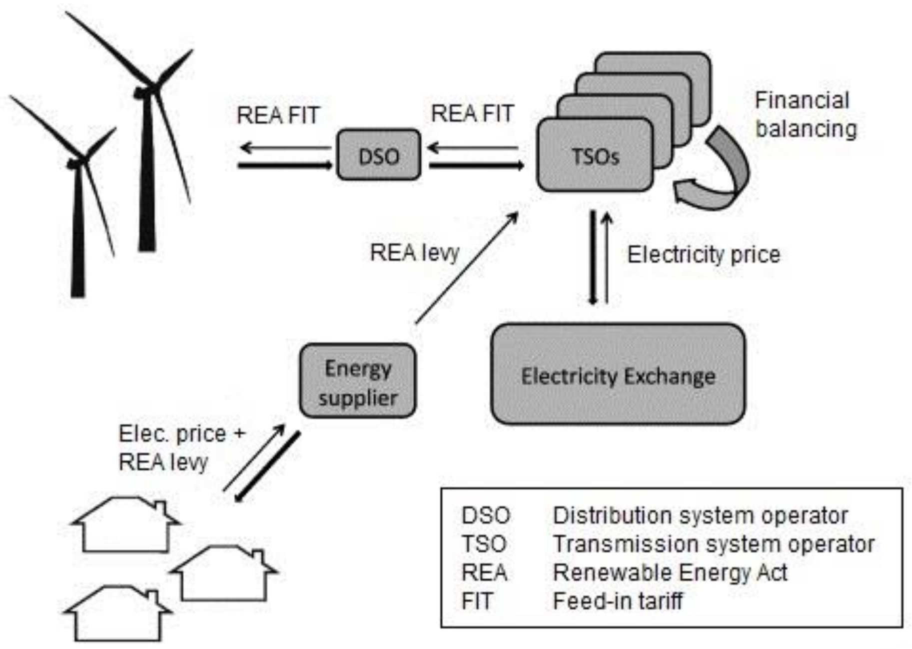

Figure 3-1: Marketing mechanism after the institutional change in 2010
Source: Ketterer (2014), modified

Before 2010, all TSOs assigned the electricity quantities and financial burdens to electricity supply companies in the respective service area. These costs were covered by the end user with a REA-levy or through the establishment of a dedicated green energy tariff. The electricity from RES was traded over the counter (OTC) and influenced the demand in the EPEX day-ahead market. Since supply companies bought the electricity in advance, the residual demand was cleared with the capacities on power exchanges (Sensfuß et al., 2008).

Since 2010, electricity from RES has to be sold at the day-ahead market because of an amendment in the REA, the so-called *Ausgleichsmechanismusverordnung* (Ketterer, 2014). Figure 3-1 illustrates the physical and monetary flows from the installations to the end users. TSOs receive revenues from selling renewable power on the wholesale market and the REA-levy paid by the customers. The location of the electricity exchange, although not legally defined, is in practice the EPEX day-ahead market.

This institutional change has had important implications for the influence of RES both on the supply side and the demand side of the EPEX day-ahead market. Since 2010, the influence of RES has been restricted to the supply side of the market. Figure 3-2 shows the daily traded volume on the day-ahead market for the years 2006 to 2014. The reason for the drastic increase at the beginning of 2010 is the amendment in the REA. An increase (decrease) in electricity from RES that has to be sold at the spot market implies that the marginal costs of the price determining power plant tend to be lower (higher). Consequently, an increase (decrease) in electricity from RES leads ceteris paribus to a decrease (increase) in the spot market price. In contrast, the demand side of the EPEX day-ahead market is no longer directly affected by changes in electricity from RES.

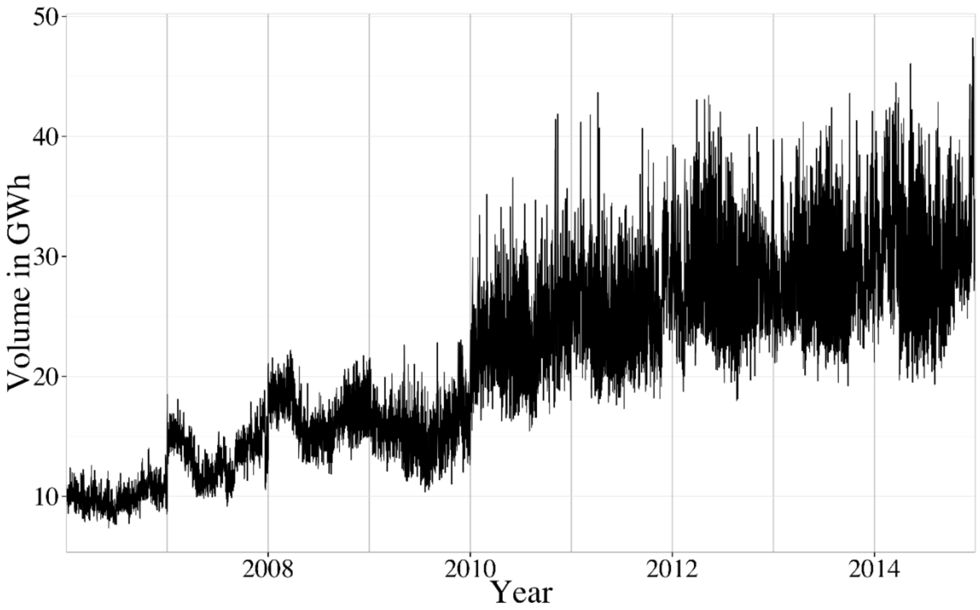

Figure 3-2: Daily electricity volume traded on EPEX day-ahead market in the years 2006 to 2014

This institutional change allows us to deal with the endogeneity problem arising from the simultaneity of price and output. To estimate the price elasticity of demand in the EPEX day-ahead market, we use an instrumental variable approach. In particular, we use wind speed to instrument for the spot market price. Wind energy has the highest share of RES in the market area, its production essentially being determined by wind speed.

To identify the causal effect of price changes on electricity demand in the EPEX day-ahead market, the instrumental variable (wind speed) has to be strongly correlated with the spot market price. At the same time, it has to influence the demand only indirectly via its effect on the spot price. While we expect to find a strong negative correlation between wind speed and spot price before and after 2010, we argue that wind speed is not a valid instrument before 2010. The exclusion restriction only holds after the institutional change because the demand side in the EPEX day-ahead market was directly affected by wind energy before 2010. In contrast, only the supply side is affected by wind energy after the amendment in the REA.

3.4 Data and results

This study combines data obtained from two different sources for the observation period from January 2006 to December 2014. First, EPEX's website provides information about the electricity volumes and prices for each trading hour on the day-ahead market. Second, we use the climate panel provided by the German weather service (Deutscher Wetter Dienst, DWD). The climate panel contains information such as wind speed, temperature and sunshine duration from more than 70 weather stations in Germany. We use the average hourly wind speeds measured at these stations as our instrumental variable for the respective hourly spot market price. Sunshine duration per hour s and the average temperature te are used as further control variables. In addition, we include dummy variables C for hours, weekends, months and years to control for time-specific effects.

In our econometric specification, we make use of the market-clearing price and quantity; i.e. the hourly traded volume q is the dependent variable and the respective hourly market price p is the (endogenous) explanatory variable:

$$ln(\mathrm{q}_t) = \alpha + \beta_1 ln(\mathrm{p}_t) + \beta_2 ln(\mathrm{te}_t) + \beta_3 ln(\mathrm{s}_t) + \gamma' C_t + \varepsilon_t, \tag{3.1}$$

with $t = 1, \ldots, N$ where N indicates the number of hours in the sample. We use a log-log specification of the demand equation that implies that the estimated coefficient of the logarithm of the instrumented market price represents the price elasticity of demand in the EPEX market.

Graf and Wozabal (2013) and Lijesen (2007) use load as the dependent variable, i.e., the total electricity demand. Lijesen (2007, p. 254) provides two major arguments for estimating the effect of spot market prices on total demand. First, he argues that "this approach captures both the effects in the spot market itself as well as the effects on the OTC contracts with prices linked to the spot price." However, this argument is only valid if the agreed-upon prices in OTC contracts are linked to the spot price. Unfortunately, the contents of bilateral OTC contracts are usually undisclosed information (Lijesen, 2007).

Second, Lijesen (2007, p. 254) states that this approach avoids "the measurement problems related to distinguishing between demand and supply on the spot market." We argue that our instrumental variable allows us to deal with this endogeneity problem. Nevertheless, using the hourly traded volume instead of load implies that our estimates do not represent the price elasticity of total electricity demand with respect to spot market price, but rather the price elasticity of demand (bids) in the EPEX day-ahead market.

Tests of endogeneity (Durbin, Wu-Hausman) reject the null hypothesis that the price variable is exogenous, which implies that OLS estimates would be biased (see Appendix Table A. 1). All variables are furthermore checked for the presence of a unit root by performing Augmented Dickey-Fuller (ADF) tests with and without a trend. The results suggest that all variables in the regressions are stationary (see Appendix Table A. 2). The results of simple OLS regressions suggest a positive relationship between price and volume in the years before the amendment in the REA. Although the effect is negative after the policy change, the estimated coefficients are biased (see Appendix Table A. 3 and Table A. 4).

Table 3-1: Second-stage estimation results before the policy change

		Years before amendment in REA			
VARIABLES	2006-2009	2006	2007	2008	2009
Price	-0.0488***	-0.0562***	-0.0188	0.0885***	-0.0657
	(0.0042)	(0.0113)	(0.0172)	(0.0094)	(0.0659)
Temperature	-0.3450***	-0.892***	-0.579***	-0.520***	-0.973***
	(0.0495)	(0.0588)	(0.161)	(0.0369)	(0.424)
Sunshine	-0.0076***	-0.00311	-0.00613***	-0.00631***	0.000389
	(0.00067)	(0.00243)	(0.000185)	(0.00142)	(0.00118)
Dummies					
Hour	Yes			Yes	
Weekend	Yes			Yes	
Month	Yes			Yes	
Year	Yes			No	
Observations	34,914	8,749	8,731	8,748	8,686
F-Test (Wind speed) (First-stage)	2,196.09***	202.45***	1,062.45***	34.12***	41.55***

Autocorrelation and robust standard errors as proposed by Andrews (1991) in parentheses.
Dependent variable: logarithm of hourly traded volume.
Significance levels: *** p<0.01, ** p<0.05, * p<0.1.

Table 3-2: Second-stage estimation results after the policy change

		Years after amendment in REA				
VARIABLES	2010-2014	2010	2011	2012	2013	2014
Price	-0.432***	-0.907***	-0.733***	-0.393***	-0.258***	-0.318***
	(0.0754)	(0.0334)	(0.0619)	(0.0687)	(0.0181)	(0.00684)
Temperature	-0.795*	-3.214***	-1.481**	-0.822***	-0.345	-0.297***
	(0.421)	(0.679)	(0.588)	(0.296)	(0.223)	(0.114)
Sunshine	-0.00873***	-0.00857	-0.0165***	-0.00769***	-0.000322	-0.0108***
	(0.000326)	(0.00826)	(0.00204)	(0.00142)	(0.00190)	(0.00327)
Dummies						
Hour	Yes			Yes		
Weekend	Yes			Yes		
Month	Yes			Yes		
Year	Yes			No		
Observations	43,609	8,748	8,744	8,726	8,695	8,696
F-Test (Wind speed) (First-stage)	58.15***	1901.10***	208.31***	95.59***	98.19***	692.60***

Autocorrelation and robust standard errors as proposed by Andrews (1991) in parentheses.
Dependent variable: logarithm of hourly traded volume.
Significance levels: *** p<0.01, ** p<0.05, * p<0.1.

Table 3-1 and Table 3-2 summarize the results of the second stage of two-stage least square regressions (2SLS) for the observation periods before and after the institutional change, respectively. In column one of Table 3-1, we report the results of the second stage regressions covering the period from 2006 to 2009. The estimated price elasticity is about –0.05 and is statistically significant. Note that the exclusion restriction does not hold for this period because wind speed may also affect the demand side of the EPEX day-ahead market. Hence, this estimate is likely to be biased. Likewise, the results of regressions conducted for each year before the institutional change tend to be biased, too. The estimated price elasticities are not statistically significant (2007 and 2009) or positive significant (2008), which underscores the violation of the exclusion restriction. Only the point estimate for 2006 suggests a negative relationship between electricity price and traded volume.

In contrast, the estimate of the price elasticity of demand obtained from 2SLS regressions for the period after the policy change should be unbiased. The point estimate for average price elasticity of demand is about –0.43 and statistically significant, implying an inelastic demand. In more detail, results of regressions performed separately for each year of the period from 2010 to 2014 suggest that electricity demand became less elastic over the years. The point estimate of the price elasticity is about –0.91 in 2010, but its average value is around –0.32 in the period from 2012 to 2014. Moreover, the hypothesis of weak instruments can be rejected with a F-test on the coefficient of the variable wind speed in the first stage regression (Stock et al., 2002).

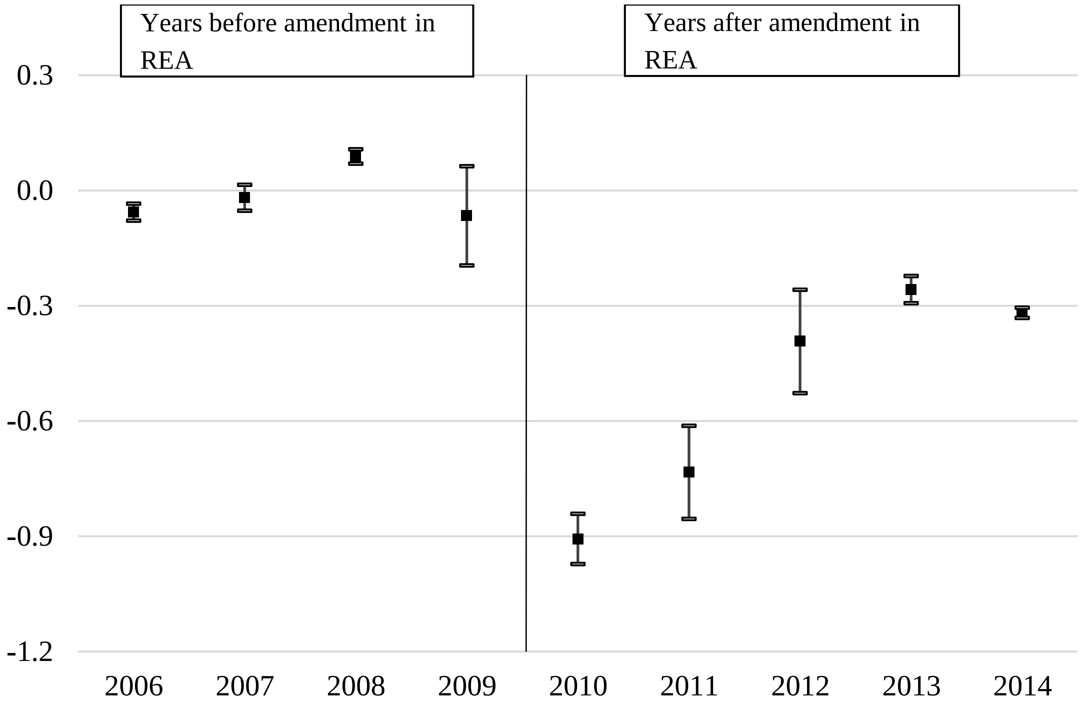

Figure 3-3: Price elasticity of demand – point estimates and the 95% confidence intervals

As explained above, we argue that the instrumental variable wind speed is only valid after the amendment in the REA. Figure 3-3 illustrates the differences between the 2SLS estimates before and after the institutional change providing point estimates of the price elasticity of demand within the respective 95% confidence intervals. All point estimates are negative and statistically significant after the institutional change, while this is not the case before 2010: For 2008 the point estimate is even positive. In general, our results suggest that wind speed is a valid instrument for the spot market price from 2010 onwards.

The log specification in Equation (3.1) leads to the consequence that negative electricity prices are excluded in the regressions. However, the sample after the regime switch in 2010 includes 211 negative prices, which might distort the presented elasticities. Negative prices reduce the yearly mean of the spot prices when compared to a sample with only positive prices. To control for this effect, we estimate Equation (3.1) again, but without a log-specification for electricity prices. This approach is conducted for yearly samples with and without negative prices, respectively. Afterwards, the estimated coefficients for the variable price are multiplied with the ratio between the mean price and the mean traded volume for every year.

Table 3-3 summarizes the year-specific estimates for the price elasticity of demand from the log-model as well as the hand-calculated elasticities with and without negative electricity prices. All estimates suggest a decrease in the absolute value during the period from 2010 to 2013. While the results for the log-model point to inelastic values in general, the hand-calculated elasticities suggest an elastic relationship in the years 2010 and 2011. Including negative electricity prices leads to a decrease in the absolute value of the point estimates.

Table 3-3: Summary of year-specific elasticities

	Years after amendment in REA				
	2010	2011	2012	2013	2014
Log-model	-0.91	-0.73	-0.39	-0.26	-0.32
Adjusted model without neg. prices	-1.34	-1.06	-0.54	-0.34	-0.45
Adjusted model with neg. prices	-1.31	-1.04	-0.48	-0.33	-0.42

3.5 Conclusion

This paper provides estimates for the price elasticity of demand in the EPEX day-ahead market using wind speed as an instrumental variable for the market price. Our identification strategy is based on an institutional change at the beginning of the year 2010. We argue and provide empirical evidence that wind speed is a valid instrument after this change but not before. Our estimation results suggest that the average price elasticity of demand in the EPEX day-ahead market is about –0.43 in the period from 2010 to 2014. In the first two years after the policy change, the absolute value of the point estimate is even higher (0.91 in 2010) but it declined over time and is around 0.32 in the years from 2012 to 2014.

It can be presumed that the price elasticity of demand was relatively high in the first two years after the institutional change because it took time for the market actors to adapt to the new institutional setting. However, an in-depth analysis of the underlying reasons for this decrease is beyond the scope of this study. Moreover, future research might use wind speed as an instrumental variable to investigate market power in the EPEX day-ahead market.

Appendix A

Table A. 1: Durbin and Wu-Hausman tests of endogeneity

		Years after amendment in REA				
	2010-2014	2010	2011	2012	2013	2014
HAC score chi2	529.6***	63.3***	134.8***	148.3***	106.4***	191.1***
HAC regression	177.9***	3482.6***	1124.8***	110.3***	4676.5***	3314.0***

Significance levels: *** p<0.01, ** p<0.05, * p<0.1.

Table A. 2: Augmented Dickey-Fuller tests for unit root

Log_Variables	ADF test statistic	ADF test statistic with trend
Volume	-4.628***	-12.095***
Price	-14.889***	-15.295***
Wind speed	-21.685***	-21.770***
Temperature	-6.931***	-6.925***
Sunshine	-13.718***	-13.737***

Automatic lag selection: Schwarz information criterion.
Significance levels: *** p<0.01, ** p<0.05, * p<0.1.

Table A. 3: OLS regression results before the policy change

VARIABLES	2006-2009	Years before amendment in REA 2006	2007	2008	2009
Price	-0.0104***	-0.0260***	0.0152***	0.0101***	0.00466**
	(0.00111)	(0.00215)	(0.00176)	(0.00181)	(0.00229)
Temperature	-0.0874**	-0.789***	-0.401***	-0.607***	-0.726***
	(0.0431)	(0.0786)	(0.0721)	(0.0713)	(0.111)
Sunshine	-0.00732***	-0.00296***	-0.00446***	-0.00841***	0.000409
	(0.000666)	(0.00107)	(0.00102)	(0.00103)	(0.00143)
Dummies					
Hour	Yes			Yes	
Weekend	Yes			Yes	
Month	Yes			Yes	
Year	Yes			No	
Constant	9.769***	13.71***	11.79***	13.13***	13.70***
	(0.243)	(0.441)	(0.406)	(0.401)	(0.620)
Observations	34,914	8,749	8,731	8,748	8,686
Adjusted R^2	0.829	0.382	0.728	0.689	0.496

Standard errors in parentheses.
Dependent variable: logarithm of hourly traded volume.
Significance levels: *** p<0.01, ** p<0.05, * p<0.1.

Table A. 4: OLS regression results after the policy change

VARIABLES	2010-2014	Years after amendment in REA 2010	2011	2012	2013	2014
Price	-0.0834***	-0.0478***	-0.108***	-0.0833***	-0.0650***	-0.103***
	(0.00130)	(0.00343)	(0.00384)	(0.00283)	(0.00222)	(0.00236)
Temperature	1.275***	1.238***	0.477***	1.436***	1.139***	1.526***
	(0.0422)	(0.102)	(0.100)	(0.0840)	(0.0894)	(0.108)
Sunshine	-0.00149**	-0.0106***	-0.00316**	0.000588	0.00764***	-0.000483
	(0.000677)	(0.00161)	(0.00142)	(0.00139)	(0.00134)	(0.00142)
Dummies						
Hour	Yes			Yes		
Weekend	Yes			Yes		
Month	Yes			Yes		
Year	Yes			No		
Constant	3.091***	3.111***	7.787***	2.401***	3.923***	1.966***
	(0.237)	(0.573)	(0.565)	(0.474)	(0.503)	(0.605)
Observations	43,609	8,748	8,744	8,726	8,695	8,696
Adjusted R^2	0.668	0.580	0.630	0.651	0.650	0.685

Standard errors in parentheses.
Dependent variable: logarithm of hourly traded volume.
Significance levels: *** p<0.01, ** p<0.05, * p<0.1.

4 Risk premia in the German day-ahead electricity market revisited: The impact of negative prices

4.1 Introduction

The process of energy market liberalization in Europe and the growth in the supply of electricity from intermittent renewable energy sources (RES) led to a significant increase in trading activities on the day-ahead markets in Germany. Due to the fact that electricity cannot be economically stored, and because forecasts of spot prices are often inaccurate, risk management plays an important role for both producers and retailers (Redl et al., 2009). A risk premium, defined as the difference between the forward price and the expected spot price, is often paid as a compensation for bearing price and/or demand risks.

The presence of risk premia in the German day-ahead market is empirically examined in a study by Viehmann (2011), where the risk premium is measured as the difference between the Energy Exchange Austria (EXAA) price and the European Power Exchange (EPEX) price for an identical hourly contract.[8] Since EXAA auction results are published two hours in advance, traders on the EPEX have time left to adjust their bidding strategy until the gate closes (Ziel et al., 2015). The results of Viehmann (2011) suggest that market participants are willing to pay significant negative risk premia in periods of low demand and positive risk premia during peak hours, which is in line with the prediction of a theoretical model developed by Bessembinder and Lemmon (2002).

8 The original paper used the name EEX day-ahead prices instead of EPEX day-ahead prices. The power exchange, EEX Power Spot, changed its name in EPEX SPOT SE in 2009.

This paper revisits risk premia in the German day-ahead market for electricity. Besides replicating the study by Viehmann (2011), it makes the following contributions to the literature: First, it extends the original analysis with data of more than three preceding years. Second, this paper investigates the impact of the introduction of negative prices on risk premia. Negative price bids for the German market were first introduced on September 1, 2008 at the EPEX. Negative price bids at the EXAA have been possible since October 15, 2013. Although not empirically investigated, Viehmann (2011) assumes the impact of negative electricity prices on risk premia: “It remains to be seen how the introduction of negative prices will affect negative risk premiums of weekend night hours in the future. Negative prices might result in a left-skewed price distribution and larger negative premiums for the hours affected” (Viehmann 2011, p. 393).

The results of this paper suggest that estimates for risk premia, as presented in Viehmann (2011), can only be replicated in part. There are large differences in the presented significance levels, which could be caused by a different lag structure of the respective Newey-West standard errors. The replication presents statistically significant risk premia for 14 hours in the total sample, whereas significant risk premia are reported for only 5 hours in the original study. An extension with prior data yields the result that more statistically significant risk premia are observed during weekdays than during weekends, in contrast to the findings of Viehmann (2011). Moreover, this extension provides some evidence that the reduced form of the model by Bessembinder and Lemmon (2002) might not accurately predict the outcome for risk premia in the German day-ahead market. Finally, the results of an econometric analysis suggest that the introduction of negative prices has led to a remarkable decrease in risk premia when compared to the period of a positive price regime.

The remainder of the paper is organized as follows. The next section reviews the literature. Section 4.3 summarizes the dataset, the methodology, and the results of the replication study. Section 4.4 comprises the dataset, the empirical strategy, and the results of the extension with negative prices. Section 4.5 concludes.

4.2 Literature review

Bessembinder and Lemmon (2002) develop an influential theoretical model that takes into account the non-storable nature of electricity in order to study the price formation of forward contracts. In their model, identical risk-averse producers and retailers are trading in a competitive spot market. Both parties can take forward positions (sell/buy electricity) as hedges to maximize their objective profit functions. The model predicts that risk premia tend to be higher if the expected demand increases. Moreover, Bessembinder and Lemmon (2002) derive a reduced form of the model where the risk premium is negatively related to the variance of the spot price distribution and positively related to the skewness of the spot price distribution. Empirical studies provide mixed evidence concerning the predictions of Bessembinder and Lemmon's (2002) model.

Longstaff and Wang (2004) conduct an empirical analysis of the wholesale electricity market in Pennsylvania, New Jersey, and Maryland (PJM) from June 2000 to November 2002. They find evidence that risk premia vary throughout the day and can be either positive or negative. Their results also confirm that risk premia are negatively related to the variance of spot prices and positively related to the skewness of spot prices.

Haugom and Ullrich (2012) revisit the empirical study of Longstaff and Wang (2004) and extend the observation period to December 2010. They find that the PJM market became efficient over time, meaning that forward prices converged to unbiased predictors of subsequent spot prices. However, their results cannot confirm the reduced relationship of the model by Bessembinder and Lemmon (2002). Results of rolling regressions reveal highly unstable parameters for the variance and skewness during the observed period.

Risk premia in the German day-ahead market are analyzed by Viehmann (2011) for the period October 2005 to September 2008. Interpreting the EXAA price as a snapshot of the continuous over the counter (OTC) market, the results of the empirical investigation suggest that market participants behave like risk-averse rational economic agents. They are willing to pay significant negative risk premia in periods of low demand and positive risk premia during peak hours.

The impact of negative prices on risk premia, however, could not be investigated because the first negative price on the German day-ahead market occurred on October 5, 2008. Viehmann (2011) concludes that the introduction of negative prices might decrease the skewness of the spot price distribution, which would lead to a negative impact on the risk premium. Due to the reduced skewness, traders would take fewer forward positions in order to hedge high power prices on the spot market. However, it must be noted that this argumentation is based on the reduced form of the model by Bessembinder and Lemmon (2002), which was designed to explain large electricity price spikes via higher variable costs of the respective conventional power plants and does not take into account the possibility of negative prices. The question of whether trading under a negative price regime affects the risk premium will be addressed in Section 4.4.

4.3 Replication of Viehmann (2011) and extension

4.3.1 Data

The dataset of the replication study is comprised of hourly day-ahead prices from the two power exchanges, EPEX and EXAA. For the exact replication of the study by Viehmann (2011), I use data from October 1, 2005 to September 30, 2008. Note, that in the last month of this period it would have been possible to trade at negative prices, since EPEX introduced negative price bids on September 1, 2008. However, this specific dataset contains only positive electricity prices because the first negative price on the EPEX occurred on October 5, 2008. The results of the descriptive statistics are identical to those published in Viehmann (2011) and are presented in the Appendix B (Tables B. 1 - B. 2).

Table 4-1: Summary of hourly EPEX prices from March 22, 2002 to September 30, 2005

Hour	Mean	Min	Median	Max	Std. dev.	Skewness
1	22.26	3.68	21.82	53.92	7.85	0.49
2	19.05	0.09	18.03	48.02	8.13	0.43
3	17.26	0.00	16.42	43.31	8.04	0.37
4	16.10	0.00	15.27	40.22	7.78	0.37
5	16.44	0.00	16.67	39.65	7.70	0.33
6	19.35	0.00	19.40	47.53	8.27	0.02
7	23.31	0.00	24.92	60.09	10.95	-0.16
8	31.40	0.00	33.02	250.02	16.48	2.45
9	35.07	0.00	34.99	300.01	19.89	4.50
10	37.50	0.16	36.07	258.16	18.50	3.23
11	40.16	1.15	37.87	492.43	22.89	7.77
12	48.80	1.92	40.33	500.01	37.14	4.85
13	39.86	1.88	37.01	210.12	19.79	3.45
14	37.63	1.03	35.88	189.92	18.53	2.64
15	16.95	0.13	34.04	217.38	16.95	2.91
16	32.42	0.00	32.17	150.22	13.95	1.19
17	31.30	0.00	31.16	95.05	12.32	0.59
18	33.54	0.00	32.25	180.07	14.15	1.97
19	36.48	0.26	33.10	1719.72	49.70	30.33
20	33.68	1.01	32.10	300.10	14.99	5.46
21	32.70	2.27	31.92	150.08	11.59	1.54
22	29.89	2.23	29.69	69.92	9.41	0.46
23	28.91	4.53	28.35	53.87	8.73	0.60
24	24.33	2.09	24.08	60.03	7.70	0.47
All	**30.10**	**0.00**	**28.17**	**1719.72**	**20.15**	**22.34**

Table 4-2: Summary of hourly EXAA prices from March 22, 2002 to September 30, 2005

Hour	Mean	Min	Median	Max	Std. dev.	Skewness
1	22.12	4.45	21.67	51.70	7.50	0.52
2	19.00	2.14	18.00	48.80	7.47	0.60
3	17.22	1.90	16.00	45.00	7.28	0.55
4	16.12	1.00	15.00	42.08	7.11	0.53
5	16.39	1.00	15.36	40.00	7.14	0.48
6	19.35	0.90	19.00	99.99	8.11	0.87
7	23.87	0.01	25.10	72.50	10.29	-0.05
8	31.06	0.44	33.00	137.71	14.04	0.54
9	36.05	1.33	35.86	267.14	19.31	3.61
10	38.25	3.00	37.00	333.89	19.99	4.76
11	41.37	7.10	38.20	837.03	30.39	15.07
12	48.84	8.96	41.00	600.00	37.19	6.08
13	40.78	6.64	38.04	500.00	23.78	7.50
14	38.45	6.67	37.00	304.82	20.53	4.21
15	36.09	6.61	35.00	295.94	19.15	4.44
16	33.96	4.32	33.50	246.40	16.16	3.20
17	32.46	6.10	32.11	100.00	12.63	0.79
18	34.47	5.00	33.14	136.36	13.67	1.22
19	35.99	6.20	33.90	191.04	15.83	2.81
20	34.38	8.10	32.51	200.50	14.00	3.53
21	32.42	9.49	31.40	117.40	10.71	1.27
22	29.81	7.98	29.60	80.00	9.13	0.54
23	29.28	9.82	28.68	99.99	8.62	0.96
24	25.09	6.70	24.41	60.01	7.51	0.59
All	**30.54**	**0.01**	**28.55**	**837.03**	**18.55**	**7.59**

Furthermore, this study extends the original research using data through March 22, 2002 (i.e. the publication of the first EXAA price). The same institutional framework exists as in the replication period: EXAA auction results are published about two hours in advance (Zachmann, 2008). Table 4-1 and Table 4-2 provide new summary statistics for both power exchanges. As in the original study, prices at the EXAA are, on average, slightly higher than at the EPEX (30.54 €/MWh vs. 30.10 €/MWh), but there are significant differences in the descriptive statistics at the hourly level. The highest price at which electricity was traded at the EPEX was 1719.72 €/MWh, which is more than double the highest price recorded at the EXAA (837.03 €/MWh) during the same period.

Statistics for the skewness reveal a new insight into the distributional properties of electricity prices under a positive price regime. Even though most of the contracts exhibit a right-skewed distribution, there is a left-skewed distribution in hour 7 on both power exchanges. This is interesting insofar as the original study presents a strictly right-skewed distribution on both markets because of the convex shape of the power supply curve and the presence of power price spikes (Viehmann, 2011). However, the highest prices are much lower during the prior period than during the replication period, which might explain the left-skewness in hour 7 (EPEX: 60.09 €/MWh vs. 94.51 €/MWh; EXAA: 72.50 €/MWh vs. 92.06 €/MWh).

4.3.2 Measurement of risk premia

Following Viehmann (2011) and Lazarczyk (2016), I use the ex-post approach with realized data of both power exchanges. Risk premia for individual hourly contracts are measured by OLS regressions:

$$\text{EXAA\_price}_{i,d} - \text{EPEX\_price}_{i,d} = \alpha_i + \varepsilon_{i,d}, \tag{4.1}$$

with $i = 1, \ldots, 24$ and $d = 1, \ldots, N$ where N indicates the number of days in the sample and i the hours of the day; the error term $\varepsilon_{i,d}$ is random noise and the constant α_i represents the mean risk premium for the hour i. The price difference between both power exchanges tends to be positive when the EXAA price is higher than the EPEX price and vice versa. As in the original study, all regressions are conducted with Newey-West standard errors.

4.3.3 Results

Tables 4-3, 4-4, and 4-5 summarize the regression results of Equation (4.1) and present the respective t-statistics of the estimated constants. These tables contain the replication of the subsamples “All Days”, “Weekdays”, and “Weekends” of Table 3 in Viehmann (2011) as well as the estimated risk premia for the extension with prior years. All estimates of the mean hourly risk premium coincide with the original study. Minor deviations might be the result of rounding errors.

In contrast, estimated Newey-West standard errors cannot be reproduced and lead to drastic changes in the reported significance levels. All t-values are calculated by the software EViews 9, which makes use of the optimal bandwidth selection algorithm of Newey and West (1994) in order to select the appropriate number of lags for the standard errors. To check whether the obtained differences might be caused due to another lag structure, I contacted the author of the original study. Viehmann states that he has used the R package “sandwich” from the year 2009 without any further lag specifications; hence, I re-estimated Equation (4.1) with R 3.4.2 including the latest version of the package “sandwich”. By default, the lag parameter is set to NULL which means that the optimal bandwidth selection process of Newey and West (1994) is used. I obtain the same results for the optimal bandwidth and, thus, the same standard errors as with EViews 9. Although not reported here, further estimates of risk premia with other Newey-West standard error specifications do not reproduce the original t-statistic either. I suspect that Viehmann might have used a different lag structure and/or Pre-Whitening lags in the original study.

While statistically significant risk premia are reported for only 5 hours in Viehmann (2011), my estimation results point to statistically significant risk premia for 14 hours in the total sample. On weekdays, the replication provides 10 significant hours in comparison to the 5 significant hours in the original study. Negative significant risk premia are only observed on weekends during the hours 1-6. Overall, the replication results are in line with the conclusion of Viehmann (2011) that traders act like risk-averse rational economic agents in the German day-ahead market for electricity.

The extension with prior data under a positive price regime for the sample “All days” points to 14 hourly contracts where the risk premium is significantly different from zero. As in the original study, negative significant risk premia are only present on weekends. In contrast, there is evidence that the preceding years exhibit more significant risk premia during weekdays than during weekends (15 vs. 11). Furthermore, one would expect negative risk premia in hour 7 because of the left-skewness of the power price distribution (Bessembinder and Lemmon, 2002). However, the regression results suggest a strictly positive significant risk premium for all subsamples. This contradiction may support the conclusions of Haugom and Ullrich (2012) that point to highly unstable signs for the parameters of the variance and skewness in the reduced form of the model by Bessembinder and Lemmon (2002).

Table 4-3: Tests of risk premia – Original results, replication and extension for all days

All days	Viehmann (2011)		Replication			Mar. 22, 2002 – Sept. 30, 2005		
Hour	Risk premium	t-statistic	Risk premium	t-statistic	Bandwidth	Risk premium	t-statistic	Bandwidth
1	0.08	0.28	0.08	0.50	4	-0.13	-1.32	11
2	-0.39	-1.36	-0.39	-2.34**	10	-0.05	-0.54	5
3	-0.48	-1.49	-0.48	-2.77***	2	-0.05	-0.49	8
4	-0.16	-0.39	-0.16	-0.82	9	0.02	0.19	4
5	-0.07	-0.19	-0.07	-0.36	9	-0.06	-0.62	6
6	-0.42	-1.15	-0.42	-2.36**	8	-0.01	-0.06	3
7	0.52	1.04	0.52	2.12**	8	0.56	4.67***	11
8	0.81	0.88	0.81	2.11**	11	-0.35	-1.65*	15
9	0.36	0.41	0.37	0.77	3	0.98	2.49**	17
10	0.58	0.60	0.58	1.42	11	0.75	1.88*	7
11	0.72	0.67	0.72	1.23	2	1.21	1.55	7
12	-0.77	-0.22	-0.76	-0.48	6	0.02	0.02	10
12a[a]	0.72	0.85	0.73	1.27	54			
13	0.55	0.56	0.55	1.19	13	0.92	1.78*	11
14	0.42	0.42	0.42	1.02	22	0.82	2.04**	13
15	0.17	0.15	0.17	0.39	22	1.23	3.67***	9
16	0.97	0.97	0.97	2.59***	23	1.54	4.85***	19
17	1.95	1.98**	1.95	4.66***	11	1.16	6.50***	20
18	3.52	2.61***	3.52	4.91***	6	0.92	4.11***	19
19	0.77	0.18	0.77	0.35	9	-0.50	-0.38	1
19a[b]	2.88	1.55	2.88	3.11***	5			
20	1.87	3.26***	1.87	4.20***	11	0.70	3.39***	50
21	0.58	1.15	0.58	2.24**	12	-0.27	-1.88*	19
22	0.53	1.14	0.53	2.40**	13	-0.07	-0.61	15
23	1.17	2.14**	1.17	4.27***	18	0.37	3.16***	5
24	1.25	2.59***	1.26	5.66***	12	0.76	7.98***	6

[a] Excludes data from July 25, 2006.
[b] Excludes data from November 7, 2006.
t-statistics are based on Newey-West standard errors.
Optimal Bandwidth for a Bartlett kernel was determined by the Newey-West method (Newey and West, 1994).
Significance levels: *** p<0.01, ** p<0.05, * p<0.1.

Table 4-4: Tests of risk premia – Original results, replication and extension for weekdays

Weekdays	Viehmann (2011)		Replication			Mar. 22, 2002 – Sept. 30, 2005		
Hour	Risk premium	t-statistic	Risk premium	t-statistic	Bandwidth	Risk premium	t-statistic	Bandwidth
1	0.42	1.24	0.42	2.63***	6	-0.01	-0.13	9
2	-0.13	-0.50	-0.13	-0.87	13	-0.05	-0.50	8
3	-0.09	-0.30	-0.09	-0.58	13	0.03	0.30	11
4	0.37	0.79	0.37	1.87*	3	0.18	1.73*	7
5	0.32	0.84	0.32	1.70*	2	0.06	0.62	4
6	-0.21	-0.58	-0.22	-1.13	10	-0.04	-0.28	9
7	0.09	0.15	0.09	0.34	7	0.24	1.81*	13
8	0.24	0.21	0.24	0.48	17	-0.95	-3.05***	2
9	0.17	0.15	0.17	0.24	1	1.04	1.88*	11
10	0.61	0.53	0.61	1.09	42	0.98	1.81*	9
11	0.81	0.53	0.81	1.42	42	1.78	1.60	8
12	-1.27	-0.26	-1.27	-0.60	2	0.23	0.17	13
12a[a]	0.82	0.73	0.82	1.11	33			
13	0.83	0.62	0.83	1.34	18	1.46	1.94*	12
14	0.35	0.26	0.35	0.63	19	1.19	1.99**	15
15	0.00	0.00	-0.01	-0.01	60	1.68	3.35***	14
16	0.93	0.71	0.93	2.78***	151	2.01	4.40***	16
17	2.29	1.66*	2.29	3.59***	14	1.48	6.45***	17
18	4.49	2.15**	4.49	4.29***	8	1.27	4.76***	11
19	0.90	0.15	0.90	0.29	6	-0.66	-0.36	2
19a[b]	3.86	1.25	3.86	2.94***	9			
20	2.68	3.79***	2.68	4.08***	17	1.09	4.54***	27
21	0.32	0.60	0.32	1.12	11	-0.37	-2.26**	15
22	0.42	0.84	0.42	1.63	11	-0.08	-0.57	16
23	1.29	2.58***	1.29	3.84***	17	0.38	2.87***	4
24	1.27	2.63***	1.27	5.16***	16	0.68	7.27***	8

[a] Excludes data from July 25, 2006.
[b] Excludes data from November 7, 2006.
t-statistics are based on Newey-West standard errors.
Optimal Bandwidth for a Bartlett kernel was determined by the Newey-West method (Newey and West, 1994).
Significance levels: *** p<0.01, ** p<0.05, * p<0.1.

Table 4-5: Tests of risk premia – Original results, replication and extension for weekends

Weekends	Viehmann (2011)		Replication			Mar. 22, 2002 – Sept. 30, 2005		
Hour	Risk premium	t-statistic	Risk premium	t-statistic	Bandwidth	Risk premium	t-statistic	Bandwidth
1	-0.74	-1.47	-0.74	-2.46**	10	-0.43	-2.39**	10
2	-1.04	-1.74*	-1.04	-3.03***	9	-0.07	-0.36	16
3	-1.46	-2.41**	-1.46	-3.86***	4	-0.25	-1.25	14
4	-1.49	-2.18**	-1.49	-3.88***	7	-0.38	-2.16**	24
5	-1.02	-1.6	-1.02	-2.91***	2	-0.37	-1.95*	13
6	-0.94	-1.48	-0.94	-2.46**	6	0.06	0.29	7
7	1.58	1.73*	1.58	3.57***	5	1.36	6.30***	11
8	2.22	3.04***	2.22	5.12***	2	1.16	5.20***	8
9	0.86	1.51	0.86	2.00**	6	0.84	3.99***	8
10	0.50	0.73	0.50	1.25	3	0.17	0.83	5
11	0.50	0.68	0.50	1.47	8	-0.22	-1.06	9
12	0.47	0.54	0.50	1.41	1	-0.52	-2.26**	3
13	-0.16	-0.26	-0.14	-0.62	13	-0.42	-2.05**	8
14	0.59	0.99	0.59	1.90*	10	-0.10	-0.52	11
15	0.62	1.47	0.62	2.54**	14	0.08	0.46	6
16	1.07	2.07**	1.07	3.40***	2	0.35	1.73*	4
17	1.10	1.98**	1.10	3.78***	18	0.37	1.71*	5
18	1.10	1.17	1.10	2.68***	6	0.07	0.28	6
19	0.46	0.55	0.46	1.10	8	-0.11	-0.43	4
20	-0.14	-0.18	-0.14	-0.34	3	-0.28	-1.30	13
21	1.20	1.42	1.20	2.97***	6	-0.03	-0.12	4
22	0.82	1.21	0.82	2.45**	7	-0.07	-0.34	10
23	0.86	1.12	0.86	2.41**	5	0.35	1.59	4
24	1.21	1.70*	1.21	2.98***	11	0.94	5.40***	12

t-statistics are based on Newey-West standard errors.
Optimal Bandwidth for a Bartlett kernel was determined by the Newey-West method (Newey and West, 1994).
Significance levels: *** $p<0.01$, ** $p<0.05$, * $p<0.1$.

4.4 Extension: The impact of negative electricity prices

4.4.1 Data and evolution of risk premia

Negative prices in the German day-ahead market are the result of a higher feed-in of RES in periods of low demand and/or interconnection failures. Market participants are willing to submit bids below variable costs in order to avoid ramping down base load power plants (Nicolosi, 2010; Fanone et al., 2013). Negative bids at the EPEX have been possible since September 1, 2008, whereas prices at the EXAA had to be positive until October 15, 2013.

In order to take into account the changes in the price regimes, I extend the dataset to December 31, 2016. Hourly day-ahead electricity prices from the two power exchanges are summarized in Table 4-6 and Table 4-7. On average, prices on the EXAA market coincide with prices on the EPEX market (39.64 €/MWh vs. 39.43 €/MWh), and there are no significant differences in the mean prices at the hourly level. Negative prices on the EPEX market occur during the whole day except between the hours 19-20 and at hour 23. There are no negative prices on the EXAA market during the hours 18-22. The lowest price was in the EPEX market with –500.02 €/MWh in comparison to –50.92 €/MWh on the EXAA market. The descriptive statistics summarize a right- as well as a left-skewed price distribution; hence, the threat of possible anti-spikes, especially during off-peak hours, might have a crucial impact on the formation of a risk premium.

Table 4-6: Summary of hourly EPEX prices from October 1, 2008 to December 31, 2016

Hour	Mean	Min	Median	Max	Std. dev	Skewness
1	31.72	-149.90	31.35	75.01	11.89	-2.46
2	28.56	-200.00	28.99	65.80	13.39	-4.70
3	26.19	-500.02	27.13	62.70	16.65	-12.93
4	24.57	-221.94	25.41	60.80	14.16	-4.97
5	25.05	-199.89	25.77	61.93	13.27	-4.23
6	28.10	-199.00	28.82	70.51	12.97	-3.82
7	34.58	-199.99	36.06	104.93	17.04	-3.18
8	43.39	-199.94	43.94	183.49	20.45	-0.46
9	46.44	-119.96	45.97	178.10	19.11	0.50
10	46.74	-36.10	45.83	180.93	17.93	0.93
11	46.24	-10.31	45.25	199.95	17.91	0.99
12	46.77	-8.30	45.92	282.59	18.74	1.47
13	44.22	-76.09	43.65	216.01	17.88	0.86
14	41.77	-100.06	40.85	160.84	18.11	0.36
15	39.90	-130.09	39.13	151.45	18.05	-0.06
16	39.38	-100.00	39.02	142.27	16.91	0.08
17	40.47	-76.00	39.77	134.78	16.59	0.53
18	46.48	-4.20	44.18	494.26	20.72	4.47
19	51.09	7.45	48.21	259.48	20.38	2.37
20	50.89	2.16	48.76	299.09	17.62	2.24
21	46.52	-1.58	45.06	194.62	14.14	1.44
22	41.88	-3.35	40.93	118.93	11.36	0.59
23	40.60	3.45	39.75	90.56	10.79	0.20
24	34.64	-90.98	34.00	71.68	10.73	-0.97
All	**39.43**	**-500.02**	**38.06**	**494.26**	**18.30**	**0.07**

Table 4-7: Summary of hourly EXAA prices from October 1, 2008 to December 31, 2016

Hour	Mean	Min	Median	Max	Std. dev.	Skewness
1	31.65	-13.99	31.00	74.04	10.30	-0.11
2	28.56	-28.97	28.37	65.48	10.48	-0.32
3	26.23	-29.69	26.31	63.44	10.62	-0.40
4	24.53	-29.84	24.71	61.03	10.61	-0.32
5	24.82	-30.01	24.99	62.95	10.63	-0.28
6	27.92	-34.98	28.08	71.48	11.07	-0.31
7	34.94	-38.30	35.60	97.37	13.91	-0.30
8	43.53	-25.01	43.75	142.10	18.48	0.45
9	46.75	-8.28	46.53	158.00	18.38	0.69
10	47.22	-4.00	46.50	170.84	17.36	0.88
11	46.88	-4.87	46.00	158.00	17.19	0.96
12	47.09	-1.50	46.00	180.03	17.80	1.06
13	44.70	-14.90	43.97	163.35	17.19	0.88
14	42.30	-24.42	41.45	153.07	17.11	0.76
15	40.45	-45.68	39.91	145.00	16.71	0.66
16	39.89	-50.92	39.30	146.50	15.98	0.60
17	41.12	-24.84	39.96	135.25	16.21	0.86
18	46.66	0.10	44.30	180.72	19.14	1.60
19	51.17	10.01	48.30	213.49	19.74	1.89
20	50.81	13.94	48.72	178.34	16.72	1.59
21	46.78	1.52	45.48	137.15	13.68	1.29
22	42.17	0.01	41.30	112.59	11.14	0.73
23	40.36	-0.51	39.25	94.94	10.53	0.32
24	34.72	-6.48	33.85	81.21	9.73	0.09
All	**39.64**	**-50.92**	**38.00**	**213.49**	**17.11**	**0.95**

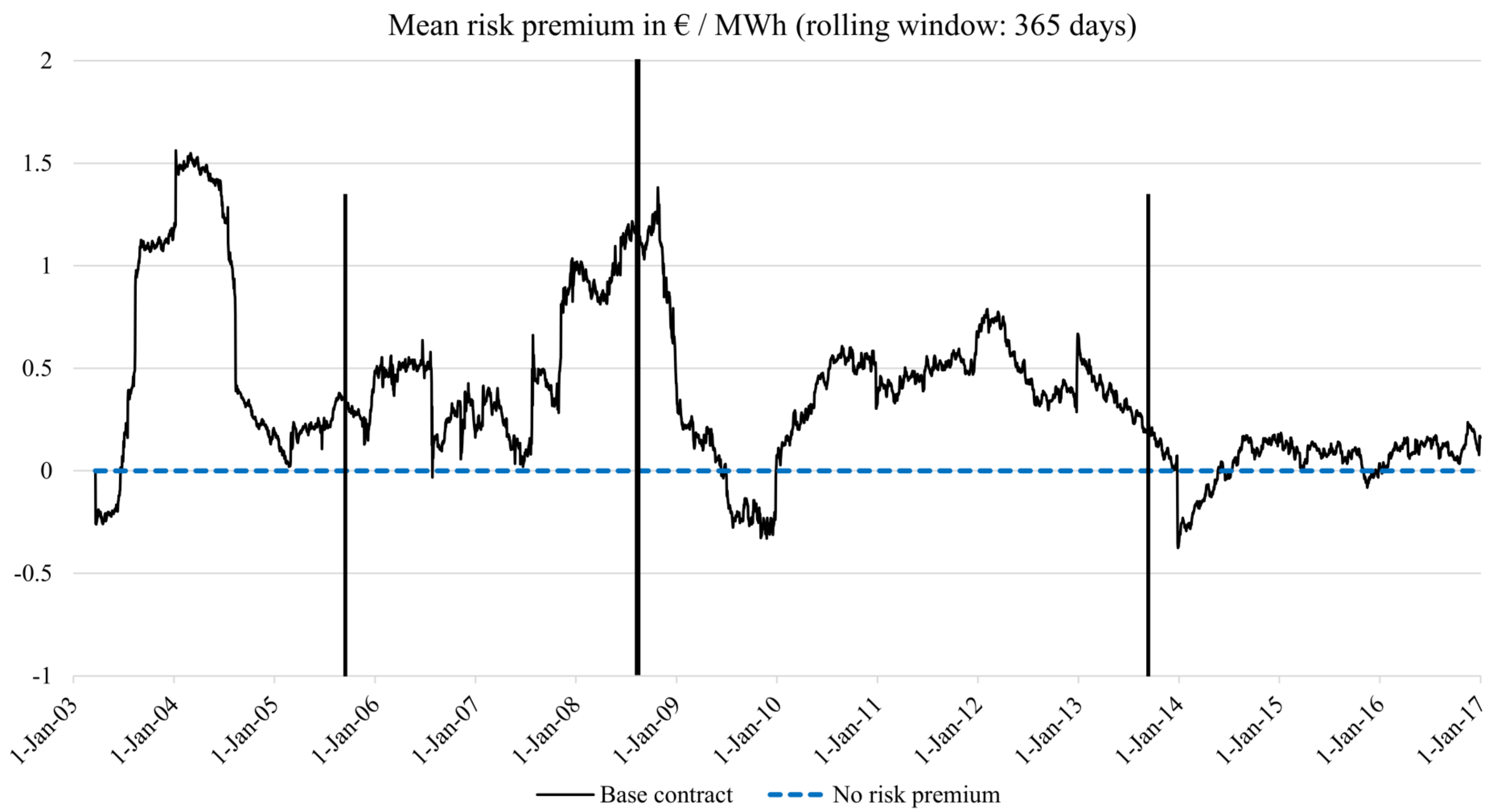

Figure 4-1: Mean risk premium for base contracts in €/MWh over a rolling window of 365 days

Figure 4-1 depicts the evolution of the risk premium for base contracts (i.e. the average of all hourly prices per day) over the total sample period. It summarizes the results of a rolling regression of the risk premium on the constant over an estimation window of 365 days. On the one hand, there is evidence that the mean yearly risk premium exhibits a highly unstable pattern over time. On the other hand, this figure points to lower risk premia after the introduction of negative prices on both power exchanges.

Appendix Table B. 3 summarizes estimates for risk premia during the period in which negative prices have been possible on at least one power exchange. Compared to the period of a positive regime, the hourly estimates tend to be lower during the period from September 6, 2008 to December 31, 2016.

4.4.2 Empirical strategy

In order to examine the relationship between risk premia and the introduction of negative prices, I conduct an econometric analysis including all data from 2002 to 2016. For this purpose, I set the period where only EPEX prices could be negative as a reference and test the differences to other price regime periods for statistical significance:

$$\begin{aligned}\text{Risk\_premium}_t \\ = \alpha + \beta_1 \text{Positive\_period}_t + \beta_2 \text{EXAA\_policy}_t + \gamma' C_t + \varepsilon_t,\end{aligned} \tag{4.2}$$

with $t = 1, \ldots, N$ where N indicates the number of hours in the sample. The dummy variable "Positive period" is one from March 22, 2002 until September 1, 2005, and the dummy variable "EXAA policy" from October 16, 2013 until December 31, 2016. C is a vector of control variables as dummy variables for electricity price spikes, which become one if the prices exceed 500 €/MWh, and one if the prices become negative in general. Furthermore, dummy variables for peak hours, weekend days, and months are included in order to take into account seasonal effects.

As a robustness check, I replace the latter time-dummy variables by the actual German load as a proxy for demand (Longstaff and Wang, 2004; Graf and Wozabal, 2013). The load data in this study is provided by the European Network of Transmission System Operators for Electricity (ENTSO-E) Transparency Platform.[9]

Since the beginning of 2010, electricity from RES must be sold directly on power exchanges because of an amendment to the German Renewable Energy Act (REA). This institutional change drastically increased the traded volumes on the day-ahead markets and could be an important driver for the occurrence of negative prices (Nicolosi, 2010; Bönte et al., 2015). I, therefore, include a dummy variable for the REA amendment that becomes one from the year 2010 onwards.

The variables "Risk premium" and "Load" are checked for the presence of a unit root by performing several Augmented Dickey-Fuller (ADF) tests. The optimal numbers of lags were chosen by minimizing the Schwarz information criterion. The results of the unit root tests with and without a trend suggest that both variables are stationary (see Appendix Table B. 4). Following Clò and D'Adamo (2015), I consider serial correlation in the residuals and conduct a Prais-Winsten regression. In particular, Equation (4.2) is estimated with FGLS where the error term is assumed to follow a first-order autoregressive process:

$$\varepsilon_t = \rho\varepsilon_{t-1} + \omega_t, \tag{4.3}$$

9 One might argue that residual load seems to be more relevant for the price formation than actual load (Pape et al., 2016). However, due to the lack of availability of reliable RES feed-in data from 2002-2010, I decided to use the absolute level of load instead of the residual load.

where $|\rho| < 1$ and ω is white noise. All regressions are conducted with heteroscedasticity robust estimators for the variance-covariance matrix.

4.4.3 Results

The Prais-Winsten regression results are summarized in Table 4-8. The first column reports the estimated coefficients of a basic model without control variables for negative prices. The results suggest that the risk premium decreased significantly by –0.41 €/MWh after the introduction of negative EPEX prices and by –0.23 €/MWh after the introduction of negative EXAA prices.

The second column of Table 4-8 presents regression results with two negative price dummies and an interaction term, the impact of negative EPEX prices after the regime switch on the EXAA. The regression results point to an increasing effect on the risk premium because of negative EPEX prices during the period of September 2, 2008 to October 15, 2013 (24.57 €/MWh). This effect diminishes by 14.33 €/MWh after the introduction of negative EXAA prices. In addition, negative EXAA prices cause a further decreasing effect on the risk premium (–2.95 €/MWh). These results remain robust after controlling for the amendment in the REA.

The fourth column of Table 4-8 presents results where actual hourly load data (in 1,000 MW) is included from January 1, 2006 onwards as a control variable. The regression results point to a positive significant impact of load on the risk premium. Note that the sample size reduces from 129,518 to 96,352 observations due to limited data availability in this model. As in the preceding models, the introduction of negative prices on the EPEX as well as on the EXAA market has a negative significant impact on the risk premium.

Table 4-8: Results of Prais-Winsten regressions

VARIABLES	(1) Risk premium	(2) Risk premium	(3) Risk premium	(4) Risk premium
Positive price period	0.405***	0.516***	0.823***	0.887***
	(0.112)	(0.106)	(0.179)	(0.228)
EXAA policy change	-0.228***	-0.202***	-0.311***	-0.270***
	(0.0697)	(0.0597)	(0.0589)	(0.0573)
Negative EPEX price		24.57***	24.60***	24.08***
		(3.245)	(3.244)	(3.186)
Negative EXAA price		-2.952***	-2.955***	-2.735**
		(1.072)	(1.072)	(1.073)
EXAA policy change*Negative EPEX price		-14.33***	-14.36***	-14.01***
		(3.348)	(3.346)	(3.291)
REA amendment			0.415**	0.257
			(0.162)	(0.167)
Peak hours	0.527***	0.589***	0.589***	
	(0.0705)	(0.0688)	(0.0688)	
Weekend	-0.206***	-0.277***	-0.277***	
	(0.0777)	(0.0742)	(0.0742)	
Load				0.0244***
				(0.00588)
Dummies				
Month	Yes	Yes	Yes	No
Price spikes	Yes	Yes	Yes	Yes
Constant	0.0240	-0.0564	-0.352**	-1.328***
	(0.100)	(0.0961)	(0.163)	(0.337)
Observations	129,518	129,518	129,518	96,352
Adjusted R-squared	0.386	0.389	0.389	0.414
Rho	0.493	0.482	0.482	0.496
Durbin-Watson statistic (original)	1.088	1.125	1.126	1.128
Durbin-Watson statistic (transformed)	2.165	2.161	2.161	2.155

Reference period September 2, 2008 to October 15, 2013.
Robust standard errors in parentheses.
Significance levels: *** p<0.01, ** p<0.05, * p<0.1.

Further OLS regressions with Newey-West standard errors confirm the sign and statistical significance of the variable “Positive price period” in all models (see Appendix Table B. 5). Likewise, as in the Prais-Winsten regression, the impact of the EXAA policy change is negative, although not statistically significant in the models without the REA dummy. Taking all results into consideration, the introduction of negative prices has a diminishing effect on the risk premium, as Viehmann (2011) expected.

4.5 Conclusion

Replicating the results of Viehmann (2011), this paper confirms the presence of risk premia in the German day-ahead electricity market. While estimates of mean hourly risk premia can be replicated, this paper fails to reproduce respective Newey-West standard errors, leading to remarkable differences between the reported significance levels. Using optimal bandwidth selection for a Bartlett kernel, I find statistically significant risk premia for 14 hours in the total sample, whereas significant risk premia are reported for only 5 hours in the original study. An empirical extension with data of preceding years points to further differences with respect to size and statistical significance.

Going beyond the results in Viehmann (2011), this study considers the impact of negative prices on risk premia. The results of an econometric analysis suggest that the introduction of negative prices on the EPEX in September 2008 as well as on the EXAA market in October 2013 reduced the risk premia remarkably when compared to a period with positive prices on both power exchanges. This is in line with the expectations of the original paper. Since negative prices reduce the skewness of the spot price distribution, market participants tend to take less forward positions as a hedge against high spot prices. Future empirical studies should take into account the question of whether negative electricity prices are possible in the market and adjust the model accordingly.

The implementation of negative electricity prices in the model presented by Bessembinder and Lemmon (2002) may be an interesting subject for further research. One must consider that negative prices can occur through shocks on the supply side as well as the demand side, thus the model would need to take into account renewable energy sources as electricity production technologies in the supply curve.

Appendix B

Table B. 1: Summary of hourly EPEX prices from October 1, 2005 to September 30, 2008

Hour	Mean	Min	Median	Max	Std. dev.	Skewness
1	36.89	1.64	34.29	76.02	14.11	0.52
2	32.03	0.00	29.96	71.07	13.46	0.45
3	28.65	0.00	27.12	67.93	12.88	0.39
4	25.73	0.00	23.99	69.52	12.55	0.39
5	26.06	0.00	24.06	69.92	12.43	0.38
6	31.61	0.00	30.29	70.28	13.82	0.23
7	36.63	0.00	34.80	94.51	19.89	0.18
8	53.11	0.00	51.14	301.01	30.72	1.25
9	59.44	0.00	55.70	437.26	33.45	2.34
10	64.60	0.00	59.85	499.68	36.47	3.16
11	68.54	0.00	62.68	998.24	44.65	9.09
12	77.05	5.56	68.01	2000.07	81.64	16.14
12a[a]	75.29	5.56	68.00	1399.99	57.33	12.23
13	67.08	6.96	63.03	699.81	37.94	6.45
14	63.57	2.65	59.17	699.88	37.12	6.31
15	59.98	0.07	55.04	800.09	37.83	7.76
16	56.04	0.12	51.57	693.23	34.21	6.80
17	54.70	3.86	50.15	300.01	29.60	2.27
18	61.84	6.90	54.07	821.90	49.03	7.11
19	67.54	15.95	59.11	2436.63	86.50	19.87
19a[b]	65.38	15.95	59.07	701.01	48.52	6.39
20	60.00	17.97	57.06	250.04	27.75	1.78
21	55.21	15.07	53.23	125.02	21.43	0.49
22	48.61	13.48	46.32	105.93	17.92	0.49
23	46.93	14.65	44.26	94.82	16.58	0.47
24	38.23	1.61	35.28	80.98	14.22	0.58
All	**50.84**	**0.00**	**44.62**	**2436.63**	**39.28**	**18.07**

[a] Excludes data from July 25, 2006.
[b] Excludes data from November 7, 2006.

Table B. 2: Summary of hourly EXAA prices from October 1, 2005 to September 30, 2008

Hour	Mean	Min	Median	Max	Std. dev.	Skewness
1	36.97	6.83	35.01	81.00	13.38	0.51
2	31.64	0.55	29.81	68.53	12.46	0.54
3	28.17	0.01	26.45	65.64	11.84	0.53
4	25.57	0.01	23.59	75.00	11.49	0.63
5	26.00	0.01	24.15	62.50	11.56	0.54
6	31.19	0.01	30.21	70.30	13.24	0.27
7	37.14	0.01	36.58	92.06	18.62	0.21
8	53.92	0.01	51.15	208.21	29.03	0.80
9	59.81	0.01	57.54	205.00	29.52	0.82
10	65.18	11.00	61.68	376.93	33.25	2.21
11	69.26	11.67	65.00	459.46	35.88	2.82
12	76.29	0.07	69.85	888.00	49.48	6.95
13	67.64	20.60	63.97	458.89	33.86	3.78
14	63.99	17.00	60.95	409.65	31.87	2.75
15	60.16	3.51	57.07	350.00	30.85	2.41
16	57.02	11.27	54.05	300.00	28.87	1.88
17	56.65	9.83	52.06	240.00	28.97	1.49
18	65.36	12.68	55.59	517.55	47.92	4.09
19	68.31	17.60	60.01	519.93	46.63	3.88
20	61.87	20.00	59.00	302.37	28.95	1.72
21	55.78	19.40	54.94	127.78	20.69	0.49
22	49.15	9.99	47.00	100.57	17.02	0.44
23	48.10	1.00	45.73	90.00	16.47	0.36
24	39.48	1.00	37.71	84.27	14.28	0.48
All	**51.45**	**0.01**	**45.07**	**888.00**	**32.07**	**3.76**

Table B. 3: Tests of risk premia from September 6, 2008 to December 31, 2016

	All days			Weekdays			Weekends		
Hour	Risk premium	t-statistic	Bandwidth	Risk premium	t-statistic	Bandwidth	Risk premium	t-statistic	Bandwidth
1	-0.07	-0.53	15	0.12	0.83	3	-0.57	-2.34**	12
2	0.00	-0.02	11	0.06	0.28	4	-0.16	-0.61	6
3	0.04	0.16	14	0.00	-0.01	4	0.14	0.23	5
4	-0.02	-0.11	8	0.21	0.76	10	-0.60	-2.33**	14
5	-0.22	-1.28	13	0.01	0.05	9	-0.80	-3.13***	12
6	-0.19	-1.13	6	-0.06	-0.32	8	-0.50	-1.86*	4
7	0.36	1.95*	3	-0.02	-0.10	10	1.31	3.48***	9
8	0.12	0.78	7	-0.30	-1.69*	13	1.16	3.74***	8
9	0.32	2.87***	13	0.24	2.00**	3	0.53	2.16**	5
10	0.49	5.35***	11	0.50	5.17***	18	0.48	2.52**	4
11	0.66	7.24***	20	0.56	5.90***	26	0.89	5.10***	6
12	0.35	3.18***	18	0.23	1.90*	22	0.63	3.44***	1
13	0.51	4.93***	26	0.43	3.87***	23	0.71	3.31***	5
14	0.55	5.15***	24	0.29	2.90***	17	1.21	4.71***	1
15	0.57	5.27***	21	0.28	2.87***	19	1.29	4.94***	11
16	0.53	5.13***	22	0.32	3.59***	11	1.05	4.48***	13
17	0.67	6.84***	4	0.61	6.46***	4	0.85	3.71***	2
18	0.22	1.70*	29	0.22	1.47	38	0.21	1.10	10
19	0.11	0.92	32	0.25	1.81*	22	-0.23	-1.23	3
20	-0.09	-0.56	23	0.05	0.27	17	-0.43	-1.92*	15
21	0.25	2.05**	22	0.09	0.82	5	0.65	2.49**	17
22	0.30	2.79***	22	0.17	1.76*	9	0.63	2.92***	17
23	-0.22	-2.16**	14	-0.18	-1.76*	12	-0.33	-1.61	13
24	0.10	0.90	6	0.08	0.64	7	0.17	0.90	6

t-statistics are based on Newey-West standard errors.
Optimal Bandwidth for a Bartlett kernel was determined by the Newey-West method (Newey and West, 1994).
Significance levels: *** $p<0.01$, ** $p<0.05$, * $p<0.1$.

Table B. 4: Augmented Dickey-Fuller tests for unit root

Variables	ADF test statistic	ADF test statistic with trend
Risk premium	-45.135***	-45.159***
Load	-25.803***	-25.884***

Automatic lag selection: Schwarz information criterion.
Significance levels: *** $p<0.01$, ** $p<0.05$, * $p<0.1$.

Table B. 5: Robustness - OLS regressions results

VARIABLES	(1) Risk premium	(2) Risk premium	(3) Risk premium	(4) Risk premium
Positive price period	0.364**	0.559***	0.921***	0.921***
	(0.166)	(0.148)	(0.276)	(0.312)
EXAA policy change	-0.228	-0.149	-0.277**	-0.248**
	(0.159)	(0.124)	(0.131)	(0.126)
Negative EPEX price		42.87***	42.94***	43.20***
		(11.08)	(11.07)	(11.22)
Negative EXAA price		-7.159***	-7.165***	-6.952***
		(2.175)	(2.176)	(2.167)
EXAA policy change*Negative EPEX price		-26.55**	-26.63**	-26.81**
		(11.26)	(11.24)	(11.40)
REA amendment			0.487*	0.331
			(0.284)	(0.281)
Peak hours	0.630***	0.739***	0.739***	
	(0.102)	(0.0912)	(0.0912)	
Weekend	-0.177	-0.309**	-0.310**	
	(0.135)	(0.128)	(0.129)	
Load				0.0318***
				(0.00726)
Dummies				
Month	Yes	Yes	Yes	No
Price spikes	Yes	Yes	Yes	Yes
Constant	0.0240	-0.0564	-0.352**	-1.328***
	(0.100)	(0.0961)	(0.163)	(0.337)
Observations	129,518	129,518	129,518	96,352
Adjusted R-squared	0.339	0.356	0.356	0.363
Bandwidth	142	140	145	120

Reference period September 2, 2008 to October 15, 2013.
Newey-West standard errors in parentheses.
Optimal Bandwidth for a Bartlett kernel was determined by the Newey-West method (Newey and West, 1994).
Significance levels: *** $p<0.01$, ** $p<0.05$, * $p<0.1$.

5 Asymmetric information in the German intraday electricity market

5.1 Introduction

An example of asymmetric information between participants in electricity markets is knowledge of an unplanned power plant outage (von der Fehr, 2013). Since missing production leads to a shortage of supply, the electricity price during that outage increases, ceteris paribus. Non-disclosure, or disclosure with a time lag, of this missing production may save the insider additional costs, since market participants cannot use this information to adapt their biddings strategically and participate in the increased buying intention. The abuse of private information in order to influence the electricity spot price is investigated for the German day-ahead market, where participants have an incentive to withhold capacities (Weigt and von Hirschhausen, 2008; Bergler et al., 2017). However, variations of the subsequent intraday price from the day-ahead price are only analyzed from a fundamental perspective (Hagemann, 2015b; Pape et al., 2016).

This paper investigates how private and public information about unplanned power plant outages impact the European Power Exchange (EPEX) volume weighted average intraday electricity price in Germany. It follows the study by Lazarczyk (2016), in which messages about unexpected outages are used to proxy public information, and introduces a method to measure the impact of private information on intraday prices. For this purpose, we use messages concerning unscheduled power plant non-usabilities that are published online at the European Energy Exchange (EEX) transparency platform. We assign the content of these messages into private and public information about the outages and test whether they explain the average intraday price in addition to market fundamentals such as forecast errors of renewable energy sources (RES), load forecast errors and cross-border flows.

The results of an econometric analysis point to a significant positive impact of private and public information about unplanned power plant outages on the intraday electricity price during 2014 to 2016. In July 2015, to provide market participants more adjustment possibilities to actively balance their portfolios in close-to-real time, the EPEX reduced the lead time from 45 minutes to 30 minutes for trading on the continuous intraday market. We show that the policy change enhances the possibilities of traders reacting to unplanned non-usabilities: an increased impact of private information on the electricity price is observed. Furthermore, the lead time change enables us to provide evidence for an asymmetric impact of private and public information on the intraday price.

The remainder of this paper is organized as follows. The next section discusses the impact of asymmetric information about unplanned power plant outages on the intraday price. Section 5.3 introduces the respective spot markets and their regulatory framework. The data of this study and the empirical strategy are presented in Section 5.4 and Section 5.5, respectively. Section 5.6 contains the results and Section 5.7 concludes.

5.2 Asymmetric information about unplanned power plant outages

The impact of information on price building and trading on financial markets is studied within market microstructure literature (Madhavan, 2000). For instance, Kyle (1985) develops an influential model where a single trader with monopolistic information places orders over time to maximize trading profit before the information becomes public knowledge. Admati and Pfleiderer (1988) analyze the strategic timing of trades and its impact on price evolution. Informed traders or insiders exploit their informational monopoly, which only becomes public information one trading period later, thus maximizing their profits by executing the trades one period in advance. This leads to a price adjustment revealing patterns of volume and price variability in the preannouncement period.

An example of private information about electricity markets is knowledge of a power plant's non-usability. Missing production leads to a shortage of supply, but other market participants are not able to adjust their bidding strategy if this information is not published or is published with a time lag, which provides the insider a temporal advantage. According to European Commission objectives, the various national markets should be integrated to facilitate the flow of electricity between the different European jurisdictions. Because respective arrangements and mechanisms such as market coupling in the day-ahead market and the intraday cross-border trading rely on trustworthy price signals, electricity markets should operate with an unbiased information set that reflects the supply- and demand-side fundamentals and is not distorted by an abuse of market power.

Bergler et al. (2017) investigate how the German day-ahead market is impacted by a strategic capacity withholding on prices. The study analyzes whether market participants are withholding capacities through failures in order to influence the auction price. By using data of the EEX transparency platform, the results of an empirical analysis indicate a positive influence of prices on power plant non-usabilities. This implies that strategic capacity withholding, and thus an abuse of private information, takes place on the day-ahead market.

Hagemann (2015b) analyzes price determinants in the German continuous intraday market. The study takes into account how unplanned power plant outages, forecast errors of RES, load forecast errors and cross-border physical flows impact intraday prices. The results suggest that supply-side shocks influence intraday prices differently during a day. Since missing production leads to a shortage of supply, the average price of the affected contracts increases.

Lazarczyk (2015) analyzes the behavior of prices, number of trades and traded volumes in the period of one hour prior to the publication of market messages on the Nordic intraday market. The results point to positive effects on prices through an increase in the number of news reports in the preannouncement period, indicating that private information may be used for trading before the content of these messages becomes public information.

Lazarczyk (2016) investigates how public information about non-usabilities impacts electricity prices for the Nordic continuous intraday market. The dataset of the study comprises messages providing information about unscheduled power plant outages that were issued between the bidding periods for the day-ahead and intraday markets. Hence, news announcing failures can only influence decisions concerning the intraday market. The results of an empirical analysis point to a significant positive effect of the number of news reports on the intraday price. However, the magnitude of this effect varies within the day and tends to be observed for news concerning changes in marginal production during peak hours, whereas the impact of news concerning changes in baseload production is observed even in off-peak hours.

These studies show that an unforeseen reduction in production, or even its announcement, leads to positive effects on the realized intraday price. The opportunity to trade with private information on a continuous intraday market arises if the time lag between the actual outage and its publication exceeds at least one tradable contract and provides the insider with a timely edge. The theoretical consideration in this paper is therefore twofold: Firstly, we assume that the involved power plant sold its production on the day-ahead market and is now obligated to deliver. Secondly, the power plant will not hedge its missing production against any schedule deviation penalties. Taking this into account, the trading responsible will now optimize its schedule deviations under technically feasible and economically efficient restrictions. In the very short run, these deviations may be voluntarily cross traded within a trader’s own portfolio, if available, by launching highly flexible generation units. Furthermore, optional reserve contracts on a bilateral basis may be activated to substitute the missing production, which is especially the case for large-scale power generation. Finally, depending on the outage duration, the trading responsible may compensate the deviations on the continuous intraday market. Since the marginal costs of claimed or counterparty generation are higher than the realized spot prizes, trading on the intraday market could be advantageous (Hagemann and Weber, 2013). Even if the affected power plant executes a bilateral or over the counter (OTC) trade, the counterparty will hedge its production on the intraday market, as it seems irrational to set aside the necessary capacities.

5.3 The short-term electricity markets in Germany

5.3.1 The legal framework

The reliability of wholesale energy market places, such as energy exchanges or OTC markets, depends not least on whether market participants consider the underlying price formation trustworthy and are willing to trade on them. To foster this rationale, the European Commission introduced a set of regulations, among which is Regulation (EU) No. 1227/2011 on Wholesale Energy Market Integrity and Transparency (REMIT), which has been in force since December 2011 in all EU member states. Its key objective is to ensure competition in wholesale energy markets. In terms of integrity, the regulation should build confidence that the wholesale price formation is reflected by market fundamentals and that no profits are gained through insider trading or market manipulation. In terms of transparency, the regulation should allow all stakeholders to have a clear picture of the market situation by making all relevant market and fundamental data publicly available (EU, 2011; EU, 2013).

One main aim of REMIT is the prohibition of insider trading. This means that persons who possess inside information are prohibited from using this information to buy or sell wholesale energy products, e.g., electricity, or from "whispering" this information to any other person and recommending that they trade on this information. According to REMIT, the Agency for Cooperation of Energy Regulators (ACER) is responsible for introducing a monitoring framework to detect and prevent market abuse. This implies access to records of transactions as well as data on capacity and use of facilities for production or transmission of electricity. Consequently, market participants as producers or traders are required to provide that information to ACER. Furthermore, ACER issues guidance to ensure that National Regulatory Authorities enforce their tasks, derived from REMIT, in national legislation (ACER, 2016). In Germany, the legislator equipped the *Bundesnetzagentur*, through the Energy Industry Act (EnWG), with the necessary investigative and enforcement powers. The EnWG distinguishes between various sanctions. Violations can be classified as administrative or even as criminal offenses.

REMIT requires all market participants to disclose inside information. Following Article 2(1) of REMIT, the concept of inside information includes all types of information that are likely to have a significant impact on prices of wholesale energy products. The obligation to disclose inside information lies with the market participant in accordance with Article 4(1), which is crucial for the scope of this study. According to Article 4(1) of REMIT,

“Market participants shall publicly disclose in an effective and timely manner inside information […] relevant to the capacity and use of facilities for production […], including planned or unplanned unavailability of these facilities” (ACER 2016, p.41).

In the context of registration, the market participants must specify where they publish their inside information. Because inside information should be spread as wide and publicly as possible to ensure equal and free of charge access, central platforms aggregating this information are considered effective. The EEX offers the publication of inside information via its transparency platform, which is supported by ACER. The notion of timely disclosure does not refer to a specific threshold, which can be measured in time units, but in combination with Articles 4(2) and 4(4) of REMIT, it prohibits any trading on this issue before this information is published in a simultaneous, complete and effective manner. Furthermore, it is up to market participants to decide whether information they hold constitutes inside information and should be published. Consequently, any change of planned or unplanned production has to be disclosed if the criteria in Article 2(1) of REMIT are violated.

Following REMIT, the impact of an unplanned power plant outage on the electricity price should not deviate from the impact of outage announcement, since trading on private information contradicts the purpose of this regulation. Hence, the duration of the time lag between the event and its publication should be irrelevant, since no information gains can be accumulated. Consequently, private information about unplanned power plant outages should not have an impact on intraday prices.

5.3.2 Market framework

Short-term electricity trading is based on the day-ahead and the intraday market. Both markets are characterized by physical fulfilment. In the day-ahead market, the participants have the option to trade (sell or buy) electricity for delivery in an anonymous auction or OTC for the next day. The EPEX hosts the auction and intraday trading platform, where standardized contracts can be executed. In contrast, OTC is a decentralized market, where market participants also negotiate bilaterally non-standard contracts (Bönte et al., 2015).

Concerning the day-ahead auction, orders contain up to 256 price/quantity combinations for each hour of the following day and must be submitted in the EPEX trading system by at least 12 pm (gate closure). The auction takes place daily after gate closure including statutory holidays. The determination of auction prices and quantities is realized by an algorithm, which sorts all sell and buy orders (offers and bids) in a price/quantity combination by increasing prices. Hence, for each hour a supply (merit-order) and demand curve is generated, and its intersection determines the market-clearing price. Under this uniform pricing, the optimal strategy for auction participants is to bid at marginal costs. On the one hand, the short-term nature of the day-ahead market satisfies the trading of reliable forecasts of RES or unexpected peak demands. On the other hand, it suits the grid system characteristics, which require balanced supply and demand in advance.

After gate closure, the market participants are offered to adjust their day-ahead schedules, if necessary, on the intraday market. Moreover, the participants are obliged by the regulator to reschedule, since the original day-ahead scheduling is affected by an unforeseen event, such as an unplanned outage. Any deviation from planned production may lead to imbalance costs which are penalized accordingly to the originator. Following the current balancing costs regime in Germany, imbalance prices significantly exceed – at least on average – the intraday prices. Therefore, the expected imbalance costs incentivize all market participants to reduce imbalance volumes and can be considered as the main motivation for intraday trading (Scharff and Amelin, 2016).

On the continuous intraday market, electricity is traded for delivery on the same or on the following day on single hours. Each hour can be traded until 30 minutes before delivery begins. Starting at 3 pm on the current day, all hours of the following day can be traded. Trading is continuous 24 hours a day, 7 days a week. Unlike the day-ahead auction market, prices on the continuous intraday market are determined by the pay-as-you-bid principle, which implies trade matching at any time whenever the counterparty accepts the offer. Hence, prices vary from trade to trade and market participants may generate incremental rents by modifying their orders. Alternatively, intraday trading can also be executed in an OTC environment. However, as Zachmann (2008) and Nicolosi (2010) derive, OTC and exchange prices converge, otherwise arbitrage between these two markets would be possible.

5.3.3 Reduction of the lead time on the continuous intraday market

To facilitate the producer's need for rescheduling, EPEX shortened the lead time for contracts on the intraday market from 45 to 30 minutes till delivery on July 16, 2015. The lead time refers to the minimum time between the execution of a trade and the delivery of the traded electricity and its reduction is the object of an ongoing process. This structural change was introduced to manage emerging flexibility challenges of power markets more efficiently, which is particularly necessary for unforeseen events such as power plant outages but even more so for renewable forecast errors (EPEX SPOT SE, 2015). Since forecasts for RES can be set up nowadays in a constant update regime, the shorter lead time trading outcome is twofold. Firstly, the correcting trading quantities for the market participants decrease and relax, ceteris paribus, the impact on the intraday price. Secondly, which is a consequence of the first point, the reduction mitigates the imbalance costs especially associated with increased amounts of fluctuating renewable energy (Holttinen, 2005; Barth et al., 2008). Furthermore, the lead time reduction enables the market participants to arbitrage between neighboring countries, provides opportunities for cross-border trading and enhancing the reaction on load deviations (Weber, 2010; Viehmann, 2017).

Concerning private information about unplanned power plant outages, the regime change may also create constellations, which enhance or limit the timely edge to trade on the continuous intraday market. According to the example in Figure 5-1, the unplanned outage starts at 15:20 and is published at 15:40. In the old regime, both the insider and the market participants can adjust their bids until 16:15 and, therefore, at the earliest for H18, which lasts from 17:00 to 18:00. Consequently, the information gain is omitted. In the new regime, the insider may trade contract H17, which lasts from 16:00 to 17:00, until 15:30 and benefit from the non-disclosure of this information, since the market participants can only adjust their biddings for H18 until 16:30. Overall, the publication time lag creates a situation for potential insider trading, which is strictly prohibited by the REMIT legislation.

Nevertheless, the lead time regime change allows possible constellations that even limit the insider opportunity. According to the example in Figure 5-2, the outage starts at 15:20 and is published at 16:20. In the old regime, the insider obtains the information gain for two tradable contracts, H17 and H18, since the market participants can only react for H19 until 17:15. In the new regime, the lead time shortage enables the market to already react for H18 until 16:30.

Figure 5-1: The impact of the lead time change on private and public information

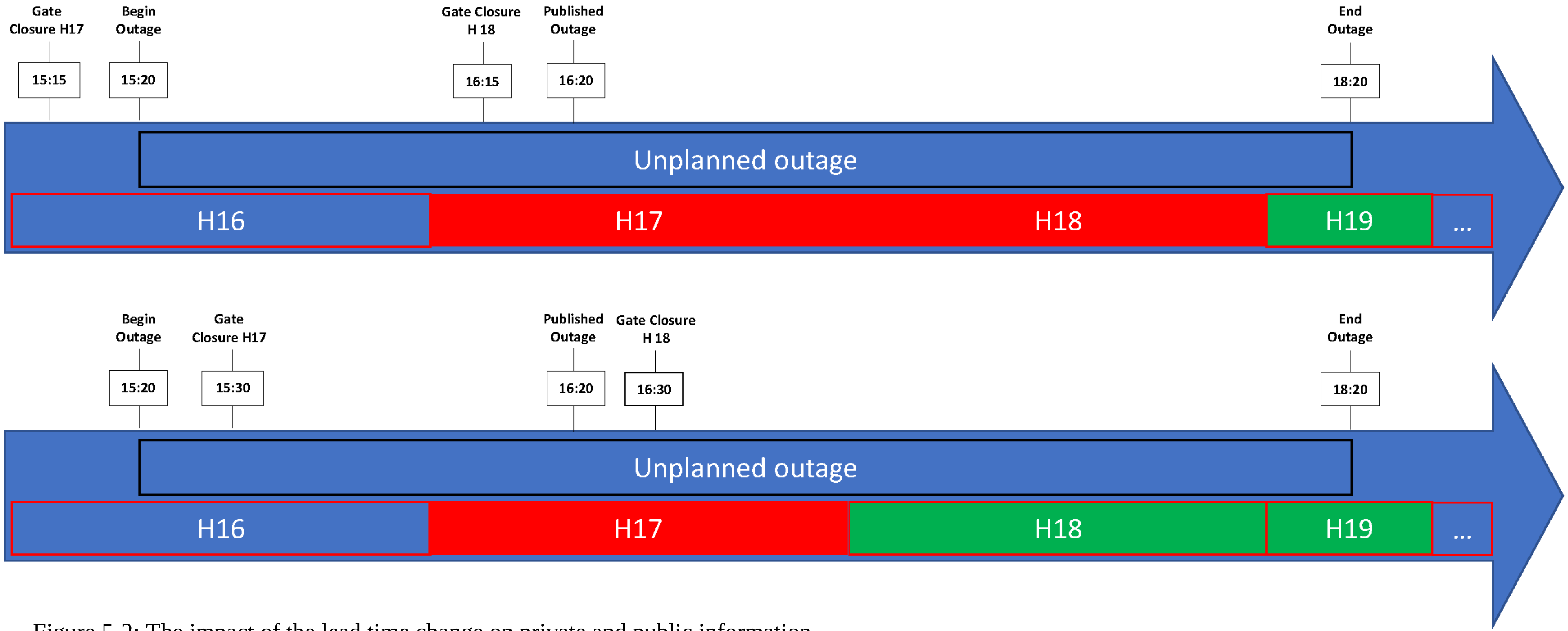

Figure 5-2: The impact of the lead time change on private and public information

5.4 Data

5.4.1 Dependent variable: The difference between the day-ahead and intraday price

Supply side shocks after the day-ahead gate closure cause open positions in the schedules of market participants and may induce trading activity on the continuous intraday market. Thus, the deviation of the volume weighted average intraday *ID* price from the day-ahead *DA* price can be explained by changes in the market fundamentals (Hagemann, 2015b) or by the publication of market messages (Lazarczyk, 2016).

Table 5-1 sizes descriptive statistics of the EPEX day-ahead and intraday continuous prices, respectively. Our dataset begins on January 1, 2014 and ends on December 31, 2016. On average, prices on the day-ahead market coincide with prices on the intraday market (31.12 €/MWh vs. 31.32 €/MWh), and there are no significant differences in the mean prices at the hourly level. However, the standard deviation on the day-ahead market is lower than on the intraday market (12.74 €/MWh vs. 13.81 €/MWh). At the hourly level, prices are less volatile on the day-ahead market during the hours 1–6 when the demand is relatively low. They exhibit standard deviations between 8.08 and 9.16 €/MWh. Electricity is traded for the highest price on the day-ahead market with 104.96 €/MWh; this is much less than the largest price on the intraday market with 139.12 €/MWh.

Negative electricity prices on the German day-ahead market have been possible since 2008. They are the result of a high feed-in of RES in periods of low demand and/or interconnections failures (Valitov, 2018). Negative prices are also possible on the intraday market. The lowest price in our dataset was on the intraday market with –155.52 €/MWh in comparison with –130.09 €/MWh on the day-ahead market.

Table 5-1: Descriptive statistics of the day-ahead and intraday prices

DA price	Mean	S.D.	Min.	Max.	ID price	Mean	S.D.	Min.	Max.
H1	25.08	8.08	-19.98	51.68	H1	25.54	9.20	-75.82	49.03
H2	23.16	8.61	-36.1	41.58	H2	23.76	9.97	-81.04	43.29
H3	21.89	9.16	-49.98	39.02	H3	22.25	10.31	-76.62	44.92
H4	21.00	9.11	-60.26	38.56	H4	21.17	10.17	-77.52	40.61
H5	21.46	8.77	-50.65	42.93	H5	21.52	9.69	-78.25	41.88
H6	23.37	8.51	-51.49	46.66	H6	23.56	9.76	-78.32	47.17
H7	29.22	11.33	-67.07	54.11	H7	29.65	12.14	-65.47	54.11
H8	35.78	14.17	-67.09	75.06	H8	35.54	14.56	-43.16	87.23
H9	37.81	13.85	-54.20	85.05	H9	37.84	14.81	-44.27	103.43
H10	36.53	12.52	-9.11	83.54	H10	36.49	13.61	-56.70	89.69
H11	34.69	12.07	-10.31	77.17	H11	34.97	13.44	-57.76	96.41
H12	34.18	11.92	-7.09	75.94	H12	34.16	13.82	-56.67	139.12
H13	31.76	12.02	-76.09	70.8	H13	32.17	14.30	-78.53	129.71
H14	30.14	13.55	-100.06	71.48	H14	30.77	15.44	-123.46	122.63
H15	29.36	14.31	-130.09	70.82	H15	30.07	15.79	-155.52	81.82
H16	30.27	13.62	-82.06	72.99	H16	30.67	14.99	-99.46	82.48
H17	31.86	13.16	-76.00	84.92	H17	32.28	14.36	-65.39	86.49
H18	36.98	13.66	-4.20	104.96	H18	36.98	14.89	-15.10	114.70
H19	40.60	12.58	7.45	86.01	H19	40.54	13.71	-3.29	110.61
H20	41.30	11.56	2.16	98.05	H20	40.90	12.81	-2.09	98.72
H21	37.49	8.90	-1.58	67.54	H21	37.01	10.55	-34.33	121.66
H22	33.78	7.76	-3.35	59.94	H22	33.46	9.32	-49.59	76.27
H23	32.12	7.18	3.45	61.95	H23	32.47	8.94	-23.45	80.68
H24	27.11	7.40	-19.93	52.49	H24	27.84	8.84	-43.74	57.42
Total	31.12	12.74	-130.09	104.96	Total	31.32	13.81	-155.52	139.12

5.4.2 Publication of unplanned power plant outages

The EEX transparency platform publishes all unscheduled power plant non-availabilities. Every planned and unplanned non-usability of 100 MW or more and of at least one hour in duration has to be reported by the power plant operator. The classification as a planned or unplanned non-usability depends on the time lag between the start of the outage and its reporting time. In case the message is issued before or simultaneously with the outage, it is classified as planned. In contrast, the message is classified as unplanned if the publication time stamp is after the beginning. Although not legally defined, news announcing failures has to be reported within 60 minutes of an outage. All messages are published online and can be updated on an on-going basis.

Table 5-2: Descriptive statistics of published unplanned missing capacities (in MW)

	Number	Mean	S.D.	Min.	Max.
Total sample	3,481	316.62	218.25	100	1,402
45 minutes of lead time	1,552	318.41	225.46	100	1,310
30 minutes of lead time	1,929	315.18	212.32	100	1,402

Our dataset is comprised of market messages regarding unplanned outages, including information about the respective power plant type, the duration and magnitude of the non-usability and its publication timestamp. From the entire dataset, we segregate messages about outages of less than 100 MW and less than one hour in duration because facility operators are obliged to report only unplanned non-usabilities of 100 MW or more that last at least one hour. This leaves 3,481 published messages about unplanned non-usabilities from 2014 to 2016. As summarized in Table 5-2, the mean missing capacity of an outage is about 317 MW.

Next, we assign the content of the messages into two distinct explanatory variables: Private Information and Public Information. “Private Information” is the sum of missing capacities that may influence the intraday price only in the period from the beginning of the outage until its publication on the EEX Transparency Platform. Consequently, all missing capacities that may have an impact on the intraday price from the publication timestamp until the expected end of the outage are summarized in the variable "Public Information."

5.4.3 Control variables: Renewable energies, load and cross-border physical flows

Hagemann (2015b) discusses further determinants of the German intraday price. Besides unplanned power plant outages, RES forecast errors and load forecast errors as well as cross-border physical flows might influence the intraday price. Forecast errors are calculated as the difference between the actual value and the day-ahead forecasted value. Concerning the case of RES, TSOs might act as a seller of electricity on the intraday market if the actual generation exceeds the forecasted generation. Thus, an increase of the RES forecast error should lead, ceteris paribus, to a decrease of the intraday price. In contrast, TSOs might also act as a buyer of electricity on the intraday market if the actual consumption (load) is higher than the forecasted values. Furthermore, cross-border trades may influence the continuous intraday price. Electricity imports into the German intraday market are expected to decrease the prices, whereas exports to neighboring countries are expected to increase the prices. We control for these market fundamentals and include data provided by the European Network of Transmission System operators for electricity (ENTSO-E) Transparency Platform. In our analysis, we use generation data from wind (onshore and offshore) farms as well as solar plants. Cross-border flows are estimated by net exports from Germany to France (Hagemann, 2015b).

5.5 Empirical strategy

Following Hagemann (2015b) and Lazarczyk (2016), we perform OLS regressions:

$$\begin{aligned} \text{ID\_price}_t - \text{DA\_price}_t \\ = \alpha + \beta_1 \text{Private\_information}_t + \beta_2 \text{Public\_information}_t \\ + \gamma' C_t + \varepsilon_t, \end{aligned} \tag{5.1}$$

with $t = 1, \ldots, N$ where N indicates the number of hours in the sample. The difference between the average intraday price and the day-ahead price is regressed on the missing capacities caused through unplanned power plant outages. As described above, we distinguish between private and public information about the non-usabilities. Furthermore, the regressions include a vector of control variables C as described in Section 5.4.3, as well as dummy variables for hours, days, and months to control for time-specific effects. Note that all explanatory variables may influence the intraday price at hour t, but have no impact on the respective day-ahead price.

As explained in Section 5.4.2, we assign the content of the market messages into two distinct explanatory variables: Private Information and Public Information. From these messages, we choose outages that arrive in time to influence decisions concerning the intraday market, but not the day-ahead market. This leaves 2,909 published unexpected outages with content that could possibly influence intraday prices from 2014 to 2016. From these 2,909 messages, we identify 705 messages for which the publication time lag creates opportunities to trade on private information. Table 5-3 summarizes the respective descriptive statistics of these messages.

Since the lead time change creates situations that can enhance or limit the number of affected prices through power plant outages, we split the sample into periods before and after the regime switch. Next, we segregate the messages in the 30 min lead time regime into four further categories—*No change in private and public information*, *No change in private information*, *Increase in private information*, and *Decrease in private information*—and assign public and private information, respectively.

No change in private and public information means that the regime switch does not affect the number of influenced intraday prices due to an unplanned power plant outage. Hence, the outcome of these variables is comparable to the outcome of the variables in the 45 min subsample. *Increase in private information* includes all messages that increase the number of affected intraday prices due to private information compared to a 45 min regime. *Decrease in private information* means the opposite.

Table 5-3: Market messages with potential impact on intraday prices (in MW)

		Number	Mean	S.D.	Min.	Max.
Total sample	All messages	2,909	320.86	222.42	100	1,402
	Private information	705	327.37	226.09	100	1,050
45 minutes of lead time	All messages	1,403	323.05	229.05	100	1,310
	Private information	412	327.98	235.91	100	1,050
30 minutes of lead time	All messages	1,506	318.82	216.12	100	1,402
	Private information	293	326.51	211.89	100	915
No change in private and public information	All messages	965	327.13	220.02	100	1,402
	Private information	143	343.49	202.59	100	875
No change in private information	All messages	242	317.34	212.52	100	1,060
	Private information	4	245.75	101.19	110	350
Increase in private information	All messages	140	314.72	224.01	100	915
	Private information	140	314.72	224.01	100	915
Decrease in private information	All messages	159	274.26	184.66	100	915
	Private information	6	250.75	176.48	120	603

The regressions are conducted with Newey-West standard errors to get autocorrelation and heteroscedasticity robust estimates. All variables are checked for the presence of a unit root by performing several Augmented Dickey-Fuller (ADF) tests. The results of the unit root tests with and without a trend suggest that all variables in the regressions are stationary (see Appendix Table C. 3). As a robustness check, we perform regressions with the first two lags of the dependent variable as further explanatory variables.

5.6 Results

Table 5-4 summarizes the OLS regression results of five models based on Equation (5.1) and including data from 2014 to 2016. The first column of Table 5-4 presents the outcome for the total sample. The coefficient of the variable Private information points to a positively significant impact on the intraday price. Holding all other variables constant, the intraday price increases by 1.21 €/MWh if the privately known missing capacities increase by 1000 MW. Furthermore, publicly known missing capacities have a positively significant impact on the intraday price, which is in line with Lazarczyk's (2016) empirical findings for the Nordic intraday market. These two results imply that the intraday price is partly affected by asymmetric information regarding unplanned power plant outages. However, from a legal perspective, there should not be any impact of private information about the actual outage on the intraday price at all. As Hagemann (2015b) expected, an increase in the forecast error of RES (i.e., excess supply) has a negative impact on the intraday price. In contrast, an increase in the load forecast error (i.e., an increase in electricity consumption) leads to a higher intraday price. The coefficient of the variable Net exports points to a positive impact on the intraday price as theoretically predicted.

Table 5-4: OLS regression results for the total sample and for the subsamples

VARIABLES	(1) Total sample	(2) 45 min lead time	(3) 30 min lead time	(4) Total sample
Private information	1.212*	0.563	2.127***	0.563
	(0.734)	(1.305)	(0.510)	(1.353)
Public information	1.053***	1.188***	1.222***	1.188***
	(0.256)	(0.385)	(0.313)	(0.397)
RES forecast error	-1.471***	-2.207***	-1.081***	-2.207***
	(0.218)	(0.107)	(0.259)	(0.110)
Load forecast error	0.264***	0.268***	0.408***	0.268***
	(0.0530)	(0.0625)	(0.0886)	(0.0628)
Net exports	0.219**	-0.141	0.510***	-0.141
	(0.110)	(0.181)	(0.146)	(0.189)
Lead time change				-0.373
				(0.864)
Lead time change*Private information				1.564
				(1.443)
Lead time change*Public information				0.0342
				(0.508)
Lead time change*RES forecast error				1.126***
				(0.284)
Lead time change*Load forecast error				0.140
				(0.110)
Lead time change*Net exports				0.652***
				(0.239)
Dummies				
Hour	Yes	Yes	Yes	Yes
Day	Yes	Yes	Yes	Yes
Month	Yes	Yes	Yes	Yes
Constant	-0.0680	-0.211	-0.584	-0.211
	(0.485)	(0.521)	(0.688)	(0.557)
Observations	25,697	13,097	12,600	25,697
Adjusted R-squared	0.185	0.278	0.153	0.221
Bandwidth	99	62	72	98

Dependent variable: ID_price – DA_price.
Newey-West standard errors in parentheses.
Optimal Bandwidth for a Bartlett kernel was determined by the Newey-West method (Newey and West, 1994).
Significance levels: *** p<0.01, ** p<0.05, * p<0.1.

The second and third columns of Table 5-4 present the regression coefficients of the subsamples before and after the policy change, respectively. Both subsamples include nearly the same number of observations. In the old 45 min lead time regime, private information about missing capacities has a positive, but not statistically significant, impact on the intraday price (0.56 €/MWh). After the regime switch, however, the coefficient of the variable Private information points to a positively significant impact of 2.13 €/MWh. Furthermore, the impact of the RES forecast error increases from –1.99 €/MWh to –1.08 €/MWh, the impact of the Load forecast error increases from 0.27 €/MWh to 0.41 €/MWh and the impact of Net exports increases from –0.14 €/MWh (not statistically significant) to 0.51 €/MWh. The increases in the coefficients might be an indicator of enhanced market adoption due to the higher flexibility of the intraday market.

To test the remarkable differences between both subsamples for statistical significance, we introduce a dummy variable for the lead time change that becomes one from July 16, 2015 onwards. Next, we multiply all explanatory variables with the policy change dummy and test these interaction terms for statistical significance. The fourth column of Table 5-4 summarizes the results. According to this test, only the increases in the coefficients RES forecast error and Net exports are statistically significant.

Table 5-5 presents the regression results for the 30 min lead time subsample with detailed explanatory variables for private and public information. Holding everything constant, the coefficient of Private information increases from 0.56 €/MWh in the 45 min regime to 1.80 €/MWh in the new regime (no change in private and public information due to the lead time reduction). This result might point to a higher adoption of the participants due to the increased flexibility on the intraday market. Furthermore, the coefficient of Private information is statistically significant for the content of market messages, which open the opportunity to trade with inside information.

Table 5-5: OLS regression results after lead time change

VARIABLES	(1) 30 min lead time	(2) 30 min lead time
Private information: total	2.127***	
	(0.510)	
Public information: total	1.222***	
	(0.313)	
No change in private and public information		
Private information		1.802***
		(0.665)
Public information		1.709***
		(0.405)
No change in private information		
Private information		-3.350
		(4.927)
Public information		0.208
		(0.681)
Increase in private information		
Private information		3.956***
		(1.054)
Public information		-0.224
		(1.934)
Decrease in private information		
Private information		1.851
		(1.792)
Public information		0.315
		(0.897)
RES forecast error	-1.081***	-1.076***
	(0.259)	(0.258)
Load forecast error	0.408***	0.413***
	(0.0886)	(0.0884)
Net exports	0.510***	0.512***
	(0.146)	(0.147)
Dummies		
Hours	Yes	Yes
Day	Yes	Yes
Month	Yes	Yes
Constant	-0.584	-0.467
	(0.688)	(0.705)
Observations	12,600	12,600
Adjusted R-squared	0.153	0.155
Bandwidth	72	72

Dependent variable: ID_price – DA_price.
Newey-West standard errors in parentheses.
Optimal Bandwidth for a Bartlett kernel was determined by the Newey-West method (Newey and West, 1994).
Significance levels: *** p<0.01, ** p<0.05, * p<0.1.

Table 5-6: Tests for differences between private and public information after lead time change

Private = Public	Total	No change (private and public)	No change (private)	Increase (private)	Decrease (private)
F-statistic	2.85*	0.02	0.52	3.81**	0.58

Period: 30 minutes lead time.
Significance levels: *** p<0.01, ** p<0.05, * p<0.1.

To check whether private and public information have asymmetric impacts on the intraday price after the policy change, we test the differences between the estimated coefficients for statistical significance. Table 5-6 presents the results of these tests. While the difference in aggregated coefficients between private and public information (Total) is significant at the 10% level, the outcome changes on the disaggregated level. Only the difference in coefficients between the variables Private information and Public information is statistically significant when the lead time reduction creates constellations that open the opportunity to trade with private information. This result provides evidence for an asymmetric impact of both types of information on the intraday price.

Appendix Table C. 1 and Table C. 2 present the regression results of the same models, but with the first two lags of the dependent variable as further explanatory variables. Our major finding is robust: private information regarding missing capacities has a positive significant impact on the intraday price, especially after the switch to a 30 min lead time regime, and its marginal impact is statistically different from the marginal impact of public information.

5.7 Conclusion

This paper investigates the impact of asymmetric information regarding unplanned power plant outages on intraday electricity prices in Germany from 2014 to 2016. In order to distinguish between private and public information, we split the content of relevant market messages into periods before and after their publication and test whether this asymmetry affects the intraday price besides further market fundamentals. The results of an econometric analysis suggest that the intraday price increases, ceteris paribus, by 1.21 €/MWh if the privately known missing capacities increase by 1000 MW. Similarly, public information regarding these missing capacities increase the intraday price by 1.05 €/MWh.

We show that a reduction of the lead time and, therefore, increased flexibility on the intraday market indicate a higher adoption of the participants: on the one hand, the impact of forecast errors of RES on electricity prices is reduced, and cross-border trading becomes more relevant. On the other hand, the policy change enhances the possibilities of traders reacting to unplanned non-usabilities: an increase in the impact of private information on the electricity price is observed. Furthermore, the results suggest an asymmetric impact of private and public information on the intraday price after the lead time reduction on the power exchange.

However, we have to acknowledge that the empirical findings in this paper provide indications for the impact of private information on intraday prices, but not evidence for actual insider trading. Since prices on the EPEX intraday market are determined through anonymous bids and offers, it is not possible to assign an abnormal trade in the data to a distinct market message ("smoking gun"). Nevertheless, policymakers could increase transparency among market participants and prevent information asymmetry by introducing a real-time updated market messages framework.

Appendix C

Table C. 1: Robustness - OLS regression results for the total sample and for the subsamples

VARIABLES	(1) Total sample	(2) 45 min lead time	(3) 30 min lead time	(4) 30 min lead time
$ID\_price_{t-1} – DA\_price_{t-1}$	0.865***	0.824***	0.892***	0.892***
	(0.0241)	(0.0368)	(0.0259)	(0.0260)
$ID\_price_{t-2} – DA\_price_{t-2}$	-0.0733***	-0.0750***	-0.0784***	-0.0786***
	(0.0191)	(0.0285)	(0.0197)	(0.0197)
Private information	0.564***	0.448	0.713***	
	(0.172)	(0.307)	(0.184)	
Public information	0.253***	0.342***	0.271***	
	(0.0483)	(0.0775)	(0.0642)	
No change in private and public information				
Private information				0.645***
				(0.211)
Public information				0.373***
				(0.0805)
No change in private information				
Private information				0.660
				(2.029)
Public information				0.0358
				(0.190)
Increase in private information				
Private information				1.109***
				(0.412)
Public information				-0.0148
				(0.337)
Decrease in private information				
Private information				-1.274
				(1.175)
Public information				0.119
				(0.222)
RES forecast error	-0.411***	-0.685***	-0.292***	-0.292***
	(0.0244)	(0.0369)	(0.0278)	(0.0278)
Load forecast error	0.0652***	0.0804***	0.0899***	0.0914***
	(0.0101)	(0.0137)	(0.0177)	(0.0178)
Net exports	0.0812***	-0.0223	0.151***	0.152***
	(0.0191)	(0.0366)	(0.0264)	(0.0267)
Dummies				
Hour	Yes	Yes	Yes	Yes
Day	Yes	Yes	Yes	Yes
Month	Yes	Yes	Yes	Yes
Constant	-0.245	-0.295	-0.374	-0.348
	(0.162)	(0.225)	(0.232)	(0.234)
Observations	25,691	13,093	12,598	12,598
Adjusted R-squared	0.733	0.725	0.750	0.751

Dependent variable: ID_price – DA_price.
Robust standard errors in parentheses.
Significance levels: *** p<0.01, ** p<0.05, * p<0.1.

Table C. 2: Robustness - Tests for differences between private and public information

Private = Public	Total	No change (private and public)	No change (private)	Increase (private)	Decrease (private)
F-statistic	5.23**	1.47	0.09	4.48**	1.36

Period: 30 minutes lead time.
Significance levels: *** p<0.01, ** p<0.05, * p<0.1.

Table C. 3: Augmented Dickey-Fuller tests for unit root

Variables	ADF test statistic	ADF test statistic with trend
ID_price – DA_price	-17.695***	-17.695***
Private information	-16.863***	-16.957***
Public information	-14.668***	-14.691***
RES forecast error	-11.898***	-11.898***
Load forecast error	-10.592***	-10.907***
Net exports	-6.638***	-6.879***
No change in private and public information		
Private information	-11.701***	-11.788***
Public information	-13.329***	-13.621***
No change in private information		
Private information	-15.781***	-15.909***
Public information	-14.553***	-14.673***
Increase in private information		
Private information	-14.392***	-14.606***
Public information	-14.615***	-14.618***
Decrease in private information		
Private information	-16.707***	-16.711***
Public information	-13.163***	-13.189***

Automatic lag selection: Schwarz information criterion.
Significance levels: *** p<0.01, ** p<0.05, * p<0.1.

6 Outlook

In writing three empirical papers, I gained deeper insights into the functioning of electricity spot markets and the role of regime changes on pricing. Consequently, the results of this dissertation could be useful from a policy perspective and may offer gateways for further research.

The first study of this dissertation presents estimates for the price elasticity of demand in the EPEX day-ahead market using average hourly wind speed as an instrumental variable for the market price. The identification strategy is based on an institutional change from that of RES having to be traded exclusively on spot markets. It is argued that wind speed is a valid instrument after this change, but not before, when RES may have influenced the market price also from the demand side. The results suggest that the average price elasticity of demand in the EPEX day-ahead market is about –0.43 in the period from 2010 to 2014, and the absolute value of the point estimates declined over time. One argument for why the price elasticity of demand was relatively high in the first years after the regime switch is that market participants may have needed time to adapt to the new institutional setting.

One might argue that the empirical analysis of the price elasticity of demand focuses on the day-ahead market and not also on the futures and intraday market. In the years 2013 and 2014, the volume traded at the day-ahead market represented around 46% of the total load in Germany. Hence, a relevant volume is traded at the spot market. If the spot market represented just a small part of all electricity trade, this might justify the use of load instead of traded volume. Lijesen (2007) provides two major arguments as to why it could make sense to estimate the elasticity of total demand with respect to the day-ahead market price. First, the approach would take into account the effects in the spot market itself and the effects on the OTC contracts with prices linked to the day-ahead price. Second, it avoids the measurement problems related to distinguishing between demand and supply on the spot market.

However, the first argument is only valid if the agreed-upon prices in OTC contracts are linked to the spot price. As Lijesen (2007, p. 254) pointed out, “contents of bilateral contracts are in general undisclosed information. Some of those contracts have fixed prices, others may be linked to the spot market price, either real-time or based on averages overtime.” Therefore, hourly spot prices may not necessarily have an immediate impact on the traded volumes outside the spot market, since many of the bilateral contracts might have fixed prices. The second argument provides support to the approach using traded volumes: it is argued that the instrumental variable wind speed allows dealing with the endogeneity problem. Using volumes traded on the day-ahead market instead of load implies that the estimates do not represent the price elasticity of total electricity demand, but rather the price elasticity of demand in the day-ahead market. Future research might use the calculated elasticities to investigate market power in the German day-ahead market (Borenstein et al., 1999).

The second study of this dissertation starts with an exact replication of original results based on the same data that were used in Viehmann's (2011) research. Replicating the results, the study confirms the presence of risk premia in the German day-ahead electricity market. While estimates of mean hourly risk premia can be replicated, the study does not reproduce respective Newey-West standard errors, leading to remarkable differences between significance levels reported in the original study and in the replication.

Next, the empirical analysis is extended to previous years. The results of this analysis point to statistically significant risk premia that are more frequent during weekdays than weekends. These results that are based on new data deviate from the findings Viehmann (2011) reported. In addition, they provide evidence that Bessembinder and Lemmon's (2002) reduced form of the model—a standard theoretical model in research on risk premia in electricity markets—might not accurately predict the risk premia in the German day-ahead market.

This manuscript is the first empirical study that addresses the impact of negative prices on risk premia. Negative prices are a relatively new phenomenon in the European electricity markets, and in the future, they might become relevant in other electricity markets as well. The results suggest that the introduction of negative prices has led to a remarkable decrease in risk premia compared to the period of a positive price regime. While Viehmann (2011) conjectured that this might be the case, he was unable to empirically test this because his analysis was based on data with only positive prices. These new results also have implications for theoretical research because Bessembinder and Lemmon's (2002) model does not consider the existence of negative prices. Hence, the implementation of negative electricity prices in this model may be an interesting subject for future research.

The third study of this dissertation investigates the impact of information regarding unplanned power plant outages on German intraday electricity prices. To distinguish between private and public information, the content of relevant market messages is divided into periods before and after their publication and tested to determine whether this asymmetry affects the intraday price. The results of an econometric analysis suggest that a reduction of the lead time enhances the possibilities of traders reacting to unplanned non-usabilities. Furthermore, the results point to an asymmetric impact of information about power plant outages on the average intraday price. Consequently, trading with private knowledge about these non-usabilities may distort electricity prices, which is prohibited by the REMIT legislature. The difference in these impacts stems from the publication time lag of market messages. Depending on the time lag, the owner of private information may trade contracts on the intraday market without the public being informed. To avoid possible insider trades, policymakers could introduce a real-time updated market messages framework. This would eliminate the timely edge of power plant owners, and thus, only public knowledge about outages would impair the electricity prices, aside from market fundamentals.

The evidence of asymmetric information about unplanned power plant outages is derived from aggregated price data of the EPEX continuous intraday market. Hence, the limitations of this study are as follows. The results present indications, but not evidence, for actual insider trading. Since bids and offers for intraday electricity contracts are determined anonymously, it is not possible to identify distinct trades as an immediate reaction to a power plant's non-availability. Another limitation is the restriction of private information to knowledge about power plant outages. Operators may manage a portfolio consisting of fossil-fueled power plants and RES. The feed-in of the latter is usually forecasted on the previous day and may be updated in a continuous manner. Thus, the possession of ongoing forecasts can also be interpreted as private information, since the public has only access to day-ahead forecasts. Consequently, it is assumed due to the lack of data that public forecasts of RES equal private forecasts of RES.

In June 2017, the EPEX reduced the intraday lead time in Germany from 30 minutes to 5 minutes until delivery, but only if trades take place in the same control area of the TSO. It would be interesting to see whether the results of an asymmetric impact of private and public information remain robust after this regime switch. To this end, it has to be assumed that missing capacities are traded in the respective control area of the power plant outage.

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