A plant-level analysis of the spill-over effects of the German *Energiewende*

Machiel Mulder[a,b] and Bert Scholtens[a,c,d]

Abstract

In order to analyse international effects of national energy policies, we investigate the spill-over effects of the German *Energiewende* on the Dutch power market, which is closely connected to the German market. We estimate the impact of the German supply of wind and solar electricity on the Dutch day-ahead price of electricity and the utilisation of the conventional power plants. We take cross-border capacity constraints into account and use hourly plant-level data over 2006-2014. We find that the price elasticity of German wind on Dutch day-ahead prices is -0.03. However, this effect vanishes when the cross-border capacity is fully utilised. We find a modest negative impact on the utilisation of the Dutch power plants. As such, we conclude that the German *Energiewende* has had modest spill-over effects to the Dutch market. The recent dramatic performance of the Dutch gas-fired plants can be attributed to the changes in the relative prices of coal versus natural gas. We conclude that national energy policies in one country do not necessarily strongly affect neighbouring markets in case of constrained cross-border capacities.

Keywords: energy transition, *Energiewende,* renewable energy, fuel efficiency, cross-border spill-overs, transport capacity

a Faculty of Economics and Business, University of Groningen, PO Box 800, 9700 AV Groningen, The Netherlands

b Netherlands Authority Consumers and Markets (ACM), PO Box 16326, 2500 BH ‘s-Gravenhage, The Netherlands c School of Management, University of Saint Andrews, The Gateway, North Haugh, St. Andrews, Fife, KY 16 9RJ Scotland, UK

d corresponding author: Phone +31-503637064, Fax +31-503638252, Email l.j.r.scholtens@rug.nl

1. Introduction

Many countries are implementing policies to stimulate renewable energy. Although these policies are meant to reach national policy targets, they may have significant spill-overs regarding the power markets in neighbouring countries. This holds in particular if countries pursue dramatic changes in their energy mix. A clear example of such a country is Germany, which is fundamentally transforming its domestic energy generation by replacing conventional power plants by renewable sources such as windmills and solar panels. This energy transition, which is called the *Energiewende* (energy turnaround), is a multi-decade effort to transform German society into a low-carbon renewables-based energy economy (Hitaj et al., 2014). Within less than a decade, its renewable energy capacity has almost tripled to 70 GW (see Figure 1).

The radical change of the electricity sector has several effects which should be considered in order to evaluate the efficiency and effectiveness of the *Energiewende*. These effects are related to the impact on energy consumers who have to pay the subsidies, the reliability of the networks which have to deal with increasing supply from renewables, the incentives to invest in storage capacity, the role of demand-side management and the necessity of capacity markets (see Kopsakangas-Savolainen and Svento, 2013; Cludius et al., 2014; Krishnamurty and Kriström, 2015). Besides these within-country effects, there are likely also cross-border effects since electricity markets are increasingly linked (Würzburg et al., 2013; Dupont et al., 2014; Huber et al., 2014). For example, the Polish TSO has complained about tensions in its network due to oversupply of German electricity, while some Dutch heavy users of electricity complain that they are in a competitive disadvantage as Dutch interconnections are not capable of importing cheap power from Germany (Gerbaulet et al., 2014).

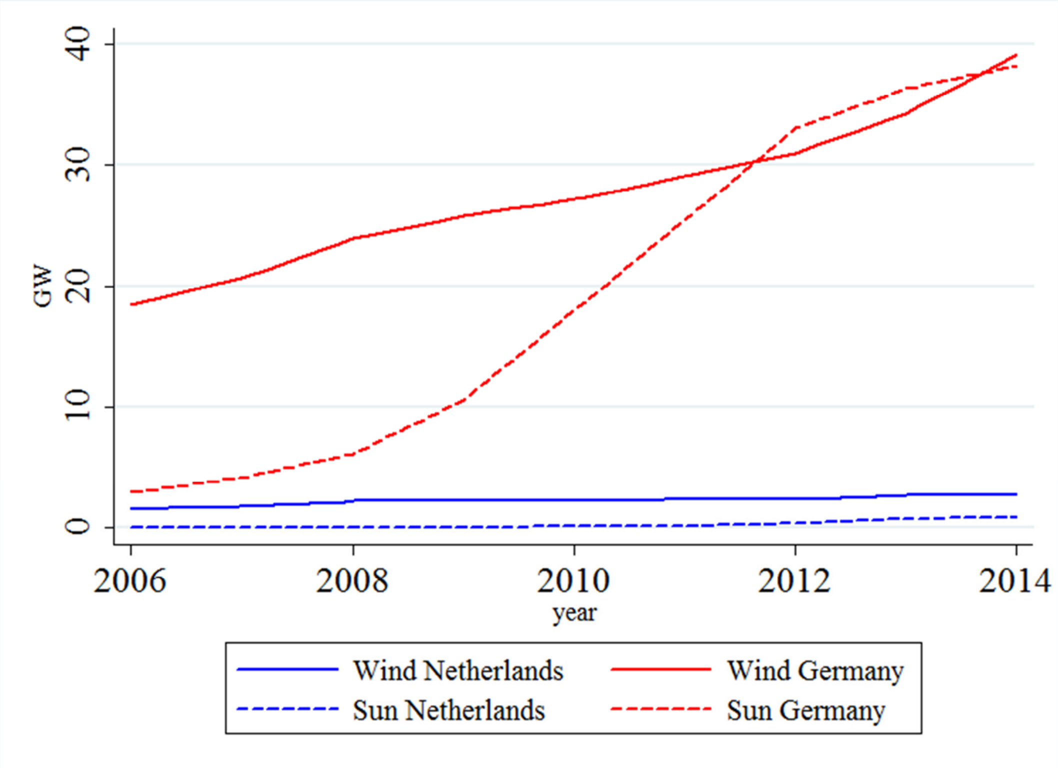

Figure 1 Wind and solar capacity in Germany and the Netherlands, 2006-2014 (source: ACM)

In this paper, we focus on the international spill-overs to neighbouring electricity markets. We investigate the spill-over effects for the Netherlands, which neighbours Germany and is directly connected to the German electricity market through a number of physical connections within a meshed network. While the German power market has changed substantially because of the *Energiewende* (Von Hirschhausen, 2014; Ederer et al., 2015; Pahle et al., 2016; Ringel et al., 2016), it is much less well-known that the Dutch market also underwent dramatic changes albeit it not in terms of an energy transition (see Figure 1). Within the EU, the Netherlands is still one of the countries with a relatively low level of renewable energy capacity and traditionally it has been highly reliant on natural gas for power production (see Verreth et al., 2015). The dramatic change within the Dutch market refers to the deteriorating profitability of conventional electricity generation. The major power firms in the Netherlands reported huge losses on their activities in the electricity market as a result of electricity prices below the level of marginal costs of many of their power plants. Consequently, several plants have been switched off, or even broken down in order to be sold abroad. The utilization of Dutch power plants which are still operating fell back dramatically. The number of plants without any production during a particular year increased strongly, as is shown by the left-hand panel of Figure 2. The right-hand panel, depicting the utilisation of plants in relation to their capacity, shows that relatively small plants are not used anymore.

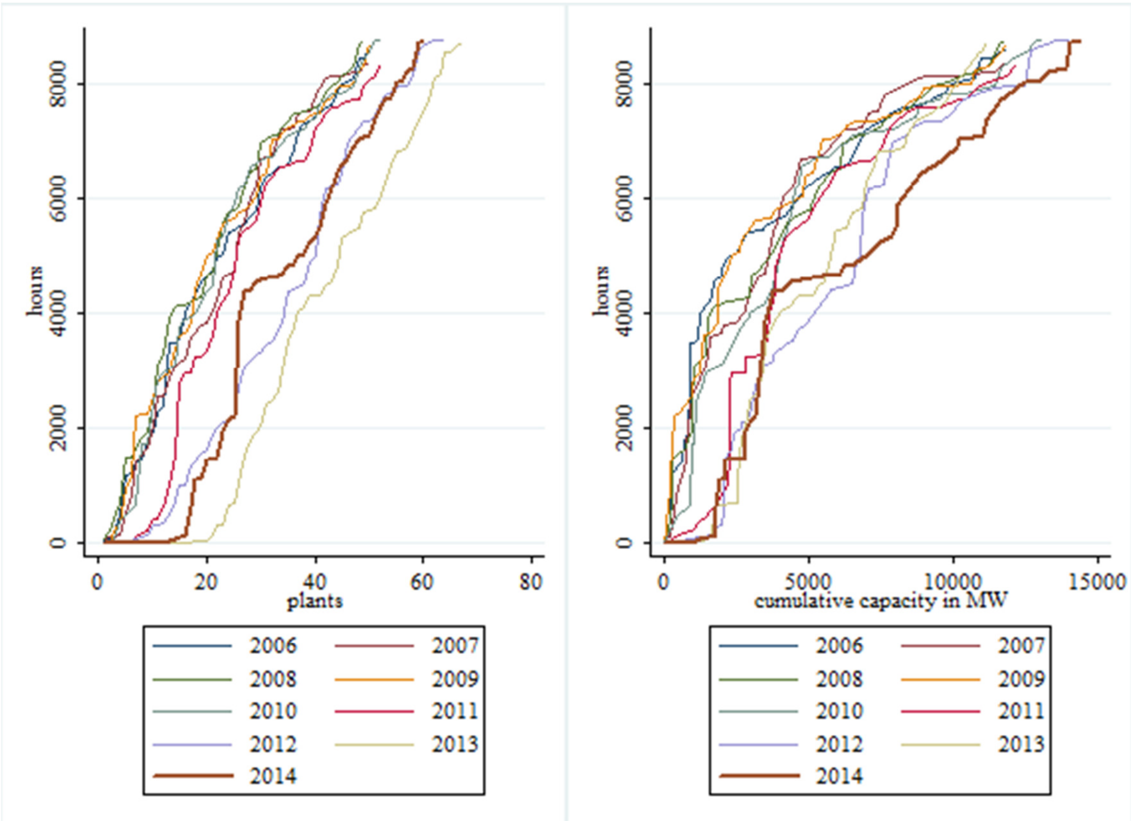

Figure 2 Utilisation of the centralised power plants in the Dutch market measured by the number of hours with production>0, 2006-2014 (number of hours per year) (source: ACM)

These developments seem to suggest that a next stage in the liberalization of electricity wholesale markets is on its way. Until to a few years ago, the market was characterized by the privatization process of previously publicly owned utilities which resulted in a bonanza of international mergers and acquisitions. The Dutch incumbent utilities Essent and Nuon were acquired by German RWE and the Swedish Vattenfall, respectively. In addition to this process of internationalisation on the firm level, national electricity markets became increasingly connected through new physical connections and improved capacity-allocations mechanisms (Mulder and Schoonbeek, 2013). Now, with the strong increase in distributed and renewable energy generation, the business model of the incumbents faces enormous challenges, as also has been expressed by the one of the largest power firms operating in the Dutch market who attributed the closure of a gas-fired power plant to the increasing supply from (German) renewables.[1]

The key question to be answered in this paper is to what extent the dramatic changes in the energy business in the Netherlands can really be attributed to the German *Energiewende*. Our analysis is related to Ederer (2015), Eser et al. (2016), Kopsakangas-Savolainen and Svento (2013), Lantz et al. (2016), Markandya et al. (2016), Matisoff et al. (2014), Mauritzen (2013), Mulder and Scholtens (2013), Traber and Kemfert (2011), Kannan (2009), Snyder and Kaiser (2009), Ucar and Balo (2009), Weigt et al. (2009), and Wiser et al. (2016), who also analyse the impact of renewable energy on the conventional business model of power producing companies and on the energy system as a whole. Using unique hourly plant-level data on the Dutch power market for the period 2006-2014, and accounting for climate factors and cross-border capacity constraints, we find that the renewable electricity production in Germany reduced the power price in the Dutch market. Furthermore, we establish that this effect is capped by constraints resulting from cross-border transmission capacity. In addition, we show that the increase of electricity from Germany reduced the residual demand for the Dutch incumbent suppliers. Coal-fired power plants, however,

---

[1] See the press release on: https://www.essent.nl/content/overessent/actueel/archief/2014/marktomstandigheden_leiden_tot_mottenballen_gasgestookte_centrale_claus_c.html.

remained producing on a fairly constant level on an annual basis, but their dispatch showed a higher level of flexibility. As a result, the utilisation of these plants has somewhat declined. The Dutch natural gas-fired plants show a strong decline in their utilisation. However, we show that this is mainly caused by the increase in the relative price of gas compared to the price of coal. Overall, we conclude that, at least so far, the German energy transition has had very modest effects on the Dutch power market.

The remainder of this paper is structured as follows. We first give an overview of the literature on the impact of renewable energy on electricity markets in Section 2. Then, in Section 3, we provide some background about the electricity markets in Germany and the Netherlands and how these markets are related. In Section 4, we explain our research method to assess the impact of the *Energiewende* on the Dutch power market. The estimation results are presented and analysed in section 5. Section 6 holds the conclusion and discusses policy implications.

2. Impact of renewables on electricity markets

An increase in generation capacity of renewable energy techniques may influence the power market through different channels (Traber et al, 2011; Fell and Lin, 2013; Hirth 2013; Würzburg et al., 2013; Cludius et al., 2014; Ketterer, 2014; Smith and Urpelainen, 2014; Eser et al., 2016; Lantz et al., 2016; Wiser et al, 2016). Firstly, more supply of renewables may reduce the electricity price because of the merit-order effect (see also e.g. Paraschiv et al., 2014; Smith and Urpelainen, 2014). This is illustrated in Figure 3 where the appearance of renewable-generation capacity with low marginal costs moves the merit order to the right (see also Fell and Linn, 2013). As a result, the equilibrium price decreases from P_0 to P_1. A consequence of this price reduction is that the average revenues per unit of conventional supply decline as well. Hence, the coverage of the fixed costs for these power plants reduces.

Secondly, an increase in the supply of renewable energy reduces the volume of the conventional production because of the merit-order effect. This is illustrated in Figure 3 by the difference between Q^*_0 and Q_1, which depicts the decline in production by conventional power plants. This effect results from two mechanisms. Renewable capacity replaces conventional capacity, which is equal to the difference between Q^*_0 and Q_0, but owing to the decline in the equilibrium price (from P_0 to P_1), the demand and, hence, the equilibrium level of total production increases from Q_0 to Q_1. The reduction in the utilisation of the power plants also results in a lower coverage of the fixed costs of the conventional plants. Thirdly, an increase in the supply of the intermitted renewable may raise the variability in the production by conventional plants which impacts on their generation costs. The increased variability in itself means higher cycle costs (including start-up and maintenance costs) (Traber et al., 2011; Kumar et al., 2012; Bruninx et al., 2014; Paraschiv et al., 2014; Eser, 2016). In addition, if a power plant is forced to produce below its maximum capacity, the fuel efficiency declines. Hence, more renewable energy may also result in higher marginal costs and a lower fuel efficiency of the conventional power plants. These two effects raise the part of the merit order that is related to these plants.

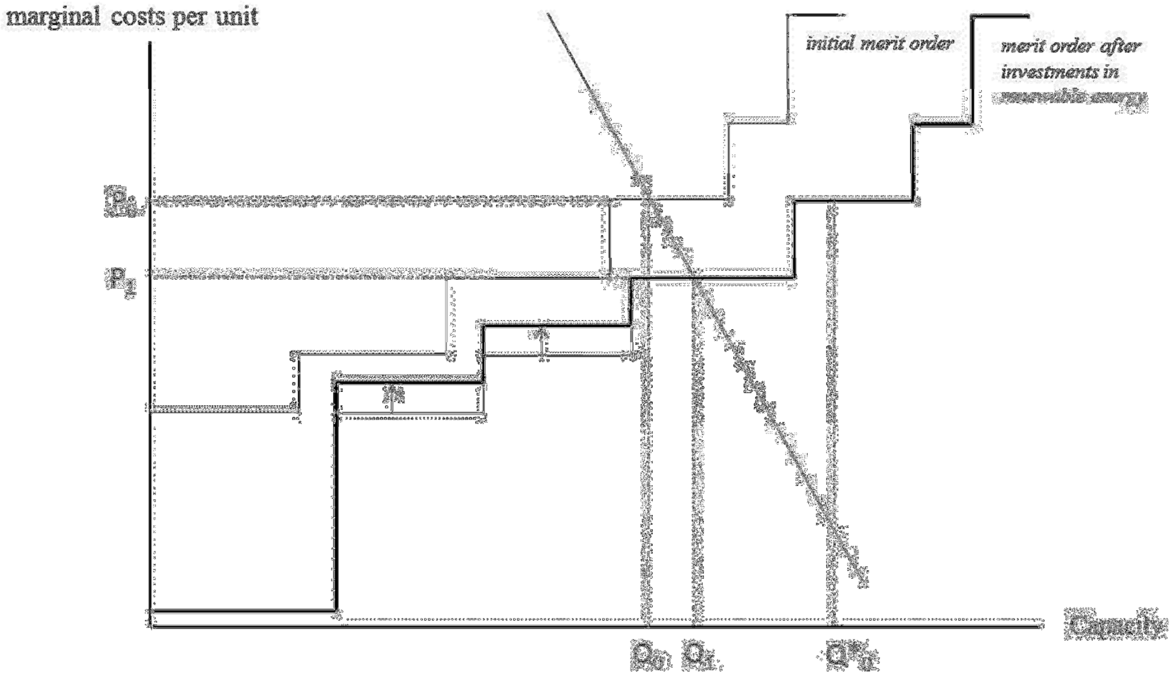

Figure 3 Effects of investments in renewable energy on the electricity market

Estimates about the impact of renewables on price levels have been reported in several studies (Jónsson et al., 2010; Holttinen et al., 2014; Paraschiv et al., 2014). The surge in renewable energy in Germany has reduced electricity prices, not only in Germany (Cludius et al., 2014; Ketterer, 2014; Ederer, 2015; Pahle et al., 2016; Ringel et al., 2016), but also in the Dutch market (Mulder and Scholtens, 2013). Policy played a key role in this respect (Hitaj, 2013; Hitaj et al., 2014; Smith and Urpelainen, 2014; Krishnamurthy and Kriström, 2015; Lantz et al., 2016; Markandya et al., 2016; Wiser et al., 2016). Ketterer (2014) models the influence of intermittent wind-power production on the level and volatility of the electricity prices in Germany by using a generalised autoregressive conditional heteroskedasticity (GARCH) model. She finds that higher wind-power production decreases the German price level but initially lead to higher daily volatility. However, since a regulatory change in 2010, this volatility-increasing impact of wind has reduced, but did not disappear completely. As such, this result is somewhat different from that of Jónsson et al. (2010) and Mauritzen (2013). Also for a number of other countries, the impact of renewable energy on prices has been estimated. Conolly et al. (2011) do so for Ireland and Liu et al. (2011) explore the case of China. Gelabert et al. (2011) study the impacts of renewable generation on daily Spanish electricity prices. Woo et al. (2011) study the impact of wind power on 15-minute price levels and variance in Texas using a time-series model that includes generation from wind and nuclear, the natural gas price, and demand as exogenous variables. Green and Vasilakos (2010) estimate the impact of wind power generation on hourly equilibrium prices and volumes with data on expected wind power production and demand in the UK. They find that the volatility of prices is higher when there is more variability in wind power production and that volatility increases if market power is exercised.

The impact of renewable energy on the utilisation of conventional plants is analysed by Mauritzen (2013). Focusing on cross-border electricity transmission between Norway and Denmark, he finds that when Denmark produces more wind power, its exports to Norway increase while Norway's hydropower plants produce less. When Danish wind-power production decreases, power flows are in the opposite direction. This is in line with the results of Green and Vasilakos (2012), who argue that the hydropower capacity of Norway, Sweden, and Finland acts as storage for Danish wind power capacity (see also Lund et al., 2011). Traber et al. (2011) conclude that an increase in the supply of wind energy reduces the load factor of in particular gas-fired power plants. Comparing an 'advanced wind' scenario with a 'no wind' scenario, they find that the utilisation of gas-fired turbines is about 40% lower in the former scenario, while the coal-fired plants show only a small drop in utilisation.

Regarding the impact of renewable energy on the generation costs of conventional power plants, Bruninx et al. (2014) find that an increase in wind energy raises the balancing costs owing to a larger uncertainty on the future wind power supply. This cost increase is estimated at about 5 Euro/MWh, which is about 10% of the average power price. Abrell and Kunz (2013), however, find only a modest effect of about 0.3% of this uncertainty on system operating costs. These authors also find that an increase in uncertainty about wind power supply reduces the production by lignite plants by about 0.9%, while it increases the production by coal-fired and gas-fired plants. This change in production portfolio is caused by the need to raise the flexibility of the power system.

Regarding the impact of renewable energy on the volatility of conventional power plant generation, Holtinnen (2005) finds for the Nordic countries that a share of wind production in total supply of 15% requires a flexible capacity of about 3% of total installed wind capacity. For Denmark, the required level of flexibility was lower owing to the higher variability in load.

From the above concise overview follows mixed evidence on the impact of renewable energy on the energy market. Apparently, this impact depends on other characteristics of these markets, such as the merit order of conventional power plants, the portfolio of power plants, the level of interconnection with neighbouring countries, and the variability and flexibility of load. In order to contribute to this literature, we analyse each of the above mechanisms for the Dutch market and German renewables. Using unique hourly plant-level data about electricity generation in the Netherlands as well with hourly data on prices, climate, and several factors affecting demand and supply, we will estimate how German renewable supply affected the power market in the Netherlands over 2006-2014.

3. The power markets in Germany and the Netherlands

3.1 The German Energiewende

The *Energiewende* is a multi-decade effort to transform the German society into a low-carbon, renewables-based economy. The process started with a feed-in-tariff for wind power in 1991, but has been expanded considerably in the past couple of years (Hitaj et al., 2014). Especially the years 2010 and 2011 are of importance. First, in 2010, to 'sweeten' the lifetime extension of Germany's nuclear reactors due to heavy lobbying by the power companies, the government added some green elements into the decision such as increasing the share of renewables and setting GHG emissions targets (Von Hirschhausen, 2014). However, the disaster with the Fukushima Daiichi nuclear power plants resulted in the closure of Germany's oldest nuclear power plants and the phasing out of nuclear energy entirely by 2022 (Von Hirschhausen, 2014). The objectives of the Energiewende have been reconfirmed by the change of government that occurred in autumn 2013.

Currently, the program is on track of increasing the share of renewables for electricity generation to 50% in 2030 and 80% in 2050 and in final energy use to 30% in 2030 and 60% in 2050. In 2014, about 25% of total electricity production came from renewable energy sources (mainly wind, biomass and solar), while this share was no more than 7% in 2000 (Statistisches Bundesambt). The share of nuclear power has reduced to about 15% in 2014. Kunz and Weigt (2014) show that the phasing out of nuclear power plants does not seem to have pronounced effects on the energy system. Furthermore, the increased share of renewables does not seem to challenge energy system security (Neuhoff et al., 2014). An important issue in Germany, however, is the cost of the Energiewende (Cludius et al., 2014). In this respect, Von Hirschhausen (2014) analyses the social costs of different techniques and concludes that the Energiewende will be very favourable in the long term. In the short term, however, this energy transition causes significant costs for energy consumers as well as for the incumbent energy producers (see also Ederer, 2015; Ringel et al., 2016; Pahle et al., 2016).

Especially for the incumbents, the business environment has changed dramatically in the recent past (Kungl, 2014). In the traditional system, production was differentiated into base load, medium load and peak load. The base-load plants ran on a continuous basis. The medium term load operated according to the demand curve which changed in the course of the day. Peak-load power was used to handle short-term demand changes. Nuclear was used as a source for the base load, as was lignite. Coal was the main medium load and natural gas was used for peak load. However, such a system does not easily accommodate the rising share of renewables. This requires much more flexible power plants and less base load due to the intermittency of the renewables and their very low marginal costs. On top of that, especially solar power is a huge competitor for the traditional peak-load power generators. This simply results from the fact that the time profile of photovoltaic power is highly in line with that of electricity demand (Hirth, 2013).

3.2 Dutch power production

Although the Dutch government also is pursuing a policy of energy transition, this policy has been much less effective than the German one, while the current policy objectives are less ambitious than those of the Germans (PBL, 2014). The share of renewables in the total electricity production has grown from 8% in 2006 to approximately 13% in 2014 (Table 1). The Dutch electricity industry is still characterized by a mixed portfolio of mainly thermal generation plants, in particular gas-fired plants which took care of 50 to 70% of total domestic production. The production by coal-fired power plants was fairly stable over the past period, but gas-fired plants recently showed a relatively steep decline in their level of production. A significant part of supply comes from import. Table 1 also shows that the level of imports decreased from 2006 to 2010 while it increased strongly afterwards.

Table 1

Supply of electricity in Dutch power market by origin, 2006-2014 (in TWh)

Origin of supply	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**
Domestic									
- gas-fired plants	57	61	65	68	74	68	54	54	49
- coal-fired plants	23	25	23	23	22	21	24	25	29
- other fossil-fuels plants	4	5	5	4	4	5	4	4	4
- wind power	3	3	4	5	4	5	5	6	6
- other renewable power	5	4	5	6	7	7	7	7	6
- total	99	105	108	114	118	113	103	101	103
International									
- import	27	23	25	15	16	21	32	33	33
- export	6	5	9	11	13	12	15	15	18
- net import	21	18	16	4	3	9	17	18	15

Source: CBS.

In the recent years, the Dutch market witnessed dramatic changes. More specifically, the merit order based on the centralised units in the Dutch market changed significantly over the past couple of years (see Figure 4). This merit order shifted to the left as a result of the closure of a number of plants, while it also became steeper because of the change in the prices of gas, coal and CO_2 (see Figure 5). While the prices of gas and coal were relatively close until 2010, afterwards the price of coal reduced gradually while the price of gas increased to historically high levels (see Figure 5). As a result, the marginal costs of gas-fired plants rose while those of the coal-fired plants declined.

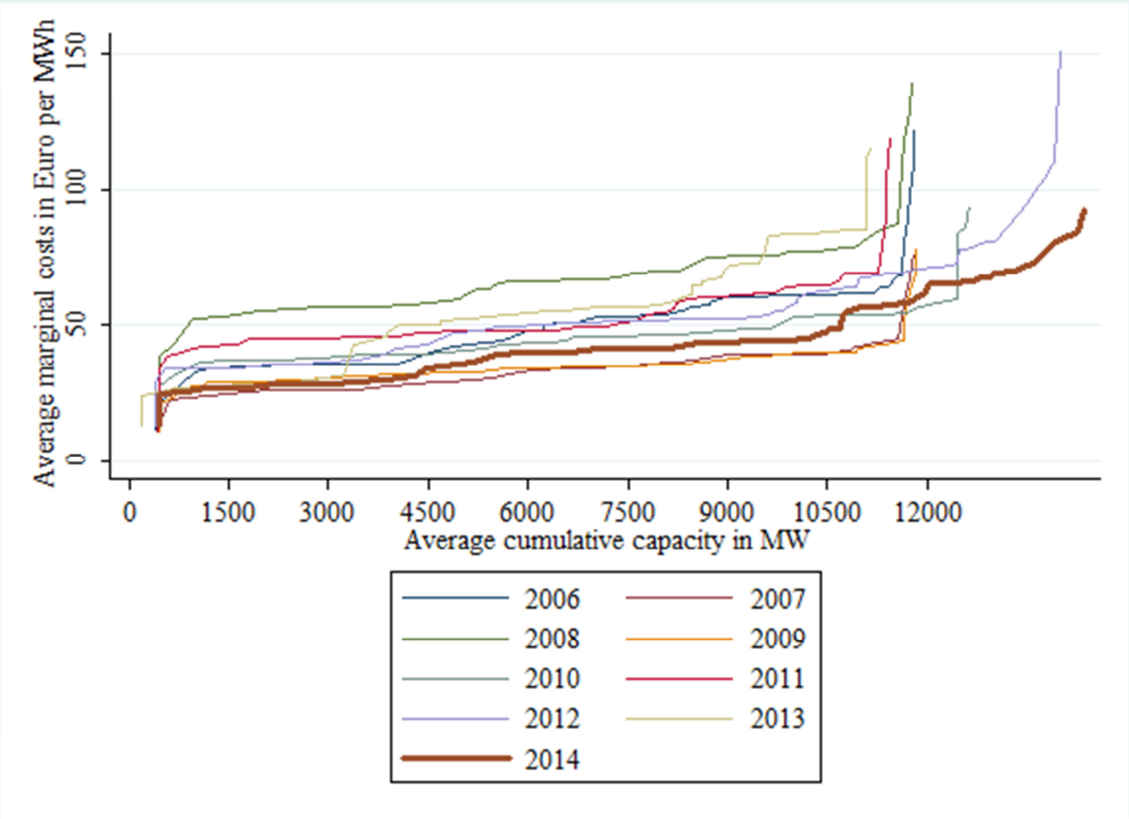

Figure 4 The annual average merit-order of centralised production units in the Dutch power market, 2006-2014 (Source: ACM)

Figure 5 Prices of gas, coal and CO_2, 2006-2014, per day (Source: Bloomberg)

3.3 Connections between German and Dutch market

The Dutch electricity network is connected to the German (2.5 GW), Belgian (1.4 GW), Norwegian (0.7 GW) and the British (1.0 GW) networks (TenneT, 2014b). The connections with Norway (NorNed line) and the UK (BritNed line) are DC lines, while the Dutch network is connected to the German and Belgian networks through AC lines. The utilisation of these lines has been improved by a number of measures, including the introduction of market coupling and netting (Mulder and Schoonbeek, 2013). Because of the meshed character of the networks, loop flows have a major influence on the availability of the cross-border transmission capacity (TenneT, 2014a).[2] This availability may fluctuate strongly from day to day and even from hour to hour, in particular depending on the level of supply by renewables in different locations within the network and the level of demand in other parts of the network. Although the technical cross-border import capacity has been constant at a level of about 2.5 GW over the period 2006-2014, the actual available capacity fluctuates strongly. This implies that the cross-border flows do not only depend on price differences, but also on the transmission capacity that has been made available for commercial transactions by the TSO. Table 2 shows how the (average annual) cross-border price differences and the cross-border flows have evolved over time since 2006. Cross-border capacity constraints may help explain the price differences between the Dutch and the German power markets (see Figure 6) in spite of the increase in the imports (see Table 1). Apparently, traders were not always able to fully utilise differences in prices between both markets. The price differences in more recent years reveal that the available cross-border capacity in the German-Dutch direction is fully utilised (TenneT, 2014c).

[2] "A loop flow in a specific system is caused by a transaction within another system. Example: a shift in the power production from the South of Germany to the North of Germany will result in a north-south flow in Germany which will partially be transported as a loop flow through the Netherlands." (TenneT, 2014a)

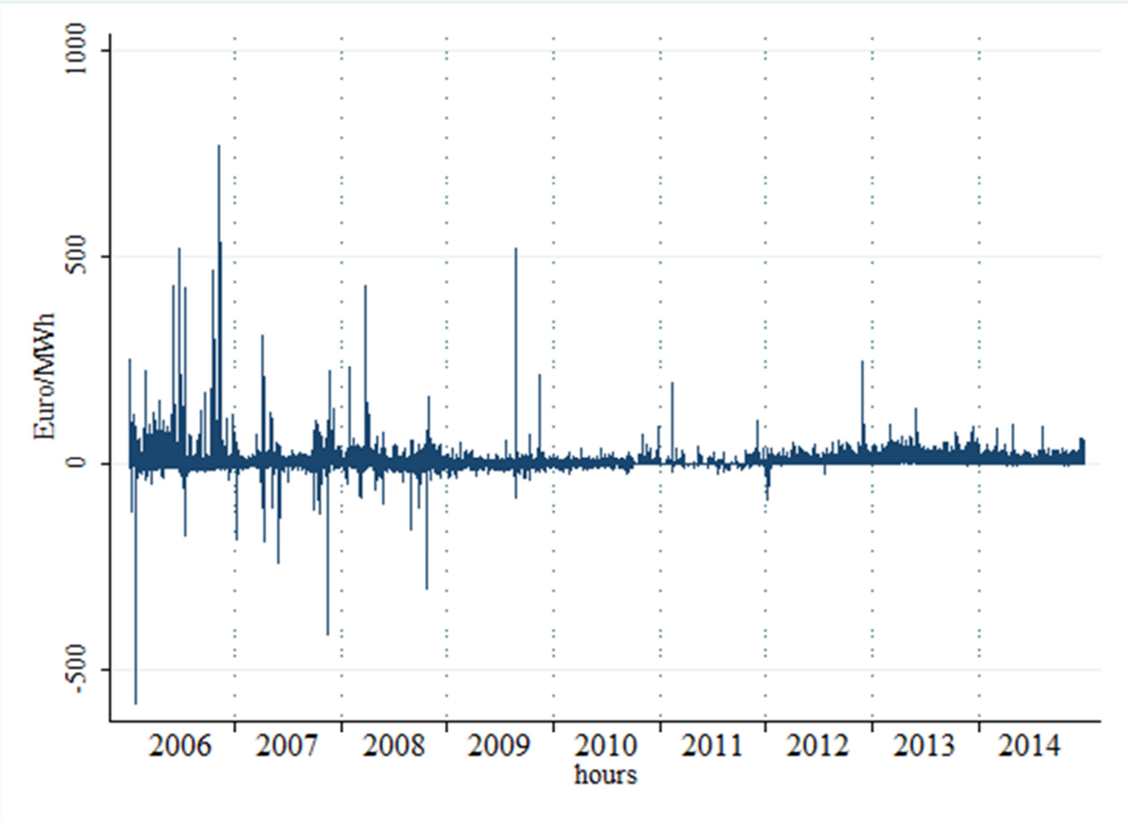

Figure 6 Difference between Dutch and German day-ahead prices, 2006-2014 (per hour) (source: Bloomberg)

Table 2

Difference in day-ahead price between Dutch and German market and size of imports and exports, 2007-2014

	APX > EEX			APX < EEX		
	average price difference	**number of hours**	**average import**	**average price difference**	**number of hours**	**average export**
2007	8,44	5262	1823	-5,77	3224	270
2008	10,34	5584	1852	-6,30	3187	339
2009	5,38	4105	1254	-4,18	4619	886
2010	4,14	4317	790	-2,98	3399	417
2011	10,07	830	1825	-5,21	162	2295
2012	12,41	3862	2171	-13,82	45	1964
2013	17,44	7087	2088	-3,14	2	2816
2014	11,85	5810	2140	-2,07	49	0

Source: Bloomberg (prices); ACM (import and export)

4. Method

The aim of this study is to estimate the impact of the German energy transition on the Dutch power market. As explained above, the energy transition may have an effect on the price of electricity as well as on the utilisation of the conventional power plants. We analyse both these mechanisms by using unique hourly data about energy generation per power plant in the Netherlands and by taking into account constraints on the cross-border transport capacity, climate factors, as well data on intensity of competition and the level of demand.[3]

[3] See Mulder (2015) for a description of the database. See Table A in the Appendix for the nomenclature of all symbols.

4.1 Estimating the impact on the electricity price

In order to determine the effect of the German energy transition on the electricity price in the Netherlands, we estimate a reduced-form model of the day-ahead electricity price (P) in the Dutch market by regressing this variable on a number of variables affecting demand and/or supply, based on Mulder and Scholtens (2013). In this reduced-form model we include all major variables which either affect the demand for electricity and/or the supply of electricity. The main economic factors affecting the electricity price are the level of electricity consumption, the intensity of competition between electricity producers and the marginal costs of production. A higher demand for electricity (D) implies that the demand curve shifts to the right along the merit order, raising the equilibrium price, and vice versa (see Figure 3). The intensity of competition determines to what extent electricity suppliers take their influence on the electricity price into account when submitting their supply bids to the market (see Mulder, 2015). In a perfectly competitive setting, suppliers base their bids only on their marginal costs of production, while in a less-competitive market suppliers may ask a margin above these costs. As a result, prices are higher in the second case. Including a variable measuring competition is important since it appears that the number of competitive suppliers in electricity markets, and hence their competitive behaviour, is related to innovation in renewable energy (see Nesta et al., 2014). The intensity of competition in the electricity industry is incorporated through the Residual Supply Index (RSI) of the firm providing the system marginal plant. The RSI measures the aggregate supply capacity remaining in the market after subtracting that firm's capacity, relative to total demand (see Mulder and Scholtens, 2013). If the RSI is below 1, at least one player in the market is viewed to be pivotal, which means that the player is needed to satisfy demand. As a result, that player is said to have market power. The lower the value of the RSI, the more market power firms have. Hence, we assume a negative relationship exists between the RSI and the price of electricity. The level of the marginal costs is important as this determines the level of the supply curve (see Figure 3). The higher the marginal costs, the higher the price of electricity. As measures for the marginal costs of production, we use fuel prices, notably the prices of gas (P_{gas}), coal (P_{coal}) and carbon permits (P_{CO2}) (see also Weber and Neuhoff, 2010; Hintermann, 2014).

Besides these fundamental economic factors, the supply and demand for electricity may be affected by other factors, such as environmental circumstances. We also take into account the impact of environmental restrictions on thermal power plants which use river water for cooling purposes. If the temperature in river water exceeds the threshold of 23 degrees Celsius, these power plants are forced to reduce the production for environmental reasons. Just as Mulder and Scholtens (2013), we implement this effect through a variable (RTR) measuring the number of degrees the actual river temperature exceeds the threshold temperature. The higher the value of RTR, the more the conventional power plants are constrained, the higher the electricity price will be. Moreover we account for the merit-order effect of the supply coming from Dutch wind mills. As data on actual wind-electricity supply is not available, we approach this supply through a variable (W) estimating the supply by wind turbines using hourly data on wind speed (see Hirth, 2013; Elberg and Hagspiel, 2015).[4] The higher the supply of Dutch wind turbines, we lower the Dutch power price will be. Finally, we control for time patterns in the consumption of electricity by including quarterly (D_q), daily (D_d) as well as hourly (D_h) dummies. These dummies capture systematic changes in the level of electricity consumption over time (from month to month, day to day and hour to hour).

[4] See Mulder and Scholtens (2013) for the translation of data on wind speed into estimates of wind power.

After having defined the above factors affecting the demand and/or the supply of electricity, we now can define the variables capturing the influence of the German *Energiewende*. The impact of the German *Energiewende* is measured in two different ways. The effect of German wind power is directly measured by the actual hourly feed-in by wind mills ($W_{GW_{GER}}$), based on data published by the German TSOs. As solar feed in this time series only exists as off 2011, we use data on daily sunshine as a proxy for the influence of the feed-in by solar panels (S_{GER}). We assume that both the supply of German wind turbines and the supply of German solar cells have a negative effect on the electricity price because of the merit-order effect.

Our current model differs from that of Mulder and Scholtens (2013) in a number of important aspects. First, our model is estimated on an hourly basis instead of on a daily basis in order to incorporate the within-day volatility. Kettener (2014) and Mauritzen (2013), for instance, have shown that the (hourly) intermittency of the renewable energy supply may have a significant impact on price volatility. Second, we explicitly control for the presence of cross-border constraints which hinder further price arbitrage between the Dutch and the German market. Mauritzen (2013) has shown that these types of constraints play a significant role on the cross-border effects between Germany and Denmark. As the precise level of the constraints depends on the outcome of unknown technical calculations related to the loop flows, we cannot directly measure this constraint. The existence of a constraint on price arbitrage can, however, be indirectly measured by the existence of a price differential. If electricity prices between the Dutch and the German differ, traders are apparently hindered to make a profit by arbitraging on these differences (TenneT, 2014c). Therefore, we argue that a cross-border constraint is present if the day-ahead prices between these markets differ. We measure the presence of the cross-border constraint as a (1-0) dummy variable (D_CBC). We test whether the impact of German wind and solar energy on Dutch prices is lower when the cross-border capacity is fully utilized. In our view, this is a novelty to the literature. For example, Würzburg et al. (2013) relate to the somewhat indirect measure of (daily) changes in exports and imports instead of capacity. Instead, we directly account for the capacity of the interconnector and rely on hourly data. The test regarding the impact of German renewable energy is conducted by including interaction terms between D_CBC and the wind and solar supply, respectively. Hence, the first model to be estimated is as follows:

$$
\begin{aligned}
log(P_t) = {} & \beta_0 + \beta_1 log(D_{t-1}) + \beta_2 \log(RSI) + \beta_3 \left(P_{coal,t-1}/P_{gas,t-1}\right) + \beta_4 \log\left(P_{CO_2,t-1}\right) \\
& + \beta_5 RTR_t + \beta_6 \log\left(W_{NL,t}\right) + \beta_7 \log\left(W_{GW_{GER,t}}\right) \\
& + \beta_8 \log\left(W_{GW_{GER,t}}\right) * D\_CBC_t + \beta_9 S_{GER,t} + \beta_{10} S_{GER,t} * D\_CBC_t + \\
& + \sum_{q=2}^{3} \alpha_q D\_q_q + \sum_{d=2}^{7} \gamma_d D\_d_{d,t} + \sum_{h=2}^{24} \delta_h D\_h_{h,t} + \varepsilon_t \qquad (1)
\end{aligned}
$$

The model is estimated in logs as the impact of the explanatory variables on the electricity prices are likely not linear. Hence, the coefficients can be read as elasticities. The variables RTR and S cannot be expressed in logs as they are zero from time to time. Moreover, we take the lag values of Demand and the fuel prices in order to control for possible endogeneity effects.

4.2 Estimating the impact on the utilisation of the power plants

Next, we test whether the utilisation of the generation capacity of both types of plants has changed in line with the increased supply of renewable electricity in Germany. We feel that this too is a novelty of our approach in relation to the literature (e.g. Weigt et al., 2009; Traber and Kemfert, 2011; Matisoff et al., 2014). A first impression of this effect is obtained by inspecting the daily standard deviation of the production levels per type of plant. If the production levels of these plants become more volatile in response to the fluctuating levels of renewable energy, the fuel efficiency of the plants is affected as well. We test this by regressing the degree of utilisation of the coal and gas fired power plants (U) on the same group of explanatory variables as used to explain the day-ahead price (see eq. 2). We assume, in line with e.g. Hirth (2013) and Matisoff et al. (2014), that this variable is related to supply coming from renewable sources and relative fuel prices. On top of that, we account for CO_2 prices, as Weber and Neuhoff (2010) show that they have an impact on different generation technologies (see also Fan et al., 2010).

$$U_{fuel,t} = \beta_0 + \beta_1 \left(\frac{P_{coal,t}}{P_{gas,t}}\right) + \beta_2 P_{CO2,t} + \beta_3 W_{NL,t} + \beta_4 W\_GW_{GER_t} + \beta_5 W\_GW_{GER_t} * D\_CBC_t + \beta_6 S_{GER,t} + \beta_7 S_{GER,t} * D\_CBC_t + \sum_{q=2}^{3} \alpha_q D_{q_{q,t}} + \sum_{d=2}^{7} \gamma_d D_{d_{d,t}} + \sum_{h=2}^{24} \delta_h D\_h_{h,t} + \varepsilon_t \qquad (2)$$

4.3 Data and statistical tests

The descriptives of the variables used in our models are provided in Table 3. This table shows that the Dutch electricity generation portfolio is dominated by gas-fired plants: on average over the period 2006-2014, the production by gas-fired plants was about 50% higher than the production by coal-fired plants. The group of gas-fired plants shows a larger variety in plant utilisation than the coal-fired power plants. The latter also have a much higher average level of utilisation. In Table 3, we also observe that the level of (residual) demand for the centralized units is highly volatile since the highest level is about five times higher than the lowest level. The price of natural gas fluctuated strongly and much more than the price of coal. Regarding the supply of wind electricity in Germany, we see that this too is highly volatile, with a minimum level close to zero and a maximum level of 29.5 GWh. The correlation coefficients between the different variables of our models are presented in Table 4.

Given that most coefficients are quite low, we may assume that the independent variables in the models are independent from each other.

Table 3

Descriptives of the variables used in the regression models, 2006-2014

Variable (symbol; unit)	**Mean**	**Standard deviation**	**Min**	**Max**
Day-ahead power price (P; euro/MWh)	49.5	23.8	0.01	850
Characteristics *coal-fired* power plants				
- aggregated production per hour ($G_{coal;}$MWh)	2801.7	673.4	504.7	4499.5
- average degree of utilisation (U_{coal}; %)	80	15	24	1
Characteristics *gas-fired* power plants				
- aggregated production per hour (G_{gas}; MWh)	4160.2	1588.6	509.5	9682.8
- average degree of utilisation (U_{gas}; %)	49	17	7	1
Demand (D; MWh)	9242.6	1762.2	2872.2	15536.5
Residual Market Index (RSI; index)	1.4	0.4	0.7	7.3
Price of natural gas (P_{gas}; euro/MWh)	20.5	5.8	2.5	50
Price of coal (P_{coal}; euro/ton)	9.8	2.7	5.3	20.0
Ratio P_{coal}/P_{gas} (index)	0.5	0.1	0.2	3.0
Price of CO_2 (P_{CO2}; euro/ton)	11.1	7.1	0.0	30.0
River temperature above threshold (RTR; degrees Celsius)	0.0	0.2	0	1
Wind power in the Netherlands (W_{NL}; Watt)	227.4	335.6	0.0	8406.7
Wind supply in Germany (W_GW_{GER}; GWh)	4.7	4.3	0.0	29.5
Sunshine in Germany (S_{GER})	0.3	0.2	0	1.0

Sources: Bloomberg (prices); ACM (production levels; RSI); German TSOs (Amprion, 50Hertz, TenneT and Transnet; wind supply); KNMI (wind speed Netherlands); DWD (sunshine Germany); Rijkswaterstaat (RTR).

Table 4

Correlation matrix of all variables used in the regression models

	P	P_{coal}	P_{gas}	P_{CO2}	W_{NL}	W_GW_{GER}	S_{GER}	D_{CBC}	G_{coal}	G_{gas}	U_{coal}
P_{coal}	0.29										
P_{gas}	0.35	0.50									
P_{CO2}	0.29	0.37	0.12								
W_{NL}	-0.02	0.02	0.01	-0.02							
W_GW_{GER}	-0.10	0.02	0.06	-0.12	0.65						
S_{GER}	-0.03	-0.01	-0.10	0.05	-0.20	-0.26					
D_{CBC}	-0.02	-0.27	-0.26	0.08	0.07	0.06	-0.005				
G_{coal}	0.25	-0.11	0.06	-0.13	0.05	0.09	-0.17	0.01			
G_{gas}	0.50	0.05	-0.11	0.11	-0.006	-0.08	-0.12	-0.10	0.35		
U_{coal}	0.31	-0.03	0.22	-0.23	0.01	0.04	-0.14	-0.04	0.70	0.33	
U_{gas}	0.52	0.02	-0.19	0.21	0.001	-0.12	-0.08	0.03	0.28	0.92	0.28

In order to control for autocorrelation within the dependent variable, we include a number of autoregressive terms based on the inspection of the correlations. As an alternative, we tested with seasonal autoregressive terms, but this did not affect the results. For the independent variables for demand and the fuel prices, we include the lagged value in order to control for possible endogeneity. We also tested the variables on a unit root by applying the augmented Dickey-Fuller Test (see Table 5). As (only) the price of CO2 appears to have a unit root, we include the first difference of this variable. The full results of the estimations are given in the Appendix (Table B).

Table 5

Results of unit root test

	Unit root test (level and intercept only)	**Unit root test (first difference and intercept only)**
	t-statistic	t-statistic
P	-18,64***	-
P_{CO2}	-2,46	-52,92***
P_{coal}	-2,10	-63,62***
P_{coal} / P_{gas}	-6,71***	-
D	-19,51***	-
U_{coal}	-16,66***	-
U_{gas}	-18,85***	-
P_{gas}	-3,92***	-
G_{coal}	-13,77***	-
G_{gas}	-21,19***	-
RSI	-21,51***	-
RTR	-11,28***	-
S_{GER}	-19,03***	-
W_GW_{GER}	-22,44***	-
W_{NL}	-26,77***	-

Note: *; **; *** refer to 10%, 5% and 1% significance levels, respectively.

Test critical values: 1% level (-3.430265); 5% level (-2.861387); 10% level (-2.566729).

5. Results

5.1 Impact on the day-ahead price of electricity

Table 6 shows the estimation results for a) the full period 2006-2014 and b) two subsequent periods in order to determine whether specific effects changed over time. The regression analysis shows that hourly day-ahead electricity price is positively related to the level of demand. It is negatively related to the ratio between the price of coal and the price of gas. If coal becomes relatively more expensive, the electricity price declines. This is related to the fact that plants lower in the merit order are more often dispatched. If the gas prices increases compared to the price coal, the electricity price also goes up. The electricity price appears to be negatively related to the intensity of competition as measured by the RSI, but this impact decreases over time indicating that the market structure became less important for competition, which is in line with the findings of Mulder (2015).

Table 6

Results of the regression analysis on the hourly day-ahead electricity price, 2006-2014

Log(APX)	**2006-2010** **first subperiod**	**2011-2014** **second subperiod**	**2006-2014** **overall period**
constant	-2.9***	2.2***	-0.5***
$\log(D_{t-1})$	0.7***	0.2***	0.5***
log(RSI)	-0.2***	-0.1***	-0.2***
P_{coal} / P_{gas}	-0.2***	0.02	-0.2***
$d.\log(P_{CO2\ t-1})$	0.01	-0.1	0.004
RTR	0.04	-0.01	0.02
$\log(W_{NL})$	-0.01***	-0.01***	-0.01***
$\log(W\_GW_{GER})$	-0.05***	-0.02***	-0.03***
$\log(W\_GW_{GER})$ * D_CBC	0.02	0.02***	0.01***
S_{GER}	-0.03	-0.05***	-0.06***
S_{GER} * D_CBC	0.02	0.04***	0.04***
AR(1)	0.8***	0.8***	0.8***
AR(2)	-0.05***	-0.1***	-0.06***
AR(24)	0.1***	0.1***	0.1***
R^2 adjusted	0.84	0.84	0.84
DW statistic	1.99	1.96	1.98

Note: *; **; *** refer to 10%, 5% and 1% significance levels, respectively.

See Table B in the Appendix for the full overview of the results.

From the full overview of the results in Table B in the Appendix, we can see that the prices are relatively high in the first and the fourth quarter (i.e. the autumn and winter seasons) compared to the other two quarters (i.e. spring and summer). Moreover, the daily dummies show that the prices during working days exceed the prices at Sundays (d=1), while the hourly dummies clearly show the relatively low prices from midnight until 8 am, while the price peaks at noon and again early in the evening. We also see that the within-day volatility has decreased, since the coefficients of the time dummies have lower values in the period 2011-2014 compared to those in the period 2006-2010.

Regarding the impact of the German *Energiewende* on the Dutch power market, we find that the supply by German wind turbines negatively affects the Dutch day-ahead power prices. The average effect over the period 2006-2014 is an elasticity of about -0.03, which was also found by Mauritzen (2013). Furthermore, we find that this effect is significantly lower when the cross-border transmission capacity is constrained: In the second period, there appears to be only a small downwards net effect of German wind supply on Dutch power prices when the cross-border capacity is fully utilised. Hence, in case the import capacity is fully utilised, any change in German wind production does hardly affect the Dutch electricity market. A comparable mechanism is found for the German solar production. During hours when the cross-border capacity is not restrictive, the impact of German solar on Dutch electricity prices has strongly increased over time and reduced Dutch electricity prices.

In order to assess the relative importance of different factors related to the German *Energiewende* for the Dutch electricity prices, we compare elasticities for the different factors. From Table 6, we observe that the elasticity for the influence of German wind power is relatively low compared to that of other factors. For the full period under investigation, we find that a 1% increase in German wind-power production reduces Dutch day-ahead power prices by 0.03% when there are no constraints on the cross-border transport capacity. The elasticities for the prices of natural gas and coal as well the elasticity for demand are much higher, indicating that the Dutch day-ahead electricity price is more strongly determined by the fuel costs of Dutch power production and the level of demand. Table 6 also reveals that the changes in fuel prices directly affect the level of the merit order, while changes in the level of demand determine which part of the merit order is needed for market equilibrium. These results are in line with those by Fell and Linn (2013) and Matisoff et al. (2014). Hence, we conclude that the German *Energiewende* affected Dutch electricity prices, but that this effect is rather modest compared to the much bigger influence from the prices of natural gas and coal due to the dominant role of fossils as the powering fuel source for Dutch power generators.

5.2 Impact on the utilisation of plants

The utilisation of the coal-fired plants appears to be negatively related to the relative price of coal, while the opposite holds true for the natural gas-fired power plants (see Table 7).[5] The higher the price of coal compared to that of natural gas, the lower the level of dispatch of coal-fired plants and the higher the level of capacity utilisation by natural gas-fired plants (see also Matisoff et al., 2014).

[5] As in Table 3, we skipped the dummies in Table 4, but Table B in the Appendix gives the complete results.

Table 7

Results of the regression analysis on plant type utilisation, 2006-2014

Utilisation of plants (production/capacity)	**Coal-fired plants**		**Natural gas-fired plants**	
	2006-2010 (first subperiod)	**2011-2014 (second subperiod)**	**2006-2010 (first subperiod)**	**2011-2014 (second subperiod)**
constant	0.77***	0.99***	0.46***	0.31***
P_{coal} / P_{gas}	-0.01*	-0.39***	0.001	0.09**
$d.P_{CO2}$	0.001**	0.003	0.002***	0.001
W_{NL}	-0.000002	-0.000006***	-0.000002	-0.000008***
W_GW_{GER}	-0.001	-0.002***	-0.00002	-0.001***
W_GW_{GER} * D_CBC	-0.0002	-0.00004	0.00007	-0.0002***
S_{GER}	0.01	-0.01**	-0.003	-0.001
S_{GER} * D_CBC	0.01	0.001	0.001	-0.001
AR(1)	1.21***	1.21***	1.30***	1.39***
AR(2)	-0.27***	-0.28***	-0.34***	-0.43***
AR(24)	0.03***	0.03***	0.02***	0.02***
R^2 adjusted	0.97	0.95	0.98	0.98
DW statistic	1.97	2.0	2.02	2.0

Note: *; **; *** refer to 10%, 5% and 1% significance levels, respectively.

See Table B in the Appendix for the full overview of the results.

Both plant types clearly show similar time patterns in the dispatch: utilisation is highest in the first quarter of the year, much higher during working days than during weekend days, and much higher as well during day time and in the evening than at night. Note that these time patterns are consistent with the time patterns which were found in the day-ahead electricity price.

The electricity supply by German wind mills and PV facilities appears to have only a very moderate effect on the dispatch by the Dutch power plants. The relation with wind energy is almost negligible, meaning that the level of production by the Dutch plants is hardly affected by how much energy is produced by wind mills in Germany. One GWh more feed-in of wind electricity in Germany, results (on average) in 0.2% lower utilisation of the Dutch conventional power plants. The level of capacity utilisation by the Dutch conventional power plants is much more affected by the relative prices of coal and natural gas.

From Table 8 we derive that the volatility in the dispatch of both fossil power plant types, in particular the coal-fired plants, increased since 2006 (see Table C in the Appendix for more detail). While the average annual level of production by the coal-fired plants hardly increased, the standard deviation in 2013 and 2014 was about 50% higher than in 2006. The gas-fired plants also show higher annual standard deviations while annual average level declined. Moreover, the difference between the minimum annual and the maximum level of production during a year became larger. It seems that not only natural gas-fired plants are increasingly used for supplying flexibility to the market, but coal-fired plants as well.

Table 8

Volatility in generation levels per type of fossil-fuel power plant, 2006-2014 (in MWh)

	Mean	Standard deviation	Minimum	Maximum	Max - Min
Coal-fired plants					
2006	2702	503	1120	3837	2717
2007	2866	616	1050	4116	3066
2008	2749	606	896	4109	3213
2009	2889	637	1147	4076	2929
2010	2778	692	949	4101	3152
2011	2423	570	835	4108	3273
2012	2981	690	904	4193	3289
2013	2817	751	504	3951	3447
2014	3023	771	1035	4500	3465
Natural gas-fired plants					
2006	4155	1407	1464	7469	6005
2007	4307	1437	1735	8079	6344
2008	4191	1451	1437	7970	6533
2009	4435	1515	807	8092	7285
2010	5001	1455	1645	8326	6681
2011	4304	1364	1107	8350	7243
2012	3997	1901	1288	9682	8394
2013	3481	1689	846	8579	7733
2014	3514	1437	1120	8268	7148

Source: ACM

In order to determine whether this increased flexibility is related to the increased supply of renewable electricity, we also analyse the correlation coefficients between the volatility in the different types of fossil power generation. Table 9 shows that the correlation coefficient between the daily standard deviation of the hourly production levels of coal-fired power plants in the Dutch market on the one hand and that of the hourly wind-electricity production in the German market on the other, is positive and increasing.[6] For the natural gas-fired plants, we do not find such a relationship. This suggests that the coal-fired plants are increasingly used to offer flexibility to the grid in order to balance the volatile supply coming from German wind electricity. The growing importance for coal-fired plants for balancing the grid is likely to be related to the increasing importance of these plants which is caused by the changing relative prices of gas and coal, as discussed above. As a result, gas-fired plants became more and more out of the money, implying that they were also less available for offering flexibility. From these data, we learn that the Dutch conventional power plants show more fluctuating levels of capacity utilisation and that the increased volatility of in particular coal-fired plants to a very small extent may be related to the volatile supply coming from German renewables.

[6] As data on sunshine is only available on a daily level, this correlation coefficient cannot be calculated.

Table 9

Correlation coefficient between the daily standard deviations of the hourly conventional production in the Dutch market and the daily standard deviations of the hourly wind-electricity production in German market, 2006-2014

	Coal-fired plants	Natural gas-fired plants
2006	0.13	0.34
2007	0.13	-0.01
2008	0.32	-0.15
2009	0.29	-0.07
2010	0.49	0.22
2011	0.48	0.20
2012	0.29	0.11
2013	0.57	-0.16
2014	0.40	0.20

Source: ACM (Dutch production); German TSOs (German wind production)

6. Conclusion

The German *Energiewende* is expected to have major effects on power markets because of the fundamental changes in the way electricity is produced (Weigt, 2009; Traber et al., 2011; Ketterer, 2014; Von Hirschhausen, 2014). In this paper we analysed how this energy transition has affected the Dutch electricity market which is connected to the German one: their interconnectors provide capacity for about 25% of average Dutch electricity demand. As the utilisation of many conventional power plants in the Dutch market has strongly reduced in the recent past, we wonder to what extent the changes in the Dutch electricity market are related to the *Energiewende* in Germany.

Using high-frequency data over the period 2006-2014, we find evidence that the German *Energiewende* has had a moderate impact on the Dutch electricity market so far. When the wind blows or when the sun shines in Germany, the day-ahead electricity price in the Dutch market is reduced. The price elasticity of wind is about -0.03, which is in line with the results from other studies (see Mauritzen, 2013; Würzburg et al., 2013; Cludius et al., 2014; Ketterer, 2014). We establish that the price impact of renewable energy vanishes when the cross-border transportation capacity is fully utilised. The constraints on the cross-border capacity also imply that German wind power producers are less able to benefit from exporting electricity at relatively favourable prices during windy hours, as Hirth (2013) found for the German-French border.

Moreover, we find that the level of capacity utilisation of the fossil power plants in the Dutch market is mainly affected by the relative fuel prices. The strong decline in the production by natural gas-fired plants has to be attributed to the relatively high natural gas prices on the one hand and the low prices for coal and CO_2 on the other. This finding is well in line with the results of Matisoff et al. (2014) on the effects of coal and natural gas prices on dispatch of power plants in the US. Hence, the dramatic events in the Dutch market cannot be attributed to the energy transition in Germany and the increased supply of renewable energy, in spite of the mechanisms found by Traber et al. (2011). The events in the Dutch market predominantly follow from the changes in the relative fossil fuel prices. Furthermore, it appears that not only natural gas-fired plants are used to supply flexibility to the market, but that increasingly the coal-fired plants offer these services. The reduced role of gas-fired plants as suppliers of flexibility is directly related to the high relative price of natural gas since this price level makes it unprofitable for them to operate. Notwithstanding the increased variability of their dispatch, the degree of utilisation of the coal plants reduced only slightly in response to the increased supply of German wind electricity.

The results of this paper show that fundamental changes in the electricity market in a large country do not necessarily have a huge impact on the markets in neighbouring countries. In particular, this seems to hold if their cross-border capacity is fully utilised. The high level of cross-border capacity utilisation seems to protect power producers in a market dominated by fossil-fuel plants from low prices in neighbouring markets with significant shares of renewable energy, while this may hinder consumers to benefit from these low prices. Although cross-border capacity constraints enable countries to implement national energy policies without bothering too much about possible adverse consequences for neighbouring countries, from a consumer point of view, an integrated electricity market with equal prices is preferred. Cross-border differences in power prices may, therefore, reduce the societal acceptance of renewable-energy policies.

This paper contributes to the discussion on the welfare effects of national renewable-energy policies in integrating markets (see Fell and Lin, 2013; Kopsakangas-Savolainen and Svento, 2013; Würzburg et al., 2013; Ketterer, 2014; Krishnamurthy and Kriström, 2015; Pahle et al., 2016). Further, it provides a novel argument for the assessment of the energy transition, esp. the spillover effect (see Lantz et al., 2016; Markandya et al., 2016; Wiser et al., 2016). Our study shows that the size of spillover effects strongly depends on the cross-border transport capacity. We have shown that the existence of cross-border constraints enables policy makers to implement national energy policies without having large (adverse) impacts on neighbouring countries. The downside of such constraints, however, is that they indicate a lack of market integration which may result in a unlevel playing field for international operating firms. With the current challenges regarding climate change and security of energy supply as well as the need to efficiently use public resources, it is important to understand not only the costs of solving transport-capacity constraints, but also the benefits for reaching policy objectives regarding the transition of the energy system. Therefore, it is key to analyse national energy policies from an international perspective taking cross-border capacity constraints into account.

References

Abrell, J., F. Kunz, 2013. Integrating intermittent renewable wind generation: a stochastic multi-market electricity model for the European electricity market. DIW, Berlin, Discussion Papers 1301.

Bruninx, K., E. Delarue, W. D'Haeseleer, 2014. The cost of wind power forecast errors in the Belgian power system. KU Leuven, Energy Institute, TME Working Paper Energy and Environment, WP EN2014-10.

Connolly, D., H. Lund, B.V. Mathiesen, M. Leahy. 2011. The first step towards a 100% renewable energy-system for Ireland. Applied Energy, 88, 502-507.

Cludius, J., H. Hermann, F.C. Matthes, V. Graichen. 2014. The merit order effect and photovoltaic electricity generation in Germany 2008-2016: Estimation and distributional implications. Energy Economics, 44, 302-313.

Dupont, B., C. De Jonghe, L. Olmos, and R. Belmans, 2014. Demand response with locational dynamic pricing to support the integration of renewables. Energy Policy, 67, 344-354.

Ederer, N., 2015. The market value and impact of offshore wind on the electricity spot market: Evidence from Germany, Applied Energy, 154, 805-814.

Elberg, C., S. Hagspiel, 2015. Spatial dependencies of wind power and interrelations with spot price dynamics. European Journal of Operational Research, 241, 260-272.

Eser, P., A. Singh, N. Chokani, R.S. Abhari, 2016. Effect of increased renewables generation on operation of thermal power plants, Applied Energy, 164, 723-732

Fan, L., B.F. Hobbs, C.S. Norman, 2010. Risk aversion and CO2 regulatory uncertainty in power generation investment: Policy and modelling implications. Journal of Environmental Economics and Management, 60, 193-208.

Fell, H., J. Linn, 2013. Renewable electricity policies, heterogeneity, and cost effectiveness. Journal of Environmental Economics and Management, 66, 688-737.

Gelabert, L., X. Labandeira, P. Linares., 2011. An ex-post analysis of the effect of renewables and cogeneration on Spanish electricity prices. Energy Economics, 33,S59-S65.

Gerbaulet, C., C. Lorenz, J. Rechlitz, T. Hainbach, 2014. Regional cooperation potentials in the European context: Survey and case study evidence from the Alpine region. Economics of Energy & Environmental Policy, 3, 45-60.

Green, R., N. Vasilakos, 2012. Storing wind for a rainy day: What kind of electricity does Denmark export? The Energy Journal, 33, 1-22.

Hirschhausen, C. von, 2014. The German " Energiewende" – An introduction. Economics of Energy & Environmental Policy, 3, 1-12.

Hintermann, B., 2014. Pass-through of CO2 emission costs to hourly electricity prices in Germany. CESifo Working Paper No.4964. Munich.

Hirth, L., 2013. The market value of variable renewables. The effect of solar wind power variability on their relative price. Energy Economics 38, 218-236.

Hitaj, C., 2013. Wind power development in the United States. Journal of Environmental Economics and Management, 65, 394-410.

Hitaj, C., M. Schymura, A. Löschel, 2014. The Impact of a Feed-In Tariff on Wind Power Development in Germany. ZEW discussion paper 14-035. ZEW Mannheim.

Holttinen, H., 2004. Effects of Large Scale Wind Production on the Nordic Electricity Market. VTT Publications 554 Available from: http://www.vtt.fi/inf/pdf/publications/2004/P554.pdf.

Hotttinen, H., 2005. Impact of hourly wind power variations on the system operation in the Nordic Countries. Wind Energy, 8, 197-218

Huber, M., D. Dimkova, T. Hamacher, 2014. Integration of wind and solar power in Europe: Assessment of flexibility requirements. Energy, 69, 236-246.

Jónsson, T., P. Pinson, H. Madsen, 2010. On the market impact of wind energy forecasts. Energy Economics, 32, 313-320.

Kannan, R., 2009. Uncertainties in key low carbon power generation technologies – Implication for UK decarbonisation targets**,** Applied Energy, 86, 1873-1886.

Ketterer, J.C., 2014. The impact of wind power generation on the electricity price in Germany. Energy Economics, 44, 270-280.

Kopsakangas-Savolainen, M., R. Svento, 2013. Promotion of market access for renewable energy in the Nordic power markets. Environmental and Resource Economics, 54, 549-569.

Krishnamurthy, C.K.B., B. Kriström, 2015. Determinants of the price-premium for green energy: Evidence from an OECD cross-section. Environmental and Resource Economics, DOI 10.1007/s10640-014-9864-y.

Kumar, N., P. Besuner, S. Lefton, D. Agan, D. Hilleman, 2012. Power plant cycling costs, National Renewable Energy Laboratory, NREL Technical Monitor: Debra Lew, Sunnyvale, California, USA, April.

Kunz, F., H. Weigt, 2014. Germany's nuclear phase out – A survey of the impact in 2011 and outlook to 2023. Economics of Energy & Environmental Policy, 3, 13-27.

Kungl, G., 2014. The incumbent German power companies in a changing environment. A comparison of E.ON, RWE, EnBW and Vattenfall from 1998 to 2013. SOI Discussion Paper 2014-03. Stuttgart.

Lantz, E., T. Mai, R.H. Wiser, V. Venkat Krishnan, 2016. Long-term implications of sustained wind power growth in the United States: Direct electric system impacts and costs, Applied Energy, 179, 832-646.

Lund, H. P.A. Østergaard, I. Stadler, 2011. Towards 100% renewable energy systems. Applied Energy, 88, 419-421.

Liu, W., H. Lund, B.V. Mathiesen, X. Zhang, 2011. Potential of renewable energy systems in China. Applied Energy, 88, 518-524.

Markandya, A., I. Arto, M. González-Eguino, M.V. Román, 2016. Towards a green energy economy? Tracking the employment effects of low-carbon technologies in the European Union, Applied Energy, http://dx.doi.org/10.1016/j.apenergy.2016.02.122.

Matisoff, D. C., D. S. Noonan, J. Cui, 2014. Electric utilities, fuel use and responsiveness to fuel prices. Energy Economics http://dx.doi.org/10.1016/j.eneco.2014.05.009.

Mauritzen, J., 2013. Dead Battery? Wind power, the spot market, and hydropower interaction in the Nordic electricity market. The Energy Journal, 34, 103-123.

Mulder, M., L. Schoonbeek, 2013. Decomposing changes in competition in the Dutch electricity market through the residual supply index. Energy Economics 39, 100-107.

Mulder, M., B. Scholtens, 2013. The impact of renewable energy on electricity prices in the Netherlands. Renewable Energy, 57, 94-100.

Mulder, M., 2015. Competition in the Dutch electricity market: An empirical analysis over 2006–2011. The Energy Journal, 36, 1-28.

Nesta, L., F. Vona, F. Nicolli, 2014. Environmental policies and innovation in renewable energy. Journal of Environmental Economics and Management, 67, 396-411.

Neuhoff, K. J. Diekmann, W. Schill, S. Schwenen, 2014. Strategic reserve to secure the electricity market. Economic Bulletin No. 9. Berlin.

Pahle, M, S. Pachauri, K. Steinbacher. 2016. Can the green economy deliver it all? Experiences of renewable energy policies with socio-economic objectives, Applied Energy, http://dx.doi.org/10.1016/j.apenergy.2016.06.073

Paraschiv, F., D. Erni, R. Pietsch, 2014. The impact of renewable energies on EEX day-ahead electricity prices. Energy Policy, 73, 196-210.

PBL - Planbureau voor de Leefomgeving, 2013. De toekomst is nu; balans van de leefomgeving. Den Haag, September.

Ringel, M., B. Schlomann, M. Krail, C. Rohde, 2016. Towards a green economy in Germany? The role of energy efficiency policies. Applied Energy, http://dx.doi.org/10.1016/j.apenergy.2016.03.063

Smith, M.G., J. Urpelainen, 2014. The effect of feed-in tariffs on renewable electricity generation: An instrumental variables approach. Environmental and Resource Economics, 57, 367-392.

Snyder, B., M.J. Kaiser, 2009. A comparison of offshore wind power development in Europe and the U.S.: Patterns and drivers of development, Applied Energy, 86, 1845-1856.

TenneT TSO B.V., 2014a. Determining securely available cross-border transmission capacity. Arnhem, April. SO-SOC 13-134.

TenneT TSO B.V., 2014b. Rapport monitoring leveringszekerheid 2012-2028. Arnhem, June. CAS 2013-103.

TenneT TSO B.V., 2014c. Market Review 2013. Arnhem.

Traber, T., C. Kemfert, 2011. Gone with the wind? Electricity market prices and incentives to invest in thermal power plants under increasing wind energy supply. Energy Economics 33, 249–256.

Ucar, A., F. Balo, 2009. Evaluation of wind energy potential and electricity generation at six locations in Turkey, Applied Energy, 86, 1864-1872.

Verreth, D.M.I., G. Emvalomatis, F. Bunte, A.G.J.M. Oude Lansink, 2015. Dynamic and static behaviour with respect to energy use and investment of Dutch greenhouse firms. Environmental and Resource Economics, 61, 595-614.

Weber, T.A., K. Neuhoff, 2010. Carbon markets and technological innovation. Journal of Environmental Economics and Management, 60, 115-132.

Weigt, H., 2009. Germany's wind energy: The potential for fossil capacity replacement and cost saving. Applied Energy, 86, 1857-1863.

Weigt, H., T. Jeske, F. Leuthold, C. von Hirschhausen, 2010. Take the long way down": Integration of large-scale North Sea wind using HVDC transmission. Energy Policy, 38, 3164-3173.

Weigt, H., A. Neumann, C. von Hirschhausen, 2009. Divestitures in the electricity sector: Conceptual issues and lessons from international experiences. The Electricity Journal, 22, 57-69.

Wiser, R.H., Bolinger, M., Heath, G., Keyser, D., Lantz, E., Macknick, J., Mai, T., D. Millstein, 2016. Long-term implications of sustained wind power growth in the United States: Potential benefits and secondary impacts, Applied Energy, 179, 146-158.

Würzburg, K., X. Labandeira, P. Linares, 2013. Renewable generation and electricity prices: Taking stock and new evidence for Germany and Austria. Energy Economics, 40, S159-S171.

Woo, C.K., I. Horowitz, J. Moore, and A. Pacheco., 2011. The impact of wind generation on the electricity spot-market price level and variance: The Texas experience. Energy Policy, 39, 3939-3944.

Appendix

Table A

Nomenclature of symbols used in the regression models

Symbol	Unit	Definition
D	MWh	hourly consumption of electricity
D_CBC	0/1	dummy for the cross-border constraint. If the cross-border capacity is fully utilized the dummy is 1, otherwise 0.
D_q	0/1	dummy for quarter of the year
D_d	0/1	dummy for day of the week
D_h	0/1	dummy for hour of the day
G	MWh	hourly level of generation per type of plant
P	Euro/MWh	day-ahead wholesale electricity price
$P_{coal,}$	Euro/ton	daily price of coal
P_{gas}	Euro/MWh	daily price of natural gas
P_{CO2}	Euro/ton	daily price of CO_2 permits
Q	MWh	hourly production level of power plants
RSI	index	Residual-Supply Index, which is a measure for competition
RTR	degrees Celsius	number of degrees the daily average water temperature of rivers is above the environmental-threshold temperature of 23 degrees Celsius
S	percentage	number of hours of sunshine as a percentage of total number of hours of daylight
U	percentage	hourly production level as percentage of plant capacity
W	Watt	average daily wind speed converted into energy by W = $windspeed^3$. If the speed of wind (in meter/second) is below 1.6 or above 24.5, W is set equal to zero since turbines are shut down in those cases
W_{GW}	GWh	aggregated hourly production by wind turbines

Table B

Results of the regression analysis on the hourly day-ahead electricity price, 2006-2014

Log(APX)	**2006-2010 (first subperiod)**	**2011-2014 (second subperiod)**	**2006-2014 (overall period)**
constant	-2.9***	2.2***	-0.5***
$\log(D_{t-1})$	0.7***	0.2***	0.5***
log(RSI)	-0.2***	-0.1***	-0.2***
P_{coal} / P_{gas}	-0.2***	0.02	-0.2***
$d.\log(P_{CO2\ t-1})$	0.01	-0.1	0.004
RTR	0.04	-0.01	0.02
$\log(W_{NL})$	-0.01***	-0.01***	-0.01***
$\log(W\_GW_{GER})$	-0.05***	-0.02***	-0.03***
$\log(W\_GW_{GER})$ * D_CBC	0.02	0.02***	0.01***
S_{GER}	-0.03	-0.05***	-0.06***
S_{GER} * D_CBC	0.02	0.04***	0.04***
D_q2	-0.05*	-0.02	-0.04**
D_q3	-0.002	-0.06***	-0.03
D_q4	0.07**	0.01	0.04**
D_d2	0.06***	0.04***	0.05***
D_d3	0.1***	0.1***	0.1***
D_d4	0.1***	0.1***	0.1***
D_d5	0.1***	0.1***	0.1***
D_d6	0.1***	0.1***	0.1***
D_d7	0.1***	0.03***	0.1***
D_h2	-0.1***	-0.1***	-0.1***
D_h3	-0.2***	-0.1***	-0.1***
D_h4	-0.3***	-0.2***	-0.3***
D_h5	-0.4***	-0.2***	-0.3***
D_h6	-0.2***	-0.2***	-0.2***
D_h7	-0.002	-0.002	-0.008

D_h8	0.2***	0.2***	0.2***
D_h9	0.3***	0.2***	0.3***
D_h10	0.3***	0.2***	0.3***
D_h11	0.4***	0.2***	0.3***
D_h12	0.4***	0.3***	0.4***
D_h13	0.3***	0.2***	0.3***
D_h14	0.3***	0.2***	0.3***
D_h15	0.2***	0.1***	0.2***
D_h16	0.2***	0.1***	0.1***
D_h17	0.2***	0.1***	0.1***
D_h18	0.3***	0.2***	0.3***
D_h19	0.3***	0.3***	0.3***
D_h20	0.3***	0.3***	0.3***
D_h21	0.2***	0.2***	0.3***
D_h22	0.2***	0.2***	0.2***
D_h23	0.2***	0.2***	0.2***
D_h24	0.1***	0.1***	0.1***
AR(1)	0.8***	0.8***	0.8***
AR(2)	-0.1***	-0.1***	-0.1***
AR(24)	0.1***	0.1***	0.1***
R^2 adjusted	0.84	0.84	0.84
DW statistic	1.99	1.96	1.98

Note: *; **; *** refer to 10%, 5% and 1% significance levels, respectively.

Table C Results of the regression analysis on plant type utilisation, 2006-2014

Utilisation of plants (production/capacity)	**Coal-fired plants**		**Natural gas-fired plants**	
	2006-2010 (first subperiod)	**2011-2014 (second subperiod)**	**2006-2010 (first subperiod)**	**2011-2014 (second subperiod)**
constant	0.77***	0.99***	0.46***	0.31***
P_{coal} / P_{gas}	-0.01*	-0.39***	0.001	0.09**
d.P_{CO2}	0.001**	0.003	0.002***	0.001
W_{NL}	-0.000002	-0.000006***	-0.000002	-0.000008***
W_GW_{GER}	-0.001	-0.002***	-0.00002	-0.001***
W_GW_{GER} * D_CBC	-0.0002	-0.00004	0.00007	-0.0002***
S_{GER}	0.01	-0.01**	-0.003	-0.001
S_{GER} * D_CBC	0.01	0.001	0.001	-0.001
D_q2	-0.04***	-0.03**	-0.03***	-0.04***
D_q3	-0.06***	0.00003	-0.03***	-0.05***
D_q4	-0.04***	0.03***	0.01	-0.004
D_d2	-0.01***	-0.02***	0.01***	0.01***
D_d3	-0.01***	-0.02***	0.01***	0.02***
D_d4	-0.01***	-0.02***	0.03*	0.01***
D_d5	-0.01***	-0.01***	0.001	0.01***
D_d6	-0.01***	-0.01***	-0.003**	0.01***
D_d7	0.01	-0.02***	-0.003**	-0.001
D_h2	-0.04***	-0.04***	-0.03***	-0.03***
D_h3	-0.07***	-0.07***	-0.05***	-0.05***
D_h4	-0.09***	-0.09***	-0.06***	-0.05***
D_h5	-0.09***	-0.09***	-0.06***	-0.05***
D_h6	-0.07***	-0.06***	-0.04***	-0.03***
D_h7	-0.03***	-0.02***	0.01***	0.02***
D_h8	0.03***	0.01***	0.09***	0.09***
D_h9	0.07***	0.05***	0.15***	0.13***

D_h10	0.10***	0.07***	0.18***	0.15***
D_h11	0.11***	0.08***	0.19***	0.17***
D_h12	0.11***	0.08***	0.19***	0.17***
D_h13	0.11***	0.08***	0.19***	0.17***
D_h14	0.11***	0.08***	0.19***	0.17***
D_h15	0.11***	0.07***	0.18***	0.16***
D_h16	0.10***	0.07***	0.17***	0.16***
D_h17	0.10***	0.07***	0.17***	0.16***
D_h18	0.10***	0.08***	0.17***	0.17***
D_h19	0.11***	0.08***	0.17***	0.17***
D_h20	0.11***	0.08***	0.17***	0.16***
D_h21	0.10***	0.08***	0.15***	0.14***
D_h22	0.10***	0.07***	0.13***	0.11***
D_h23	0.10***	0.06***	0.10***	0.08***
D_h24	0.08***	0.04***	0.05***	0.05***
AR(1)	1.21***	1.21***	1.30***	1.39***
AR(2)	-0.27***	-0.28***	-0.34***	-0.43***
AR(24)	0.03***	0.03***	0.12***	0.02***
R^2 adjusted	0.97	0.95	0.98	0.98
DW statistic	1.97	2.00	2.02	2.00

Note: *; **; *** refer to 10%, 5% and 1% significance levels, respectively.