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Abuse of Dominance and Antitrust Enforcement in the German Electricity Market*

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Abstract In 2008, the European Commission investigated E.ON, a large and vertically integrated electricity company, for the alleged abuse of a joint dominant position by strategically withholding generation capacity in the German wholesale electricity market. The case was settled after E.ON agreed to divest 5 GW generation capacity as well as its extra-high voltage network. We analyze the effect of these divestitures on wholesale electricity prices. Our identification strategy is based on the observation that energy suppliers have more market power during peak periods when demand is high. Therefore, a decrease in market power should lead to convergence between peak and off-peak prices, after controlling for different demand and supply conditions as well as the change in generation mix due to the expansion of renewable technologies. Using daily electricity prices for the 2006 - 2012 period, we find economically and statistically significant convergence effects after the settlement of the case. In a richer specification, we show that the price reductions appear to be mostly due to the divestiture of gas and coal plants, which is consistent with merit-order considerations. Additional cross-country analyses support our results.

Keywords: electricity, wholesale prices, EU Commission, abuse of dominance, *ex post* evaluation, E.ON

JEL Codes: K21; L41; L94

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1 Introduction

There has been a substantial increase in the number of retrospective studies of the effects of competition policy enforcement on market outcomes. Developments in both the academic literature (Aguzzoni et al., 2016; Ashenfelter and Hosken, 2010; Ashenfelter et al., 2014a,b; Kwoka, 2013) and the policy discussion (Ilkzkovitz and Dierx, 2015; OECD, 2016; Ormosi et al., 2015) have helped to identify and define the best practices for *ex post* evaluation. However, the empirical evidence is not evenly spread across all areas of competition policy: while there is a large body of literature on the retrospective analysis of merger control and at least a number of studies on cartel enforcement, very little evidence exists on the effects of antitrust decisions pertaining to an abuse of market dominance (Davies and Ormosi, 2012).

Contrary to their scant discussion in the empirical literature, allegations of an abuse of dominance are quite common. This is particularly true in wholesale electricity markets, which are more susceptible and vulnerable to the exercise of market power than other industries due to a few key economic characteristics. For one, demand is highly time-dependent and inelastic. Moreover, electricity cannot be stored on an economically sufficient scale, which makes the design of an electricity market subject to peak-load pricing. Finally, the large fixed cost of energy production typically leads to concentrated markets. The vulnerability of wholesale electricity markets to market power is documented in several empirical studies (Borenstein et al., 2002; Puller, 2007).¹ A number of academic studies focusing on Germany analyze the 2002-2008 period and find that while prices were relatively high, there appears to be insufficient empirical evidence to link this to an abuse of market power (Möst and Genoese, 2009; Müsgens, 2006; Schwarz et al., 2007).²

The primary goal of this paper is to close this gap and contribute to the emerging empirical literature on the *ex post* analysis of competition policy interventions in abuse of dominance cases. Specifically, we aim at providing new evidence on the effects of different structural remedies in electricity generation, whose retrospective analysis is very scarce not only in the energy sector.³

¹Our paper also relates to the literature on strategic capacity withholding in wholesale electricity markets (Joskow and Kahn, 2002; Kwoka and Sabodash, 2011).

²A similar conclusion was reached by the German Federal Cartel Office in its wholesale electricity market inquiry (Bundeskartellamt, 2011). However, Bergler et al. (2017) provide empirical evidence of capacity withholding through faked failures of generation capacity in the German-Austrian electricity market.

³Under the second package of the Directive 2003/54/EC of the European Parliament and of the Council and repealing Directive 96/92/EC wholesale electricity markets have been subject to structural remedies, mostly related to the unbundling of transmission and distribution networks. Nardi (2012) studies structural remedies in the electricity transmission and Pollitt (2008) discusses the benefits of network unbundling but finds the empirical evidence to be insufficient to provide a reliable *ex post* analysis. Yet, retrospective evaluations of structural remedies at the electricity generation stage do not exist to the best of our knowledge.

By focusing on electricity markets, we also add to the more general discussion on the existence – and potential abuse – of market power in this industry and provide an empirical analysis of one of the most important European competition landmark cases in the industry since its liberalization. To this aim, we assess the impact of the abuse of dominance case brought by the European Commission (EC) against E.ON, the largest German utility company. In 2008, the EC alleged that E.ON was withdrawing available generation capacity from the German wholesale electricity market in order to raise prices. Moreover, the Commission also raised concerns that E.ON may have favored its production affiliate for providing balancing services, while passing the resulting costs on to consumers. Despite contesting the allegations, E.ON agreed to divest a total of 5 GW generation capacity (about one fifth of its total generation capacity) as well as its ultra-high voltage transmission network and the case was settled.⁴

We empirically analyze whether and how the shift in ownership of generation capacity that followed the divestitures affected wholesale electricity prices. Our identification strategy is based on the observation that energy suppliers have more market power during peak periods when demand is higher. Since the supply schedule is highly convex and much steeper during the peak period, shifts to a lower or higher capacity schedule should be expected to have much larger effects during peak times than off-peak times. Hence, we expect a convergence between peak and off-peak prices if market power is reduced, once other relevant factors such as electricity demand and supply drivers are controlled for. In the context of the German market during that period, we need to account for the substantial expansion of generation capacity from subsidized, renewable resources that could have had an impact on the price convergence. This simple identification strategy need not be valid in general and further depends on ownership structure, the various generation technologies, the identity of the buyers, as well as the size of the divestitures. We therefore enrich our basic model to account for these factors.

We look at the evolution of daily German wholesale electricity prices as determined through the centralized energy exchange market, the EEX, over the 2006-2012 period. We find strong and statistically significant convergence effects after the implementation of the Commission’s decision both in the short-run as well as in the long-run. The size of the effects is also economically relevant, with convergence varying between 5 to 11 €/MWh, accounting for up to 36% of the gap between peak and off-peak prices. We further distinguish the individual divestitures by technology type and find that only divestitures involving coal and gas plants entailed significant price reductions. This is consistent with the EC’s theory of harm since, based on the technology types’ merit order,

⁴In 2008, the installed generation capacity in the German market was about 130 GW. More than half was produced via coal, oil, and gas. While the divestiture accounted for less than 5% of the market, most of the divested capacity affected mid-merit units, where market power tends to be more acute.

precisely the capacity generated from coal and gas would have been strategically withheld. Using data from four other European countries in a difference-in-difference-in-difference specification and using a synthetic control approach, we show that the implementation of the remedies did not impact, or impacted to a much smaller extent, wholesale electricity prices in those markets. Finally, we analyse the effect of the divestiture on quantities rather than prices and find that peak and off-peak electricity consumption has significantly converged in the long-run, as one would expect.

We run several robustness checks to assess various assumptions. First, placebo regressions using different timing for the occurrence of the treatment fail to find an effect. Second, we use different treatment windows, and define different peak-price periods. Third, we address issues of autocorrelation and change the frequency of the data. All these checks corroborate our main findings. In sum, our findings support the view that the settlement of the case and the accompanying divestitures, by affecting the extent – and potential abuse – of market power, had the effect of reducing the gap between peak and off-peak wholesale prices and, accordingly, shifted electricity consumption from off-peak to peak periods. As changes in German electricity wholesale prices are, to a substantial degree, passed on to consumers (Duso and Szücs, 2017), we conclude that the remedies are likely to have increased consumer welfare by a significant extent.

The paper proceeds as follows. Section 2 describes the functioning of the German electricity market. Section 3 presents the details of the case, while section 4 presents the data. Section 5 explains the econometric model and discusses a pricing equation for the German wholesale electricity market as well as the data and identification strategy. The main results are presented in section 6, several robustness checks in section 7. Section 8 then summarizes the findings and concludes.

2 The German electricity market

Since liberalization in the 1990s, the German electricity sector is characterized by a vertical supply chain consisting of a generation stage, a wholesale market, a transmission (higher voltages of 220-380 kV) grid, a distribution (lower voltages of 20-110 kV) grid, and a retail market.⁵ While the wholesale and retail level have been substantially opened up to competition, the network infrastructure is still regulated. Finally, a parallel balancing market ensures constant equilibrium between actual production and consumption.

⁵Various sub-markets, where different trading products with different periods of time between purchase and actual supply are exchanged, make up the electricity wholesale market. While in future markets, electricity can be traded several years in advance through long-term contracts, the short-term spot market is made up of the day-ahead and intraday markets. The day-ahead wholesale price represent is an important reference value for the electricity market and is the focus of our empirical analysis.

Historically, German power supply was provided by fossil-fueled generation. In the early 2000s, comprehensive subsidization schemes for renewable power sources were introduced and their market share quickly rose from 8% in 2003 to 30% in 2015 (BDEW, 2016). However, this rapid expansion was not due to market forces, but rather due to the regulatory environment. Specifically, it was determined by two factors: i) prioritized feed-in of renewables – especially the two predominant types of wind and photovoltaic generation – and ii) monetary compensation via a regulated price mechanism. Hence, both this regulatory framework as well as the random nature of resource availability of wind and solar render renewable electricity supply to be a quasi-exogenous supply-shock in the market system. Consequently, this is a crucial element to control for in our analysis of price dynamics, as power produced from wind and photovoltaic significantly impacts wholesale prices, especially during peak hours, which are central to our identification strategy.⁶

Our study focuses on the price effects due to changes in the conventional, fossil-fuel based generation as this generation capacity is the most relevant in terms of market power abuse. Conventional generation is dominated by four large vertically integrated – though legally unbundled – companies: E.ON (now split into E.ON SE and Uniper SE), RWE, Vattenfall, and Energie Baden-Württemberg (EnBW), who are also the main players in the retail market and have historically owned large parts of the transmission network.⁷

In 2004, the European Commission (Case No COMP/M.4110 - E.ON / ENDESA pg. 10) reported that "[b]y far the largest proportion of electricity in Germany is generated by four vertically integrated energy suppliers: E.ON, RWE, Vattenfall and EnBW. In generation (installed capacity) RWE Power is market leader, with a [30-40%] market share (2004 data), followed by E.ON ([20-30%]), Vattenfall ([10-20%]) and EnBW ([10-20%]). Other companies jointly represent [10-20%]". This picture remained quite stable over the subsequent years. In its sector inquiry in 2011 (Bundeskartellamt, 2011), the German Federal Cartel Office (FCO) reported that the German electricity market is (still) characterized by joint dominance.

Even in 2014, when generation from renewable sources accounted for over a quarter of produc-

⁶In the typical merit order curve, coal- or gas-fired power plants are often pivotal and, thus, hold a certain degree of market power. While the merit-order effect of renewables may not fully mitigate this market power, it can still act as an effective exogenous price constraint. The higher the share of renewables in generation, the more significant is the excess capacity from displaced conventional power plants, whose operators have to compete for a smaller residual demand. Unless capacity is quickly mothballed or competitors decide to collude, then prices should decrease. The extent to which prices are depressed also depends on the type of technology that is crowded out. If only flexible, but expensive gas turbines were to remain in the market, prices could significantly increase during phases of high residual demand.

⁷Since 2007, the regulatory framework requires vertically integrated energy suppliers to legally unbundle from system operators. Suppliers serving fewer than 100,000 customers are exempt from this regulation.

tion, these four dominant companies still accounted for more than two-thirds of electricity production. The remaining German energy demand is covered by a large number of municipal operators ('Stadtwerke') and other smaller producers as well as imports.

While market shares are an important indicator for the existence and extent of market power, they may be less relevant in markets with highly inelastic demand, such as wholesale energy. Here, even firms with relatively small market shares can play a pivotal role and find it profitable to withdraw capacity with the aim of increasing prices. Still, this strategy is most attractive (and practicable) for suppliers with a diverse power plant portfolio. Following this logic, the FCO's investigation in 2014 not only looked at market shares of the alleged dominant firms, but also applied additional quantitative tests to analyze the extent of market power in energy markets.

Based on the results of this analysis, the FCO stressed that all four big players in the German wholesale energy markets in 2007-2008 were "in a position to behave to an appreciable extent independently of their competitors, customers and ultimately of their consumers and to restrict competition on the first-time sales market Each of these undertakings was essential for meeting Germany's electricity demand in a considerable number of hours"(Bundeskartellamt (2011), pg. 6). The FCO also indicated that the market power of the big four was expected to decline as the result of the implementation of the remedies imposed by the EC on E.ON and by the economic crisis. Nevertheless, they still expected joint dominance to persist in the German wholesale electricity market.⁸

Several empirical studies analysed the German wholesale electricity market between the years of 2001 and 2006, but the results are mixed. Müsgens (2006) finds evidence for strategic behaviour for the years 2001 to 2003. Similarly, Zachmann and Von Hirschhausen (2008) conclude that an asymmetric pass-through of emission allowance costs may be due to exercise of market power. On the other hand, Schwarz et al. (2007) identify cost factors to be primary reasons for price increases between 2004 and 2005, while Möst and Genoese (2009) are also cautious to attribute high prices in 2006 to the exertion of market power. A key reason why abusive exercise of market power is difficult to distinguish from a price spike induced by high demand is that power markets are subject to peak-load pricing. Demand is quite inelastic, consumption immediate and the potential for load shifting is restricted for many energy-intensive industries, albeit that even a delay for one or two

⁸The FCO's Decision Division did not reach a clear conclusion on whether the observed power plant operational management constitutes evidence of abusive capacity withholding or, rather, the consequence of "objective reasons for not operating power plants whose marginal costs are lower than the day-ahead spot market price" (Bundeskartellamt (2011), pg. 6). Consequently, the FCO concluded that "the non-operation of profitable power plants identified in the present inquiry is too limited to initiate specific abuse proceedings with respect to the period examined" (Bundeskartellamt (2011), pg. 6).

hours may already resolve some potential market capacity constraints. Consequently, a decrease in market power may cause lower prices, but not necessarily significantly higher consumption. We will come back to this point in section 5.4.

In wholesale electricity markets, most of the generated electricity is sold either internally to the retail outlets of the vertically integrated producers or sold to other retailers via bilateral, over the counter (OTC) contracts as well as centralized energy exchange markets, such as the European Energy Exchange (EEX; currently in partnership with EPEX, European Power Exchange). Still, most of energy trade between wholesalers and retailers in Germany is done by means of OTC (long-term) bilateral contracts between producers and suppliers, with only a minor, albeit increasing, percentage of energy trade covered through the EEX.⁹ In spite of its relatively low share in total market transactions, the electricity price determined at the power exchange serves as a reference price for the whole market due to potential arbitrage opportunities (see Ockenfels et al. (2008) and Schwarz et al. (2007)).¹⁰ While in the beginning of the EEX the spot market prices may have deviated from OTC prices, Growitsch and Stronzik (2011) provide empirical evidence for increasing convergence on a very high level in the following years, especially from 2005 onwards. Therefore, the overall price effects of anti-competitive behavior or structural remedies should be reflected in the power exchange prices and, consequently, quantifiable by analyzing the evolution of the EEX prices. Indeed, all aforementioned studies on market power in German electricity markets also focus on EEX spot exchange prices (Möst and Genoese, 2009; Müsgens, 2006; Schwarz et al., 2007).

3 The case

In 2008, the European Commission investigated claims about E.ON withdrawing available generation capacity from the German wholesale electricity market in order to raise prices. The investigation confirmed the presence of competition concerns. Consequently, E.ON agreed to divest a total of 5,000 MW of generation capacity, almost one fifth of its overall capacity, and the case was settled.¹¹ Figure 1 illustrates the location of the plants concerned, whereby the sizes of the circles

⁹For instance, Ockenfels et al. (2008) report that only 15% of energy consumption was traded at the EEX in 2008.

A 2013 EEX press release mentions that the share of EEX in the German market rose to 20% (EEX, 2013) and in 2015 increased further up to 30% (EEX, 2015).

¹⁰Specifically, Ockenfels et al. (2008) state that the day-ahead uniform price auction held at the EEX leads to a clear reference price for overall market clearing. This price is transparent, easily accessible, and it is used by market participants in upstream markets for strategic planning.

¹¹As noted by Sadowska (2011), the E.ON case has to be considered a "commitment decision". The Commission, pursuant to Article 9, neither demonstrated nor confirmed the existence of a dominant position or an abuse thereof, but it simply made the commitments proposed by the undertakings binding. Sadowska (2011) discusses the advantages and drawbacks of commitment procedures in antitrust cases.

represent the volume of the divestitures. While the Commission’s decision was announced in 2008, the various plants were sold to different buyers between January 2009 and May 2010.

At the same time, the Commission raised the concern that E.ON may have favored its production affiliate for providing balancing services, thereby preventing other power producers from exporting balancing energy into its transmission zone, while passing the resulting costs on to consumers. To address the Commission’s concerns in the electricity balancing market, E.ON committed to divest its ultra-high voltage network. This divestiture also took place in early 2010. The timing and details of the individual divestitures are summarized in table 1.

Table 1: Date and details of divestitures

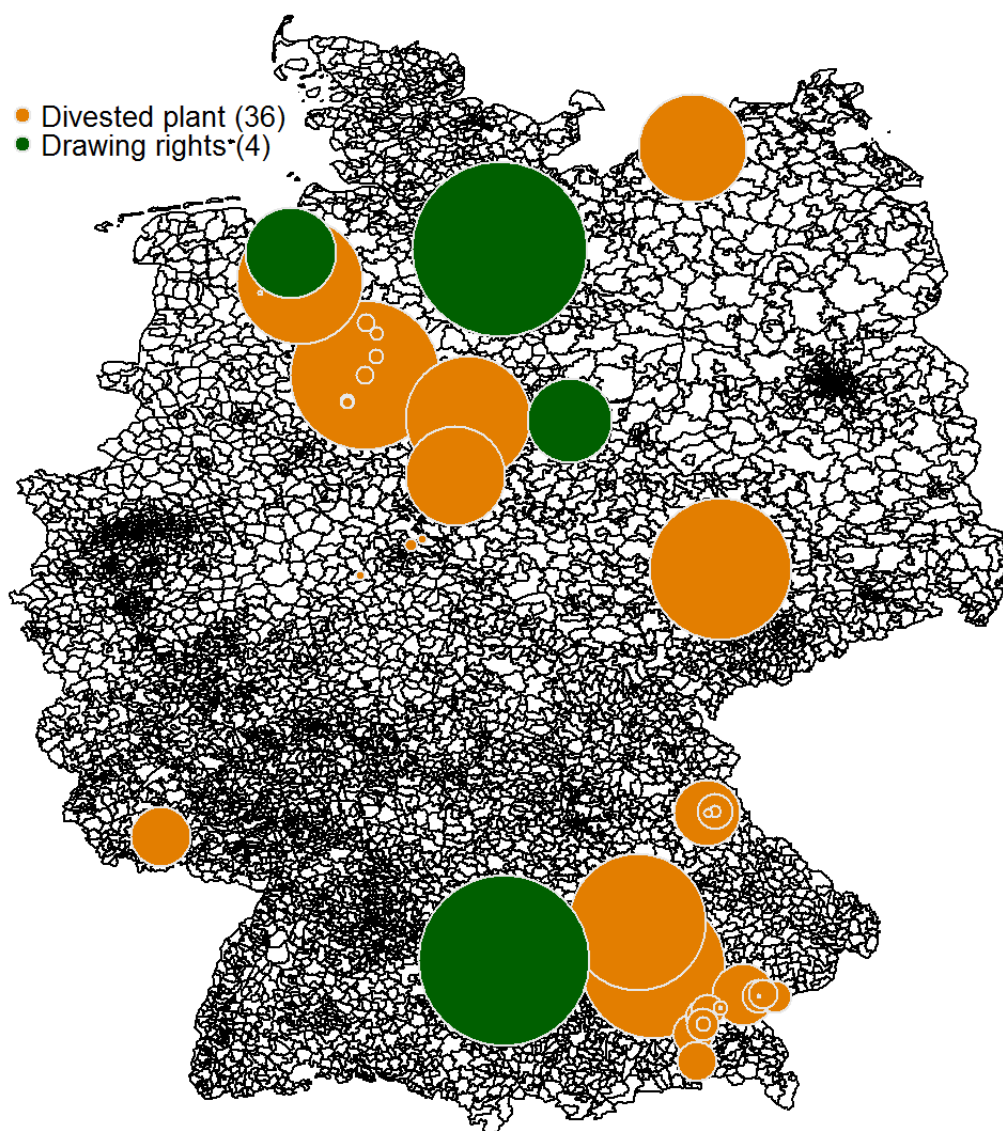
Date	Buyer	# of plants	Capacity MW	Technology	Remedy
01.01.2009	Statkraft	12	753	water and gas	divest
11.04.2009	Electrabel	6	931	water and coal	divest
31.05.2009	EnBW	2	525	coal	divest
31.08.2009	Verbund	13	312	water	divest
19.10.2009	Electrabel	3	1500	nuclear	drawing rights
01.01.2010	EnBW	3	760	coal	divest &
	SW Hannover				drawing rights
25.02.2010	TenneT	1 (+grid)	415	gas	divest
03.05.2010	Morgan Stanley	2	265	coal	divest

Source: Our elaboration on information provided by the EC.

Cumulatively, the Commission decisions affected two main product markets: the German whole-sale energy market and the balancing energy market. We will concentrate on the former and, in what follows, we briefly explain why we think that this is a reasonable approach.

Balancing markets are ancillary mechanisms that are key for a well-functioning energy market as they ensure that consumption is equal to production in real time. Since most electricity capacity is bought well in advance via long-term contracts based on expected demand, it is common that changes in the announced demand and/or supply schedules generate an excess short-run differences between generation and consumption in a grid. Since the voltage on the grid needs to stay constant at around 50 Hz, unexpected insufficient supply or demand for electricity needs to be compensated. In Germany, electricity generators are required to reserve a fraction of their capacity for this balancing mechanism. This capacity needs to be sold to the transmission system operators, which they can use to restore frequency in the electricity grid (Haucap et al., 2014). Wholesale electricity

Figure 1: Capacity-weighted location of divestitures



Source: Our elaboration on information provided by the EC.

markets and balancing markets should be expected to be related as there exist arbitrage opportunities between the spot market and the balancing mechanism (Just and Weber, 2015). Indeed, prices in the balancing markets (capacity prices) constitute a sort of opportunity cost for energy suppliers who commit themselves not to use the reserved capacity on wholesale spot markets. Therefore, abuse in the balancing market might be expected to affect competition on the wholesale level.

However, empirical evidence for the German market suggests that this relationship is of second-order importance. Just and Weber (2015) quantify the effect of strategic arbitrage behavior between the German wholesale and balancing markets and find relatively modest effects.¹²

Thus, although the effect of unbundling in the balancing market might be important in the long-run, we consider it to be of second-order when compared to the direct effect of the potential abuse in the wholesale market, particularly in the short-run. Consequently, we focus on the evaluation of the first part of the decision, i.e. the alleged abuse of dominant position in the wholesale electricity market. Specifically, we try to isolate the effect of the implementation of the individual capacity divestitures. Yet, we are unable to separate the different effects from the two parts of the decision, especially with regard to the long-run implications. Moreover, given that the divestiture of the network grid was implemented jointly with the divestiture of some of the E.ON's capacity, even the most disaggregated analysis cannot separately identify the effects of the two remedies. Hence, our empirical measurement are the cumulative effect of both parts of the decision.

4 Data

The data for the analysis of wholesale prices come from a number of different sources. The hourly electricity prices are obtained from the EEX in Leipzig and aggregated to the daily level for peak and off-peak periods separately.¹³ Temperature data during peak and off-peak periods in degree Celsius as well as data on daily sunshine duration in minutes are obtained from the German Weather Service (dwd.de). As data on daily photovoltaic generation is not available on a daily basis before

¹²Specifically, they find a "clear tendency that market participants use the arbitrage opportunity to fulfil their supply commitment with relatively cheap balancing energy when spot prices are relatively high, and vice versa. In periods with intraday spot prices above 120 €/MWh, the control zones are predominantly undersupplied. The Amprion control zone is undersupplied in 75%, and the GCC control zone in 80% of those 64 1/4-hours, with an average imbalance of -267 MW and -488 MW, respectively. The opposite is true for prices roughly below -20 €/MWh with Amprion being oversupplied in 77% with an average of 501 MW and GCC in 74% of those 196 1/4-hours with 819 MW on average. It should be noted that imbalances did not exceed the contracted reserve capacity and that periods with extreme spot prices were not overly exploited as the incentives might suggest" (Just and Weber, 2015).

¹³In various robustness checks we use the disaggregated hourly prices as well as different aggregations of them.

2010, we use daily sunshine duration to proxy for solar production.¹⁴ Additionally, we collect data on the installed solar and wind capacities from <https://data.open-power-system-data.org>.

Data on electricity generation from wind as well as data on cross-border energy flows with all neighboring countries are retrieved from the websites of the four network operators (50 Hertz, Amprion, TenneT, and TransnetBW). The industrial production index is obtained from <https://www.sachverstaendigenrat-wirtschaft.de>. The oil price index is chosen from ICE Brent Europe (in US \$/tonne) and the gas price reference is that of ENDEX/TTF. Uranium prices were obtained from www.uxc.com. The coal price is a combined price series of two sources (Platts and Argus McCloskey), which is adequate since they are highly correlated and both measure the daily European reference price for coal imports into North-western Europe. The emission price is the weighted emission certificate price from the EEX.

The sample ranges from 2006 to 2012¹⁵ and contains two observations (peak and off-peak) per day. The data are summarized in table 2.

5 The framework

To understand how capacity divestitures affect equilibrium prices, it is useful to start with a simple oligopoly pricing model of the German electricity market. In this model, capacity constrained electricity suppliers strategically choose the quantity to set on the market, responding to changes in (highly inelastic) demand (e.g. Puller, 2007). The total residual demand faced by these strategic suppliers ($Q_t^{(D,RES)}$) is determined as the difference between the exogenous and inelastic total market demand (Q_t^D) and the supply by a competitive fringe ($Q_t^{(S,Fringe)}$) at the price level p :

$$Q_t^{(D,RES)}(p) = Q_t^D - Q_t^{(S,Fringe)}(p) \quad (1)$$

This model seems to fit quite well with the German market characterized by four major strategic players (E.ON, RWE, Vattenfall, and EnBW) and a competitive fringe that is composed of municipalities, imports, as well as electricity generation from renewable and nuclear sources.

Given this residual demand, strategic players maximize their profit under the constraint that they cannot offer a quantity larger than their capacity. We follow Puller (2007) and assume that

¹⁴To assess the quality of the proxy variable, we used post-2010 solar production data from the four network operators and estimated the following regression: $solar_t = \sigma_0 + \sigma_1 sun_t + \sigma_2 solar_cap_t + \zeta month_t + \varepsilon_t$. Since the model fits the data very well ($R^2 = 0.86$) and the model predictions highly correlate with actual solar production (with a correlation of $\rho = .93$), we conclude that daily sunshine duration and solar capacity adequately proxy for solar production.

¹⁵All our findings are robust to excluding 2012 from the sample, when Germany's electricity markets might have been affected by the aftermath of the 2011 Fukushima disaster.

Table 2: Summary statistics of the dataset

Variable	Obs	Mean	Sdt. Dev.	Min	Max
Price	5114	46.61	22.2	-131	508
Price peak	2557	56.01	25.3	-7	508
Price offpeak	2557	37.22	13.0	-131	81
Temperature peak	2557	12.33	8.2	-11	33
Temperature offpeak	2557	8.47	6.6	-13	24
Cross-border flows peak	2557	-469.45	1693.5	-5702	6040
Cross-border flows offpeak	2557	4651.96	18135.5	-27645	124474
Wind peak	2557	4811.61	3953.5	225	22053
Wind offpeak	2557	4410.40	3448.6	376	22927
Minutes of sun, peak	2557	227.96	178.2	0	683
Minutes of sun, offpeak	2557	56.06	68.2	0	284
Wind capacity	5114	22.02	3.4	16	29
Solar capacity	5114	11.42	9.4	2	33
Industrial production index	5114	102.82	7.1	84	112
Oil price	5114	85.54	23.9	34	144
Gas price	5114	19.62	5.9	4	53
Uranium price	5114	58.44	20.3	36	136
Coal price	5114	96.32	32.1	53	225
Emission price	5114	9.31	7.0	0	30

Notes: Observation frequency is either daily (peak/off-peak are reported separately, 2557 observations) or two daily observations (when peak/off-peak are reported pooled, 5114 observations), where 'peak' refers to the 08:00 - 20:00 and 'off-peak' to the 21:00 - 07:00 period.

each of these strategic players chooses the quantity of energy to supply to the market and not the price. This Cournot assumption better mimics the functioning of the EEX market where firms submit bids specifying how much electricity they would provide at a given price. Moreover, in a world with capacity constraints this model seems to be more appropriate.

This basic model is further enhanced through a conjectural variation framework to allow firms to choose different conducts than the Cournot-Nash outcome. Specifically, the model can rationalize perfect competition and joint profit maximization. The first order condition for this model is as follows:

$$P(q_{it}^* + q_{-it}) - c_{it}(q_{it}^*) + \theta_{it}P_t'q_{it}^* - \lambda_{it} = 0 \quad (2)$$

where q_{it}^* is firm i 's optimal quantity, $P(q_{it}^* + q_{-it})$ is the inverse demand function (and P_t' its first derivative), and $c_{it}(q_{it}^*)$ is firm i 's marginal cost of electricity generation. The conjectural variation parameter $\theta_{it} = (\partial Q_t^* / \partial q_{it}) = (1 + \sum_{j \neq i} (\partial q_{jt}^* / \partial q_{it}))$ measures firm i 's belief about the effect of increasing its output on total industry output, whereas the Lagrangian multiplier λ_{it} represents the shadow cost of the capacity constraint.

The equilibrium pricing in such a model captures important elements that are useful for motivating the pricing equation used in our empirical analysis. First, prices represent the value of added capacity in the sense that they rise when more expensive electricity capacity is brought to the market. Second, prices can reflect suppliers' unilateral incentives to withhold capacity and earn high profits from their infra-marginal units. Finally, suppliers can jointly coordinate, i.e. collude, to achieve joint profit maximization.

For the logic of our empirical analysis, it is important to understand how the divestitures might affect firms' unilateral incentive to withhold output in order to raise the price and earn higher revenues on their infra-marginal units - the theory of harm put forward in the EU antitrust case against E.ON. Now imagine that E.ON, who allegedly withheld output, is forced to divest 5 GW capacity. This capacity is mostly divested to the fringe. This implies a reduction of the residual demand for E.ON as well as all other strategic players, which, in turn, results in an outward shift of the energy supply-curve. Subsequently, wholesale prices should, *ceteris paribus*, decrease.¹⁶

Still, identification and empirical measurement of the impact of such capacity reallocation are not straightforward. The functioning of this general mechanism depends on the ownership structure, the various technologies, the identity and size of the divested plants, as well as on several demand-

¹⁶Whether divestitures to other strategic players have a similar effect depends on their capacity constraint and incentive to withhold capacity. This is, however, less relevant for our analysis since only 20% of the capacity was divested to EnBw, a smaller and less aggressive player in the German wholesale electricity market. Although EnBw was thought to be pivotal during the period of the analysis, we can still expect that the overall effect of the divestitures was to reduce prices.

side and supply-side factors. Thus, our empirical approach will need to expand on this simple logic to encompass these factors into our framework. Moreover, we need to control for as many observable factors as possible to help explain short and long term prices dynamics.

5.1 The empirical approach

Following the literature on ex-post evaluation, we adopt a difference-in-difference (DiD) approach to identify the effect of the divestitures. In our basic setting, we compare wholesale price evolution in a 'treatment' group, which is mostly affected by the divestiture, to that of a 'control' group, which is not (or to a lesser extent) affected. The crucial challenge in the implementation of such a framework is the choice of a suitable control group. We adopt an identification strategy based on several steps.

First, we make use of within-country variation. We contrast two different outcomes in Germany – the peak and off-peak wholesale electricity prices – which we expect to be affected differently by the divestiture. Specifically, while during peak-times firms can sustain significant mark-ups over the marginal cost of energy production and, hence, the extent of market power plays a significant role in determining equilibrium prices, off-peak prices in most cases reflect the marginal cost of the highest-cost plants/technology and are, under these conditions, unaffected (or less affected) by a reduction of market power.¹⁷ These different price regimes constitute the treatment and control groups in our DiD-framework. Looking at the evolution of the two prices before and after the implementation of the divestitures, we expect to identify the effect of the Commission's intervention. One of the main advantages of this approach is that both groups are equally affected by common institutional, cost, and demand drivers. Hence, there is less reason to worry about differences across the two groups, which would likely occur in a cross-country comparison. Nonetheless, to account for potentially different dynamics during peak and off-peak, we also control for demand and supply conditions being different between periods.

¹⁷Empirical evidence for Germany shows that off-peak prices are much closer to marginal costs than peak prices.

By using a linear optimization dispatch model, Müsgens (2006) estimates marginal costs for German electricity production plants. He shows that peak prices were more than 75% above marginal costs, while during low demand periods (off-peak) this is not the case. Indeed, the ratio of off-peak prices to estimated marginal costs ranges between 0.9 and 1.21. Notice that this claim is also consistent with theoretical predictions. For instance, using a duopoly auction model, Fabra et al. (2006) show that both suppliers active in the market submit bids that are equal to the marginal cost of the inefficient firm during low demand states, i.e. off-peak. Yet, only the most efficient firm produces. Therefore, one can consider off-peak prices as reflecting the marginal cost of inefficient suppliers, though not necessarily the marginal cost of all active supplier(s).

Thus, the basic empirical model that we use consists of an hedonic price equation, where the wholesale price is a function of demand and supply drivers:¹⁸

$$p_{it} = \alpha + \beta \text{peak}_i + \gamma \text{post}_t + \delta \text{peak}_i \times \text{post}_t + \omega X_{it} + \zeta_1 \text{dow}_t + \zeta_2 \text{month}_t + \varepsilon_{it} \quad (3)$$

The daily power price p_{it} , at day t , for group i – peak and off-peak – is regressed on a treatment (i.e. peak-price) indicator (peak_i), an indicator for the evaluation period (post_t)¹⁹ as well as the interaction of the two, which measures the treatment effect. Further, we include a large number of supply and demand drivers, subsumed in the matrix X_{it} , such as: variables indicating the daily amount of energy produced from wind and the daily amount of sunshine in minutes, both in linear and quadratic form as well as separately for peak and off-peak periods; a variable indicating the (day-specific) total solar and wind capacity installed in Germany; the daily average temperature in the peak and off-peak time periods in both linear and quadratic form to account for the non-linear relationship between temperature and power consumption as well as the relationship between temperature and power production;²⁰ daily net cross-border energy flows during peak and off-peak periods to account for potential cross-country spill-overs; an indicator variable for market coupling with Denmark after November 2009 as well as an indicator for market integration with Belgium, France, Holland and the Scandinavian countries after November 2010;²¹ a monthly industrial production index, which acts as a control for energy demand from industrial customers as well as proxy for the business cycle; an indicator variable for holidays, when business activities are low and input prices such as the daily price of oil, gas and CO₂ emissions as well as weekly coal and uranium prices. Additionally, we include fixed effects for the day of the week (Mo - Sun) and every month in the sample period (Jan 2006 - Dec 2012).

Finally, the error term is assumed to be auto-correlated and heteroskedastic. We, therefore, estimate Newey-West standard errors and assume the maximum lag order of autocorrelation to be

¹⁸See Böckers and Heimeshoff (2014) for a similar approach to analyse the effect of market coupling. While we choose a model in levels to estimate the convergence between peak and off-peak prices, alternative models could also be used. In particular, we could use both the daily difference between peak and off-peak prices or their ratio as a dependent variable. We estimated both versions, alternatively using explanatory variables in levels or differences. All results presented in this paper are robust to these changes in specification. Note also that, being a reduced-form price equation, we refrain from using the daily load as a control variable as this might be endogenously determined in equilibrium (see also section 6.4).

¹⁹In some specifications of the evaluation period, the post-indicator is collinear with the included month fixed effects and, thus, dropped from estimation.

²⁰See for example Engle et al. (1992) and Pardo et al. (2002).

²¹The inclusion of the coupling dummies does not affect the identification of treatment effects, which are identified from peak/off-peak differences, while the market integration variables are set to one for peak and off-peak periods after their respective dates. Empirically, all results are robust to excluding the market integration dummies.

equal to one week (seven days). Since the assumptions on the error term play a crucial role for making accurate inference, we perform several robustness checks to test their relevance, which we discuss in section 7.

The definition of treatment groups and post-period indicators are discussed in the next subsections. The double differencing implied by a DiD framework as well as the inclusion of a large set of demand-side and supply-side drivers helps mitigating endogeneity problems due to omitted variables and increases confidence in the causal nature of the estimated effect.

5.1.1 Identification of the treatment group

The proposed identification strategy is based on the different price response to the capacity divestitures between peak (8am-8pm) and off-peak prices (9pm-7am).²² Thus, the treatment is defined by the following dummy variable:

$$peak_i = \begin{cases} 1 & \text{if peak demand} \\ 0 & \text{if off-peak demand.} \end{cases} \quad (4)$$

The logic of our identification is based on the oligopoly model discussed above and it is graphically explained in figure 2. The underlying idea is that energy suppliers have more market power during peak periods where demand is higher due to business activities. Put in the logic of the model, the residual demand for the strategic suppliers is higher during peak periods. Since the supply schedule is highly convex and much steeper in the such periods (due to the merit order of the underlying fuel types), a shift to a lower capacity schedule through capacity withdrawal from the market has a larger effect during the peak time.

The difference in the peak price between the high capacity scenario ($P^{Peak,H}$) and the low capacity scenario ($P^{Peak,L}$) is much larger than the difference in the off-peak price between the high capacity scenario ($P^{Off-Peak,H}$) and the low capacity scenario ($P^{Off-Peak,L}$). Hence, a policy intervention that shifts the supply schedule to the 'high capacity' scenario should noticeably reduce market power and prices during peak hours while having a smaller effect during off-peak hours.

Consequently, we compare the two series of prices in peak and off-peak periods. Figure 3 illustrates the evolution of monthly averages of predicted day-ahead prices in peak and off-peak periods.²³ While there is some seasonal variability, both prices seem to move to a lower level after 2009 and one can also observe convergence between the two series following 2009.

²²In section 7.2 we thoroughly discuss how we define peak time and present the results for several specifications based on various definitions.

²³Predicted values are obtained by estimating equation 3 sans post- and treatment indicators. We show monthly

Figure 2: Effect of a shift in supply during peak and off-peak demand

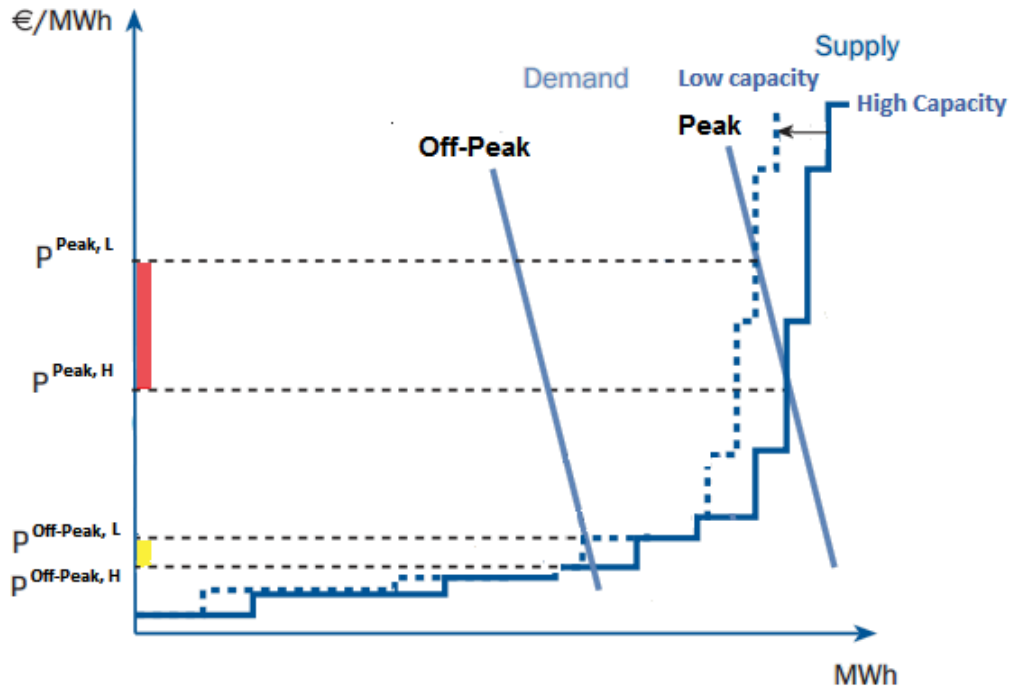
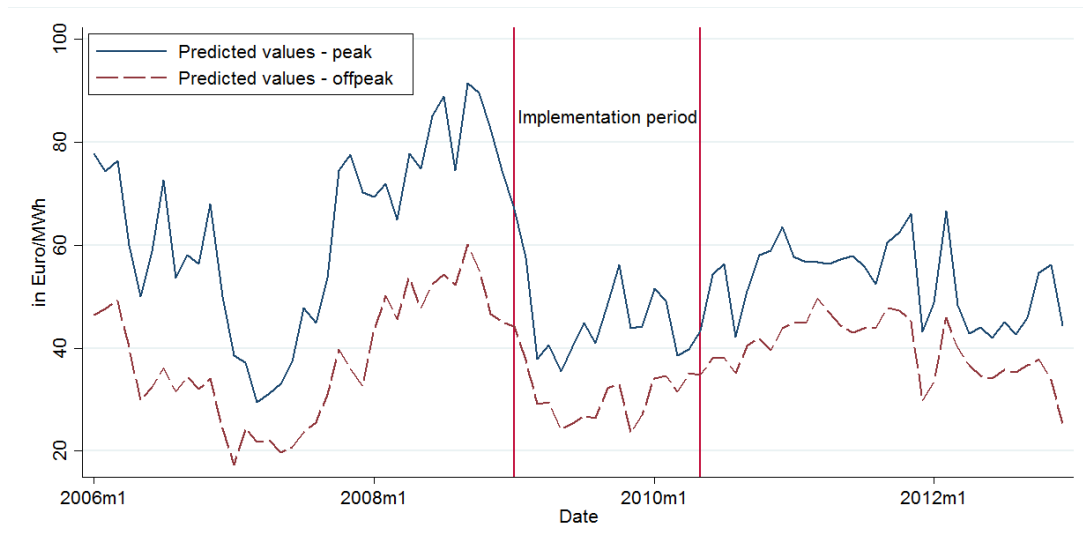


Figure 3: Monthly averages of predicted peak and off-peak prices



Source: Own calculation based on EPEX price series, 2014

5.1.2 Identification of the treatment period

The second crucial element of the identification strategy is the definition of the treatment period; i.e. the time during which we expect the decision's effect to materialize. We start by defining three major periods: the before period (up to December 2008), the implementation period during which the remedies were implemented (January 2009 to May 2010), and the after period (after May 2010). Given the high frequency of electricity trade and because wholesale energy markets are very dynamic, a swift response to changes in supply conditions is expected. Thus, we consider four different impact scenarios that should allow us to identify both the short-term and long-term effects of the policy intervention. The advantage of the short-run scenario is that it identifies the effect of the remedies from a short and well-defined period of time around them. Hence, the risk of contaminating the effect of the intervention with other, unobserved factors is low.

However, it could be that the effects of an important policy intervention are much more pervasive. Therefore, it seems reasonable to also look at long-term effects and to evaluate the impact of the decision over one or more years. The disadvantage of the long-term analysis is that the precise causal identification of the policy intervention is weakened by the likely existence of confounding factors.

Long Run Effects of the Decisions

We assume that the Commission's decision had long-lasting effects. We then consider two possible situations. First, we assume that these effects can be observed as soon as the commitments were implemented. Thus, we construct a dummy variable that takes on a value of 1 from the first divestiture onwards including the implementation year 2009:

$$post_t^1 = \begin{cases} 1 & \text{if date} > \text{Dec 31 2008} \\ 0 & \text{if date} \leq \text{Dec 31 2008} \end{cases} \quad (5)$$

Alternatively, we assume that the overall effect of the decision can only be observed when the last remedy has been implemented. Thus, we define the post period from the May 3 2010 onwards and exclude the implementation period from the analysis.

$$post_t^2 = \begin{cases} 1 & \text{if date} > \text{May 3 2010} \\ 0 & \text{if date} \leq \text{Dec 31 2008} \end{cases} \quad (6)$$

The Short-run Effects of the Remedies

averages of predicted values to wash out the volatility of daily prices. A similar, but messier, figure is obtained by plotting daily predicted values or actual prices.

In this setting, the impact of the divestiture is assumed to be immediate and is estimated from price changes directly after them. Therefore, the dummy variable $post_t^3$ takes on the value of 1 for one week after each of the eight divestitures. In order to focus on the divestitures, we discard post-period data outside of the one-week evaluation windows.

$$post_t^3 = \begin{cases} 1 & \text{for } t \in \{t | t_j \leq t \leq t_j + 6, j = 1 \dots 8\} \\ 0 & \text{else,} \end{cases} \quad (7)$$

where t_j designates the date of divestiture j . Hence, the coefficient of this dummy measures the average short-run effect of the divestitures.

The above approach pools the effects of all individual divestitures, assuming a single average effect. To relax this assumption, we also estimate the individual effects of the remedies by defining a dummy variable akin to the one described above for each individual remedy:

$$post_{t_j}^4 = \begin{cases} 1 & \text{for } t \in \{t | t_j \leq t \leq t_j + 6\} \\ 0 & \text{else,} \end{cases} \quad (8)$$

where each coefficient estimate represents the impact of the individual remedy implemented at that particular date.

5.2 Enhancing identification: ownership and merit order considerations

In the previous discussion, the effect of a divestiture is measured by a binary variable that takes the value one during peak pricing schedules in the evaluation period. However, this approach neglects the fact that the type of divested technology as well as the identity of the buyer are important drivers of market power. Hence, we refine our identification by exploring three dimensions of heterogeneity, which allow us to further qualify our assessment of the short-run impact of the divestitures.²⁴

First, while our baseline approach considers all individual divestitures to be equal, the actual generation capacity sold in the individual divestitures varies strongly as discussed in table 1. Clearly, the impact of the divestitures on the market should depend on the amount of divested capacity: as more capacity is divested, the effect should become more pronounced. Therefore, we interact the treatment effect indicator with the capacities divested in the plant sales.

Second, divestiture effects are likely to be dependent on the divested technology. Technologies differ in their production costs depending on the fuel type used to generate electricity, which translates into their positioning in the merit order curve. They, therefore, have different likelihoods

²⁴This differentiation is only possible when estimating short-run treatment effects, since in the estimation of long-run effects, the treatment effect is reflected in a single treatment variable, hence it is not possible to split it according to different dimensions of heterogeneity.

of being strategically withheld from the market. For example, the marginal cost of power plants running on renewable fuels such as wind or sun is essentially zero, while combined cycle gas turbines (CCGT) and coal plants are expensive and tend to be price-setting units during peak-times. Thus, renewables are less likely to be withdrawn from the market, if at all, than capacities generated by means of gas and coal that are higher up the merit order curve and compete to be dispatched ahead of each other. To investigate treatment heterogeneity due to technology types, we interact the treatment with indicators for the type of generation technology divested. Specifically, we differentiate between coal and gas, renewables (including hydro), nuclear and the grid divestiture.

Third, we account for the identity of the buying firm. While some capacity was sold to one of the other strategic buyers (EnBW), most of it went to foreign firms. As we discussed in our theoretical framework, the divestitures to non-pivotal buyers entail a reduction of the residual demand for all strategic players, which, in turn, results in lower equilibrium prices. Whether divestitures to other strategic players have a similar effect depends on their capacity constraint and incentive to withhold capacity. In any case, it might be expected that the strengthening of a direct strategic competitor would affect E.ON's incentive to *individually* abuse a joint dominant position.

5.3 Triple differences and synthetic controls

To further support the identification strategy, we propose using cross-country differences in the evolution of the spread between peak and off-peak prices. We implement a triple difference approach using France and Spain as counterfactuals. France is similar to Germany in size, but uses a rather different energy mix. Spain is similar in both size and energy mix. While the French and German markets are integrated, the Spanish market can be assumed to be remote. Thus, the comparison with France might measure a lower bound of the divestiture's effects as the German and French markets are more interconnected and the divestiture effects could have spilled over.

Additionally, we have also collected data on other European nations (Austria, Belgium, the Czech Republic, the Netherlands, Norway, Poland, Portugal and Sweden). We use these data to implement a synthetic control group approach (Abadie and Gardeazabal, 2003). Thus, we generate a synthetic German electricity market as a weighted average of these other European markets and compare the evolution of the real and the synthetic peak prices after the implementation period.

5.4 The effect of the divestitures on electricity consumption

As discussed above, we do not think that the mechanism we have in mind to identify the effect of the potential abuse on prices – i.e. the convergence of peak/off-peak prices – would work in the same clear way for quantities, at least not in the short run. Indeed, energy markets differ

from most other markets, because aggregate demand is very inelastic. This means that there are few possibilities to shift demand from peak to off-peak when the relative prices change since much of the demanded quantity can only be consumed at a given point in time. On the household-consumption side, customers are mostly price insensitive since, in most contracts, they pay an equal amount whether they use electricity in peak or off-peak times. Hence, they have no incentive to change their consumption patterns if relative prices change. From the industrial-consumption side, demand is also quite inelastic as consumption is often immediate, and the potential for load shifting is restricted for many energy-intensive industries. Consequently, in the short run, a decrease in market power may cause lower peak prices relative to off-peak, but not necessarily significantly higher peak consumption.

While this reasoning seems accurate in the short-term, in a longer-term, one might expect the divestitures to have some effects on quantities as well. If industrial customers perceive that the reduction of peak prices relative to off-peak prices is significant and permanent and they can adapt their production process, they might re-allocate production from off-peak to peak. This might have the additional advantage of further reducing production costs as, for instance, labour is more expensive at night than during the day. Thus, in the long run, we might expect to see an adjustment of peak and off-peak quantities. From the econometric perspective, the long-term nature of this effect makes it more difficult to identify, as other confounders can play a role. Moreover, we cannot expect to observe the short-term reactions around the single divestitures that we see when we focus on prices.

Nonetheless, we regress the difference in mean peak and off-peak daily consumption, which averages over 11,000 MWh, on a post-2009 indicator, different sets of control variables as well as fixed-effects for months (Jan - Dec) and day-of-the-week to account for electricity demand shifters.

6 Results

6.1 Main results

In table 3, we report the main results of the estimation. First, the model fits the data well, as we are able to capture between 67 and 69% of the variation in wholesale prices. Second, we observe an average difference between peak and off-peak prices that varies from 31 - 36 €/MWh. Third, the coefficient estimates for the control variables mostly have reasonable signs and sizes. The amount of electricity generated from wind decreases prices during peak hours and remains mostly insignificant during off-peak hours. The amount of solar capacities decreases prices, while the coefficients of the sunshine measures are not significant. Prices linearly decrease and quadratically increase in both

peak and off-peak temperatures. Net cross-border flows decrease peak and (slightly) increase off-peak prices. European market integration seems to have significantly affected electricity prices, as they fell significantly around both market integration events contained in the data. While electricity prices significantly increase with gas and emission prices, they do not respond to oil, uranium, or coal prices. Finally, prices decrease during holidays.

Our main interest, however, lies in the treatment indicators. Their coefficients measure the treatment effect, i.e. the differential evolution of peak prices if compared to off-peak prices after the implementation of the divestitures. In the long-run scenarios, we find a significant convergence between peak and off peak prices. This effect is not only statistically, but also economically, significant. In both specifications (post December 2008 or post May 2010 period, excluding the entire implementation period), we observe a significant reduction of peak prices with respect to off-peak prices of around 11 €/MWh, other things equal. Considering that off-peak prices can be thought as a rough measure of marginal costs for the highest-cost generator, this result implies that the average peak/off-peak margins are around 35% lower after the implementation of the remedies.

In the short-run specifications, we only retain data from the pre-treatment period as well as one week of data after each divestiture; thus, the sample size is approximately halved. We also obtain negative and significant treatment effects in both the pooled-coefficient and the individual-coefficient specifications. The pooled coefficient is, at -12 €/MWh, very similar to those obtained in the long-run specifications.

In the individual-coefficient short-run specification, we see that all eight individual divestiture dummies carry a negative sign, with effect sizes ranging between -4 and -32 €/MWh. In seven out of the eight instances, the effect is statistically significant. These findings suggest that the markets price reaction was swift and substantial, with the short-run effects i) being mostly individually significant and ii) resulting in a pooled effect very similar to that estimated in the long-run scenarios.

All proposed approaches have advantages and disadvantages. The short-run scenarios are possibly more intuitive because the short time windows minimize the likelihood that unobserved factors or events influence measurement. However, they might fail to measure long-term changes in the market structure and operators' incentives, or to capture slow adjustments in firms' bidding behavior. Moreover, they cannot be interpreted as average treatment effects. The long-run effects, which can be better interpreted within a difference-in-difference framework, are more likely to capture permanent strategic adjustments in the bidding behavior of both incumbents and the smaller competitors. However, they are likely to be contaminated by other policy interventions or market changes that happened during the same period. Indeed, during the years 2009-2011 several other national and EU-wide policy interventions affected the German electricity wholesale market.

Table 3: The Effect of the Divestitures on German Wholesale Prices

	Long-run				Short-run			
	Post 2009		Post 2010		Pooled		Individual	
Peak	30.76***	(2.15)	32.52***	(2.50)	34.37***	(3.40)	35.87***	(3.85)
Peak*Post	-10.96***	(1.12)	-10.97***	(1.13)	-12.04***	(2.22)		
Peak*Div1							-21.10***	(6.54)
Peak*Div2							-13.38***	(2.50)
Peak*Div3							-7.54***	(2.36)
Peak*Div4							-4.05	(2.89)
Peak*Div5							-8.38**	(3.82)
Peak*Div6							-31.93***	(6.08)
Peak*Div7							-6.13***	(2.32)
Peak*Div8							-7.66**	(3.69)
Post					126.49*	(75.90)		
wind_cap	-8.51	(6.52)	-11.80	(8.48)	14.40	(11.43)	-3.00	(9.71)
wind ₁	-0.00***	(0.00)	-0.00***	(0.00)	-0.00**	(0.00)	-0.00**	(0.00)
wind ₀	-0.00	(0.00)	-0.00	(0.00)	-0.00***	(0.00)	-0.00***	(0.00)
wind ₁ ²	0.00	(0.00)	0.00	(0.00)	0.00**	(0.00)	0.00*	(0.00)
wind ₀ ²	-0.00**	(0.00)	-0.00**	(0.00)	-0.00	(0.00)	-0.00	(0.00)
solar_cap	-2.80**	(1.19)	-2.07	(1.33)	-27.44**	(12.45)		
sun ₁	-0.01	(0.01)	-0.01	(0.01)	-0.02	(0.01)	-0.02	(0.01)
sun ₀	0.01	(0.02)	0.01	(0.02)	0.01	(0.02)	0.02	(0.02)
sun ₁ ²	0.00	(0.00)	0.00	(0.00)	0.00	(0.00)	0.00	(0.00)
sun ₀ ²	-0.00	(0.00)	-0.00	(0.00)	-0.00	(0.00)	-0.00	(0.00)
temp ₁	-1.57***	(0.26)	-1.84***	(0.34)	-2.44***	(0.64)	-2.46***	(0.69)
temp ₀	-0.39***	(0.11)	-0.40***	(0.13)	-0.47**	(0.21)	-0.22	(0.21)
temp ₁ ²	0.06***	(0.01)	0.07***	(0.02)	0.09***	(0.03)	0.09***	(0.03)
temp ₀ ²	0.01**	(0.01)	0.01**	(0.01)	0.02*	(0.01)	0.01	(0.01)
cb ₁	-0.00***	(0.00)	-0.00***	(0.00)	-0.01***	(0.00)	-0.01***	(0.00)
cb ₀	0.00**	(0.00)	0.00***	(0.00)	0.00***	(0.00)	0.00***	(0.00)
coupling	-19.96***	(2.40)	0.00	(.)	32.16*	(18.13)	38.20	(70.91)
coupling2	-4.89***	(1.90)	-5.26***	(2.02)	0.00	(.)	0.00	(.)
oil	0.08	(0.07)	0.11	(0.08)	0.10	(0.14)	0.19	(0.14)
gas	0.93***	(0.17)	0.92***	(0.18)	0.76***	(0.20)	0.77***	(0.20)
uranium	0.10	(0.10)	0.13	(0.11)	0.01	(0.12)	0.06	(0.12)
emissions	0.31*	(0.18)	0.36	(0.23)	0.42	(0.26)	0.42	(0.26)
coal	0.06	(0.07)	0.07	(0.07)	0.08	(0.09)	0.06	(0.09)
holiday	-12.59***	(1.71)	-13.28***	(2.02)	-14.09***	(1.66)	-14.27***	(1.68)
ind_index	-4.66***	(1.08)	24.52***	(1.42)	5.72**	(2.60)	1.63	(1.65)
R ²	0.69		0.67		0.68		0.68	
N	5114		4142		2304		2304	

Notes: * p<0.1, ** p<0.05, *** p<0.01, Newey-West standard errors (7 lags) in parentheses. Fixed-effects for months and day-of-the-week are included. In the first two estimations, the post-indicator is collinear with the month fixed-effects. The fourth estimation contains 8 individual post-indicators, which are dropped from output. Subscripts denote peak (₁) and off-peak periods (₀).

The comparison of these various approaches yields a rather coherent picture, pointing to an increase in competition that can be related to the abuse of dominance case. Our results suggest that around the dates of the divestitures, the short-run and long-run difference between peak and off-peak prices was, *ceteris paribus*, significantly reduced. This finding is consistent with the Commission’s investigation effectively stopping or at least reducing the alleged abuse of market power.

6.2 Heterogenous effects: ownership and merit order considerations

In the next step, we make use of the information on which type of generation units were divested to whom. Thus, we explore the heterogeneity in the treatment effects along differences due to technology types, buyer identity and the amount of generation capacity divested. Table 4 reports the results. The specification is equivalent to the third specification of table 3, i.e. pooled short-run effects.²⁵

In column (1), we find that the average short-run treatment effect remains significant when we weigh divestitures with the capacity divested. The coefficient’s estimate can be interpreted as the per MW impact of a divestiture: on average, peak prices decreased by 1.4 cents per MW divested. In column (2) we interact divestitures with technology types and find that the divestitures of coal and gas plants, nuclear plants and the grid divestiture have significantly decreased prices. When weighing divestitures with capacities (column 3), this finding is confirmed and we see that the per-MW impact is largest for coal and gas plants. Their impact upon divestiture – a price reduction of 2.7 cents per MW divested – is almost twice the overall effect reported in column (1). The divestiture of renewables does not have a significant impact on prices in either specification. This is consistent with them not being strategically withheld in the first place.

Column (4) differentiates buyer identities and shows that most transactions led to significant price decreases. The capacity-weighted results confirm this. The largest per-MW effect is due to the divestitures to EnBW, a close competitor of E.ON. Yet, the assets sold to Electrabel (a Belgian generation company), Morgan Stanley (an investment company), Statkraft (a Norwegian generator) and TenneT (a Dutch grid operator) have also reduced peak prices. Only the divestiture to Verbund (an Austrian generator) did not decrease peak prices. Notably, this is a rather small divestiture involving *only* hydro power plants.

²⁵Heterogeneous treatment effects cannot be estimated in the long-run scenarios as we cannot use the heterogeneity among the various divestitures in a simple before/after setting. We obtain similar results estimating individual effects, i.e. the fourth specification of table 3.

Table 4: Heterogenous Effects

	Short-run \times Cap	Fuel	Fuel \times Cap	Buyer	Buyer \times Cap
Peak	34.24*** (3.404)	34.87*** (3.420)	34.91*** (3.420)	35.15*** (3.548)	35.56*** (3.588)
Peak*Post	-0.0142*** (0.00342)				
Div(Coal&Gas)*Peak		-14.69*** (3.551)	-0.0268*** (0.00541)		
Div(Renewable)*Peak		-2.561 (3.188)	-0.00375 (0.0108)		
Div(Nuclear)*Peak		-8.343** (3.676)	-0.00557** (0.00245)		
Div(Grid)*Peak		-5.945*** (2.240)	-0.0143*** (0.00540)		
Div(Electrabel)*Peak				-10.98*** (2.609)	-0.00794*** (0.00233)
Div(EnBW)*Peak				-19.28*** (5.757)	-0.0326*** (0.00728)
Div(MorgStan)*Peak				-7.739** (3.874)	-0.0292** (0.0146)
Div(Statkraft)*Peak				-19.67*** (6.184)	-0.0269*** (0.00832)
Div(TenneT)*Peak				-6.016*** (2.246)	-0.0146*** (0.00544)
Div(Verbund)*Peak				-4.317 (2.982)	-0.0136 (0.00954)
R ²	0.68	0.68	0.68	0.68	0.68
N	2304	2304	2304	2304	2304

Notes: * p<0.1, ** p<0.05, *** p<0.01. Newey-West standard errors (7 lags) in parentheses. Fixed-effects for months and day-of-the-week, post-indicators and control variables are included, but not reported.

6.3 Using variation across countries to enhance identification

6.3.1 A difference-in-difference-in-difference approach

One potential concern with our basic DiD setting is that our empirical strategy might pick up common developments of European energy markets, that have led to a convergence of peak and off-peak prices but are unrelated to changes of market power in Germany. To address such concerns, we re-estimate our models in a triple difference setting, where the German differences (before/after, peak/off-peak) are contrasted with those found in other large European countries, namely France and Spain. Thus, any amount of price convergence that is also present in French or Spanish energy markets will be controlled for.

Table 5 contains the estimation results. Compared to the DiD setting, there are a few additional regressors: 'treated' is an indicator variable, assuming a value of one for Germany and zero for the control group (i.e. France or Spain). 'Peak' and 'post' are as before (and, as before, the 'post' indicator is omitted due to collinearity with the month fixed-effects), the interactions with treated pick up effects in the peak- and post-periods that are specific to Germany. Finally, the triple interaction of treated, peak and post measures the treatment effect. Due to the addition of another country, the number of observations doubles compared to table 3. The R^2 s are comparable to those in the main regressions for Spain and slightly lower in the French case, because we lack data on French renewable generation.

The coefficient estimates for the treatment effects are negative and significant in all six specifications. The sizes of the coefficient estimates are practically identical to those reported in table 3 and suggest a convergence of peak and off-peak prices in Germany of around 11 - 12€.

All in all, the findings are remarkably robust to replication in a triple difference setting. The extent of peak/off-peak price convergence in Germany is not diminished when estimated relative to France or Spain. Thus, price convergence in Germany appears to be orthogonal to that experienced by other countries. This alleviates concerns, that the results are driven by common patterns across European energy markets instead of the specific interventions that occurred in Germany.

6.3.2 A synthetic control group approach

When evaluating a treatment taking place at the country level, one typically has limited choice when it comes to choosing control observations. On the one hand, countries in general and their energy markets in particular are quite different, making comparisons difficult. On the other hand, data availability often is an issue. In such a setting, a synthetic control group (Abadie and Gardeazabal, 2003) can often generate more plausible inference than traditional techniques. A synthetic control group is a weighted basket of non-treated units, that mimics the treated unit as well as possible

Table 5: Difference-in-Difference-in-Difference approach: Comparison to France and Spain

	Comparison to France			Comparison to Spain		
	Post 2009	Post 2010	Short-run	Post 2009	Post 2010	Short-run
Treated	-27.16*** (3.752)	-28.00*** (8.852)	0 (17.28)	-12.05*** (3.085)	-6.127 (12.15)	0 (6.421)
Peak	25.25*** (1.616)	26.26*** (1.866)	33.69*** (3.159)	12.28*** (1.411)	13.27*** (1.742)	17.65*** (3.227)
Treated*Peak	5.611** (2.394)	6.350** (2.571)	0.742 (3.645)	17.36*** (2.032)	17.52*** (2.273)	14.12*** (3.116)
Treated*Post	19.27*** (4.476)	0 (.)	8.460 (.)	-2.884 (2.714)	0 (.)	-25.94 (.)
Treated*Peak*Post	-10.98*** (1.162)	-11.15*** (1.196)	-11.79*** (2.179)	-10.69*** (1.129)	-10.66*** (1.141)	-10.88*** (1.966)
R ²	0.54	0.53	0.54	0.67	0.66	0.69
N	10228	9256	4608	10228	9256	4608

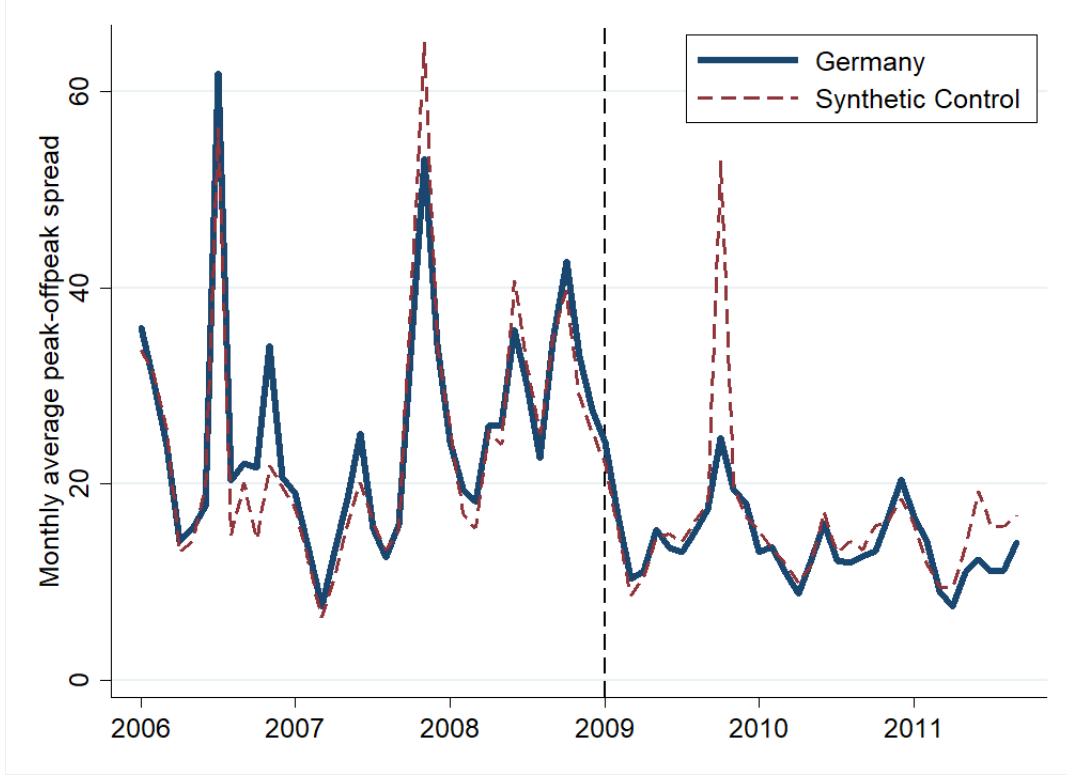
Notes: * p<0.1, ** p<0.05, *** p<0.01. Newey-West standard errors (7 lags) in parentheses. Fixed-effects for months and day-of-the-week, post-indicators and control variables are included, but not reported.

during the pre-treatment period. The approach of 'tailoring' a control unit can be seen as controlling for both observable and unobservable heterogeneity. The divergence between the treated unit and the synthetic control group in the post-treatment period can then be interpreted as the effect of the treatment.

In our case, we collected data on ten other European countries (Austria, the Czech Republic, France, Holland, Norway, Poland, Portugal, Spain and Sweden) during the same period and merge them with the data on Germany. For each country, we calculate the spread between peak and off-peak prices for the 2006-2011 period. The synthetic control algorithm then uses lagged values of the price spread, along with information on consumption patterns, temperatures, national holidays and installed wind and solar capacities to obtain the best possible fit with German pre-treatment price spreads. To reduce noise, we aggregate our data to the monthly level and use the three months preceding the implementation of the remedies as predictors. The synthetic control algorithm assigns positive weights to three countries, namely Austria (8%), Spain (3%) and France (89%).

Figure 4 plots the average, monthly spread of peak and off-peak prices in Germany and the synthetic control group. While the synthetic control group slightly underpredicts the mean spread in the pre-treatment period, the difference of -1.06€ is not significant at $p = 0.11$. In the post-period, conversely, the German spread is overpredicted and the difference of 1.71€ is significant at $p = 0.07$. Thus, relative to the control group, the German price spread has declined by 2.77€.

Figure 4: Evolution of peak - off-peak gap for Germany and synthetic control group



6.4 Effects on electricity consumption

As discussed in section 5.4, we expect divestitures to affect electricity consumption only in the long run, if at all. Similarly to our analysis on prices, we look at the different evolution of peak and off-peak consumption before and after the divestiture.

We perform an econometric analysis where we regress the consumption gap on a post dummy and control for several factors. Table 6 reports our results. The coefficient estimate for the post dummy shows that, after the implementation of the remedies, peak consumption increased by 5,7% (649 MWh) relative to off-peak consumption in the baseline model up to almost 13% (1,492 MWh) in the richest model. Therefore, we can cautiously conclude that the relatively lower peak prices are correlated with the decision of some customers to shift their consumption from off-peak to peak periods.

7 Robustness Checks

7.1 Placebo: Effect in different treatment periods

In this section, we report the findings of two time placebo trials, where we shift the evaluation period to a time period when no actual treatment occurred. We limit the dataset to the pre-treatment

Table 6: Changes in peak-period consumption after the divestitures

	(1)		(2)		(3)		(4)	
Post	648.6***	(90.3)	857.0***	(88.0)	927.8***	(92.4)	1492.4***	(94.6)
temp_peak			42.4	(70.0)	21.9	(70.2)	-35.6	(67.0)
temp_offpeak			351.4***	(79.0)	399.8***	(78.8)	447.8***	(75.1)
temp_peak ²			-5.9***	(2.0)	-6.2***	(2.0)	-4.4**	(1.9)
temp_offpeak ²			-1.8	(3.2)	-2.3	(3.2)	-4.0	(3.0)
sun_peak			-3.0***	(1.0)	-2.9***	(1.0)	-2.9***	(1.0)
sun_offpeak			-3.3	(2.8)	-2.4	(2.8)	-3.8	(2.7)
sun_peak ²			0.0	(0.0)	0.0*	(0.0)	0.0	(0.0)
sun_offpeak ²			0.0**	(0.0)	0.0**	(0.0)	0.0***	(0.0)
cb_offpeak					-0.0	(0.0)	0.0**	(0.0)
cb_peak					-0.4***	(0.1)	-0.5***	(0.1)
ind_index							100.1***	(6.2)
R ²	0.73		0.77		0.77		0.79	
N	2551		2551		2551		2551	

Notes: * p<0.1, ** p<0.05, *** p<0.01, Newey-West standard errors (7 lags) in parentheses. Fixed-effects for months and day-of-the-week are included.

period (2006 - 2008) and consider two scenarios: first, we assume that the 'treatment' started in 2007, such that 2006 is the pre-treatment period and 2007 and 2008 constitute the evaluation period; second, we let 'treatment' start in 2008 and evaluate its impact during that year. We move the dates of the individual divestitures forward by two and one year(s) respectively. In the second scenario, two divestitures are dropped because moving them forward by one year only would leave them in the actual treatment period (see table 1). We report the findings in table 7.

In both scenarios, we find no significantly negative long-run convergence effects (columns 1 and 4 of table 7), in 2008 the gap even significantly increased. The short-run specifications (columns 2 and 5) show no significant effects around the pre-dated divestitures. The individual effects specifications (columns 3 and 6) show some significant coefficients, but in both cases the partial sums alternate between positive and negative significance, showing no clear pattern.

7.2 Different definitions of the peak

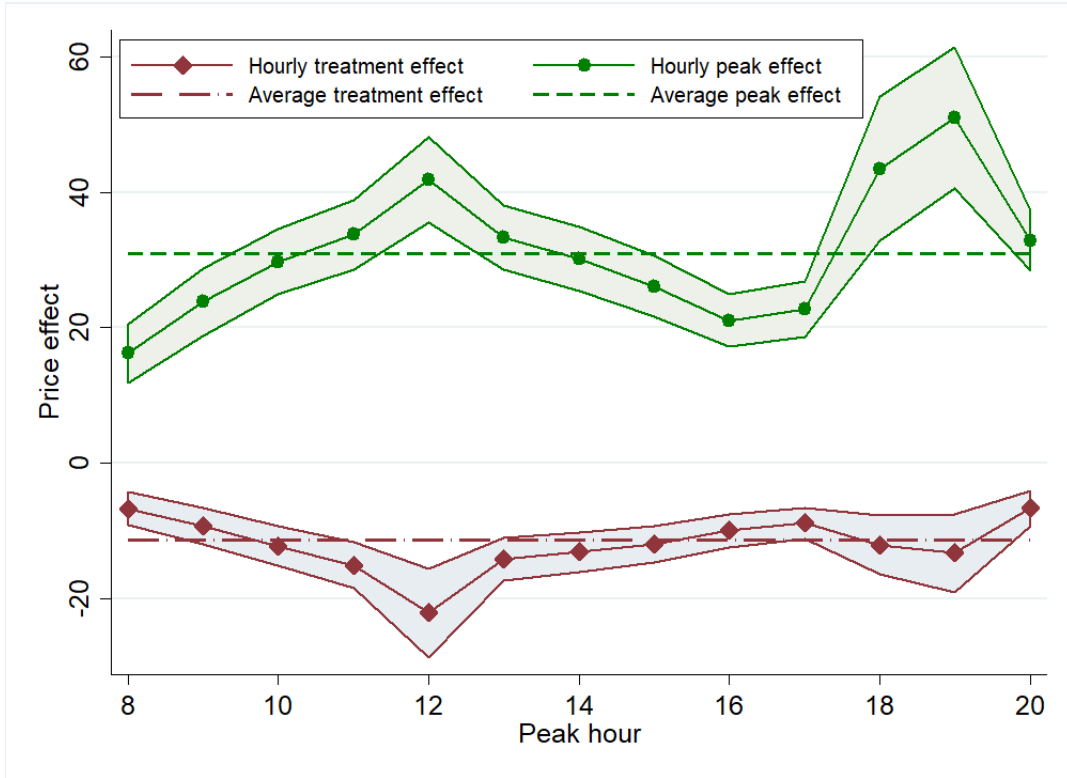
Throughout our analysis, we assume that the peak period starts at 8am and ends at 8pm. While this seems a reasonable assumption as it measures the average peak price, there might still be quite different price dynamics during the day. Indeed, it is well known that there generally are two high price peaks during the day: around 12pm and around 6pm. Hence, the convergence effect could

Table 7: Time placebos in pre-treatment period

	Treatment period 2007-2008			Treatment period 2008		
	Post 2006	Short-run pooled	Short-run individual	Post 2007	Short-run pooled	Short-run individual
Peak	36.85*** (4.938)	37.38*** (4.043)	37.33*** (4.048)	34.41*** (4.194)	37.08*** (4.030)	37.87*** (3.895)
Peak*Post	0.674 (2.992)	1.417 (3.311)		6.617*** (2.316)	6.309 (5.079)	
Peak*Div1			-2.252 (2.648)			-6.189 (8.748)
Peak*Div2			-5.502 (5.143)			9.048*** (3.408)
Peak*Div3			9.576 (6.500)			9.577 (7.986)
Peak*Div4			-9.414*** (3.356)			2.129 (4.549)
Peak*Div5			10.25 (7.612)			21.02*** (4.532)
Peak*Div6			6.071** (2.632)			-24.73*** (5.578)
Peak*Div7			-0.246 (2.542)			0 (.)
Peak*Div8			2.473 (3.794)			0 (.)
R ²	0.64	0.64	0.65	0.65	0.64	0.65
N	2192	2192	2192	2192	2192	2192

Notes: * p<0.1, ** p<0.05, *** p<0.01. Newey-West standard errors (7 lags) in parentheses. Fixed-effects for months and day-of-the-week, post-indicators and control variables are included, but not reported.

Figure 5: Estimated peak and treatment effects using single-hour peak definitions



non-monotonically depend on the peak definition. As documented by e.g. Kwoka and Sabodash (2011), the incentive to withdraw capacity is particularly high during the hours of highest demand.

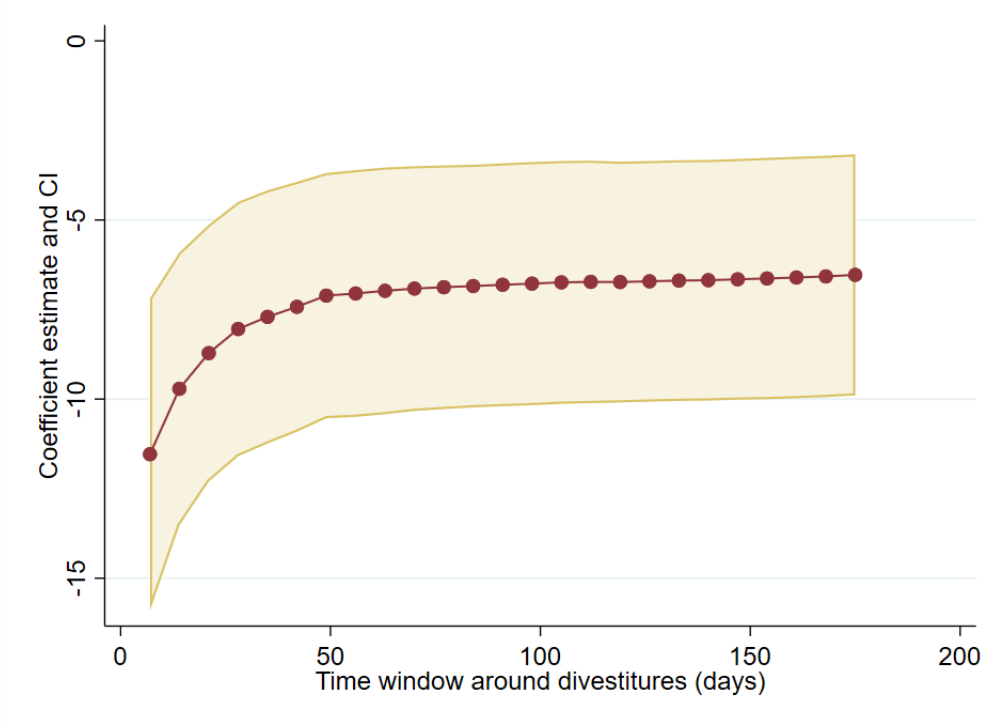
As a robustness check, we therefore replicate the main specifications using twelve different definitions of the peak. Instead of using the average daily price, we use the hourly price at different hours of the day from 8am to 8pm. Figure 5 graphically reports the results of the estimation based on the long-run specification.

The difference between peak and off-peak prices (green dots) substantially varies over the course of the day, reaching its highest values around 12pm as well as 6pm to 7pm. The green-shaded area corresponds to the 95% confidence intervals of the estimated peak coefficients. The green (red) dashed line indicates the average peak (treatment) effect of 31 (-11) € reported in column 1 of table 3.

Similarly, the treatment effect varies over the course of the day, although to a lesser extent. The largest effect is measured when the peak period is defined as 12pm, where the effect is as large as 21 €/ MWh. This implies a reduction of the spread between peak and off-peak prices of 53%. This is consistent with the view that the benefits of withdrawing capacity substantially increase with higher demand and that this increase is non-linear.

While these additional estimations show that there is substantial heterogeneity on the estimated

Figure 6: Short-run coefficient estimates for different time windows



size of the convergence depending on the exact definition of the peak time, the figure also confirms that the qualitative results are not affected by this assumption. Independent of the definition of the peak-hour, we always obtain significant convergence effects. The results reported in our main specification are essentially a conservative estimate of the larger convergence that one could obtain by having a stricter definition of the peak.

7.3 Generalizing the measurement of the short-run effects

Our estimates of short-run effects – where the impact is measured in the week following each divestiture – might be imprecise due to the high volatility of energy markets and the subjective choice of the length of the window. We therefore propose an extension that aims at more precisely measuring the impact of the divestitures by showing how this estimate is affected by the size of the window. The idea is to consecutively increase the size of the window around the divestiture and, accordingly, estimate different models with different windows' lengths. To do this, we reduce the dataset to only include only the pre-treatment period and the n weeks before and after each of the eight divestitures and let n vary from $1, \dots, 25$. Figure 6 plots the resulting coefficients estimates for the treatment effects, along with 90% confidence intervals. The coefficient estimates are significantly negative and range between -11 and -7€ per MWh.

7.4 Autocorrelation of errors & data frequency

Autocorrelation of the residuals is one of the main econometric issues we face with high-frequency time-series data. The use of a Newey-West estimator for the standard errors addresses this issue. In the specifications reported above, we allow for autocorrelation of up to seven days. To better understand the effects of autocorrelated errors on our results, we propose three tests. First, we use a Newey-West estimator with lower order autocorrelation lags (two days). We report our findings in table 8. Results are almost identical to those reported in our main specification and none of the coefficients lose statistical significance.

Table 8: Second-order Autocorrelation

	Post 2009	Post 2010	Short-run pooled	Short-run individual
Peak	30.76*** (1.988)	32.52*** (2.350)	31.36*** (3.505)	35.87*** (3.690)
Peak*Post	-10.96*** (0.962)	-10.97*** (0.975)	-11.16*** (2.637)	
Peak*Div1				-21.10*** (7.295)
Peak*Div2				-13.38*** (3.631)
Peak*Div3				-7.538** (3.234)
Peak*Div4				-4.051 (3.645)
Peak*Div5				-8.376* (4.802)
Peak*Div6				-31.93*** (6.058)
Peak*Div7				-6.130** (2.948)
Peak*Div8				-7.664* (4.078)
R ²	0.69	0.67	0.57	0.68
N	5114	4142	2304	2304

Notes: * p<0.1, ** p<0.05, *** p<0.01. Newey-West standard errors (2 lags) in parentheses. Fixed-effects for months and day-of-the-week, post-indicators and control variables are included, but not reported.

Second, to account for a more general structure in the autocorrelation of the disturbances, we use a bootstrap estimation with 1,000 replacements to obtain consistent standard errors. Results are reported in table 9 and are again very similar to those reported in our main specification.

Third, we reduce the frequency of the data to a weekly level. We compute the weekly averages

Table 9: Bootstrapped standard errors

	Post 2009	Post 2010	Short-run pooled	Short-run individual
Peak	31.86*** (1.704)	33.60*** (1.996)	24.66*** (1.419)	24.95*** (1.505)
Peak*Post	-11.43*** (0.801)	-11.39*** (0.821)	-4.838*** (1.432)	
Peak*Div1				-7.656* (4.345)
Peak*Div2				-6.356** (2.729)
Peak*Div3				-2.505 (3.292)
Peak*Div4				-0.193 (3.786)
Peak*Div5				2.150 (3.896)
Peak*Div6				-16.24*** (3.117)
Peak*Div7				-4.081 (3.141)
Peak*Div8				-4.243* (2.550)
R ²	0.65	0.63	0.64	0.64
N	5114	4142	5114	5114

Notes: * p<0.1, ** p<0.05, *** p<0.01. Newey-West standard errors (7 lags) in parentheses. Fixed-effects for months and day-of-the-week, post-indicators and control variables are included, but not reported.

for the peak and off-peak prices, as well as all control variables. Results are reported in table 10. Once more, all conclusions from the main analysis are supported. While reducing the size of the dataset by a factor of 7, neither the coefficients nor their significances are strongly affected.

Table 10: Aggregating to Weekly Data

	Post 2009	Post 2010	Short-run pooled	Short-run individual
Peak	37.81*** (3.841)	41.66*** (4.279)	48.48*** (6.247)	50.99*** (6.518)
Peak*Post	-11.59*** (1.238)	-11.91*** (1.248)	-14.19*** (3.707)	
Peak*Div1				-29.58*** (8.546)
Peak*Div2				-9.748*** (3.210)
Peak*Div3				-8.669*** (2.712)
Peak*Div4				-3.600* (2.071)
Peak*Div5				-11.94** (4.812)
Peak*Div6				-41.89*** (8.515)
Peak*Div7				-6.948** (2.893)
Peak*Div8				-17.06*** (4.266)
R ²	0.84	0.83	0.75	0.84
N	728	590	328	328

Notes: * p<0.1, ** p<0.05, *** p<0.01. Newey-West standard errors (7 lags) in parentheses. Fixed-effects for months and day-of-the-week, post-indicators and control variables are included, but not reported.

8 Conclusion

In this paper, we study the effect of a specific competition policy intervention: the EU Commission's case against E.ON for its alleged abuse of a dominant position in the German wholesale electricity market. The investigation confirmed the presence of competition concerns and, as a consequence, E.ON committed to divest a total of 5 GW of generation capacity as well as its high-voltage transmission network. The focus on a specific case study allows us to be quite precise in modelling the peculiarities of the market and the case, thus providing more convincing evidence that our estimates reflect the effect of the divestitures. Because the intervention directly affected upstream

electricity markets, we study the effect of the Commission’s decision on wholesale prices. We adopt a difference-in-difference methodology to identify the impact of the policy intervention.

Our approach and identification strategy are tailored to the specificities of the German electricity market. We exploit the fact that prices are mostly determined through a centralized energy exchange market, the EEX. Although most electricity is traded via over-the-counter contracts, the EEX price is the opportunity cost for energy trading and, therefore, a good benchmark.

Identification proceeds in different steps. It starts from the observation that energy suppliers have more market power during peak periods (8am-8pm) when demand is higher. Since the supply schedule is highly convex and much steeper during the peak period, parallel shifts to a lower or higher capacity schedule would have larger price effects during peak time. Thus, we expect a convergence between peak and off-peak prices if market power is reduced. We enrich this basic identification strategy to account for the fact that the type of the divested assets and the identity of the buyers play an important role. Specifically, mostly capacity in the mid of the merit order might be expected to be strategically withdrawn. Moreover, we also exploit cross-country variation in the degree of convergence and use a triple difference approach to further refine the analysis.

We estimate a wholesale price equation using daily data on peak and off-peak prices, while controlling for a large set of relevant determinants of wholesale prices, such as input prices and demand and supply conditions. Moreover, we carefully control for the evolution of renewables that, due to the regulatory environment, dramatically changed the functioning of German wholesale electricity markets starting from the second half of the 2000s.

We identify the short-run effect of the divestitures spurred by the Commission’s investigation by looking at convergence between peak and off-peak prices in the weeks around each of them, while the long-run effects are identified by looking at the convergence over a period of one or two years after the implementation of the remedies. We find strong and statistically significant convergence effects in the short-run as well as in the long-run. The size of the effect is economically relevant, with convergence of 11 - 12 €/MWh. Extending the basic model to account for merit order considerations, we confirm that the effect is mostly driven by the divestiture of coal and gas generation plants, as expected. Cross-country regressions and a synthetic control approach based on data from other European countries, as well as a number of robustness checks corroborate our results. Our findings are consistent with the view that the divestitures following the Commission’s investigation, reduced market power and, consequently, wholesale prices. These findings are supported by the fact that we also observe convergence in peak and off-peak electricity consumption.

A final note on the economic significance of the effects is warranted. While a full welfare analysis is not possible given the reduced-form nature of our exercise, we can try to assess the implications

of this effect in term of consumer welfare. To do that, we need information about how changes of upstream wholesale price are passed-on downstream to final customers. Duso and Szücs (2017) study the pass-through of cost changes to retail electricity tariffs for households over the 2007-2014 period. They show that, on average, 60% of upstream cost changes are passed on to consumers. At this rate, the estimated decrease of wholesale electricity prices by 11 €/MWh implies a reduction of consumers' tariffs by approximately 6.60 €/MWh, on average. Considering the average yearly electric power consumption of a household with four members in Germany is around 4,000 kWh, this price reduction would imply yearly savings of about 26.40 €. Thus, the aggregate yearly effect of the divestitures would be in the range of several hundred million €.

Another way of assessing the economic significance of the estimates is to look at the average net electricity consumption for Germany, including not only residential but also industrial customers. Between 2010 and 2017 yearly electricity consumption oscillated around 530 TWh for a total revenue of almost 70 billion €. Assuming that around 65% of this energy was consumed during peak time and that the pass-through to industrial customers is similar to the pass-through to households (around 60%), the reduction in prices due to the divestiture may have induced savings of around two billion € per year.

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