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Market integration and technology mix: Evidence from the German and French electricity markets

Klaus Gugler[a,*], Adhurim Haxhimusa[b]

[a] Vienna University of Economics and Business, Department of Economics, Research Institute for Regulatory Economics, Welthandelsplatz 1, 1020 Vienna, Austria
[b] Vienna University of Economics and Business, Research Institute for Regulatory Economics, Welthandelsplatz 1, 1020 Vienna, Austria

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ABSTRACT

We employ hourly data from German and French electricity markets and show that integration of German and French electricity markets depends on the technology mix and the characteristics of neighbouring markets. Only when German and French electricity markets employ 'similar' generation mixes price spreads and the likelihood of the congestion of electricity flows are significantly reduced. We find that up to 31% of the price convergence is not attributed to the forces of arbitrage backed by interconnection capacities, but it is driven by coincident similarities in technology mixes. Furthermore, we document consistent evidence for the most important predictions of trade theory if markets are characterised by increasing marginal cost curves and limited cross-border capacities, i.e. limited convergence, congestion and cross-border externalities. Our results call for a coordinated European energy policy.

1. Introduction

A feature of electricity markets is that in certain hours two neighbouring electricity markets may employ either different or similar generation technologies to meet demand. This has never been considered in previous empirical studies, yet the similarity/dissimilarity of technology mixes has important implications for the integration[1] of electricity markets. Two adjacent markets may employ similar generation technologies and, as a result, they would seem to be very well integrated (assuming they have similar demand patterns), when in fact they exhibit equal prices/no congestion[2] only due to the use of similar technologies and not due to the forces of trade/arbitrage. Forces of trade only appear when there are differences in market prices that can be arbitraged.[3] However, in case of asymmetric demand or supply shocks spot prices would diverge because trade cannot take place (although there is an opportunity to trade) since no interconnection is available. As a result, this kind of 'market integration' does not necessarily imply an improved reliability of the electricity system as promoted by the three Energy Packages (96/92/EC, 2003/54/EC and, 2009/72/EC). On the other hand, adjacent markets with free available interconnection capacities and equal spot prices can still absorb asymmetric demand or supply shocks, leading to higher security of supply. Moreover, the similarity/dissimilarity of the technology mixes varies from hour to hour depending on demand and the amount of electricity generation from intermittent renewables.

This study adopts a novel approach based on the construction of a generation mix similarity index (*GMSI*) for the German and French electricity markets following Jaffe (1986). The *GMSI* between the

* Corresponding author.
E-mail addresses: klaus.gugler@wu.ac.at (K. Gugler), adhurim.haxhimusa@wu.ac.at (A. Haxhimusa).

[1] In this paper, we use the terms 'convergence' and 'integration' interchangeably. We view markets as being integrated and as having reached full convergence if prices are equal and there is no cross-border congestion.

[2] Congestion of interconnection capacities exists when demand for electricity trade exceeds interconnection capacity. Consequently, prices diverge (price spreads) and full price convergence, thus, cannot be achieved.

[3] This might also explain the reason behind the convergence of spot prices of two symmetric electricity markets (i.e. equal supply and demand characteristics) located far apart from each other without interconnection. Gugler et al. (2016a) provide an empirical evidence that between two electricity markets with market coupling and sufficient interconnection capacity, electricity flows freely and thus the law-of-one price holds.

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German[4] and French merit orders (i.e. supply curves) up to their intersection with their demand curves is a measure of how similar their generation mixes are in a certain hour. We consider three important issues in the integration[5] of European electricity markets, with a particular emphasis on the German and French spot markets:

(1) To what extent do technology mix similarities, as measured by the *GMSI*, determine the degree of price equality (Castagneto-Gissey et al., 2014; Jamasb and Pollit, 2005; Lise et al., 2008)? – This allows us to distinguish between price convergence driven by trade/arbitrage and convergence compelled by technology mix similarities.
(2) How do direct trade barriers (lack of interconnection capacities) affect price convergence depending on the level of the GMSI?
(3) How does trade with other neighbouring markets affect the integration of two adjacent markets?

We consider spot price spreads and interconnection capacity congestion to be good measures of the degree of market integration (e.g. Engel and Rogers, 2004; Keppler et al., 2016). Our extensive dataset contains hourly data from 01.04.2011 to 31.12.2014. We find that the law of one price and no cross-border congestion occur only in those hours when generation mixes are fairly similar. In contrast, excess demand for interconnection capacity and price divergences are common in those hours when generation structures are dissimilar. The aim of integrating European electricity markets is to ensure access to a more diversified range of power generation capacity, which in turn is expected to increase the security of electricity supply and improve the reliability of the electricity system by reducing the cost of maintaining adequate generation capacity. In this regard, we identify two important issues affecting the integration of European electricity markets. First, according to standard trade theory (see e.g. Grossman and Helpman, 1994; Matsuyama, 2000), the benefits of market integration[6] (e.g. less need for a large reserve margin[7] or outright capacity markets[8]) (Agora-Energiewende, 2015; Baritaud and Volk, 2014; UN, 2006) are largest exactly when Germany and France employ dissimilar generation mixes. However, in these exact hours, the congestion of interconnection capacities is most likely to occur, and the full benefits of trade cannot be obtained. Second, technology mixes in Germany and France have become more dissimilar in recent years, which can be seen by the decrease of the average *GMSI* from 0.78 in 2011 to 0.59 in 2014. Clearly, enormous investment in the wind and solar generation capacities paralleled by the nuclear phase-out in Germany have made generation mixes very different to those of its neighbour France. This further increases the need for additional investment to increase the interconnection capacity in order to complete full market integration, and thus obtain the advantages of increasing diversification. However, additional interconnection capacity is linked to huge investments that are sunk once made.

We also find that the integration of two adjacent electricity markets heavily depends on the influences from neighbouring markets. Increasing the interconnection capacity between France and Italy would increase price spreads and the likelihood of congestion between Germany and France.[9] Likewise, wind electricity in Denmark strongly affects the probability of interconnection congestion between Germany and France in the same way as German wind electricity does. Hence, externalities from cross-border trade matter for European electricity markets, and therefore deciding on purely national energy policies to solve the main problems, such as the integration of renewables and security of supply, may not represent an efficient approach.

This paper is organised as follows. Section 2 reviews the literature to date and the actual developments in European electricity markets. Section 3 discusses the generation mix similarities and integration of adjacent electricity markets, and describes the construction of the *GMSI*. Data and variables are described in Section 4. Section 5 describes the empirical strategy. Section 6 shows the main empirical findings. Section 7 presents conclusions.

2. Literature review of internal European electricity markets

The existing literature is mainly focussed on assessing the degree of integration of European electricity markets (e.g. Böckers et al., 2013; Da Silva and Soares, 2008; Zachmann, 2008). Some studies assess the impacts of certain national energy policies on the integration of European electricity markets.

The EC has adopted three Energy Packages (96/92/EC, 2003/54/EC and, 2009/72/EC) over the last two decades in order to establish an internal European electricity market and decarbonize its electricity supply. Therefore, investment has been made to reduce interconnection capacity limitations, which directly supports market integration. In this context, the EC has identified energy infrastructure priorities for 2020 and beyond, and has proposed guidelines for the development of a European energy infrastructure (EC, 2011).

Jamasb and Pollit (2005) report that European member states have been pursuing two parallel policies designed to establish an internal European electricity market: (a) liberalisation of national markets, and (b) increasing cross-border capacities, while at the same time improving cross-border trading rules, e.g. promotion of market coupling.[10] They also emphasise the importance of unbundling of vertically integrated monopolies to introduce competition in both generation and retail supply. Although unbundling was designed to foster both static and dynamic efficiency, Gugler et al. (2013) find a negative impact of ownership unbundling on investment in transmission capacity. This is worrying because investment in additional transmission capacity is crucial to integrate European electricity markets and will ensure a smooth transition toward a low carbon electricity generation system (Agora-Energiewende, 2015; Fürsch et al., 2013). In addition, Lise et al. (2008) emphasise that under perfect competition conditions the level of market integration is constrained by interconnection capacities and cross-border technology differences. Castagneto-Gissey et al. (2014) also point out that market integration depends on the technology mix. A novel feature of the present study is that we employ quantitative measures for both cross-border technology differences (following Jaffe, 1986) and interconnection capacities.

Generally, EU member states employ quite different electricity generation structures due to their different natural resources and political priorities. In the last decade, in an attempt to decarbonize the

[4] Because Germany and Austria constitute one spot market-pricing zone, we refer to this pricing zone as Germany.

[5] For studies on market integration, see, e.g., De Vany and Walls (1999); Gugler et al. (2018); Keppler et al. (2016); Nepal and Jamasb (2012); Nitsche et al. (2010); Pellini (2012); Zachmann (2008).

[6] The reader is referred to Agora-Energiewende (2015), Baritaud and Volk (2014), OECD/IEA (2014) and UN (2006), which summarize the benefits of market integration.

[7] A country's reserve margin measures the difference between the peak electricity generating capacity and the peak demand (Joskow, 2007). Countries mostly hold reserve generation capacities, which is very costly, to respond to short- and long-run outages (e.g. overnight solar electricity, hydroelectricity in a year with little rainfall, etc.), and thus ensure security of supply.

[8] Capacity markets remunerate electricity firms not only for actually producing and delivering electricity, but also for holding available generation capacity. The core idea of capacity markets is to assure sufficient generation capacities when they are necessary (Cramton and Ockenfels, 2012). This also increases the costs of electricity supply.

[9] In section 3, we thoroughly discuss this relationship.

[10] Market coupling entails the simultaneous auctioning of available transfer capacity and electricity. Hence, it promotes the efficient allocation of interconnector capacity.

electricity supply (Directive 2009/28/EC) many countries have introduced diverse support schemes to promote renewable technologies. As a result, wind and solar generation capacity is highly concentrated in some EU member states, such as Germany, Spain and Great Britain. These three countries account for 56% of the total wind generation in the year 2014, while Germany, Italy and Spain account for 78% of the total solar generation (ENTSO-E, 2015). Despite the German nuclear phase-out in 2011 after the Fukushima reactor accident in Japan, some EU member states (France, Finland, Poland, Slovakia, Bulgaria and Romania) are still constructing nuclear power plants (EC, 2015). If these changes in the technology mixes among European countries, which are mainly driven by national energy policies, are not associated with an adequate regulatory policy to foster transmission and interconnection capacity investment, they may generate serious obstacles to the establishment of an integrated European electricity market.[11]

Gugler et al. (2018) report that market integration increased from 2010 to 2012; however, partly due to the increased feed-in from the intermittent use of renewables, integration then decreased until 2015. Gianfreda et al. (2016) also note that one of the reasons why European spot markets are becoming less integrated is the increased share of renewable electricity. In addition, Gugler et al. (2018) find that the efficiency of integration (measured by the speed of price adjustment) was quite modest. They emphasise the importance of additional investment in interconnection capacities and the further promotion of market coupling for integrating European electricity markets.

Keppler et al. (2016) use hourly data for German wind and solar electricity and French nuclear generation from November 2009 until June 2013 and assess their impact on the convergence of German and French spot prices and on the congestion of interconnection capacities. According to the authors, additional wind and solar electricity in Germany increases the likelihood of interconnection congestion, and thus hampers price convergence, while nuclear generation in France has the opposite effect. In contrast to Keppler et al. (2016), we specifically control for the *GMSI* and trade with a third country, which is important as we will later argue.

The literature also identifies spill over effects from national unilateral energy policies. In this regard, Grossi et al. (2018) investigate the impacts of the German nuclear phase out and the expansion of renewables driven by fixed feed-in tariffs on the energy markets of neighbouring countries. They find that nuclear phase out caused a price increase in neighbouring spot prices of up to 19%, while renewable energy generation caused a price decrease of up to 0.17% for each 1% of additional generation from German renewables. This underlines the importance of a coordinated approach to European energy policy.

Although an integrated European electricity market would ensure better security of electricity supply, governments still drive national energy policies primarily with regard to the security of electricity supply, which is not in line with the efforts of the EU to establish an internal European electricity market (Grigorjeva, 2015). Many EU member states[12] have implemented different capacity remuneration mechanisms because energy-only markets, heavily distorted by national low-carbon policies, may provide inefficient price signals for long-term investment[13] (Ellenbeck et al., 2015). The introduction of these mechanisms in several EU member states has resulted in some countries selecting an isolated approach toward addressing the concerns relating to the security of electricity supply, even though the security of electricity supply has become a regional issue (Eurelectric, 2016). Booz&Co (2013) report that national-based approaches to ensure the security of supply will cost EU member states between €3 and 7 billion per year. Moreover, these approaches may: (1) induce changes in the composition of generation mixes across EU member states; (2) create institutional barriers to market integration, and thus represent a considerable risk in achieving an internal European electricity market; and (3) cause market distortions, such as hampering competition (Mastropietro et al., 2015; Zgajewski, 2015).

3. Generation mix similarities and market integration between neighbouring markets

Electricity day-ahead spot markets first construct hourly merit order curves and then use the demand for electricity to determine the marginal power plants whose marginal costs determine the spot price at that particular hour in a competitive market. A feature of European electricity markets is that they employ different technology mixes, which means that different technologies meet the demand in each hour of the day. In this section, we graphically illustrate how the structure of the generation mixes of two adjacent markets affects spot price spreads.

Electricity is a homogenous good in terms of its physical properties. Additionally, we assume that there is no abuse of market power (Graf and Wozabal, 2013). Fig. 1 shows actual generation capacity data ordered according to the marginal costs of production by generation technology[14] in market A (France) and neighbouring market B (Germany). Market A has quite a flat merit order curve based on the high share of water and nuclear capacities, which becomes very steep at the end due to the low share of peak-load technologies with high marginal costs.[15] On the other hand, the flat section of the merit order curve in market B is strongly dependent on the level of intermittent renewable generation, while the second part is relatively steep because of the high share of coal and then gas power plants.

In Fig. 1, we show markets A and B, with equal national demand schedules ($D_A^{off-peak} = D_B^{off-peak} and D_A^{peak} = D_B^{peak}$). In both periods, peak and off-peak, and under autarky, the price in market A is lower than in market B ($P_A^{off-peak} < P_B^{off-peak} and P_A^{peak} < P_B^{peak}$). Note that when demand peaks the price spreads between markets A and B become smaller ($\Delta P^{peak} < \Delta P^{off-peak}$),[16] if the generation technologies become more similar. If trade between markets A and B is supported with only a limited interconnection capacity, interconnection capacity congestion is less likely to occur when demand peaks, because the generation mixes are more similar, than in off-peak periods, where generation mixes are less similar (see also Mutreja et al., 2014; Zachmann, 2008).

[11] One recent example is the splitting up of the German-Austrian day-ahead price zone (ACER, 2015), which will be implemented by October 2018. As a result of the massive deployment of wind and solar energy, and the lack of an adequate regulatory policy to promote investment in additional transmission capacities in Germany, the high level of green power from wind and solar farms in Germany affects network stability not only in Germany, but also in neighbouring countries, e.g. Poland and the Czech Republic. The huge amount of green electricity from wind parks in north Germany cannot be transmitted to the consumers located in south Germany and Austria because of the congested transmission capacity within Germany. Therefore, electricity flows through indirect routes, namely Poland and Czech Republic – looping around the congestion (CEPS, MAVIR, PSE and SEPS, 2013).

[12] Belgium, Finland, Great Britain, Ireland, Italy, Lithuania, Poland, Portugal, Spain and Sweden.

[13] Cramton et al. (2013) thoroughly discuss capacity remuneration mechanisms.

[14] All types of renewables (wind, solar, geothermal, pellets, etc.), hydro, nuclear, coal, gas and oil power plants.

[15] Renewables and hydro power plants (i.e. run of the river) with essentially zero marginal costs and nuclear power plants with relatively low marginal costs are located in the flat section of the merit order curve. Note that wind and solar electricity is quite volatile hour by hour, while hydro generation is characterised only by seasonal fluctuations. Like nuclear power plants, various types of coal power plants have a low level of generation flexibility. Usually, renewables, hydro, nuclear and coal power plants are known as base-load technologies. Various types of gas and oil power plants have both a high level of generation flexibility and marginal costs and, as such, are known as peak-load technologies.

[16] $\Delta P^{off-peak} = P_B^{off-peak} - P_A^{off-peak}; \Delta P^{peak} = P_B^{peak} - P_A^{peak}$.

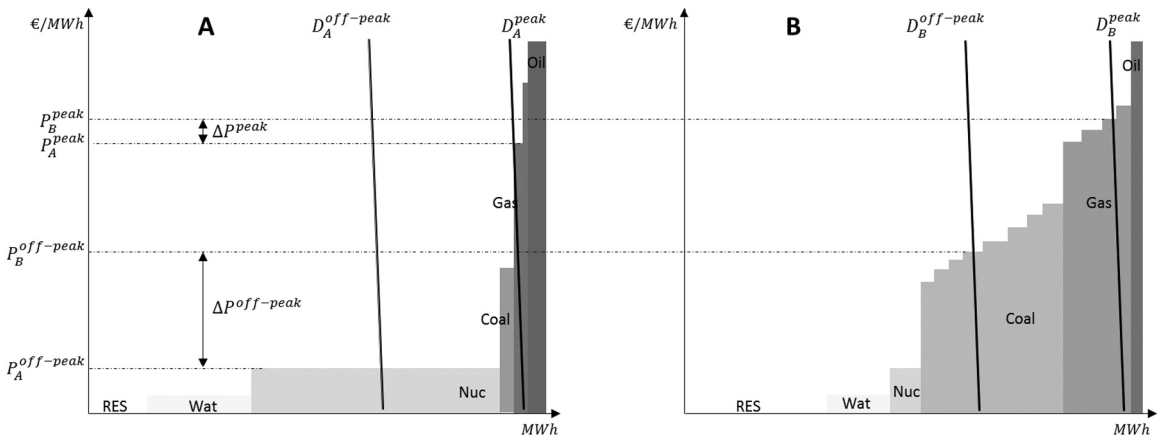

Fig. 1. Generation mixes and price convergence.

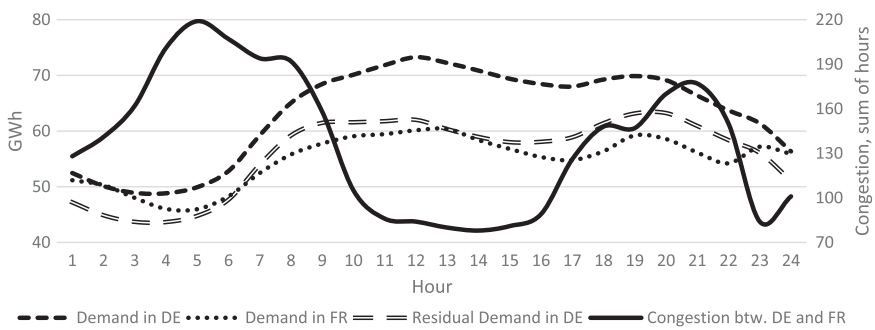

Fig. 2. Hourly average load in Germany (DE) and France (FR) (GW) and the number of congested hours per hour of the day in 2011.

The above analysis makes clear that inframarginal technologies[17] are important for price convergence and absence of congestion (abstracting from trade) from an ex ante perspective (i.e. before demand and supply realizations materialized), and therefore for security of supply considerations. They matter for how likely marginal technologies and therefore prices are similar or equal ex ante. In that sense our index of similarity of production technologies, GMSI, measures how likely marginal technologies and therefore prices will be similar or equal (abstracting from trade) in an ex ante perspective.

Fig. 2 shows hourly average demand in Germany (*DE*) and France (*FR*) and residual demand in Germany (left axis) and the number of congested hours per hour of the day between Germany and France (right axis) in 2011. It can be seen that as the demand peaks in Germany (dashed line) and France (dotted line) the number of congested hours decrease. Accordingly, in addition to demand levels, generation mix similarities and interconnection capacities determine the likelihood of interconnection capacity congestion and the level of price spreads in the presence of increasing marginal cost (supply) schedules and limited interconnection capacity (Castagneto-Gissey et al., 2014; Jamasb and Pollit, 2005; Lise et al., 2008; Zachmann, 2008). Note that this kind of 'convergence' is not only driven by the forces of arbitrage backed by interconnection capacities, but also by the increased similarity of the generation mix that occurs in peak periods.

3.1. GMSI

To measure the similarity of generation structures between the German and French electricity markets we follow Jaffe (1986)[18] and construct a *GMSI* for each hour using specific information from the German and French merit-order curves (see Appendix A). We identify 70 different generation technology classes[19] in Germany and France, and denote electricity generated by generation technology class τ for hour h in Germany and France, respectively, by $g_{DE,\tau,h}$ and $g_{FR,\tau,h}$. Using the example of Germany, total electricity generation $g_{DE,h} = \sum_{\tau=1}^{70} g_{DE,\tau,h} = d_{DE,h}$ meets demand $d_{DE,h}$ in a certain hour, h. The vector $T_{DE,\tau,h} = \frac{g_{DE,\tau,h}}{g_{DE,h}}$ is the share of electricity generated by the generation technology class τ over total electricity generation for a specific hour, h. The Jaffe index between German and French merit orders (i.e. supply curves) up to their intersection with their demand curves is used as a measure of the similarity of the generation mixes:

$$GMSI_{DE,FR,h} = \frac{T_{DE,\tau,h}\, T'_{FR,\tau,h}}{(T_{DE,\tau,h}\, T'_{DE,\tau,h})^{1/2}(T_{FR,\tau,h}\, T'_{FR,\tau,h})^{1/2}} \tag{1}$$

$T_{DE,\tau,h}\, T'_{FR,\tau,h}$ is the uncentered covariance between the share of electricity in Germany and France generated by generation technology class (τ) at a specific hour (h). The advantage of $GMSI_{DE,FR,h}$ is that it normalizes the uncentered covariance on the standard deviations of the share vectors. As a result, $GMSI_{DE,FR,h}$ will not automatically rise when generation technology classes are aggregated. $GMSI_{DE,FR,h}$ takes values between zero and one, with a value of zero indicating completely different generation mixes in Germany and France in a given hour, and a value of one indicating that essentially the same technologies are employed in that hour.

[17] In the Appendix A, Fig. A1 shows the frequency distribution of marginal technologies in Germany and France.

[18] Bloom et al. (2013) also employed the same approach as Jaffe (1986) and constructed firm technological and product market proximity measures to estimate R D spillovers.

[19] Generation technology classes differ not only on variable costs per MWh, but also on flexibility and intermittency. Thus, the type of generation technology is the relevant factor to look at when determining the effects on reliability. It could be that two generation types have the same marginal costs but completely different intermittency, start up or ramping characteristics.

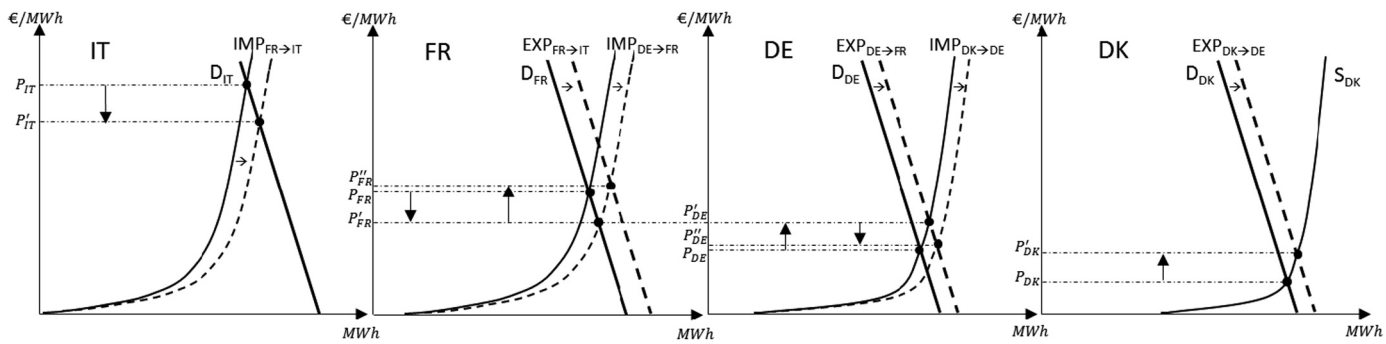

Fig. 3. Integration of German (DE) and French (FR) electricity spot markets and trade with Italy (IT) and Denmark (DK).

3.2. Trade with other neighbouring countries

The standard literature on the integration of electricity markets does not consider trade with a third country. In contrast to Zachmann (2008), who find that market integration is mainly driven by bilateral cross-border trade, we argue that the integration of two adjacent electricity markets is very much dependent on trade with other neighbouring markets. Fig. 3 shows how electricity trade between Germany and Denmark and between France and Italy affects the price spreads of German and French electricity spot markets.

A particularly high share of renewables and other technologies with low marginal costs distinguishes the structure of the merit-order of the Danish (DK) and German (DE) electricity markets from the French (FR) and Italian (IT) markets. Therefore, in an assumed autarky scenario, Danish and German markets obviously meet their national demands at the lowest price followed by France and Italy ($P_{DK} < P_{DE} < P_{FR} < P_{IT}$). According to trade theory, if interconnectors are installed and trade between adjacent markets takes place, electricity flows[20] from low to high price markets.[21] Hence, if Germany exports electricity to France it shifts both the German demand curve D_{DE} ($EXP_{DE\rightarrow FR}$) (dashed line) and the French supply curve S_{FR} to the right ($IMP_{DE\rightarrow FR}$) (dashed line). Accordingly, the equilibrium price in the French market decreases ($P_{FR} > P'_{FR}$) and in the German market it increases ($P_{DE} < P'_{DE}$). Thus, the two markets have one uniform electricity spot price ($P'_{FR} = P'_{DE}$) in those hours with abundant interconnection capacity.

If France at the same time exports electricity to Italy, shifting both the French demand curve D_{FR} ($EXP_{FR\rightarrow IT}$) (dashed line) and the Italian supply curve S_{IT} to the right ($IMP_{FR\rightarrow IT}$) (dashed line), the equilibrium price in Italy decreases ($P_{IT} > P'_{IT}$) and in France it increases ($P'_{FR} < P''_{FR}$).[22] Note that these standard trade theory results imply that electricity exports from France to Italy increase the price spreads ($(P''_{FR} - P'_{DE}) > (P'_{FR} - P'_{DE})$) and the likelihood of congestion between Germany and France because of the limited interconnection capacity.

Another example is provided by Denmark. If Denmark exports its abundant supply of wind electricity to Germany, it shifts both the demand curve D_{DK} ($EXP_{DK\rightarrow DE}$) (dashed line) and the supply curve S_{DE} ($IMP_{DK\rightarrow DE}$) (dashed line). This leads to a price decrease in Germany ($P'_{DE} > P''_{DE}$) and a price increase in Denmark ($P_{DK} < P'_{DK}$). The price decrease in Germany further increases price spreads to France ($(P''_{FR} - P''_{DE}) > (P''_{FR} - P'_{DE})$) and the likelihood of congestion.

Regulation EC 714/2009 introduces network codes that apply to capacity allocation and congestion management (CACM) between European electricity markets. The CACM network codes call for the usage of both available transfer capacity (ATC) and flow based (FB) methods for capacity calculation. The data we employ cover the period between 2011 and 2014 characterised by the ATC method. The CACM network codes allow risk hedging through long-term physical transmission rights with the option to use it or sell it (UIOSI). A holder of a certain cross border capacity right has the right to sell it or use that particular interconnection capacity by transmitting a certain amount of electricity in a certain time in one direction from one market to the other. If the holder uses his right to transmit electricity, he is obliged to nominate it to the TSO before the calculation of the ATC in the day-ahead market takes place. The UIOSI option allows the TSOs to make the non-nominated capacity available for the day-ahead allocation. So, the amount of cross-border capacity available in the day-ahead market is the sum of capacity allocated for the day-ahead market plus the unused cross-border capacities that has been allocated in long-term contracts (ETSO, 2001; EC, 2009; Booz&Co, 2013).

In summary, in markets with increasing marginal cost (supply) schedules and limited cross-border capacity (e.g. in electricity markets) cross-border externalities abound. For example, exporting from France to Italy and importing from Denmark to Germany increase spot price spreads and the likelihood of congestion between Germany and France.

4. Data and variables

We consider the German and French electricity markets because they together account for nearly 40% of the EU-28 total electricity generation in 2014 (Eurostat, 2014), and they also play a central role in the process of European electricity market integration because they are interconnected with 13 other European electricity markets. The empirical analysis uses an extensive data set that covers the period from 01.04.2011 to 31.12.2014. Hourly electricity spot prices are derived from the respective power exchanges: the European Power Exchange (EPEX Spot) for Germany and France and Gestore del Mercato Elettrico (GME) for Italy. We acquire generation capacities by plant type and construction year for Germany and France from Platts Power Vision. The Energy Economics Group (EEG) from the Technical University of Vienna (TU) and Austrian Power Grid (APG) provide information regarding the availability of power plants and efficiency factors by plant type, turbine type and construction year. Together with information from other sources, we combine these data sets to construct the merit orders for each hour in both the German and French electricity markets (see Appendix A).

Hourly load data for Germany and France are obtained from the European Network of Transmission System Operators for Electricity (ENTSO-E). Hourly day-ahead forecasts for electricity generation from intermittent renewables (wind and solar) in Germany are obtained from the German TSOs (TransnetBW, Tennet, 50hertz and Amprion) and the Austrian TSO, APG. French hourly day-ahead wind forecasts and nuclear generation data are obtained from the French TSO, Réseau de Transport d'Électricité(RTE). Hourly day-ahead forecasts for wind electricity in east and west Denmark are obtained from Energinet. Hourly data for available transfer capacities (*ATCs*) and scheduled

[20] Please note that we use day-ahead market data and as such we always refer to schedules and not metered values.

[21] See Baldwin and Wyplosz (2015) for a thorough discussion on open-economy supply and demand curves.

[22] Due to congested interconnection capacities, uniform prices between France and Italy are rarely observed.

cross-border flow in the day-ahead market (S_CBF_DAM) between Germany and France and between France and Italy are obtained from the capacity allocation service company for central Europe (CASC).

4.1. Dependent variables

We employ two different dependent variables, namely the absolute values of spot price spreads and a dummy for interconnection capacity congestion between Germany and France. The absolute values of spot price spreads are defined as $Spread_{DE,FR,h} = |P_{DE,h} - P_{FR,h}|$.[23] To obtain the *interconnection capacity congestion between Germany and France*, $ICC_{DE,FR,h}$, we first calculate the difference between $ATC_{DE,FR,h}$ and $S\_CBF\_DAM_{DE,FR,h}$, and then generate the variable available interconnection capacity, $AIC_{DE,FR,h} = ATC_{DE,FR,h} - S\_CBF\_DAM_{DE,FR,h}$. If $AIC_{DE,FR,h} = 0$, the interconnection capacity is congested, while $AIC_{DE,FR,h} > 0$ indicates free interconnection capacity. The dummy variable $ICC_{DE,FR,h}$ is zero if $AIC_{DE,FR,h} > 0$ indicating no congestion, otherwise it has a value of one.

4.2. Main variables

The following four variables are of most interest: (1) the $GMSI$ of the German and French electricity markets; (2) the interconnection capacity between Germany and France; (3) the interconnection capacity between France and Italy; and (4) wind electricity forecasts in Denmark.[24] We additionally control for wind and solar generation forecasts in Germany, nuclear generation and wind generation forecasts in France, load in Germany and France, and day of the week, yearly and holiday dummies. Next, we make a detailed description of our explanatory variables and their expected effect on our dependent variables, $Spread_{DE,FR,h}$ and $ICC_{DE,FR,h}$.

Generation mix similarity index of German and French electricity markets, $GMSI_{DE,FR,h}$. All other things being equal, we expect a low (high) $GMSI_{DE,FR,h}$ (relatively dissimilar (similar) generation mix) to increase (decrease) interconnection congestion and spot price spreads, as shown in Section 3.

Interconnection capacity between Germany and France, $IC_{DE,FR,h}$, takes the value of $ATC_{DE\rightarrow FR,h}$ when $S\_CBF\_DAM_{DE\rightarrow FR,h} > 0$ and $ATC_{FR\rightarrow DE,h}$ when $S\_CBF\_DAM_{FR\rightarrow DE,h} > 0$.[25] Thus, $IC_{DE,FR,h}$ measures the interconnection capacity in GW between Germany and France in a certain hour, h. We expect that increasing the interconnection capacity between Germany and France would decrease both spot price spreads and the likelihood of congestion.

Interconnection capacity between France and Italy, $IC_{FR,IT,h}$, takes the value of $ATC_{FR\rightarrow IT,h}$ when $P_{FR,h} < P_{IT,h}$ and of $ATC_{IT\rightarrow FR,h}$ when $P_{FR,h} > P_{IT,h}$. As such, it measures interconnection capacity in GW between France and Italy. In Section 3, we present the impact of trade with a third country on market integration between two adjacent markets. We envisage that increasing the interconnection capacity between France and Italy would lead to an increase in spot price spreads, $Spread_{DE,FR,h}$, and in the likelihood of congestion of the interconnection capacities, $ICC_{DE,FR,h}$. This is likely to occur because France exports to Italy in about 90% of all hours, because electricity spot prices are higher in Italy. Thus, when more capacity becomes available, France is likely to export more to Italy, and as a result French spot prices will increase (Baldwin and Wyplosz, 2015). However, this would increase the average price spread between Germany and France, because French electricity prices are already higher on average. This logic also leads us to expect that a larger interconnection capacity between France and Italy would lead to a higher likelihood of congestion between Germany and France.

We introduce *wind electricity forecast in Denmark*, $W_{DK,h}$, to control for the impact of renewable policies in a third country. Denmark is a good example because of the huge amount of wind electricity generated in the country. Denmark exported wind generated electricity to Germany in approximately 65% of the hours from 2011 to 2014, and the number of hours with equal prices between Germany and Denmark (east and west) is very high and increases over time. Thus, exports of cheap wind electricity to Germany are likely to further decrease German spot prices, which results in a larger spread between German and French spot prices.[26]

The wind and solar electricity forecasts in Germany, $W_{DE,h}$ and $S_{DE,h}$, are introduced to control for German wind and solar electricity generation. Every additional GW of low cost electricity generated from renewables in Germany decreases the spot price in Germany due to the well-known merit-order effect (Gelabert et al., 2011; Hirth, 2016; Jonsson et al., 2010; Sensfuß et al., 2008; Woo et al., 2011; Würzburg et al., 2013), and would therefore increase spot price spreads and the likelihood of congestion of electricity flows between Germany and France. Hence, like Keppler et al. (2016), we envisage that additional $W_{DE,h}$ and $S_{DE,h}$ would increase price spreads between Germany and France (by decreasing German spot prices), because Germany is the net exporting market area. At the same time, we expect that additional wind and solar electricity in Germany would increase the likelihood of congestion, because more electricity exports would be necessary to achieve price equality.

Nuclear generation and wind electricity forecasts in France, $N_{FR,h}$ and $W_{FR,h}$, are introduced to control for the high amounts of French nuclear and wind electricity generation. Nuclear electricity has very low marginal costs, and therefore we expect that nuclear generation in France would exert a downward pressure on the spot price level in France and, because France mostly imports from Germany, also on spot price spreads, as well as on the likelihood of interconnection capacity congestion between Germany and France. Wind electricity in France, $W_{FR,h}$, is envisaged to have the same effect on price spreads and congestion.

Loads in Germany and France, $L_{DE,h}$ and $L_{FR,h}$, are introduced to control for electricity demand on both sides of the border. Because France imported from Germany in most hours between 2011 and 2014 (implying $P_{DE} < P_{FR}$), we expect that an increase in demand for electricity in Germany would increase the spot price in Germany and lead to lower spot price spreads in France. We envisage the opposite effect for an increase in demand for electricity in France. The same logic could be applied to interconnection capacity congestion, i.e. more load in Germany would decrease congestion, whereas more load in France would increase congestion.

Tables 1 and 2 show the definition of variables, expected signs, and the source of the data, as well as all descriptive statistics. Wholesale spot prices are lower on average in Germany than in France (40.5 versus 42.6 €/MWh). Negative spot prices in Germany and France appear in 195 and 37 h, respectively. The average absolute spread is 5.3 €/MWh. In 45% of the hours, the interconnection capacity between Germany and France is congested and thus prices spreads are positive. The average $GMSI$ is 0.64; however, the $GMSI$ has values across almost the whole range between zero and one. Thus, there is huge variation in

[23] On 9 February 2012 between 9 a.m. and 12 p.m., French spot prices lay between 967 and 1939 €/MWh. In the empirical analysis, we filter out these extreme values.

[24] We introduce Italy because France has the highest interconnection capacity with Italy and exports mostly to Italy. Denmark is introduced due to: (1) a high share of wind electricity generation capacity, and (2) the availability of data over a long period. We also check the interconnection capacities with Spain, Sweden, Czech Republic, Hungary and Slovenia. The data for these countries are only available for short periods and therefore we do not report the results. The results are available upon request.

[25] After market coupling day-ahead cross-border capacities can be allocated either from Germany to France or from France to Germany. This implies that when $S\_CBF\_DAM_{DE\rightarrow FR,h} > 0$ then $S\_CBF\_DAM_{FR\rightarrow DE,h} = 0$ and vice versa.

[26] Section 3 and Fig. 3 show the impacts of exporting low marginal cost wind electricity from Denmark to Germany on German and French price spreads.

Table 1
Description of variables, sources and expected signs.

Variable name	Description	Source	Expected sign: $Spread_{DE,FR,h}$	Expected sign: $ICC_{DE,FR,h}$
Dependent variables				
$Spread_{DE,FR,h}$	Absolute value of spot price spreads between Germany and France, in €/*MWh*	EPEX		
$ICC_{DE,FR,h}$	Derived from available transfer capacities (*ATCs*) and scheduled cross-border flow in the day-ahead market (*S_CBF_DAM*) between Germany and France. A value of one indicates congestion of interconnection capacities and a value of zero indicates no congestion.	CASC		
Main hypotheses				
$GMSI_{DE,FR,h}$	Measures the similarity of generation mix structures between Germany/Austria and France. It lies between zero and one.	*Several*[a]	(-)	(-)
$IC_{DE,FR,h}$	Interconnection capacity between Germany and France in *GW*	*CASC, EPEX*	(-)	(-)
$IC_{FR,IT,h}$	Interconnection capacity between France and Italy in *GW*	*CASC, EPEX, CASC*	(+)	(+)
$W_{DK,h}$	Forecasts for wind electricity generation in Denmark (sum of wind generation in both east and west Denmark) in *GW*	*Energinet*	(+)	(+)
Other control variables				
$W_{DE,h}$	Forecasts for wind electricity generation in Germany in *GW*	*German TSOs*[b]	(+)	(+)
$S_{DE,h}$	Forecasts for solar electricity generation in Germany in *GW*	*German TSOs*	(+)	(+)
$N_{FR,h}$	Nuclear generation in France in *GW*	*RTE*	(-)	(-)
$W_{FR,h}$	Forecasts for wind electricity generation in France in *GW*	*RTE*	(-)	(-)
$L_{DE,h}$	Load in Germany in *GW*	*ENTSO-E*	(-)	(-)
$L_{FR,h}$	Load in France in *GW*	*ENTSO-E*	(+)	(+)

[a] Platts Power Vision, APG, RTE, TransnetBW, Tennet, 50hertz and Amprion, E-Control, EEG – Technical University of Vienna (TU), Energy Agency, European Energy Exchange (EEX), the German Federal Office of Economics and Export Control (BAFA), U.S. Energy Information Administration.
[b] APG, TransnetBW, Tennet, 50hertz and Amprion.

Table 2
Descriptive statistics.

Variable name	Observations	Mean	Std. Deviation	Min	Max
$P_{DE,h}$	32,904	40.36	16.92	− 221.99	210.00
$P_{FR,h}$	32,900	42.63	19.02	− 200.00	605.21
$\boldsymbol{P_{DE,h} > P_{FR,h}}$**:**					
$P_{DE,h}$	4888	37.73	14.30	− 5.03	130.27
$P_{FR,h}$	4888	27.11	16.59	− 200	86.21
$\boldsymbol{P_{DE,h} < P_{FR,h}}$**:**					
$P_{DE,h}$	9820	36.54	18.23	− 221.00	210.00
$P_{FR,h}$	9820	49.43	20.37	− 5.07	605.21
$\boldsymbol{P_{DE,h} = P_{FR,h}}$					
$P_{DE,h}$	18,192	43.13	16.32	− 100.03	175.55
$P_{FR,h}$	18,192	43.13	16.32	− 100.03	175.55
Dependent variables					
$Spread_{DE,FR,h}$	32,900	5.43	11.14	0.00	480.25
$ICC_{DE,FR,h}$	32,904	0.45	0.50	0.00	1.00
Main explanatory variables					
$GMSI_{DE,FR,h}$	32,904	0.64	0.15	0.01	0.99
$IC_{DE,FR,h}$	32,904	2.21	0.58	0.00	3.67
$IC_{FR,IT,h}$	32,904	0.74	0.72	0.00	3.58
$W_{DK,h}$	32,904	1.26	1.00	0.00	4.89
Other control variables					
$W_{DE,h}$	32,904	5.88	4.82	0.32	29.30
$S_{DE,h}$	32,904	3.23	5.00	0.00	24.50
$N_{FR,h}$	32,904	46.21	6.33	14.25	61.04
$W_{FR,h}$	32,904	1.64	1.12	0.10	7.37
$L_{DE,h}$	32,904	62.38	11.79	34.48	89.94
$L_{FR,h}$	32,904	54.10	12.02	29.70	102.10

Note: The data relating to load, nuclear, wind and solar forecasts and interconnection capacities are in *GW*. $GMSI_{DE,FR,h}$ is an index that takes values between zero and one. $P_{DE,h}$, $P_{FR,h}$ and $Spread_{DE,FR,h}$ are in €/*MWh*. The other variables are dummies.

the similarity of generation mixes in Germany and France across the hours studied. $IC_{DE,FR,h}$ and $IC_{FR,IT,h}$ take values between 0 and 3.67, and 0 and 3.58, respectively. There are 37 and 432 h with $IC_{DE,FR,h} = 0$ and $IC_{FR,IT,h} = 0$. Although $IC_{DE,FR,h}$ and $IC_{FR,IT,h}$ have almost the same minimum and maximum value, the mean for $IC_{DE,FR,h}$ is higher, while $IC_{FR,IT,h}$ has a higher standard deviation.

Table 3
Dependent variables and $GMSI_{DE,FR,h}$, 2011–2014.

Variable name	2011	2012	2013	2014
$ICC_{DE,FR,h}$	41%	37%	53%	49%
$Spread_{DE,FR,h}$	4.46	4.52	7.76	4.75
$GMSI_{DE,FR,h}$	0.78	0.63	0.60	0.59

Table 3 shows the development of the dependent variables and $GMSI_{DE,FR,h}$ between 2011 and 2014. It can be seen that in the year 2011 the interconnection capacity was congested in 38% of all hours, with a further increase to around 50% in more recent years. Note that $GMSI_{DE,FR,h}$ decreased from 0.78 in 2011 to 0.59 in 2014, which implies that generation technologies have become less similar in recent years.

5. Empirical model

First, we estimate the impacts of $GMSI_{DE,FR,h}$ and other control variables on the magnitude of spot price spreads between German and French electricity spot markets,

$$\begin{aligned} Spread_{DE,FR,h} = {} & \varphi_1 Spread_{DE,FR,h-1} + \beta_1 GMSI_{DE,FR,h} + \theta_1 IC_{DE,FR,h} \\ & + \mu_1 IC_{FR,IT,h} + \omega_1 W_{DK,h} + \pi_1 W_{DE,h} + \rho_1 S_{DE,h} + \epsilon_1 N_{FR,h} \\ & + \tau_1 W_{FR,h} + \gamma_1 L_{DE,h} + \delta_1 L_{FR,h} + D_h' \partial_1 + \varepsilon_{1,h} \end{aligned} \quad (2)$$

The subscript h indicates the frequency of observations (hours). The dependent variable is $Spread_{DE,FR,h}$, which we define as the absolute value of the difference between the German and French spot electricity prices. The one hour lagged dependent variable is included to control for intraday demand and supply rigidities.[27] We use a simple ordinary least squares (OLS) estimator to estimate Eq. (1). β_1 measures the impact of $GMSI_{DE,FR,h}$ on the price spread. θ_1 measures the impact of the interconnection capacity between Germany and France on the price

[27] For example, most conventional power plants (nuclear and coal) cannot adjust their generation from hour to hour over the day due to fixed start-up and ramping costs. When we exclude this variable, the results are unchanged.

spread. μ_1 is the coefficient of the interconnection capacity between France and Italy. ω_1 is the coefficient for day-ahead forecasts for wind electricity in Denmark. π_1 and ρ_1 measure the impact of day-ahead forecasts of wind and solar electricity in Germany on the price spread, respectively. ϵ_1 is the impact of nuclear generation in France on the price spread. τ_1 is the coefficient for day-ahead forecasts for wind electricity in France. γ_1 and δ_1 are the load coefficients in Germany and France, respectively. The vector D includes dummies for the day-of-week, year and holidays.

Second, we estimate the determinants of interconnection capacity congestion. We use a probit model to estimate the impacts of our explanatory variables on the likelihood of interconnection capacity congestion between Germany and France.

$$P(ICC_{DE,FR,h} = 1) = \varphi_2 ICC_{DE,FR,h-1} + \beta_2 GMSI_{DE,FR,h} + \theta_2 IC_{DE,FR,h} + \mu_2 IC_{FR,IT,h} + \omega_2 W_{DK,h} + \pi_2 W_{DE,h} + \rho_2 S_{DE,h} + \epsilon_2 N_{FR,h} + \tau_2 W_{FR,h} + \gamma_2 L_{DE,h} + \delta_2 L_{FR,h} + D_h' \partial_2 + \varepsilon_{2,h} \quad (3)$$

6. Discussion of the main results and robustness

6.1. Main results

Table 4 shows the model results based on Eqs. (2) and (3). All reported standard errors are robust against any form of heteroscedasticity and serial correlation for all specifications. Columns (1) and (2) show the OLS estimation for Eq. (2). Column (1) includes a lagged dependent variable, in column (2) we exclude the lagged dependent variable. For Eq. (3) we employ a probit regression, for which we report the coefficients in columns (3) and (4), the former including and the latter excluding a lagged dependent variable. Note that the lagged dependent variable introduced in Eq. (2) does not imply inconsistency in the very large time series data sets we use (see Keele and Kelly, 2006). Moreover, De Jong and Woutersen (2011) prove the validity of the dynamic probit model, and Kauppi and Saikkonen (2008) find that dynamic probit models outperform the static models. As in previous studies, we assume that demand for electricity is exogenous, because of its negligible short-term elasticity (see, e.g., Borenstein, 2009; Fabra and Reguant, 2014; Green and Newbery, 1992). We perform Philips-Perron, Augmented Dickey Fuller and Dickey Fuller GLS unit root tests. All tests reject the null hypothesis of the existence of a unit root (the results are reported in Table A5 in the Appendix A). We additionally check for the correlation coefficients between German load, wind and solar forecast and French load, wind forecast and nuclear electricity (see Table A3 in the Appendix A). Almost all estimated correlation coefficients are below 0.5, which do not give rise to severe collinearity concerns.

Table 4
Regression Coefficients.

	(1) - OLS $Spread_{DE,FR,h}$	(2) - OLS $Spread_{DE,FR,h}$	(3) - Probit $ICC_{DE,FR,h}$	(4) - Probit $ICC_{DE,FR,h}$
$Spread_{DE,FR,h-1}$	0.6993***			
	(0.0355)			
$ICC_{DE,FR,h-1}$			1.7649***	
			(0.0174)	
$GMSI_{DE,FR,h}$	−2.9171***	−6.4545***	−0.3590***	−0.8062***
	(1.1246)	(1.8092)	(0.1133)	(0.0993)
$IC_{DE,FR,h}$	−1.4135***	−4.3889***	−0.4533***	−0.6965***
	(0.1487)	(0.1229)	(0.0192)	(0.0163)
$IC_{FR,IT,h}$	0.6739***	1.8428***	0.0922***	0.1392***
	(0.0814)	(0.0881)	(0.0135)	(0.0119)
$W_{DK,h}$	−0.0149	−0.1786**	0.0213*	0.0319***
	(0.0487)	(0.0735)	(0.0119)	(0.0103)
$W_{DE,h}$	0.1101***	0.4009***	0.0183***	0.0304***
	(0.0200)	(0.0276)	(0.0033)	(0.0029)
$S_{DE,h}$	0.0242*	0.2005***	0.0188***	0.0308***
	(0.0128)	(0.0205)	(0.0025)	(0.0022)
$N_{FR,h}$	−0.1154***	−0.2077***	0.0070*	0.0225***
	(0.0234)	(0.0414)	(0.0037)	(0.0032)
$W_{FR,h}$	−0.2549***	−0.9109***	−0.0532***	−0.0879***
	(0.0480)	(0.0695)	(0.0098)	(0.0086)
$L_{DE,h}$	−0.1606***	−0.4759***	−0.0365***	−0.0560***
	(0.0175)	(0.0171)	(0.0018)	(0.0015)
$L_{FR,h}$	0.2770***	0.7236***	0.0477***	0.0644***
	(0.0312)	(0.0335)	(0.0025)	(0.0022)
Day_of_week_FE	Yes	Yes	Yes	Yes
Yearly_FE	Yes	Yes	Yes	Yes
Monthly_FE	Yes	Yes	Yes	Yes
Holiday_FE	Yes	Yes	Yes	Yes
Observations	32,899	32,900	32,904	32,904
$R-squared$	0.620	0.208		

Robust standard errors in parentheses.
*** $p < 0.01$.
** $p < 0.05$.
* $p < 0.1$.

Most estimated coefficients of both equations are statistically significant and *all* have the expected sign. The coefficients of the lagged dependent variable (column (1) and (3)), are positive and highly significant, implying persistent price spreads and interconnection capacity congestion stemming from intraday supply and/or demand rigidities. For example, the operators of nuclear and most conventional power plants might not be able or willing to adjust their supply according to demand from hour to hour throughout the day, e.g. due to fixed start-up and ramping costs. In addition, demand is mostly rigid over several hours of the day.

From Table 4, it can be seen that after excluding the lagged dependent variables (column (2) for Eq. (2) and column (4) for Eq. (3)), the long run coefficients of $GMSI_{DE,FR,h}$ and other variables of interest remain very stable.[28] Since we are interested in long-run equilibrium relationship, we discuss only the results presented in columns (2) and (4) in what follows. The negative and statistically significant coefficient of $GMSI_{DE,FR,h}$ (column (2)) indicates that the use of more similar generation technologies in Germany and France significantly decreases price spreads. In addition, from column (4) it can be seen that $GMSI_{DE,FR,h}$ has a negative and statistically significant impact on the probability of interconnection capacity congestion. Ceteris paribus, when $GMSI_{DE,FR,h}$ approaches zero (dissimilar generation mixes) and one (similar generation mixes),[29] the estimated predicted probabilities for congested interconnection capacities are around 66 and 34%, respectively.

We next provide a rough indication of the proportion of hours where we observe 'convergence' that is not driven by forces of arbitrage but by similarity of technology mix. Hence, this kind of price convergence does not deliver diversification benefits and reliability improvements, because it is not backed by interconnection capacities. To disentangle this kind of 'convergence', we first estimate the predicted probabilities of congestion for two different scenarios, i.e. when $GMSI_{DE,FR,h}$ is equal to 0 or 1, and depending on the varying levels of $IC_{DE,FR,h}$ starting at 0 GW (autarky) and reaching 7 GW (the maximum).[30] In Fig. 4 we show these predicted probabilities of congestion (left axis) when $GMSI_{DE,FR,h}$ is 0 (dotted line) and 1 (dashed line) for different levels of interconnection capacity (from 0 to 7GW). For a given cross-border capacity, the predicted probability of congestion is significantly lower if the technologies are more similar. For a given

[28] In column (1), we report short-run coefficients. The long-run coefficient of e.g. $IC_{DE,FR,h}$ can be obtained using the formula $\frac{\theta_1}{1-\varphi_1} = \frac{-1.4135}{1-0.06993} = 4.7007$. Same

[29] We estimate the predicted probabilities of interconnection capacity congestion for $GMSI_{DE,FR,h} = 0$ and $GMSI_{DE,FR,h} = 1$, by fixing other control variables at their means using the Stata command *margins*, *at*$(GMSI_{DE,FR,h} = (0\ 1))$ *atmeans atmeans* (see Torres-Reyna, 2014).

[30] We also calculate congestion probabilities for hypothetical values (between 3.67 and 7 GW) for out of sample prediction.

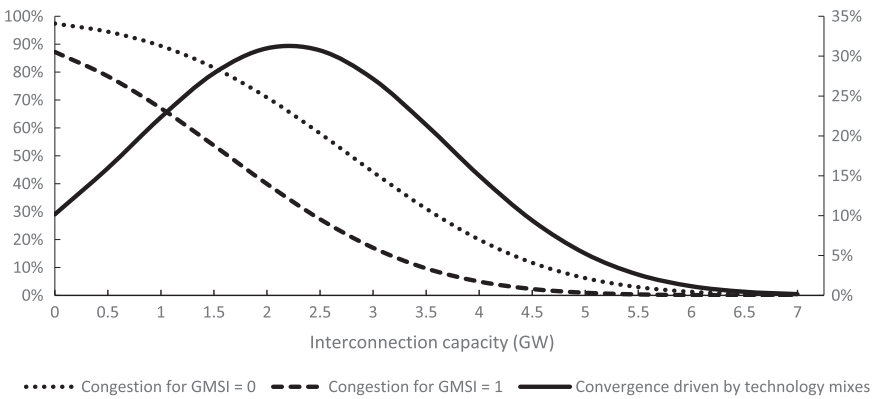

Fig. 4. Probability of congestion and 'convergence' driven by technology mixes relating to the generation mix similarity index (*GMSI*) and interconnection capacity.

cross-border capacity, the difference in the two series is a measure of the predicted decrease in the probability of congestion due to a shift in the similarity of generation from completely different to essentially the same technologies. Thus, this difference in these predicted probabilities gives an indication of the 'price convergence' that has been driven only by similar generation mixes and not by arbitrage due to trade.

It can be seen that the incidence of 'convergence' that has been driven by similar generation mixes (right axis) increases by up to 31% when the cross-border capacity approaches $2.5GW$ ($IC_{DE,FR,h}$ is $2.2GW$ on average), and then decreases at more available interconnection capacities. These results provide evidence that with an abundance of interconnection capacities *GMSI* would not affect the probability of congestion. Fig. 2 shows that the probabilities of 'convergence' that has been driven only by similar technology mixes would go to zero for an interconnection capacity of about $7GW$, i.e. one would need this amount of capacity to achieve full market integration and thus reap all benefits from trade coming from different technology mixes (see also Sinn, 2017).

The supply structures of both German and French markets are most similar during peak times when both predominantly use gas as the marginal technology. In these hours, price spreads are mostly lower or even eliminated (see Table A2 in the Appendix A); consequently the low export volumes at peak times imply an abundance of interconnection capacities and bring about price equality.

Not surprisingly, we find that an increase in German-French interconnection capacity, $IC_{DE,FR,h}$, is associated with significantly lower price spreads and lower probabilities of congestion. Ceteris paribus, the predicted probabilities of congestion between Germany and France for the minimum and maximum interconnection capacities ($IC_{DE,FR,h}$) of $0GW$ and $3.665GW$ (see Table 1) are around 92 and 13%, respectively. On the other hand, increasing the interconnection capacity between France and Italy, $IC_{FR,IT,h}$, would increase both price spreads and the probability of interconnection capacity congestion between Germany and France. Because France mostly imports from Germany, exporting more electricity from France to Italy would further increase the spot price in France relative to the German spot price and as more trade develops capacity would likely become more congested. Thus, all other things being equal, once French and Italian electricity spot markets become better integrated, the integration of German and French electricity spot markets may suffer. All other things being equal, the predicted probabilities of congestion between Germany and France for the minimum and maximum interconnection capacities between France and Italy of $0GW$ and $3.579GW$ (see Table 1) are around 41 and 61%, respectively. Table 3 shows that the export of wind electricity from Denmark also increases the likelihood of congestion between Germany and France. Thus, our results show that externalities are significant in European electricity markets.

We find that electricity generation by wind in Germany increases price spreads and congestion. The same signs are obtained using solar generation in Germany. As expected, wind electricity in France has the exact opposite effects.

Comparing the estimated coefficients in columns (2) and (4) of Table 4, the expectation of negative and positive impacts of $L_{DE,h}$ and $L_{FR,h}$ is confirmed, respectively. On average, German spot prices are lower than French spot prices (see Table 2), and as a result, when the demand for electricity in Germany (France) increases electricity spot prices increase (decrease), and thus, $Spread_{DE,FR,h}$ becomes smaller (larger). This in turn means that high electricity demand in Germany (France) would on average have a negative (positive) impact on the probability of interconnection capacity congestion (column (4)). Load in France has the exact opposite effect.

In summary, the main results of this study are that electricity spot price spreads and the probability of interconnection capacity congestion are significantly reduced if both German and French electricity markets employ very similar generation technology mixes. Therefore, if German and French electricity generation mixes remain very dissimilar, there is a large likelihood of congestion and or large price spreads. Part of the observed 'convergence' is only observed because the generation technologies applied have been similar and not due to the forces of trade/arbitrage backed by interconnection capacities. We further find that a greater interconnection capacity between France and Italy and more wind generation in Denmark positively affect both price spreads and the likelihood of interconnection capacity congestion between Germany and France. All standard predictions of trade theory in markets characterised by increasing marginal cost and limited cross-border trade capacity are borne out by the data. Interdependencies and externalities are clearly the main features of European electricity markets.

6.2. Endogeneity

One may consider that the $GMSI_{DE,FR,h}$ is endogenous with German and French spot prices and thus with both the price spreads and interconnection capacity congestion and, as a result, the OLS and probit estimates are not consistent. In order to address this issue, we employ a two-stage instrumental variables approach and use German and French electricity from renewables ($RES_{DE,h} = W_{DE,h} + S_{DE,h}$; $RES_{FR,h} = W_{FR,h}$)[31] as exogenous instruments for $GMSI_{DE,FR,h}$. Our first-stage estimating equation is thus:

$$GMSI_{DE,FR,h} = \beta_3 RES_{DE,h} + \gamma_3 RES_{FR,h} + X_h \delta_3 + D_h' \partial_3 + \varepsilon_{3,h} \quad (4)$$

Hence, $GMSI_{DE,FR,h}$ is a function of German and French renewables, a vector of control variables (X_h) that are involved in the second-stage, as well as day-of-week, monthly, yearly fixed effects (D) and the error term ($\varepsilon_{3,h}$).

In the second-stage we have two equations, one for $Spread_{DE,FR,h}$

[31] Since France has a relatively low share of solar electricity and no data are available for the period we consider, we take into account only the French wind electricity.

and one for $ICC_{DE,FR,h}$:

$$Spread_{DE,FR,h} = \varphi_4 Spread_{DE,FR,h-1} + \beta_4 G\hat{M}SI_{DE,FR,h} + \theta_4 IC_{DE,FR,h} + \mu_4 IC_{FR,IT,h} + \omega_4 W_{DK,h} + D_h' \partial_4 + \varepsilon_{4,h} \quad (5)$$

and

$$ICC_{DE,FR,h} = \beta_5 G\hat{M}SI_{DE,FR,h} + \theta_5 IC_{DE,FR,h} + \mu_5 IC_{FR,IT,h} + \omega_5 W_{DK,h} + D_h' \partial_5 + \varepsilon_{5,h} \quad (5')$$

The results of 2SLS estimates for Eq. (5) and instrumental variables probit[32] estimates for Eq. (5′) are reported in Table 5, and first-stage results are reported in the. Comparing the results of OLS and 2SLS estimates in Tables 4 and 5, respectively, no big differences can be observed. The same is valid for estimates of probit and instrumental variables probit estimator presented in Tables 4 and 5, respectively. Hence, even after employing a two-stage instrumental variables approach, our results remain robust. Further robustness checks are made available in the.

7. Conclusions and policy implications

The EC has been constantly attempting to harmonise and integrate the historically independent national electricity systems of member states in order to achieve an internal European electricity market. However, the absence of well-coordinated national energy policies across EU member states, despite the implementation of the three Energy Packages, may distort the development of an internal European electricity market. The integration of European national electricity markets necessitates interconnection capacity to make possible electricity flows from one market to another.

We find that the law of one price and no cross-border congestion between Germany and France occurs only in those hours where generation mixes are fairly similar. However, in those hours where generation mixes are dissimilar, prices still diverge and cross-border capacities are still exhausted between Germany and France. Our results show that up to 31% of the 'convergence' in prices is not driven by the forces of arbitrage, but by coincident similarities in the generation structures.

This study identifies two important issues relating to the integration of European electricity markets. First, according to standard trade theory, the integration of two adjacent electricity markets with different technology mixes (low *GMSI*) would provide potentially high integration benefits, but would also require a large investment in interconnection capacity. This would ensure access to a more diversified portfolio of power plants, and thus provide greater security of electricity supply and improve the reliability of the electricity system by reducing the cost of maintaining adequate generation capacity. However, currently not all trade benefits can be obtained if cross-border capacities become congested at exactly the point when generation structures are dissimilar. Second, our index for similarity shows that German and French generation structures have become more dissimilar in recent years, particularly due to the enormous deployment of wind and solar generation capacity in Germany and the nuclear phase out in Germany but not in France. This calls for proper policies to encourage further transmission and interconnection investment in order to take the advantages from the increasing benefits of trade. Of course, for optimality one would also need to take into account the costs of this capacity.

Table 5
Coefficients for two-stage instrumental variables.

	(1) – 2SLS $Spread_{DE,FR,h}$	(2) - IVPROBIT $ICC_{DE,FR,h}$
$Spread_{DE,FR,h-1}$	0.7248***	
	(0.0345)	
$GMSI_{DE,FR,h}$	−2.9790***	−1.1253***
	(0.5516)	(0.0916)
$IC_{DE,FR,h}$	−1.0467***	−0.5674***
	(0.1295)	(0.0146)
$IC_{FR,IT,h}$	0.8501***	0.2167***
	(0.0950)	(0.0116)
$W_{DK,h}$	0.1566***	0.0646***
	(0.0444)	(0.0085)
Day_of_week_FE	Yes	Yes
Yearly_FE	Yes	Yes
Holiday_FE	Yes	Yes
Hansen J Stat. $(p - val)$	0.2435	–
Observations	32,899	32,904
$R - squared$	0.611	

Robust standard errors in parentheses.
**p < 0.05.
*p < 0.1.
*** p < 0.01.

In addition, we obtain several other interesting and consistent results that are all derived from and embedded in standard trade theory. For example, price spreads and the likelihood of congestion between a pair of countries are heavily dependent on the influences of neighbouring countries. More interconnection capacity between France and Italy increases price spreads and the likelihood of congestion between Germany and France, because France mostly imports from Germany and exports to Italy. Wind electricity generated in Denmark affects the likelihood of congestion between Germany and France in the same way as German wind electricity.

We derive the following policy implications from our results. First, convergence in European electricity markets has been exaggerated so far, since part of it is due to generation mix similarity and not arbitrage. In view of rising dissimilarity of generation mixes, investment in cross-border capacities becomes ever more important to reap the (increasing) benefits of trade. Second, interdependencies and cross-border externalities abound in European electricity markets, and any sensible solutions to the main problems, such as the integration of renewables and security of supply, cannot be achieved by national energy policies alone.

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[32] We use the Stata command IVPROBIT.

Appendix A

A1. A fundamental model for calculating marginal costs

We developed a state-of-the-art standard fundamental market model of electricity supply and demand in electricity generation, as applied in other studies (e.g. Borenstein and Bushnell, 1999; Burger et al., 2007, Chapter 4; Graf and Wozabal, 2013; Hirth, 2013; Schröter, 2004; Sensfuß, 2007; Sensfuß et al., 2008) to identify generation technology classes that are in merit order. Hence, we construct hourly supply curves (i.e. the merit order curve) by applying data for installed capacity and combining them with technical information regarding plant characteristics and other relevant data (e.g. plant availability scores and efficiency factors; see below). Hourly demand is simply determined by the hourly load in the market (net cross-border trade). The Austrian transmission system operator, APG, and the EEG of the TU Vienna, have both developed their own fundamental models and provided us with background knowledge, modelling support and information.

Trading in wholesale electricity in Europe happens to a large extent in day-ahead spot markets, which are organised at power exchanges. In a power exchange, suppliers and consumers place bids (e.g. EPEX at 12 a.m.) for any hour of the following day. Such power exchanges are generally characterised by many suppliers and consumers and have high liquidity (Gugler et al., 2016). According to Graf and Wozabal (2013), firms bid their capacities at marginal costs at the EPEX day-ahead market and thus markets work efficiently. In our case, it was necessary to determine which generation technology classes are in the merit order, i.e. firms will only generate electricity from their own technology capacity if its marginal cost of production is below the spot price. Therefore, we calculate the hourly marginal costs of each generation technology class in order to construct hourly merit orders.

A2. Data

We obtain detailed information regarding installed capacity (*Cap*) at the generation unit level for the period 2011–2014 from Platts PowerVision. The following information is obtained at the generation unit level: plant name, construction and retirement date, turbine type, fuel type, plant type, operational status, and installed capacity (MW). In contrast to other sources, e.g. Bundesnetzagentur (2011), in which a list of German power plants with installed capacities larger than 20 MW is published, Platts PowerVision provides data for all European countries, irrespective of size.

APG provided us with information regarding the availability factors *(AF)* of power plants by turbine and fuel type. The availability of a power plant is an operational limitation determined by planned revisions (e.g. maintenance) and seasonal demand fluctuations. In accordance with Schröter (2004), we consider three periods, winter, summer and the transition phase, in order to adjust our availability measure to seasonal demand fluctuations. Low electricity demand during summertime allows for higher operational flexibility. Most of the planned maintenance occur during summer, and therefore our availability measure is significantly lower during this period. Our availability measure is a percentage (i.e. a value between zero and one). We additionally assume that pump storages and water reservoirs generate electricity only during peak hours and days of weeks when spot prices are high. With respect to renewables, we use hourly data for wind and solar forecasts (provided by the respective transmission system operators) to assess their availabilities. Bids at day-ahead markets generally follow wind and solar generation forecasts based on wind and sunshine forecasts. Biogas power plants are considered a renewable source of electricity and receive fixed rates for their generation, and thus generate a constant power output (Graf and Wozabal, 2013). Finally, we multiply the respective installed capacity with the availability score for each plant type to create a measure of available capacity.

APG and the EEG of TU Vienna (internal power plant database) provided us with information regarding the efficiency factors (*EF*) of power plants by fuel and turbine type. The *EF* shows the relationship between energy input in terms of primary energy and energy output in terms of electricity. In our model, the *EF* of each generation unit is a function of turbine type, fuel type and the year of construction (see Graf and Wozabal, 2013; Schröter, 2004; Sensfuß et al., 2008). It has a value between zero and one.

A3. Construction of marginal costs and electricity generated by generation technology classes

Next, we calculate marginal costs for each hour (h) and for 70 generation technology classes (which were a combination of turbine type, fuel type and year of construction). For this purpose, we use fuel prices, the carbon dioxide (CO_2) price, emission factors the *EF* into consideration. Because some variables do not vary by the hour (e.g. daily), we impute these values for each hour (h).

$$mc_{\tau,h} = mc_{tt,ft,cy,h} = \frac{FP_{ft,h} + (CO2P_{ft,h} \times CO2E_{ft})}{EF_{tt,ft,cy}}$$

where:

mc = Marginal cost (€/MWh)
τ = Generation technology class
FP = Fuel price (€/MWh)
EF = Efficiency factor (%)
$CO2E$ = CO_2 emission factor (tCO_2/MWh)
$CO2P$ = CO_2 spot price (€/MWh)
tt = Turbine type (steam turbine, combined cycle, etc.)
ft = Fuel type (hard coal, gas, oil, etc.)
cy = Construction year
h = Hour

We distinguish between 22 plant types, which are combinations of 12 turbine types and 12 fuel types. For these plant types, we collect data on their *EF* depending on their respective construction years, which produced 70 different combinations. Older plants are less efficient, and thus have higher marginal costs. Moreover, we collect data on fuel prices *(FP)* depending on the 12 fuel types over time. As the daily price of coal, we use the

ARA monthly future data provided by the European Energy Exchange (EEX). For gas, we use the daily price data provided by the German Federal Office of Economics and Export Control (BAFA). Because there is no spot market for lignite and consequently no price information available, in accordance with Graf and Wozabal (2013), we assume the lignite price to be 80% of the coal price. As the daily price of oil, we use Europe Brent Spot (FOB) provided by the U.S. Energy Information Administration. For uranium prices for nuclear power, in accordance with Graf and Wozabal (2013), we assume a constant (and negligible) input price of USD 9.33 per MWh (see OECD/IEA, 2010). Furthermore, we collect data on the degree of CO_2 emissions by fuel type, which provide CO_2 emission factors (CO2E). The respective information is provided by APG. We utilise data on daily CO_2 spot prices from the EEX.

Next, we obtain electricity generation values for each generation technology class τ in the German and French merit orders for hour h (up to their intersection with demand). Our *AFs* (i.e. percentage of total installed capacity) vary across the 22 plant types and across three seasons of the year (i.e. summer, winter and the transition period). To obtain electricity generated by generation technology class in Germany and France ($g_{DE,\tau,h}$ and $g_{FR,\tau,h}$), we multiply the installed capacities (*Cap*) of generation technology classes with their respective *AF*s.

$$g_{DE,\tau,h} = \quad Cap_{DE,\tau,h} \times AF_{\tau,h} \text{and} g_{FR,\tau,h} = \quad Cap_{FR,\tau,h} \times AF_{\tau,h}$$

where:

g = Electricity generated (MWh)
Cap = Installed capacity (MW)
AF = Availability factor (%)

A4. Frequency distribution of marginal technologies in Germany and France

Fig. A1 depicts a histogram of the frequency distribution of being the marginal technology across employed technologies in France and Germany. It is obvious that all technologies have been a marginal technology at least for a couple of hours during the time period. This is of course a manifestation of the huge demand and supply swings within and across days. Thus, clearly inframarginal technologies matter from a system perspective. Please note that the number of employed technologies differs between Germany and France, as for Germany we identify 58 technologies, in France only 35.

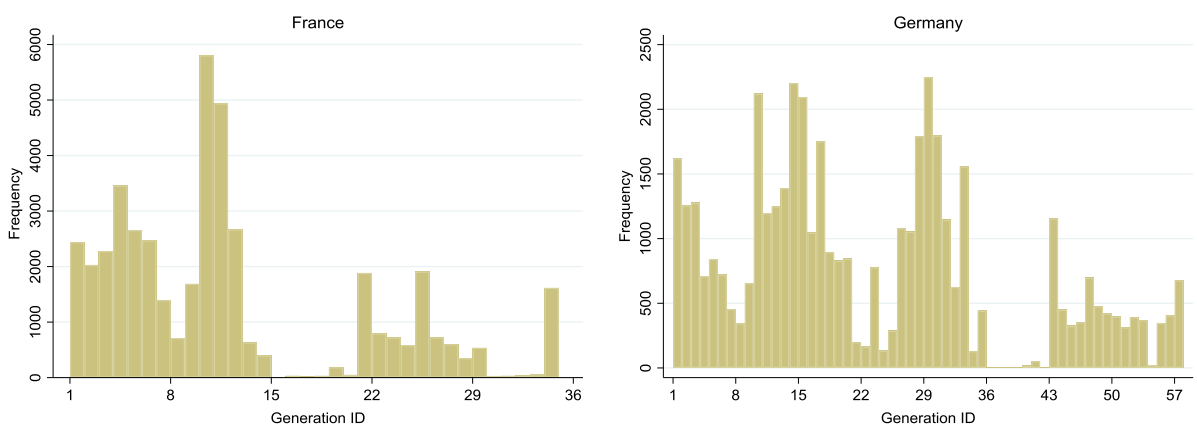

Fig. A1. Frequency distribution of marginal technologies in Germany and France.

A5. Further robustness checks

Next, we perform some robustness check with respet to GMSI. In Table A1, we show that the coefficient of GMSI changes only slightly after controlling for hours of the day (see column (1)). This shows that our estimated coefficients are very stable. After we control for interactions of hours of the day and months, interactions of hours of the day and years, and interactions of months and years, the coefficient of GMSI has become even larger (see column (2)). Further, the coefficient of solar electricity in Germany ($S_{DE,h}$), and nuclear electricity in France ($N_{FR,h}$) have also become larger. The rest of coefficients are very stable

In addition, we interact GMSI with hour of the day dummies. In Table A2, we report the estimated coefficients. In column (1), the estimated coefficients of hourly interactions with GMSI are all negative however some are statistically insignificant (i.e. hours 4, 5 and 24). Additionally, we generate a dummy for off-peak hours (*off_peak*) and interact it with GMSI. The dummy for off-peak hours equals zero for hours between 8 and 20, and 1 otherwise. In Column (2), the estimated coefficients of GMSI and interaction term between GMSI and off-peak dummy show that the impact of GMSI on price spread is larger negative in peak than in off-peak.

In Table A3, we report correlation coefficients. While GMSI is negatively and highly correlated with solar electricity (-0.4984) and load in Germany (-0.5086), the correlation coefficient of about 0.5 does not give rise to severe collinearity concerns.

We also perform additional robustness check relating to our probit model. In Table A4, after we control for the hours of the day dummies and their interactions with monthly dummies, most of the estimated coefficients get larger (see column (1) and (3)). In addition, the magnitude of the coefficients slightly changes after the introduction of interactions of hour of the day and monthly dummies, and interaction of year and month dummies (see column (2) and (4)). (Tables A5 and A6)

Table A1
Regression coefficients.

	(1) $Spread_{DE,FR,h}$	(2) $Spread_{DE,FR,h}$
$Spread_{DE,FR,h-1}$	0.7019***	0.6769***
	(0.0359)	(0.0392)
$GMSI_{DE,FR,h}$	− 2.7725**	− 4.2969***
	(1.2000)	(1.2531)
$IC_{DE,FR,h}$	− 1.3947***	− 1.3713***
	(0.1502)	(0.1575)
$IC_{FR,IT,h}$	0.6619***	0.6830***
	(0.0801)	(0.0799)
$W_{DK,h}$	− 0.0234	− 0.1000*
	(0.0485)	(0.0518)
$W_{DE,h}$	0.1136***	0.1190***
	(0.0210)	(0.0225)
$S_{DE,h}$	0.0791***	0.1649***
	(0.0187)	(0.0293)
$N_{FR,h}$	− 0.0968***	− 0.1941***
	(0.0230)	(0.0313)
$W_{FR,h}$	− 0.2402***	− 0.2596***
	(0.0478)	(0.0497)
$L_{DE,h}$	− 0.1241***	− 0.1188***
	(0.0167)	(0.0164)
$L_{FR,h}$	0.2460***	0.2537***
	(0.0342)	(0.0357)
Day_of_week_FE	Yes	Yes
Yearly_FE	Yes	Yes
Monthly_FE	Yes	Yes
Holiday_FE	Yes	Yes
Hourly_FE	Yes	Yes
i_Hourly_Monthly_FE	No	Yes
i_Hourly_Yearly_FE	No	Yes
i_Monthly_Yearly_FE	No	Yes
Observations	32,899	32,899
$R-squared$	0.623	0.655

Robust standard errors in parentheses.
*** $p < 0.01$.
** $p < 0.05$.
* $p < 0.1$.

Table A2
Regression coefficients of interactions of GMSI and hourly dummies.

	(1) $\boldsymbol{Spread_{DE,FR,h}}$	(2) $\boldsymbol{Spread_{DE,FR,h}}$
$Spread_{DE,FR,h-1}$	0.7003***	0.6988***
	(0.0358)	(0.0355)
$GMSI_{DE,FR,h}$		−3.5045***
		(1.1283)
$i\_GMSI_{DE,FR,h}\_off\_peak$		0.9590***
		(0.2016)
$i\_GMSI_{DE,FR,h}\_hour1$	−3.7977***	
	(1.2484)	
$i\_GMSI_{DE,FR,h}\_hour2$	−3.8042***	
	(1.2081)	
$i\_GMSI_{DE,FR,h}\_hour3$	−3.1522***	
	(1.1913)	
$i\_GMSI_{DE,FR,h}\_hour4$	−1.9060	
	(1.2028)	
$i\_GMSI_{DE,FR,h}\_hour5$	−1.5856	
	(1.1915)	
$i\_GMSI_{DE,FR,h}\_hour6$	−3.0467**	
	(1.2018)	
$i\_GMSI_{DE,FR,h}\_hour7$	−2.6639**	
	(1.2695)	
$i\_GMSI_{DE,FR,h}\_hour8$	−3.8749***	
	(1.3325)	
$i\_GMSI_{DE,FR,h}\_hour9$	−4.7261***	
	(1.2753)	

(*continued on next page*)

Table A2 (*continued*)

	(1) $Spread_{DE,FR,h}$	(2) $Spread_{DE,FR,h}$
$i\_GMSI_{DE,FR,h}\_hour10$	−3.2498**	
	(1.3583)	
$i\_GMSI_{DE,FR,h}\_hour11$	−3.8468***	
	(1.2799)	
$i\_GMSI_{DE,FR,h}\_hour12$	−4.7576***	
	(1.3118)	
$i\_GMSI_{DE,FR,h}\_hour13$	−3.7377***	
	(1.2842)	
$i\_GMSI_{DE,FR,h}\_hour14$	−5.3412***	
	(1.3136)	
$i\_GMSI_{DE,FR,h}\_hour15$	−4.3343***	
	(1.2451)	
$i\_GMSI_{DE,FR,h}\_hour16$	−5.6581***	
	(1.2381)	
$i\_GMSI_{DE,FR,h}\_hour17$	−4.2479***	
	(1.2651)	
$i\_GMSI_{DE,FR,h}\_hour18$	−4.1478***	
	(1.2992)	
$i\_GMSI_{DE,FR,h}\_hour19$	−2.9335**	
	(1.4096)	
$i\_GMSI_{DE,FR,h}\_hour20$	−2.9367**	
	(1.3679)	
$i\_GMSI_{DE,FR,h}\_hour21$	−2.6160*	
	(1.3590)	
$i\_GMSI_{DE,FR,h}\_hour22$	−3.9312***	
	(1.3334)	
$i\_GMSI_{DE,FR,h}\_hour23$	−3.7123***	
	(1.3802)	
$i\_GMSI_{DE,FR,h}\_hour24$	−1.4011	
	(1.2936)	
$IC_{DE,FR,h}$	−1.3763***	−1.4409***
	(0.1473)	(0.1503)
$IC_{FR,IT,h}$	0.6458***	0.6498***
	(0.0806)	(0.0801)
$W_{DK,h}$	−0.0169	−0.0159
	(0.0485)	(0.0487)
$W_{DE,h}$	0.1096***	0.1105***
	(0.0207)	(0.0200)
$S_{DE,h}$	0.0602***	0.0385***
	(0.0176)	(0.0139)
$N_{FR,h}$	−0.1008***	−0.1181***
	(0.0230)	(0.0232)
$W_{FR,h}$	−0.2339***	−0.2585***
	(0.0474)	(0.0482)
$L_{DE,h}$	−0.1317***	−0.1377***
	(0.0173)	(0.0173)
$L_{FR,h}$	0.2638***	0.2734***
	(0.0342)	(0.0312)
Day_of_week_FE	Yes	Yes
Monthly_FE	Yes	Yes
Yearly_FE	Yes	Yes
Holiday_FE	Yes	Yes
Observations	32,899	32,899
$R-squared$	0.623	0.620

Robust standard errors in parentheses.
*** $p < 0.01$.
** $p < 0.05$.
* $p < 0.1$.

Table A3
Correlation coefficients.

	$GMSI_{DE,FR,h}$	$W_{DE,h}$	$S_{DE,h}$	$N_{FR,h}$	$W_{FR,h}$	$L_{DE,h}$	$L_{FR,h}$
$GMSI_{DE,FR,h}$	1						
$W_{DE,h}$	−0.3176	1					
$S_{DE,h}$	−0.4984	− 0.1379	1				
$N_{FR,h}$	−0.0717	0.2457	−0.2568	1			
$W_{FR,h}$	−0.1301	0.5049	−0.1555	0.2232	1		
$L_{DE,h}$	−0.5086	0.0506	0.3277	0.4176	0.0297	1	
$L_{FR,h}$	−0.2871	0.2014	−0.0721	0.8412	0.2235	0.6404	1

Table A4
Probit regression coefficients.

	(1) $ICC_{DE,FR,h}$	(2) $ICC_{DE,FR,h}$	(3) $ICC_{DE,FR,h}$	(4) $ICC_{DE,FR,h}$
$ICC_{DE,FR,h-1}$	1.8533***	1.8135***		
	(0.0194)	(0.0204)		
$GMSI_{DE,FR,h}$	−0.5202***	−0.4354***	−1.1463***	−1.0596***
	(0.1248)	(0.1289)	(0.1127)	(0.1200)
$IC_{DE,FR,h}$	−0.4955***	−0.5696***	−0.7218***	−0.8064***
	(0.0212)	(0.0229)	(0.0177)	(0.0195)
$IC_{FR,IT,h}$	0.0715***	0.0732***	0.0992***	0.0976***
	(0.0143)	(0.0154)	(0.0126)	(0.0138)
$W_{DK,h}$	0.0240*	0.0231*	0.0358***	0.0331***
	(0.0124)	(0.0132)	(0.0107)	(0.0115)
$W_{DE,h}$	0.0190***	0.0195***	0.0345***	0.0345***
	(0.0035)	(0.0038)	(0.0031)	(0.0033)
$S_{DE,h}$	0.0383***	0.0610***	0.0532***	0.0823***
	(0.0048)	(0.0056)	(0.0044)	(0.0052)
$N_{FR,h}$	0.0112***	−0.0116**	0.0215**	−0.0148**
	(0.0040)	(0.0050)	(0.0034)	(0.0044)
$W_{FR,h}$	−0.0527***	−0.0644***	−0.0856***	−0.1022***
	(0.0102)	(0.0109)	(0.0089)	(0.0097)
$L_{DE,h}$	−0.0326***	−0.0295***	−0.0497***	−0.0435***
	(0.0026)	(0.0029)	(0.0023)	(0.0026)
$L_{FR,h}$	0.0516***	0.0546***	0.0808***	0.0823***
	(0.0029)	(0.0034)	(0.0025)	(0.0030)
Day_of_week_FE	Yes	Yes	Yes	Yes
Yearly_FE	Yes	Yes	Yes	Yes
Monthly_FE	Yes	Yes	Yes	Yes
Holiday_FE	Yes	Yes	Yes	Yes
Hourly_FE	Yes	Yes	Yes	Yes
i_Hourly_Monthly_FE	Yes	Yes	Yes	Yes
i_Hourly_Yearly_FE	No	Yes	No	Yes
i_Monthly_Yearly_FE	No	Yes	No	Yes
Observations	32,904	32,904	32,904	32,904

Robust standard errors in parentheses.
*** $p < 0.01$.
** $p < 0.05$.
* $p < 0.1$.

Table A5
PP, DF and DF GLS tests.

Variable	PP test stat.	ADF test stat.	DF GLS test stat.
$Spread_{DE,FR,h}$	-80.3773***	-16.8023***	-42.4604***
$GMSI_{DE,FR,h}$	-36.0387***	-10.0833***	-47.5339***
$IC_{DE,FR,h}$	-59.8777***	-14.1787***	-47.8720***
$IC_{FR,IT,h}$	-78.6554***	-13.4146***	-50.5167***
$W_{DK,h}$	-20.1533***	-22.1946***	-7.2436***
$W_{DE,h}$	-17.2321***	-20.0846***	-6.9125***
$S_{DE,h}$	-13.0459***	-10.0796***	-26.9117***
$N_{FR,h}$	-6.9821***	-6.8967***	-6.8457***
$W_{FR,h}$	-18.1123***	-21.7752***	-10.5417***
$L_{DE,h}$	-17.4306***	-36.4274***	-23.5192***
$W_{FR,h}$	-12.4126***	-14.6578***	-17.0084***

Notes: The 1% critical value to reject the H0 of a unit root of PP is -2.58, of ADF it is 3.960, and of DF GLS it is -3.480.

Table A6
First-stage regression coefficients.

	(1) $GMSI_{DE,FR,h}$	(2) $GMSI_{DE,FR,h}$
$Spread_{DE,FR,h-1}$	-0.0001	
	(0.0001)	
$RES_{DE,h}$	-0.0147***	-0.0147***
	(0.0001)	(0.0001)
$RES_{FR,h}$	0.0162***	0.0163***
	(0.0006)	(0.0005)
$IC_{DE,FR,h}$	-0.0141***	-0.0138***
	(0.0010)	(0.0010)
$IC_{FR,IT,h}$	-0.0021**	-0.0023***
	(0.0008)	(0.0008)
$W_{DK,h}$	0.0124***	0.0124***
	(0.0006)	(0.0006)
Day_of_week_FE	Yes	Yes
Yearly_FE	Yes	Yes
Monthly_FE	Yes	Yes
Holiday_FE	Yes	Yes
First − stage F test	2182.48	1968.77
Observations	32,899	32,904
R − squared	0.6179	0.6179

Robust standard errors in parentheses
* $p < 0.1$
*** $p < 0.01$
** $p < 0.05$

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