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Integration and Efficiency of European Electricity Markets: Evidence from Spot Prices

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Abstract: *This paper seeks to investigate the current state of market integration among European electricity day-ahead spot prices. We provide reasoning that market integration brings about benefits, such as lower average prices and increased welfare from allocative efficiency. Yet, price convergence leads to higher prices in the low-price market and to lower prices in the high-price market, which creates winners and losers and thus makes the political implementation of market integration cumbersome. In our empirical analysis, we utilize a large sample of hourly spot prices of 25 European markets for the period 01.01.2010–30.06.2015 and combine it with other relevant data such as interconnector capacities and the existence of market coupling. Firstly, empirical results from cointegration analysis indicate that market integration increased from 2010 to 2012 but then declined until 2015, most likely due to increased feed-in from intermittent renewables. Secondly, we empirically assess the speed of adjustment from price shocks and reach the conclusion that the resulting efficiency of integration is rather modest. In general, our findings suggest that integration among European electricity markets has a large potential for improvements from additional capacity investments and further promotion of market coupling.*

Keywords: Market integration; Spot Price; Convergence; Internal Market, Electricity

JEL codes: F15, L81, L98, Q48

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1. Introduction

The introduction of a common internal market has been at the top of the European Union's agenda. A functioning market should foster competition and reduce trade barriers. Energy, and in particular electricity, is among the key sectors targeted by efforts to integrate market areas and, as a consequence, promote competitive prices, enhance efficiency, achieve higher standards of service, and secure supply and sustainability (Directive 2009/72/EC). "A well-integrated internal energy market is a fundamental pre-requisite to achieve these objectives in a cost-effective way." (European Commission, 2014, p. 2). The integration of electricity markets requires substantial investments to remove transmission bottlenecks and to enhance interconnector capacity. Moreover, market coupling[1] is necessary to allocate cross-border capacities efficiently.

Economic theory suggests that, like with any other good, electricity trade is welfare enhancing compared to autarkic supply, since it enhances the markets' allocative efficiency. Besides, electricity is a homogenous good.[2] If traded freely and unconstrained, the law of one price must hold, so that spot prices between two markets become equalized. However, electricity markets were initially designed to meet their national demands, and, hence, complications arise when trying to interconnect market areas among each other. Interconnection capacities are frequently exhausted (apart from domestic transmission bottlenecks) and, thus, place obstacles for free trade. As a result, spot prices diverge during times of cross-border congestion.

Interconnection capacity limitations are not the sole reason for deviations from uniform spot prices. "Market design imperfections", such as differences in auction design, pricing rules, or closing hours between power exchanges of adjacent market areas may hinder price convergence (Nitsche et al., 2010). This is why market coupling, in addition to the extension of interconnection capacity, is an important tool for fostering market integration. Currently, flow based market coupling ensures that not only the market designs become synchronized, but also that power and capacity are traded *simultaneously*, so that electricity markets fully utilize the available interconnection capacities (Keppler et al., 2014).

Politically, electricity market integration is a relevant topic, which bears some controversy. In general, market integration is desirable because it entails *enhanced balancing of supply and demand shocks, better integration of intermittent renewables, security of supply*, *reduced price*

[1] As argued in more detail below, market coupling entails simultaneous auctioning of available transfer capacity and electricity. Hence, it promotes efficient allocation of interconnector capacity.

[2] At least what concerns physical properties. Electricity is, of course, differentiated regarding its production technology (conventional vs renewable production), location and time of day.

variance (i.e. less risk), lower prices (for consumers) on average and *increased total welfare (as well as consumer surplus)* due to *increased allocative efficiency* (see, e.g. Nepal and Jamasb, 2012; Vattenfall, 2015). Yet, market integration does not bring about increased consumer surplus for everyone. While electricity trade causes a decline in the initially high-price market, the price in the low-price market rises.[3] As a consequence, *not everyone* benefits from price convergence. Both consumers in the low-price market and producers in the high-price market experience *losses* in their economic rents. These potentially negative effects may render the practical implementation of an integration policy across Europe cumbersome.

Against this background, this paper seeks to analyze the current state of integration among European wholesale electricity markets by analyzing price convergence of day-ahead spot markets. We illustrate the social welfare effects of market integration and provide reasoning that price convergence may be desirable from a welfare perspective but politically cumbersome to realize, because the transition brings about winners and losers.

Key for our empirical analysis is the rich and novel dataset on hourly day-ahead spot prices from 25 European electricity market areas for the period 01.01.2010–30.06.2015. We combine these data with a large set of control variables. A particular feature of the data is the ability to explicitly address hourly interconnection capacity congestion and its direction. Moreover, we are able to assess the effects of market coupling on market integration.

The empirical approach follows a two-step procedure. First, we apply *cointegration analysis* to draw conclusions about the *long-run price relations* of adjacent and indirect market pairs. Second, we focus on *error correction* to infer about markets' speeds of adjustment after price shocks, from which we may come to a judgement about *markets' efficiency* to deal with new information. This paper puts price convergence to empirical scrutiny that goes beyond econometric modelling of the existing literature: (1) We argue that error correction models can only be applied *during times of trade frictions* so that shocks resulting in differential prices can be observed); (2) We stress that, for the sake of comparability across market pairs, the error correction model should be constrained to a *perfect long-run price relation* in order to assess the speed of adjustment back to uniform prices. (3) We evaluate integration and market efficiency both for daily averages, which provides a general overview, and at the hourly frequency, which allows for including a *one-hour lag to account for intra-day demand and*

[3] Under the assumption of an increasing supply curve (i.e. marginal cost schedule). This Assumption is fulfilled in the electricity sector given its increasing merit order curve.

supply rigidities. Other studies focusing on daily averages are not able to control for such intra-day patterns.

Our results indicate that market integration increased from 2010 to mid of 2012 but then declined until 2015, foremost due to the increased production from intermittent renewables. We argue that for the counterfactual scenario of missing efforts to integrate markets, interconnection congestion and more extreme price effects (of peaking positive and negative prices) are likely to increase. Furthermore, we reach the conclusion that the efficiency of integration is rather modest, as the average speed of adjustment from price shocks is quite limited. Although investments are costly and generally sunk, this gives rise for a large potential for welfare improvements from additional capacity investments and further promotion of market coupling among European electricity markets, given their modest levels of integration and limited efficiencies (i.e. speeds of adjustment). Since European markets undergo significant structural changes, such as increased promotion of intermittent renewables, nuclear phase-out, and low investment incentives from falling spot prices, the benefits of market integration – particularly balancing and supply security – become especially pronounced

2. Literature

In this section, we first summarize findings from the relevant empirical literature on electricity market integration, which has mainly focused on price correlations. Second, we discuss studies on the potential effects of market integration.

De Vany and Walls (1999) evaluate cointegration of price pairs during daily peak and off-peak periods of 11 western US power markets from 1994 to 1996. They conclude that these markets are already well integrated, especially during times of off-peak demand. Zachmann (2008) evaluates price convergence based on filtered price relations, principal component analysis and unit root tests for 11 European markets for the hourly period 2002–2006. His results indicate that despite decreasing price differentials over time (due to better cross-border interconnections), markets were still far from full integration. Nepal and Jamasb (2012) show, based on the Kalman filter method, that the Irish Single Market was hardly integrated with other European markets during 2008–2011.

Keppler et al. (2014) investigate the effects of increased renewable supply and market coupling on hourly price differences between France and Germany from November 2009 to June 2013. Their results indicate that increased supply from intermittent renewables often leads to *interconnection congestion* and hence to price divergence, while *market coupling* strengthens price convergence. This gives rise to the importance of investments in interconnection capacities and market coupling during times of subsidized and prioritized feed-in for intermittent renewables.

Jacottet (2012) highlights that market integration and consequently price convergence leads to an *overall gain in welfare*, which explains the efforts of the European Commission to promote investment in interconnection capacities. Despite the general positive welfare aspect, additional interconnections bring about *welfare redistribution* and cause consumers from markets with initially low (high) price levels to lose in surplus, whilst consumers (producers) from high (low) price areas benefit. Consequently, Member States that expect prices to rise from increased trade disapprove with EC's efforts to foster integration. Keppler et al. (2014, p. 4) support this argument: "With unconstrained interconnections, consumers in the higher price zone would gain more in terms of consumer surplus than what other consumers in the lower price zone would lose."

Böckers et al. (2013) emphasize that market integration may significantly reduce the possibilities for electricity firms to exercise market power (e.g. strategic withholding of generation capacity). Dominant firms operating in concentrated national markets may face a severe *increase in competition* from market integration resulting in a *more efficient market with competitive prices*.

Some studies argue that market integration bears potential benefits that go beyond welfare enhancement and reducion of market power. Interconnected markets generate *supply security*, *reduce the need for considerable reserve capacity, increase markets' liquidities* and *lower the operating costs of the system* (Zachmann, 2008; Nepal and Jamasb, 2012). Besides, interconnections lower price volatility (e.g. from intermittent renewable production) and thus *provide better investment incentives* through the mitigation of uncertainty (Nepal and Jamasb, 2012).[4]

3. Market Integration and Spot Price Convergence

Given our empirical analysis on the current state and the efficiency of electricity market integration, in this section we discuss how the integration process affects prices and

[4] Yet, Bar-Ilan and Strange (1996) argue that investment incentives may even rise under increased market uncertainty if there is a long time-to-build lag.

redistributes welfare. As is shown below, prices between two markets may *converge partially* (they approximate each other) or *fully* (law of one price holds), depending on the degree of market integration.

Market integration necessitates investment in *interconnection capacity* (assuming no bottlenecks in the transmission grid) as a prerequisite for potential electricity exchange between adjacent market areas. As long as interconnection capacity is not exhausted, electricity may flow from the low price area to the high price area, causing prices to converge. Still, price convergence not only hinges upon the existence of interconnection capacity but also on capacity allocation mechanism. Without market coupling, electricity and interconnection capacity are traded *separately* allowing for coordination failures and strategic withholding of interconnection capacities. Hence, misallocation of available capacity may hinder price convergence. For that reason, market coupling imposes *implicit auctioning* of interconnector capacity, so that electricity and transfer capacity are auctioned *simultaneously*.

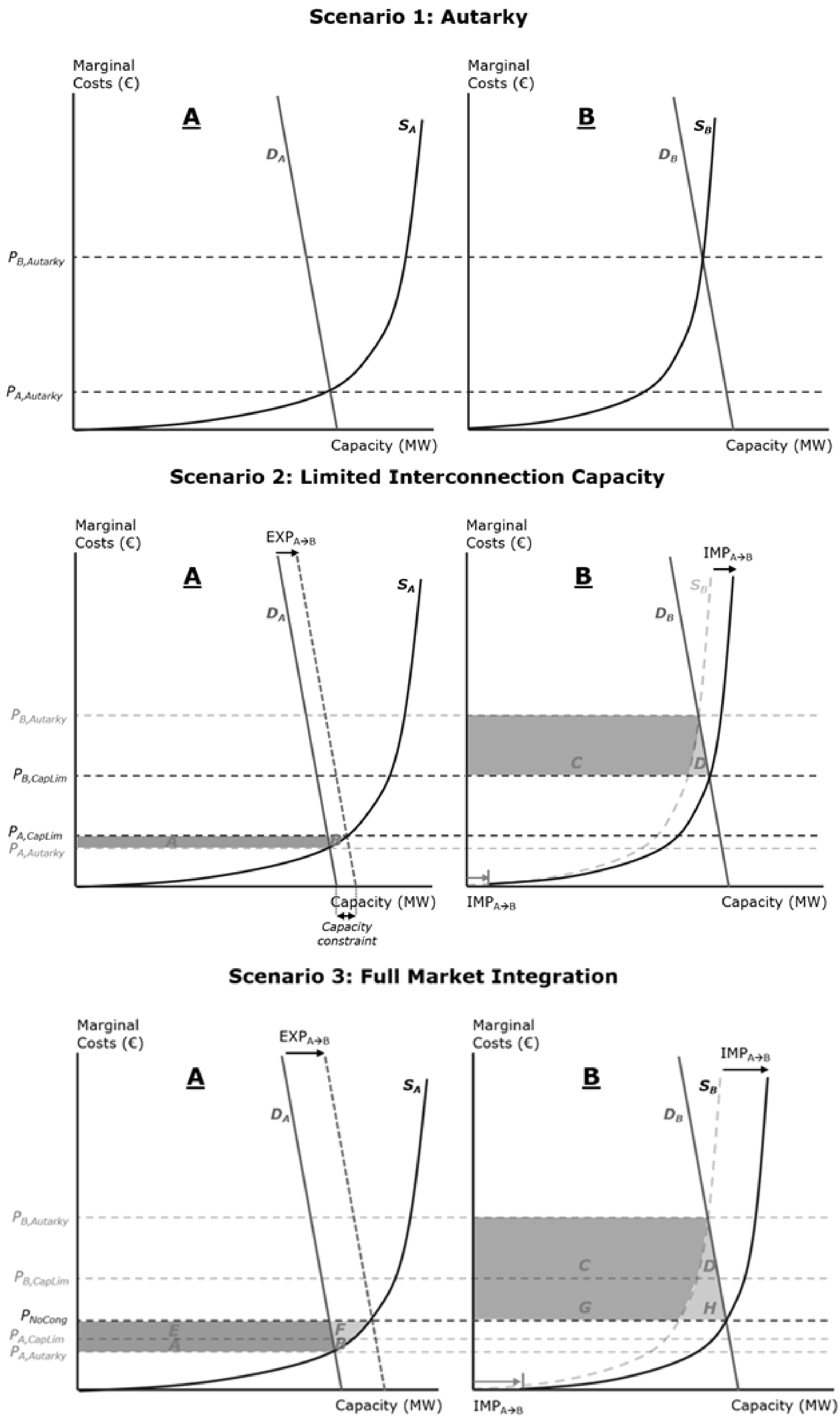
Figure 1 shows how electricity trade between two initially autarkic market areas may help improving supply efficiency. Electricity supply follows a merit order of generation technologies' marginal costs. In the flat beginning of the supply curve, renewables (e.g. wind and solar) and hydro (run of river) plants are located with marginal costs close to zero, followed by nuclear plants and various types of coal. Gas, pump-storage and oil encompass peak-load technologies with relatively high operating costs located in the steep parts of the supply curve. Both markets A and B are equal in terms of national demand. However, while market A is able to meet its national demand relatively cheaply, market B's supply curve is relatively steep and utilizes a great share of power plants with high marginal costs (e.g. gas). In the case of *autarky (Scenario 1)*, no exchange takes place due to missing interconnection capacity. As a result, the price of market A ($P_{A,Autarky}$) lies much lower than the price of market B ($P_{B,Autarky}$).

In Scenario 2 we assume that there is limited interconnection capacity (and market coupling) allowing for some trade resulting in *partial price convergence*: Market A with the initially much lower price exports its electricity to market B, which shifts its demand curve (D_A) to the right (additional demand from market B), until the available capacity is exhausted. Thus, $P_{A,Autarky}$ rises to $P_{A,CapLim}$. Market B imports electricity from market A (until the interconnection capacity is exhausted), which shifts its supply curve to the right (additional supply from market A). As market B produces in the steep part of the supply curve, some trade already brings about a large price decline from $P_{B,Autarky}$ to $P_{B,CapLim}$. We can observe that limited trade not only brings about a *welfare gain* (areas B+D) but also a *welfare redistribution*: In market A consumers lose a little

(-A) while producers gain a little (A+B), whereas in market B consumers gain substantially (C+D) while producers lose substantially (-C).

Full market integration is depicted in scenario 3, where abundant transfer capacity paralleled by market coupling lead to uniform prices from uncongested trade. Market A exports to market B without constraints until prices fully converge to P_{NoCong}. The two formerly separate markets become one uniform electricity market. In market A, producers gain a little on the back of consumers (A+E) and from the newly created welfare (B+F). In market B, consumers are confronted with a substantial gain on the back of producers (C+G) and from the newly created welfare (D+H). Evidently, *full market integration maximizes social welfare* due to allocative efficiency. In total, the price drop in market B outweighs the price increase in market A. Hence, full integration is a desirable market outcome from a welfare perspective. However, *welfare redistribution* may place a political obstacle on integration efforts, such as investments in additional interconnection capacity and/or the promotion of market coupling.

Figure 1: Market integration and price convergence



4. Methodology

To provide the basis for policy implications, this study seeks to empirically evaluate the efficiency of electricity market integration in Europe. The analysis is based on a two-step approach. Firstly, we investigate the *long-run price relationships* between both adjacent and indirect (no common border) market pairs based on *cointegration analysis*. From this we infer about the current state of market integration in Europe. Secondly, we apply an *error correction model*, which allows to make statements about the speed of adjustment from price shocks. This provides an indication of how efficiently markets deal with new information.

4.1. Cointegration

We evaluate the *long-run relationship* between two (non-stationary) hourly spot price series, $P_{A,t}$ and $P_{B,t}$, where the subscripts *A* and *B* denote two distinct markets and *t* indicates the time. We estimate the following linear combination:

$$P_{A,t} = \alpha + \beta P_{B,t} + Z_t \tag{1}$$

and take the residuals:

$$\hat{Z}_t = P_{A,t} - \hat{\alpha} - \hat{\beta} P_{B,t} \tag{2}$$

If the two price series are integrated of order one ($P_{A,t}$ & $P_{B,t} \sim I(1)$)[5] and the errors are integrated of order zero ($\hat{Z}_t \sim I(0)$)[6], they have a *long-rung equilibrium relation,* so that they cannot move away from each other for long. Random shocks (in $P_{B,t}$) can only cause deviations for a short time period, after which the price series converge back to their long-run equilibrium.

While the intercept α indicates institutional price differences, between the two markets, the trend coefficient β measures how closely the two price series move along. A β coefficient of one indicates a perfect co-movement between $P_{A,t}$ and $P_{B,t}$. In contrast, if $\alpha \neq 0$ and $\beta \neq 1$, prices diverge (e.g. due to interconnection congestion and/or absence of market coupling).

Equation (1) may be extended by cross-border congestion (CBC_t) and its interaction term with the price in market B ($P_{B,t}CBC_t$). CBC_t is a binary indicator, which equals one during hours of congested interconnection capacity between markets A and B. To address the *direction* of

[5] There is strong indication that many price series are non-stationary (or at least exhibit non-stationary properties) using KPSS and Adjusted Dickey-Fuller tests (see also Fezzi and Bunn, 2010). Moreover, integration of order one holds throughout. Results are available upon request.
[6] KPSS and Adjusted Dickey-Fuller tests indicate that the errors are integrated of order zero throughout.

congestion, we may separate CBC_t into congested hours from market A to B ($CBC_{AB,t}$) and from market B to A ($CBC_{BA,t}$). Hence, we expand Equation (1) accordingly, to show that alternating directions of congestion have different impacts on the degree of integration:

$$P_{A,t} = \alpha + \beta P_{B,t} + \gamma CBC_{AB,t} + \delta P_{B,t} CBC_{AB,t} + \epsilon CBC_{BA,t} + \zeta P_{B,t} CBC_{BA,t} + Z_t \quad (3)$$

From Equation (3) the cointegration coefficient β tells us how well markets' prices would move together under the hypothetical scenario of uncongested interconnectors. Under this condition, we would assume extensive electricity trade between the market pairs leading to a close price relation, and β coming closer to unity than without controlling for cross-border congestion. Yet, the absence of market coupling tends to cause capacity misallocation so that markets are still imperfectly integrated. We, thus, estimate Equation (3) for periods without market coupling ($MC_{AB,t} = 0$) and for periods where market coupling is in place ($MC_{AB,t} = 1$):

$$P_{A,t} = \alpha + \beta P_{B,t} + \gamma CBC_{AB,t} + \delta P_{B,t} CBC_{AB,t} + \epsilon CBC_{BA,t} + \zeta P_{B,t} CBC_{BA,t} + Z_t \begin{cases} if\ MC_{AB,t} = 1 \\ if\ MC_{AB,t} = 0 \end{cases} \quad (4)$$

This accords with an empirical test that shows that with *market coupling* ($MC_{AB,t} = 1$) and *uncongested interconnection* ($CBC_{AB,t} = 0$, $CBC_{BA,t} = 0$), *perfect market integration* (i.e. $\beta = 1, \alpha = 0$) must apply. In other words, we empirically show that no other determinants than market coupling and uncongested interconnection capacity cause price convergence.

4.2. Error Correction Model

From the estimation of an error correction model, we may assess how *efficiently* two markets are able to absorb random shocks through trade:

$$\Delta P_{A,t} = \theta + \vartheta \Delta P_{A,t-24} + \eta \hat{Z}_{t-24} + \mu' X + \varepsilon_t, \quad (5)$$

where Δ measures a first difference (e.g. $\Delta P_t = P_t - P_{t-24}$). The coefficient of the lagged error correction term (η) measures the speed of adjustment of a shock that causes the two prices series ($P_{A,t}$ and $P_{B,t}$) to deviate from their long-run equilibrium relation in the previous day back to their steady-state. Hence, η leads to inference about the *efficiency* of the markets: "the higher the speed of price adjustment […] the more efficiently information can be converted into price signals" (Growitsch et al., 2013, p. 94). In other words, η measures the "feedback effect" of a *dis*equilibrium in the previous period on the current price $P_{A,t}$ (Asteriou and Hall, 2011, p. 359).

The autoregressive term $\Delta P_{A,t-24}$ may capture typical patterns of demand persistency (e.g. peak and base load demand) and supply persistency (rigidity versus flexibility of peak or base-load power plants, e.g. due to fixed costs of run-ups) 24 hours earlier.[7] The vector X includes control variables that may influence demand or supply (e.g. wind and solar forecasts, dummy for market coupling, gas prices, seasonal fixed effects, national holidays; see also Fezzi and Bunn, 2010).

The application of an error correction model is somewhat tricky with respect to electricity spot prices, which has not yet been debated in the literature, as far as we know. During times of uncongested trade flows (i.e. when interconnection capacity is abundant and market coupling is in place), the law of one price holds and, thus, shocks to the system are absorbed instantaneously. As a result, shocks resulting in differential prices cannot be observed, which renders the estimation of an error correction model impossible.

Against this backdrop, we estimate the error correction model only when differential price shocks can be measured (i.e. during times of trade frictions). We, thus, *restrict the estimation of the error correction model to times of unequal prices in t-24 ($P_{A,t-24} \neq P_{B,t-24}$), when we observe the shock ($\hat{Z}_{t-24}$),* so that error correction must not be instantaneous. This kind of analysis allows for inference of *how effectively market areas deal with shocks during times of trade frictions*. On the other hand, during times of uncongested trade, markets work perfectly efficient by definition. Hence, we introduce a binary indicator for a price difference, $PD_{AB,t} = 1\ if\ P_{A,t} \neq P_{B,t}$ and $PD_{AB,t} = 0\ if\ P_{A,t} = P_{B,t}$, and impose the constraint on Equation (5) accordingly:

$$\Delta P_{A,t} = \theta + \vartheta \Delta P_{A,t-24} + \eta \hat{Z}_{t-24} + \mu' X + \varepsilon_t\ \ if\ PD_{AB,t-24} = 1, \qquad (6)$$

Besides, we posit that the error correction model should be constrained to a *perfect* long-run cointegrating relation, which not only allows for assessment about the speed of adjustment to uniform prices, but also to be able to compare the efficiency of integration across market pairs. At the hourly frequency[8], we are able to include a one-hour lag in our model, which accounts for intra-day demand and supply rigidities. As we will argue below, this bears an important feature of this study, since other empirical studies focusing on daily averages are not able to control for such intra-day patterns.

[7] Subsequently, we extend the model by a one hour lag (t-1), that may capture intra-day supply and demand rigidities: $\Delta P_{A,t} = \theta + \lambda \Delta P_{A,t-1} + \vartheta \Delta P_{A,t-24} + \eta \hat{Z}_{t-24} + \mu' X + \varepsilon_t$. For example, it takes time to ramp (nuclear or conventional) power plants, so that it may not be possible to adjust their supply in each hour. On the other hand, changes in demand may be rigid over several hours over the day.

[8] We also run regressions for each hour of the day.

Additionally, we argue that it may be misleading to compare the speeds of adjustment (η) back to the long-rung equilibria (i.e. β coefficients estimated in the first stage), since these differ across market pairs.[9] Hence, we *restrict error correction to a perfect equilibrium price relation (i.e.* $\alpha = 0, \beta = 1$*)*:[10]

$$\Delta P_{A,t} = \theta + \vartheta \Delta P_{A,t-24} + \eta\left(P_{B,t-24} - P_{A,t-24}\right) + \mu' X + \varepsilon_t \;\; if \;\; PD_{AB,t-24} = 1. \tag{7}$$

In this restricted form, the error correction term η measures how long it takes to absorb a systemic shock back to uniform prices (i.e. $P_{A,t} = P_{B,t}$), which allows for direct comparison across market pairs.

5. Data and Descriptive Statistics

Compared to the existing literature on electricity market integration, our novel and rich dataset is a key asset. We collected information on hourly day-ahead spot price series from 25 European electricity markets for the period 01.01.2010–30.06.2015. The following markets are included: the Czech Republic (CZ), Denmark East (DKe), Denmark West (DKw), Estonia (EST), Finland (FIN), France (FR), Germany-Austria (DE; one pricing zone)[11], Hungary (HU), Italy North (IT), Latvia (LV), Lithuania (LT), Norway – Oslo, Kr.Sa, Molde, Tromso, Bergen (NO1–5), Portugal (PT), Slovakia (SK), Slovenia (SL), Spain (ES), Switzerland (CH), and Sweden 1–4 (SE1–4). Data emanate from the respective power exchanges for the period: EPEX, SouthPool, GME, NordPool, OMIP, OTE and HUPX.

In order to construct a measure for cross-border congestion (CBC), we calculate free transfer capacities (FTC) as the difference between the available transfer capacity (ATC) and already allocated capacity (AAC): $FTC = ATC - AAC$. Hourly data for ATC and AAC are obtained from CASC (Capacity Allocation Service Company), CAO (Central Allocation Office) and Energinet.dk. If free capacity is available ($FTC > 0$), interconnection capacity is not exhausted, while no free capacity ($FTC = 0$) indicates congestion. Hence, the binary indicator CBC takes the value of one if cross border capacity is congested and zero otherwise. Besides, we have ATC and AAC for *both directions*, from market A to market B (ATC_{AB} & AAC_{AB}) and for the

[9] It may be the case, that two price series are not well integrated (β strongly deviates from one), but their speed of adjustment may be high (η close to minus one). This would suggest that price shocks can be absorbed very fast, but only back to a very loose long-run equilibrium relation. On the other hand, another market pair may have a high price correlation but a slow speed of adjustment. This makes comparison cumbersome.
[10] With uniform prices, $Z_{t-24} = P_{B,t-24} - P_{A,t-24}$. See Growitsch and Nepal, 2009, for a similar approach in gas markets
[11] We refer to the German-Austrian pricing zone as Germany.

reverse direction (ATC_{BA} & AAC_{BA}). This allows decomposing our indicator for cross border capacity congestion for both directions (CBC_{AB} & CBC_{BA}).

Hourly day-ahead forecasts for wind and solar production are only available for Germany, Austria and Denmark for the full sample period 2010–2015Q2 and for Italy from 2013–2015. Given their limited availability, we use these data for robustness estimation of the respective subsamples. It turns out that the exclusion of wind and solar production forecasts does not alter the respective estimated coefficients of the error correction terms[12], which indicates that the omission of such data may be of minor importance for this paper's objective to assess the efficiency of market integration.

Data on national holidays are provided by www.feiertagskalender.ch and included together with seasonal (daily and monthly) fixed effects as demand shifters (see e.g. Escribano et al., 2011). Market coupling (MC_{AB}) is a binary indicator, which takes the value of one after the introduction of market coupling between two markets A and B. The daily spot price of gas (EUR/MWh; which is highly correlated with the oil price) is obtained from BAFA (German Federal Office for Economic Affairs and Export Control) controls for costs of conventional technologies.

After the European liberalization process of the respective national electricity markets, wholesale electricity markets were established subsequently. These power exchanges represent a fundamental pillar toward the implementation of one single European electricity market. Alternatively, trade may happen through OTC markets or bilateral contracting. Table 1 provides information on the liquidity (i.e. hare of traded volumes in total national load) of selected power exchanges, for which proper data were available. Table 1 reveals that the liquidities of power exchanges have been growing over time (for the exception of OMIP where the liquidity was initially high already), pointing to an increasing importance of electricity spot markets.

Table 1. ***Liquidity of selected power exchanges***

		Volumes Traded (GWh)		National Load (GWh)		Share (%)	
Country	**Exchange**	**2010**	**2014**	**2010**	**2014**	**2010**	**2014**
DE/AT	EPEX	205,000	285,000	547,000	625,000	37%	46%
FR	EPEX	52,600	73,100	512,000	514,000	10%	14%
CH	EPEX	9,325	22,000	58,500	51,400	16%	43%
SL	SP	179	6,806	7,086	14,100	3%	48%
ESP	OMIP	196,000	187,000	260,000	265,000	75%	71%

[12] See Section 6.2.

Table 2. Yearly day-ahead electricity spot prices

Country	2010	2011	2012	2013	2014	2015Q1,2	2010–2015Q2
CH	51.02	56.18	49.52	44.73	36.79	38.71	46.84
CZ	43.70	50.56	42.38	36.74	32.96	30.25	40.28
DE/AT	44.49	51.13	43.01	37.81	32.76	30.21	40.79
DKE	54.53	49.42	37.54	39.61	32.15	26.46	41.18
DKW	46.49	47.96	36.34	37.90	30.67	24.65	38.50
ES	37.01	49.92	47.23	44.26	42.13	47.12	44.38
EST	44.68	43.35	39.20	43.14	37.61	31.26	40.47
FIN	54.59	49.31	36.53	41.16	36.02	28.94	42.20
FR	47.50	48.89	46.11	43.38	34.63	38.74	43.62
HU	46.44	55.13	51.55	42.34	40.50	36.06	46.16
IT	62.47	71.16	73.87	61.05	49.58	48.73	62.29
LT	NA	NA	45.50	48.93	50.13	37.82	46.90
LV	NA	NA	NA	52.41	50.12	37.69	47.79
NO1	54.25	46.42	29.56	37.57	27.33	23.63	37.63
NO2	50.82	46.09	29.16	37.34	27.23	23.58	36.81
NO3	56.06	47.50	31.46	38.96	31.54	24.67	39.60
NO3	55.41	47.48	31.15	38.60	31.44	24.22	39.31
NO5	51.80	45.86	28.95	37.60	27.14	23.57	36.94
PT	37.32	50.45	48.07	43.64	41.86	47.21	44.54
SE1	NA	47.70	31.70	39.19	31.42	24.26	39.46
SE2	NA	47.70	31.76	39.19	31.42	24.26	39.47
SE3	54.9	47.85	32.30	39.45	31.62	24.81	39.73
SE4	NA	48.48	34.18	39.93	31.92	26.16	40.45
SK	NA	50.90	42.84	37.20	33.64	30.89	40.02
SL	47.77	57.20	53.15	43.17	40.43	36.59	47.25
Average	50.47	48.07	38.41	39.80	34.41	30.41	40.26

Note: NA indicates missing data.

In Table 2 we report yearly spot prices for all 25 market areas. On average, prices have declined over the period 2010–2015Q2. This negative price trend is related to an enormous investment in subsidized renewables (foremost wind and solar[13]), headed by Germany, which is well interconnected among its neighbors. The nuclear phase out in Germany (see Grossi et al., 2014) and the halt in investment in nuclear power in other European countries in the aftermath of the Fukushima-Daiichi nuclear accident in March 2011 may have counteracted an even further drop in European spot prices. Moreover, developments of gas and oil prices may have an influence on electricity spot prices. Over the period 2010–2015, Italian consumers have faced the highest spot price, which may be explained by the fact that Italy is largely disconnected from other European markets[14] and generates electricity at relatively high marginal costs. In contrast, the Nordic consumers are confronted with relatively low prices on average, given their predominance of hydro generation.

[13] In Europe solar and wind capacities increased from 31GW and 86GW in 2010 to 88GW and 135GW in 2014, respectively (BP, 2015).

[14] According to our data, the few Italian interconnectors are congested almost 100% of the time over the sample period.

Table 3. Direction of congested hours: DE and selected neighbors

Direction	Market Coupling	2010	2011	2012	2013	2014	2015Q1,2
DE → HU		NA	94%	100%	99%	100%	100%
HU → DE	*Not introduced*	NA	97%	99%	99%	99%	99%
Total		NA	100%	100%	100%	100%	100%
DE → FR		90%	11%	30%	42%	32%	67%
FR → DE	*Since Nov. 9, 2010*	85%	27%	7%	12%	17%	7%
Total		92%	38%	37%	53%	49%	73%

Note: NA indicates missing data.

Table 3 stylistically explains how market coupling is indeed successful in reducing cross-border congestion through efficient capacity allocation by two selected market pairs: Germany–Hungary have not yet implemented market coupling; Germany–France have introduced market coupling in the end of 2010. The table shows the share of hours with congested interconnectors and the direction of congestion. Without market coupling, interconnector capacity is congested throughout – and thus, allocated inefficiently – as Germany–Hungary shows. Indeed, we see that available capacities are almost entirely congested in both directions at the same time.

Similarly, for Germany–France in 2010, before the introduction of market coupling, interconnection capacities were frequently exhausted (92% in total) in both directions. Upon the introduction of market coupling, congestion was limited to 38% in 2011. Additionally, we see that with market coupling, capacity can only be allocated in one direction exclusively. Evidently, simultaneous auctioning of capacity and electricity leads to an efficient allocation of available capacity.[15] After 2011, congestion between Germany and France increased again, which may be explained by the rising share of subsidized and prioritized generation from intermittent renewables, which frequently lead to excess supply in Germany, which is then exported to neighboring markets (e.g. France).

6. Results

In the following, we show regression estimates based on our empirical methodology as presented in section 4. Given that our large dataset of 25 price series for the hourly period 2010–2015Q2 yields a number of 625 market pairs (adjacent and indirect pairs in both directions), it may be difficult to present tables containing complete estimation results. For this purpose, we either present summary tables of selected results for a complete set of all sample markets, or

[15] For more information relating to the benefits of market coupling see Booz & Co, et al. (2013).

tables of selected markets (foremost Germany and selected neighboring markets) including a richer detail of information.

6.1. First Stage: Degree of Market Integration

This section presents regression results from the cointegration model as introduced in Equation (1). If two price series have a strong co-movement in equilibrium, their estimated β-coefficient must be close to one. Table 4 presents the deviations[16] of the β-coefficients from perfect market integration ($\beta = 1$) for both adjacent and indirect market pairs estimated at the hourly frequency by year. Since some price data are not available for the early years in our sample, the number of included market pairs increases over time.

Table 4. 1st stage results, deviation from full integration ($\beta = 1$)

Adjacent market pairs						
Year	**Pairs**	**Dev. +/-0.10**	**Dev. +/-0.20**	**Dev. +/-0.30**	**Dev. +/-0.40**	**Dev. +/-0.50**
2010	60	32%	45%	53%	70%	78%
2011	72	47%	63%	74%	79%	89%
2012	72	42%	60%	72%	85%	88%
2013	76	46%	63%	66%	76%	91%
2014	76	36%	61%	68%	74%	79%
2015Q1, 2	76	41%	61%	71%	78%	89%
Indirect market pairs						
Year	**Pairs**	**Dev. +/-0.10**	**Dev. +/-0.20**	**Dev. +/-0.30**	**Dev. +/-0.40**	**Dev. +/-0.50**
2010	282	5%	10%	17%	25%	35%
2011	434	10%	17%	23%	30%	38%
2012	480	9%	17%	28%	38%	47%
2013	524	12%	21%	29%	35%	46%
2014	524	10%	20%	26%	35%	41%
2015Q1, 2	524	13%	22%	30%	37%	47%

Notes: "Dev. +/-" refers to positive or negative deviations of the estimated β-coefficients from unity in the respective magnitude. All reported numbers are statistically significant at the 99% level.

We can see that adjacent electricity markets show higher price correlations than market pairs with no common border, yet, indirect market pairs catch up more strongly than adjacent pairs. Despite an already high degree of integration at least in some markets, the European spot markets seem to be still far away from one single price (i.e. $\alpha = 0, \beta = 1$).

[16] For example, "Dev. +/-0.10" indicates a deviation of plus or minus 0.10 from $\beta = 1$ ($0.90 \leq \beta \leq 1.10$) and shows how many market pairs fall in this category.

Table 5. 1st stage results: β-coefficients and time effects

	All pairs (# = 600)						Adjacent pairs (# = 72)						Indirect pairs (# = 524)					
Hour	β		$P_{B,t} * T$		$P_{B,t} * T^2$		β		$P_{B,t} * T$		$P_{B,t} * T^2$		β		$P_{B,t} * T$		$P_{B,t} * T^2$	
1	0.303	***	0.0050	***	-0.00012	***	0.716	***	0.0017	***	-0.00006	***	0.244	***	0.0054	***	-0.00013	***
2	0.350	***	0.0038	***	-0.00011	***	0.744	***	0.0012	***	-0.00005	***	0.293	***	0.0042	***	-0.00011	***
3	0.388	***	0.0025	***	-0.00009	***	0.756	***	0.0009	***	-0.00004	***	0.334	***	0.0027	*	-0.00009	*
4	0.380	***	0.0028	***	-0.00009	***	0.750	***	0.0014	***	-0.00005	***	0.326	***	0.0030	***	-0.00009	***
5	0.330	***	0.0046	***	-0.00010	***	0.734	***	0.0020	***	-0.00005	***	0.272	***	0.0050	***	-0.00011	***
6	0.361	***	0.0042	***	-0.00010	***	0.744	***	0.0015	***	-0.00005	***	0.306	***	0.0046	*	-0.00010	*
7	0.427	***	0.0035	*	-0.00008	*	0.780	***	0.0011		-0.00004		0.376	***	0.0038	*	-0.00008	*
8	0.377	***	0.0081	**	-0.00012	*	0.816	***	0.0011		-0.00003		0.314	***	0.0091	**	-0.00013	*
9	0.330	***	0.0096	*	-0.00014	*	0.812	***	0.0012		-0.00004		0.260	***	0.0109	*	-0.00015	*
10	0.340	***	0.0081	*	-0.00013	*	0.805	***	0.0006	*	-0.00003		0.272	***	0.0092	*	-0.00014	*
11	0.343	***	0.0067	*	-0.00012	*	0.797	***	0.0003	*	-0.00003	*	0.278	***	0.0077	*	-0.00014	*
12	0.346	***	0.0058	*	-0.00012	*	0.789	***	0.0003		-0.00004		0.281	***	0.0066	*	-0.00013	*
13	0.303	***	0.0075	*	-0.00014	*	0.780	***	0.0007		-0.00004		0.234	***	0.0085	*	-0.00015	*
14	0.366	***	0.0058	*	-0.00012	*	0.789	***	0.0008	*	-0.00004	*	0.305	***	0.0065	*	-0.00013	*
15	0.392	***	0.0051	*	-0.00011	*	0.800	***	0.0005		-0.00004		0.333	***	0.0057	*	-0.00012	**
16	0.341	***	0.0077	*	-0.00013	**	0.787	***	0.0014		-0.00004		0.276	***	0.0087	*	-0.00014	**
17	0.334	***	0.0082	*	-0.00013	*	0.780	***	0.0018	*	-0.00004		0.270	***	0.0091	**	-0.00015	*
18	0.300	***	0.0112	*	-0.00016	*	0.783	***	0.0027		-0.00005		0.230	***	0.0125	**	-0.00018	**
19	0.285	***	0.0113	**	-0.00016	*	0.778	***	0.0027	*	-0.00005	*	0.213	***	0.0126	**	-0.00018	**
20	0.322	***	0.0086	**	-0.00015	*	0.735	***	0.0031		-0.00006	*	0.262	***	0.0093	**	-0.00016	*
21	0.266	***	0.0085	**	-0.00015	**	0.663	***	0.0040	*	-0.00008	***	0.208	***	0.0092	**	-0.00017	**
22	0.330	***	0.0035	***	-0.00011	***	0.664	***	0.0028	***	-0.00007	***	0.281	***	0.0036	*	-0.00011	*
23	0.426	***	-0.0008	***	-0.00008	***	0.714	***	0.0007	***	-0.00005	***	0.385	***	-0.0010	*	-0.00008	*
24	0.349	***	0.0024	***	-0.00010	***	0.702	***	0.0015	***	-0.00006	***	0.298	***	0.0025	*	-0.00011	*
Peak	0.341	***	0.0079	**	-0.00013	**	0.794	***	0.0012	*	-0.00004	**	0.276	***	0.0089	**	-0.00014	**
Off-peak	0.475	***	0.0025	**	-0.00008	**	0.798	***	0.0013	**	-0.00004	**	0.429	***	0.0027	**	-0.00008	**
Daily	0.456	***	0.0048	***	-0.00009	**	0.814	***	0.0011	***	-0.00004	**	0.404	***	0.0054	***	-0.00010	**

*Notes: Peak period: 08:00-20:00, Off-peak period: 00:00-08:00 & 20:00-24:00. T is a monthly indicator (2010m1: T=0, …, 2015m6: T=65). ***, **, * indicate significance at the 99%, 95%, and 90% level, respectively.*

Table 5 shows a summary of the first stage regression results for all sample market pairs, and additionally distinguishes between adjacent and indirect market areas. Moreover, the table provides estimates for each daily hour (01:00–24:00), for averages of peak and off-peak periods, and for daily averages. The analysis follows Equation (1) but is extended by additional interaction terms with a monthly time trend ($P_{B,t} * T$) and its squared term ($P_{B,t} * T^2$) to capture non-linear time effects on the cointegrating relation (β) between the two price series. Hence we can reformulate Equation (1) as:

$$P_{A,t} = \alpha + \beta P_{B,t} + \beta_1 P_{B,t} * T + \beta_2 P_{B,t} * T^2 + Z_t, \quad (8)$$

where T runs from zero in the first month (2010m1) to 65 in the last month (2015m6). The estimates thus shed some light on the question of how market integration evolves over time.

For the daily average over all market pairs, a cointegration coefficient of $\beta = 0.456$ means that, on average, all 600 market pairs tend to exhibit a co-movement of their daily spot prices of 45.6%.[17] This number seems to be quite modest and is a preliminary indication that market integration among European electricity markets is limited and far from full convergence.

Yet, the 72 adjacent market pairs tend to be already well-integrated concerning their cointegrating relation of $\beta = 0.814$ at the daily average. Evidently, the 524 indirectly linked markets are, on average, only half as well cointegrated ($\beta = 0.404$) as adjacent market pairs. Besides, while adjacent market areas tend to be equally cointegrated in peak ($\beta = 0.794$) and off-peak ($\beta = 0.798$) times, indirect pairs show a higher degree of cointegration during off-peak periods ($\beta = 0.43$) compared to peak periods ($\beta = 0.28$). Table 5 also shows that the cointegration coefficients vary by each daily hour indicating that markets may work better in some hours than in others.[18]

Graph 1 shows how the degree of market integration (β-coefficients) change over time according to our estimations. We can see that integration increases until mid of 2012 but then decreases in subsequent years. It seems that investment in interconnector capacity and in market coupling have led to higher levels of integration, yet with structural changes in the electricity markets – foremost the increasing share of subsidized and prioritized feed-in of intermittent renewables – have counteracted integration in Europe in later years.

[17] Non-adjacent markets dominate the overall effects, given their relatively large number of 524 indirect pairs, compared to only 72 direct pairs.

[18] Note that the daily averages do not necessarily reflect the averages of the daily hours, since their moments (mean, variance) are different.

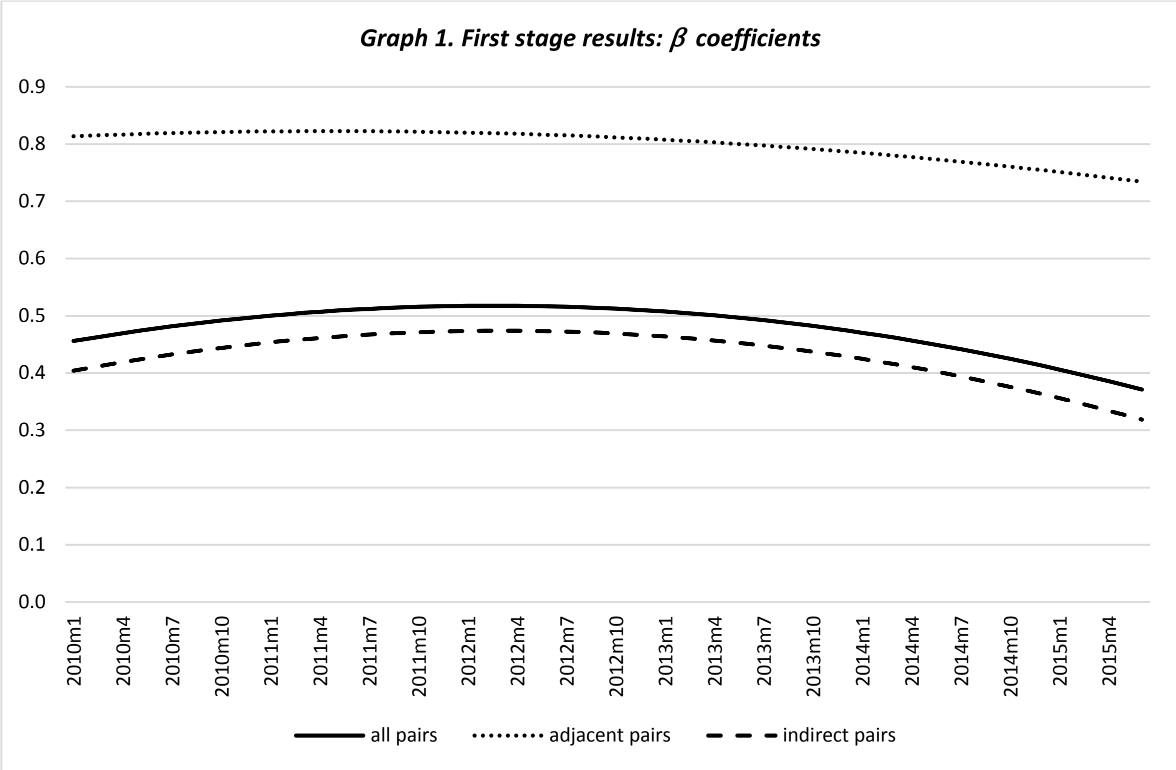


Table 6 is based on a subsample of market pairs that were subject to the establishment of market coupling and provides first stage regression results according to Equation (4). We are able to distinguish the direction of congestion in the regressions and explicitly watch their effect on the degree of integration with and without market coupling. While cross-border congestion in levels (CBC_{AB} and CBC_{BA}) directly influences the institutional difference, α, the interaction terms ($P_B * CBC_{AB}$ and $P_B * CBC_{BA}$) show how the degree of integration, β, changes with congestion in the respective direction. Evidently, before market coupling, cross-border congestion has ambiguous effects on α and β, since available capacities may have been allocated inefficiently in either direction (independently of the relative prices between markets A and B). For example, between Germany and Italy, prior to market coupling, uncongested trade ($CBC_{AB,t} = 0$, $CBC_{BA,t} = 0$) results in $\alpha = 11.79$ and $\beta = 0.47$. The two markets have a relatively high institutional price difference of EUR 11.79 per MWh, and their long-rung price relation of 47% is relatively modest. While export congestion ($CBC_{AB,t} = 1$) lets α decrease by 3.47 to 8.32 and β increase by 0.04 to 0.53, import congestion ($CBC_{BA,t} = 1$) lets α increase by 1.91 to 13.70 and β decrease by -0.04 to 0.43.

Table 6. 1st stage estimates before and after the introduction of market coupling

Market		Before MC							After MC					
A	**B**	**Intro. MC**	α	β	CBC_{AB}	CBC_{BA}	$P_B * CBC_{AB}$	$P_B * CBC_{BA}$	α	β	CBC_{AB}	CBC_{BA}	$P_B * CBC_{AB}$	$P_B * CBC_{BA}$
DE	FR	10.11.2011	0.64	0.89	4.68	8.46	-0.19	-0.05[a]	0.00[a]	1.00	1.61	16.70	-0.29	-0.25
DE	IT	24.02.2015	11.79	0.47	-3.47	1.91	0.04	-0.04	0.00[a]	1.00	-1.54[a]	16.03	-0.37	-0.29
DE	DKE	05.02.2014	1.79	0.96	11.95	15.21	-0.47	-0.14	0.00[a]	1.00	-4.38	12.35	-0.12	-0.15
DE	DKW	05.02.2014	-0.08[a]	1.00	-7.72	20.00	-0.03	-0.25	0.00[a]	1.00	-1.86	13.85	-0.19	-0.19
DE	$SE4$	05.02.2014	2.38	0.95	5.72	24.32	-0.38	-0.34	0.00[a]	1.00	-6.75	12.84	-0.05	-0.16
FR	DE	10.11.2011	11.18	0.85	-14.53	5.33	0.13[a]	0.03[a]	0.00[a]	1.00	-7.50	18.46	-0.04	-0.16
FR	IT	24.02.2015	10.43	0.56	2.49	-3.32	-0.11	0.25	0.00[a]	1.00	1.54[a]	25.89	-0.36	-0.40
FR	ES	13.05.2014	21.07	0.55	-18.65	12.72	0.15	-0.02	0.00[a]	1.00	-7.67	21.47	-0.22	-0.29
SL	IT	01.01.2011	7.49	0.87	0.05	-0.55	-0.29	0.14	0.00[a]	1.00	-2.98	21.44	-0.31	-0.31
IT	DE	24.02.2015	28.87	0.92	2.64	-0.74	-0.04	-0.08	0.00[a]	1.00	-9.93	32.59	-0.01[a]	-0.46
IT	FR	24.02.2015	28.84	0.74	-11.73	5.00	0.06	-0.03	0.00[a]	1.00	-7.21	31.87	-0.13	-0.48
IT	SL	01.01.2011	0.48	1.00	-4.65	28.85	-0.08	-0.24	0.00[a]	1.00	-7.02	31.85	-0.11	-0.46
DKE	DE	05.02.2014	0.45[a]	0.98	1.69	11.64	-0.21	0.01[a]	0.00[a]	1.00	-0.37	20.68	-0.58	-0.58
DKW	DE	05.02.2014	1.84	0.96	2.95	17.53	-0.25	-0.27	0.00[a]	1.00	5.67	15.79	-0.39	-0.39
$SE4$	DE	05.02.2014	1.56	0.94	6.17	19.56	-0.33	-0.14	0.00[a]	1.00	7.11	21.94	-0.40	-0.63
ES	FR	13.05.2014	21.96	0.41	-15.42	4.45	0.11	0.21	0.00[a]	1.00	-7.56	32.97	-0.07	-0.42

Notes: [a] *insignificant coefficient (below the 90% significance level). "Intro. MC" stands for the date of the introduction of market coupling.*

Besides, Table 6 shows that without market coupling the law of one price does not hold even when interconnection capacities were not exhausted due to misallocation of available capacity. In other words, in spite of controlling for cross-border congestion, adjacent market areas' prices do not fully converge to perfect cointegration as $\alpha > 0$ and $\beta \neq 1$.[19] After the introduction of market coupling, markets are indeed perfectly integrated ($\alpha = 0$, $\beta = 1$), when we control for interconnection congestion. This may not be surprising, yet empirically proofs that no other drivers except for market coupling and interconnector capacities are responsible for price convergence.

6.2. Second Stage: Efficiency of Market Integration

Provided the discussion in Section 4.2., we estimate the error correction model during times of unequal prices (i.e. trade restrictions) at the time when the shock is measured (in t-24). From this, we draw inference about how effectively markets deal with shocks during times of trade frictions. In the following, we present estimates (i) for the *unconstrained error correction model* as in Equation (6), which shows the speed of adjustment back to the actual long-rung equilibrium relation between a price pair; and (ii) for the *constrained model*, where we impose perfect price relations ($\alpha = 0, \beta = 1$) and estimate the speed of adjustment back to uniform prices.

Table 7 presents a comprehensive summary of the estimated coefficients of the error correction terms between all adjacent market areas.[20] The table only includes values for which Granger causality tests indicate causal relations (i.e. rejection of the H_0 that P_B does not Granger cause P_A at the 90% level). In Column (1), the table shows ECT estimates of the unconstrained model (Equation (6)) back to the actual long-run equilibrium relationship (β). The average estimated ECT across adjacent market pairs is $\bar{\eta} = -0.30$. However, as mentioned above, this estimate is not representative across markets, since β-coefficients vary strongly.

[19] One exemption is DE-DKw, for which α is statistically insignificant and β equals one.

[20] The estimations exclude wind and solar forecasts due to unavailable data for most markets. However, including wind and solar forecast for DE, DKe, and DKw does not alter the coefficients of the ECT in the respective estimations. Hence, wind and solar forecasts may be of subordinate significance for our estimations. Moreover, all regressions include a binary indicator for market coupling (and other control variables). The estimates indeed proof that market coupling leads to a price increase in the initially low price market and vice versa. Results are available upon request.

Table 7. Second stage results: ECT for unconstrained and constrained models, hourly

Market			**ECT**		**Obs.**			**Market**			**ECT**		**Obs.**		
A	B	β	**(1) unconst.**	**(2) constr.**	$P_{A,t-24} \neq P_{B,t-24}$	**Total**	**%**	**A**	**B**	β	**(1) unconst.**	**(2) constr.**	$P_{A,t-24} \neq P_{B,t-24}$	**Total**	**%**
DE	FR	0.74	-0.30	-0.18	24,541	48,137	51.0	SE3	NO1	0.94	-0.36	-0.35	20,711	48,136	43.0
DE	CH	0.73	-0.37	-0.23	45,480	48,149	94.5	SE2	SE3	0.97	-0.27	-0.26	1,075	48,136	2.2
DE	IT	0.49	-0.25	-0.09	45,823	48,149	95.2	SE2	NO4	1.00	-0.39	-0.39	7,992	48,136	16.6
DE	DKE	0.63	-0.20	-0.10	31,218	48,114	64.9	SE1	NO4	1.00	-0.39	-0.39	7,800	48,136	16.2
DE	DKW	0.89	-0.22	-0.19	28,835	48,144	59.9	PT	ES	0.96	-0.23	-0.20	4,914	48,168	10.2
DE	SE4	0.52	-0.22	-0.12	37,672	48,117	78.3	ES	FR	0.34	-0.27	-0.15	44,543	48,154	92.5
DE	CZ	0.93	-0.45	-0.35	45,266	48,149	94.0	ES	PT	0.99	-0.38	-0.37	4,914	48,168	10.2
FR	CH	0.88	-0.30	-0.23	45,390	48,154	94.3	NO5	NO2	1.05	-0.38	-0.37	7,856	48,168	16.3
FR	IT	0.50	-0.21	-0.08	45,622	48,154	94.7	NO5	NO1	0.88	-0.04	-0.03	5,557	48,168	11.5
CH	DE	0.90	-0.26	-0.22	45,504	48,149	94.5	NO3	SE2	0.98	-0.21	-0.21	6,860	48,134	14.3
CH	FR	0.88	-0.29	-0.23	45,413	48,154	94.3	NO3	NO4	1.01	-0.50	-0.50	3,495	48,134	7.3
CH	IT	0.53	-0.18	-0.06	45,715	48,168	94.9	NO3	NO1	0.95	-0.39	-0.37	23,165	48,134	48.1
SL	DE	0.89	-0.27	-0.25	42,507	45,029	94.4	NO2	DKW	0.61	-0.02	-0.01	26,923	48,163	55.9
SL	IT	0.65	-0.26	-0.16	36,426	45,048	80.9	NO2	NO5	0.93	-0.18	-0.15	7,856	48,168	16.3
HU	DE	0.89	-0.40	-0.38	40,657	43,316	93.9	NO2	NO1	0.83	-0.09	-0.06	6,162	48,168	12.8
HU	SK	0.92	-0.46	-0.45	23,312	39,404	59.2	NO1	SE3	0.86	-0.06	-0.04	20,745	48,136	43.1
IT	DE	0.81	-0.24	-0.22	45,847	48,149	95.2	NO1	NO5	1.03	-0.25	-0.25	5,557	48,168	11.5
IT	FR	0.67	-0.24	-0.21	45,646	48,154	94.8	NO1	NO3	0.89	-0.10	-0.08	23,203	48,134	48.2
IT	CH	0.71	-0.25	-0.22	45,715	48,168	94.9	NO1	NO2	1.09	-0.25	-0.25	6,162	48,168	12.8
IT	SL	0.73	-0.25	-0.21	36,449	45,048	80.9	FIN	SE3	0.92	-0.55	-0.52	11,999	48,128	24.9
DKE	SE4	0.90	-0.45	-0.42	11,917	48,133	24.8	FIN	SE1	0.92	-0.56	-0.52	12,617	48,128	26.2
DKW	DE	0.74	-0.25	-0.15	28,840	48,144	59.9	FIN	EST	0.91	-0.16	-0.15	14,683	45,993	31.9
DKW	DKE	0.68	-0.21	-0.09	13,352	48,128	27.7	LV	EST	0.95	-0.37	-0.37	9,414	18,192	51.7
DKW	SE3	0.59	-0.36	-0.21	22,274	48,131	46.3	EST	FIN	0.56	-0.30	-0.12	14,678	45,993	31.9
DKW	NO2	0.64	-0.37	-0.29	26,918	48,163	55.9	CZ	DE	0.94	-0.40	-0.34	45,290	48,149	94.1
SE4	DE	0.61	-0.11	-0.07	37,638	48,117	78.2	SK	CZ	1.01	-0.81	-0.81	897	39,408	2.3
SE4	SE3	0.98	-0.43	-0.43	2,286	48,136	4.7								

Notes: The Table only includes values for which Granger causality tests reject the H_0 that P_B does not Granger cause P_A at the 90% level. The constrained model imposes a uniform price relation ($\alpha = 0, \beta = 1$). Estimates of β>1 are statistically not different from 1. "Obs." is the number of hours for which $P_{A,t-24} \neq P_{B,t-24}$. All ECT coefficients are significant at the 99% level. Robust standard errors are applied. All regressions include the following control variables: 24h lag of the dependent variable, dummy for market coupling, price of gas, fixed effects for holidays, days and months.

Column (2) of Table 7 gives estimates of the constrained model (Equation (7)) back to uniform prices (i.e. $\alpha = 0,\ \beta = 1$). In this specification, we can directly compare the estimated coefficients of the ECT across market pairs in order to evaluate their efficiency to deal with systemic shocks. The number of observations is low for some market pairs indicating that price differences are hardly observed and that most of the times market integration is perfectly efficient already. The average speed of adjustment back to uniform prices is $\bar{\eta} = -0.25$ indicating that 25% of a price shock within 24 hours. This number is somewhat lower than what the unconstrained model would predict.

Form Table 7, the ECT coefficient estimates from the unrestricted model suggest that some market areas work well in terms of high speeds of adjustment (i.e. high negative ECT coefficients), yet their long-rung price relations may be far from perfect (β deviates from unity). For example, the market pair DE-FR exhibits a speed of adjustment of $\eta = -0.30$, yet $\beta = 0.74$. This means that 30% of a price shock are absorbed within 24 hours back to an equilibrium level of integration of 74%. The ECT coefficient from the restricted model, however, is only $\eta = -0.18$, indicating that 18% of a price shock are absorbed within 24 hours back to uniform prices. It takes longer to converge to perfect integration.

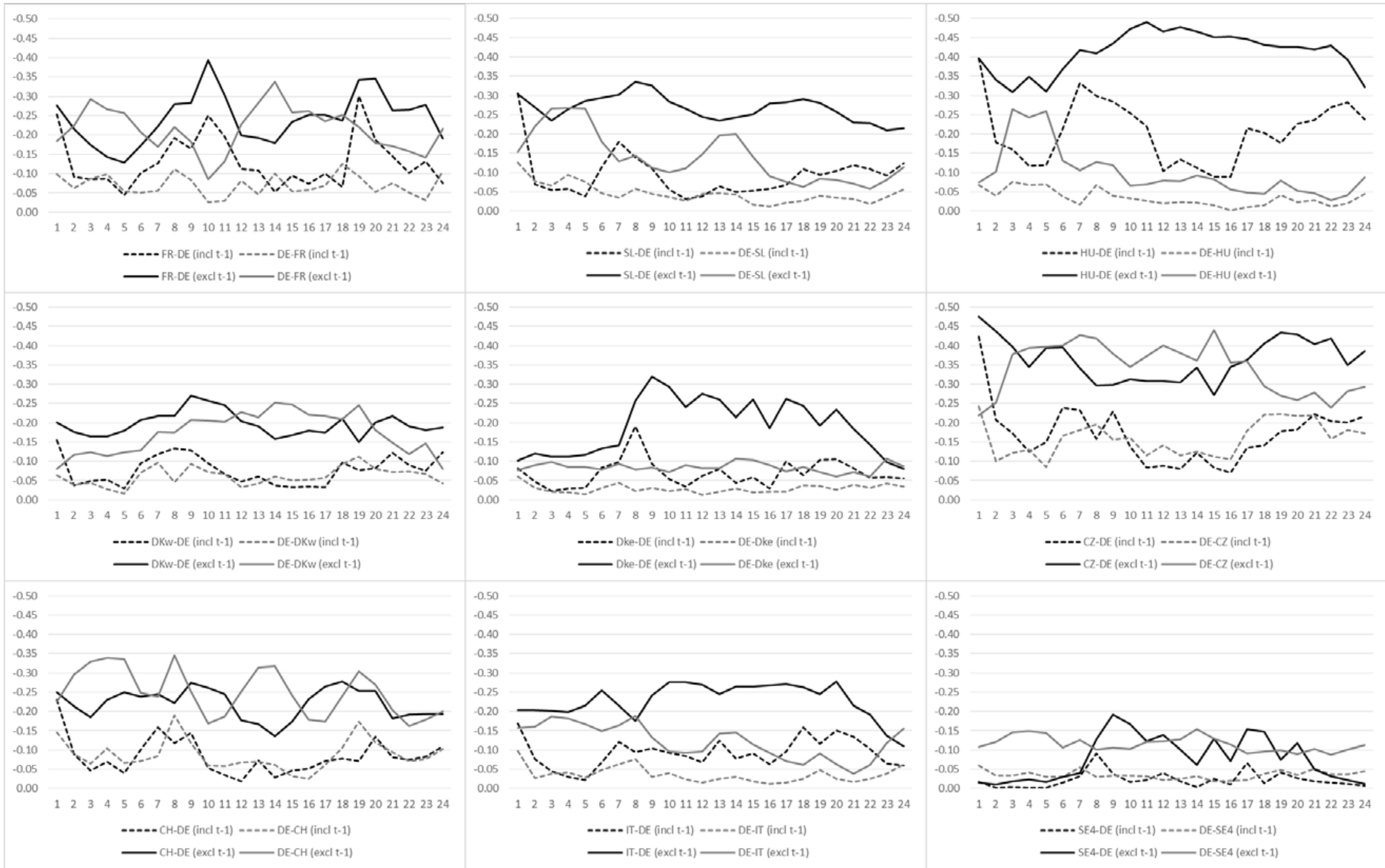
Also, Table 7 shows that some market pairs work more efficiently in one direction than in the other. While, for example, the constrained model delivers a parameter estimate of $\eta = -0.09$ for DE-IT, it yields $\eta = -0.22$ for IT-DE. Provided that Italy is relatively shut-off from its neighbors, we can see that the markets work more efficiently from Germany to Italy than in the other direction.

Finally, we discuss the lag structure of the error correction model. Compared to many other studies, which employ daily averages in their analyses, our data are at the hourly frequency. This allows for the additional inclusion of a one-hour lag in the error correction model to capture intra-day demand and supply frictions. For example, the demand in a particular hour may depend on the daylight, and thus hinge upon the previous hour. Conventional power plants, which cannot adjust their electricity production (i.e. "ramping") according to each hour's demand may represent an example for an intra-day supply rigidity.

For this purpose, Graph 2 presents ECT coefficient estimates from the constrained model (Equation (7)) for Germany and its neighboring markets both with and without including a one-hour autoregressive term. Evidently, the magnitudes of the ECT coefficients are larger when the model does not control for the intra-day lag. Intuitively, without changes of demand and supply in the previous hour, the model indicates any price adjustments as error corrections (captured by η). The inclusion of the intra-day lag leads to a drop in the estimates of the ECT, on average, since the model only captures ceteris paribus price adjustments that are not explained by daily or intra-day supply and demand changes. Moreover, Graph 2 shows that for most of the time, markets exhibit a higher degree of efficiency when Germany represents the exogenous market (DE on the right-hand side).

In summary, once we control for intra-day demand and supply changes, markets' efficiency to absorb price shocks seems to be limited and drops well below the 20% level during most hours of the day. This is an indication that the efficiency of market integration in Central Europe is quite moderate. The application of the error correction model, thus, may signpost that additional investment in interconnector capacity and the establishment of market coupling may be necessary in order to enhance the performance of market integration. Especially for regions with low performance, investment in additional interconnector capacity and the establishment of market coupling (if not already implemented) may bring about great welfare improvements.

Graph 2. Second stage results: ECT from constrained model, DE and neighboring markets, hourly



Notes: Estimates for ECT are based on the constrained model as in Equation (7). Black lines: DE on the right-hand side; Gray lines: DE on left-hand side; Solid lines: excluding intra-day lag (t-1); Dashed lines: including intra-day lag (t-1).

7. Conclusions

In this study, we empirically investigate the current state of the integration of day-ahead electricity spot markets in Europe. We argue that market integration may be desirable from a welfare perspective (through allocative efficiency) and thus represents a normative benchmark for policy making. Moreover, recent developments call for better market integration for the purposes of balancing and supply security. For example, the increasing production from intermittent renewables puts pressure on the grid and increases interconnector congestion (Baritaund & Volk, 2014). Moreover, an increasing share of prosumers tend to feed electricity into the grid (from the downstream end) at times of low demand, which also destabilizes the grid.

To obtain these benefits, enhanced market integration necessitates the availability of physical transport facilities (reduction of intra-market bottlenecks in the grid and the extension of interconnection capacity between adjacent markets) as well as the establishment of market coupling in order to efficiently allocate capacities. Each of these prerequisites is directly linked to enormous investments that are sunk. Besides the enormous investment costs, welfare redistribution may place an obstacle on the political realization of a single European electricity market, since we argue that market integration also creates winners and losers. This is why market integration *up to some degree* may be desirable, in order to attain a great deal of its associated positive effects, yet avoid the enormous investment costs of inducing perfect market integration.

The econometric approach of this paper goes beyond the scope of other related empirical literatures on this topic. First, we collected data on a rich sample of prices from 25 European electricity spot markets for the hourly period from January 1, 2010 to June 30, 2015. Second, we extend this dataset by interconnection congestion, its direction, and market coupling, in order to control for trade frictions. Third, we posit that the estimation of an error correction model may be inadequate during times of uncongested trade (i.e. uniform prices), when markets are already fully efficient, so that no shocks resulting in differential prices can be observed. We therefore restrict our estimations to times of trade frictions (i.e. interconnection congestion and/or absence of market coupling) to infer about how efficiently markets deal with price shocks when the system does not work fully efficient. Fourth, we stress that estimates of the error correction model should be constrained to a perfect cointegrating relation in order to make statements about markets' speeds of adjustment after shocks back to uniform prices. Fifth, we provide evidence that the inclusion of intra-day price lags is important in order to control for demand and supply rigidities. When doing so, there is indication that European markets still seem to have rather low efficiency in absorbing price shocks.

In a first step, we provide empirical evidence from cointegration analysis that market integration among European electricity markets increased in the beginning of the sample period, but has been declining since about the second quarter of 2012. This result may be largely driven by the increased electricity production from subsidized intermittent renewables. Hence, market integration represents a desirable policy instrument for markets with increasing shares of renewable electricity generation in order to balance volatility and secure network stability through trade. While adjacent market pairs seem to be well cointegrated ($\beta = 0.81$) already, indirect pairs' cointegration tends to be only half as high ($\beta = 0.40$). In sum, the level of integration among European electricity markets is still modest, and for some regions very low. In addition, we empirically show that interconnector capacity and market coupling are the sole drivers of price convergence – in the presence of market coupling and uncongested interconnectors, markets have uniform prices.

In a second step, the empirical results from an error correction model indicate that adjacent markets have limited efficiency to deal with price shocks conditional on observed trade frictions (i.e. price differences). On average, European market pairs have a speed of adjustment of, on average, $\eta = -0.25$ indicating that 25% of a shock are absorbed within one day back to uniform prices. Moreover, at the hourly frequency, we are able to include a one-hour autoregressive lag (which cannot be done at the daily frequency), which accounts for intra-day demand and supply rigidities. Doing so, the estimated parameters of the error correction terms between Germany and its neighboring markets drop well below the 20%-level for most of the hours. This is a strong indication that the state of market integration is still quite limited, raising the potential for further welfare improvements from additional capacity investments and the establishment of market coupling. Especially markets with low initial levels of available interconnection capacity may experience substantial benefits from investment in market integration.

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