Convergence of Electricity Wholesale Prices in Europe?

- A Kalman Filter Approach -

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Abstract:

This study tests the hypothesis that the ongoing restructuring process in the European electricity sector as well as the market participants adaptation to the new legal framework caused electricity wholesale day ahead prices to converge towards arbitrage freeness. Using the hourly cross-border capacity auction results at the Dutch-German and at the Danish-German border for the years 2002 to 2004 as well as the respective spot prices a model based on the law of one price (LOP) is estimated by applying the Kalman filter. The obtained results are used to calculate a one number summary that indicates the convergence of markets towards the LOP. It comes out that only 19 out of the analyzed 72 hourly pairs of spot prices and cross border transmission capacity prices did not converge towards the LOP in the years 2002 to 2004. This is a clear sign that sector reforms and the adaptation of the market participants to the new framework were able to reduce market inefficiencies. However, the convergence processes differed between the observed borders

Keywords: L94, C5, G1

JEL classification: Electricity Prices, European Integration, Time Series Analysis

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[1] The study has been prepared in the framework of the SESSA Work Package 5. The author would like to thank Franziska Holz and Christian von Hirschhausen for their many helpful comments and discussions regarding this work. All remaining errors are the authors' sole responsibility.

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1 Introduction

Electricity markets throughout Europe were undergoing significant changes in recent years. These developments were mainly due to an European economic policy that targets on creating a single sustainable European market for goods and services and thus for electricity, too. The latter is not an aim in itself but it is to create competition and to collect the gains from international cooperation such as reserve sharing or combining different national consumption and production patterns. Consequently a common electricity market is expected to increase welfare by increasing security of supply and improving allocation through more cost reflective prices. Two important Directives, one Regulation and a variety of Decisions issued by the European Union obliged all old and new EU member countries to take substantial reform steps to prepare the path for the development of a single European market of electricity. Along with other measures European rules required market opening (e.g. Directive 2003/54/EC), obstacles to cross border trade were reduced (Regulation 1228/2003), and non-discriminatory third party access was guaranteed (e.g. Directive 2003/54/EC). The implementation of the aforementioned obligations into national law differed significantly among countries. Therefore a variety of reports benchmarking the national electricity sector reforms appeared recently (e.g. EC (2005), OXERA (2004), EBRD (2004)). From those it is clear that although substantial progress was made in the last years some national markets are still faced with major obstacles to market entry and electricity trade.

Given the structural changes that took place in the national electricity sectors in the last years this article now asks whether the market outcomes indicate an improvement of the competitive situation in the covered countries. One strong indicator for the success of the market reforms is the interaction of price signals across countries. Equal electricity prices in Europe[2] would be evidence for a single European market of electricity. Therefore the studies of Bower (2002), Boisseleau (2004) as well as Armstrong and Galli (2005) compare electricity day ahead wholesale prices at various power exchanges in Europe. Bower (2002) applies correlation and cointegration analysis to prices from the Nordic Countries, Germany, Spain, England

[2] When corrected for transmission costs and congestion fee.

and Wales as well as the Netherlands in 2001.[3] He concludes that some integration of European markets was already present in 2001, especially between the Netherlands and its neighbors and within the NordPool area. The relevant chapter in Boisseleau (2004) focuses on regression and correlation analysis. Boisseleau (2004) finds a very low level of integration of European markets and that except of the NordPool, European prices contain no unit root. Both, Bower (2002) and Boisseleau (2004) describe the respective status quo of electricity market integration. By way of contrast, Armstrong and Galli (2005) analyzes the European price developments over time. They study the evolution of price differentials between France, Germany, the Netherlands and Spain in the years 2002 to 2004. This allows them to conclude that European electricity markets converged in this period. Though this study is a leap forward since it is the first to analyze the process of price convergence in Europe it is faced with several flaws. *First*, the reasoning is based on the comparison of three yearly averages of price differentials only. Given the large number of data points (the three years amount to 26,304 hours) this approach seems relatively undifferentiated. *Second*, no statistical tests (e.g. t-tests) on the significance of the dissimilarity of the yearly average price differentials were performed. And *third*, the study excludes available relevant information as for example the results of the explicit cross border capacity auctions between the Netherlands and Germany.

In this paper, we propose a different approach. We aim at investigating the success of European electricity sector reforms by analyzing the development of wholesale prices over time. The hypothesis that prices converge is derived from both the potential instantaneous effects of the various reform steps on prices and the assumed indirect reaction due to market players, adapting to the new framework. The hypothesis will be tested by applying a time varying coefficient model to day ahead electricity prices of Denmark, Germany and the Netherlands. This approach was chosen to be able to monitor a continuous evolution over time. The considered countries were selected with respect to the availability of transmission capacity auction results which allow to incorporate cross border transmission costs into the analysis.

In the next section the electricity wholesale day ahead price series for eight price zones in Europe are introduced and some static principal component analysis of the interaction of those is carried out. Then the considered cross border transmission auction result data are

[3] Boisseleau points out that cointegration approach used in Bowers analysis is inappropriate because the original price series contained no unit root. In addition his use of unweighted daily averaged data is a flaw given the strong differences of peak and off-peak price behavior on the electricity market.

presented and the related arbitrage opportunities in international electricity trade are revealed and commented. In the third section a time varying coefficient model is described and applied to test whether the prices at the Dutch-German and the Danish-German border converged during 2002 to 2004. The fourth section concludes and provides policy conclusions of the analysis.

2 Data

2.1 Wholesale spot prices

Workable wholesale markets are one cornerstone of the European approach towards a common electricity market. Thus most old and some new member countries established power exchanges in recent years. Usually "day ahead" (spot) and "future" contracts are traded at these markets. The various maturities of future contracts makes it hard to compare their price developments among markets. By way of contrast the number of products at spot markets is by far lower. Usually only electricity for single hours of the following day as well as for different bands like peak and off-peak period are traded. Since the definition of the load periods varies across markets and because the single hour prices allow to obtain a much more detailed impression of the intraday developments, the latter are used in the analysis. Apart of their good comparability across markets and their accurate representation of intraday patterns, hourly spot prices also have the advantage of reflecting the current market situation where lots of the uncertainties that future markets are faced with are absent.

This study uses data of three West European countries (France, Germany, Netherlands), two Central European new EU member states (Poland, Czech Republic) and three North European price areas (Denmark East, Denmark West, Sweden). Sample length, used abbreviations and some key figures of these markets are summarized in Table 1. Note that since the participation on the considered wholesale spot markets is voluntary, their liquidity only represents a comparably small fraction of domestic consumption. Especially the French, Polish and Czech day ahead prices stand for but a minor market segment.

Despite all differences in structure, liquidity, products and market mechanisms the power exchanges in France (Powernext), Germany (EEX), the Netherlands (APX) and Poland (PolPX) are all running a comparably working "day ahead" (spot) segment for their respective national markets. The Nordic countries (Denmark, Finland, Norway and Sweden) have a common power exchange called NordPool which organizes the joint spot market Elspot. To incorporate congestion into the price formation mechanism the Nordic region is split into different price areas for which simultaneously spot prices and congestion fees are calculated. Finally, the Czech market operator OTE has also organized a day ahead market. Although OTE is not a usual power exchange, it provides the only available data on hourly spot prices from this big electricity exporting country.

Table 1: Hourly spot prices and volumes as well as the abbreviations for the power exchanges used in the analysis

Power Exchange	Currency	Spot Market Volume 2004 in GWh	Total Consumption 2004 in GWh[4]
APX – Amsterdam Power Exchange (NL)	€	13,402	110,047
EEX – European Energy Exchange, Leipzig (D)	€	59,414	513,015
DKE – East Danish NordPool price area (DK)	DK		14,251
DKW –West Danish NordPool price area (DK)	DK		21,244
SWE – Swedish NordPool price area (S)	SK		145,476
PNX – Powernext, Paris (F)	€	14,179	475,966
PPX – Polish Power Exchange, Warsaw (POL)	Zt	1,590	130,275
OTE – Czech Market Operator (CZ)	CZK	289	61,449

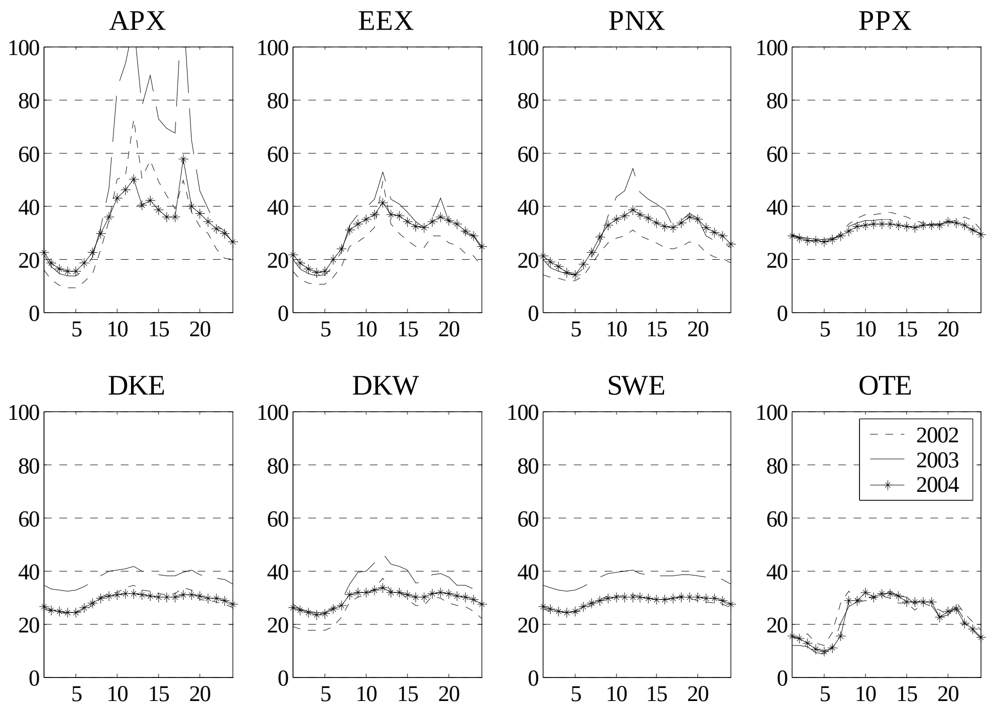
Figure 1 reveals one of the peculiarities of electricity prices – the strong seasonalities. In Amsterdam, for example, average power prices at the 12th hour (11am-12am) were around three times higher than average 4th hour (3am-4am) prices in 2004. These high differences during the day are due to the non-storability of electricity. In addition to the daily patterns, also weekly and yearly seasonalities exist. Unless these price fluctuations are less severe in some of the considered power markets[5], they have to be coped with. Unfortunately it is very difficult to deseasonalize the data because the daily, weekly and yearly seasonalities interact, national holidays differ across countries and the seasonality effects themselves are changing

[4] Source: Nordel and UCTE.

[5] The relatively modest daily seasonalities in Poland and Sweden have completely different reasons. The low price volatility in Poland can be linked to the low liquidity of the Polish market which signals inefficient pricing and the high number of combined heat and power plants that run whatever the prices are. By way of contrast the relatively flat Swedish and East-Danish price profile is explained by the high share of hydropower in the region (Norway).

over time. Therefore we choose to circumvent the seasonality problem by dividing all series into 24 sub series each of which represents one hour of the day. The weekly seasonalities were mainly removed by excluding all Saturdays and Sundays from the sample. Thus we obtained 192 series (8 x 24) consisting of 782 weekdays each. Finally the missing values in each series were replaced by the last observed value. The conversion into Euro was done using the exchange rates provided by www.oanda.com.

Figure 1: Yearly average of the wholesale electricity spot prices for each hour of the day



To access the quality of the obtained data two pre-tests are performed. *First* we check the unit root hypothesis because the absence of a unit root is both a typical statistical feature of electricity prices and a perquisite for many statistical methods. The results of the ADF tests given in Table 2 are in line with the assumption that electricity price do not experience unit root behavior. This absence of a unit root in electricity prices can be partly explained by the fact that in contrast to most other commodities power is not economically storable and thus can not easily be allocated between different periods. Therefore today’s electricity prices are basically not the best guess for tomorrows prices, which is what the unit root hypothesis suggests.

Table 2: Summary of ADF-test results – number of hours where the unit root hypothesis could not be rejected at the 1% significance level[6]

APX	DKE	DKW	EEX	OTE	PNX	PPX	SWE
0	0	0	0	0	0	0	7[7]

Second a Principal Component Analysis (PCA) is performed to reveal the interaction between the price series.[8] The underlying idea of PCA is to calculate the linear combinations of the original data matrix that explain most of the variance. Our data matrix consists of the week-days price series for the eight wholesale markets at a certain hour of the day. We calculate the first and second principal component (PC) for the normalized data and compute the correlation between the PCs and the original data.[9] The results are summarized in the form of a scatter plot. As Figure 2 indicates the eight wholesale markets can be roughly divided into three regional groups. The first group consists of the Dutch, German and French market. The second group contains the two considered Nordel transmission sub-zones East-Denmark and Sweden. And the third group assembles the two new member countries Poland and the Czech Republic. The only market that can not be clearly attributed to either of these groups is the West-Danish price area of the NordPool. At the same time, Figure 2 indicates that the West-Danish price is located in the halfway point of a line connecting the Nordic and the West European markets which algebraically represents its real function as link between those two regional markets. Together with the aforementioned clustering of strongly interconnected markets this is evidence that at least some arbitrage between neighboring countries is taking place and thus that the data are likely to be appropriate for the following in-depth analysis.[10]

[6] The detailed results are given in the Appendix (Table 5). We used 7 lags and incorporated a constant plus time trend in the estimation.

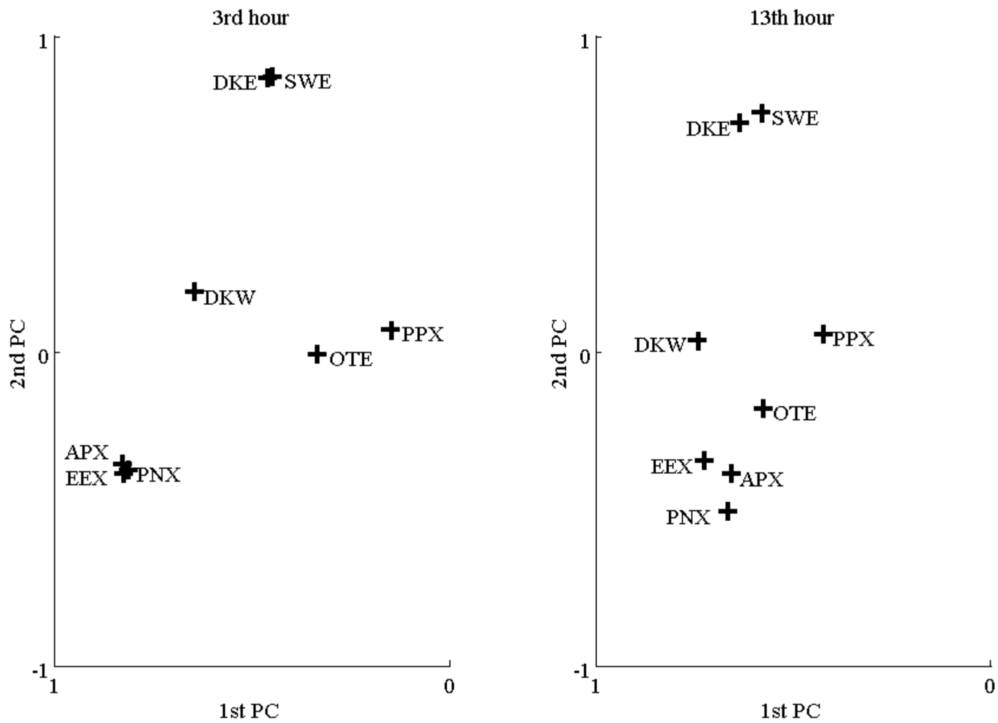
[7] The unit root hypothesis was rejected for all but one hour at the 5% significance level.

[8] For the technical details of PCA see for example Jackson (1991).

[9] Detailed results can be found in the Appendix (Table 6).

[10] Note however that a part of the common regional developments can be explained by shared supply and demand conditions (e.g. weather) and that thus not all correlation is only due to arbitrage between countries.

Figure 2: Correlation of the 3rd and 13th hour wholesale spot prices with their first and second common component[11]



Although principal component analysis is able to provide evidence for distinct regional price developments and thus for the existence of international arbitrage, it fails to examine whether markets converge or diverge over time. Furthermore a convenient description of international electricity wholesale markets is only possible when incorporating the allocation mechanisms of cross border transmission capacities in the analysis.

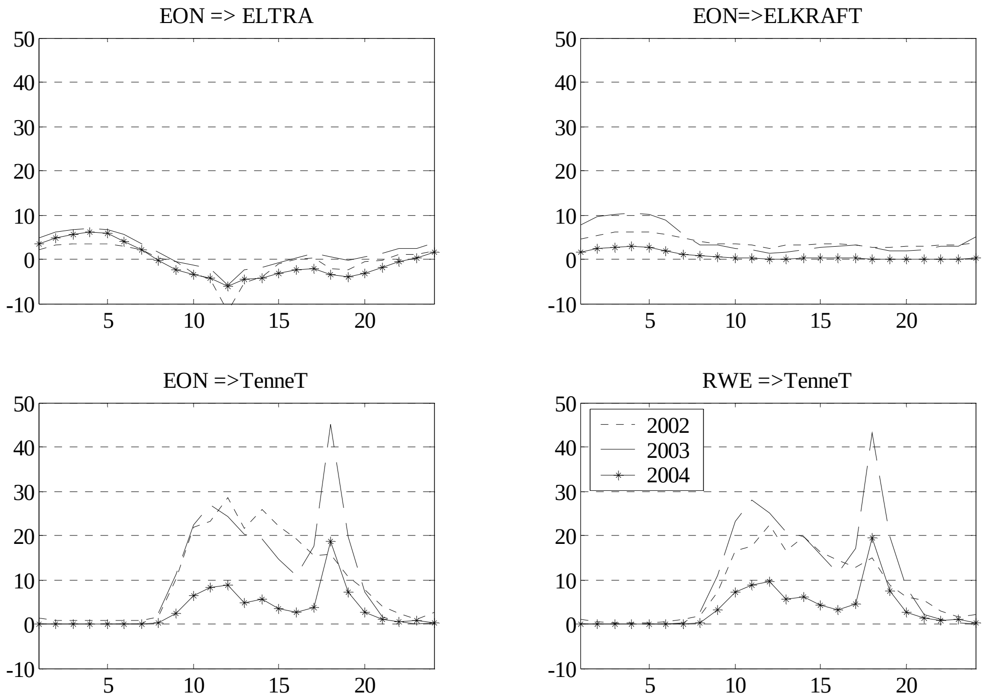
2.2 Cross border transmission auction results

To trade electricity across different regional markets it must be possible to transmit it from one region to another. This task is achieved via cross border transmission lines. Since those interconnection lines have only limited capacity, the right of their utilization in case of excess demand has to be allocated to the interested parties. These so called congestion management methods vary significantly throughout Europe (for more details see ETSO (2004)). The schemas applied reach from uneconomic first come first serve approaches between Belgium and France, over explicit auctions between Germany and the Netherlands up to the implicit auc-

[11] Note that the axes of the 1st PC have been inverted to adjust the plot towards the familiar geographic direction (Poland in the East, Sweden in the North and so forth).

tions in the NordPool area. The advantages and disadvantages of those methods are discussed in ETSO (2004) and CONSENTEC (2004). Apart from all allocation distortions, the non-auction based congestion management methods also fail to provide data on the utilization of the interconnection lines and the actual willingness to pay for the limited capacities.[12] On the other hand the implicit auctions of the NordPool area fulfill the arbitrage freeness condition by construction. Therefore only daily auction results for the Dutch-German and the Danish-German border are available to our analysis.

Figure 3: Cross-border transmission price differential (export price minus import price) in €/MWh 2002-2004



On the Danish-German border there are three adjacent transmission zones, one at the German (EON) and two at the Danish side (Eltra and Elkraft). Because the West Danish transmission network operated by Eltra is part of the West European UCTE-transmission system and the East Danish network (Elkraft) operates within the Nordel-system, interconnection capacities between them are relatively low and prices thus significantly different. Therefore both Danish areas are incorporated in the analysis.

[12] It is worth noting that there are projects for the replacement of non-auction based schemas by explicit auction between some of the considered countries. For example the transmission system operators (TSO) in Poland (PSE), the Czech Republic (CEPS) and Germany (Vattenfall ET) are planning a joint explicit daily auction of their interconnection capacities.

On the Dutch-German border the auction is operated by TenneT, the Dutch transmission system operator (TSO). From the German side two TSOs (RWE and EON) maintain cross border transmission lines with the Dutch grid. Therefore TenneT calculates the prices for both interconnections (EON-TenneT and RWE-TenneT) separately. Figure 3 indicates that the auction results at both borders are almost equal on average. Because only one German spot price is available the RWE-TenneT interconnection is omitted in the analysis.

Figure 4: EEX-DKW price differential and the associated physical flows between West Denmark and Germany 2002-2004

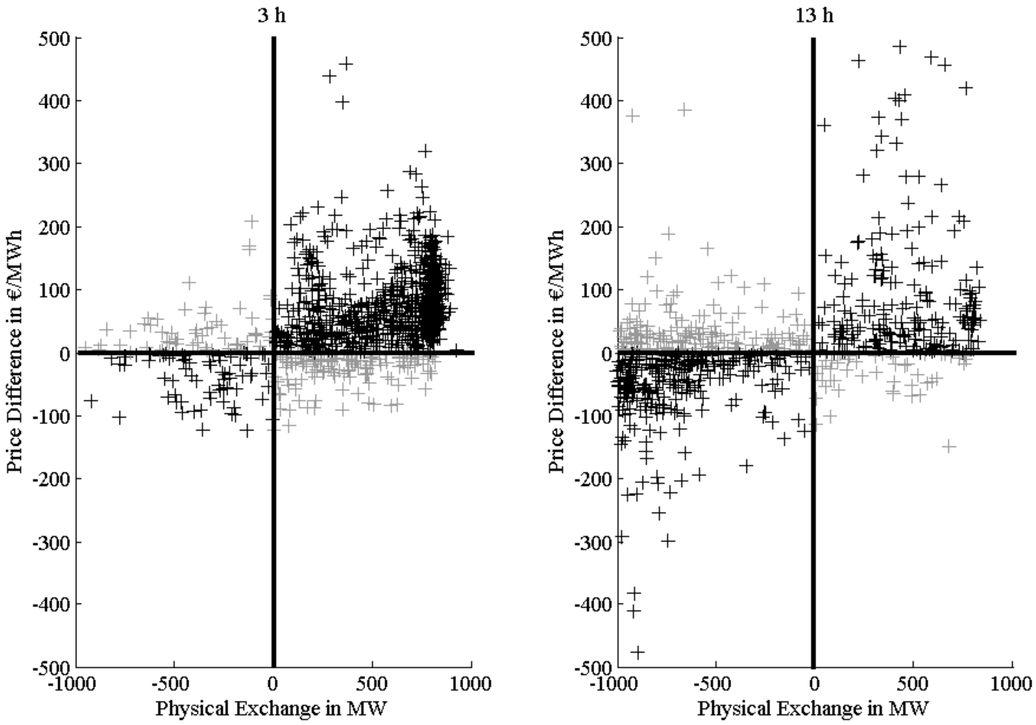


Figure 4 shows at the example of the West Danish-German border that electricity relatively often flows from high price to low price areas (gray crosses) which is counterintuitive. These deviations can hardly be explained by loop flows because West Denmark is a peninsula. If long term contracts were responsible for this unusual behavior this would imply that domestic arbitrage is imperfect. Another reason for the deviation from economic intuition is the uncertainty arising from the timing of the day ahead price setting processes.

As Table 3 illustrates, first the transmission capacity available to the daily auction is announced, then the bids are submitted, thereafter the auction is closed and finally the results are published. In parallel to the transmission capacity auction the power exchanges are collecting bid and sell offers. A certain time after the publication of the capacity allocation, outcomes the power exchanges subsequently close the bidding, calculate the spot prices and publish them. Therefore a trader who aims at doing arbitrage operations by selling cheaper German power to the Netherlands has to first bid for transmission capacity without knowledge on the exact spot prices, then he has to submit his sell offer for electricity in Amsterdam only knowing the transmission auction result. After being aware of the APX price, the transmission capacity price and the quantities he bought he can now bid for buying German power at the EEX.[13]

Table 3: Timing of cross border auctions and spot markets

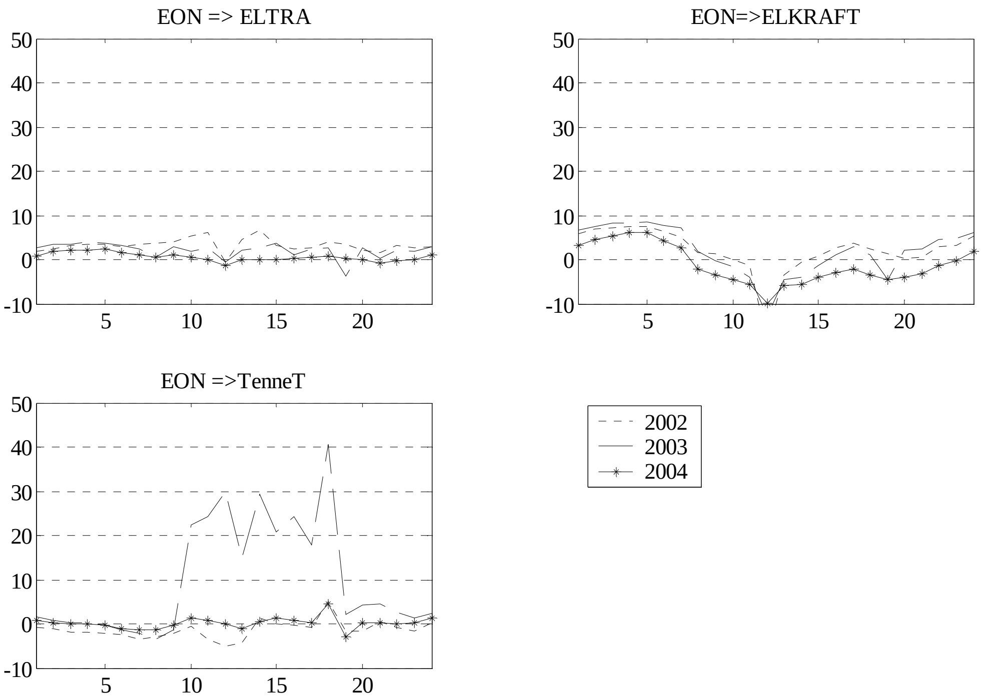
	Cross Border Auctions		Power Exchanges		
	EON-TenneT	EON-ELTRA	APX	Elspot	EEX
Available capacity known to market participants	8:30	9:00			
End of bidding	9:00	9:30	10:30	12:00	12:00
Publication of Results	9:30	10:00	11:00	12:00	12:15

From the above described example it is clear that that explicit auctions will not always result in (full informational) arbitrage freeness. However whether there are fundamental distortions is another question. Therefore we calculate the difference between the yearly average of the daily transmission auction prices and the yearly average of the spot price differentials for each hour of the day. Figure 5 gives clear evidence of the existence of arbitrage opportunities[14] between German and Dutch as well as German and Danish prices. But the comparison of the yearly averages also indicates that the inefficiencies have decreased over time. This might be explained by an improved legislative and regulatory framework, learning of the market participants, or both.

[13] Note that this example ignores the trader might be in the possession of long term contracts in some of the three markets.

[14] Here arbitrage opportunities are: | domestic price_t – foreign price_t – import cost_t + export cost_t | > 0.

Figure 5: Yearly average arbitrage opportunities



Although Figure 5 is able to provide a first insight and gives understandable graphical representation of the development of cross border arbitrage possibilities, simply averaging over the years tends to neglect much valuable information. Periods where exporting and periods where importing provides arbitrage opportunities might cancel out over the year, the effect of events like a transmission line closure is ignored and intra-year patterns remain undetected. Therefore an approach providing more differentiated results is applied in the next section.

3 Method and Results

The starting point for the analysis of the efficiency of markets usually is the law of one price (LOP). The LOP states that two similar commodities, when offered at the same location, have the same price. In theory the LOP should apply to wholesale electricity spot prices, too. However there are several factors that lead to deviations from price equalization. The hypothesis to be tested in our analysis is that some of the reasons for these inefficiencies were removed or alleviated as an effect of the ongoing electricity sector reforms and thus prices converged in the period under consideration. The analysis is carried out in three steps: *First*, a time variant coefficient (α_t) representing the difference of domestic and import prices is estimated. *Sec-*

ond, a proximity index is calculated, indicating the nearness of the observed prices to the LOP. And *third*, the speed of convergence towards the LOP is calculated by estimating the slope of the proximity's trend index.

When comparing the prices of goods at different locations, the costs associated to the transport have to be included in the analysis. Therefore arbitrage freeness is given if the price in the exporting country plus the transmission costs is equal to the price in the importing country. This relationship is formalized in (6) for the example of German and Polish prices. Here the variable $transm_{EEX->PPX,t}$ is the transmission price for one MW/h flowing from Germany to Poland. In the considered full information case either $transm_{EEX->PPX,t}$ or $transm_{PPX->EEX,t}$ is zero[15].

$$p_{PPX,t} + transm_{PPX->EEX,t} = p_{EEX,t} + transm_{EEX->PPX,t} \qquad (6)$$

In reality there are several factors that may lead to deviations from the LOP, e.g. uncertainty, market power and regulation. Therefore model (7) incorporates a random component as well as constant deviations from the LOP. Assuming the errors to be normally distributed those deviations can be calculated using ordinary least square estimations:

$$p_{PPX,t} = \alpha_0 + \alpha_1 p_{EEX,t} + \alpha_2 (transm_{EEX->PPX,t} - transm_{PPX->EEX,t}) + \varepsilon_t \qquad (7)$$

While this model might be valid in the short run, in the long run it ignores the effects of the ongoing restructuring process in the electricity industry. A straightforward way to address the question of long-run changes are time varying coefficient models of the form:

$$y_t = \alpha_t x_t + \varepsilon_t \qquad (8)$$

$$\alpha_t = \beta \alpha_{t-1} + \upsilon_t$$

with $\varepsilon_t \sim N(0,\sigma^2)$ *and* $\upsilon_t \sim N(0,\Sigma)$ *white noise process,*

α_t *the vector of unobservable coefficients at time t,*

β *a vector of time invariant coefficients,*

[15] In the real world cross border transmission capacity auctions often end up having positive prices in both directions, which is a clear sign of market inefficiencies (e.g. incorrect spot price forecasts, inner market frictions caused by market design or market power). The occurrence of such departures from our trade model are no flaw for us since we aim at benchmarking the real world versus our perfect market model.

y_t *the dependent variable at time t and*

x_t *the vector of independent variables at time t.*

The idea behind (8) is to allow the coefficient α_t to smoothly change over time. Thus (8) is well suited to model long run convergence processes as for example purchasing power parity or the law of one price. As described in Hamilton (1992 p.399 ff)[16] time varying coefficient models such as (8) are estimated using the Kalman Filter. Applying the time varying coefficient framework to (6) leads to the following equation:

$$p_{PPX,t} - (transm_{EEX->PPX,t} - transm_{PPX->EEX,t}) = \alpha_{1,t}\, p_{EEX,t} + \varepsilon_t \quad \textbf{(9)}$$

$$with\ \alpha_{1,t} = \beta\alpha_{1,t-1} + \upsilon_t$$

In contrast to (7) transmission costs are no longer an independent variable. This is done to circumvent the colinearity problem associated with the fact that the price of the exporting country is negatively correlated with the transmission costs. Therefore in (9) a new dependent variable is defined as the price in the importing country minus the importing costs. In addition to removing correlation of independent variables, this has the positive side effect of reducing the number of coefficients to estimate. To further decrease the number of estimated variable no constant term is included. This can be justified by the law of one price. Another question is whether β should be estimated or predefined. Since setting $\beta = 1$ ex ante is economically sound[17], this is done to further reduce the degrees of freedom.

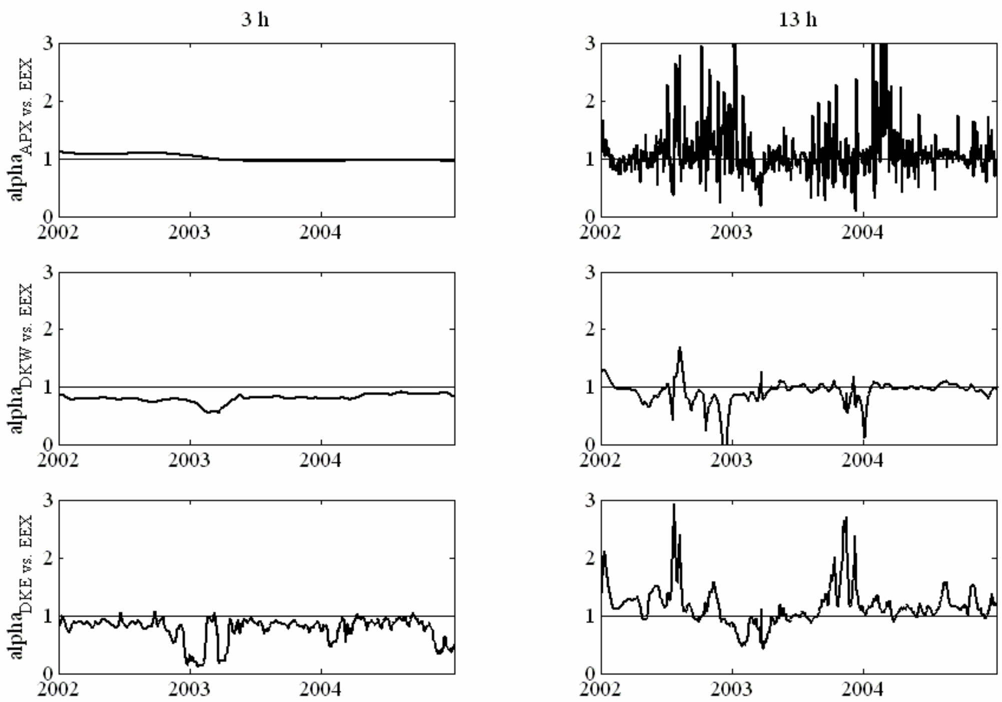
A less intuitive problem is the assumption on the initial variances for $\alpha_{1,t}$ which is required by the two-sided Kalman Bucy filter algorithm. The initial variances can be interpreted as the starting point of the search for the global extrema of the likelihood function. Therefore, if the function has several local maxima, a “wrong” starting point can lead to undesirable results. That is why the initial variances should be selected in close proximity to the theoretically expected variances. The trade off can be described as follows: Using too high variances would lead to the inclusion of short term behavior into $\alpha_{1,t}$ which would make it difficult to distinguish whether idiosyncratic shocks can be attributed to ε_t or υ_t. One the other hand,

[16] For technical details on the algorithm and its properties the reader is referred to the aforementioned author.

[17] It formalizes the assumption that the best guess concerning the development of price differentials is that they neither grow nor decline.

setting a low variance for υ_t would possibly lead to ignoring significant developments in the convergence process. Although in general this decision can be of great importance, numerous estimations suggested that our results are very robust with respect to the initial variances.[18] Another issue one has to address when estimating (9) is which data to use. To be able to distinguish peak from non-peak developments, we estimated (9) for each hour of the weekdays series. By doing so, peak time (9-21h) and off peak time (22-8h) can be clearly identified. Finally, the $\alpha_{1,t}$ are estimated for each hour of the day separately using the two-sided Kalman Bucy filter proposed by Schlicht (1988).[19] Due to the lack of hourly transmission prices for most of the borders, (9) can only be estimated for the German - Dutch (APX-EEX), the German - West Danish (DKW-EEX) and the German - East Danish (DKE-EEX) border.

Figure 6: Time variant coefficient (α_t) for the German (EEX) – Dutch (APX) and German (EEX) - Danish (DKE, DKW) border for the 3rd and 13th hour



The results depicted in Figure 6 clearly show periods of price equalization and periods of price divergence. Some of the latter can be explained by transmission line failures as for ex-

[18] Finally we adjusted the initial variance of ε_t to 1 and υ_t to 0.005. Note that adjusting these values up or down by factor 100 do not change results as long as ε_t remains more than 10 times bigger than υ_t.

[19] VC Version 5.21, a Program by Ekkehart Schlicht © 2004 for estimating time-varying coefficients was used.

ample the closure of the Kontek direct current cable between East Denmark and Germany that caused enormous deviations from the LOP in early 2003[20]. Other periods of deviations are the result of national price spikes that did not lead to higher cross border transmission capacity prices. Whether uncertainty or other reasons are responsible for these repeated market failures remains unclear. The overall picture is however an indication of slight convergence.

Though the above presented results are able to provide an in depth picture of the development of market interactions over time in some situations a single number summary describing the convergence process is preferable. Therefore we now construct an indicator for the proximity of markets using the filtered coefficients. This is done by inverting all $\alpha_{1,t}$ that are bigger than one:

$$\gamma_t = \begin{cases} \alpha_{1,t} & \alpha_{1,t} < 1 \\ 1/\alpha_{1,t} & \alpha_{1,t} > 1 \end{cases} \qquad \textbf{(10)}$$

The proximity indices (γ_t) are depicted in Figure 7 together with their trend line. The slope of the trend line (θ) is a one number summary for the convergence or divergence of each pair of the two markets.[21] A significant positive θ points to convergence of the price series towards the LOP by indicating that formerly existing arbitrage opportunities diminished over time.

As Table 4 shows, more than half of each border prices are converging towards the LOP. This strongly supports our hypothesis that changes in the framework conditions as well as market participants adaptation to these were efficient in moving prices towards their allocation optimal value. The highest rates of convergence are to be found at the West Danish - German border. Since spot price differentials between EEX and DKW did not fell significantly, the effect can be attributed to improved behavior of the transmission capacity market participants as well as some optimizations of the auction procedure that were implemented in the period under observation[22]. Although more than half of the hourly prices for the Dutch - German

[20] From 4th to 28th of January 2003, the Kontek line was closed due to a cable malfunction at the German side. Despite bad weather, Vattenfall immediately started to repair the cable because of high prices following water shortages in the Nordel area. [Source: http://www.udo-leuschner.de/energie-chronik/030212.htm]

[21] The results are summarized for all hours of the day in Table 7 in the appendix.

[22] With beginning of 01.04.2002 FTP via ISDN was made the prior way for the delivering of the schedules and the bids instead of e-mail. E-mail is used alternatively. With beginning of 17.06.2003 a pro-rata allocation of the rest capacity (several requests with the same price bid exceed the available capacity) is introduced and the timetable will be tightened. [Source: Rules for the Daily Auction of Transmission Capacity at the Danish - German Transmission Border]

interconnection converged towards the LOP evidence is less striking here. Only 13 hourly series at the EON - TenneT border converged and even two diverged significantly in the sample period. This is partly explained by a more developed point of interception in 2002, and by the enormous price spikes occurring at the Amsterdam market which lead to higher uncertainty for market participants. Even though the East Danish - German interconnection links two asynchronously operating transmission systems, namely the UCTE and Nordel, which are characterized by relatively different production structures and thus price patterns it is unclear why the cross border capacity auctions so often do not determine the economically efficient scarcity rents. One plausible reason for the modest convergence towards the LOP at the East Danish - German border might be the existence of just one undersea cable (the Kontek line) which has been subject to various planned and unplanned closures in the sample period.[23] However, an extensive explanation of the deviations from the LOP should probably also encompass uncertainty and market power.

Figure 7: Proximity indices (γ_t) and convergence indicator (θ) for the German - Dutch, the German - West Danish and the German - East Danish border at the 3rd and 13th hour

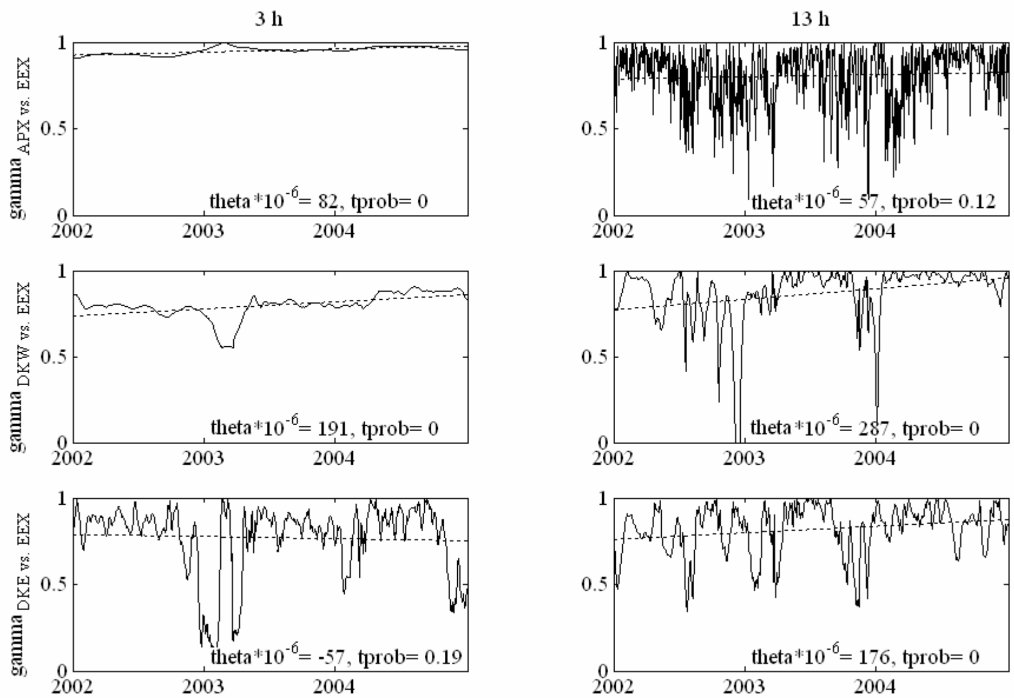


Table 4: Number of significantly converging/diverging hourly series between 2002 and 2004 at the 5% significance level

	APX - EEX	DKE - EEX	DKW - EEX
Convergence towards the LOP	13	16	24
Divergence from the LOP	2	0	0

We have thus seen that the time varying coefficient model is well suited to demonstrate that electricity and transmission prices of Denmark, Germany and the Netherlands converged towards the LOP. Unless it is impossible to figure out the driving factors of this process using this methodology, Figure 7 suggests that the development did not occurred stepwise. This observation would be in line with the hypothesis that market players were steadily learning how to use (and by that way reduce) the remaining arbitrage possibilities.

4 Conclusion

Using a time varying coefficient model our study showed that only 19 out of the analyzed 72 hourly pairs of spot prices and cross border transmission capacity prices did not converge towards the law of one price (LOP) in the years 2002 to 2004. This is an indication that sector reforms and the adaptation of the market participants to this new framework were able to reduce market inefficiencies. However, the convergence processes differed between the observed borders. Whereas all 24 hourly price series of the West Danish - German border approached the LOP, at the Dutch - German border a significant convergence towards arbitrage freeness was to be found for 13 hours only. Therefore an increasing liquidity of spot and transmission capacity markets, a raising number of wholesale market participants and market based congestion management methods are likely to further promote the convergence process. As was to be seen at the example of the Kontek line between East Denmark and Germany the reduction of physical bottlenecks remains important on the way towards a single European market for electricity, too.

[23] Another explanation, the difficulty to reverse the power flows in a single line system is not satisfactory, since usually the direction in HVDC (high voltage direct current) lines (like the Kontek or the Baltic cable) can be switched within some seconds.

One of the main prerequisites not only for the analysis but also for the workability of cross border trade is the introduction of market based congestion management methods like the explicit auctions between Germany and Denmark as well as between Germany and the Netherlands. Since the daily transmission capacities at six of the twelve interconnections between the eight analyzed price areas are not allocated on a transparent market, it was impossible to analyze them within our framework. Thus a study incorporating long term contracts as well as non market based capacity allocation mechanisms to compare the convergence of various European markets would be desirable.

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Appendix

Table 5: ADF-test results for the wholesale spot prices of each hour of the day

Power Exchange	APX	DKE	DKW	EEX	OTE	PNX	PPX	SWE	1% critical value
1h	-20.42	-5.43	-22.85	-16.47	-20.07	-17.90	-19.46	-4.57	-4.00
2h	-18.24	-6.05	-19.84	-17.09	-19.09	-16.69	-17.53	-4.91	-4.00
3h	-17.66	-7.87	-20.16	-17.00	-20.34	-16.36	-15.78	-6.77	-4.00
4h	-17.13	-6.39	-19.15	-17.21	-20.58	-15.81	-15.52	-5.25	-4.00
5h	-16.91	-6.76	-19.03	-17.22	-18.00	-16.54	-14.78	-5.14	-4.00
6h	-16.89	-5.41	-17.25	-17.38	-19.27	-17.69	-15.69	-4.91	-4.00
7h	-17.42	-5.25	-17.80	-20.46	-20.03	-18.02	-17.80	-4.63	-4.00
8h	-21.91	-12.73	-18.63	-24.60	-19.43	-19.10	-13.85	-5.30	-4.00
9h	-24.93	-7.81	-28.69	-25.02	-19.21	-17.19	-14.73	-6.06	-4.00
10h	-29.12	-7.63	-27.01	-22.16	-19.45	-31.66	-15.70	-5.74	-4.00
11h	-24.09	-14.06	-27.88	-26.41	-20.41	-30.42	-16.75	-5.95	-4.00
12h	-22.49	-16.49	-26.30	-18.39	-20.53	-27.11	-15.80	-8.49	-4.00
13h	-25.41	-7.90	-25.81	-21.59	-19.20	-29.70	-15.67	-5.11	-4.00
14h	-24.37	-7.98	-30.11	-21.83	-19.86	-31.17	-16.54	-4.64	-4.00
15h	-22.10	-8.36	-28.53	-20.44	-21.67	-31.73	-16.91	**-3.92**	-4.00
16h	-21.04	-5.77	-18.77	-20.72	-20.28	-32.51	-17.61	**-3.58**	-4.00
17h	-9.28	-5.57	-15.64	-18.82	-20.64	-16.42	-17.05	**-3.50**	-4.00
18h	-14.74	-10.80	-15.43	-20.49	-19.10	-14.96	-16.58	-6.56	-4.00
19h	-20.54	-14.13	-18.80	-34.08	-19.15	-16.79	-15.68	-4.76	-4.00
20h	-19.71	-5.60	-16.10	-15.00	-18.09	-15.74	-14.66	**-3.42**	-4.00
21h	-21.68	-5.17	-14.56	-15.31	-19.87	-15.00	-14.28	**-3.93**	-4.00
22h	-23.11	-5.08	-17.45	-15.10	-21.80	-16.28	-15.26	**-3.47**	-4.00
23h	-23.68	-4.89	-18.31	-15.99	-23.45	-17.51	-9.80	**-3.86**	-4.00
24h	-25.45	-5.65	-23.18	-14.63	-21.28	-16.73	-16.67	-4.63	-4.00

Table 6: Principle component (PC) analysis results

	tau		1st PCs factor loadings							
	1st PC	1st & 2nd PC	APX	DKE	DKW	EEX	OTE	PNX	PPX	SWE
1h	0.39	0.63	**0.45**	0.31	**0.40**	**0.46**	0.18	**0.44**	0.09	0.31
2h	0.38	0.63	**0.48**	0.25	0.37	**0.48**	0.22	**0.47**	0.09	0.24
3h	0.37	0.62	**0.48**	0.27	0.37	**0.48**	0.19	**0.47**	0.09	0.26
4h	0.38	0.62	**0.47**	0.28	0.37	**0.47**	0.23	**0.46**	0.08	0.27
5h	0.39	0.63	**0.45**	0.30	0.37	**0.45**	0.26	**0.44**	0.15	0.29
6h	0.44	0.68	**0.44**	0.28	0.39	**0.44**	0.26	**0.43**	0.23	0.27
7h	0.47	0.72	**0.45**	0.25	0.39	**0.45**	0.29	**0.42**	0.26	0.24
8h	0.53	0.73	**0.40**	0.32	**0.40**	0.39	0.34	0.37	0.28	0.31
9h	0.42	0.62	0.31	0.39	0.31	**0.42**	0.31	**0.40**	0.30	0.37
10h	0.38	0.57	0.30	**0.44**	**0.40**	0.36	0.30	0.29	0.29	**0.42**
11h	0.36	0.55	0.36	**0.41**	**0.41**	0.35	0.27	0.34	0.28	0.39
12h	0.39	0.58	0.37	0.36	**0.43**	0.39	0.31	0.36	0.28	0.31
13h	0.40	0.61	0.37	0.35	**0.41**	**0.41**	0.32	0.37	0.24	0.32
14h	0.36	0.56	0.37	**0.40**	0.35	**0.41**	0.34	0.34	0.21	0.37
15h	0.36	0.57	0.37	**0.40**	0.36	0.38	0.35	0.36	0.18	0.38
16h	0.38	0.60	0.26	**0.44**	**0.48**	0.36	0.28	0.27	0.18	**0.43**
17h	0.44	0.66	0.22	**0.41**	**0.45**	**0.40**	0.30	0.37	0.22	**0.40**
18h	0.48	0.66	0.28	**0.41**	**0.42**	0.39	0.30	0.37	0.20	**0.40**
19h	0.44	0.60	0.34	**0.42**	**0.43**	0.28	0.25	**0.41**	0.18	**0.42**
20h	0.49	0.68	0.30	**0.41**	**0.43**	0.38	0.27	0.38	0.18	**0.40**
21h	0.41	0.64	0.32	**0.43**	**0.46**	0.39	0.25	0.32	0.05	**0.42**
22h	0.38	0.63	0.35	**0.45**	**0.47**	0.37	0.05	0.32	-0.14	**0.45**
23h	0.38	0.62	0.33	**0.44**	**0.47**	**0.41**	0.01	0.30	-0.15	**0.44**
24h	0.36	0.61	0.36	0.38	**0.45**	**0.45**	0.07	**0.41**	-0.06	0.37

Table 7: Growth of the convergence indicator and significance between 2002 and 2004

	EON - TenneT			EON - Elkraft			EON - ELTRA		
	Growth (theta* 10^-6)	tprob	Intercept (average = **0.85**)	Growth (theta* 10^-6)	tprob	Intercept (average = **0.81**)	Growth (theta* 10^-6)	tprob	Intercept (average = **0.80**)
1h	**-44**	**0**	0.95	53	0.15	0.82	**150**	**0**	0.82
2h	**37**	**0**	0.94	-2	0.96	0.79	**156**	**0**	0.78
3h	**82**	**0**	0.92	-57	0.19	0.79	**191**	**0**	0.74
4h	**83**	**0**	0.92	-68	0.12	0.78	**195**	**0**	0.71
5h	**165**	**0**	0.90	-50	0.24	0.78	**186**	**0**	0.73
6h	**164**	**0**	0.87	-27	0.49	0.82	**154**	**0**	0.80
7h	**227**	**0**	0.83	-18	0.59	0.86	**247**	**0**	0.80
8h	**178**	**0**	0.85	**183**	**0**	0.80	**195**	**0**	0.82
9h	20	0.56	0.82	**102**	**0**	0.82	**149**	**0**	0.82
10h	41	0.3	0.78	**76**	**0**	0.83	**221**	**0**	0.79
11h	16	0.67	0.79	**84**	**0**	0.81	**260**	**0**	0.77
12h	30	0.43	0.79	**197**	**0**	0.68	**292**	**0**	0.76
13h	57	0.12	0.79	**176**	**0**	0.76	**287**	**0**	0.77
14h	**95**	**0.01**	0.76	**93**	**0**	0.80	**307**	**0**	0.75
15h	**90**	**0.02**	0.77	**90**	**0**	0.84	**158**	**0**	0.84
16h	**111**	**0.01**	0.77	**75**	**0.01**	0.85	**123**	**0**	0.89
17h	**88**	**0.02**	0.78	**75**	**0**	0.86	**129**	**0**	0.88
18h	12	0.76	0.80	36	0.18	0.85	**211**	**0**	0.81
19h	-44	0.19	0.83	**118**	**0**	0.79	**153**	**0**	0.79
20h	29	0.32	0.84	**112**	**0**	0.84	**78**	**0**	0.88
21h	**92**	**0**	0.84	**168**	**0**	0.82	**190**	**0**	0.86
22h	**60**	**0**	0.89	**121**	**0**	0.85	**231**	**0**	0.83
23h	-11	0.51	0.93	**158**	**0**	0.83	**250**	**0**	0.83
24h	**-47**	**0**	0.92	**72**	**0.03**	0.83	**170**	**0**	0.82