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DETERMINING OPTIMAL INTERCONNECTION CAPACITY ON THE BASIS OF HOURLY DEMAND AND SUPPLY FUNCTIONS OF ELECTRICITY

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DETERMINING OPTIMAL INTERCONNECTION CAPACITY ON THE BASIS OF HOURLY DEMAND AND SUPPLY FUNCTIONS OF ELECTRICITY[1]

Jan Horst KEPPLER[2], William MEUNIER[3], Alexandre COQUENTIN[4]

Abstract

Interconnections for cross-border electricity flows are at the heart of the project to create a common European electricity market. At the time, increase in production from variable renewables clustered during a limited numbers of hours reduces the availability of existing transport infrastructures. This calls for higher levels of optimal interconnection capacity than in the past. In complement to existing scenario-building exercises such as the TYNDP that respond to the challenge of determining optimal levels of infrastructure provision, the present paper proposes a new empirically-based methodology to perform Cost-Benefit analysis for the determination of optimal interconnection capacity, using as an example the French-German cross-border trade. Using a very fine dataset of hourly supply and demand curves (aggregated auction curves) for the year 2014 from the EPEX Spot market, it constructs linearized net export (NEC) and net import demand curves (NIDC) for both countries. This allows assessing hour by hour the welfare impacts for incremental increases in interconnection capacity. Summing these welfare increases over the 8 760 hours of the year, this provides the annual total for each step increase of interconnection capacity. Confronting welfare benefits with the annual cost of augmenting interconnection capacity indicated the socially optimal increase in interconnection capacity between France and Germany on the basis of empirical market micro-data.

1. INTRODUCTION

Interconnections for cross-border electricity flows are at the heart of the project to create a common European electricity market. Interconnections allow exporting electricity from countries with relatively lower costs of production to those with relatively higher costs of production thus increasing economic efficiency. During this process, prices in the high cost country will fall and prices in the low cost country will rise thus increasing the combined producer and consumer surplus in both countries. The process will come to an end only when either prices in both countries are equalized and the total surplus is maximized, or when the available interconnection capacity is saturated.

The challenge for regulators and electricity policymakers is to determine the optimal amount of interconnection capacity. Constructing cross-border capacity is costly. Installing interconnection

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capacity up to a level at which it would never be saturated, yielding zero benefits at the margin, would constitute an inefficient form of over-investment. Determining the socially optimal interconnection capacity requires specific methodologies and data, which is the subject of this article.

Expanding the physical infrastructure for cross-border interconnection in an economically optimal manner has become more critical in recent years due to the large-scale deployment of variable renewables energies (VRE), i.e., wind and solar PV. Due to their dependence on a varying meteorology, wind and solar generation tends to be concentrated during a limited number of hours, during which large amounts of low cost electricity flood the European electricity system. The fact that most wind turbines produce at the same time, an effect even stronger for solar panels, is also referred to as the auto-correlation of VRE production. The increasing number of hours with high VRE production implies a more frequent saturation of existing interconnection infrastructure. Saturation of infrastructure implies price divergence between European countries with concomitant welfare losses (Keppler *et al.*, 2016). The optimal amount of interconnection infrastructure will thus *ceteris paribus* be higher in the presence of variable renewables than in their absence.

The ambitious objectives of the countries of the European Union (EU) to increase the amount of energy from renewable energy sources to 20% by 2020 (27% by 2030) implies that in the power sector a share of more than 30% (40% by 2030) of electricity must be produced from renewable energy sources, much of it from wind and solar. Already, the EU has seen an important increase in generation from wind and solar, which has risen from 7.6% in 2010 to 14.4% in 2014 (ENTSO-E, 2014). Even more important than the share of electricity, which reflects average production over the year, is, due to the auto-correlation of VRE production, the installed capacity. The latter, for instance, has risen in Germany from 6 GW for wind and 0.1 GW for solar in 2002 to 39 GW for wind and 38 GW for solar in 2014 (BMWi, 2014). At the European level, the less than 400 GW of VRE capacity that exist today will increase up to 1 150 GW by 2030, depending on the scenario considered.

In the presence of such momentous changes, the question of what constitutes the socially optimal level of optimal interconnection capacity poses itself with new urgency. Larger VRE capacities imply higher levels of network and interconnections. The EU thus pursues a great number of projects to increase interconnection capacity summarized in the *Ten-Year Network Development Plan* (TYNDP) developed by the European Network of Transmission System Operators for Electricity (ENTSO-E, 2016). On average, interconnection capacity should double throughout Europe by 2030.

The objectives for the augmentation of interconnection capacities have been developed on the basis of an extensive, forward-looking scenario analysis that includes benefits in consumer and producer surplus as well as a large number of additional criteria such as security of supply, VRE integration, reduction of transmission losses, CO2 emission reduction, technical resilience and flexibility for future investments. The TYNDP is a sophisticated modelling exercise augmented by extensive public consultation and provides a convincing road-map for European network development. However, the Cost-Benefit Analysis (CBA) that it proposes lacks any explicit feedback with the actual production and consumption decisions of the actors in the European electricity markets. This is where the present research comes in. It provides in fact an alternative and complementary methodology based on real market data for the assessment of optimal interconnection capacity.

An economic approach based on empirical electricity market data

On the basis of detailed hourly supply and demand data from the EPEX Spot Day-ahead electricity market, this paper calculates the annual consumer and producer surpluses for different levels of additional interconnection capacity at the French-German border. The available data on consumer preferences and the marginal cost of supplier is used to estimate analytically treatable supply and demand functions and to establish net export supply and import demand curves in the spirit of Spiecker *et al*. (2013) for both countries. This allows the estimation of consumer and producer surplus for each hour for different increments of additional capacity. Summing the hourly surplus over the year and confronting the resulting combined annual welfare gain with the annualized cost of additional infrastructure allows determining the economically optimal, *i.e.*, welfare maximising, amount of interconnection capacity that should be added to the already existing infrastructure between France and Germany.

The precise data on real market supply and demand functions, indispensable to establish meaningful estimates of consumer and producer surpluses, was so far unavailable for economic research at this level of detail. This is thus the first time that cost benefit analysis on the basis of systematic, empirical supply and demand data has been applied in the economic analysis of electricity markets. For comparison purposes, estimates were produced for the years 2011 and 2014. The two years are, in particular, differentiated by the capacity for variable renewables, in particular in Germany. In 2011, the combined output of wind and solar PV in Germany was 68 TWh. This figure rose to over 90 TWh in 2014. Consistent with intuition, this yielded a higher level of optimal interconnection capacity. In the context of the discussion of future European infrastructure needs in the presence of large amounts of VRE capacity, the results for 2014 are clearly the more relevant.

While the data and methodology employed in this paper are straightforward and the results easily replicable, there exists also an obvious limitation, although its impact on overall results is modest. In fact, this paper determines the optimal interconnection capacity between France and Germany exclusively on the basis of French and German supply and demand data. While France and Germany are, by far, their largest electricity trading partners respectively, they do not only trade with each other but also with Belgium, the Czech Republic, Denmark, Italy, the Netherlands, Poland, Switzerland and the United Kingdom. A complete analysis would have had to take into account hourly supply and demand curves from each of these countries in order to establish France's and Germany/Austria's hourly net export supply and import demand curves. The recent switch towards the flow-based allocation of interconnection capacity between coupled markets, since March 2015, would further require taking into account also trilateral trade flows in future analyses. This, however, would have exponentially increased the already large amounts of data treated in this project (the total amount of data used in this research already amounted to 2.5 Go of Excel files) and would have pushed them beyond feasibility in the framework of the computing resources available at the Chaire European Electricity Markets (CEEM) at the Université Paris-Dauphine.

While the authors encourage the adoption of the methodology proposed at the European level with computing resources to match, they are confident that the results would not change substantially from those obtained here. The principal reason for this confidence is that there exists an official benchmark for unlimited multi-lateral trading, i.e., trading that includes all trading partners of France and Germany, which can be directly compared to the equivalent metric established in this research. This metric is the price of electricity under the hypothetical assumption of unlimited interconnection capacity at all borders. This hourly maximum efficiency price established on the supply and demand data in all concerned countries is published under the name of ELIX by EPEX Spot.

For comparison purposes, the present research thus also established for each hour the bilateral maximum efficiency price on the basis of French and German supply and demand data, i.e., the price that would result if bilateral interconnection capacity was unlimited. The difference between the two sets of prices, i.e., the modelled price on the basis of French and German data only and the ELIX based on the exchanges between all the countries of the CWE amounted to € 2.05 in 2011 and € 2.13 in 2014 (see Chapter 4 for detailed statistical analysis). This quite limited divergence shows that also the bilateral producer and consumer surplus calculations provide, if confronted with relevant cost data, highly meaningful indications for the optimal provision of interconnection capacity.

Enlarging the methodological tool-box for optimal infrastructure assessment

This article presents an economic approach that is both narrower but also methodologically more coherent than the broader approach pursued in TYNDP 2016. Both approaches have their uses. The development of networks for electricity systems takes place in a complex world with overlapping political priorities of which maximizing the economic surplus is only one. The empirical approach presented here is based on real market data for 2014. Like all empirical research, it is inevitably backward-looking, while the TYNDP develops scenarios for 2020 and 2030. Given the level of VRE capacity in 2014, which is certain to be lower than the one deployed in 2030, the results calculated here should thus establishes a lower bound of the economic benefits of the development of additional interconnection capacity. It is thus all the more remarkable that these results exceed the levels of optimal additional interconnection capacity established by the TYNDP.

First and foremost, however, the contribution of this paper is methodological. For the first time, it makes use of the detailed hourly demand and supply curves of the EPEX Spot electricity market. This valuable information must be mined and rendered meaningful in economic discussions about the benefits of network expansion. Complementing electricity market simulations with empirical and econometric research is all the more important in the light of recent developments in electricity markets. Recourse to scenario modelling is routinely justified by the fact that electricity markets were operating largely without frictions and that electricity could be considered a homogenous good. *Ergo* simulation results can replicate the phenomena of real-world electricity markets with reasonable accuracy.

Two important points limit the validity of this point of view. First, electricity market simulations concentrate on the supply side and only have a very rudimentary representation of the demand side. Part of the value added of the present research consists in the economic information contained in the 8 760 demand functions in addition to the same number of supply functions of the EPEX Spot market. Second, economically speaking, electricity is less and less a homogenous good. The variability of renewable production in conjunction with emerging phenomena such as auto-consumption and demand response makes explicit modelling of the objective functions that determine the dispatch of power suppliers vastly more difficult and less accurate than only a few years ago. The variability of VREs, for instance, requires all producers to vary their output frequently and with steep gradients. This increases the importance of ramping constraints that are notoriously hard to model as they vary at the individual level between otherwise comparable plants. An added difficulty of correctly modelling dispatch is that in the new electricity systems that producers are facing the economic value of providing ancillary services to the system such as primary, secondary or tertiary reserves has increased considerably while the value of simple electricity provision has fallen. Taking reserves into account is thus ever more necessary but doing this in a systematic and coherent manner is again an enormous challenge. In the past, leaving out ramping constraints and ancillary services would still allow arriving at reasonable approximations. Today, disregarding them implies modelling an ideal market that no longer exists.

The massive structural changes that have taken place in electricity markets during a very short period thus add pertinence to the sort of empirical research proposed here. In combination with the large amount of relevant new data on detailed demand and supply function that was hitherto unavailable for economic research, this article thus aims at enlarging the boundaries of the methodologies currently employed for determining optimal interconnection capacity.

The remainder of the paper is organized as follows. Section 2 will briefly present the context of German-French electricity trade as part of the transition to a unified European electricity market. Section 3 will provide a detailed description of the data used, the methodology employed and the model that was developed. Section 4 will present the results in terms of the optimal amounts of additional infrastructure capacity required to maximise the combined surplus in the French and German electricity markets. Section 5 will conclude.

2. THE CONTEXT OF FRENCH-GERMAN ELECTRICITY TRADE

Both France and Germany are actively engaged in the pan-European electricity trade. Both are also net exporters of electricity as long as the totality of their trading partners is taken into account. Traditionally, France is a net exporter during the summer time and a net importer during winter time due to the specificity of having a relatively high share of electric heating in its consumption mix. Germany's exports and imports depend primarily on the availability of surplus power from the 70 GW of wind and solar PV capacity of which it disposes.

As far as bilateral trading is concerned, Germany is France's most important trading partner contributing 13 TWh of the total 27 TWh that France imported in 2014. France used to be a net exporter to Germany but due to the availability of cheap electricity from renewable sources has become a net importer. The bilateral trade balances in 2011 and 2014 are summarised in the following table:

Table 1: The Electricity Trade between France and Germany (GWh)

	2011	2014
French Imports from Germany	5 214	9 919
German Imports from France	7 603	4 040
Hours of French Imports	3 531	5 652
Hours of German Imports	5 229	3 108

Source: www.epexspot.com

Between 2011 and 2014, French electricity imports have increased by 90%, whereas exports have decreased by 88%. This fact is primarily explained by the significant development of renewable energies in Germany during this period. These electricity flows pass through a total of 2.6 GW of interconnection capacity from France to Germany and of 3.6 GW from Germany to France. There has been no investment in new interconnection capacity between France and Germany between 2011 and 2014.

The capacities indicated are commercial capacities that can be acquired by commercial auctions with appropriate adjustments, decided upon by the TSOs of both countries for safety margins to ensure network security. The available capacity differs for the two directions, France-Germany or Germany-France, due to physical constraints on the upstream and downstream networks to which the interconnections are connected. Potential flows from France to Germany are thus smaller than flows from Germany to France due to the limited capacity of the intra-German transport lines in the Rhine-Ruhr area.

The impacts of VRE variability

Germany's energy supply has significantly changed over the last few years due the rapid deployment of new capacities of wind and solar PV. These sources present three major features:

- They are variable which means they do not supply a constant amount of electricity since their production is subject to climatic variation.
- The amount of electricity to be delivered cannot be predicted with certainty at any moment in time before the actual dispatch.

- There VRE production from wind and solar PV is auto-correlated, which means that total production is concentrated during a limited number of hours during which the capacity of the electric interconnections tends to saturate.

We may notice that the maximum daily solar and wind-combined production in 2014was 0.58 TWh (January 31st), while the minimum was 0.022 TWh (January 16th), which corresponds to factor of 30. The hourly maximum load of wind and solar PV combined was 40.68 GW on 14 April 2014 (Fraunhofer ISE, 2016). Such high variations require flexibility responses, which can be provided either by other generators (dedicated back-up), demand response, storage or, the aspect that is of primary interest here, interconnections with neighbouring countries. Other things equal, the more significant the penetration of renewable energies, the more cross-border electricity flows will be required in order to re-balance total supply and demand in national electricity systems.

In the presence of limited interconnection capacity, the variability of wind and solar PV has an economically relevant impact on the convergence of electricity prices between European countries. From the point of view of welfare economics, price convergence between countries is desirable as it maximizes the combined surplus of the two countries. Due to the rapid development of VRE in Germany coupled with constant bilateral interconnection capacities, however, prices between France and Germany *diverged* in recent years. This development was dampened but not overcome by the introduction of market coupling, which allows for a more efficient allocation of available interconnection capacity, between the two countries (see Keppler, Le Pen and Phan (2016) for an econometric analysis of the behaviour of French and German electricity prices between 2009 and 2013).

Table 2: The Convergence between French and German Electricity Prices (GWh)
(Percentage of hours with price differences of less than 0.1€)

	2011	**2012**	**2013**	**2014**
Convergence Rate	74.05%	68.49%	47.61%	58.73%

Source: Keppler et al. (2016) and own calculations.

While the convergence rate increased somewhat again in 2014, this was a year of exceptionally low wind production. The econometric study of hourly price and generation data shows that power generation by both solar PV and wind in Germany clearly has a positive impact on the price spread. Keppler et al. concentrated on the role of interconnections congestion in this context. Prices thus converge as long as interconnection capacity is available and power flows can circulate freely between all neighbouring countries and, in particular, Germany and France. However, during hours when export demand due to massive German VRE production exceeds available interconnection capacity, prices diverge. In an economic perspective, such price divergence translates into welfare losses, which could have been avoided if more substantial interconnection capacities had been available.

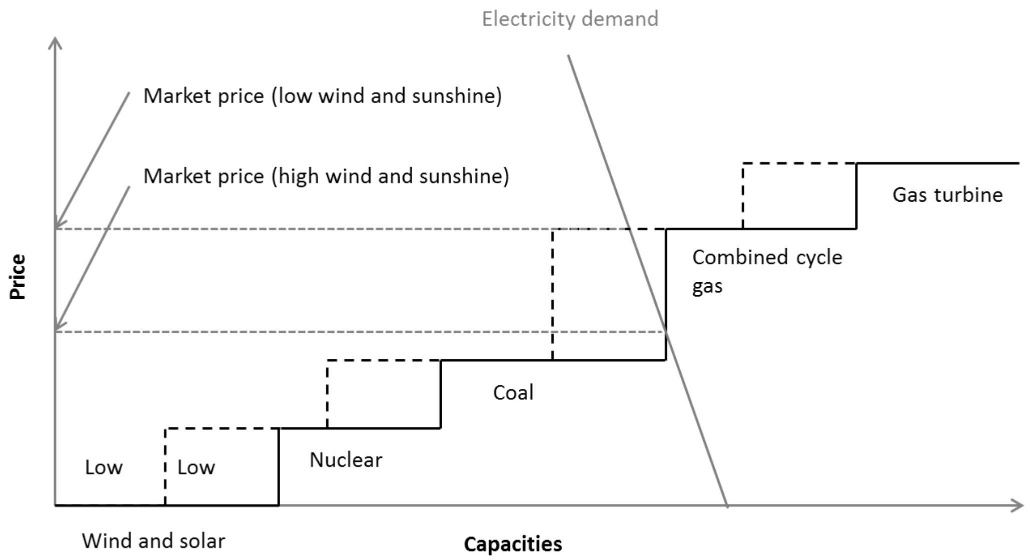
Assessing the impact of constraints on interconnection capacity, the article concluded that "the significant increase in the production of variable renewables that Europe has witnessed in recent years requires a new look at European power market integration. It poses, in particular the question of… what is the socially optimal level of physical infrastructure provision of both at the national and the European level." This paper takes its starting point from this observation. It thus attempts to answer the question "what would be the optimal level of interconnection capacity between France and Germany given current levels of production of variable renewables?"

3. DATA, METHODOLOGY AND THE CALCULATION OF CONSUMER AND PRODUCER SURPLUS

As far as exchanges on organized multilateral markets with transparent price formation are concerned, most electricity trading takes place on the EPEX Spot and EEX exchanges that couple the electricity markets of the majority of European countries. The hourly Day-ahead market remains for the time being the most liquid platform for the different products that can be traded and is still widely considered to provide the relevant reference for the price of electricity.

Electricity generation technologies vary by their costs structures and are dispatched according to the increasing order of their variable costs. These variable costs form a bidding or merit order curve that consists of a set of stacked quantity-cost tuples, which is equivalent to the short-term supply curve in the electricity. In the presence of electricity produced by wind or solar PV at zero short-run marginal costs, the merit curve shifts to the right (see Figure 1 below). As long as demand remains unchanged, this means that technologies with lower variable costs will be selected and prices will fall.

Figure 1: Shifts in the Merit Curve Due to VRE with Zero Short-run Marginal Costs



In the short run, electricity demand is indeed highly inelastic to the prices due to the importance attached by consumers to the continuity of electricity supply and due to the non-storability of electricity. With time, demand response (DR) might introduce some flexibility on the demand side, but current levels are still relatively modest. While demand is not elastic to *ex post* price changes, it varies strongly according to different consumption patterns during the different hours of the day, the week and the season.

With changes in the weather, also the effective supply curve of electricity represented by the merit curve is characterised by strong hourly variations. Cross-european electricity trading implies handling the respective supply and demand curves of two or more countries jointly, according to the *overall* merit order, a process known as “market coupling”. Coupled markets match the buy and offer bids independent of their origin. Exchanges between two countries continue for as long as the offer price in one country is lower than the buy price in another, until prices converge or available cross-border capacity is saturated. Market coupling also implies implicit rather than explicit auctioning. With implicit auctioning, daily cross-border capacities are implicitly allocated among actors, depending on their bidding on the different Power Exchanges. In other word, buyers and sellers automatically receive the capacity needed without explicitly acquiring it separately.

Despite the efficiency gains due to market coupling, due to the limitations in interconnection capacity, some price divergence is the norm rather than the exception. This is why the market operator, EPEX Spot, calculates since 2010 a benchmark, the European Electricity Index or ELIX, which is the hypothetical market price that would prevail in all markets under the assumption that interconnection capacity was unconstrained on the basis of the actual aggregated bid and offer curves for all market areas.

The ELIX is an important indicator for the additional benefits of further market integration and provides researchers, regulators and TSOs with an important benchmark for policy decisions, including further investments in interconnection capacity.

Presentation of the data

The following section describes the data used to determine the welfare maximizing level of interconnection capacity between France and Germany. The idea for this work to identify the optimal level of additional capacity in markets with large shares of VRE follows up on the work by Keppler, Le Pen and Phan (2016) on interconnection connection and price divergence. Using hourly offer and supply curves to assess the welfare impact of increasing infrastructure capacity was first suggested in an unpublished paper by Phan (2014).

All data used in this study is hourly data, in order to take into account intraday variations of variable production. The precise data sets used were:

- The EPEX Spot market auction prices for the market zones of France and Germany/Austria;
- The ELIX price for each hour (EPEX Spot data);
- The EPEX Spot auction aggregated demand and supply curves in the market zones of France and Germany/Austria;
- The import and export capacities for interconnection between France and Germany provided by RTE.

The basic idea is to calculate the hourly variations in consumer and producer surplus in function of different levels of added interconnection capacity. Let CS_i be the consumer surplus and PS_i the producer surplus at each hour i, D_i the quantity demanded at each price p_i, S_i the corresponding supply and IC the available interconnection capacity and it holds that

$$CS_i = \int_0^{qi} \mathrm{D}_i(p_i)\mathrm{dq} - p_i(\mathrm{IC}) * q_i(\mathrm{IC})$$

$$PS_i = -\int_0^{qi} \mathrm{S}_i(p_i)\mathrm{dq} + p_i(\mathrm{IC}) * q_i(\mathrm{IC})$$

The crucial new step in this research is making use for the first time in economic research on electricity markets of the hourly demand and supply curves (auction aggregated curves) in the French and the German markets in order to calculate the prices and the respective surplus *that would have prevailed at different levels of interconnection capacity*.

Such auction aggregated curves are a data set providing the price and quantity information for each single offer or demand bid in both the French and the German market. The specific format in which they are provided can be seen in Table 3 below. Offer bids are marked “sell”, demand bids (not represented), are marked “buy”.

Table 3: Example of an Auction Aggregated Supply Curve

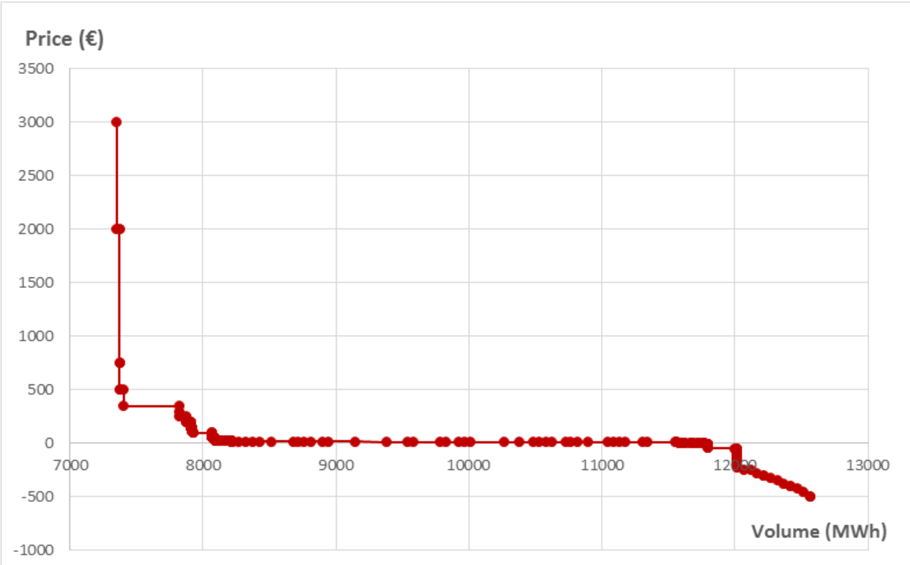
(Price in Euros/MWh and Volumes in MWh)

Date	Week	Week Day	Hour	Price	Volume	Sale/Purchase
12/31/2014	1	3	1	-500.00	5,702	Sell
12/31/2014	1	3	1	-499.00	5,712	Sell
12/31/2014	1	3	1	-498.90	5,742	Sell
12/31/2014	1	3	1	-498.00	5,742	Sell
12/31/2014	1	3	1	-497.90	5,742	Sell
12/31/2014	1	3	1	-200.10	5,743	Sell
12/31/2014	1	3	1	-200.00	6,115	Sell
12/31/2014	1	3	1	-180.50	6,115	Sell
12/31/2014	1	3	1	-180.00	6,140	Sell
12/31/2014	1	3	1	-150.10	6,140	Sell
12/31/2014	1	3	1	-150.00	6,180	Sell
12/31/2014	1	3	1	-49.98	6,180	Sell
12/31/2014	1	3	1	-49.90	6,274	Sell
12/31/2014	1	3	1	-10.00	6,274	Sell
12/31/2014	1	3	1	-5.00	6,275	Sell

Source: www.epexspot.com

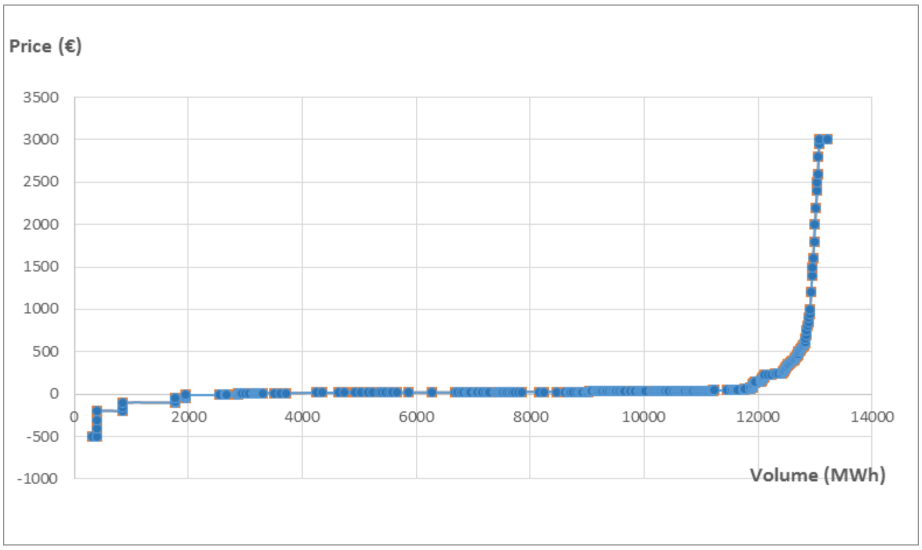
Taken together, these bids form demand and supply curves for each hour of the year. Below are the examples of a demand and supply curve in the French electrical market.

Figure 2: Example of a Demand Curve in the French Market (3 June 2014, Hour 7)



Source: www.epexspot.com

Figure 3: Example of a Supply Curve in the French Market (20 May 2014, Hour 8)

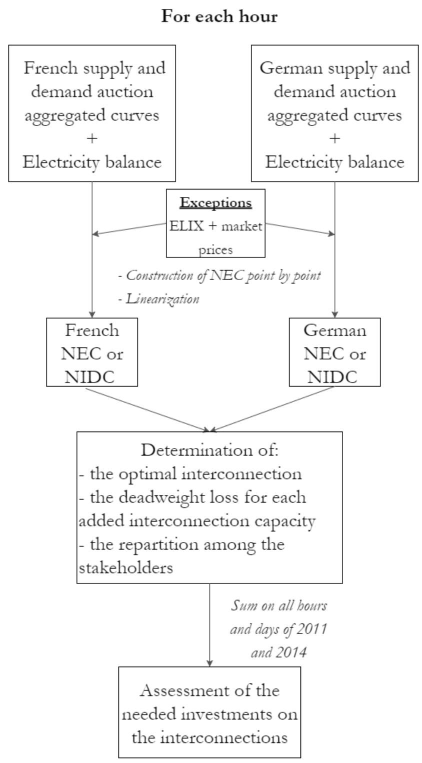


Source: www.epexspot.com

An overview of the methodology: working with NECs and NIDCs

Figure 4 below synthesizes the methodology employed. On the basis of the hourly offer and supply curves from the EPEX Spot day-ahead market as well as from the observed exchanges between France and Germany, net export curves (NEC) and net import demand curves (NIDC) for both countries were constructed. To this purpose the offer and demand curves are linearized by means of ordinary least square (OLS) regressions. In order to be able to treat the vast amount of data, a number of small adjustments for extreme outliers and corrupted results were applied (see below).

Figure 4: Synthesis of the Methodology



Net Export Curves (NEC) and Net Import Demand Curves (NIDC) are convenient tools for assessing the welfare gains from increased electricity trading in France and Germany. Net Exports (NE) and Net Imports (NI) are defined as the difference between local supply and demand, depending on whether the latter exceeds the former or the other way round. Both NE and NI are positive quantities, hence their mathematical definition with P* the equilibrium price at which local supply and demand are balanced and no further trade takes place:

$$NE(p) = S(p) - D(p)\ \forall\ P \geq P^*$$

$$NI(p) = D(p) - S(p)\ \forall\ P \leq P^*.$$

The Net Export Curve (NEC) and the Import Demand Curve (NIDC) respectively represent the market price corresponding to net exports and imports. In other words, the NEC (resp. NIDC) provides for each additional MWh exported (resp. imported) the price that would be observed in the market.

Combining the aggregate auction curves of the EPEX auctions with the demand and supply balances of France and Germany, NEC and NIDC curves were constructed for each of the 8760 hours of the year according to the following steps. Since the amount of data is large (around 600 Mo for one year), the statistics Software R was employed.

First, aggregate auction curves were linearized concentrating on the affine parts and eliminating extreme outliers. There is indeed good reason to believe that these outliers do not provide economically relevant information. Very high or very low prices, for instance, are quoted for bids that are inserted into the 24-hour bidding forms only for completeness sake but are not intended to be actually executed. Working with linear demand curves is the only operationally feasible one. Trading never takes place at such extreme values.

Given this premise, the choice to work with a very good fit for the overwhelming majority of quotes was superior to the one of working with a mediocre fit for the totality of quotes. The criterion to eliminate outliers was to exclude all points outside a 3-sigma band around the mean price of the hourly data set. This yielded the following results:

Table 4: Statistics for Outliers Eliminated from the Construction of NECs and NIDCs

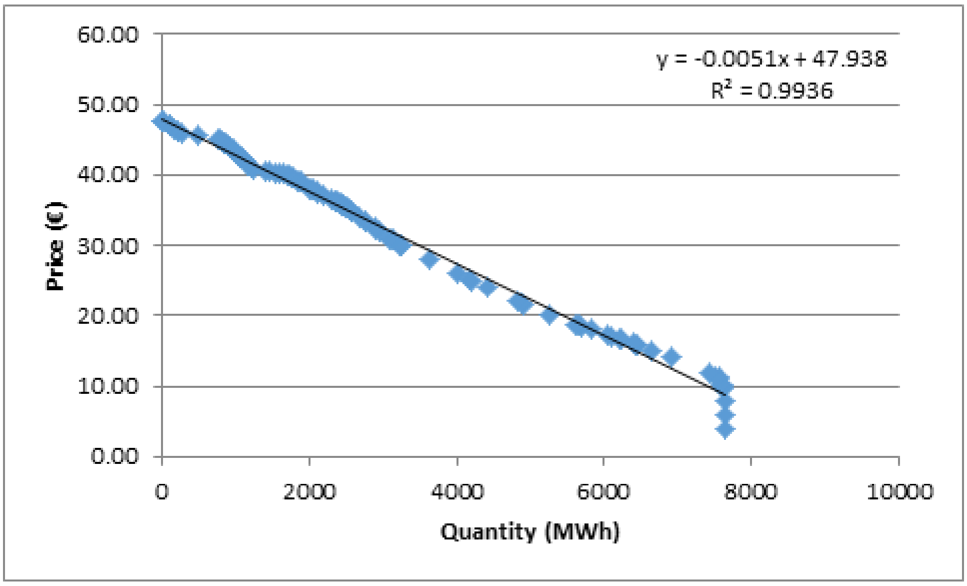
	2014
Mean of percentage of outliers excluded for each hour	4.12%
Maximum percentage of the points excluded at each hour	31.7%
Minimum percentage of the points excluded at each hour	0.51%
Mean of standard deviation of percentage of excluded points	1.75%

The linearized demand and supply curves from the hourly auction were then confronted with the observed values for the domestic supply and demand in each country. The difference between demand and supply curves from the EPEX Spot auctions and observed demand and supply provides for each price the desired quantities for export and import. Needless to say, what stops these desired quantities to be realised and reach full price convergence are limitations in interconnection capacity. More precisely, one obtains:

- The desired net exports for the exporting country, i.e., the difference between potential supply and domestic demand; this provides the net export curve (NEC).
- The desired net imports for the importing country, i.e. the difference between desired demand and domestic supply; this provides the net import demand curve (NIDC).

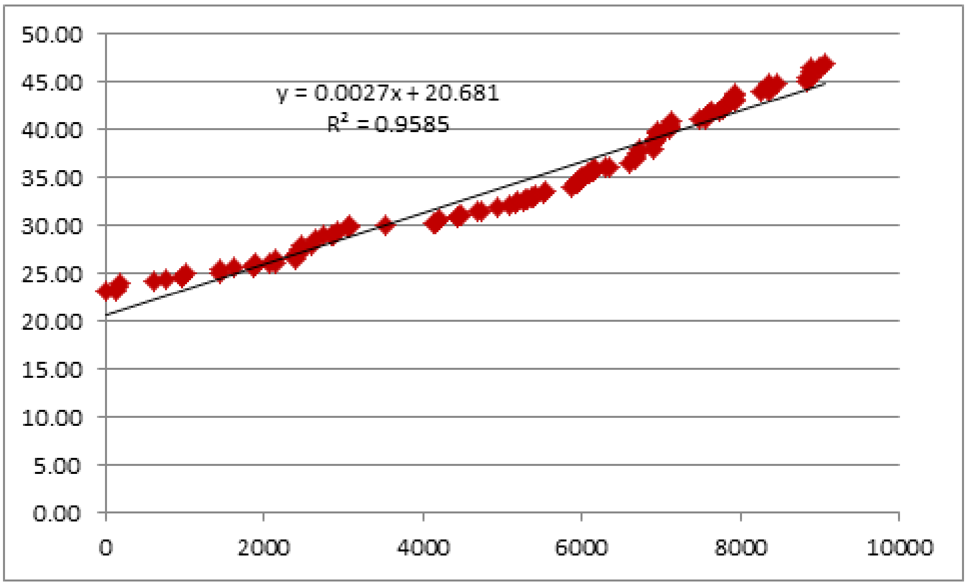
Below are provided examples of for a French net import demand curve (NIDC) and a German net export curve (NEC).

Figure 5: A French Net Import Demand Curve (NIDC)



Source: www.epexspot.com and www.rte-france.fr

Figure 6: A German Net Export Curve (NEC)



Source: www.epexspot.com and www.rte-france.fr

A certain number of further adjustments to the results of the econometric regressions for specific hours became necessary as completeness of the data was a prerequisite for the necessary automation process. Such adjustments were applied in two cases:

- If there existed a significant difference, more than €10, between the real equilibrium price reported for France and Germany provided by EPEX and the equilibrium price resulting from the linear regressions of the model.
- If there existed a significant difference, more than €15, between the ELIX price and the unconstrained equilibrium price predicted by the model.

In both cases, exchanges with third countries that were not included in the model are the obvious explanation for such divergences. The amounts chosen reflect the arbitrage between maintaining completeness of data as high as possible and the need to exclude individual data points that were clearly determined by factors outside the model. In these cases, the linear regressions of the reported supply and demand curves were rejected and NECs and NIDCs were constructed on the basis of the reported equilibrium values for national prices and the ELIX. These provide neutral results included only to satisfy the completeness requirements of the automation process. The share of thus adjusted hourly values out of a total of 8 760 hours per year was less than 1.5% (see Table 5 below).

Table 5: Number of Rejected Estimations

	2014
Divergence with reported real equilibrium prices	88
Divergence with ELIX	29
Divergence with reported prices and ELIX	11

These adjustments permitted to establish a complete and workable set of NEC and NIDC curves for calculating with the help of the software R the welfare implications of the stepwise provision of additional interconnection capacity on social welfare.

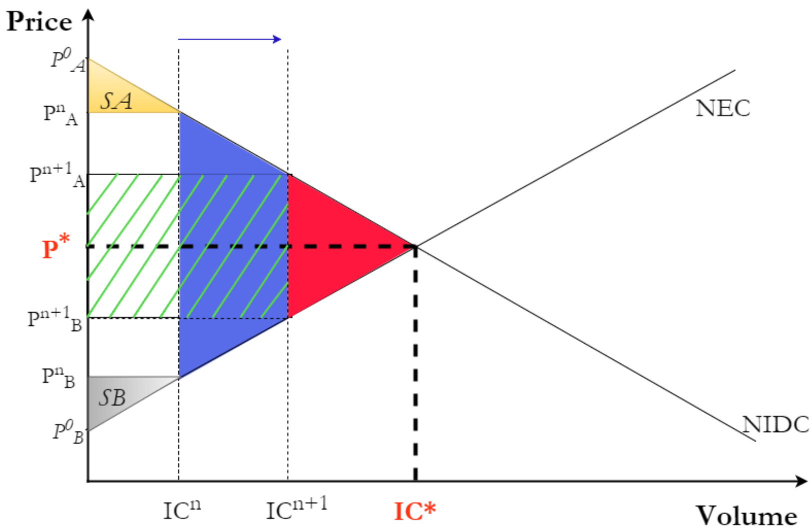
The welfare benefits of providing additional interconnection capacity: basic concepts

As indicated by Turvey (2006), interconnecting two or more regions has several positive consequences such as reducing investment costs, unserved energy and operating cost. These gains show up in the respective net import demand curves. Consumers in the high-price country and producers in the low-price country will gain, while consumers in the low-price country and producers in the high-price country will lose, with net gains being unequivocally positive.[5]

Following Spiecker et al (2013), we use a simple two-country linear model to analyse how market coupling increases social welfare thanks to interconnection, and how those gains are distributed among the different agents, namely electricity consumers, producers and the TSOs. Consider two countries A, the importing one, and B, the exporting one with an occasionally congested interconnection. As a result, there is a price divergence between the different market places: the two countries have a different equilibrium price P_A^0 and P_B^0due to differences in generation costs. As an electricity exporter country B is the low-cost area, with $P_B^0 \leq P_A^0$. Integrating the two energy markets, thanks to investments in interconnection capacity or market coupling, allows electricity to flow from B to A, causing prices to converge, increasing social welfare in the process.

The resulting welfare gain from electricity trading can be interpreted as a reduction in the deadweight loss, i.e., the opportunity cost of mutually beneficial trades that were not made, due to limited interconnection capacity. Maximizing social welfare is equivalent to minimizing this deadweight loss.

Figure 7: Welfare Impacts Due to Additional Interconnection Capacity



Improving social welfare implies a trade-off with the earnings of the operator of the interconnection, however. As capacity is constrained and price differences persist during a certain number of hours, this price difference generates an income for the TSOs, referred to as the congestion rent (CR). The congestion rent is calculated straightforwardly as the product of the price gap and the electricity flow from the low-cost area to the high cost area:

$$CR = (P_A - P_B) \times Q_{IC}.$$

[5] The net gain in welfare is ensured by the possibility of arbitrage. If the gains of the winners from market coupling were not larger than the losses of the losers, it would be profitable for consumers in the exporting low-price country to buy back the electricity sold abroad. Conversely, it would be profitable for the producers in the importing high-price country to sell electricity at less than the new equilibrium price.

Consider now that investments are made to increase the interconnection capacity between the two countries. This enables country B to export more by using the added interconnection capacity. Figure 5 above shows that the new transmission capacity (moving from IC_n to IC_{n+1}) allows electricity to flow from the low-cost area to the high-cost area. In country B, producers face higher demand, and in country A, consumers can buy additional electricity at lower prices thanks to cross-border exchanges. The shift of the demand from supply in country A to supply in country B causes prices to converge, as they increase in country B and decrease in country A.

The blue-coloured area represents the newly available advantageous trades that are possible following the investment in new interconnection capacity and the associated gains in consumer and producer surplus resulting from price convergence. For each increment of added interconnection capacity, the surplus resulting from these new trades can be split into three different components:

- The additional consumer surplus in importing country A, noted ΔSC_A (or SA in Figure 5);
- The additional producer surplus in exporting country B, note ΔSP_B (or SB in Figure 5);
- The reduction in the congestion rent which is shared, by assumption, equitably between the TSOs of the two countries.

As indicated above, interconnection capacity is costly and some remaining congestion is thus socially optimal. This implies also in the optimum the continuing existence of a residual deadweight loss (in red in Figure 5) as well as a continuing congestion rent (in striped green).

4. RESULTS: DETERMINING THE OPTIMAL INVESTMENT IN ADDITIONAL INTERCONNECTION CAPACITY

On the basis of NECs and NIDCs constructed on the basis of the observed aggregated auction curves, welfare changes were calculated for each hour in function of step-wise incremental increases in interconnection capacity. Summing the combined welfare increases on the producer and the consumer side over the 8 760 hours of the year provides the annual increase in welfare for each step increase of interconnection capacity. This benefit in welfare terms is confronted with the annual cost of augmenting interconnection capacity. The point of equality between costs and benefits indicates the socially optimal increase in interconnection capacity.

The first step is, of course, the estimation of the NECs and the NIDCs for each of the 24 hours of the 365 days of the year. As indicated in Table 6 below, this allows immediately the determination of a no-congestion interconnection capacity (Optimum added IC quantity) that would ensure full price convergence between the two countries at an equilibrium price (Optimum added IC price) that can be confronted for verification with the ELIX and the reported market prices in France and Germany.

As explained earlier, the differences of the calculated values with the ELIX are due to the fact that the present model only considers two markets (France and Germany/Austria) whereas the ELIX takes into account all the markets to which France and Germany are connected. As expected, the mean of the difference between the full convergence price and the ELIX is positive. A higher number of participant countries in trading, as is the case with the ELIX, will always allow for achieving more efficient outcomes than trading arrangements with a more constrained number of participants. The linear coefficient of correlation R^2 for the estimation of NECs and NIDCs for 2014 is above 0.90.

Table 6: Summary Information for NECs, NIDCs

Hour	A_fr	B_fr	R²_fr	A_ger	B_ger	R²_ger	Optimum added IC quantity (MWh)	Optimum added IC price (€)	France exports	Difference to ELIX	Real equilibrium Price France	Real equilibrium Price Germany
1	0,01586	2,064045	668569099	-0,00857	40,30608	0,88	1565,302245	26,88930381	TRUE	-4,26069619	13,02	39,83
2	0,006282	10,24911	671887381	-0,00902	35,51396	0,92	1651,263417	20,62283778	TRUE	-3,757162218	11,229	36,53
3	0,00433	9,203532	796860195	-0,00889	33,46113	0,90	1834,483497	17,14761057	TRUE	-4,672389432	10,924	33,33
4	0,001678	9,827503	800904385	-0,00398	25,45796	0,94	2762,077683	14,46310279	TRUE	-1,336897215	10,251	26,92
5	0,002274	8,88237	058301574	-0,00569	32,20981	0,88	2929,649988	15,54486466	TRUE	-3,235135343	10,466	33,08
6	0,007083	2,238243	805594671	-0,00813	35,34806	0,81	2175,730055	17,64862089	TRUE	-11,07137911	10,67	38,24
7	0,00935	36,32263	889753296	-0,00345	47,0909	0,82	841,0716859	44,18651208	TRUE	-3,483487921	36,359	45,94
8	0,00189	52,66263	172505672	-0,00363	52,67863	0,93	2,898755644	52,66811174	TRUE	-1,371888259	52,906	52,91
9	0,008014	55,53264	213692515	-0,00983	56,14489	0,99	34,32031693	55,80766451	TRUE	-4,192335486	55,97	55,97
10	0,003539	57,8719	997564588	-0,01062	57,8774	0,99	0,388174489	57,87327536	TRUE	-3,126724635	57,871	57,87
11	-0,00408	57,70289	917330642	0,009623	57,20022	0,97	36,67132319	57,55310935	FALSE	-0,916890651	57,331	57,33
12	-0,00343	59,85868	859733409	0,00876	59,00613	0,91	69,91767976	59,61859191	FALSE	0,058591905	59,969	59,97
13	-0,00855	58,65586	811075261	0,012385	58,53372	0,98	5,834348367	58,60597717	FALSE	0,915977171	58,503	58,5
14	-0,0158	56,66041	030097185	0,0083	56,17769	0,95	20,03086617	56,34394521	FALSE	1,07394521	56,187	56,19
15	-0,00238	52,5174	662620946	0,004039	52,49342	0,88	3,733606031	52,50849938	FALSE	-0,451500622	52,951	52,95
16	-0,00214	50,46715	383642814	0,003895	50,23747	0,88	38,04466836	50,38566662	FALSE	-0,664333383	49,905	49,91
17	-0,00824	50,54597	217514713	0,004156	50,51746	0,95	2,300527716	50,52702023	FALSE	-0,712979771	50,067	50,07
18	0,001813	51,4179	285063115	-0,00622	51,74846	0,87	41,16134443	51,49252777	TRUE	0,162527772	51,471	51,47
19	0,010874	59,72075	443049396	-0,00714	59,76436	0,99	2,421035924	59,74707261	TRUE	3,207072612	59,809	59,81
20	0,018085	60,22666	516702078	-0,00927	60,29712	0,98	2,575678481	60,27324624	TRUE	1,643246237	60,339	60,34
21	0,003845	60,44508	625334382	-0,00694	60,82944	0,97	35,63403544	60,5820884	TRUE	2,142088399	61,037	61,04

... 20110824 | 20110825 | 20110826 | 20110827 | 20110828 | 20110829 | 20110830 | 20110831

The results show that the full convergence interconnection capacity varies strongly hour by hour. Ensuring complete convergence at all times would require near-infinite capacity, which is clearly not optimal given the associated costs. The following cost-benefit analysis thus provides precisely an assessment of optimal level of capacity investments, which maximises benefits over the year.[6]

On the basis of the linearized NECs and NIDCs, it was possible to assess first the prices in France and in Germany for each added increment of interconnection capacity in every single hour. This allows subsequently, the calculation of the consumer and the producer surplus, the congestion rent, as well as the resulting total gain of social welfare, again at the hourly level for each increment in infrastructure capacity. For each hour capacity was added until prices converged completely. Table 7 below shows the format in which the results were obtained for four capacity increments from 50 to 200 MW.

[6] Clearly, a definitive analysis of investment needs in additional interconnection capacity would have to take into account the fact that results vary strongly from year to year in function of consumption patterns and the weather. Ideally, multi-year or average data over the prospective lifetime of the project would need to be used. This issue harks back to the methodological discussion in section 1. Full assessments of the economic benefits of infrastructure provision must make use both of available microdata of real economic behaviour as well as of the insights about future multi-year developments that can only come from scenario building.

Table 7: Hourly Prices, Surplus and Congestion Rent for Different Capacity Additions

Capacity Addition in MW	50				100				150				200			
H1	47.085411	46.888693	13.023855	13.023855	47.80001	46.680599	0	13.023855	48.51461	46.472505	0	13.023855	49.229209	46.264411	0	13.023855
H2	43.405202	42.376192	0.3693299	0.3693299	44.22956	42.144506	0	0.3693299	45.053918	41.91282	0	0.3693299	45.878276	41.681134	0	0.3693299
H3	39.518646	39.056585	8.8015965	8.8015965	40.468309	38.794489	0	8.8015965	41.417973	38.532393	0	8.8015965	42.367637	38.270297	0	8.8015965
H4	20.957406	40.645246	25.989337	25.989337	21.613344	40.26161	77.96801	103.95735	22.269282	39.877975	129.94668	233.90403	22.92522	39.49434	181.92536	415.82938
H5	15.120365	42.119127	21.478577	21.478577	15.544688	41.684307	64.435731	85.914308	15.969012	41.249487	107.39288	193.30719	16.393335	40.814668	150.35004	343.65723
H6	17.627196	41.483116	24.646379	24.646379	18.268554	41.138619	73.939136	98.585515	18.909911	40.794121	123.23189	221.81741	19.551269	40.449623	172.52465	394.34206
H7	21.187259	38.789145	25.935789	25.935789	21.924838	38.489292	77.807368	103.74316	22.662417	38.189439	129.67895	233.4221	23.399996	37.889587	181.55053	414.97263
H8	15.930201	45.08011	27.124937	27.124937	16.793207	44.858118	81.37481	108.49975	17.656213	44.636127	135.62468	244.12443	18.519219	44.414135	189.87456	433.99899
H9	20.523679	49.351939	31.688988	31.688988	21.496635	49.057335	95.066964	126.75595	22.469591	48.762732	158.44494	285.20089	23.442546	48.468128	221.82292	507.02381
H10	35.679467	49.180275	26.761344	26.761344	36.596293	49.026648	80.284033	107.04538	37.513119	48.87302	133.80672	240.8521	38.429946	48.719393	187.32941	428.18151
H11	44.729504	48.191473	28.245842	28.245842	45.70542	48.037555	84.737525	112.98337	46.681336	47.883637	141.22921	254.21257	47.657252	47.72972	197.72089	451.93346
H12	45.784561	44.46126	0.0772202	0.0772202	46.705635	44.011635	0	0.0772202	47.62671	43.56201	0	0.0772202	48.547784	43.112385	0	0.0772202
H13	45.500808	44.044301	0.2112339	0.2112339	46.551143	43.624921	0	0.2112339	47.601479	43.205542	0	0.2112339	48.651814	42.786162	0	0.2112339
H14	35.884825	37.661385	0.5487722	0.5487722	34.637486	38.413572	0	0.5487722	33.390148	39.165759	0	0.5487722	32.142809	39.917946	0	0.5487722
H15	36.581494	38.204311	0.0789384	0.0789384	35.55673	38.948825	0	0.0789384	34.531965	39.693339	0	0.0789384	33.507201	40.437852	0	0.0789384
H16	34.774898	33.349667	1.1304067	1.1304067	35.71325	32.799982	0	1.1304067	36.651601	32.250297	0	1.1304067	37.589952	31.700612	0	1.1304067
H17	27.806364	27.531142	4.1512753	4.1512753	28.574453	27.255788	0	4.1512753	29.342542	26.980435	0	4.1512753	30.11063	26.705081	0	4.1512753
H18	14.09312	44.538554	33.221152	33.221152	14.96415	44.080738	99.663455	132.88461	15.83518	43.622922	166.10576	298.99037	16.70621	43.165106	232.54806	531.53843
H19	28.427656	50.219038	30.196494	30.196494	29.406222	49.989744	90.589483	120.78598	30.384787	49.760451	150.98247	271.76845	31.363353	49.531157	211.37546	483.14391
H20	24.646456	52.631801	29.266576	29.266576	25.544842	52.359525	87.799727	117.0663	26.443229	52.087248	146.33288	263.39918	27.341616	51.814972	204.86603	468.26521
H21	17.372243	51.544385	13.794685	13.794685	17.633173	51.253528	41.384056	55.178741	17.894103	50.962671	68.973426	124.15217	18.155033	50.671813	96.562796	220.71496
H22	17.623684	52.190018	15.93323	15.93323	18.033262	51.962267	47.799691	63.732921	18.442841	51.734517	79.666152	143.39907	18.85242	51.506766	111.53261	254.93169
H23	35.501679	49.376369	28.824668	28.824668	36.517155	49.238859	86.474004	115.29867	37.532632	49.101349	144.12334	259.42201	38.548109	48.963839	201.77268	461.19469
H24	47.203877	46.223844	0.6897589	0.6897589	48.448889	46.018591	0	0.6897589	49.6939	45.813337	0	0.6897589	50.938912	45.608084	0	0.6897589
Mean			392.19038	392.19038			1089.324	1481.5144			1815.54	3297.0544			2541.756	5838.8103
	New price France	New price Germany	Consumers surplus	Producers surplus	Congestion rent	Marginal gain of social welfare	Total gain of social welfare	New price France	New price Germany	Consumers surplus	Producers surplus	Congestion rent	Marginal gain of social welfare	Total gain of social welfare	Net_gain_marginal	Net_gain_Total

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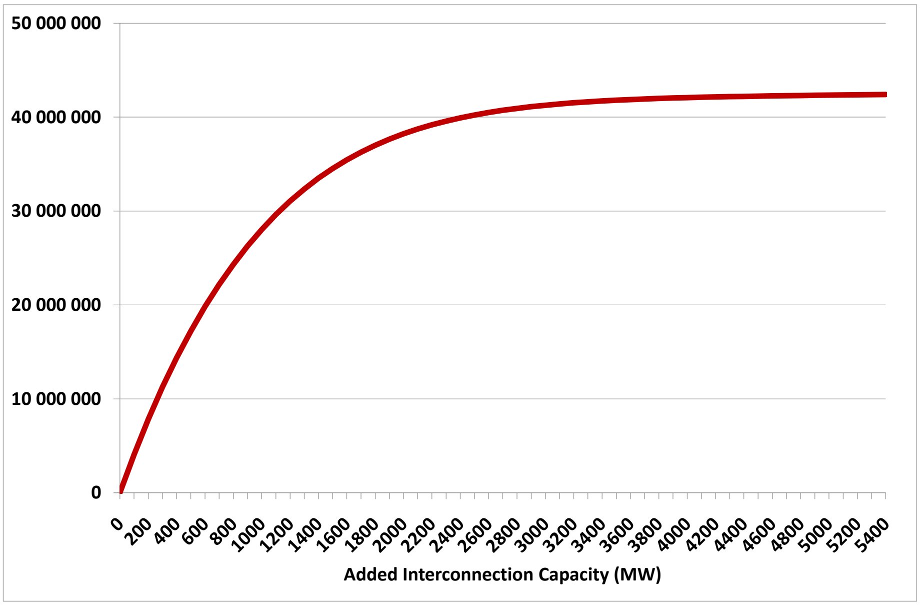
The welfare gains obtained for each hour of the day and for each day of a year were added in order to assess the annual social welfare increase for each increment of added interconnection capacity (2014 data). Figure 8 below shows the total results obtained in graphic form.

Figure 8: Annual Welfare Increases in Function of Different Levels of Additional Interconnection Capacity between France and Germany

(Euros, 2014 Data)



As one would expect, the function is increasing and convex. Up to the point of capacity where prices converge at all hours, adding interconnection capacity always increases the social surplus albeit at progressively smaller increments. Increasing capacity up to a point that would allow price convergence at all hours would imply for the year 2014 the extremely high level of 28.6 GW of interconnection capacity.

Assessing the cost side

In order to determine the optimum level of additional interconnection capacity, it is necessary to confront its benefits with the corresponding costs. Marginal costs and benefits will be equalised at the optimum.

Precise cost data for the construction of additional interconnection projects between France and Germany is unfortunately unavailable. The *Ten Year Network Development Plan (TYNDP)* of ENTSO-E does, however, provides the overall investment costs of new interconnection capacity of 1 000 MW between France and Germany. Under the hypothesis that cost is a linear function of capacity it is then possible to determine that the investment cost for an interconnection line (C_{IC}) between France and Germany is roughly equal to $C_{IC} = 100\ 000$ € per MW for a line with a length of 50 km. Taking a discount rate (i) of 4% and, following the TYNDP, a lifetime (n) of 25 years, the annual annuity (A) per MW will be determined according to:

$$A = \frac{i * C_{IC}}{1 - \frac{1}{(1+i)^n}} = 6\ 401\ €/\mathrm{MW}.$$

For an interconnection with a capacity of 1 000 MW, this will amount to annual costs of roughly 6.4 million Euros.

While currently the costs of investments in electric lines are not published by the TSOs, any future refinement of this analysis of the costs side would need to consider that:

- Cost is not necessarily a linear function of capacity;
- Maintenance costs were not included here;
- The discount rate may vary from the one used above;
- The lifetime of the interconnection capacity to be installed needs to be verified.

In addition, a more precise analysis would need to take into account that the total physical interconnection capacity is not available in its entirety for the commercial exchanges that are the basis of our analysis. Any gross interconnection capacity would also need to be adjusted for the Transmission Reliability Margin (TRM), which is the security margin deducted from the gross physical IC to cover unexpected events such as:

- Unintended load frequency changes;
- Emergency exchanges;
- Constraints on voltage changes.

Following the deduction of the TRM, which is partly a function of the amount of VRE capacity available on both sides of the border, it is the Net Transfer Capacity (NTC) that represents the total available capacity for commercial exchanges. The latter is composed of the Available Transfer Capacity (ATC) for immediate auctioning, capacity that is allocated to long-term contracts, as well capacity that is withheld for delayed auctioning. For modelling purposes, the NTC would be the relevant metric as prices are a function of the sum of all commercial exchanges.

Putting benefits and costs together in order to establish optimal infrastructure capacity

The optimal amount of additional interconnection capacity is determined by equating the marginal benefits and the marginal costs established in the two previous sections. Benefits are measured in terms of the total annual increase in the sum of producer surplus, consumer surplus and the congestion rent of the TSO, *i.e.*, the total annual benefit (TB) gained from the more efficient pricing of electricity due to each increment in interconnection capacity (ICC). Annualized investment costs (AIC) are measured for each increment in capacity as indicated in the previous section. It is then beneficial to add interconnection capacity to the system as long as the benefit of each increment is greater than its cost.

Total annual benefits (TB) from additional exchanges in electricity between the two countries are a positive function of the added interconnection capacity (ICC) exhibiting decreasing returns to scale. It thus holds that

$$TB = f(ICC) \ \ with\, f' > 0\ and\, f'' < 0.$$

Annualized investment costs (AIC) are a linear function of the added interconnection capacity. It thus holds that

$$AIC = g(ICC) = k * ICC \ \ with\, g' = k > 0\ and\, g'' = 0.$$

Total social surplus (TSS) is maximized in function of the added interconnection capacity when the sum of total annual benefits (TB) and annualized investment costs (AIC) is maximized

$$Max\!: \ TSS = h(ICC) = TB - AIC = f(ICC) - g(ICC).$$

At the optimum it holds that

$$\frac{\partial TSS}{\partial ICC} = \frac{\partial h(ICC)}{\partial ICC} = \frac{\partial f(ICC)}{\partial ICC} - \frac{\partial g(ICC)}{\partial ICC} = 0.$$

This yields

$$\frac{\partial f(ICC)}{\partial ICC} = \frac{\partial g(ICC)}{\partial ICC}\ or\, f'(ICC^{*}) = g'(ICC^{*}) = k.$$

The thus defined point is a maximum due to the fact that over the whole range it holds that

$$h''(ICC) = f''(ICC) - g''(ICC) = f''(ICC) + 0 = f''(ICC) < 0.$$

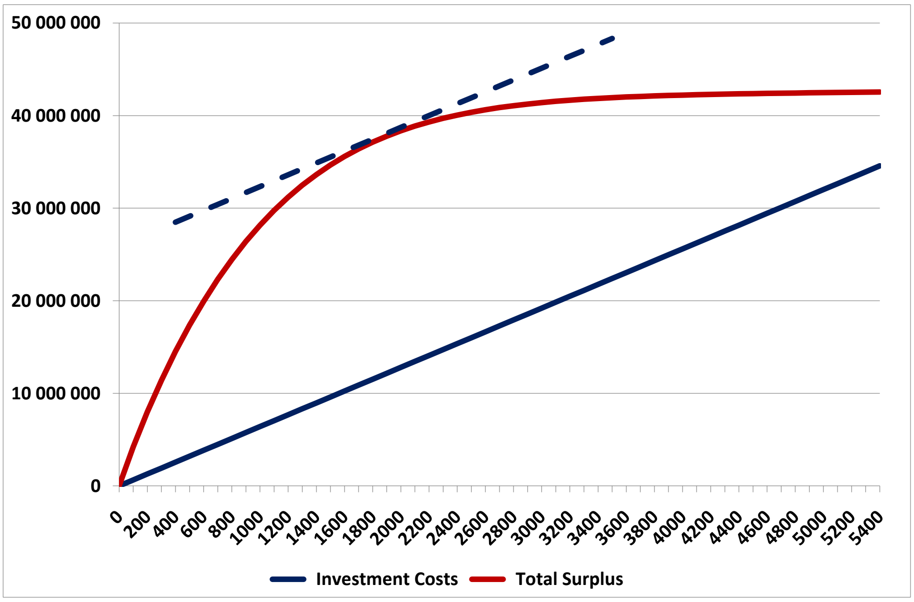
In other words, the marginal annual benefits in terms of added surplus from trading need to be equal to the marginal annual costs in terms of the annualized investment costs of the added interconnection capacity.

Clearly, adding interconnection capacity is not an entirely differentiable function. The optimal additional interconnection capacity (ICC*) is thus the largest additional capacity for which it holds that

$$f'(ICC) \geq g'(ICC) = k.$$

Applying this reasoning to the data, the optimal additional level of interconnection between France and Germany on the basis of 2014 data can be established amounting to 1 900 MW (see Figure 9 below). Given that current interconnection capacity is at 3 600 MW, this implies that the overall optimal interconnection capacity between France and Germany would be 5 500 MW. The additional total annual benefit of this increase (based on 2014 data) would amount to € 38 million, while the additional annual costs would amount to slightly less than € 12 million. Joint annual net benefits would thus amount to € 26 million.

Figure 9: Determination of the Optimal Interconnection Capacity between France and Germany
(Euros, 2014 Data)



This result is of the same order as the one derived at in the 2030 scenario presented in the TYNDP 2016, which indicates a reference transmission capacity of 4 800 MW. It should, however be kept in mind that the TYNDP works with considerably higher shares of VRE in production, which would suggest an optimum for the French-Germany interconnection higher not only higher than 4 800 MW but even higher than the 5 400 MW calculated in this paper on the basis of the real market data provided by electricity producers and consumers. The ancillary benefits of added interconnections that are valued in the TYNDP would further support this conclusion.

This underscores the usefulness of the contribution that the empirical, market-based methodology proposed here can make to the assessment of the optimal interconnection investment. It provides, in particular a methodologically sound benchmark of the economic value of interconnection capacity based on market microdata.

5. CONCLUSION

Interconnections for cross-border electricity flows are at the heart of the project to create a common European electricity market. Interconnections allow exporting electricity from countries with relatively lower costs of production to those with relatively higher costs of production thus increasing economic efficiency and welfare.

The significant increase in production from variable renewables such as wind and solar in recent years has made the need for increased interconnections in European electricity markets more urgent. Production from wind and solar clusters around a limited number of hours per year and thus saturates given levels of existing infrastructures more frequently than before and thus requires *ceteris paribus* higher levels of interconnection capacity. The general qualitative implications of this autocorrelation are widely recognized. The challenge for regulators and electricity policymakers is to determine the optimal amount of interconnection capacity in function of these new realities. Scenarios and simulations such as those developed in the *Ten Year Network Development Plan* by ENTSO-E aim address precisely this challenge. While indispensable, such modelling increasingly require empirical verification due to the rapid structural change that European electricity markets are undergoing in the context of the energy transitions under way in a number of European countries.

The present paper proposes a new empirically-based methodology to perform Cost-Benefit analysis for the determination of optimal interconnection capacity for French-German electricity exchanges. Using a very fine dataset of hourly supply and demand curves from the EPEX Spot day-ahead market, we constructed the net export curves (NEC) and net import demand curves (NIDC) of both countries. To this purpose the offer and demand curves were linearized by means of ordinary least square (OLS) regressions. On the basis of NECs and NIDCs, the increase in welfare for each incremental increase in interconnection capacity was determined hour by hour. Summing the welfare increases over the 8 760 hours of the year an annual total was obtained for each step increase of interconnection capacity. This benefit in welfare terms was confronted with the annual cost of augmenting interconnection capacity. The point of equality between costs and benefits indicated the socially optimal increase in interconnection capacity between France and Germany.

The authors of this study strongly believe that such empirical analysis in complement to the use of simulation models is becoming increasingly important as European electricity markets are becoming considerably more complex. As the technical and behavioural parameters of the electricity system are no longer stabilized, the econometric verification of scenario results becomes ever more necessary in order to arrive at pertinent conclusions concerning the infrastructure needs required to optimize welfare in electricity markets at the European level.

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