Chapter 9
Power exchanges and transmission pricing

The poor level of integration between European electricity markets was demonstrated in chapter 8. The next step of the analysis is to try to explain the reasons of such low market integration. The hypothesis developed in this chapter is that the actual wholesale market design at the European level lacks efficient transmission pricing which hampers the development of an integrated market. The purpose of this chapter is not to go into the details of all approaches to transmissions pricing but rather to focus on the role of organized markets for dealing with congestion. In this chapter, we first emphasize the importance of transmission constraints in electricity networks. While at national levels dense grids have allowed most European power exchanges to be designed in a way that ignores transmission constraints, at the international level the existence of important bottlenecks make this issue critical. Different theoretical approaches to transmission pricing, nodal/zonal, and the study of actual successful examples of integrated markets, PJM/Nord pool, are presented. Using these two examples we identify possible lessons for the European market, it appears that an efficient transmission pricing mechanism is a fundamental cornerstone for such markets. The inadequacy of the actual transmission pricing mechanisms between European countries is discussed. Some empirical evidence of inefficient pricing between European countries is provided in the last part of this chapter.

9-1 Transmission pricing
9-1-1 Introduction

The creation of an integrated market is confronted with the fact that transmission capacity between countries is limited[1]. In such a context trading arrangements regarding transmission represent one of the most complex, but also one of the most important, issues of market design. While there is a general agreement among academic practitioners and policy makers that direct and non-discriminatory access to the transmission grid is an essential centerpiece for a competitive electricity market, in Europe little attention has been paid to instituting direct access.

In continental Europe, two levels of transmission pricing can be identified, a national level and an international level. When pricing transmission at the national level, the lake model, also called copper plate or postage stamp approach, is mainly used, i.e. generators “pour in“ electrons and consumers “draw out “ electrons (Albers, 2001). This model is a zonal model, each country is a single zone[2], is relevant when there are no transmissions constraints. The justification for such a model is that national network are very dense in most European Members States. Access to interconnectors is an essential element of the Trans-European network and it is a fundamental condition for the creation of the internal electricity market. The existence of interconnection is an important factor for international competition since it allows consumers to import electricity from Members States with lower electricity prices. Moreover in Members States, characterized by a dominant incumbent, interconnectors are the only source of competition and choice for consumers[3].

An important problem with power exchange is that they offer a price for a wide area regardless of the location of producers. Buyers on a power exchange only

[1] See chapter 7
[2] Note that regional zones are delineated within the United Kingdom and in the Nordic countries
[3] See chapter 7

buy energy and have to add the price of transport. In most European countries the charges for transmission are regulated and do not take into account the location of generating companies. Because of this transmission system operators may face difficulties in insuring physical delivery of power when congestion occurs. At the national level, most European member states have dense transmission grid and excess generation capacity which allows them, in the short term, to leave the problem of efficient grid pricing for later review (Newbery, 1999). The different power exchanges ignore differences in nodal prices, and have adopted a single integrated market approach at the national level and are not directly involve in transmission pricing of interconnector capacity with neighboring countries.

The hypothesis developed in this chapter is that the actual wholesale market design at the European level lacks efficient transmission pricing which hampers the development of an integrated market and explains the low level of market integration presented in the previous chapter. The purpose of this chapter is not to go into the details of all possible approaches to transmissions pricing but rather to focus on the role of organized markets for dealing with congestion. As introduced in chapter 3 in the presence of transmission constraints, economic theory suggests the application of locational pricing[4]. In this chapter we elaborate from a theoretical point of view on the difference between the two main approaches: zonal and nodal pricing[5]. These two approaches are illustrated with two successful examples of existing markets, in Nordic countries (Nord pool) and on the east coat of the US (PJM), with particular attention paid to the role of the power exchanges. Then, the inadequacy of the actual approach followed in Europe and empirical evidence for this are discussed[6]. We compare the cost of transmission between locations, based on the result of auctions for interconnector capacity, with the difference in the prices at the locations, based

[4] See section 3-3-4
[5] For the sake of brevity we do not consider other possible approaches such flow-based transmission approaches. For a presentation of flow-based approaches see Chao *et al* (2000) and Ruff (2000)
[6] Current discussions and proposals for changes are presented in chapter 10

on power exchanges prices. This analysis shows that from a theoretical and an empirical point of view the actual transmission pricing mechanism is inefficient and it is a fundamental missing piece of the actual European market design.

9-1-2 Transmission constraints

Due to its physical features electricity flows regardless of contract between generators and consumers. The main determinant factor of electricity flow is transmission constraints. Transmission constraints arise on transmission networks from time to time, due to changing patterns and costs in generation and demand. Due to the complex interactions in the electricity transmission network, loop flows, physical limits and reliability constraints, transmission constraints represent a significant challenge for the creation of competitive electricity markets. In a meshed network, characterized by the existence of several interconnected lines, electrons do not only flow on the line directly connecting the generation point with the load point they also flow on other parallel lines in accordance with the law of least resistance (Kirschoff's law). Hence, it is a physical fact that, in a meshed system, the flow along any transmission line at any time depends upon the all other flows in the system at that time (Turvey, 2001). Due to these loop flows identification of a specific transaction is impossible. For this reason, transmission constraints represents one of the most complicated issues in electricity market design (Hogan, 1995).

At national levels most European power exchanges have been designed as if they were operating in an unconstrained network[7]. In an unconstrained network, the transmission capacity is considered to be infinite, i.e. the transport of electricity is a secondary issue. Electricity can be produced at a location and consumed at another one without any risk for the system. In such a system price differs across location only by the marginal costs of power losses in transmission. However, marginal losses on high voltage transmission grids are relatively small

[7] See chapter 5, section 5-4-2

and represent only a few percent of the cost of delivered power. Hence, in such a system the price of power is the same at any location. In practice, unconstrained networks do not exist since they involve over-investment which is not an economic optimum[8]. Hence an optimal level of capacity for transport capacity involves transmission constraints, or congestion. While at national levels the dense networks have allowed the creation of a single hub regardless of transmission constraints, at the international level the weak interconnections between countries make congestion management a fundamental issue.

The capacity of transmission lines and the way transmission is priced determine the degree to which generators in different locations compete (Borenstein *et al*, 2000). Due to the existence of transmission constraints between countries, transmission capacity is a scare good and needs to be allocated. Economic theory recommends that market mechanisms are used to do this. In theory, the marginal cost of transmission between two locations should equal the difference in the prices at the two locations (Schweppe *et al*, 1988). From a practical point of view, experience has showed that an organized market for electricity is an institution which can be used to support the market mechanisms for dealing with transmission constraints.

9-1-3 Zonal versus nodal[9]

In most European countries, power exchanges provide a single price for the hub of their country. For this reason the existing European market can be viewed as a zonal system, although a very basic form. Each zone consists of a country. No intra-country zone exists even if congestion can occur within the country. Moreover this zonal system is incomplete because the existing coordination

[8] Since the demand for electricity vary widely between "super" peak hours and off peak periods, it is wasteful to build expensive capacity that will be use only for a couple of hours during the year

[9] When describing transmission pricing system, the term 'nodal' pricing is conventionally used to describe markets with a high resolution of locational energy prices, while 'zonal' pricing is used to describe markets with one or very few locational prices.

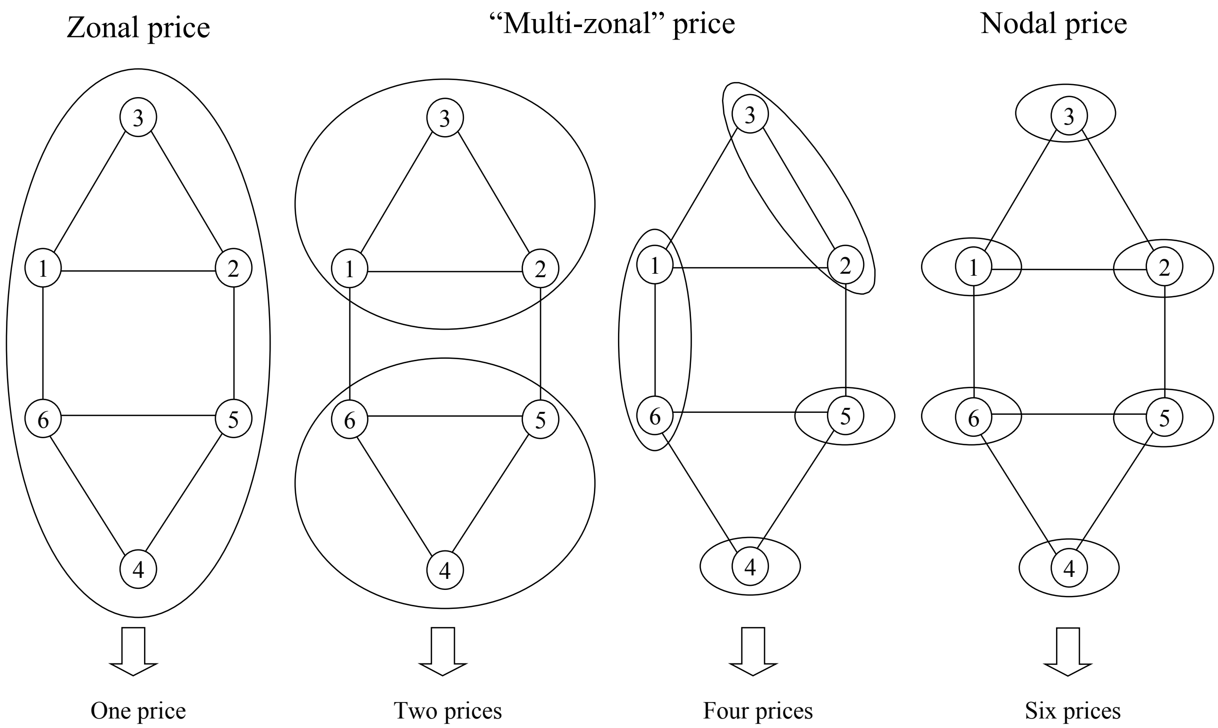
mechanisms between countries (zones) present several shortcomings[10]. The main features of the zonal approach in contrast to the nodal approach, and the different controversies related to the zonal/nodal pricing debate are presented from a theoretical[11] point of view in this section.

In presence of transmission constraints, economic theory suggests the application of locational prices (Schweppe *et al*, 1988; Hogan, 1992). In such a system, each constrained area has its own electricity price. This approach is known as *nodal pricing* (Hogan, 1998). The nodal approach defines "area" with respect to transmission constraints. An area is defined when it does not have any internal constraints. In a very constrained area, prices are determined for each node of the network. Due to changes in physical constraints related to change in production-consumption, prices may differ between nodes. A price should be set to reflect transport constraints for each node of the physical network. The first visible effect of implementing nodal pricing rather simple zonal pricing is that the market consists of a set of prices, one for each location.

A schematic network introduced in Chao and Peck (1998) consisting of six nodes is presented in figure 9-1 to illustrate the difference between nodal and zonal approach. Grouping all nodes into one single zone (zonal price) we obtain a single zone system, which defines a single price for all of the area regardless of any transmission constraints within the zone. In contrast defining a price at each node takes into account all possible transmission constraints and defines a price at each node (nodal price). Finally a combination of the two approach can be defined using both zones and nodes ("multi-zonal" price)

[10] See section 9-4

Figure 9-1: Locational price-illustration



With respect to transparency, the nodal approach is often criticized for its complexity and its requirement for a very high level of technical coordination between system operator and market operator. Due to the complexity of this approach an alternative method consists of aggregating many nodes into a smaller number of zones which simultaneously reduce the number of prices (Bjorndal and Jornsten, 2001). Such an approach is known as *zonal pricing* (Hogan, 1998). The use of zones rather than nodes for pricing purposes is a common simplification (Green, 1997). The zonal approach has as its main advantage, from a market participant point of view, that it is simple to operate and provides only one (zonal) or a few prices (multi-zonal) while the nodal approach require complex calculations and results in many prices. This characteristic makes the single market approach at a first glance more

[11] Practical advantages and shortcoming of the two approaches are presented in section 9-2 based on case study

transparent and more “trading-friendly”. However, in the presence of real transmission constraints such “advantages” become problematic.

One shortcoming of zonal pricing is the problem of how to define a zone with respect to loops flows, while one major advantage of the nodal approach consists of its capacity to take into account loop flows which are a very important feature in a meshed network. Indeed, in the presence of a network with loop flows, price may differ within an unconstrained zone due to the indirect effect of “distant” constraints in neighboring zones[12]. Hence zones definition may change according to substantial differences in nodal prices within the zones[13]. It is then necessary to calculate nodal prices within a zone to assess the suitability of the zone definition (Harvey, 1996).

A second problem of the zonal approach is that there is a lack of signals on where to invest both for new generation and for new transmission capacity. Nodal pricing systems are criticized for producing complicated prices, highly volatile, and large price differences between areas which might hamper trading. Indeed, nodal prices can be higher than the marginal cost of the most expensive units reflecting the need simultaneously to increase output from expensive plants and decrease output from cheap plant to keep the system in balance. Moreover, nodal prices can be negative at constrained areas reflecting the value of a counterflow in the system, i.e. it would be cheaper to pay market players to consume electricity at some nodes in order to relieve transmission constraints. Although such a system is more complicated than a single-price system, it provides the right locational signals for new investment. For this reason, the nodal approach also offers better investment incentives, high prices areas will attract new investment in generation which in turn will lead to lower prices.

[12] For illustration see Hogan (1998), *Competitive electricity market design: a wholesale primer,* Harvard Electricity Policy Group, p 51

[13] See box 9-2 for an example

Nodal pricing systems are often criticized for calculating too many prices which reduces transparency, however in the presence of imperfect markets bilateral trading also produces many, if not more prices. While differences between nodal prices are based on real technical constraints, differences in bilateral prices are due to different levels of bargaining power, or worst, of market power. In a bilateral system, trade at the same node can results in different prices while a nodal system ensures one price for one location for a given period (Stoft, 2002). In the zonal approach, when transmission constraints occurs within a zone, the system operator needs to intervene to resolve conflicts between contracts and technical reality, and the system operator will use a balancing mechanism that takes into account these particular constraints. Such a system therefore requires an additional mechanism where players make additional adjustment bids/offers which in fact reduce the overall transparency of the system. From an operational point of view, accurately aggregating nodes into zones first requires a knowledge of individual flows per nodes, this aggregation requires additional computation and because of this the zonal approach adds supplementary work for less accurate price signals (Hogan, 1998).

A last problem with nodal pricing points that is often mentioned is the fact that such a system is difficult to implement in practice. This argument appears particularly weak with respect to international experiences. Indeed such system has been already implemented in the east of the United States (PJM) and in New Zealand and to lesser extent in the Nordic Countries, Argentina and Chile.

An important drawback from the perspective of the market participants is that nodal pricing involves intricate calculations which reduces transparency (Deng and Oren, 1998). In practice nodal pricing computations are often compared with a “black box”. The black box is based on different models which like all models[14] are based on assumptions (security constraints, power flows…) simplifications and lot of human input. For instance, the complexity of the mathematical

[14] See Chapter 4

algorithm can produce different equilibrium results. Hence, arbitrary choices may have to be made by the system operator between different solutions (Glachant and Pignon, 2002).

An additional concern about nodal pricing is the volatility of prices and the problem of ex-post pricing while separate auctions allow market participants to know in advance, ex-ante, the total costs of transporting electricity between two locations, nodal prices are only known ex-post. From a participant perspective, such a system involves more uncertainties which might hamper trading. Moreover, with nodal pricing, price differentials between locations can be substantial and vary widely from time to time. Such volatility can also represent an important barrier for the development of a liquid market.

Another concern with regard to nodal pricing is the fact that it does take into account the cost of operating transmission facilities. Nodal pricing is totally a function of generation costs. Hence in practice nodal prices can far exceed the redispatch cost necessary to relieve congestion (Rosenberg, 2000).

In conclusion, even if zonal pricing in providing a single price appears to be simpler and more transparent, the aggregation of nodes into a fewer number of zones is problematic in the presence of real transmission constraints and may add complexity and diminish price signal and transparency. When the system is unconstrained, the use of zonal pricing and nodal pricing is equivalent but the important question is how does the market design deal with the problems when the system is constrained. In contrast, nodal pricing is criticized when used in practice as having numerous flaws. The intense debate between advocates of each system can be illustrated as follows.

"The real impact of zonal pricing is to create more administrative rules, poorer incentives for investment, demands to pay generators not to generate power, and

proposals to "socialize" the higher costs by using the taxing power of the ISO. This is not the way of a market. ***It creates more problems than it solves****."* (Hogan ,1999).

"[nodal pricing]… ***suffers from numerous flaws****: it is divorced from the actual cost of providing transmission, it can far exceed the redispatch costs necessary to relieve congestion, and it may even provide perverse incentive to retain congestion."* (Rosenberg, 2000)

Table 9-1: Comparison of Nodal and Zonal pricing approaches

	Nodal pricing	**Zonal pricing**
Theoretically efficient without transmission constraints	Yes	Yes
Theoretically efficient with intra-zone transmission constraints	Yes	No
"Trading -friendly"	No	Yes

In sum, from a purely theoretical point of view the nodal approach, lavishly praised by Hogan, appears to be more suitable than the zonal approach. However, applying such approach in practice meet some difficulties. Practical experiences and empirical studies suggest that a compromise that combines the best of both approaches represents a workable solution (Tabors, 1999). Such a compromise is used in the Nordic countries (9-2-1). In PJM, though nodal prices are used (9-2-2), some empirical studies have shown that zonal prices in this market would capture most of transmission constraints with much simpler system[15]. Hence, the debate between the two approaches continues with respect to economic theory and practical applications. In the following section we

[15] See box 9-2 for an example

illustrate the functioning of these two approaches by elaborating on these two practical examples.

9-2 Case studies: the Nordic countries and PJM

9-2-1 The "Zonal"[16] approach: the Nordic countries

The analysis presented in chapter 8 showed a low level of integration between most locations within Europe, though within the Nord pool area, price changes at one location were generally highly correlated with price changes at other Nord pool locations. In this section we argue that such a good level of market integration is directly related to market design, especially with respect to the articulation between power exchanges and transmission pricing.

Table 9-2: Key figures for the Nordic electricity system 2001

		Denmark	Finland	Iceland	Norway	Sweden	**Nordel**
Installed capacity	MW	12 480	16 827	1 427	27 893	31 721	**90 348**
Generation	GWh	36 009	71 645	8 028	121 872	157 803	**395 357**
Imports	GWh	8 603	12 790	-	10 753	11 167	**43 313**
Export	GWh	9 180	2 831	-	7 161	18 458	**37 630**
Total consumption	GWh	35 432	81 604	8028	125464	150512	**401040**

Source: Nord pool

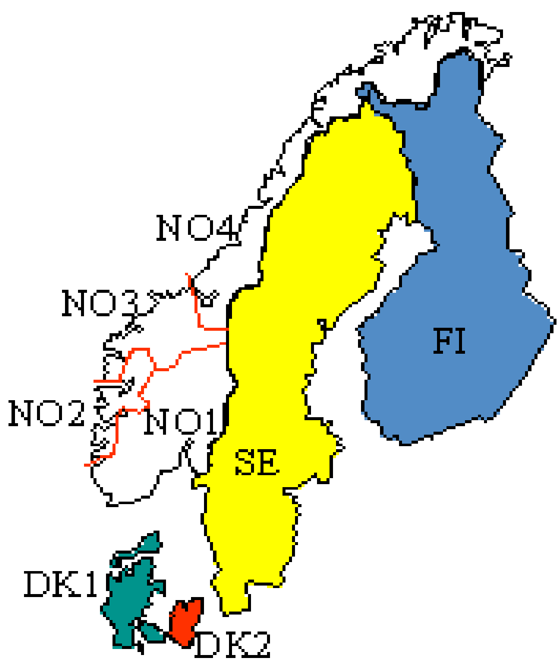
The Nordic countries, Norway, Sweden, Finland and Denmark, present a very interesting example of how a power exchange is used for dealing with congestion. First, it is worth noting that two methods are used simultaneously to deal with congestion: market-splitting, also called implicit auctions, for cross-border congestion and counter trading[17] for internal constraints in Sweden, Denmark, Finland and for some congestion within Norway (Johnsen *et al*, 1999).

[16] While nodal pricing refers to a system where prices at each node of the network can vary, under zonal pricing, nodal prices are aggregated across several zones. In the Nordic countries zones may varies. Hence the distinction between nodal and zonal pricing is less clearly defined. For the sake of brevity, we refer to the Nordic system as zonal "pricing".

[17] Under Counter trading, congestion is eliminated by the system operator who chooses counterparties on one or both sides of the congestion to reduce capacity demand, either by buying in the high price area and selling in the low price area or by securing demand reduction in the high price area.

For the sake of the discussion we will only consider the market-splitting mechanism because it deals with cross border flow while counter trading is only use at the national level. Nord pool was primarily the Norwegian market, Denmark, Finland and Sweden joining progressively later. Currently Nord pool covers five areas, Norway, Sweden, Finland, East Denmark and West Denmark and potentially up to eight congestion zones since Norway may be divided into four zones (figure 9-2). In general, due to a weak level of interconnection between countries with respect to national grid density, the first determinants of congestion zones are national borders (Gronli, 2001). Secondly within Norway different zones are defined due to internal bottlenecks.

Figure 9-2: Zone definition for Nord pool



Source: Nord pool

Like all European power exchanges, Nord Pool is a non-mandatory marketplace for physical day-ahead trades. Hence market participants can choose between using the power exchange or contracting on a bilateral basis, however, an important feature of Nord pool is a ban on players entering into physical[18] bilateral contracts between zones. For inter-zones transactions, sellers have to sell in their generation area and buyers have to buy in their consumption area through Nord pool. Nord pool is therefore mandatory for physical cross-border trades. Concretely, buyers have to specify their withdrawal zone and sellers their injection zone day-ahead, to allow the system operators to check the feasibility of transactions.

Congestions between zones are handled by Nord pool through the *market-splitting* mechanism. The main characteristic of market splitting is that transmission constraints and energy are coupled and traded simultaneously[19]. The objective of such system is to ensure that transmission capacity is allocated with respect to energy trading requirements. In such a system Nord pool collects bids for specific grid input and consummations points to assess the physical flows that would be created. If acceptance of all the bids does not create congestion, all input and consumption points form a single zone. However, if the flows create congestion, the area is then "split" into different zones with respect to congested interconnectors and new market prices are determined for each zone. At the same time, the system ensures that, for every hour, all interconnector capacity is used in accordance with the price differentials.

Concretely, in the first phase Nord pool, as a power exchange, calculates the system price, which is the price that could have been obtained if it was possible to accommodate all the transmission demands on the interconnector between the two areas. Then, the exchange checks whether this price will enable transmission between the areas over and above the capacity on the interconnector. If no restrictions are encountered, the system price will be the valid current price in both areas. This situation corresponds to the case where no transmission constraints occur.

[18] In contrast to financial contracts such as Contracts for Differences or financials contracts traded on "Eltermin", the financial market.

[19] ETSO discussion paper, *Coordinated use of PXs for congestion management*, February 2002

In the presence of transmission constraints between two areas, the exchange will split the whole market into two areas and repeat the price calculation separately in the two areas. The price in one area will therefore be higher than in the other. The exchange will then purchase in the low price area and sell in the high price area. The increased demand in the low price area will in turn raise the price in that area. Correspondingly, the price in the high price area will fall when the amount of available power increases. This will be done until the amount of electricity bought and sold reaches the maximum capacity of the interconnector. The revenues of these operations are collected by Nord pool and paid back to the TSOs.

Market splitting indicates the local value of electricity. This mechanism relies on a liquid organized spot market within each zone. The use of market-splitting gives a central position to the power exchange: all physical trade between zones has to go via the exchange. There is only one exchange for all areas defining different prices, in contrast to continental Europe where each zone (country) has its own exchange which defines one price. Finally, zones are clearly defined, and may change, with respect to transmission constraints and are based on the TSO's load-flow calculations.

The Nordic system is often presented as a very sophisticated example of zonal pricing. However since the system operator has the possibility to change the definition of zones daily or hourly with respect to transmission constraints, this system can be better described as a nodal pricing system. Indeed, Nord pool is continuously investigating new ways of dividing up the joint Nordic electricity market according to structural bottlenecks in the grid and independently of national borders to reflect actual physical constraints in the grid and thus provide market players with better signals as to where surplus and shortfall areas are located[20].

[20] Nordel 2001, Annual Report, *Congestion management in the electric power system*

With 10 years of experience of a competitive market, the overall output of the Nord pool system is generally considered to be successful (Midttum, 1997; Gjerde, 2002). This system is of particular interest for the rest of Europe because it involves collaboration between several countries. One of the key elements of its success is the development of a common cross-border mechanism managed by a common institution formed by the system operators that directly run the power exchange. Hence the example of Nord pool is a concrete application of how a power exchange may play a central role in the creation of an integrated market.

9-2-2 The nodal approach: PJM

The PJM (Pennsylvania-New Jersey-Maryland) market is the largest centrally dispatched control area in North America (figure 9-3) and is often cited as one of the leading example of a successful competitive electricity market. Similar to Nord pool, PJM provides an interesting example of market design where organized markets and transmission pricing are integrated and are at the heart of the functioning of the electricity market. PJM reaches into eight states and the District of Columbia in North America. It serves about 11 millions customers. The installed generating capacity in the PJM area represents about 70 000 MW.

Table 9-3: Key figures for the PJM electricity system 2001:

		PJM
Installed capacity	MW	67,269
Generating Units		594
Peak Load	MW	64,127
Annual Energy	MW	298,011

Source: PJM Annual reports 2001

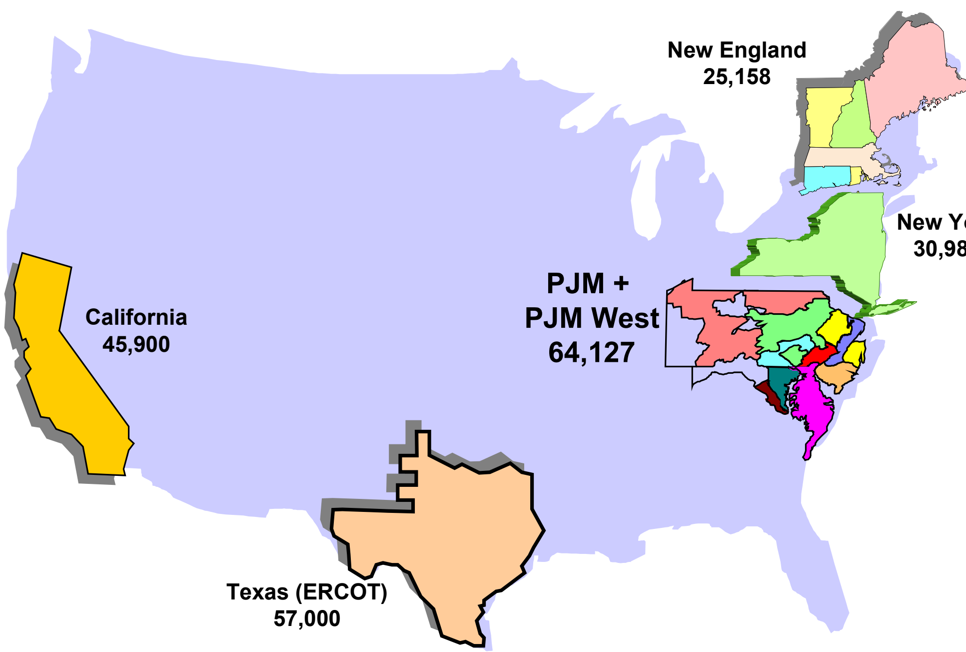
PJM combines the power exchange and the system operator. Similar to Nord pool[21], PJM operates several markets, although different in detail: two generating

[21] See chapter 2, Box 2-2

capacity credit markets (daily and long term), two energy markets (day-ahead and real time), a financial transmission entitlements market and an ancillary services market.

PJM started operation of its spot market in 1997. At that time the spot market provided a single price for the entire PJM region. Hence, the PJM area was treated as one zone with hypothetical unconstrained dispatch. In situation of congestion, some generators were constrained on, while others were constrained off. The main drawback of this method was that generators constrained off were paid nothing, even though they had bids below the system price. The cost incurred by using more expensive generation was socialized into a charge applied to all loads.

Figure 9-3: Major markets in the US (peak load)



Source: PJM

The single price system proved quickly to be problematic as it was unable to reflect adequately locational value of energy throughout the market related to transmission constraints. For this reason PJM switched from a single price system to a locational marginal pricing (LMP)[22] methodology. In November 1997, the Federal Energy Regulatory Commission (FERC) approved locational marginal pricing for transmission congestion for PJM[23]. Since 1998, PJM has determined hourly Locational Marginal Prices (LMPs) on a nodal basis which reflects the underlying cost of the energy and the marginal cost of transmission congestion. The energy market represents the cornerstone of the PJM system.

Concretely, PJM collects bilateral schedules and voluntary bids from market participants. Based on these schedules and bids, PJM determines an optimal dispatch for power flows and the associated locational marginal prices. PJM calculates (and publishes) the five minutes marginal prices at each node which are then aggregated on an hourly basis and used for energy transmission pricing[24]. PJM provides prices for approximately 2000 locations.

In order to allow financial hedging against price differences between locations, the LMP system is accompanied by a system of transmission rights (Hogan, 1992) called fixed transmission rights (FTRs) since 1999. FTRs entitle the holder to receive compensation for transmission congestion charges that arise from locational differences in the hourly market prices (the LMPs) resulting from the dispatch of generators out of merit in order to relieve congestion. FTRs are financial transmission rights rather than physical transmission rights[25], they do not represent a right to the physical delivery of power, but they do ensure that access is financially firm. FTRs represent a financial hedge against the ex-post-calculated locational prices. PJM also facilitates the trading of FTRs by running monthly FTR auctions that allow participants to adjust their FTR positions.

[22] LMP= Generation marginal cost + transmission congestion cost + cost of marginal losses
[23] FERC order, Docket No. OA97-261-000, issued 25 November 1997
[24] See www.pjm.com for locational current and historical LMP information
[25] See section 9-3-3

In conclusion, the example of PJM is of particular interest because it first worked with single zonal pricing and collapsed due to transmission constraints. Subsequently PJM adopted a nodal pricing system which appeared, from an economic theory point of view, to be the most efficient approach and has delivered in practice successful outcomes. PJM’s successful experience with nodal pricing system shows the practical feasibility of such a system and the relevance of nodal pricing for concrete applications. Similar to Nord pool, the key elements of success at PJM are the development of a transmission pricing mechanism integrated with the market operation.

Box 9-1: Would "multi-zonal" pricing be a simpler approach for PJM?

Though the single zonal price system has proved to be problematic and was replaced by nodal pricing in 1998, it has been argued that a multi-zones approach would have been sufficient to capture major transmission constraints and would have avoided *the "unnecessarily cumbersome and complex aspects of nodal pricing"* (Tabors, 1999). In order to compare the relevance of nodal pricing compared to zonal pricing, different authors have estimated the additional value of calculating hundreds of nodal prices versus aggregating these nodal prices in a small number of zones. For instance, Hogan and Tabors have used actual nodal prices calculated by PJM and have tried to identify the existence of nodes with the same prices. The basic principle for aggregating two nodes into a single zone is that the two nodes should always have the same price. From a methodological point of view such a calculation consists of first identifying nodes with the same averages prices and same standard deviation. We present the finding of these two studies below.

Hogan (1999) has argued that nodal pricing is the truly simple approach for PJM because the location of constraints is unpredictable. Hogan made the calculations for six months, since the criterion of no differences in prices may be too strict, he used a threshold of $1 for aggregating two nodes into one zone and found that 94 zones would have been necessary in April 1998, 83 in May, 75 in June, 57 in July, 52 in August and 64 in September. Thus he found the number and also the geographical definitions of the zones differed monthly. This result proved for Hogan that zonal pricing for PJM would not produce real simplification.

Tabors (1999) argues that a smaller number of zones would capture the most important transmission constraints, he argues that the threshold of $1 used by Hogan is too strict with respect to the average zonal price, $1 represent less than 5% of the average zonal price, and to uncertainties due to the used of a model for calculating nodal prices. Using a 10% of average zonal price criterion would mean that less than 10 zones would be able to capture 98% of the variations in majors transmission constraints proving that a zonal system

9-2-3 What can be learned from these two examples?

A common characteristic of Nord pool and PJM is the direct relationship between system operators and a single institution (power exchange) that organizes market operations. In Europe most power exchanges are independent[26] entities, from their respective system operators, in Nord pool and PJM the two functions, power exchange and system operator, are integrated, i.e. technical constraints are taken into consideration in the functioning of the marketplace. Such integration allows transmission constraints and energy trading to be taking into account simultaneously. According to Hogan (1995) this type of integration is essential since it allows efficient dispatch and efficient pricing.

Nord pool and PJM are multinationals with one market operator acting for a whole area regardless of national boundaries. In others words, division of the market into zones/nodes is defined by actual physical bottlenecks and not by national borders. The two marketplaces calculate, from a technical point of view, the physical feasibility of proposed trades. In the absence of congestion the two marketplaces define a single price zone, when congestion occurs the markets are split into different zones/nodes according to transmission constraints which result in different locational prices. Due to the relative “simplicity”, radial network opposed to meshed network with numerous loop flows, of the network in the Nordic Countries, it is possible to determine a small number of zones. Hence market-splitting may be effective in areas where constrained flow gates are easily identifiable, e.g. North-South, but would probably operate poorly in continental Europe where the constrained flow-gates change too often (Smeers, 2001). In PJM, which is a most complex network, the existence of numerous loop flows requires more locational prices to be determined.

The size of the underlying networks (90 0000 MW of installed capacity in the Nordic Countries for 64 000 MW in PJM) appears to be relatively low compared to the size of the Continental European Market. For instance, the installed capacity in Nordic countries is 20% inferior to installed capacity in France alone (116 000 MW) while the PJM system has a smaller load than England and Wales. The open question is whether it is possible, from a technical point of view,

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[26] With the exception of APX which has been taken over by the Dutch system operator. However the APX does not deal with any technical constraints. To less extent the French TSO is a shareholder of Powernext.

for a many times larger system, to implement the integrated approach used in the two examples studied.

The market structure of Nord pool and PJM, number of players, number of power plants, technology used etc, of these two markets also represents an important condition for the development of these markets. A part of Nord pool's success can be attributed to the existence of important hydropower generators and the presence of numerous players[27]. Hydropower allows electricity to be stored which is not possible with other technologies. At the same time, the low level of concentration in generation has favored the development of competition and restricted possible market power. Similar, PJM does not have a high level of market concentration in comparison to most others markets.[28] Indeed the average annual HHI for PJM in 2000 was 1270[29] which is generally considered to be moderately concentrated.

In sum, though Nord pool and PJM have adopted market design models which differ in details, they share some common characteristics. Identifying such characteristics and comparing then with the actual European market design is of particular interest because it might provide guidance for further changes in the European market design. One, in Nord pool and PJM the size of the underlying networks is relatively small compared to the overall European market. Two, Nord pool and PJM are characterized by a low level of concentration which obviously is a facilitating factor for the development of competition. Three, participation is mandatory for transaction subject to transmission constraints. Four, the most important characteristic of the two markets is that a single institution is used to combine the function of system operation (TSOs) and market operation (power exchange). This type of integration appears to be fundamental to market functioning, regardless of any choice between a nodal or a zonal approach, in the sense that it allows the marketplace to take into consideration transmission

[27] See chapter 7
[28] The Brattle Group (1998), "PJM market competition evaluation white paper", October1998

pricing which represents a key aspect of market design. We therefore investigate the functioning of transmission pricing in continental Europe in the following section.

9-3 Transmission pricing in the EU

9-3-1 Introduction

Historically, European electricity networks were built to serve national "markets", and not a European market, therefore only about 8-10% of national consumptions originates from cross-border trading (EC, 2001a). Congestion is relatively prevalent on interconnectors because they were not built to facilitate large electricity flows between countries as is being encouraged by the EC's liberalization process. Originally, their main purpose was to allow exchange of power between countries for the purpose of system stability. The existing prices differences between national markets have increase the demand for interconnector capacity, EC competition law does not prescribe any particular method for the calculations of transmission prices (Albers, 2001), only unfair selling prices or others unfair trading conditions are prohibited following article 82 of the EC treaty. In the event of cross-border disputes, the competition rules of the Treaty apply.

Moreover, the EU Directive 96/92 does not contain any specific rule for the allocation of interconnector capacity, which is considered to be a key issue for the implementation of a truly internal electricity market. The Directive[30] only established the general principles of open access to cross-border transmission capacity. Following these principles each Members States was free to choose how they will implement transmission pricing mechanisms and interconnectors access arrangements nationally. Paradoxically, this implies that in practice, the design of the internal European power market has been decided at the respective national levels (Boisseleau and Hakvoort, 2003), and, due to this freedom granted by the Directive different kinds of arrangements have emerged.

[29] PJM 2000, "PJM Interconnection State of the Market Report 2000", www.pjm.com

Subsequently, the actual European electricity market is presently characterized by a patchwork of national and bilateral arrangements (Hancher, 1997; Glachant and Finon, 2000).

In contrast to Nord pool and PJM, presented in the previous sections, in continental Europe, transmission constraints and energy trading are treated separately and the system operator ensures physical delivery of trade on the exchange regardless of any possible physical congestion involved in these transactions. We will now identify the technical characteristics and the institutional framework of transmission pricing in Europe and we shed some light on the choice that was made to separate transport and energy (9-3-2) which has led to a system of physical transmission rights being put into place. We show that the physical nature of transmission rights hampers the development of an integrated European-wide market (9-3-3). Finally the drawbacks related to the methods used to allocate these transmission rights are addressed (9-3-4). We argue that these three related aspects, separation energy/transport→physical rights→allocation methods, represent a fundamental barrier to the creation of an integrated market in Europe due to the existence of serious transmission constraints at the European level [31]. This is illustrated using empirical evidences in the last section (9-4).

9-3-2 Technical system and institutional framework

Before addressing the functioning of the actual system in Europe with respect to transmission pricing and power exchanges, it is helpful to describe from a technical point of view, the structure of the European electricity network. Electricity networks are generally divided into four categories according to voltage levels. The first level is the extra high voltage network (380 kv/220kv) which represent the backbone of any electricity network. The extra high voltage network connects most of the large power plants and large industrial consumers.

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[30] Further work by the European commission is discussed in chapter 10

[31] In contrast to national levels where transmission constraints are relatively limited

The second network level (150kv/110kv) connects medium power plants and medium industrial consumers. The third network level (50kv-10kv) connects small power plants and small industrial consumers. Finally, the last network level (0.4kv) connects very small power plants and domestic consumers. All these different levels of networks are connected together using transformers. The extra high voltage network is used for the long distance transport of electricity and for connecting national networks, this level of network is the most important with respect to cross-border trade.

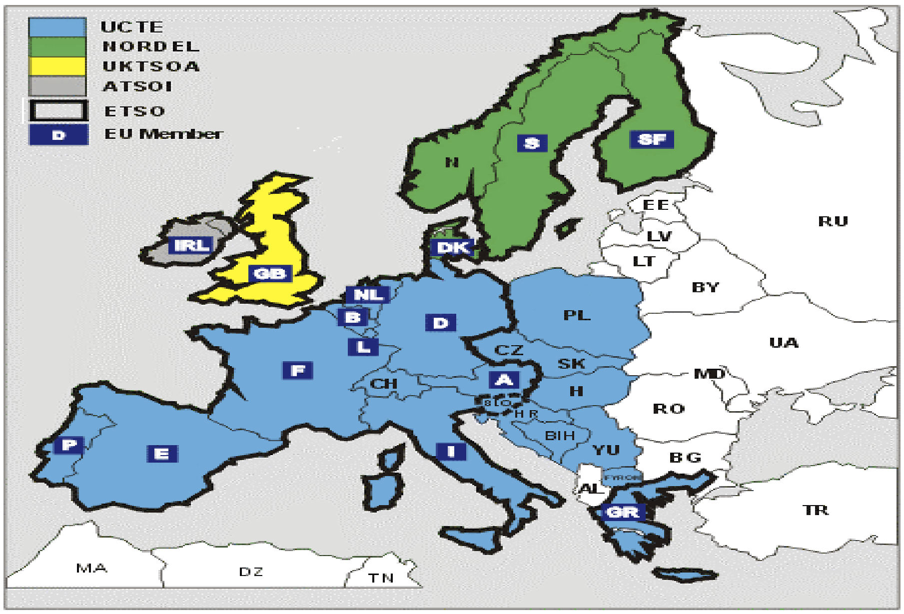
Technical co-operation has already existed for many years between the different European countries in order to ensure the operation of the interconnected system. This co-operation is founded in data exchange for planning purpose (Vasconcelos, 2002). In the past, cross-border transactions were realized according to the technical and economic rules defined by Association of Transmission Organization (ATO[32]) such as UCPTE or Nordel (figure 9-4). These transactions were limited to owners of the high-voltage grids and final customers had no access to the interconnection. Following the Directive 96/92, eligible customers and other type of players, e.g. traders, distribution companies, were allowed to have access to transmission network.

Each TSO, created following the liberalization process, is part of an ATO within which they agree to coordinate their activities. Due to the importance of cross-border trade for the creation of a single electricity market, the four ATO created the European Association of Electricity Transmission System Operators (ETSO) in 1999. ETSO is composed of 32 independent TSO companies from the 15 countries of the European Union plus Norway and Switzerland. This association works mainly on network access conditions at the European level, e.g. congestion management methods, cross-border transmission capacity definition

[32] To some extent, the concept of ATO is similar to the concept of Regional Transmission Organization (RTO) in the US

etc[33]. However the actual mechanisms for allocation of interconnectors are defined bilaterally regardless of the physical impact of a transaction between to countries on the network of neighboring countries[34].

Figure 9-4: European Association of Transmission Organizations.



Source: UCTE

In conclusion, the existence of several system operators and the separation between energy (product) and transport (service) characterizes the actual market design of the European electricity market(s) with respect to transmission pricing. From an institutional point of view, and in contrast to PJM and Nord pool, all European networks are operated by different national or local transmission system operators who deal with transmission pricing while markets for energy are separated and left to bilateral transactions and power exchanges. Due to this separation between transport and energy a system of physical transmission

[33]For instance, ETSO introduced in 2002 a pan-European border fee scheme for cross-border trade (ETSO *Proposal for a Temporary Cross-border Tariff Mechanism 3 September 2001)*

[34] Current discussions and proposals for change of the actual system such as for instance the use of joint-auction mechanisms are presented in chapter 10

rights has been put in place and this presents important drawbacks that hamper the development of an integrated European-wide market.

9-3-3 The nature of transmission rights

An important feature of market design in Europe is the separation of the energy market, the power exchange and bilateral market, from the market for transportation, transmission pricing. Transmission pricing combines two types of mechanisms with respect to national and international congestion. At national levels congestion is not priced, but socialized ex-post on a cost-basis to firm users of the system. Hence at a national level in Europe congestion is managed by national TSO according to national rules and not by market-mechanisms.

In practice, at the international level allocation of interconnector capacity for cross-border exchanges implies that interconnection capacities are defined in advance by the involved TSOs and that market participants should acquire capacity before contracting the energy. While details of allocation procedures differ between interconnections[35], cross-border exchanges share a common characteristic in the sense that they all use a physical transmission rights system (PTRs). Indeed, the separation of energy and transport has led to the creation of physical transmission rights. In this system, the physical capacity of each interconnector is first defined. ETSO has published a set of net transfer capacities (NTC) for each European interconnection (ETSO, 1999; ETSO 2001c). The system operators create rights to use this capacity and allocate them in some way, using allocation methods, to market participants. These PTRs are rights that allow their holder to use a congested interconnector. Within this framework, market participants conduct their trades insulated from the details of system operation. Such a system allows ex-ante (before actual delivery) pricing which make the market simpler and (apparently[36]) transparent. From a theoretical point of view such an approach is questionable since the separation of

[35] See 9-3-4
[36] See 9-1-3

energy flows, resulting from trade, and transmission capacity, resulting from network capacity calculations, easily results in inefficient allocation of the available capacity because the real capacity available can only be determined once physical flows are known (Ruff, 2001). This approach is, in general, opposed to the Financial Rights (FTRs) approach.

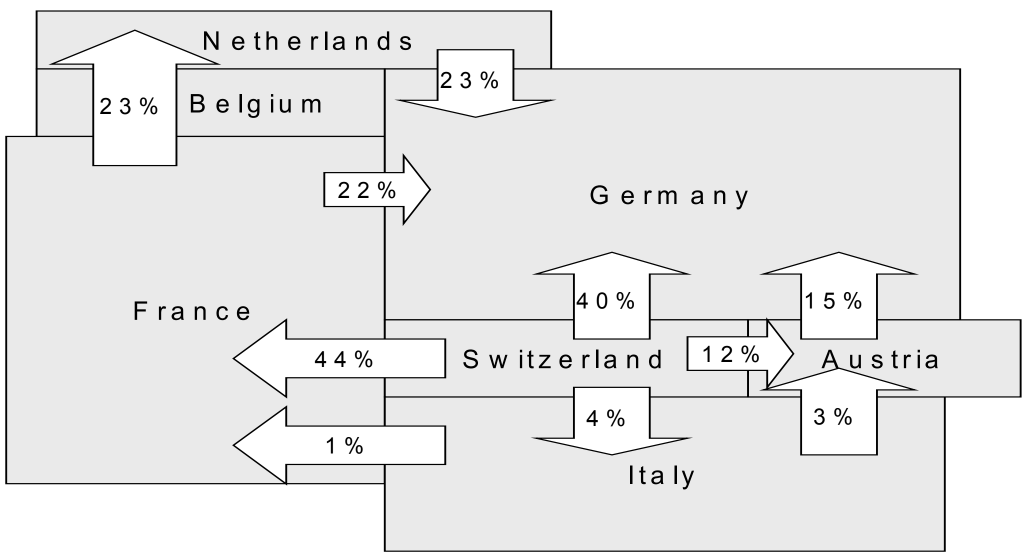
The major difference between the physical transmission rights approach and the financial transmission rights approach is in the way the final settlement is reached and the impact the systems have on the value of transmission rights (Green, 1998). In the PTRs system, the price of transmission is set in advance by market participants while in the FTRs system prices are determined ex-post by the TSO that administer the power exchange and operate the transmission system (like PJM) and payments are made to right holders.

Table 9-4: FTRs and PTRs

Financial Transmission Rights (FTRs)	**Physical Transmission Rights (PTRs)**
- Guarantees the holder the financial equivalent of using the transmission right, but not the physical certainty - The value is independent of actual flows, and depends on congestion on the system - Do not affect the way the system operator dispatches the system	- The right to inject a certain amount of power at point A and take it out at point B - The holders are guaranteed the scheduling certainty for their right - Do affect the way the system operator dispatches the system

An important drawback of the PTR approach is related to the assumption that electricity can be directed to follow a particular path in the network, this breaches the physical laws (Kirschoff) that dictate the flow of electricity (Hunt, 2002). Due to important differences in production costs and prices between national markets, the liberalization process has created an important demand for interconnector capacity and thus for physical transmission rights. For instance, based on the actual European market design a trader wishing to sell 100 MWh from Switzerland and Germany will secure the corresponding interconnector capacity between the two countries (100 MW) through a firm physical capacity right, regardless of any physical impact of such a transaction on neighboring countries. In practice such a transaction has an effect on the Austrian, Italian, French, Belgian and Dutch network (figure 9-6). Hence, when there are too many transactions the difference between the contract path and the actual flows may be really large. National system operators are well aware of this problem and to ensure that interconnectors are not overload they reduce available capacity which results in very inefficient usage of the system.

Figure 9-6: Difference between physical flows and contractual paths: example from a transaction between Switzerland and Germany



Source: RTE

Furthermore, since electricity does not follow the contracted path, transmission system operators face transit flows on their network which involve costs. To compensate the system operators, ETSO has developed a compensating mechanism for loop flows or transit costs (ETSO, 2000; ETSO, 2001g). The practical problem is that it is technically not possible to identify participants who cause transit and therefore to identify who should pay for the cost of transit; and it is difficult to estimate this cost accurately. A nodal system would remove this difficulty but this approach has not been considered by ETSO (Smeers, 2001).

With respect to market power, PTRs introduce the possibility for dominant players to withhold these rights from the market, which will reduce competition (Borenstein *et al*, 2000). For instance a generator can buy transmission rights to import within its national market and not use them in order to restrict access to its competitors (Joskow and Tirole, 1999). Furthermore, since until now physical rights have been defined regardless of to the impact that flow on the interconnector considered has on other interconnectors, players who are aware of the impact their behavior will have on transmission constraints may take advantage of this system. For instance, if a player owns generation assets at node A and B of a three nodes network, it may increase generation at node A relative to a competitive scenario if the loop flows created reduce the total energy delivered and increase prices at node B (Hogan, 1997).

Another important issue related to PTRs is the problem of “pan-caking”[37]. For example, a Spanish supplier wishing to sell electricity in the Netherlands, while allowed to do so under the electricity Directive, may face difficulty in competing with local generators because it would have to pay for transmission capacity in France, Belgium and in the Netherlands.

In conclusion the use of physical rights present serious limitations, one they reduce available interconnector capacity this results in very inefficient usage of the system and, two physical rights fail to take into account loops flows. Three, even under the, relatively unrealistic, assumption that transmission system operators can accurately estimate actual network use, the actual methods applied to allocate transmission rights lack harmonization, co-ordination and efficient design.

[37] “pan-caking” corresponds to an addition of charges for power transmission crossing several borders

9-3-4 Allocation methods for physical rights

The EU Directive 96/92 only established general principles for open access to cross-border transmission capacity[38]. Each Member State was free to implement a system for national transmission pricing and for access arrangements to cross-border capacity. Due to this freedom it is not surprising to encounter a range of bilateral arrangements for the allocation of cross-border capacity. Subsequently, the actual European electricity market is characterized by a patchwork of national and bilateral arrangements with respect to the allocation of PTRs.

Many methods exist to handle congestion on power lines, that is several mechanisms can be use to allocate physical transmission rights. In order to deal with the fundamental issue of transmission pricing at the international level, the European Commission initiated the European Regulatory Forum for electricity[39] in 1998. The forum, which does not have any regulatory powers, is a platform for discussion about the progress of the implementation of the Directive with particular attention being paid to cross-border trade. The forum has identified two majors categories of allocation methods: market-based methods and non-market based methods. Market-based methods rely on market mechanisms to allocate transmission rights while non-market based methods rely on administrative rules. For the sake of brevity we will only consider three major types of non-market based mechanisms and one type of market-based approach[40].

While the European Commission has explicitly mentioned its preference for market-based mechanisms for the allocation of interconnector capacity (EC,

[38] On this issue, the new Directive 2003/54/EC and especially the new regulation No 1228/2003 on conditions for access to the network for cross-border exchanges in electricity are discussed in chapter 10, section 10-2-2

[39] This bi-annual forum is attended by national regulatory authorities, member states, the European Commission and organizations representing the transmission system operators (ETSO), generators, electricity traders, consumers and power exchanges. The forum was set up to discuss issues regarding the creation of a truly internal electricity market that are not addressed in the Electricity Directive. See http://europa.eu.int/comm/energy/en/elec_single_market/ florence/index_en.html.

[40] An extensive discussion on congestion management methods in Europe can be find in Knops *et al* (2001) and De Vries and Hakvoort (2001)

2001d), in practice non-market-based system are still used for several interconnections (table 9-5). By definition, these methods allocate transmission capacity following criteria that are not based on any kind of market mechanism. For instance, to allocate transmission rights at one location, one can simply give the rights to those who first apply to use them. This method is called “first-come, first-serve”. One can also distinguish between different types of contracts and, for instance, give the rights to those with the longest-running contracts. This method is called “type of contract” allocation. Another method is to allocate scarce capacity “pro rata”, which means that all applicants receive an equal percentage of the total amount of capacity they apply for.

Table 9-5: Example of the diverse methods applied for the allocation of cross-border capacity: the case of France

Location:	Allocation frequency*	Method 1	Method 2
France to UK	d, m, q, y,	call for tender	auction
UK to France	d, m, q, y,	call for tender	auction
France to Italy	d, m, y,	long term contracts	prorata
Italy to France	d, m, y,	long term contracts	prorata
France to Germany	d	list of priority	prorata
Germany to France	d	prorata	-
France to Belgium	d.m	first come first serve	prorata
Belgium to France	d	prorata	-
France to Spain	d	first come first serve	prorata
Spain to France	d	prorata	-

*daily, weekly, monthly, quaterly, yearly

Source: RTE

Non-market-based methods suffer several drawbacks with respect to economic efficiency. These methods do not provide any price signal and thus suffer from a lack of transparency. Moreover these methods discriminate against new entrants. Finally, in the presence of “imperfect unbundling” between the utilities and network operation (e.g. Germany), there is a high risk that the system operator will discriminate in favor of its own interests in supply. “Type of contract” allocation generally favors large long-term contracts. Hence, long term contracts signed before the new regulatory framework allow incumbent generators to control a large part of interconnection capacity and limit possibilities for new comers. “Pro-rata” methods work poorly in the presence of a large excess in demand with respect to available capacity. In a pro-rata system players integrate the fact that they will receive only a small part of what they will ask into their bids. They thus have incentives to ask for many times what their real needs are, which can lead to distorted results. Moreover the capacity attributed to each participant may become so small that is no longer commercially interesting (Albers, 2001). This method also discriminates against small players. Since these methods are not compatible with an efficient market, the Member States decided at the sixth Electricity Regulatory Forum in Florence meeting that the allocation of transmission rights for scarce interconnector capacity should be based upon market-based mechanisms (EERF, 2002).

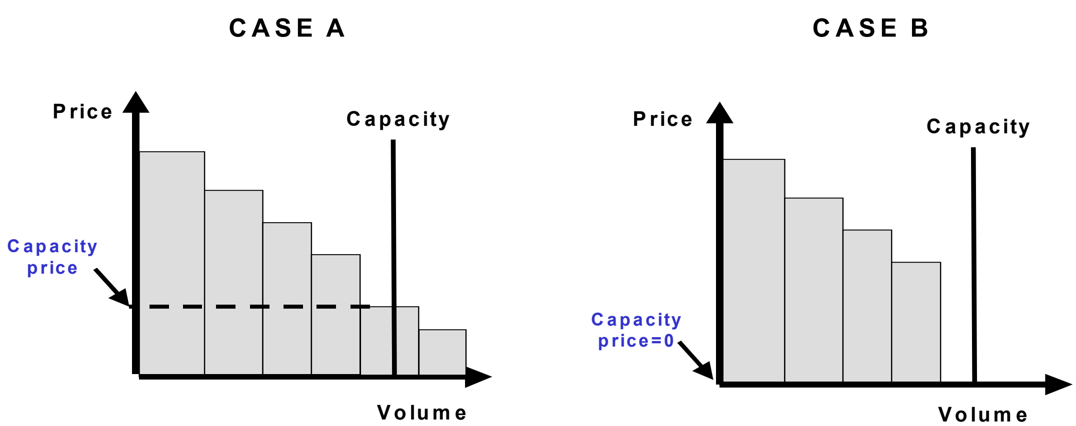
While several market-based methods have been considered in Europe, e.g. explicit auction, implicit auction, market splitting, counter trading, redispatching, joint auction, in practice the most popular market-based option for congestion management in Europe is explicit auctions (ETSO, 1999; ETSO, 2001a, 2001b, 2001e, 2001f). In an explicit auction of interconnector capacity, the TSOs of the systems between which congestion exists sell their interconnector capacity to the highest bidder. Variations in auction design are possible with regard to bidding mechanisms, the time periods which are auctioned (days, weeks, months, years) and the firmness of capacity rights (see box 9-2 for an example). Auctions are interesting because they provide a transparent market-based allocation method. Such a method allows players who value the capacity the most to use it. It is worth noting that auctions are allocation methods above all, thus they work in situation of congestion and “non-congestion”[41].

[41] See Case B box 9-2, figure 9-5

Box 9-2: Price formation mechanism for interconnector auction

The first step in the price formation mechanism is to determine the available capacity. The different system operators determine the available capacity in accordance with applicable laws and regulations. As soon as this capacity is defined the auction office informs market parties. Market participants wishing to acquire capacity then have to submit their bids, volume and prices, to the auction office. If the total amount of capacity asked by participants exceeds the available capacity (figure 9-5, Case A), all the highest bids, that when aggregated do not exceed the available capacity, are accepted. The remainder of capacity is awarded to the bidder that has submitted the next highest bid. This last bidder will only receive part of the capacity it requested. The price of the capacity corresponds to this lowest accepted bid, and every party will pay the same price. If the total amount of capacity requested by participants is equal to or lower than the available capacity the clearing price is zero (figure 2, Case B). In other words, when there is no congestion the price of interconnection capacity is zero.

Figure 9-5: Price determination mechanism



Due to the relatively low level of interconnection capacity at the European level, several TSO have chosen auctions to allocate the "remaining"[42] cross-border capacity. Although auctions present a significant improvement compared to non-market-based mechanisms they still present important drawbacks. A classical criticism of auctions is that they allow TSO to extract profits from congestion. Hence, auctioning interconnector capacity may create perverse incentives

[42] The rest of the capacity consists of that allocated to long term contracts signed before the new regulatory framework

especially in the presence of vertically integrated suppliers and network operators. Since congestion creates revenues for the system operator, it has no incentive to make new investments in interconnection capacity as these will involve a reduction in its revenues. In the presence of a vertically integrated supplier and network operator, the supplier has the incentive to influence national market prices to allow it to rise extra revenues from congestion. Therefore auctioning of capacity in some circumstances can be criticized as an abuse of dominant position (Albers, 2001). These two weaknesses can be handled by clear unbundling of supply and network operations, as clearly stated in the EU Directive, and by forcing TSO to not consider congestion rent as a profit, for example by forcing them to use it for new investment in capacity or to reduce costs for cross-border transactions.

A real problem with bilateral auction is that they allocate physical rights for transmission. As presented above, TSOs define available interconnector capacity *ex-ante*. However the real available capacity can only be determined once physical flows are known due to loop flows, contingencies and deviations from expected estimations of the available capacity. For this reason, the available capacity defined by the TSO, and auctioned, is lower than the real available capacity because it is necessary to take into account a rather high safety margin. Thus the separation between energy flow and transmission capacity is artificial and this results in an inefficient mechanism. Moreover, from a practical point of view, this separation increases risk for market players, as trader have to buy interconnector capacity before the spot prices are known.

Even assuming that system operators are able to define accurate levels of available interconnector capacity, the last category of flaws regarding pricing of interconnector capacity is related to the detail of their practical implementation. In practice, the capacity of a large number of interconnectors is still allocated according to non-market-based mechanisms. Moreover, when market-based mechanisms are used they are often used in combination with non-market-based mechanisms, i.e. one part of available capacity is allocated via auction while the remaining part is allocated via non-market-based mechanisms. For instance, for the capacity of a single interconnector, one part can be allocated to long term contracts signed before the new regulatory framework, another part can be allocated using to pro-rata rationing and a last part allocated according to auction. Added to this, auctions are run simultaneously but separately in each direction, from country A to country B and from B to A. Such a system does not allow netting between the two directions and does not reflect the physical characteristics of electricity flows, i.e. two flows in opposite directions cancel each other. Finally, the design of the auction also represents an important issue in the sense that a poorly designed auction can hamper efficient arbitrage (box 9-3).

Box 9-3: The interconnection France-UK: a poorly designed auction?

The auction between France and UK represents an interesting example of a poorly designed auction. One, the auction is a pay-as-bid auction, which mean that the rights for using the auction are allocated to the highest bidders at the price they offer. As discussed in chapter 4 the choice for such type of auction has important drawbacks. For instance, pays-as-bid auction can have an important impact on the behavior of market participants and may be discriminatory toward new entrants. Further the capacity does not have a unique price and thus the different participants do not pay the same price.

Two, the definition for the time period of the daily auction is a daily period of 24 hours from 23.00 to 23.00 UK local time. Hence, while prices vary widely over the day, players willing to arbitrage these two markets cannot do it on an hourly basis and are forced to buy capacity for a day at an average daily price. Such characteristics reduce trading possibilities and discourage participation from small players who may want arbitrage between specific hours. This is especially important because for instance, the price difference between the two markets can be positive during the night and negative during day. Hence, such system favors large players who are more likely to be able to arbitrage the markets. This lack flexibility is unlikely to favor arbitrage.

Three, all bids are subject to a reserve price of 3 Euro/MWday. The existence of such a reservation price represents a barrier to trade since in a market with low margin, it may be higher than spread between the two markets, this combined with the lack of netting limit arbitrages possibilities.

In conclusion, although the Member States decided at the sixth Electricity Regulatory Forum in Florence meeting that their allocation procedures should comply with an agreed set of rules based on market mechanisms, in practice different methods are still being used and non market-based methods remains in many cases. Moreover, beyond the shortcoming of explicit auctions and non-market-based mechanisms, the total capacity of a single interconnector can be allocated according to different methods which reduces transparency and may favor incumbents. Finally, the total separation of transmission pricing mechanisms from the operation of energy markets, power exchanges in particular, does not allow efficient usage of transmission capacity. Hence, an important weakness of the actual market design based on bilateral auction is that it ignores the implications of trade on one path of the network for the rest of the network.

9-4 Empirical evidences of inefficient transmission pricing

9-4-1 Introduction

A first measure of the efficiency of actual transmission pricing between countries can be done using hourly interconnector auctions results[43]. Thus in this section such an analysis is done using the following explicit auctions: Germany-Netherlands, Germany-Denmark, Belgium-Netherlands, and UK-France. The data used in this section are hourly results of interconnectors auctions[44]. Such an analysis will shed light on the problem of netting, i.e. power flows in opposite directions "net" each other. For this purpose we have looked the results of explicit auctions and identified the number of occurrence where within a single hour two prices, from A to B and from B to A, for physical rights coexists despite a lack of economic sense. Such situations reveal economic inefficiencies since in theory the price level of the auction should equal the difference between the two locations. In other words, no positive price should exist from the expensive location to the cheap location because no players will transport electricity from a

[43] or daily in the case of the auction between France and the United Kingdom

high-price to a low price area will all the corresponding losses entailed in such an action.

We will then compare the results of the auction with price differentials between power exchanges. Since there is no power exchange in Belgium this analysis could only be done for three cases, Germany-Netherlands, Germany-Denmark, and UK-France. The idea is to compare price differentials between exchanges and auctions results for interconnection capacity which link the respective exchanges to asses the efficiency of the actual cross-border transmission pricing scheme and power exchanges prices. In an efficient market these two values should be equal. To the extent that they are not, indicates the inefficiency of the actual transmission pricing system. Concretely, we first estimated the theoretical interconnector price between the locations using power exchanges prices according to formula 9-1:

$$T_t = Y_t - X_t \qquad (9\text{-}1)$$

where T_t is the theoretical price for transmission between X and Y at time t, Y_t the price at location Y at time t and X_t the price at location X at time t. In the absence of transmission constraint Y_t equal X_t , and T_t equal zero. For different locations, we compared T_t with the actual results of the auction (R_t). While in theory only one price for transmission exists, from the cheap location to the expensive location, the design of the auction, e.g. no netting and/or reservation prices, produces on several occasion prices in both directions. For this reason, when X_t is higher than Y_t we use the result of the auction from Y to X and when X_t is lower than Y_t we use the result of the auction from X to Y (table 9-6). In an efficient market T_t and R_t should be equal and the difference between T_t and R_t measures the level of (in)efficiency (E_t) of the system. For instance if the price of UKPX at time t is higher than the price of Powernext at time t, i.e. the difference

[44] Germany-Netherlands/Belgium-Netherlands: www.TSO-auction.org; Germany-Denmark: www.eltra.dk; UK-France: www.rte-france.com

UKPX minus Powernext is positive, we use the result of the auction France-UK. This is consistent with the locational model where, in theory, the result of the auction UK-France should equal zero and thus it makes little sense to use it. Our results are then split into two categories:

Table 9-6 Efficiency measure

	Theoritical price (Tt)	Actual price (Rt)	Efficiency measure (Et)
If Yt > Xt	Yt-Xt	Auction from X to Y	Tt-Rt
If Yt < Xt	Xt-Yt	Auction from Y to X	Tt-Rt
If Yt = Xt		No congestion	

9-4-2 The problem of netting

Netting of opposite direction flows has two main advantages compared to separate auctions for import and export. One it gives more capacity to the market, assuming that the TSO can rely on the flows in both directions really taking place. Two, it ensures that the price of the interconnection is only for one direction, i.e. from the cheap location to the expensive location. In order to illustrate the inefficiency of separated two-direction auctions, we computed the number of occurrence where two prices, from A to B and from B to A, coexisted. These results are presented in table 9-7 for the year 2002. The first analysis shows that in 3% to 70% of the hours in 2002, auction results led to inefficient outcomes, i.e. one positive price in each direction.

Table 9-7: The inefficiency of separated two-direction auctions

	Fra-UK	Bel-Nl	Ger-Nl	Ger-Den
Frequency	47*	229	6147	4435
%	13%	3%	70%	51%
Frequency (> Pr)**	31	139	2993	1557
%	8%	2%	34%	18%

** This auction is a daily auction ** Pr is the resevation price*

However due to the existence of reservation prices, positive prices can occur even in absence of congestion in one direction. For this reason the second part of table 9-7 only shows the number of occurrences when two prices coexisted and when both prices were higher than the reservation price. As expected the number of hours where two prices coexisted decreased significantly, for instance, from 70% to 34% between Germany and the Netherlands. The fact that some players bought interconnector capacity at the reservation price, almost for free, can be a rational behaviour in a situation governed by uncertainties. Indeed, it can be interpreted as an option to move power from one location to the other if prices differences move a direction opposite to that expected. However, once this has been taken into account the results shows clearly that the auction results are inconsistent with what one would expect in an efficient market for a significant number of hours, ranging from 2% to 34%. Hence, the design of the auction characterised by the absence of netting induces significant economic losses.

9-4-3 France-UK

An analysis of the results from the auction of transmission capacity between France and the UK requires that specific attention is given due to the design of this auction[45]. Since this auction is a daily pay-as-bid auction, the other auctions considered are hourly marginal price auctions, several prices can exists and are expressed in Euro/MW per day[46]. In order to allow comparison with a theoretical price we first had to estimate an average price for each day. This average price is a volume-weighted average of prices. For example on the 11th of January 2002 the results of the auction from France to the UK were the following:

- 100 MW at 4,16 Euro/day
- 25 MW at 3,06 Euro/ day
- 25 MW at 3 Euro/ day
- 100 MW at 3 Euro/ day

Hence the actual average price per MW per day was calculated as follows:

[45] See box 9-3
[46] In contrast to Euro/MW per hour for the other auctions

$[(100\times4{,}16)+(25\times3{,}06)+(25\times3)+(100\times3)]\div(100+25+25+100)=3{,}47$ Euro/MWd
The average price per hour is:

$3{,}47\div24=0{,}14$ Euro/MW

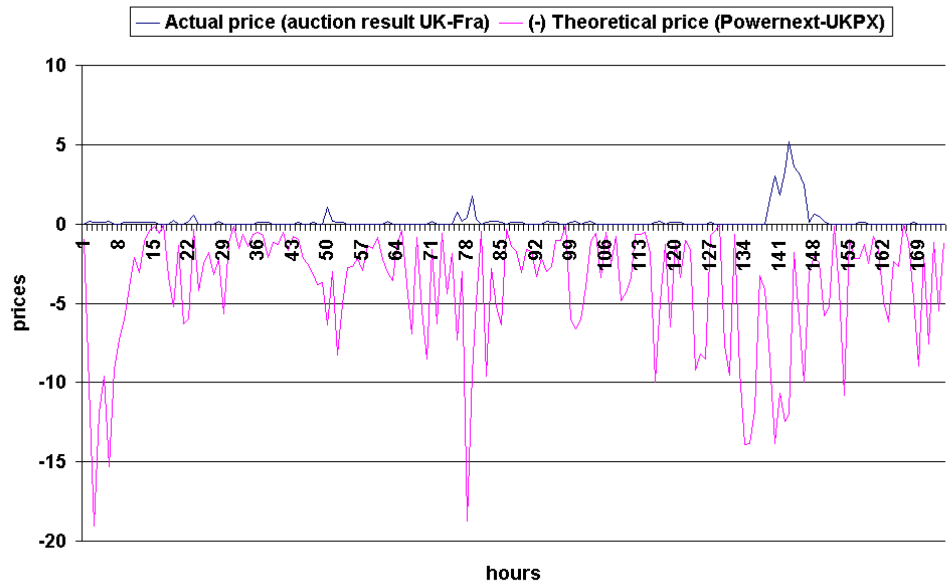
Once the average actual price was determined for both directions (France-UK, UK-France), we considered the sign of the spread between UKPX prices and Powernext prices to allowed us to choose the relevant auction result for our comparison. The daily average prices of UKPX were higher than the daily average prices of Powernext for 191 days and lower for 174 days in the year 2002. The results of our efficiency estimation are presented in table 9-8.

Table 9-8: Efficiency of the France-UK interconnection pricing

	Occurence	Mean (Tt)	Std Dv (Tt)	Mean (Rt)	Std Dv (Rt)	Mean (Et)
UKPX > Powernext	191	5,66	0,95	3,77	6,09	1,89
UKPX < Powernext	174	4,02	3,80	0,21	0,68	3,81
UKPX = Powernext	0	-	-	-	-	-

Table 9-8 shows that when the price of UKPX was higher than the price of Powernext the average difference between the two exchanges was 5,66 Euro/MWh while the average price for interconnection capacity was 3,77 Euro/MWh. The difference between these two prices represents the extent of inefficiency of transmission pricing from France to the UK. Figure 9-7 illustrates the opposite case, UKPX<Powernext, at a finer level, actual daily prices resulting from the auction and theoretical prices multiplied by minus one to give the opposite have been plotted. If the theoretical and actual prices were equal for each day, this graph would show perfect symmetry between the two curves. The extent of the asymmetry between the two curves indicates the extent of inefficiency of the mechanism.

Figure 9-7: Actual prices and theoretical prices (case: UKPX<Powernext)



These results show that market participants are able to secure interconnection capacity at a lower price than the theoretical price in both directions. This can be interpreted as serious lack of competition for acquiring transmission rights, and this is consistent with the results of the auction which shows that very few players are competeing. The pay-as-bid system allows the number of bidders accepted for each day to be identified, and during the year 2002 on average about 1,6 bids per day were accepted. Even, under the assumption that each player only made one bid these results show clearly that in practice very little competition takes place at the auction. The highest difference of 3,81 Euro/MW between theoretical price and actual prices (from France to UK) reflect that, with the exception of EDF, very few players are able to export electricity from France to the UK on a short-term basis. In the opposite direction, more competition seems to take place but the actual outcome of the auction remains lower than one would expect in an efficient market. This indicates that in both directions the actual system is inefficient since markets participants have been able to secure capacity below its arbitrage value and hence increase trading profits.

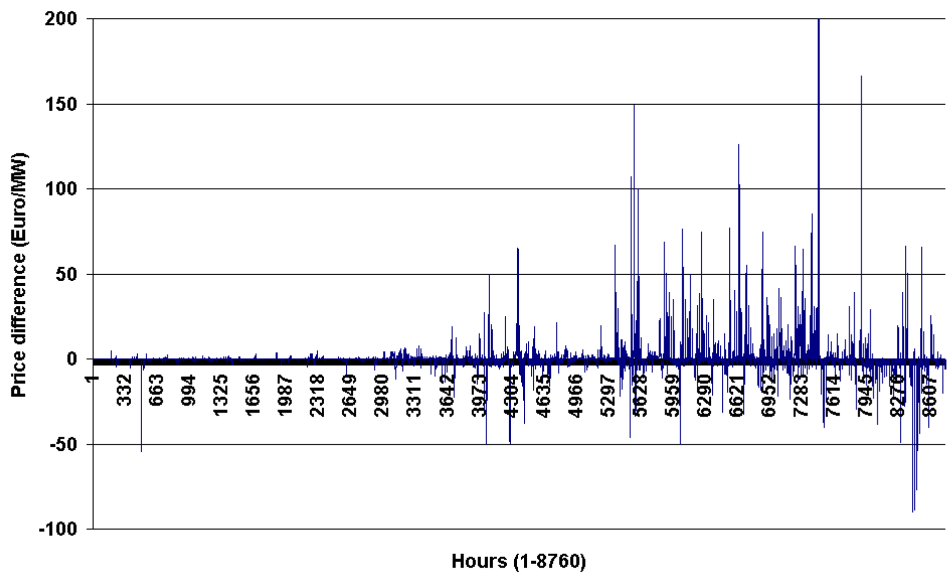
9-4-4 Germany-Netherlands

The interconnections between Germany and the Netherlands are of particular interest for three reasons. One, prices in the Netherlands are significantly higher than in neighboring countries which creates important opportunities for cross-border trading[47] and thus a high demand for interconnection capacity. Two, the comparison of exchanges prices is especially relevant because a specificity of the Dutch system is that parties who acquired import capacity on the daily auction are obliged to trade the electricity transmitted on the Dutch side through the Dutch Power Exchange[48]. Three, in practice, two auctions exist between Germany and the Netherlands (E.on-TenneT and RWE-TenneT[49]) while it would appear simpler to combine E.on-TenneT's and RWE-TenneT's capacity to form a generic "Germany-TenneT" capacity.

In contrast to the UK-France interconnection, the short-term capacity between Germany and the Netherlands is allocated according to an hourly marginal price auction. This design allows us to investigate the efficiency of the mechanism at a finer level by using hourly prices rather than daily prices. Such a level is better since electricity prices vary widely within the days and it is thus likely that price spread between markets also differs within the days. Due to the existence of two auctions we first compared the outcome of these two auctions for the year 2002. Since these two auctions have exactly the same design, auction format, timing, price formation mechanism etc, and that they both allow market participants to move power from Germany to the Netherlands, they could be considered as perfect substitutes. As such one would expect that prices at the two auctions would be equal for any period. However as shown in figure 9-8, though the two prices behave similarly and are often the same, the results of the two auctions are not always equal revealing a first level of inefficiency.

[47] Price differences can be largely attributed to differences in system marginal cost, domination of gas-fired in the Netherlands, coal and nuclear in Germany. See chapter 7
[48]See chapter 5
[49] See www.TSO-auction.org

Figure 9-8: Difference between E.on-TenneT and RWE-TenneT (E.on minus RWE)



On average the difference between the two auctions was 1,47 Euro/MW. As can been seen, such a difference is largely due to some “spikes” in differences. The largest difference was observed on the 7th of November at hour 15 where the price E.on to TenneT was 555,01 Euro/MW and the price RWE to TenneT was 50,08 Euro/MW showing important inefficiency in the arbitrage mechanism between the two auctions.

A second level of inefficiency was estimated by comparing the hourly results of the auctions with electricity prices differences from the APX and the LPX. The results of the comparison between theoretical and actual prices for the interconnection capacity are presented in table 9-9.

Table 9-9: Efficiency of the Germany-Netherlands interconnection pricing

	Occurence	Mean (Tt)	Std Dv (Tt)	Mean (Rt)	Std Dv (Rt)	Mean (Et)
LPX > APX	3842	3,96	8,39	0,04	0,09	3,92
LPX < APX	4912	16,36	46,43	12,58	35,23	3,78
LPX = APX	6	-	-	-	-	-

These results show that, surprisingly, the arbitrage between Germany and the Netherlands is not just in one direction. Indeed for 3842 hours during the year it was profitable to buy electricity in the Netherlands and sell it in Germany, i.e. 44% of the time. However the average of the theoretical price for interconnection shows clearly that when the APX price is higher than the LPX price the price difference is on average higher (16,36 Euro/MWh) than in the other direction (3,96 Euro/MWh). Similar to the auction between France and UK, these results show that in both directions, market participants are able to secure interconnection capacity at a lower price than the theoretical price. This is measured by E_t which, in both directions, is close to 4 Euro/MW (3.92 and 3.78). A first reason for this difference is related to the separation of the energy markets, i.e. the power exchanges, from the market for transportation, i.e. capacity auction[50]. This has important consequences in terms of "timing". Timing refers to the period when trading is allowed, i.e. when buyers and sellers are allowed to submit bids, and when results are communicated to market participants. The prices for capacity are determined via the auction based on the expectation of market participants about spreads between the two energy markets. The prices cannot be adjusted if the results of the power exchanges, which are known later, are different. This design means it is therefore likely that differences will occurs between theoretical prices and actual prices. What is important is the extent of this difference.

Without access to the data per players it is quite difficult to identify the reasons for such lack of competition. However one major issue concerning this auction is the fact that both RWE and E.on are vertically integrated with their grids and TSOs. One can speculate that these two players may have access to confidential information about biding behaviors of others participants. The important point is that what price vertically integrated utilities pay for interconnection capacity is half

[50] See 9-3-3

of the price that other players pay because half of the revenue[51] of the auction goes to the German "TSOs" which they own. The fact that a significant part of the revenues of the auction goes back to some of the market participants may distort competition.

9-4-5 Germany-Denmark

The interconnection between Germany and Denmark also represents an interesting example since it links together the Nord pool area and the largest continental market. For this purpose we use the price from the German power exchange (LPX) and the price produced by Nord pool for Denmark West (hereafter Nord pool DK).

Table 9-10: Efficiency of the Germany-Denmark interconnection pricing

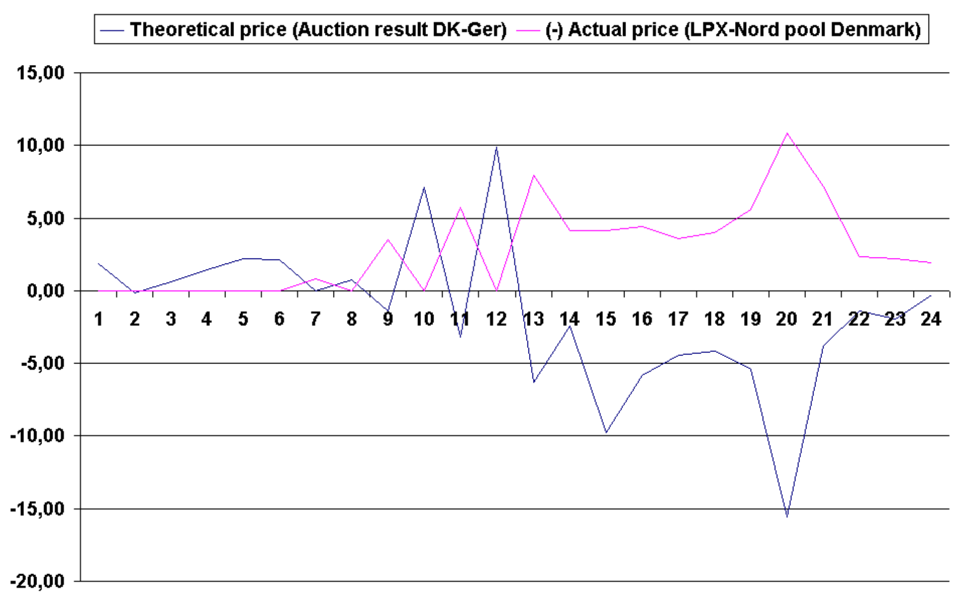
	Occurence	Mean (Tt)	Std Dv (Tt)	Mean (Rt)	Std Dv (Rt)	Mean (Et)
LPX > nordpool DK	3566	7,39	15,88	5,42	20,48	1,97
LPX < nordpool DK	5194	9,96	13,94	3,63	7,48	6,33
LPX = nordpool DK	0	-	-	-	-	-

The hourly prices of LPX were higher than the daily average prices of Nord pool DK for 3566 hours and lower for 5194 hours for the year 2002. Table 9-10 shows that when the price of LPX was higher than the price of Nord pool DK the average difference between the two exchanges was 7,39 Euro/MWh while the average price for interconnection capacity was 5,42 Euro/MWh. The high standard deviation of theoretical prices reflects important volatility for certain hours on both exchanges. From Denmark to Germany, the price for transmission was on average 1,97 Euro/MW lower than its theoretical value and 6,33 Euro/MW lower from Germany to Denmark. This indicates that on average, players exporting electricity from the German exchange to Nord pool DK, when it was profitable to do so, made 6,33 Euro/MWh of extra profit.

[51] The other half goes to the Dutch System operator

Figure 9-9 illustrates these results. Using an example (the 27th of March 2002), this graph plots the theoretical prices and the of the actual prices time minus one. The extent of the asymmetry shows the important differences between actual prices and theoretical prices. For hours 12 and 17 the prices on LPX were 41,42 and 22,28 Euro/MWh and the prices in Denmark were respectively 51,29 and 17,81 Euro/MWh. In the first case it was profitable to buy electricity in Germany and sell it to Denmark and vice versa in the second case. In the second case the difference between the theoretical price (4,47) and the actual price (3,56) indicates some inefficiency but this is relatively low. However, in the first case the difference is huge. While the theoretical price should have been 9,87 Euro/MW for moving electricity from Germany to Denmark, the actual price was 0.

Figure 9-9: Actual prices and theoretical prices (example: 27/02/2002)



Again these results suggest that the auction does not work properly. Similar to the previous example, timing of the auction and timing of the power exchange may explain part of the difference. However, only an analysis of the details data per player would allows us clearly to understand the reason for these differences between theoretical and actual prices. Without such confidential information, one may only point out the fact that the auction on the German side is handle by E.on Netz. In Germany system operation is left to vertically integrated utilities and no national system operator has been created. Hence, as for the auction between the Netherlands and Germany, one may speculate that the lack of neutrality of the organization that runs the auction has an impact on the extent of competition.

9-4-6 Conclusion

The empirical analysis illustrates the fundamental flaws of separating markets for interconnections and markets for energy. One, in all cases the absence of netting results in the existence within a few hours of two prices, from A to B and from B to A, for physical rights against any economic logic. Two, a comparison of the results of the auction with price differentials between power exchanges reveals significant inefficiencies. In particular this analysis shows that market participants were able to secure capacity below its arbitrage value. Such inefficiencies do no exist in systems such as Nord pool and PJM because transmission pricing and energy markets are integrated through a centralized power exchange, i.e. there are no transmission rights, there is only an energy market which takes into account directly the problem of transmission constraints. Thus, it appears that the actual design of European electricity markets based on the separation of transmission pricing and energy markets represents an important reason for the poor level of integration at the European level.

9-5 Conclusion

In this chapter we have shown the importance of transmission pricing in electricity markets. In this respect economic theory of transmission pricing provides interesting guidance, although the debate between academics continues as to which approach is the best, i.e. nodal or zonal. Moreover successful examples such as Nord pool and PJM show that there is not only one model which works. However with respect to the role of organized markets, it appears to be fundamental that a single institution should combine system operations (TSOs) and market operations (power exchanges) regardless of the choice made between nodal and zonal system. Such an integration allows the marketplace to handle transmission pricing and thus use transmission capacity efficiently.

In Europe transmission pricing and energy trading are treated separately bringing into play a physical transmission rights system. Such a system presents serious limitations with respect to efficient usage of the system and loops flows. Moreover, although the Member States have decided at the sixth Electricity Regulatory Forum in Florence meeting that their allocation procedures should comply with an agreed set of rules on congestion management based on market-based mechanisms, in practice several non-market based methods are still being used. Finally, when market-based mechanisms are used, empirical evidence suggests that their outcome is far from what can be expected in an efficient market.

In conclusion, despite the goodwill of the parties attending the Florence forum, the fact that the Directive 96/92 lacks a design for handling cross-border congestion has led to the creation of a non-harmonized patchwork of (mainly) non-market-based methods. Moreover, the separation between transmission and energy markets has led to inefficient transmission pricing and appears to be a fundamental reason for the poor level of integration between European electricity markets. Several measures needs to be taken to improve the functioning of the market with respect to market design but also with respect to “market regulation” in general. These aspects are discussed in chapter 10.