Development of Electricity Wholesale Prices in Northwest European Markets

*By Frits van Oostvoorn and Monique Voogt**

Abstract

In 1996 the Electricity Directive (followed in 1998 by a Gas Directive) was adopted in the EU which started an enormous restructuring process of electricity and gas markets in EU Member states. In the continental European countries a step-wise implementation of the EU Directives has resulted in a dynamic transformation process with great unpredictability and anomalies in market prices. This study, which was finalised at the end of 2000, analysed the outlook for deregulation of power markets, the changes in electricity production technologies, ownership, fuel consumption, cross border trade, production costs, short-run and long-run marginal costs and wholesale price of electricity for four northwestern European countries (France, Germany, the Netherlands and Belgium). The main conclusions are that in France and Belgium, in the short and medium term, electricity prices will approach average production costs of power production, which results in market prices higher than Germany and Netherlands. In the next five or more years cross-border trade will have a limited impact on price formation. Gas consumption of power markets in these four countries will increase substantially (doubling in the next 10 years), particularly for peak power.

Introduction

If we assume over capacity on the Northwest European electricity markets and we assume that markets are tending towards full competition, short run marginal costs are a more accurate approximation of future market prices than average costs. However, if due to demand increase or mothballing or closing down of existing capacity there is a need for new investments in capacity, the long run marginal costs (LMRC) of production seems a more accurate approximation of the expected market price. Finally other factors such as market power can push up prices even more. So in a perfect competitive market firms act as price takers, i.e. they consider the price as given and consequently act as if their output will not alter it. Firms will not produce if the market price is higher than the short run marginal cost, which is given by variable costs such as the fuel, operating and maintenance costs. Costs that do not depend on the quantity of power generated are fixed costs and these are irrelevant in the short-run production decision making. In the long term companies are able to alter the allocation and composition of all production factors and, therefore, if they will not cover the total costs of production they will stop operating.

When firms exercise market power they act in a way that they can influence the market price. Under the uniform price setting system in which the price is settled by the most expensive plant dispatched, there are two methods of exercising market power. The first one is strategic bidding. This method comprise companies bidding prices that are higher than their operational costs of the plants that will probably set the market clearance price, in order to increase the price and therefore the benefits. This method provides a risk for the firms, as if they bid too high they could probably not be dispatched.

The second method consists of companies withholding some of their capacity in the bidding process so as to cause more expensive units to increase the system supply curve, and consequently increase the market clearance price. Firms opting for this strategy consider that losses in cutting inframarginal capacity will be overweighed by gains from other dispatched capacity.

The electricity industry is characterised by a highly variable price inelastic demand, significant short run capacity constraints, and extremely costly storage. These factors combined make the concentration of a market not a good indicator of the potential for, or existence of, market power. The possibility for the firms to exercise market power also depends on a number of other factors. These are the amount of demand in a certain market, the fringe production capacity, the demand elasticity and the transmission capacity. When electricity demand levels are low, it is difficult for utilities to exercise market power, as generally the number of bidding plants is relatively high. If a generator decides either to bid high prices or to withhold available capacity, other generation units will be able to dispatch their plants. At high demand levels, the number of competition plants tends to reduce. Consequently utilities that own marginal plants are able to withhold output and increase the market clearance price. The amount at which some utilities can exercise market power depends on the fringe production capacity, which generally are inclined to bid low in order to dispatch as much electricity as possible. Price mark-ups can only be sustained at high demand levels when demand is not price responsive, i.e., when consumers do not alter their behaviour when prices increase. Transmission congestion occurs whenever power deliveries are limited by the size or availability of transmission resources needed to serve a load. Constrained transmission capacity into certain regions can have important impacts on the level of competition in those markets by restricting potential short-term entry, and, therefore, allowing the enforcement of monopolistic behaviour.

Forecasting wholesale electricity prices for the four EU countries over the period 2000-2015 in the current transformation phase of the EU electricity markets is a very complex undertaking. An enormous number of uncertainties are influencing the electricity wholesale prices today and will be in the next decade. For this reason, the study is based on a combination of qualitative and quantitative analysis. The qualitative analysis concerns an assessment of the current and expected development of deregulation in the four countries conducted by ECN. The quantitative analysis is supported by a model called PRIMES (NTUA, 2000) and a complete database of the electricity market in the four EU countries (ESAP, 2000). Furthermore, ECN analysed and assessed the cross-border trade and other conditions for production, trade, transport of electricity and taxes, tariffs, etc. in the electricity markets in the EU.

The following approach was adopted for estimating wholesale prices:

- In-depth analysis of the current market structure in four northwestern European countries and the strategies of the

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main players in these four markets (market power).

- Analysis of the status and role of cross-border transmission capacities between these four countries regarding the scope for cross-border trade and influence on price formation.
- Assessment of efficiency and costs of current production capacities in these countries.
- Identify and analyse new investment opportunities, particularly regarding gas technologies.
- Development of a reference (scenario) forecast for calculating electricity costs (prices).
- Conduct sensitivity analysis on the reference scenario to 'forecast' ranges for electricity production costs per country.
- Estimation of the short run and long run marginal cost curves.
- Estimate developments of electricity wholesale prices for the four EU countries regarding the competitiveness in each country.

To calculate the production costs (first crude approximation value for developments of market prices) for five consumer categories in the four countries, assumptions were made on the implementation of the EU Electricity Directive (regulatory setting), fuel prices, economic (electricity demand) growth, etc. Furthermore we also assume the establishment of fully competitive gas markets in Europe (strong assumption). To ascertain the possible and most likely developments of electricity prices under different circumstances a number of policy/sensitivity variants are analysed with the model. Finally, expected electricity prices were estimated based on plant (technology) production costs, actual production and load curves of the different generation options in the scenarios and other information, such as scattered information on 'forward prices', SRMC and LRMC curves and the influence which is expected from the competitiveness of the market, thereby influencing company behaviour (implementation of the EU Directive) in each country. Altogether this leads us to as careful as possible an estimation of the expected electricity prices in each of the four countries.

The structure of the paper is as follows. In Section 2 we present the current situation and in Section 3 the results of the scenario analysis, including a sensitivity analysis. Section 4 contains the analysis and expectations regarding the electricity prices for the next fifteen years in the four northwestern European countries.

Current Situation

In the Netherlands, the first phase of liberalisation started in 1999, when the first 33% of the market was opened for competition. The new Dutch electricity Act further stipulates in 2002 a 66% and in 2004 a complete opening-up of the market. Adopted was the Regulated TPA system and DTe was appointed as regulator. DTe sets conditions for grid access tariffs after submission of proposals on this by TSOs. In 1999 the Amsterdam Power Exchange (APX) was established for spot trade. In the Netherlands the main factor influencing electricity price formation in the year 2000 was the so-called Protocol, which is an agreement between the four major generators and the distribution companies (utilities), stipulating from 1997 till the end of 2000 mandatory sales of electricity at fixed prices. Furthermore, the contracting of additional volumes via the spot market and thus by imports was limited due to cross-border capacity made available for current long-term contracts between producers and foreign companies. On top of that, unexpected revisions of generation plants took place. The consequences were erratic rises in wholesale prices and panic reactions by utilities facing shortages in their purchases to meet commitments from already contracted sales to consumers. However, it must be pointed out that this volatility in prices concerned only peak load supplies and that the volume of electricity traded via APX covers only about 2-3% of the total electricity supplies to the utilities.

Germany, the largest European electricity market, started the liberalisation process in April 1998 with a sudden and complete opening up of the market. It adopted a negotiated TPA and, therefore, it claimed that it did not need a regulator and an Independent System Operator. As a consequence of this sudden liberalisation the transmission constraints increased dramatically and tariffs became relatively much higher than in the neighbouring countries. On the other hand, the commodity prices for residential and industrial consumers declined dramatically in 1998 but recently are more or less stable and moving upward.

In France EDF has the monopoly over production, transmission and most of the distribution activities. In 2000 a law was introduced to meet the EU requirements for implementation of the EU Directive. It stipulates that consumers (larger than 16 GWh), about 30% of the market, are allowed to choose their supplier. About 75% of electricity generation is by nuclear plants. Regulated TPA was adopted and a system operator RTE was appointed. Nevertheless, the emergence of competition is largely reduced by the favourable position of EDF and existing generation overcapacity in France. Also divestment of the EDF structure seems very unlikely. So far the number of eligible consumers leaving EDF as supplier is minimal.

Belgium started late, May 2000, with enabling large consumers (<40 GWh/year) to freely choose their supplier. Only in 2007 will the other consumer markets be opened for competition. The company Electrabel produces 93% of the electricity, of which 55% is produced by nuclear plants. Belgium adopted the system of regulated TPA. The regulator's situation, however, is not very transparent. The national coordinator of the production, etc. of electricity CPTE (subsidiary of Electrabel) proposed itself to be the system operator and also published grid access tariffs. So far ERC (Regulator) has not officially named a system operator.

The main conclusion drawn is that the models implemented for and the pace of liberalisation is very different in the four EU countries. Another aspect that should be pointed out (but is not elaborated in this paper) is the fact that the system and level of network charges, still differs largely between the four countries.

Electricity Market Scenario

Based on a large number of assumptions concerning GDP, varying between 1.7 and 2.7% p.a. and demand growth, fuel prices (crude 25 US$/bbl in 2000 to 16 US$/bbl in 2002 and later), etc. in the four countries, the most likely development of the electricity market was calculated for the next fifteen years.

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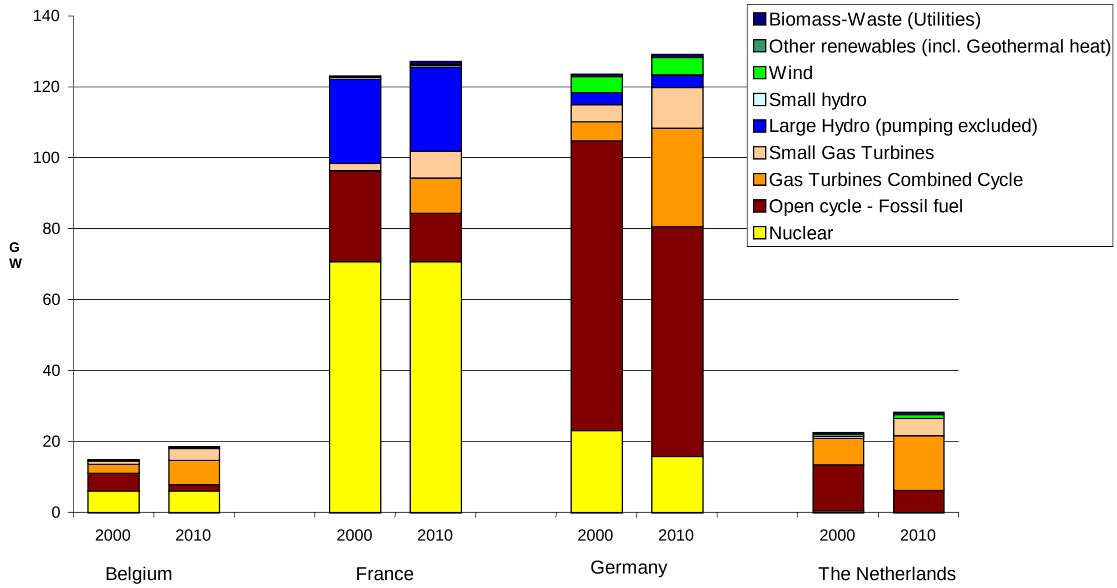
Figure 1
Capacity Per Country and Type of Plant [GW]



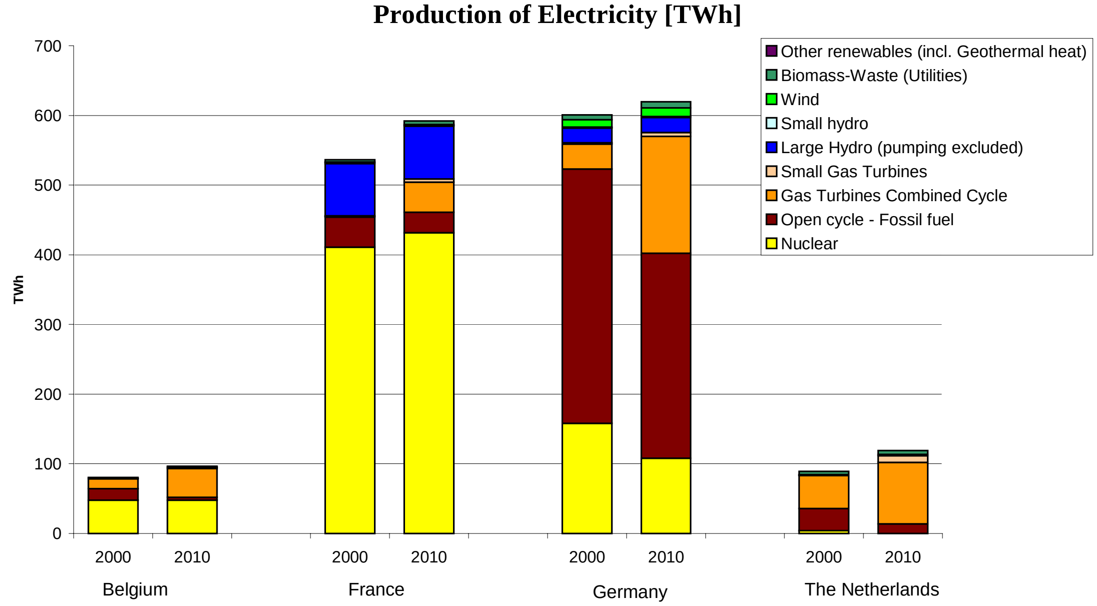
NW European Electricity Wholesale Prices *(continued from page 7)*

The key developments of the scenario are:

- generation capacity developments in the four countries,
- electricity production and fuel input,
- electricity trade between the countries,
- electricity generation costs (approximation of electricity wholesale prices).

The outlook for the total capacity in the four countries is presented in Figure 1. Generally the capacity of CCGT plants increases, whereas that of open cycle plants decreases. Also the contribution of renewables increases in most countries. In Germany the capacity of nuclear plants decreases slightly. Despite the decreasing overall demand for electricity in Germany the total capacity increases slightly because the reserve margins increase. This seems to contradict the current large overcapacity on the northwest European market. However, it should be noted that this is merely a replacement of older and less efficient plants that cannot operate profitably at low levels of electricity prices and are thus replaced by higher efficiency plants. These model results are clearly 'supported' by some recent developments on the German and Dutch power markets. In Germany, RWE and E.On have announced the closing of a significant part of their capacity, while RWE has recently opened a new high-efficient STAG CHP unit at Bayer (480 MW, Oct. 2000) and has started building one at Thyssen-Krup Stahl (255 MW, expected to operate end of 2002). In the Netherlands, Epon has announced it will close two of its plants (523 MW and 352

Figure 2
Production of Electricity [TWh]

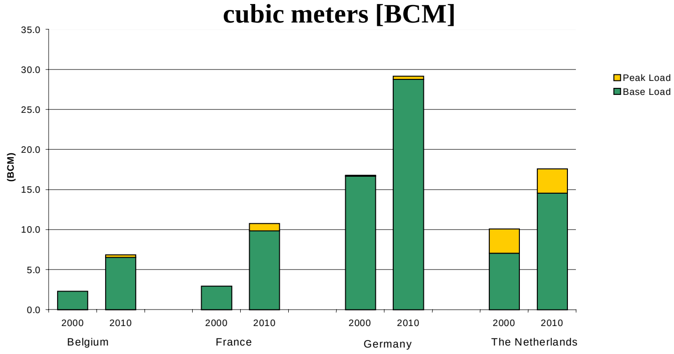


MW) from January 2001, while other parties such as Norsk Hydro are developing plans to invest in new gas-fired production plants.

Due to the changes in the direction of investments in new capacity and utilisation of existing capacity, the structure of electricity generation also gradually changes from 2000 to 2010 (see Figure 2). Due to relatively low oil and gas prices, the contribution of plant technologies using natural gas increases and that of solids (coal) decreases. Low natural gas prices appear to be favourable for penetration of CHP, particularly in the Netherlands. As a consequence fuels such as coal and nuclear electricity generation will not contribute anymore in 2010.

As expected, the relative low gas prices in the reference scenario lead to an enormous increase in the use of natural gas for the electricity generation in north-west Europe (see Figure 3). In the year 2000 natural gas is used for meeting peak load only in the Netherlands . However, in the year 2010, the other countries will also be using some natural gas to meet peak loads. Most remarkable is the newly arising gas-fired plants for electricity production to meet (part of) peak load demand in France.

Figure 3
Natural Gas Use for Electricity Generation in billion cubic meters [BCM]



Regarding the trade in electricity, the results were as follows. Germany is mainly importing electricity from France during its base load hours period, whereas Germany exports base load electricity during base load hours to the Netherlands. However, during the peak load hours, trade flows are going in the opposite direction. Especially between Germany and France, trade via the pool market is increased considerably. France mainly exports electricity during the base load and it imports electricity during the peak hours. Imports from France during the peak are the result of the relatively favourable diesel prices in Germany. In practise, part of this trade demand could be replaced by cheap (hydro) electricity from Switzerland. However, this option is only partly incorporated in the outcomes since Switzerland is not explicitly taken into account in the study. Besides France, Belgium also exports electricity during the base load hours. In general, one can conclude that countries with a lot of nuclear power plants, such as France and Belgium, are exporting in the period of base load production. The imports contracted from France, including the exports contracted to the Netherlands, mainly involve cross-border transit through Belgium, which in turn also imports electricity from the Netherlands during its peak demand hours. Note that the nuclear plant Thiange is 32.5% owned by EDF. The Netherlands imports electricity during the base load demand period. One of the main reasons for contracting (nuclear) electricity imports has been the decommissioning of the Dutch nuclear and other base load power plants. Due to favourable gas prices, the Netherlands to some extent exports electricity during the peak hours.

Finally, to check the robustness of the scenario outputs, particularly regarding the electricity costs for changes in the key assumptions such as fuel prices, carbon taxation etc., a sensitivity analysis was conducted for the following variants:

a. relatively higher oil and gas prices (called high prices),
b. termination of all fixed trade contracts (called no contracts),
c. increase of the investment costs of CHP of 20% (called CHP inv.),
d. introduction of a carbon tax of $ 6.5 per tonne CO_2 (called carbon),
e. better utilisation of existing cross border transmission capacities for trade (called transmission).

Only for the 'high prices' and 'carbon tax' variants the production costs are substantially deviating from the reference scenario. For a more elaborate (costs) price analysis see next section.

Electricity Prices

The price outlook is based on the following analyses:

- current market developments
- current and expected market concentration and power in the four markets,
- current and expected structure of electricity production in the four countries,
- current daily prices and forward prices on the European spot markets,
- average cost, short run and long run marginal costs in the different markets as calculated by the model.

Note that data presented on the reference scenario are based on relatively low world market prices for oil and gas. The outlook for electricity wholesale prices presented in this section is consistent with these oil and gas prices. However, this does not mean that wholesale market prices are assumed to be able to decline to the SRMC of the whole production system as determined by the model calculations. The market price is not determined by the SRMC of the whole production system, but by the price of the highest bid needed to satisfy demand, i.e., the merit order. It is, furthermore, noteworthy to realise that the level of world market prices for oil and gas evidently influences the height of electricity market prices, but that the present trend in price developments seems to be rather robust according to our sensitivity analysis.

Price Paths and End of Overcapacity

For each of the four countries, two price paths are presented, indicating the most likely scope of future price developments. The two paths are based on a different assumption (relatively slow or faster) regarding the increase of market opening and establishment of competition in the respective countries.[1] Furthermore, the paths don't comprise possible government policies such as enforcing price reductions in non-competitive markets or enhancing transit capacities. Note that the scope of possible developments does not

[1] See footnote at end of text.

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NW European Electricity Wholesale Prices *(continued from page 9)*
include radical policy changes of national governments and/or the European Commission and does not include external market developments such as changes in the implementation of the gas Directive. However, we expect that in all four markets prices will be largely affected by the fact that a large part of the current production system is expected to be closed down in the period 2005-2010, and thus overcapacity in the northwestern European market will decline substantially. As a reference, the long run marginal cost of the price setting base load technology is presented for all countries. For Belgium and France also the long run marginal cost of the complete production system is included as a reference to the absolute upper bound of market prices (see explanation below the corresponding graphs). Note that this latter figure includes both base and peak load supply.

Market Prices for Base Load Supplies

The market prices for base load supplies are expected to tend towards the long run marginal cost of the expected price setting technology on the wholesale markets for base load supplies. In most cases this will be a large or medium gas-fired CCGT plant; in Germany this could also be a modern high-efficiency coal-fired plant. For the countries of Belgium and France, market prices are largely influenced by the lack of market competition. EDF and Electrabel, respectively, dictate wholesale prices in France and Belgium, and no serious competition is expected within the next ten years. In spite of over-capacity in both markets, prices in both countries are currently not based on the short run marginal costs but on average costs. The long term trend is influenced by the long run marginal cost of the price setting base load technology, but we expect that the market power of both companies mentioned is strong enough to keep prices higher than long run marginal costs. This is supported by restrictions on import capacities in Belgium and insufficient TPA in both countries.

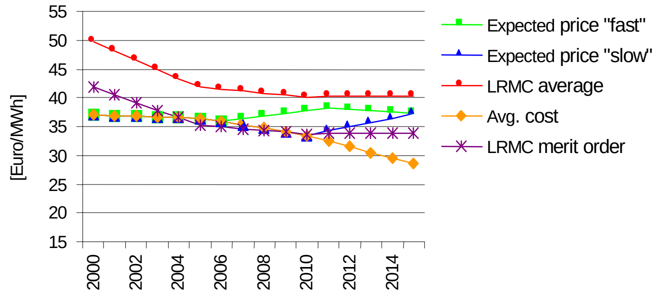
For Germany and Netherlands, the outlook is significantly different (see Figure 6 and 7). Wholesale market prices in recent years have decreased, especially in Germany, and are currently based on short run marginal costs. This situation is expected to continue until there is no longer overcapacity on the German and Dutch market. At that time, which is expected to be around the year 2006, prices will gradually increase towards the long run marginal costs of a new gas-fired CCGT plant.

The price outlooks include the following information:

- Expected price of wholesale base load supplies; indicated by a 'fast' and 'slow' price path. The 'fast' and 'slow' paths indicate the possible scope of price developments.
- LRMC merit order: the long run marginal cost of the price setting base load technology on the electricity market of the country indicated.
- For Belgium and France: Avg. cost: the average cost of electricity production in the electricity market.
- For Belgium and France: LRMC average: the long run marginal cost of the complete electricity production park.

Next to the price-influencing factors mentioned above, in Belgium the timing and trend of price developments largely depends on the level of government regulation on the market, see Figure 4.

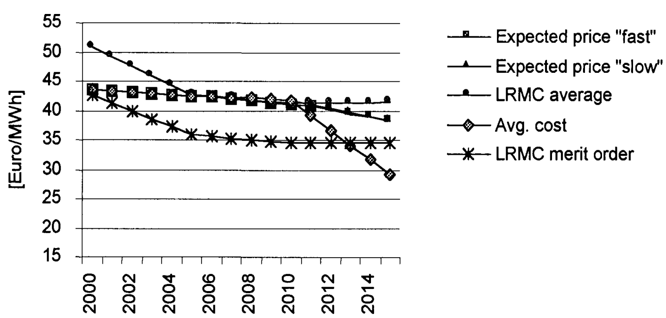
Figure 4
Expected Wholesale Price for Base Load Capacity in Belgium



As long as Electrabel can set prices and no efforts are made to either divest Electrabel, improve actual TPA or increase import capacity on the Belgium market, prices are not expected to decline towards German and Dutch market prices. If the Belgian market would be more open to competition, prices would certainly tend towards levels in between Germany and the Netherlands. The discussion on the current situation in Belgium points out the limited possibilities to increase competition in the Belgian electricity market.

The most remarkable fact in the French market is the lack of variation in price developments, see Figure 5. Current wholesale prices are based on average costs, which are not significantly different from the long run marginal costs of electricity production in France. Moreover, for a number of years EDF is expected to remain the only company that is able to set the system marginal price in France. As is the case for Belgium, the average cost of production is likely to decrease significantly due to relative smaller increase of new investments in capacity.

Figure 5
Expected Wholesale Price for Base Load Capacity in France



The average costs in both Belgium and France decrease steeply according to the calculations. This is due to the declining amount of new investment, the reduction of over capacity and the increase in operating hours. In Belgium, approximately 1500 MW of fossil fuelled open cycle plants are decommissioned every 5-years, which is steadily being replaced by higher efficiency CCGTs. In France, the calculated reserve margin reduces from 1.47 in 2000 to 1.42 in 2010 and a large number of existing plants are decommis-

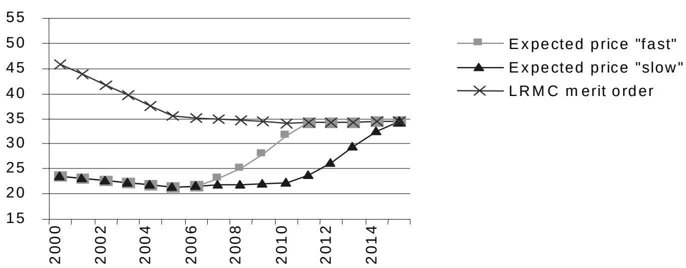
[1] See footnote at end of text.

sioned and replaced by (a somewhat smaller amount of) higher efficiency plants.

The market prices on the German market in the early years will follow the trend in SRMC developments calculated by the model. Around the year 2006, when large amounts of new capacity are required, prices will slowly increase toward the long run marginal cost of the price setting technology.

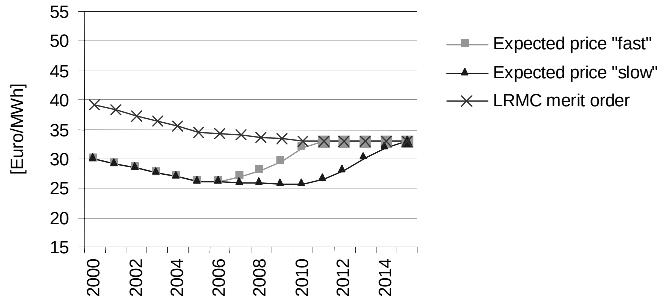
It is remarkable to notice that prices on the German market are not expected to decrease much further than current price levels. Apparently, wholesale prices have almost reached their absolute minimum at this moment. From earlier analysis we learnt that the Protocol in the Netherlands and restrictions in import capacity have influenced prices upward. However, with the Protocol ending after 2000 and expected increased flexibility and the increase of import capacity, prices are expected to decrease in the short term toward German price levels. As holds for Germany, at the time of ending of the current situation of over capacity on the market, prices will tend to increase towards the long run marginal cost of the price setting CCGT gas-fired technology. This level is expected to be around 1 EURO/MWh lower than for Germany (see Figure 6).

Figure 6
Expected Wholesale Price for Base Load Capacity in Germany



Comparison of the price paths of Germany and the Netherlands shows that although current market prices are significantly lower in Germany, in the longer run they will be around 1 EURO/MWh higher than in the Netherlands. This is mainly induced by the relatively lower gas price in the Netherlands. Moreover, earlier analysis has already indicated that given the large scope for gas-fired peak generation in the Netherlands, there is a potential export for peak load electricity from the Netherlands, especially to Germany. The expected price difference supports this possibility. It should, however, be indicated that differences in wholesale prices alone do not determine international trade opportunities. To be able to exploit this possible export potential, sufficient trade capacity between the Netherlands and Germany should be available. Furthermore, it should be noted that costs of transit are not included in the graphs shown above. If the costs of transit exceed the price difference of about 1-2 EURO per MWh, exports are no longer profitable. Given this estimated price difference, it is unlikely that new investments in cross-border transit capacity between Germany and the Netherlands would become cost-effective in the next decade. It is, therefore, expected that firstly the options to increase the net transfer capacity of existing transmission lines will be exploited, and secondly - when this option is satisfied - no new network investments are taking place, but companies operating on the Germany market will extend their gas-fired peak capacity.

Figure 7
Expected Wholesale Price for Base Load Capacity in the Netherlands



Conclusions

Focusing on the four northwest European countries it would be fair to state that the transformation from a more or less strongly regulated electricity market towards a full competitive market is currently in a beginning phase. Clearly this process of transition and changes takes place faster in the Netherlands and Germany than in Belgium and France. So given the fact that current differences in generating capacity, outlook for regulatory systems and relatively limited cross-border trade capacity, over the five next years prices in Germany are expected to be the lowest of all four countries. Thereafter, however German prices will rise, and become slightly higher than in the Netherlands, mainly due to the relative lower gas prices in the Netherlands, in the long run. Although it is expected that (average) electricity prices in Belgium and France will gradually decline and thereafter stay almost constant, they will probably remain higher than in the other countries in the next decades.

Of course, other factors will influence the future wholesale prices in northwestern European countries. Electricity companies will merge, relatively high cost capacity with limited flexibility will be dismantled, all of which is part of a dynamic process. The emergence of the IPP and particularly small and medium scale generators of electricity based on renewables or highly efficient Combined Cycle Gas Turbines plants might influence wholesale prices of electricity in the future. Finally the EU Regulators will have to avoid that companies will create market power for pushing up prices, above acceptable levels. More research in these topics is required.

Footnote

[1] Note that we believe that, although market prices are expected to converge as is indicated in the graphs, for the next ten years full integration of electricity markets in Northwest Europe will not be achieved.

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