FACULTY OF ECONOMICS AND
APPLIED ECONOMIC SCIENCES
CENTER FOR ECONOMIC STUDIES
ENERGY, TRANSPORT & ENVIRONMENT

KATHOLIEKE
UNIVERSITEIT
LEUVEN

WORKING PAPER SERIES
n°2000-3

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November 2000

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The Liberalisation of the Energy Sector in the European Union

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I. INTRODUCTION

The energy sector covers the coal, oil, gas and electricity sector. The European coal and oil sector have already been liberalised in the past. The current debate concerns mainly the electricity and the gas sector. In this paper we will concentrate on the electricity sector for three reasons. First, the sector is more important in terms of value added, secondly it is considered to be more complex and, finally, the opening of the electricity market precedes that of the gas market. Obviously, this does not mean that the gas sector should not be studied as there are many challenges left.

In section II, we discuss the institutional background for the liberalisation. Section III then analyses the British experience. This is of interest because the UK has liberalised its market about 10 years ago and this experience has been the subject of extensive economic research. In the sections IV to VII, we focus on the four main problems in the liberalisation of the European electricity market: the stranded costs issue, the cross-subsidies issue, the pricing of transmission and the regulation of the environment. Finally, section VIII concludes.

II. BACKGROUND

The different energy sectors

Traditionally, one distinguishes at least four different energy sectors that each use a different energy product to satisfy the energy needs of the consumers. These are summarised in Table 1.

Trade in coal and coke was liberalised first in the EU in the early 1950s. At that moment it was still the dominant energy vector, and its liberalisation was a necessary component of an open market for steel. Whereas most of the European Union’s energy sectors are relatively healthy, this cannot be said for the coal mines, which are chronically unprofitable and heavily subsidised by national governments. The ECSC Treaty, which provides the legislative framework for the coal and steel industry, prohibits state aid. However, in a series of framework Decisions over the years, the Commission has the authority to approve aid provided by governments.

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[1] This text is based on work carried out for the Belgian Minister of Economic Affairs and for the K.U.Leuven Energy Institute.

The Commission made large efforts to persuade or coerce the Community coal industry to reduce the very high operating costs by restructuring and closing pits. An important transition took place at the end of 1993, when the new ECSC coal aid regime came into force, which regulates state aid until the ECSC Treaty expires entirely in 2002. During the 1986-93 period, all the coal mining industries in Belgium, Portugal, France and the UK cut back capacity and reduced government subsidies ahead of or at least in line with the Commission's policy. For each State, the Commission was concerned to ensure that subsidies decreased each year. In Belgium, mining ceased altogether in 1992. France has made production cutbacks in recent years and is now on a path to cease output by 2005.

Oil products became more important than coal in the 1960s. Most oil was imported and processed by international companies, but the European oil sector has been liberalised for some decades now**.** It is now the most open and liberalised energy industry in the European Community.

	Share of total final energy consumed	
	in 1971	**in 1997**
Coal	16,4%	3,9%
Oil	61,8%	51,8%
Gas	8,7%	21,7%
Electricity	10,8%	17,5%

Table 1 : The different energy sectors.

The electricity industry has been growing since its origin, as can be seen in Table 1. The sector has also been a legal monopoly mostly run by public companies in many countries. This has changed only very recently, as in 1996 all EU member countries were forced to organise competition at the generation level while accepting regulated monopolies at the transport and distribution level.

The conversion from coal based gas to natural gas in the early 1970s required a transition from local production facilities and networks to an industry that relied entirely on international pipeline networks bringing gas from the Netherlands, Norway, Algeria and Russia. In most countries, the gas industry was a legal monopoly. The EU gas directive has been adopted in 1998. Member countries have until August 2000 to develop the laws, regulations and institutions to liberalise the gas market. The general principles of the gas directive are not different from the electricity directive. However, the main element of competition in the gas sector comes from the possibility to buy gas from different producers via non-discriminatory access to the network.

Electricity sector developments

The Directive 96/92/EC, concerning common rules of the internal market in electricity was adopted by the Council of Ministers on December 19, 1996. It entered into force two months later on February 19, 1997. The Directive starts with a list of considerations that have led to the Directive. These are important for a clear understanding of the background of the Directive and its overall aims. The ultimate goal is "*to increase efficiency in the production, transmission and distribution of electricity, while reinforcing security of supply and the competitiveness of the European economy and respecting environmental protection.*"

Basically, the Directive provides for:

- free competition in generation, with either an authorisation or a tendering procedure for building new generation capacity. Most countries have opted for an authorisation procedure, which means that all parties that satisfy the safety, security, environmental and public service criteria are able to produce as much as they want.
- a market on the consumers' side, that is open to a minimum degree[2]. The largest consumers will be the first to benefit from an open market, smaller consumers will follow. A member state that opens up its market for a larger percentage than provided by the directive, is allowed to restrict access to suppliers from countries that did not open up to the same degree (reciprocity).
- free access[3] to the transmission network via Third Party Access, a Single Buyer, or a mix of these. The national transmission network (high voltage transport) has to be run by a system operator that is responsible for the network maintenance and development and for the dispatching of the generation plants. Most countries have opted for regulated access, which means that the tariffs for the use of the grid are fixed and can not be renegotiated.
- an unbundling of accounts between generation, transmission, distribution and other non-electric activities, if these are present within one company. The accounts must be accessible to the regulatory authorities;
- public service obligations that may relate to security, including security of supply, regularity, quality and price of supplies and environmental protection.

Even if the directive leaves some degrees of freedom to the member countries, it seems that most countries opt for the same general orientations. Figure 1 summarises graphically the liberalisation of the European electricity sector.

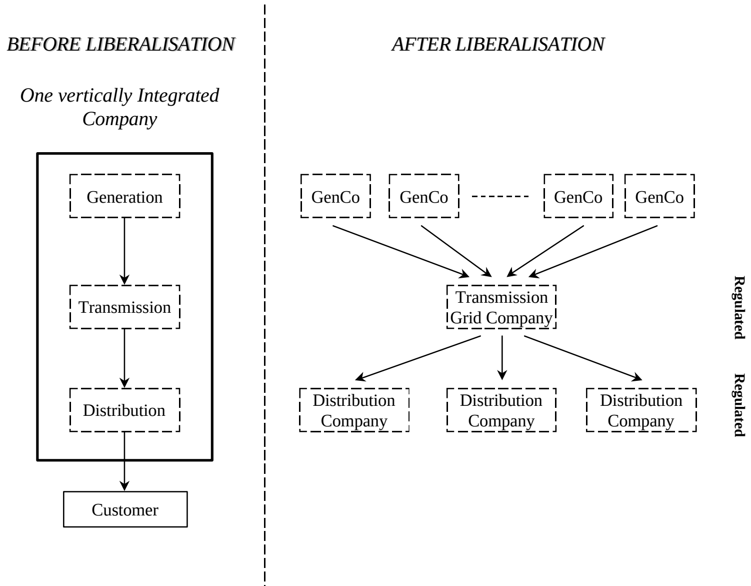

Figure **1:** the effect of liberalising the electricity market.

The liberalisation of the electricity sector is well underway but this is not the end of the reform. Many problems remain unsettled. In this text we will focus on four problems. First, we examine two transition problems that have received special attention the last years: stranded costs and cross-subsidies. Next, we briefly discuss how to set transmission tariffs and how to integrate

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2 Certain consumers are defined as "eligible". These consumers only can move on the open market.

3 Between generators and eligible consumers.

environmental considerations into an open electricity market. We start however by surveying the British experience. They liberalised the market in 1989 and we can learn from their experience.

III. THE BRITISH EXPERIENCE

In March 1990, the state owned CEGB was divided into 4 public limited companies: The National Grid Company, PowerGen, National Power and Nuclear Electric. The 12 Regional Electricity Companies (RECs), who owned the local distribution assets, were given shares in the National Grid Company and were sold to the public in December 1990. In 1991, a majority share of National Power and PowerGen was sold to the public. Initially, the nuclear power stations were kept in the public company Nuclear Electric, but in 1996 this company was also privatised (Newberry (1998)).

The electric power producers were privatised with long term British coal contracts above the world market price and with long term contracts that guaranteed that the REC's would buy an important share of the total production. Both the coal contracts and the electricity delivery contracts were to decrease in importance over the years. Initially, only the industrial customers had access to an open electricity market, but from 1998 onwards all consumers are able to select their supplier.

The situation in 1995 is summarised in the following figure (taken from Wolfram (1999)).

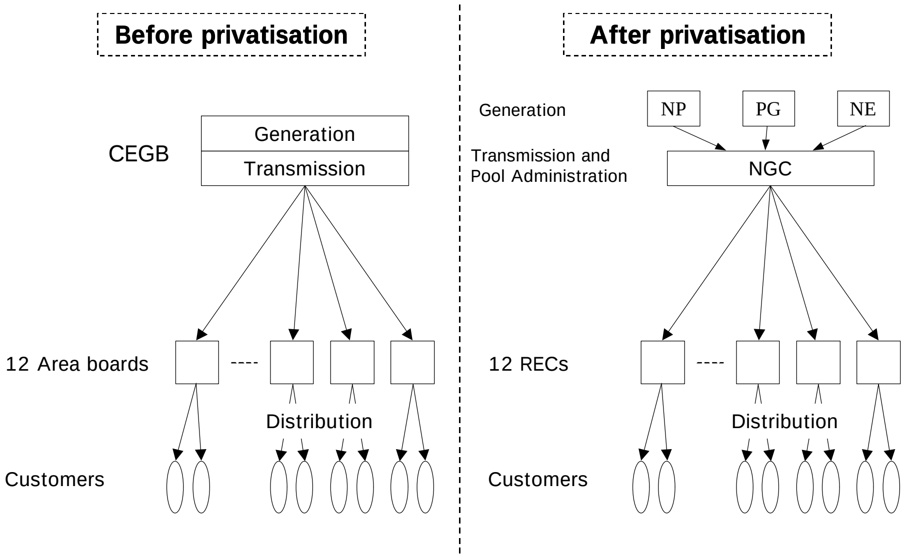

Figure 2: The UK electricity market in 1995.

Wolfram (1999) gives a further description of the British electricity market system. All wholesale electricity transactions in England and Wales go through a central pool. The pool is a "day ahead market" where for every day ahead, producers submit bid schedules that detail the prices and capacities of each plant they are prepared to operate. The network operator uses these received bids and demand forecasts to determine a system marginal price (p^* in Figure 3). This is done for every half an hour. The pool price that is received by all producers equals the system marginal price plus an additional factor that covers the capacity cost. The vast majority of the transactions are covered by direct contracts between generators and their customers. These direct contracts most often take the pool price as reference but can include different types of protection against price uncertainties.

The pool prices are market prices and are not directly regulated. However, the industry regulator (OFFER) possesses an important instrument for intervening in the pool when he judges the prices as too high because he can refer the generators to the Monopolies and Mergers Commission (MMC). This Commission can take drastic steps such as breaking up the existing companies so as to create more competitors. As a result, the regulator's appreciation of the pool price level is certainly taken into account by the generators.

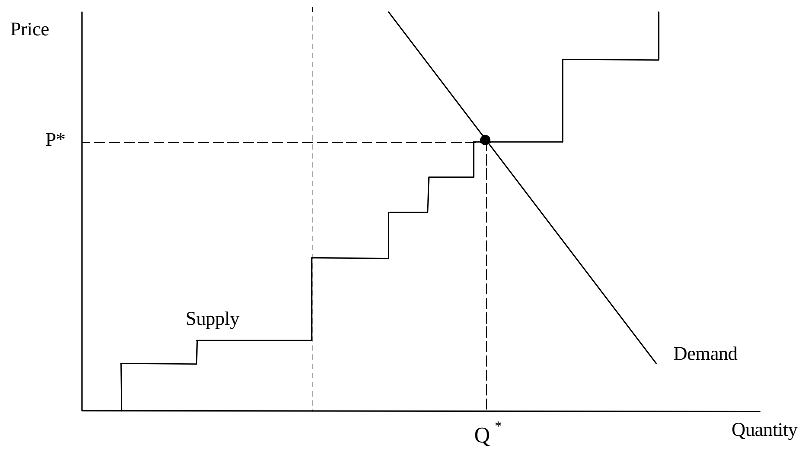

Figure 3: Determination of System Marginal Price.

What explains the price setting of generators?

In the UK, the breaking up of the CEGB resulted in a duopoly where PowerGen and National Power restricted the capacity made available at low prices in order to get better prices. This was demonstrated by Green and Newberry (1992). Wolfram (1999) analysed a longer period and used different techniques. The values she found for the mark-up are reported in Table 2.

Time period	% of maximal market power used[4]	(P – MC)/P
Jan 92 – March 93	15%	0,241
April 93 – March 94	20%	0,259
April 94 – Dec 94 (price cap)	20%	0,208
4 weeks before a regulatory decision		0,329
4 weeks after a regulatory decision		0,156

source: Wolfram (1999) and own computations

Table 2: Mark-up values in the UK electricity sector.

[4] This coefficient was constructed by dividing column 2 by column 3 of Table 2 in Wolfram (1999).

This table shows clearly that mark-ups were important (of the order of 25%) and that two generators was not enough to have perfect competition[5]. Another sign of market control is that after the setting of a price cap in March 1994, the generators were able to arrange prices that matched almost exactly the price cap.

However, the mark-ups are below the theoretical mark-ups a duopoly could get. Column 2 in Table 2 shows this: the realised mark up is only some 20% of the profit maximising mark up of a pure duopoly.

Wolfram advances two factors to explain this restraint in their price setting behaviour:

- The presence of a regulator that can cap prices, send the firms to the Monopolies and Mergers Commission, etc. The mark-up after a regulatory decision was always much lower 4 weeks after than 4 weeks before a regulatory decision (see Table 2).
- The potential entry of new competitors: pool prices were set just under a potential entry's long run marginal cost (CCGT plants) and pool prices followed the fluctuations of the gas prices although gas plants were not the marginal plants.

Who gained from the introduction of competition?

Newberry (1998) and Newberry and Pollit (1997) analysed the costs and benefits of the liberalised electricity market in the UK.

On the generation side they found very strong gains in productivity. They give the example of a coal power station of 4000 MW that halved its labour force from 1200 to 600 people. Productivity increases were realised as well in (the publicly owned) Nuclear Electric.

Important changes also occurred on the fuel side. Before the privatisation, the electricity sector used about three quarters of the total coal production in Britain and paid coal prices above the world market price. After a few years, these long term contracts for British coal were abolished and cleaner and cheaper imported coal and gas were used instead. The British nuclear power stations were build as a weapon against coal mine strikes and their construction and operation was subsidised[6]. Initially, these nuclear power stations proved non-competitive, but under pressure of the market they also experienced large productivity increases.

Newberry and Pollit (1997) analysed the distribution of the gains of this liberalisation. They found a permanent cost reduction in the order of 5% and important environmental benefits. The major beneficiaries of these cost reductions were the new shareholders while the consumers and the taxpayer actually lost money. This is possible because not all the productivity gains and fuel price decreases were fully passed on to the consumers and the government. The major explanation why important profits subsisted has to do with the small number of competitors on the generation market.

Another factor is that before 1998, the small consumers that could not choose their supplier. They have been forced to pay for the decommissioning liabilities of nuclear plants and, via the RECs, for the expensive British coal used in power generation.

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[5] the nuclear generator wanted its units running continuously (base load) and did not have a large capacity therefore there were only two real competitors.

[6] The Thatcher government decided to build 10 Pressurised Water Reactors (PWR). In the beginning of the privatisation there was an obligation for the RECs to buy nuclear power and a fuel levy to pay for decommissioning liabilities.

According to Newberry (1998), governments are keen on privatisation but tend to restrict competition. More competition reduces the privatisation receipts and the power to intervene. Abuse of market power is an excellent reason for political and regulatory guidance. By using the anti-trust suit, the government can persuade those with market power to burn more local coal, or collect more money for specific consumer groups, to invest in green energy, etc.

Another lesson drawn by Newberry (1998) is that it has been very difficult to design a good and cheap system for competition at the retail level.

A final lesson drawn by Newberry (1998) is that the Labour government’s ban on new gas fired entry has decreased competition again. The objective of Labour was to stimulate the demand for coal. The likely result is that the windfall profit tax imposed by Labour will be paid by the consumers.

Note however that, even if some important lessons can be drawn, the European market liberalisation cannot directly be compared with the British case. At least 3 important differences can be identified.

- First in the UK, a public monopoly was privatised and broken up into parts that will compete. In the EU, there is not necessarily a privatisation or a braking up of existing companies, but a liberalisation via opening of national borders. The number of competitors is also very likely to be higher than three.
- In the UK, there is one integrated national electricity network that allows competition between generators in the same country. In the EU, there is a collection of national grids that each are well integrated and that are interconnected to solve reliability problems. However, the international connections were not designed to create one integrated European market so that trade possibilities could be restricted in the first years of competition.
- In the UK (England and Wales), there is one regulator and one market for power. In the EU, there are national regulators and a European monitoring of competition.

We now move on with a brief discussion of some major issues that need some special attention in the process towards liberalised electricity markets.

IV. THE STRANDED COST ISSUE

Stranded costs have to do with the transition from a regulated to a competitive electricity market. They refer to the problem of recovering past investments costs and have been presented as a major obstacle in the transition to an open electricity market. They are more typical in electricity markets where the initial firm was a private monopolist because he will accept less easily to absorb losses from past investment than a public company or than a public company that is privatised. In the United States the market opening started a few years earlier than in Europe, and the stranded costs concept was invented there. The discussion focused on several questions, such as what is the exact definition of stranded costs? Should the industry be able to recover them? If so, who should pay for them? And how should they be recovered?

In the European Directive, there is an explicit provision dealing with stranded costs (article 24). Obviously, the definition of stranded costs is crucial as this will have an effect on the ultimate stranded cost estimate. For Belgium, stranded cost estimates ranged between 500 M EURO and 5000 M EURO. We now present our definition of stranded costs. Furthermore, we show when stranded costs will exist and what are the consequences of allowing generation firms of recovering them.

A. A definition of stranded costs

Before the liberalisation, electricity generating firms made different expenditures that are considered sunk or fixed. It would be wrong to label all of them as unrecoverable or 'stranded' when the electricity market is opened up. Some of these costs would also have been made in a competitive market. But some are typical for a firm operating in a regulated market. Because they were imposed by the regulator, or because the firm chose to make these costs. Concerning the first category, the fixed or sunk costs imposed by the regulator, one could argue that it should be allowed to the firm to recoup these costs, whatever the market structure is. We will call them *strandable costs*. However, it is difficult to defend this position for the latter category of fixed costs.

		IMPOSED BY THE REGULATOR	
		Yes ↓ ***Strandable***	***No*** ↓ ***Not strandable***
RECOVERABLE VIA THE MARKET	***Full recovery***	Not stranded	Not stranded
	Partial recovery	Non-recoverable part is stranded	Not stranded
	No	stranded	Not stranded

Table 3: The definition of strandable and stranded costs.

This is summarised in Table 3. Two categories of fixed or sunk costs are distinguished, those imposed by the regulator and those resulting from decisions taken by the firm itself. In this paper, the costs in the first category are called *strandable,* those in the second category are *not strandable*. If stranded costs are present, then they should be in the strandable category, the non-strandable costs cannot become stranded. But not all strandable costs are necessarily stranded, since some of them can be (partially) recovered via the market. Only those strandable costs that *can not* be recovered via the market are stranded. In the table the shaded area indicates the stranded costs.

Summarising, strandable costs are defined as *those fixed and sunk costs that were imposed by the regulator in the regulated market.* Stranded costs are then defined as *strandable costs that cannot be recovered via the market if the market is opened up for competition.* Comparing this latter definition with other ones in the literature learns that it closely resembles the one given by Baumol, Joskow and Kahn[7]. However, our definition puts more emphasis on the role of the regulator or the supervising authority. We stress that the regulator should *impose* the expenditures, whereas Baumol *et. al.* include expenditures *approved* by the regulator. Clearly,

[7] Taken from Doane and Williams (1995), p. 42.

the latter is a much broader definition of stranded costs because it implicitly opens the door for *all* sunk costs made by the regulated firm to become stranded.

B. The economics of stranded costs : A graphical analysis

The link between strandable costs, stranded costs and other cost concepts can be illustrated graphically. This section presents this illustration. Furthermore, it tackles questions such as when do stranded costs exist? If stranded costs exist, are there economic reasons to allow for stranded costs recoupment? Can, on a theoretical basis, anything be said about the size of the stranded costs? Each of these questions is answered by using the graphical tool and the analysis is kept as simple as possible[8].

The regulated market

Assume that the total demand for electricity is perfectly inelastic and equals q_D, which corresponds to the size of the horizontal axis. Initially, there is only one generation firm. This firm is called the incumbent and its cost structure is shown in figure 2. It is assumed that the average cost of electricity *generation* ($l_i \geq 0$) decreases for some smaller levels of output, but in the range we are considering the average cost of electricity generation is increasing. The incumbent's marginal cost of electricity generation is assumed to increase linearly[9]. The average variable cost is labelled AVC_I. The vertical distance between AC_I and AVC_I is a measure of the average fixed generation cost AFC_I. The present analysis only considers the cost of electricity generation.

We assume that it is compulsory in the regulated market to meet the market demand and that the regulator sets the price for electricity generation such that economic profit equals zero, i.e. $p^R = AC_I(q_D)$. The latter assumption is made for illustrative purposes, and has no effect on the conclusions of the analysis.

The liberalised market

Now assume that the market for electricity generation is opened up for competition and that the market demand for electricity remains equal to q_D. Furthermore, assume that several potential entrants are competing for a market share and that each of these entrants has sufficient capacity to supply the market at a constant marginal cost (MC_E). This assumption may be a good approximation for what will happen on the Belgian electricity market. Belgium is a small

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8 More particularly, we focus on a market with one homogenous commodity. This can be electricity delivered at a constant flow over the year with a given level of quality. Using a multiproduct approach for electricity (peak, off peak, etc.) is more realistic but will obscure the stranded costs analysis in this section without adding value to the argument.

9 The linearity of MC_I (and thus also AVC_I) is assumed for the sake of simplicity. Unless it is mentioned explicitly, this does not influence the main conclusion of the analysis.

open economy, with a relatively small production capacity compared to the available capacity in the surrounding countries[10].

Competition between entrants ensures that the entrant's price equals his marginal cost. Furthermore, we assume that if the incumbent increases his price above the entrant's marginal cost, then he would immediately be pushed out of the market.

In Figure 4 the market demand for electricity q_D is supplied by two generation firms, the incumbent (*I*) and the entrant (*E*). The vertical axis on the left-hand side is the incumbent's axis, the entrant's axis is at the right-hand side.

The competitive outcome

Under the assumptions listed above, the competitive market outcome will always be such that $p = MC_I = MC_E$, which is generally accepted as optimal from an efficiency point of view. In Figure 4, the incumbent's output would reduce to $q*$, whereas the entrant's output would be $(q_D - q*)$. The implied price of electricity generation decreases ($p^C < p^R$), but this is not a general result. In fact the market price is determined by the marginal cost of the entrant.

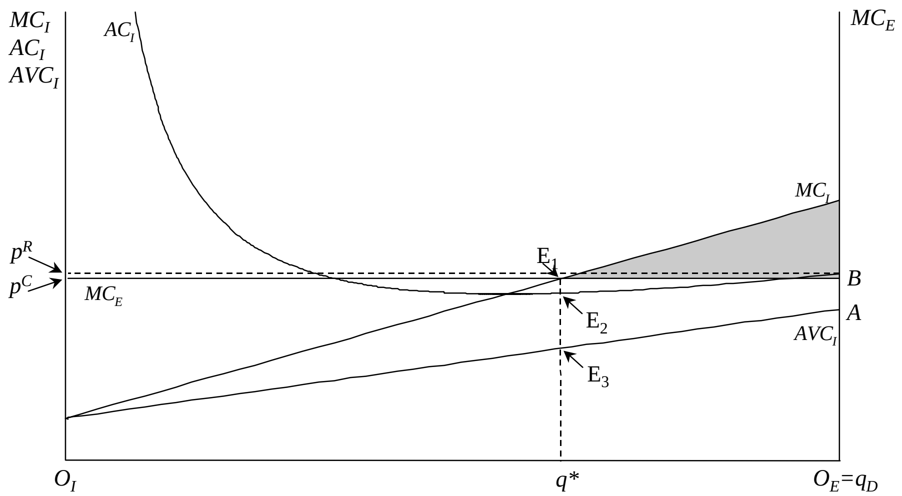

Figure 4: The competitive market.

Economic welfare

It can be shown that in this simple model social welfare increases as the market is liberalised. Furthermore, it can also be shown that the change in social welfare is equal to the efficiency gain that is made through improved production efficiency. The shaded area in Figure 4 is a measure of this 'benefit'.

[10] It is assumed that one entrant enters the domestic market. The results would not change if more than one competitor would enter. The assumption of perfectly inelastic demand for electricity is acceptable in the short run and helps the exposition.

The stranded costs

In order to show the stranded costs in a figure, we need to take a closer look at the fixed costs. According to our definition, only those fixed or sunk costs imposed by the regulator are candidates to become stranded, i.e. are *strandable.* In order to make this distinction, the fixed costs are divided in *strandable* and *non-strandable* fixed costs (F_S and F_{NS}). This results in the $AF_{NS}C_I$-curve in Figure 5 and Figure 6, which represent the average non-strandable fixed costs. Now, consider two cases[11].

The market price covers the average costs

In Figure 5, both the strandable and the non-strandable fixed costs are covered by the market price. The domestic firm produces q^* and makes an economic profit equal to the area $p^C E_1 E_2 D$. As was said before, from an efficiency point of view this market outcome is optimal. There is no reason why the government or any other regulator should intervene by allowing the recovery of strandable costs since the market automatically arrives in a Pareto-optimal situation. In fact, *there are no stranded costs in this case*.

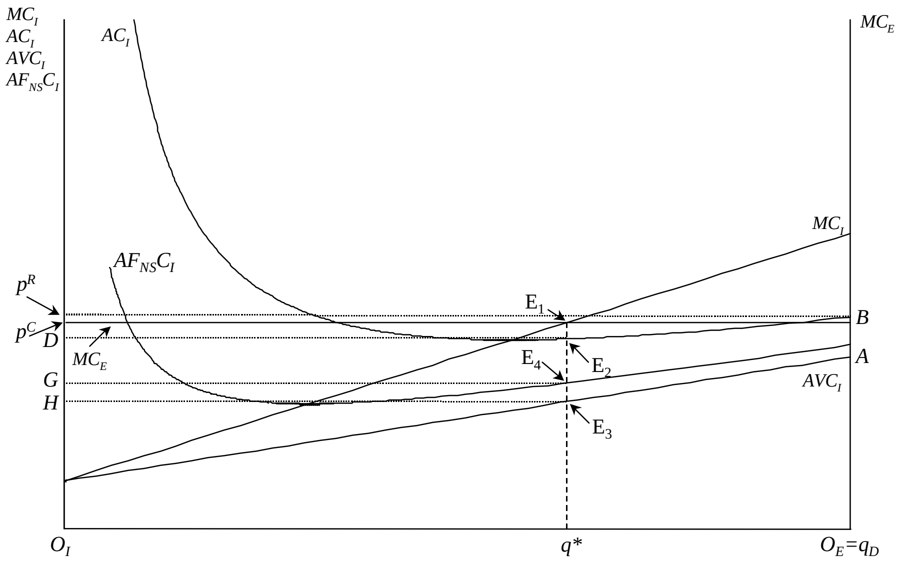

Figure 5: The competitive price is higher than the average cost of the incumbent.

The market price does not cover the average costs but does cover average variable costs

In this case, the market outcome could be as shown in Figure 6. Standard economic theory then suggests that in the short run the firm will stay in the market since stopping activity will only imply an even larger loss. The point E_1 indicates the short run price-output combination for the incumbent firm. This point implies a loss per unit of output equal to E_2E_1 and a total loss equal

[11] Note that other definitions of *strandable* costs would result in an other position of the $AF_{NS}C_I$-curve.

to the rectangle $DE_2E_1p^C$. The stranded costs in this case are equal to that part of the strandable costs that is not recovered via the market, which also equals $DE_2E_1p^C$.

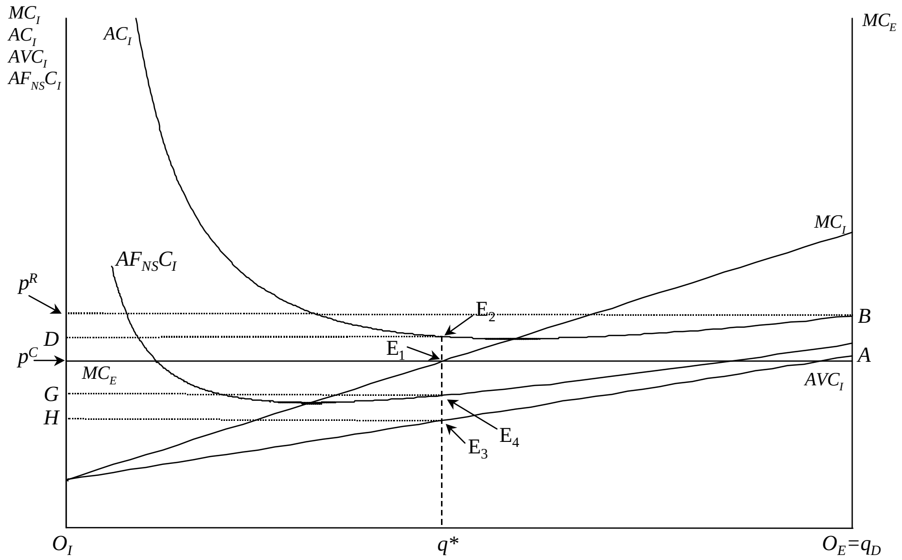

Figure 6: The competitive price is lower than the average cost of the incumbent.

Again, there is no case for allowing stranded costs recovery from the point of view of efficiency. The incumbent incurs a loss due to the presence of strandable costs, but this does not influence the output decision. The Pareto-efficient output will still be the outcome.

One could also turn around the question: is there a case for *not* allowing stranded costs recovery? No, there is neither. If the incumbent is allowed to recover stranded costs and if the recovery is organised in a competitively neutral way, then the firm will choose the same Pareto-efficient output. The difference between both cases is that the burden of stranded costs is (partially) shifted from the firm to the consumers and/or the government.

Standard economic theory also suggests that a firm, not able to cover its fixed costs in the short run, will leave the market in the long run. This is true, but in the present model, the situation might be slightly different because *strandable costs are a short run phenomenon*. In the long run, the owners of the firm will absorb the strandable costs, and the firm will only reoptimise its *non*-strandable fixed costs. If it is possible for the firm to cover its long run average costs (now not containing any strandable costs anymore) with the market price, then it will stay in the market. If on the other hand, the firm is not able to cover its long run average costs through the market price, then it will leave the market. From an efficiency point of view, this would even be optimal.

This reasoning puts an upper limit on the financial support for stranded costs recovery. The support should *not be larger* than the amount of the *strandable costs*. If the regulator sets the compensation at a level that covers more than the strandable costs, then he is subsidising some of the non-strandable fixed costs of the incumbent, which may create the wrong incentives for the incumbent. The incumbent may decide to stay in the market, whereas we know that this is not optimal from the point of view of efficiency.

Some simulation exercises

A simple simulation model was used to test what could be the welfare effects of a transmission fee to recover stranded costs on the Belgian market. The effect on welfare of opening the electricity market for the big industrial consumers depends on the supply price of the foreign producers and on the ease with which the big consumers switch to another supplier. When the supply price of the foreign producer is only slightly lower than the marginal cost of the home producer, opening the market could give welfare gains and higher profits for domestic generator. The welfare gains come from imports at lower costs than the indigenous production. Despite the loss of market share for the home producer, his gross profits are not affected much because of two reasons. First, the protected market is responsible for the major share of the gross profits. Secondly, the home producer might be able to charge higher prices at home for the market share he keeps at home. Sensitivity studies show that the opening of the market does not lead to negative profits and therefore that the strandable cost would never become stranded.

conclusions

When one is concerned about economic efficiency, allowing for stranded cost recovery is not necessary. On the other hand, allowing for recovery would not hurt either, but if financial support for stranded costs recovery is given, then it should be organised in a competitively neutral way. Moreover, there is an upper limit to the size of the support, i.e. it may not be larger than the strandable costs. Of course, if there is no recovery of stranded costs, then the firm will make a loss on the home market but this does not result in inefficiencies.

V. CROSS SUBSIDIES

In most European countries the market is not liberalised at once. In general, one started with the biggest customers, while the SME's and the residential sector have to wait a few years before they have access to the European market. This situation creates a potential for cross-subsidies between the liberalised and the non-liberalised market.

This risk is one of the recurrent topics in the liberalisation debate and the Belgian Electricity law explicitly foresees measures to avoid such cross-subsidies. One can expect an increasing attention for the problem both from the side of the small consumers and from the competitors of Electrabel. In this section we first examine the definition of cross subsidies and then we indicate where and why cross subsidies occur. Next, we discuss the potential for cross subsidies after the liberalisation and the ways to reduce or eliminate this potential. We conclude with a proposal for reducing cross-subsidies.

The cross-subsidy definition

According to the economic literature, prices are cross-subsidy-free if they satisfy the following two conditions [12].

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[12] See Faulhaber (1975) and Curien (1991).

- For each customer the price is below the average stand-alone cost for that customer. The stand-alone cost is the cost for a customer of self-providing the good or the service. This defines an upper bound on the set of cross-subsidy free prices.
- Each consumer is paying a price not lower than the average incremental cost. This defines a lower bound on the set of cross-subsidy-free prices.

Note that price differences are not necessarily an indication of cross-subsidies, and uniform pricing might still hide cross-subsidies.

The major disadvantage of this 'definition' is the size of the gap between the lower and the upper bound of the set of cross-subsidy-free prices. Furthermore, applying this definition requires a lot of information not readily available in practice. This makes that cross-subsidies are difficult to identify. In this paper, we accept the existence of a cross-subsidy if a disproportional share of the joint costs is included in the tariffs applicable for a given segment of the market.

Why is there a problem with cross-subsidies?

Prices convey important economic information. They should give incentives to customers and producers to allocate scarce resources in an efficient way, i.e. to squeeze the maximum out of the available resources. Prices containing cross-subsidies will confront the economic agents with the wrong price signals.

In some cases, cross-subsidies were introduced intentionally, because it was deemed to be fair that some customers paid more or less than other customers. In economics, however, a preference is given to achieve income distribution goals via income transfers rather than via subsidised prices.

Where can cross-subsidies occur?

In the regulated electricity market, the price level and price structure at the *generation level* were set and controlled by the regulator. Cross-subsidies could easily be sustained because of the lack of alternatives to the electricity customers. After the liberalisation, this type of cross-subsidies is still possible in the non-liberalised part of the market.

However, prices for electricity charged to the liberalised part are now beyond the control of the regulator and a cross-subsidy from the liberalised customers towards the captive customers is not sustainable. Cross-subsidies from the regulated towards the liberalised part of the market may still exist as the incumbent producers or traders will try to recover a disproportionate share of their costs via the captive customers.

Because of its typical natural monopoly characteristics, it can be expected that the *transmission activities* remain under the control of a regulator, who may create (or allow) cross-subsidies between different types of customers.

The interaction of cross-subsidies at *the generation and the transmission level* depends on the degree of unbundling of the generation/trading and transmission activities. The European Directive on the opening of the electricity market requires integrated undertakings to keep separate accounts for their generation, transport and distribution activities. In Belgium, the law imposes that transmission activities are strictly separated from any other activity. If this separation is successful, then cross-subsidies between generation and transmission activities will not exist. If the separation is only partially successful, and if the incumbent owner of the transmission firm is able to influence the transmission prices, then cross-subsidies between the two levels may occur.

Why do cross-subsidies occur?

Cross subsidies may arise because of political reasons, because one likes to give a preferential treatment to some type of customers or because one does not want to charge the full cost of providing a good or a service to a given customer type.

By definition, joint costs cannot be allocated to one product because these costs were made for the production of more than one product. Some sharing rule is needed to allocate these costs to the different products. Other allocation rules will result in other split ups of the costs, and using a wrong sharing rule results in an incorrect allocation of the joint costs and thus – maybe – in a cross-subsidy.

In most European countries, the ongoing liberalisation process in the electricity market has lead to a claim from the sector for stranded cost recovery. Several instruments are available and proposed to finance this transfer. If a fee is imposed only on the captive customers (e.g. a tax on the distribution level), then this might result in a cross-subsidy from the captive customers to the free customers.

Through predatory pricing, the incumbent firm tries to protect its market share in the liberalised market by charging very low prices on that market. Charging higher prices in the captive market then must compensate the resulting loss in revenue. This can be done, because in that part of the market there is no risk of entry. The incurred short run losses are then compensated through price increases and thus higher profits when the potential entrants are defeated. Such a strategy assumes that the defeated entrants will not try to reenter once the prices have increased and this is rather unlikely especially if the sunk cost involved in entering a market is rather small, which is the case in the presence of overcapacity in generation equipment.

When the incumbent firm is supplying both the liberalised and the regulated part of the market, and when price regulation is of the cost-of-service (COS) type[13], then the firm has an incentive to allocate as much as possible its joint costs of production to the regulated market. In that market, the firm can recover its costs through the regulated price. In the liberalised market, the firm can increase its profit margin (keeping the price constant while decreasing the average cost), since now only a small share of the joint costs is to be collected through that market.

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[13] Until 1999, Belgium had a pricing system that closely resembled COS regulation. With COS regulation, prices are set such that a revenue requirement is realised. There are two major problems with this type of pricing. First, the mechanism has little incentive power. The incentive power of a pricing scheme is measured by the pressure it puts on the regulated firm to provide its goods or services at the lowest possible cost. Second, tariffs are not necessarily close to the marginal costs and thus they do not necessarily provide incentives to consumers for a correct use electricity.

Existing voluntary cross-subsidies in the current Belgian electricity market

In Belgium, the price per kWh covers the cost of the generation, the transmission and (if applicable) the distribution stage. Thus, not much is known about how the cost of the transmission service is allocated to the different types of customers (large industrial customers, small industrial customers (SME's) and residential customers). It can very well be the case that these costs are recovered from the customers by charging a fixed amount per kWh, irrespective of the size of demand, the timing of consumption, ... This would correspond to a so-called postage stamp tariff. Aalbers *et al.* (1999) made some calculations for the Dutch transmission grid and they conclude that the potential for cross-subsidies is quite large if a pure postage stamp pricing method would be used[14].

If in Belgium an implicit postage stamp is used, then it is likely that the industrial customers are cross subsidising the low voltage and (to a lesser extent) the medium voltage consumers. This is because electricity generators supply their output mainly to the high voltage grid, and large industrial customers usually take their electricity from the high voltage grid. Therefore, they would only have to pay for transmission over the high voltage grid, whereas with a postage stamp they also pay a part of the cost for transport over the medium and the low voltage grid.

Currently, a few small intentional cross-subsidies exist. They have to do with the stimulation of the production of "green electricity", the stimulation of rational use of energy and the tariffs for combined heat and power production. Overall they represent only a small share of total costs.

In the past, transfer pricing took place between the generation firm (Electrabel) and that part of the distribution sector under the control of Electrabel. This mechanism exploited the difference in the tax treatment of profits at the corporate level and at the distribution level. Thus, a cross-subsidy may be (have been) present in the sense that mixed intercommunalities are (were) paying too low prices for their electricity compared to the prices paid by the other customers. According to the regulator of the captive market (the CCEG), this mechanism is not operational any more as there is now a fiscal compensation in place. One is also thinking about applying the same tax rate at the distribution level as well as at the corporate level.

Cross-subsidies in a partially liberalised Belgian electricity market

Competitive forces will push the market price for electricity generation towards a level that more closely reflects the marginal cost of electricity generation. Therefore, existing cross-subsidies from the liberalised part of the market towards the captive part of the market cannot be sustained.

On the other hand, existing cross-subsidies from the regulated part of the market to the non-regulated part of the market will continue as this helps the incumbent firm to improve its

[14] On the basis of the figures in their report, a *pure* postage stamp price of 0.700 BEF per kWh was calculated. If the price would be differentiated according to the customer type (high voltage, medium voltage and low voltage customers), then Aalbers *et al.* (1999) find transmission prices ranging from 0,256, over 0,531 to 1,025 BEF per kWh, respectively. With a further differentiation according to the voltage level at the generation side, the price differences would become even larger.

competitive position in the liberalised part of the market (predatory pricing) or to make higher profits in that market.

If the COS mechanism is maintained in the regulated market, the risk exists that the incumbent firm allocates more than a fair share of the joint costs of electricity generation to the captive market because of its de facto monopoly position in that market.

Major potential channels for cross-subsidies after the liberalisation

At the *generation level*, there is a clear incentive for the regulated firm to allocate a more than reasonable share of the joint costs to the regulated market. Therefore, a careful and thorough study of the cost allocation mechanism in the regulated firm is necessary, whatever the pricing mechanism that is chosen in the regulated market (COS, price cap or yardstick). This is because in each of the three cases, the initial price levels are determined on the basis of such a cost allocation exercise. Basically, the three pricing mechanisms only differ in the way prices are allowed to evolve in the later periods.

A second important channel for unwanted cross-subsidies is the *transmission sector*. This activity remains under the (in)direct control of the incumbent firm. In the liberalised market, the large industrial customers have three options:

- buy electricity from the current electricity producer (Electrabel);
- buy electricity abroad, or;
- invest in an own generation plant (CHP or CCGT).

Under the first two options, the transmission grid still needs to be used to supply electricity. Under the last option, the use of the transmission grid is avoided (except for back-up services). The presence of this third option indirectly puts a pressure on the pricing strategy applied by the transmission company. If the transmission company sticks to a pure postage stamp tariff (and the implied cross-subsidies), then this will give more incentives to the large industrial customers to choose for an own CHP or CCGT installation.

Reducing the potential for unwanted cross-subsidies: a proposal

The current pure COS-based pricing rule should be abandoned because of the incentives it provides to the regulated firm to allocate joint costs maximally to the regulated market. Furthermore, COS pricing gives very little incentives to the regulated firm to produce in a cost-efficient way. It is therefore preferable to move to a pricing mechanism that makes the firm the residual claimant of its cost savings. This will give more incentives to the incumbent firm to look for the most efficient production process, and to allocate the costs in a correct way. This pricing mechanism could be a price cap system or a system based on yardstick competition. Two other options to reduce the potential for unwanted cross-subsidies are to speed up the liberalisation process and to organise a better control of the cost allocation.

A price cap scheme features high incentive power in the sense that the regulated firm is the residual claimant of its cost savings. The regulator sets a price ceiling for each good or for a basket of goods that is provided by the regulated firm. This price ceiling is then adjusted over the regulatory period on the basis of a price index[15]. If the price ceiling is defined for a basket of goods, then the firm has some discretion in determining the price structure within the basket as long as the (weighted) average price of the basket is not above the price ceiling.

Giving some discretion to the regulated firm with respect to the price structure of the goods in the basket is to be preferred above setting a price cap for each good in the basket. This gives the firm more flexibility in adapting to changes in the cost structure. If necessary, some constraints can be put on this discretion in order to avoid abuses at the level of cross-subsidies. When a price cap system is added to a COS system that contains important cross-subsidies, it can take a long time to eliminate the cross-subsidies

With yardstick competition, the evolution of the prices in the regulated market is made a function of the observed evolution of prices in similar markets in other countries. Therefore, the yardstick should be chosen carefully. This system requires careful preparation, as the underlying characteristics of the different electricity markets can be very different. (The level of the prices at the beginning of the benchmark period compared to the prices in the national markets, the stranded cost policy, the size of the market opening...).

A second way to reduce the potential for unwanted cross-subsidies at the generation level is to speed up the liberalisation process and to allow distribution companies to shop for lower priced electricity.

The third way to reduce the potential for unwanted cross-subsidies is to organise a better control of the cost allocation mechanism that is used by the regulated firm. A comprehensive cost allocation analysis should be conducted on a regular basis. This exercise must be well documented and the results must be made public.

Our proposal for the electricity market is to base the delivery prices for regulated consumers, during the transition period 1999-2007, on a weighted average of two elements:

- the cost of delivery using the present COS system;
- the prices offered by competitors in neighbouring countries for similar delivery conditions;

The weight of the second component will increase so as to reach 100% in 2007.

This system has three advantages compared to the continuation of the present COS system:

- It provides a smooth transition to the fully liberalised system;
- By introducing elements of a price cap, it contains a stronger incentive for cost minimisation;
- By benchmarking the price cap in function of the prices abroad, one guarantees that gains in productivity are also translated into the prices for the protected market segment.

In order to avoid cross-subsidy via the present COS system, it is necessary that the cost allocation exercise is systematic and carried out in a more open process with independent experts.

It is also advised to make sure that generation and transmission activities are fully unbundled, not only in the legal sense, but also in practice. The obligation that generation or trading and transmission activities are carried out by legally separated firms is not sufficient. In practice,

[15] A well-known example is the RPI-X formula that is used in the British electricity sector.

Electrabel will still be a major shareholder in the electricity transmission company. Monitoring this separation of generation/trading and transport activities will be a difficult task and requires access to detailed cost information of transmission activities.

VI. TRANSMISSION PRICING ISSUES

In the liberalised market, the network operator has an important but difficult role. He has to make available sufficient transmission capacity for all trades between consumers and generators and he has to cover his costs. First, we discuss the specific difficulties of running a transmission network. Then, we review a possible pricing solution that has been proposed.

A. What makes transmission pricing of electricity difficult?

Transmission congestion

If transmission constraints are binding, so that the amount of power flowing through a line is at the safety limit, cheap but distant generation may have to be replaced with more expensive local generation, in order to reduce power flows. In the constrained area, the optimal price of electricity rises to the marginal cost of the local generation, or to the level needed to ration demand to the amount of electricity available[16].

Transmission losses

Even if there are no constraints, power is lost in the transmission process and prices should reflect the fact that marginal losses are higher in some places than in others due to the distance of the electricity transport Ceteris paribus, the higher the voltage level, the lower these losses will be.

Other elements that affect transmission prices

Ancillary services

The costs associated with delivery of electric energy include many services. The direct fuel cost of generation is only one component. In analyses of energy pricing, there is no uniformity in the treatment of the other, ancillary services (transport lines with sufficient reliability, spinning reserve, standing reserve, replacement reserve[17], reactive power (voltage control)[18], 'black-start'

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[16] Congestion has to be avoided for economic but also for reliability reasons. The total cost of capacity, losses and reactive power requirements of a line are minimised when the line is loaded at around 50% of its capacity. For reliability reasons, the loss of a line may not lead to a system collapse. With two identical lines in parallel on a route, this is achieved automatically by not loading the lines above 50%. When alternative routes exist, higher loading is of course possible. However, higher loading leads to an increased risk of voltage instability. Even though there is no sharp limit, a maximum safe rating is calculated for every line, depending on temperature and power factor of transmission over the line. It should be noted that power flows in the opposite direction of the dominant power flow diminish the total power flow, and relieve congestion.

[17] A characteristic of electricity is that it can not be stored. At each second, generation has to match demand, which fluctuates unpredictably. This is the so-called generation-demand balancing. To achieve this, power plants do not operate at maximum power, but keep a certain amount of reserve. The power output from all plants is constantly adapted, automatically, in a matter of seconds. Reserve power is also used for compensating large unbalances, due to e.g. errors in predicting demand and generator failures. If the amount of instantaneously available reserve power (the

capability[19], active power losses, area control error[20]). These services have to be supported by adequate dispatching and metering systems.

Market power at the supply side

When at the generation side, the number of suppliers is limited (as will probably be the case in Belgium), then strategic behaviour might occur in the sense that the suppliers will try to influence the market outcome through their own behaviour. This might be possible, because changes in demand or supply in one node of the transmission grid have an impact (through transmission losses and capacity constraints) on the transmission prices in the whole grid. Clearly, the possible existence of such behaviour must be taken into account when a pricing mechanism is designed.

Green (1998) compares a nodal transmission pricing system with more simple mechanisms. His conclusion is that using simpler pricing schemes decreases overall economic welfare, but not necessarily to a large extent.

B. Alternative pricing systems for transmission

As regards transmission pricing, one has the choice between three types of pricing rules: postage stamp, distance related tariff and pure marginal cost pricing.

We examine the performance of the three systems keeping in mind the three criteria to be satisfied by a good transmission pricing system (Green (1997)):

- cost coverage;
- incentives for efficient operation, investment and cost minimisation by the transmission company;
- incentives for optimal siting of new generation plants and important customers;

postage stamp

In a postage stamp system one pays for every transaction a fixed tariff per MWh , this tariff is independent of the distance, place and time where the transport flow is needed. The major advantage of this system is that it is easy to administer and allows to cover costs easily by using average cost pricing.

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spinning reserve) is used, other power plants that were at stand-by are started up (standing reserve). These power plants are replaced in their turn by power plants designated as replacement reserve.

[18] Power in an AC system consists of active and reactive power. Active or real power is the power component that can be transformed in any other form of energy, such as mechanical energy. It can be transported over large distances, although there always is some loss. Reactive power is needed to maintain the overall voltage level in the grid, enabling the transport of real power. Reactive power itself can not be transported over large distances or imported from other countries, i.e. it has to be produced locally.

The blackout in a large part of The Netherlands in the summer of 1997 is an interesting example of one of the risks due to a large import of electricity (i.e. active power only) combined with a very significant independent generation (decentralised production) and an inappropriate price structure. The independent generators are only paid for their active power output. The ensuing lack of reactive power in the grid was the main cause of the blackout. It is clear future price structures have to incorporate a compensation for the reactive power.

[19] The ability to restart the power system after an overall black-out, without support from other countries.

[20] Each country, or to be more precise each control area, performs generation-demand balancing, taking account of the scheduled import or export. This intended level of import or export is called the area control error.

The major disadvantages of this pricing rule is that it does not contain incentives for more cost-efficient operation and no incentives for a good siting of investments in power generation of power consumption.

distance related tariff

In this system, the tariffs are proportional to the (geographical) distance between the generator and the consumer.

This system allows cost coverage and contains incentives for minimising the transport distance between the generator and the consumer. Minimising geographical distance may not be a good criterion as transport capacity may be in surplus on some links and may be too small on other links. Furthermore, this system does not contain any incentives for cost-minimisation by the network operator.

Marginal cost pricing

In this system the transmission price for a given trade is computed on the basis of the marginal cost of this transaction. This marginal cost can vary according to time and location. It includes the actual system cost (power losses, ancillary services) and the opportunity cost of transport capacity. The latter means that, when there is a capacity shortage, one customer precludes other customers from making interesting transactions. This is the theory, in practice there are many implementation constraints.

The advantage of this system is that it contains different good incentives for correct use of the existing transmission possibilities. It is however complex to manage. Furthermore, simple marginal cost pricing does not guarantee cost recovery. Some kind of Ramsey pricing or two part pricing is necessary to conserve the efficiency properties of marginal cost pricing and have cost recovery. Finally, marginal cost pricing as such does not guarantee cost minimisation from the side of the operator.

C. A proposal for Belgium

In the firmly linked Belgian grid, in which actual power flows are very difficult to predict due to the large number of parallel paths and the dynamic characteristics (open switches or maintenance), marginal cost pricing is almost impossible. Therefore, a pricing scheme starting from a postage stamp method, with improvements to give incentives for optimal siting of new generation and demand in the future, efficient use of the existing grid and cost minimisation is proposed. The postage stamp is applicable to both producers and consumers.

We sketch some of the features of this proposal here:

Postage stamp for cost coverage and non-discrimination

The annual postage stamp tariff should allow the transmission company to recover its costs for running the system while treating all grid customers, using the grid at the same time and place, in a similar way. Starting from the existing situation, these costs should include all functions the system operator has to provide:

- maintenance, general improvement, increasing reliability and keeping the system in line with the present state of technology– this cost will be referred to in short as ‘maintenance cost’;[21]
- reserve capacity (spinning reserve, standing reserve and replacement reserve);
- reactive power and voltage control;[22]
- black start capability, bought by the transmission company from generation companies;
- losses in the grid;
- metering and billing of energy and power flow;
- personnel and operational cost.

Next to the actual costs, a fair return on investments should be part of the basic postage stamp rate.

These costs are allocated to customers according to the following principles:

An individual cost component

Costs that can clearly be identified as being due to a particular customer are charged to this customer. These include:

- connection costs (being different for different voltage levels);
- metering and billing, and;
- reactive power for outlyers.

A demand component

Fixed costs, i.e. maintenance, general improvement, increasing reliability and keeping the system in line with the present state of technology, black-start capability and personnel cost plus the fair return on investment, are charged per kVA peak demand.

In order to avoid cross-subsidies between grid users at different voltage levels, it can be argued that all transmission clients (generators, consumers, traders, brokers,...) directly connected to the extra high voltage grid (380, 220 and 150 kV) should only be charged for the extension and maintenance of the extra high voltage part of the grid. Consumers or generators connected to the high voltage level (70, 36 and 30 kV) should be charged for the entire grid (30 to 380 kV). This assumes that all power passes through the extra high voltage grid, or at least that all customers benefit from the extra high voltage grid.

In this respect, the present system with various types of contracts (clients requiring only 50 Hz and meeting power fluctuations – clients requiring back-up power if available – clients requiring total system services) could be largely maintained.

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[21] This cost, part of the demand component, is considered separately for the different voltage levels, i.e. extra high and high voltage.

[22] The cost of reserve and reactive power, making up the energy component, is considered separately for the different voltage levels, i.e. extra high and high voltage.

An energy component

Variable costs, i.e. the costs of losses, reserve and reactive power, are charged per kWh.

In order to avoid cross-subsidies between users at different voltage levels, the cost of losses, reserve and reactive power is differentiated per voltage level, through a charge based on a voltage dependent multiplication of the actual consumption.

This simple approach could in the future be replaced with more accurate calculations, which should indicate – in average, but perhaps not for each individual node - the dependence of losses, reserve and reactive power on the different voltage levels.

Incentive for dispatching generation and for the siting of new generation or demand

The system operator should provide incentives for both dispatch of generation and for future investments in generation and new demand nodes to be located at those places where they best support the overall system regarding congestion, losses (including those under peak conditions), voltage stability, reliability and safety. A generator may be at a point in the grid where its presence is essential to maintain voltage stability. Therefore, the value of that generator should be higher than that of a generator at a very stable node.

For particular investments, the parties involved may require the grid operator to make a confidential study of the precise effect for their intended investment in the potential nodes.

The node dependent surplus or discount leads to a better dispatching, reducing congestion and losses and improving the network stability, and in this way encourages efficient use of the existing network. Furthermore, it also provides a long-term incentive for siting new generation or demand.

Incentive for efficient operation and network investment

Maintenance and operation

The system operator should be rewarded or penalised for the quality of his operation, including maintenance, switching of lines, voltage regulation, ... The criterion is the overall system reliability. The best way to judge this is to measure the amount of energy in kWh that has not been delivered to the consumers, or the amount of energy not taken from the cheapest generators because of system failure or congestion. The quality could be compared with neighbouring systems.

Investment and network expansion

By investing, the network operator can improve the quality and reliability of the power system, thereby reducing penalties. Furthermore, included in the total cost leading to the basic postage stamp rate, is a fair return on investment and capital cost.

However, all this may lead to over-investment and a gold plated network. Therefore, an incentive for overall cost reduction is needed. This is a fundamental problem in any monopoly system. The best solution is a system of benchmarking, through comparison with similar power systems in other countries. Great care has to be taken in selecting systems that are comparable with the Belgian grid, and in making a fair comparison taking due note of objective differences.

Transparency

Clearly all tariffs – or at least the formula to calculate them - should be published in order to allow the clients to use the system in an optimal and efficient way. This also applies for the node dependent Grid Quality Charge.

VII. ENVIRONMENTAL REGULATION

Environmental standards in electricity production

Environmental standards, mainly those focussing on air pollution, influence the choice of generation technology and therefore the cost of electricity generation. This chapter discusses the existing secondary EU legislation as well as new developments on environmental policy.

Actually, there exist three main directives dealing with large combustion plants. Directive 84/360 sets a framework for dealing with air pollutants from industrial plants and introduced principles such as prior authorisation of construction of industrial processes and use of Best Available Technologies Not Entailing Excessive Cost (BATNEEC). LCPD, the Directive on controlling Emissions from Large Combustion Plants sets out emission standards for particulates, SO_2 and NO_x, and emission ceilings for SO_2 and NO_x. Finally, Directive 96/61/EC concerning Integrated Pollution Prevention and Control (IPPC) requires the introduction of an integrated environmental licensing system, which will apply to a range of industrial processes, including power stations larger than 50 MW.

The following developments will affect pollution control for power plants in the EC:

Air Quality	Stringent national caps for SO_2 and NO_x and particulates and lead
Acidification	Reducing SO_2 emissions across the EC by placing restrictions on the sulphur content of certain liquid fuel products
Revision of LCPD	Overall update, promotion of CHP (Combined Heat and Power)
Water	A special Directive on water would set standards and mechanisms for ensuring that limit values under the IPPC Directive are observed.
Waste	Will be covered by the IPPC Directive and by the EC's existing legislation on waste.
Kyoto Protocol	Under the Kyoto Protocol, the EC is committed to reducing greenhouse gases emissions by 8% by 2008-2012. In relation to 1990 levels.

The Commission is examining the measures that need to be taken at Community level to ensure equivalent competitive conditions as a result of environmental requirements to meet the above-formulated requirements.

Standards for nuclear decommissioning

Unlike other types of generation, nuclear power plants must include in their cost a factor for the storage of nuclear waste and future decommissioning of the plant. Diverging regulatory approaches to the management of decommissioning funds may cause market distortions.

At the moment, there is no specific EC legislation on the decommissioning of power plants, but, within the single market, a common approach will be needed, also leading to a better protection of population and environment, to a reduction of waste,... .

According to the Commission, decommissioning costs must be seen as part of the electricity production and may not be cross-subsidised from the transmission activity nor directly subsidised via state aid. To identify the decommissioning cost, a detailed preliminary study must be executed taking into account all the relevant factors such as safety, environmental and financial issues,.... . The fund must be secured and controlled by the mandated authorities and only dedicated to decommissioning. The full fund must be available at the foreseen time.

Healthy competition for environmental regulation when there is no transboundary pollution

Let us discuss first the case of pollution that is strictly national: some types of generation plants only affect the neighbourhood. In this case differences in national regulations should correspond to differences in national environmental preferences (say lower population density) or differences in public efficiency. An example of less efficient public regulation could be that marketable permits are not accepted.

The result of these differences in regulation and preferences could be changes in the location of power production in Western Europe. A transfer of polluting power production to less densely populated areas could happen and this is for economists a demonstration of beneficial international trade.

Unhealthy competition as a result of inefficient regulation of transboundary pollution

Now take the case of pollutants that affect the national population but also affects the bordering countries. If the cross-border effects are not internalised by every country, unhealthy competition can exist. Internalisation requires compensation of neighbouring countries for any damages done to them or at least their consent for any new plant or production. Whenever transboundary pollution is allowed without internalisation, those countries upriver or upwind will overspecialise in dirty power production. This is an example of inefficient competition.

The EU commission will face some tough questions here. A first question is nuclear energy. Some countries want to close nuclear power stations before the end of their economic life (Sweden, Germany). Other countries (France?) might want to expand their nuclear power production. Heavy nuclear accidents imply clearly cross boundary damages. Pollution from normal operation is probably confined to the region. Will we accept that some countries expand nuclear power while others are trying to close it?

A second case of interest is the CO2 emission reduction ceiling that has been imposed on the EU by the Kyoto agreement. This global cap has been translated into national caps that are not necessarily efficiently distributed in the sense that the marginal cost of emission reduction is equalised over countries. The result will be a bias against electricity production in those countries that have received an inefficient cap. This could be overcome by allowing the EU countries (or the electricity producers) to trade CO2 emission rights.

VIII. CONCLUSION

Although there is a clear momentum and direction towards liberalisation, many issues are still unsolved. The first 10 years of the British experience learn us that liberalisation does not produce its full economic benefits when the number of competing producers remains too small. We identified four major problems in the liberalisation of the European electricity sector. The stranded cost issue can most easily be resolved by not accepting any compensation for stranded costs. Cross-subsidy problems between the liberalised and the non-liberalised section of the market will probably only disappear when the whole market is liberalised. The toughest intellectual problem is the design of a good transmission pricing scheme. This is now left largely to the member states so that country experiences might teach us interesting lessons over the coming decade. Differences in environmental regulation have been identified as the fourth major problem in the European liberalisation. The solution here has to include a correct internalisation of cross-boundary pollution.

Liberalising the European electricity sector is not an easy task and will keep us busy in the next ten years.

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