Benelux market integration: 
Market power concerns

David Newbery
Eric van Damme
Nils-Henrik M von der Fehr

25 September 2003

Summary

Integrating the Benelux electricity market is a highly desirable step in the further development of the Western-European market. Benefits of electricity market integration include increased efficiency of generation and cross-border trade, enhanced security of supply due to diversification of risks and shared reserves, and potentially increased competition. The Benelux market may be one of the regions where integration can be most easily achieved, and may set an example for further developments in Europe.

Various methods of integration of electricity markets have been discussed. Efficient market mechanisms include market coupling (or market splitting), that leads to increased co-ordination between energy markets and transmission capacity markets. On the other hand, creation of a single price market that disregards physical transmission limitations and necessitates redispatch by the system operator will lead to inefficiency and ample scope for market manipulation, and should therefore be avoided.

Although in general integration is beneficial to consumers, in the situation of the Benelux, generator market power is a concern that should be explicitly addressed as a part of the integration process. Electrabel, part of Tractebel, French Suez’ energy and services subsidiary, is the dominant generator in Belgium and has a significant generation share in the Netherlands. The size of Electrabel’s generation assets in the Benelux would enable the company to significantly influence prices in the region. While it is not clear that the firm currently uses its market power to raise prices, its potential to do so in the future should be taken into consideration when deciding on the steps required for further integration of the power markets in the Benelux.

While under the current structure of the market Electrabel’s market power would have greatest effect on Belgian prices, where the company enjoys an almost complete monopoly, further integration might lead to a dilution of Belgian market power accompanied by a potential increase in prices in the Netherlands.
Conclusions and recommendations

Market coupling can bring benefits for consumers in the Benelux, in the form of greater efficiency and increased security of supply. Market power may however undermine these benefits.

Under the necessary condition that additional measures will be taken to mitigate market power in the Benelux market, we recommend the implementation of market coupling in the Benelux. This may consist of two components:
1. Coupling of the balancing markets in Belgium and the Netherlands
2. Coupling of the spot markets.

Possible measures to reduce market power of the Belgian dominant player may include:
1. Requirements on this player to offer long-term contracts to the market at regulated prices, or to increase the amount of virtual capacity offered to the market;
2. Substantial divestiture of its generation capacity;
3. Reforms of the Belgian balancing system, ensuring provision of balancing services for Belgian consumers is open, transparent and non-discriminatory, perhaps by coupling the balancing markets;
4. Regulation of bids by the Belgian incumbent;
5. Increased information requirements on the Belgian player;
6. Further unbundling of the Belgian system operator;
7. Reform of the allocation methods for import capacity on the French border towards a market-based methodology (as required by the Electricity Regulation), and restrictions on the share of the capacity by this dominant player;
8. Further European integration of the Benelux (e.g. with Germany).

Before market integration we recommend undertaking further studies and actions:
1. Assessing the impact of current virtual power plant auctions, and the impact of potential further auctions or real divestitures on market power.
2. Investigating the alternatives for market coupling on the balancing market, where technical constraints limiting possible reforms in relation to security and adequacy of supply should be taken into account.
3. Setting up market monitoring and surveillance capabilities in co-operation with the appropriate Belgian authorities, and ensuring adequate information exchange between these authorities, including confidential information.
1 Introduction

Recently several suggestions have been made to further integrate the Dutch and Belgian electricity markets. At present these are separate, but well-interconnected markets. The total available capacity on the interconnector, which usually amounts to circa 1,170 MW in both directions, is allocated by means of an auction organised by TSO Auction BV (www.tso-auction.nl).

In its 2001 Annual Report\(^1\), TenneT announced its intentions to further the integration of the Benelux markets by 2003. As a result, APX, TenneT and Elia commissioned studies to The Brattle Group on the development of a spot market exchange infrastructure for Belgium.\(^2\) Both studies investigate two possible mechanisms for integrating the Dutch and the Belgian electricity markets: 'market coupling' (similar to the NordPool concept of market splitting) and a 'single price market', creating an alternative to the current auction. DTe has asked the Market Surveillance Committee for advice on the market power aspects of such integration methods.

The two mechanisms under study are:

- **Market coupling**, in which the allocation of interconnection capacity is co-ordinated with the clearing of energy markets. The energy market operators use available interconnection capacity to equilibrate prices in both markets, unless the interconnection capacity constraint is binding. In the latter case different prices in each market result. These energy markets might be power exchanges or balancing markets. Market coupling is an efficient method of allocating scarce transmission capacity. In contrast to separate auctions for transmission capacity, the market coupling concept integrates decision processes on energy and transmission capacity markets, which avoids co-ordination problems between the two markets and ensures more efficient dispatch of generation, thus lowering the costs of supplying both regions. Market coupling in effect implements netting of transmission capacity and hence increases effectively available transfer capacity. In addition market coupling allows more efficient sharing of security of supply, and is furthermore in line with anticipated developments towards integration of the wider European market of the kind required by the Electricity Regulation.

- In the **single price market** the physical capacity limit on the interconnector is ignored, and one uniform market price is used for the entire region. Any potential violations of transmission limits are resolved by the system operators, who contract with individual generators to increase or reduce load. These redispacht costs are socialised in system tariffs. Creation of a single price region is well known to provide misguided incentives for generation dispatch, by hiding the costs of transmission congestion, and may in fact create perverse incentives to generators in load pockets, which will eventually show up in substantial redispacht costs.

---

\(1\) http://www.tennet.nl/publicaties/jaarverslag/
Creating a Benelux market for electricity might be a first step towards one integrated European electricity market. However, given the market structure in the Belgian market, the effects of market power could be a concern that should be analysed. In order to contribute to this analysis and to the more general discussion on market integration we investigate the potential effects of introducing market coupling or a single price market between the Netherlands and Belgium.
2 Overview of the Benelux markets

The Dutch and Belgian power markets differ substantially in the following aspects:

<table>
<thead>
<tr>
<th>Aspect</th>
<th>Belgium</th>
<th>Netherlands</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Level of market concentration</td>
<td>One dominant generator</td>
<td>Four larger players</td>
</tr>
<tr>
<td>2. Fuel mix</td>
<td>Many nuclear power plants</td>
<td>Most plants are gas-fired units</td>
</tr>
<tr>
<td>3. Balancing regime</td>
<td>Charges based on mathematical formulas</td>
<td>Market based</td>
</tr>
<tr>
<td>4. Spot market</td>
<td>No hourly day-ahead market</td>
<td>Relatively liquid hourly day-ahead market (APX)</td>
</tr>
<tr>
<td>5. Price transparency</td>
<td>Electrabel’s price offer</td>
<td>APX and OTC prices</td>
</tr>
</tbody>
</table>

Generation market, players

The Dutch generation system consists of, in total, slightly over 20 GW of installed capacity. Of this, roughly 14 GW is connected to the extra high and high tension grids (traditionally known as ‘central generation’), while the remainder consists of distributed (or ‘decentral’) generation. The vast majority of the units are gas fired, the rest is mainly coal fired. Roughly 7 GW (located both on the high tension grids and on local grids) is CHP capacity, serving industrial, horticultural and city heating demands, and operating to some extent on a must run basis. Central generation is mostly operated by 4 large players: Essent/EPZ, Electrabel, Nuon and E.On. The peak load on the central grid measured in 2002 was 14 GW, peak load on the entire grid is estimated at 16-17 GW.

Electrabel ownership of capacity in the Netherlands amounts to 4,626 MW, or slightly over 20% of Dutch installed capacity. It is the largest generator when counting only central production. Both Essent and Nuon however also have (partial) control over some decentral cogeneration capacity. Figure 1 shows the shares of the larger players in total production capacity (including decentral capacity) in the Netherlands.

In Belgium, total installed capacity amounted to 15.5 GW in 2001. A large fraction (5.7 GW, and 58% of total production) consists of nuclear generation. This can be concluded from Figure 1 in which the fuel mix of the Belgian and Dutch production park is shown. The remaining capacity in Belgium is mainly gas and coal fired, as well as 1,164 MW of pumped hydro at the Coo station covered by the category ‘other’. Electrabel also operates some high-

---

3 CBS.
4 EPZ is in fact a joint venture with Delta. We assume operational control is exercised by Essent.
5 Assuming the acquisition by Nuon of Reliant’s Dutch production assets to be completed.
cost oil/diesel units. The marginal cost curve of Belgian production is for low loads quite low at about 23 euro/MWh, but the marginal system price is set by more expensive gas fired units at peak loads\textsuperscript{8}. Belgian marginal costs in 2001 were estimated to be on average 3 euro/MWh below Dutch marginal costs for all but a small number of hours per year.

**Figure 1 Share in total production capacity by producer for different markets (including decentral capacity)\textsuperscript{9}**

Compared to the Dutch generation park, Belgian generation has relatively few flexible units, and has a small reserve margin. Considering the peak demand of Belgium in 2001, amounting to 13 GW\textsuperscript{10}, and the total production capacity of 15.5 GW the reserve margin in Belgium is around 19%. In the Netherlands (based on the numbers mentioned above) the reserve margin was around 43%.

Electrabel operates 13.4 GW of Belgian capacity\textsuperscript{11}. As illustrated in Figure 1 this corresponds to 86% of total production capacity. SPE is second largest and operates some 1.3 GW; 8% of total capacity. Until the end of 2002, Electrabel and SPE participated in the joint venture

\textsuperscript{8} Source: The Brattle Group.

\textsuperscript{9} Source: ECN, www.energie.nl.

\textsuperscript{10} Prospex, European Power Trading 2002.

\textsuperscript{11} Electrabel annual report 2001
CPTE\textsuperscript{12} that co-ordinated their overall production covering 98% of total production in Belgium.\textsuperscript{13} Autoproducers account for the remaining several hundred MW.

For the Benelux, Electrabel’s market share in capacity adds up to slightly over 50% of installed capacity. This is illustrated in Figure 1 above.

**Figure 1 Fuel mix of the production park in Belgium and the Netherlands\textsuperscript{14}**

![Fuel mix of the production park in Belgium and the Netherlands](image)

*Imports/exports*

The Dutch electricity network is interconnected with Germany and Belgium, Belgium with the Netherlands and France, as shown in Figure 2. In 2001, the Netherlands was a large importer from Germany (over 16 TWh net). Total available transfer capacity on this interconnector is roughly 2,200 MW, most of which is allocated by auctioning. The line is normally congested during most of the day-time, with interconnector prices reasonably in line with the Dutch-German market differential.

French-Belgian capacity is also used for imports most of the time, with total net imports of 11.4 TWh in 2001. Capacity for imports on this line is normally around 1,500 – 2,000 MW\textsuperscript{15},

\textsuperscript{12} In July 2003 SPE and Electrabel have officially decided to end their cooperation in CPTE. SPE confirmed that the CPTE has been dissolved retroactively as of 1 January 2003.

\textsuperscript{13} CREG annual report 2002

\textsuperscript{14} Source: The Brattle Group.

\textsuperscript{15} based on nominations published by RTE
which implies that this connection is congested most of the time. Capacity is allocated on a first-come-first-serve basis.

Figure 2 Schematic picture of cross-border transfer capacities

Within Benelux, the Dutch and Belgian markets are connected by a link, that has a normal available transfer capacity of about 1,170 MW, for flows in both directions. Most import capacity is awarded via auctions for capacity. In 2001 transfers from Belgium to the Netherlands were, at 4.5 TWh, slightly larger than trade in the opposite direction, 3.5 TWh. In the twelve months from September 2002 through August 2003, Belgian-Dutch flows already amounted to 6.9 TWh, with opposite flows of 2.7 TWh, suggesting a further increase of net flows into the Netherlands.

Interconnector prices between Belgium and the Netherlands
Whereas German-Dutch (day auction) prices are positive during most of the day-time, reflecting congestion of the interconnector, Belgian-Dutch capacity is sold for very low prices most of the time. Table 1 below gives for 2002 the percentage of time when hourly prices were positive, respectively larger than 1 Eur/MW, and the maximum price that occurred.

<table>
<thead>
<tr>
<th>Table 1 Price information on the interconnector between Belgium and the Netherlands for 2002¹⁶</th>
</tr>
</thead>
<tbody>
<tr>
<td>Belgium to Netherlands</td>
</tr>
<tr>
<td></td>
</tr>
<tr>
<td></td>
</tr>
</tbody>
</table>

¹⁶ information from TSO-auction, at www.tso-auction.nl
Besides looking at the interconnector prices, we can also analyse congestion directly by looking at nominations on the border (in both directions) and comparing them to available capacity. Elia publishes data on available capacity and nominations, which we compared for the period September 2002 through August 2003.\(^{17}\) For flows from Belgium to the Netherlands, nominations where closer than 100 MW to available capacity in only 10% of the time, while for flows in the other direction, this only occurred in 0.5% of all hours. We can conclude that capacity in either direction is hardly ever fully used.

**Balancing regimes**

In the Netherlands, TenneT is responsible for system balancing. The mechanism is centred around Program Responsible Parties (PRPs) who are required to submit balanced E-programmes, which guarantees a forecasted balanced system. In real time, possible imbalance is measured via involuntary exchanges over the interconnectors. For each quarter of an hour (Program Time Unit, or PTU), TenneT organises an auction, where parties (mainly generators) offer increments or decrements in power dispatched. Net realised imbalance is resolved against a uniform price (one for increments, one for decrements), and PRPs responsible for the imbalance pay or receive the imbalance price depending on whether their individual imbalance increased or decreased aggregate system imbalance.\(^{18}\) All generators owning units larger than 60 MW are obliged to bid in this market, contributing to the bid ladder for each PTU. To ensure sufficient availability of balancing bids (in particular, bids for regulating power, which consists of synchronised generation that can be ramped up or down at short notice), TenneT tenders among generators for capacity dedicated to this market.

In Belgium, the balancing mechanism\(^ {19}\) also consists of a system of Access Responsible Parties (ARPs), who submit quarter-hourly balanced schedules of electricity consumption and production. Here the mechanism for resolving imbalance is different. Imbalance charges are not determined by a market mechanism but calculated with a formula. This formula relates imbalance prices to the realised day-ahead prices of APX and Powernext. The formula differs by time of day, time of year and with the size of the imbalance. Imbalance charges are capped at a certain (varying) maximum price. The exact formulae are published on the website of Elia (www.elia.be).

As an example Table 2 shows the formulae that apply to imbalances below a certain threshold $T$ during the winter months. The table illustrates that the formula differs by time period and whether the imbalance is negative (injection is less than off-take) or positive. It also indicates that the charges depend on the realised APX-prices (‘APX’) and are limited to a maximum tariff. For example, for negative imbalances during the day period this cap amounts to 60 Eur/MWh. For imbalances above a threshold $T$ another set of formulae applies, leading to higher charges. For more detailed descriptions of the formulae we refer to www.elia.be.

\(^{17}\) information from Elia, at www.elia.be.

\(^{18}\) The situation is slightly more complex if in a given PTU imbalance occurred in both directions.

\(^{19}\) The calculation of imbalance prices is explained at http://www.elia.be/2index.asp?l=EN.
Table 2 Charges for imbalances below threshold T during winter months.

<table>
<thead>
<tr>
<th></th>
<th>Formulas for imbalance charges in Eur/MWh</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Day period (7.00 – 23.00)</td>
</tr>
<tr>
<td>Negative imbalance</td>
<td>Min (175% *APX, 60)</td>
</tr>
<tr>
<td>Positive imbalance</td>
<td>Min (25% *APX, 30)</td>
</tr>
</tbody>
</table>

Markets
Dutch electricity is traded before real time on various markets. Trade on the day-ahead market APX involves transactions for each hour of the following day. Typical volumes traded on the APX amount to 15-20% of Dutch electricity consumption, which was around 100 TWh in 2001. Part of the volume on the APX consists of power imported using interconnector capacity acquired in the daily auction, which is required to be traded via the APX (grid code). On the Over-The-Counter (OTC) forward market, standard contracts for electricity (base load and peak load) are traded, ranging from daily contracts to yearly contracts. Most of the OTC transactions are brokered. Another way of trading power is through bilateral contracts. Estimated total traded volume is around 1.8 times total Dutch consumption. \(^2^0\)

In Belgium no day-ahead market exists, but since March 2002 Electrabel publishes a Belgian Price Index, BPI, at which it offers to buy or sell 25 MW blocks of day-ahead baseload capacity against a fixed price, up to a limited volume (usually 100 MW). In practice this index follows closely the day-ahead price that appears in the Dutch OTC market. There is currently no other publicly quoted price (for e.g. OTC contracts). Belgium electricity consumption was 80 TWh in 2001.

Market opening
In the Netherlands, markets for larger and medium sized users are currently opened representing roughly 62% of the market. For small consumers (including households), the market for green electricity has been opened since mid 2001, and about 26% of households did indeed switch to green contracts. \(^2^1\) Full market opening for all consumers is planned for July 2004.

In the Belgian market the rate of market opening differs by region. In Flanders, complete opening took place in July 2003, while in Brussels and Wallonia only large consumers are free and others follow gradually in later years (2004-2007).

Supply
In Belgium, supply to largest consumers is dominated by Electrabel and its subsidiary Electrabel Customer Solutions (ECS). CREG reports that of the 130 customers directly connected to the Elia high voltage grid, in 2002 128 were supplied exclusively by Electrabel and SPE (19.5 TWh), while the remaining two were supplied only partly by these firms, partly by 4 other firms (2.0 TWh). The Flemish regulator VREG reports on market shares for

\(^2^0\) Estimate by Prospex, European Power Trading 2002.

\(^2^1\) Source: [www.greenprices.nl](http://www.greenprices.nl), May 2003.
all eligible customers. For the 4th quarter of 2002, Electrabel and ECS have a market share of 85% (or 75% in terms of number of customers), Luminus is second with 11% (21%). Smaller suppliers include RWE, Wattplus, E.On, Nuon.

Electrabel is the major supplier in those areas where it is shareholder in the distribution company, the so-called mixed distribution grids (16 companies of 33) representing over 50% (42 TWh) of total consumption. In 'pure' municipal distribution grids, Luminus is the larger supplier.
3 Proposed changes in market design

Two proposals for market integration of the Belgian and the Dutch market are currently under discussion. Both are described and commented on in the Brattle reports for APX, Elia and TenneT\textsuperscript{22}. One option is to introduce market coupling (also known as market splitting). The second option is a single price market with redispatch (also known as market with counter trade). The following two sections describe these two systems and discusses their (dis)advantages in relation to the current market situation.

3.1 Market coupling

In a market coupling (or market splitting) system, spot markets are introduced in both price regions. In the Netherlands this could be the APX, in Belgium a new spot market would have to be established (or a new market place, covering both countries, could be established, for example by an extension of the APX). Both markets would be cleared simultaneously. Interconnection capacity (either the entire capacity or only part of it) is effectively assigned to the independent market operator, who uses this capacity as part of the market clearing process. When the transmission capacity constraint is not binding, the market operator uses the capacity to ensure prices in both markets are equal, by increasing demand in the lower price region (by exporting) and decreasing it by the same amount (through the resulting imports) in the higher price region. In case the required amount of capacity exceeds available interconnection capacity, all capacity is used, and a price difference between both markets remains (the market splits). Effectively, the market operator acts as an efficient arbitrageur between both regions. Full market coupling would involve both the balancing and energy markets. Alternatives might involve just spot markets or just balancing markets. A benefit of coupling balancing markets would be that any barriers to competition arising from the current structure of the Belgian balancing services would be addressed right away. One natural progression might be to start with coupling the balancing markets and then extending to full market coupling.

A market coupling framework tackles three important limitations of the current Benelux market, potentially leading to more efficient cross-border trade and scope for price reductions.

- First, transmission capacity is used more efficiently than is currently the case, since both spot markets and the interconnection market will be cleared simultaneously. The market operator has full knowledge about market bids in both spot markets, and therefore can assign transmission capacity to its highest price use. This is in contrast to the present situation, where market participants bid for transmission capacity before the hourly spot market has cleared, so that they have to estimate market prices in advance, and additionally they are not certain that they will acquire the required energy in both markets.
- Secondly, in the current auction, offsetting flows across the interconnector are not netted, reducing potential for arbitrage. A market coupling framework on the other hand is theoretically equivalent to a situation with netting and efficient arbitrage.

A third current limitation of the Benelux market is that hourly markets in Belgium do not yet exist. Market parties do not have access to hourly price information, and a market for trade in power does not exist, which makes use of interconnection capacity even more inefficient. The market coupling proposal by APX involves the creation of an exchange in Belgium (the “BPX”) where auctions for hourly day-ahead electricity will be held. This will increase the price transparency required for efficient use of interconnection capacity. If market coupling between balancing markets is considered, this would require the establishment of a transparent market for balancing power in Belgium.

In general the introduction of market coupling can increase the efficiency of power generation and trading. In an environment where generator market power plays a role, well functioning market coupling will in most cases also mitigate the effects of market power, and increase social surplus. The reason is that under market coupling, generators face the combined residual demand of both markets, allowing for the supply of competing generators. If the interconnector clears before the spot markets open, generators face the less elastic residual demand in their own market as trade is no longer price sensitive. In the current situation, with extreme market concentration in Belgium, there are however three reasons for studying the effects of market coupling in more detail:

1. In a successful implementation of market coupling, total welfare loss aggregated over the Benelux will decrease. One may expect nevertheless that this decrease in market power may occur primarily in Belgium, possibly at the expense of increased prices in the Netherlands. Dutch consumers may therefore turn out to finance the benefits for the Belgian consumers.
   It is worth noting that Brattle, in their report\(^\text{23}\) also comment on the market power aspects of market coupling. They remark that market coupling will not worsen the market power situation of Electrabel in the Netherlands, since prices will diverge to the same extent as currently when the interconnector constraint is binding. We believe the situation differs when market coupling is in place. The allocation mechanism of interconnector capacity will be different: market coupling introduces netting and full arbitrage across the border, leading, on aggregate, to more efficient trade and increased price elasticity, impacting prices in both regions.

2. Successful market coupling requires well functioning power markets in both countries. The Belgian market at this moment lacks a power exchange and a market for balancing power. Due to the scarcity of suppliers in Belgium it is questionable whether a newly created BPX will provide prices that are good indications of Belgian wholesale prices. One should therefore investigate the scope and incentive for the dominant party in Belgium to manipulate prices at the BPX.

3. A third effect of market coupling will be the reduction of entry barriers for Dutch suppliers to the Belgian market. The establishment of an hourly market in Belgium will remove the need to find individual customers in Belgium, and delivery to this market does not expose firms to imbalances. It is therefore possible that market coupling will increase Dutch exposure to exercise of market power in Belgium, increasing prices in the Netherlands. We study the quantitative effects of market coupling later in chapter 6.

3.2 Single Price Market

The second alternative discussed in the Brattle study is the transformation of the Benelux into a single price region. Brattle refers to this system as the “Single Product” mechanism. We will refer to it as a ‘single price market’. In this setting, there would never be differences in market prices in Belgium and the Netherlands. The interconnector is viewed as equivalent to any other part of the domestic grids. Flow constraints on these lines would have to be solved by the system operator(s) by paying one or several generators to redispatch, i.e. increase production on one side of the constraint, and decrease on the other side.

Single pricing with redispatch does not provide locational signals to generators (or, more precisely, to those generators not participating in the market for redispatch), indicating the effects of physical constraints in the grid. Hence, to the extent that physical capacity of transmission lines is constrained, dispatch of generation in such markets is likely to be inefficient. On the longer run, also efficient investment in generation capacity is impeded. The costs of this inefficiency turn up in the costs of redispatch, which are socialised in the transmission tariffs. In markets with market power, the failure to internalise the costs of congestion makes the system vulnerable to manipulation. Dominant players could deliberately induce congestion by setting high bids, creating large flows on the interconnector towards this high priced market. In an unconstrained situation the high bids would not be accepted, but when flows are large enough the interconnector will be constrained. The dominant player will be invoked in the redispatching procedure and he will receive his high bids.

For suppliers of electricity, the advantage of a single price market would be the elimination of any transaction costs or market barriers between the two countries: suppliers could deliver power to any customer regardless of location, without being exposed to additional price risk associated with interconnector transmission constraints, and without having to participate in either interconnection auction or external power exchange. These advantages for suppliers come at the expense of the system operator(s) who are responsible for redispatching to ensure internal transmission limits are not violated.

On the issue of market power, concerns for introducing a single price market might firstly be the same as in the case of market coupling. While single price market could dilute concentration in the joint market, elimination of barriers to enter the Belgian market may well increase prices for the Dutch market. In addition the danger of redispatch gaming may seriously enlarge the scope for market power effects.
4 Analysing the current market situation

Our aim is to investigate potential effects of market power on the introduction of market coupling or a single price market in a Benelux market. In order to evaluate how the situation may change when such a reform is carried through, it is essential to understand the underlying reasons for the current market situation regarding market prices and the current interactions between the two markets.

We showed (see also Table 1) that the interconnector capacity between the Netherlands and Belgium is hardly ever fully used. The implication would seem to be that in virtually all hours, available transfer capacity is sufficient for prices to equilibrate between both countries.

We analyse the situation in some more detail in appendix C. We see that on the one hand marginal cost data suggest that prices in Belgium should be similar to, or lower than prices in the Netherlands (except possibly in the peaks). The publication by Electrabel of its index also suggests wholesale prices in the Netherlands and Belgium are equal most of the time. The Belgian wholesale market however is not at all liquid, and it seems that the index is actually set according to Dutch day-ahead OTC prices. On the other hand, there seems to be a large mark-up to end-user prices in Belgium (except for the largest users), as evidenced by Table 3.

Table 3 End-user prices for electricity in Belgium and the Netherlands in 2000 based on Eurostat data

<table>
<thead>
<tr>
<th></th>
<th>Belgium (Eurct/kWh)</th>
<th>Netherlands (Eurct/kWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Industrial, 10 GWh/year</td>
<td>6.73</td>
<td>5.90 (^1)</td>
</tr>
<tr>
<td>Industrial, 2 GWh/year</td>
<td>7.34</td>
<td>5.02</td>
</tr>
<tr>
<td>Business, 50 MWh/year</td>
<td>14.30</td>
<td>8.32</td>
</tr>
<tr>
<td>Domestic, 7.5 MWh/year</td>
<td>10.77</td>
<td>8.73</td>
</tr>
<tr>
<td>Domestic, 3.5 MWh/year</td>
<td>11.71</td>
<td>9.41</td>
</tr>
<tr>
<td>Domestic, 1.2 MWh/year</td>
<td>15.20</td>
<td>11.64</td>
</tr>
</tbody>
</table>

Note 1: price for July 1999  
Source: Oxera report for Commission

It is therefore likely that the market price for the bulk of electricity in Belgium, deduced from the end-user tariffs, is higher than published wholesale prices suggest.

We evaluated the scope for price increases using the electricity-pricing model COMPETES by ECN (described in appendix A). Under the assumption that all consumers in Belgium have become eligible, strategic modelling demonstrates there is substantial scope for raising market prices in Belgium above Dutch levels. Market power in Belgium would make it possible to raise prices (or decrease output) in the Belgian market. In the absence of barriers to supply this would trigger Dutch exports towards Belgium, in some demand conditions congesting the interconnector.

An alternative explanation for observed high end-user prices in Belgium may be high grid charges instead of high wholesale prices. A player that has a stake in grid companies as well
as production may be able to use its position in transmission and distribution to deter entry by cross subsidisation between energy and network charges.

If indeed effective price levels implied by end-user tariffs in Belgium are higher than Dutch wholesale levels, one should wonder about the limited flow of power from the Netherlands to Belgium. We can identify several potential barriers for Dutch suppliers to enter the Belgian market:

a) The structure of balancing charges in Belgium: in order to enter the end user market, suppliers need to offer energy profiles to customers, while only hourly constant blocks of electricity can be imported. The price for deviations from such block flows will be set by Belgian generation, and will be reflected in the balancing tariffs. If these charges are prohibitively large, the aggregate cost of supplying the market may be larger than the prices offered by Belgian generation, and exporting to Belgium is no longer profitable. In appendix D we have included an analysis of the balancing charges in Belgium and we conclude that these charges can indeed be quite significant. Since the cost of imbalances rises sharply with the degree of imbalance it may in particular impact new entrants, who experience smaller diversification due to portfolio effects.

b) The difficulty of finding customers for suppliers due to the absence of a liquid trading market. Suppliers have to find individual customers to deliver power, and cannot import power to sell into a liquid wholesale market.

c) The need for back-up power contracts: supplying power via the interconnector depends on obtaining sufficient interconnector capacity. To avoid non-delivery to customers, back-up facilities need to be contracted to provide power in case of interconnector outages.

d) The existence of an (inefficient) time lag between the auction of interconnection capacity and the APX clearance. Market parties have to purchase interconnection capacity before the APX market is settled.

One effect of market coupling will be the establishment of a wholesale market in Belgium. If this market is well functioning and sufficiently liquid, it will remove several of the barriers mentioned above. Additionally, a system of market integration will also remove the barrier of inefficient co-ordination of the interconnection auction and to a certain extent the need for back-up power. One may anticipate that market coupling increases cross border arbitrage, potentially increasing Dutch exports towards Belgium.
5 Effects of future developments

In the (near) future, the current market situation may alter as a consequence of various developments that are independent of the present discussion on Benelux market architecture. These exogenous developments should also be taken into consideration when discussing possible forms of market integration as they may influence the optimal decision. Relevant developments are:

- Opening of the Belgian retail markets;
- Introduction of an (EU) emission trading system;
- Proposed government intervention in Electrabel’s dominant position;
- Nuclear decommissioning in Belgium;
- The requirement to implement Electricity Regulation (EC) 1228/2003 by 1 July 2004.

We will briefly discuss some potential effects of these developments.

Further opening of Belgian market
As explained the Flemish retail market was opened on 1 July 2003; the Walloon and Brussels markets will follow later. As noted in the previous chapter, Belgian retail market prices are substantially above Dutch retail prices, and it is conceivable that the opening of this market may provoke more substantial sales of Dutch supply companies to Belgium. The balancing risks of supplying to low voltage consumers is lower than for individual high voltage consumers, as these customers are not individually metered on an hourly basis. Rather their individual loads are calculated from aggregate loads using fixed profiles. This reduces the imbalance risks for these clients. As a result one might expect more intense competition for interconnector capacity from the Netherlands to Belgium, while competition among supply companies may provide better insight in actual Belgian energy prices.

Emission trading system
The effect of the introduction of a European emission trading system will impact the merit order of generation techniques. Apart from a general rise in generation costs, an effect could be the reversal of the roles of gas and coal, with coal becoming the more expensive fuel (depending on the size of the taxation). While in Belgium and the Netherlands, coal represents a relatively modest share of total generation (about 13% and 20% respectively of total production in each country), the effect will probably be the largest in Germany. It is expected that Germany will become a net importer from the Netherlands. This will impact the marginal generation costs in the Benelux, effectively increasing demand by over 4,000 MW in the peaks (through reversal of interconnection flows), and driving the system to peak production more often.

Reduction of market concentration
As to the third point, recently the Belgian competition authorities have investigated the proposed take-over of various Belgian supply companies by Electrabel Customer Solutions. Discussion on mitigating measures to be enforced included the proposal of Electrabel divesting part of its capacity in Belgium in the form of auctioning virtual power plants. The Belgian government asked CREG for advice on the amount of capacity to be auctioned; Electrabel itself, meanwhile, offered to auction 10% of its capacity. A study for the
Competition Council suggested that the required capacity should be much larger, between 2 and 5.6 GW. In the final decision, the Competition Council decided that 1,200 MW (or only 9% of Electrabel’s total capacity) should be auctioned. The duration of the virtual power contracts will be between 3 months and 3 years, and auctions will take place until 2008. It should be noted that short duration virtual power plants have typically less effect on market power than longer term contracts or complete divestments. Apart from this measure, the government also announced to review the long-term contracts on the Belgian-French border. Given the stake of Belgian heavy industry in these cheap imports of French power, it remains to be seen whether any intervention in these contracts will result. If such measures are taken, they will evidently impact the analysis of Electrabel’s dominant position; the magnitude of the impact can only be estimated on the basis of the precise conditions, however.

Decommissioning nuclear generation
The Belgian government’s commitment to gradual decommissioning of nuclear generation may lead to a further shortage of generation in Belgium, if not compensated by substantial investment in thermal capacity and increased investment in renewables. A situation of capacity shortage in the Benelux will increase market prices and due to a change in the production portfolios marginal costs in Belgium could rise above Dutch levels.

The impact of Electricity Regulation (EC) 1228/2003
Article 6 of the Electricity Regulation 1228/2003 (Official Journal of the European Union, 15.7.2003 L176/1-/10) sets detailed rules for congestion management, which must include netting ‘as far as technically possible’ (Art 6(5)). Article 6(1) requires that all cross-border capacity should be made available by market mechanisms, and this will affect trade between Belgium and France. Together these developments are likely to precipitate market opening to some extent within the next year in any case.

24 Platt’s EPD, 2 July 2003.
6 Market power in the presence of transmission congestion

Current market power concerns are:
- The large market share of Electrabel in Belgium and in the Benelux as a whole would allow the firm to influence market prices in both countries. Both market coupling and introduction of a single price region would increase the effect on the Netherlands.
- The threat of regulatory intervention might currently restrain prices in Belgium; a perceived reduction in market share as a consequence of integration might decrease regulatory pressure.
- A single price framework would result in inefficient dispatch and increase scope for manipulation.
- The ownership structure of Elia creates concern for generator influence on transmission system operation.

6.1 Cournot analysis of various scenarios

We have employed ECN’s strategic model COMPETES to obtain insight in the strategic incentives for market parties under the current situation, and see how behaviour of players changes as various changes in design are adopted. The model is a Cournot model, a type of model that has often been used in analyses of market power in electricity markets. Different scenarios are established and simulated for which the description and results are discussed in detail in appendix A. The scenarios try on the one hand to capture the effect of design parameters, such as caps on import or export flows, adoption of market coupling mechanisms, or creation of a single price market. Secondly we have attempted to incorporate current market effects, such as the current difficulty of penetration of the Belgian market due to potential entry barriers, the absence of market places, or costs of balancing. While practical behaviour and market outcomes may differ from the outcomes of these analyses, for instance due to factors that are not incorporated into the model such as the threat of regulatory intervention, they do give insight in the scope of potential market power.

From the model results we conclude that when market power is fully exercised in the current Belgian market it can significantly raise Belgian prices above marginal costs. The extent to which Dutch prices are affected depends on the level of interconnector flows. If Belgium is relatively inaccessible to Dutch players, the impact of market power on Dutch prices is less severe than when the Belgian market opens up. If Belgian market power succeeds in driving up prices in Belgium, Dutch prices will react to this to the extent that this will trigger additional cross-border trade. If exports towards Belgium are impeded, the aggregate effect on the Dutch market will be lower.

According to the modelling results market coupling is an efficient way of arbitraging prices between the two countries, and decreases the aggregate market power of the dominant Belgian player. This however happens at the expense of Dutch consumers, who partly offset the consumer gains in the Belgian market. Similarly, a single price market lowers Belgian prices at the expense of Dutch prices. Thus, according to the game-theoretic analysis, in both proposed market reforms (market coupling and single price market) prices in Belgium and the Netherlands converge through a decrease in the Belgian price and an increase in Dutch prices.
The effect of the single price market is however underestimated since the costs of redispatching are ignored.

In Figure 3 below we graphically present the model results. The various scenarios represent different developments in cross-border trade. The most important differences between the scenarios are indicated by the arrows. The scenario ‘Current Situation’ represents the current market design in which barriers, for Dutch players to export to Belgium, increase the scope for market power in Belgium. In the ‘Market Opening’ scenario increased entrance of Dutch suppliers to the Belgian market is assumed which lowers prices in Belgium and increases Dutch prices. The last two scenarios at the right represent the two options under investigation, in which most current existing barriers to an integrated Benelux market are removed; netting of the interconnector capacity is assumed combined with effective arbitrage between the two markets. The ‘Market coupling’ scenario leads to a convergence of prices, similarly as the creation of a single price market. In the latter case the costs of redispatching would have to be added to the prices shown.

**Figure 3 Average market prices in Belgium and the Netherlands for 4 different scenarios**

Source: ECN, modelling results (see also appendix A)

### 6.2 Other market power issues

In this section we consider various market power issues that are not captured by the Cournot model used in the above analysis but can be relevant in the discussion on market integration. Some other technical issues are discussed in appendix B.
**Regulatory threat on Electrabel**

One possible explanation for Belgian power prices not exceeding Dutch prices by a large amount may be the threat of regulatory intervention. Electrabel might have the power to increase prices in its home market, but refrain from doing so for fear of action by regulatory or competition authorities on the basis of abuse of dominance. In this situation, the result of market integration may be a reduced pressure from regulatory authorities due to a perceived reduction of market share by Electrabel in the relevant market, now deemed to be the Benelux. In this case the relaxation of such constraints on Electrabel’s bidding might by itself constitute a cause for increased prices.

**Redispatching costs**

In the single price scenario (see appendix A), it is assumed that the interconnection capacity is never binding, and both countries have the same prices. In reality there are constraints on flows between the Netherlands and Belgium. Total capacity may be larger than current available transfer capacity for the auction of 1,150 MW since the TSOs may jointly have better insight and control over generation allowing less conservative bounds. The Brattle Group estimates this could increase the available maximum capacity for cross-border trade from 1,150 MW to 1,700 MW. If generation and load patterns in the Benelux are such that this bound would be exceeded, the TSO will have to take measures to alleviate the constraints. This will be achieved by redispatching generation, i.e. paying generators on one side of the constraint for reducing their scheduled production, and on the other side for increasing production.

Such redispatching is however vulnerable to gaming. Generators may deliberately schedule generation to cause congestion, in order to collect the payments for dispatching up or down. Incentives for collecting these redispatch payments can thus affect bidding behaviour of companies on the exchange and/or balancing markets.

Even in the absence of deliberate manipulation of redispatching, there will be additional costs for required redispatch in the single price model. From the model calculation for the single price scenario described in appendix A, we can derive the total net interconnection flow for each simulation period. For each period these net flows are shown in Figure 4 below. The figure illustrates that for several periods we may expect the net flow to exceed the maximum available interconnector capacity, indicating that redispatching will be necessary.

We also see that net flows are directed mainly from Belgium to the Netherlands, except in winter (super)peak periods when Belgian demand is high and approaches national capacity. Flows are largest in summer periods, when Belgian load is low, and a relatively large proportion of Dutch generation is on maintenance, or has lower capacity due to reduced heating requirements. Flows exceed the current 1,150 MW capacity limit in summer off-peak, middle and peak periods, a total of roughly 2,150 hours per year or 24% of the time. Flows also exceed the 1,700 MW limit, which is estimated by the Brattle Group as the maximum capacity that can be made available in a single price market, during a third of these hours, or

---

25 Strategies to create congestion and receive revenues to subsequently reduce congestion were employed for instance by Enron in the Californian market, as documented for example in “Analysis of Trading and Scheduling Strategies Described in Enron Memos”, by California ISO (2002).
8% of the time. Dispatching payments would have to be made in these hours to Belgian units to back down, and Dutch, more expensive units, to ramp up.

Figure 4 Total net flow on the interconnection from Belgium to the Netherlands for each simulated time period

Source: ECN, modelling results

We may conclude that the single price model gives no transparent signals to the market about congestion. Secondly, it may provoke gaming by generators on the wholesale market in order to receive additional payments in redispatching process. Both consequences are not desirable and create market inefficiencies.

Electrabel’s stake in Elia
The Belgian system operator Elia is partly owned (70%) by CPTE, which is in its part a joint venture of Electrabel (91.5%) and SPE. CPTE’s stake is to be reduced, by floatation of 40% of shares. Independent operation of Elia is supervised by its board of directors, and ensured by provisions in Belgian electricity law. Three of the twelve members of the board of Elia are representatives of Electrabel.

Despite the administrative measures taken to ensure independence of Elia, the participation of Belgian production in the ownership structure of TSO gives grounds for concern. Decisions on investment and maintenance of infrastructure have implications for generation, and generators may therefore try to influence such decisions. Of particular concern in the present context would be the availability of interconnector capacity on both borders of Belgium, which in the first place determines the competitive position of generation in Belgium and secondly determines the possible revenues that can be attained from redispatching. On the
system operation side, there should be special concern for non-discrimination in the balancing mechanism, and other aspects that may involve barriers for competing suppliers.

**Conclusion**

Based on the model analysis we conclude that in the presence of market power in Belgium Dutch power prices may further rise as a consequence of market integration, whether by market coupling or if a single price region is created. However, as mentioned earlier, the single price market disregards physical transmission limitations, leads to inefficient dispatch and provokes gaming by generators, and should hence be avoided. On the other hand, to capture the benefits of market coupling, it should be accompanied by additional measures. In the next chapter we elaborate on such measures.
7 Conclusions: possible mitigation measures

Although integration via market coupling is capable of increasing efficiency, would be beneficial for consumers in the Benelux and is a step in the direction of a more fully integrated European market, the analysis presented in this document indicates that there is significant concern for the adverse effects of generator market power on Dutch consumers. Steps towards market coupling should therefore be accompanied by measures to reduce these concerns.

At the heart of the market power problems lies the dominance of Electrabel in the Benelux. It seems that without any structural reforms, some of the adverse effects of market power cannot be avoided, and the Netherlands would, under the proposed changes in market design, suffer higher prices. Some of these measures will directly involve Electrabel, while others are aimed at increasing competition in the Benelux market more generally.

- Structural measures to reduce Electrabel dominance could be, for instance, the auctioning of sufficient virtual capacity, which has already been under discussion in Belgium as a result of the Competition Council investigation. The extent of required virtual divestments would have to be investigated by performing various market simulations (including those of the type used in this document). In any event, careful attention will have to be paid not only to the size, but also to the marginal cost structure (strike prices) of the auctioned capacity, and to the duration of the virtual capacity (since shorter duration will increase the incentive to drive up spot prices in order to increase auction results for the next auction). To be effective, holders of auctioned capacity would need transparent and non-discriminatory access to balancing services within Belgium. These may be more readily supplied if the balancing markets are coupled.

- An alternative measure would be the requirement that Electrabel offer a certain quantity of long-term (several years) contracts to the market at regulated prices (over and above the amounts contracted to eligible customers). Long-term contracts reduce the incentives of parties to exercise market power, and the requirement to offer contracts at regulated prices means that Electrabel cannot exercise its market power in the contract market. Again, this would require access to competitive local balancing services to be effective.

- Thirdly, in case of joint bidding on an integrated market, bids by Electrabel might be subjected to regulatory limits. Electrabel might for example be allowed to participate in a coupled balancing market with bids that are related to marginal production costs, to prevent it from raising prices above competitive costs, perhaps until such time as its market share falls below some specified limit.

- Furthermore, competition in Belgium may be increased by auctioning French interconnection capacity and abandoning long-term contracts on this border. The holders of these rights would be entitled to receive the revenue from the auction, so there would be no claim of unfair expropriation. The current holders would be eligible to bid for shorter-term contracts providing the auction were open, transparent and non-discriminatory, so that other participants would be able to compete for these contracts. In
addition, Benelux competition may be increased by improving the connection with Germany (in the form of market coupling or co-ordinated congestion management, including netting). As mentioned above, Article 6 of the Electricity Regulation 1228/2003 (Official Journal of the European Union, 15.7.2003 L176/1-/10) sets detailed rules for congestion management, which must include netting ‘as far as technically possible’ (Art 6(5)), and this regulation comes into effect on July 1, 2004.

- Fifth, one would wish to avoid the generator having influence over the grid operator Elia. This means in particular that representatives of Electrabel (or any other generator) should be excluded from the board of Elia. The new Directive (2003/54/EC) lays down clear rules for effective unbundling.

- Finally, it is imperative that on an integrated market, information about market behaviour in both regions be accessible for monitoring and surveillance, and that transparency be harmonised across all markets. Regulators in both regions should be enabled to freely exchange information and both should have access to all dispatch information. In addition, further information disclosure requirements may be imposed on the dominant player. The rules on information disclosure on transmission operators are associated with tough penalties for violation set out in Article 12 of the Regulation 1228/2003 (not exceeding 1% of total turnover), and these might include information on generator actions that influence cross-border flows. In practice almost all such actions will have an impact on cross-border flows and would be subject to this disclosure rule.
Appendix A: Modelling market power

The model
The results discussed in chapter 6 are based on analysis performed with ECN’s strategic model COMPETES. This model describes the generation systems, including marginal costs and ownership structures, of the Benelux, Germany and France.

The transmission system is modelled as the four different regions, connected with interconnectors of limited capacity. Interconnector capacity is assumed to be auctioned on each border, i.e. we ignore the fact that on some borders, such as the French-Belgian border, another allocation mechanism is used which gives Electrabel larger control over flows across this border. The cross-border capacities are chosen to reflect current actual available transfer capacities.

Figure 5 Schematic picture of cross-border transfer capacities

In each region, there is a native demand for electricity. This demand is based on current consumption in the countries. Customers are, however, price sensitive: if prices rise customers reduce their demand. The model considers a linear price-demand relationship, with a chosen elasticity value, if price equals marginal costs, of 0.4 (and therefore higher when market power is exercised). In reality, in the short term demand response is probably substantially smaller. On longer time scales the effective elasticity facing existing generators will be higher than in the short run, as new firms are encouraged to enter in response to higher prices.

The model considers 12 different levels of demand, corresponding to generic conditions in superpeak, peak, shoulder and off-peak hours in summer, winter and autumn/spring months. The model is independently solved for each of these time periods, so that dynamic adjustment costs are neglected in the game-theoretic analysis.

The model now calculates optimal behaviour for all generators, who simultaneously attempt to maximise their profits. All generators choose how much capacity to offer to the various

---

26 Marginal costs consist of fuel and operating costs.
markets taking the capacity choices of other players as given (i.e. this is a Cournot game, with as strategic variables each firm’s supply to each country) and acting as price takers on the interconnection auction (but see Appendix B which considers alternative assumptions). Market prices are calculated by equating demand to supply in each region. The model outcome thus consists of quantities of power offered by generators to the various regional markets, prices for electricity in each market and prices for interconnection capacity on the various borders.

Description of the scenarios

Scenario 1: Current situation
We start by attempting to model the current situation. Firms in Belgium can produce power for their own market or export to other countries (Netherlands, Germany or France). As mentioned, we assume all transmission capacity to be auctioned, i.e. we ignore the precise allocation method on the French border. For transmission on the Dutch borders, however, we impose a cap of 400 MW: no firm can use more than 400 MW of import capacity on the combined German-Dutch and Belgian-Dutch borders. We assume French firms can sell to Belgium, and other countries as well (subject to securing transmission capacity); this is consistent with the observation that Belgium’s southern interconnection is fully used most of the time, and the claim that large Belgian industry have direct power contracts with French generation. For entry to the Belgian market via the northern (Dutch) border, however, we impose some restriction to reflect potential barriers to entry. We will assume that only a limited number of companies succeed in finding Belgian customers for their power, and restrict total imports into Belgium from this side to 400 MW. This equals more or less the average Dutch Belgian flow in 2002. We will relax this restriction in a later scenario. Electrabel’s units in the Netherlands have access to the remainder of capacity, up to the cap of 400 MW. Conforming to current practice, netting is not applied when determining the available interconnector capacity.

Scenario 2: Opening of the Flemish market
In our second scenario we assume that the market for small consumers in Belgium opens, (as is the case for Flanders since July 2003), and assume that this sufficiently reduces entry barriers for Dutch suppliers to make all NL-B capacity potentially available for Dutch sales to Belgium. Netting is not imposed and the cap of 400 MW per company is still applied.

Scenario 3: Market coupling
We now introduce market coupling between the Netherlands and Belgium. We assume complete coupling, i.e. all 1150 MW of capacity are assigned to the exchanges who arbitrage the markets. In this case, on this border no more cap is applicable. On the German border, the cap remains valid.

Scenario 4: Single price market
In the fifth scenario we study the effect of fully integrating the Benelux into a single price zone. For this we assume that the constraint on the interconnection does not restrain players any more: net flows exceeding transmission capacity would be dealt with by redispersching generation by the TSOs. We ignore potential effects of redispach gaming in this scenario.
Scenario 5: Market coupling also with Germany

For comparison, we include a scenario where market coupling not only involves the Netherlands and Belgium, but also Germany.

As mentioned, in all scenarios, we will assume Electrabel behaves as a Cournot player (effectively a monopolist in Belgium). If one believes that there are (regulatory) constraints on Electrabel, prices may evidently be lower. The simulations give a worst case scenario.

Model results of the scenarios

We now turn to the results of the various scenarios. The main components of the first, current situation scenario, are a limit of total exports from the Netherlands into Belgium to 400 MW (reflecting difficult access into that market), and a limit of 400 MW on import capacity for each individual player on the Dutch borders.

In all periods, it is profitable for Belgian firms to withhold capacity and raise prices in Belgium, so that these are higher than Dutch prices. Average prices in Belgium are 44.4 Eur/MWh, versus base load prices in the Netherlands of 33.3 Eur/MWh. Due to this large price difference, in all periods it is profitable for Dutch firms to sell as much as possible to Belgium, restricted to 400 MW by assumption. On the other hand, one finds as well imports into the Netherlands, equalling 400 MW. These originate from Electrabel, who has incentive to keep prices up in Belgium, but can sell spare capacity into the Netherlands, (this capacity presumably having lower marginal costs than Electrabel’s higher cost units in the Netherlands), or, sometimes, to Germany.

The prices for interconnection capacity between Belgium and the Netherlands are equal to zero in all cases, in spite of the price differences between the regions. This can be explained by the lack of players able to participate in the auction: on the Belgian side, only Electrabel can sell at a profit in the Netherlands, due to the fact that additional sales in Belgium would decrease its marginal revenues in Belgium below zero, while Dutch prices are still far above its marginal cost in Belgium. On the Dutch side, entry into the Belgian market is limited by entry barriers (such as the absence of a liquid wholesale market).

As indicated, limited access to Belgium is simulated by limiting the exports to 400 MW. To assess the impact of the amount of possible exports to Belgium, we compare with situations in which the access is further reduced to 200 MW and 0 MW respectively. The effect on prices is plotted in Figure 6. The prices shown in this graph are weighted average over the twelve different time periods (note that prices on the y-axis start at 30 Eur/MWh).

From this graph, one can verify that restriction of the export volumes to Belgium leads to lower prices in the Netherlands, and higher prices in Belgium.

We can also compare the results of scenario 1 with scenario 2, where we assume that opening of the Flemish market increases the accessibility of the Belgian market due to increased trading activity in Flanders. If we assume that all 1,150 MW of capacity will be available for exports into Belgium, we find that Dutch average prices increase substantially, to 34.5 Eur/MWh, while Belgian prices decline under the pressure of the extra imports, to 42.1
Eur/MWh. Furthermore, we now find positive interconnection prices for exports into Belgium, as expected.

**Figure 6 Average market prices under different levels of access to the Belgian market for Dutch suppliers**

![Figure 6](image)

*Source: ECN, modelling results from COMPETES*

Scenario 3 deals with market coupling, which facilitates cross border arbitrage even more. Market coupling in general decreases market power for all players. This gives rise to a result in which prices between the Netherlands and Belgium converge much more, to average levels of 36.7 and 37.1 Eur/MWh respectively. Unlike in the previous situations, we now find results where in some periods market prices are actually lower in Belgium (mainly in summer periods). In all other periods, the market couples and as a result prices are the same in both regions.

Finally we compare the results of scenario 4; the single price market. In this case we assume the interconnector constraint can be ignored. (We omit in this analysis the possible incentives for redispatch gaming. Comments on this follow below). In this market, by definition prices are equal. Electrabel market power is now most diluted by mixing with the Dutch system. The simulated average system price is 36.9 Eur/MWh. In this case, total interconnector flows between Belgium and the Netherlands exceed current available capacity in summer off-peak, peak and shoulder periods, signalling potential need for redispatch by the system operator. In all other periods, prices equal the results found in previous scenario 3 of market coupling.

We summarise the results for the different scenarios in the following graph. Note that the y-axis starts at 20 Eur/MWh.
We conclude with the results of the fifth hypothetical scenario where we include Germany in the market coupling mechanism. It might seem from the above results that market coupling will in general be beneficial to the higher price country, but a disadvantage to the lower priced region. This is not the case however. If Germany, where prices are lower than in either the Netherlands or Belgium, is coupled as well, all countries benefit from significantly lower prices. In both Belgium and the Netherlands, prices would drop below 30 Eur/MWh, in Germany the drop would be less pronounced. The introduction of market coupling implies netting. This increases the available interconnector capacity for cross-border trade and thereby the level of competition.

**Conclusions of scenario analysis**

We find that market power in Belgium currently is capable of significantly raising Belgian prices above marginal costs. The extent to which Dutch prices are affected depends on the level of interconnector flows. If Belgium is relatively inaccessible to Dutch players, the impact of Electrabel market power is less severe than when the Belgian market opens up.

Market coupling is an efficient way of arbitraging prices between the two countries, and decreases aggregate market power of Electrabel. This happens at the expense of Dutch consumers, however, who partly offset the gains in the Belgian market. Similarly, a single price market leading to complete convergence of both markets lowers Belgian prices at the expense of Dutch rates.
Appendix B: More detailed description of market power issues

This appendix gives a more detailed description of some parts of chapter 6, section 6.2.

Stackelberg effects

In the analysis presented in appendix A, the equilibrium outputs for all generators are computed on the assumption that all outputs by other generators are kept constant, and also that firms are price takers on transmission capacity (i.e. they ignore that changes in their output levels will affect interconnection prices). We saw that in the market coupling scenario, this leads to market coupling (absence of congestion) in most periods. In theory, a second, different equilibrium may exist as well. The Belgian incumbent anticipates that if it raises price above the Dutch market price, it will cause extra imports from the Netherlands, initially reducing its profitability. These imports will however be limited by the available interconnection capacity, and if the interconnector becomes congested, Electrabel will once more become the monopolist for residual Belgian demand. It is possible that charging the monopoly price on this reduced volume will lead to higher profits for the company.

The effect of this would be that in some situations prices in Belgium and the Netherlands may actually be higher than predicted by the simulations above, and that the market will decouple more frequently. This is more likely to occur in situations of high Belgian demand. It would, however, be more readily detected as the abusive exercise of dominance by a vigilant regulator or Competition Council and may therefore be unattractive.

Manipulation of the exchange

So far we assumed that after market coupling, the BPX exchange in Belgium would reflect market prices in Belgium. Given the scarcity of suppliers in Belgium, one might however be concerned that this market would be easily manipulated, so that the relation between exchange price and wholesale market prices might be disturbed.

First, there is scope for Electrabel to control price on the exchange. Electrabel will be the major supplier on the exchange. After market coupling, suppliers from the Netherlands, or indirectly, Germany, will not be direct suppliers into the BPX, since imports from this side into Belgium will be controlled by the market coupling mechanism. The main other contribution would be from imports from the southern border, but part of this capacity appears to be directly contracted by Belgian industry. Hence, by offering sufficiently large quantities of supplies at a desired price level, and if necessary participating as a large buyer on the demand side, Electrabel might set the price at any desired level. As argued above, it is possible that such price setting behaviour can currently be observed in the BPI published by Electrabel, which as demonstrated closely follows the Dutch OTC market.

Second, it should be assessed whether it would be profitable for Electrabel to set prices to levels that do not reflect actual price levels in the wholesale market. One may here distinguish two cases.

a. If prices are set below actual price levels (and below levels in the Netherlands), Electrabel may direct interconnection flows in the northern direction. In this way it may benefit from increased sales into the Netherlands. However, this situation is unlikely to be stable, as independent supply companies would increasingly source power from the BPX to supply
Belgian customers below current price levels, increasing the demand for Electrabel supplies to the BPX to maintain this level. Effectively therefore, such price differences between exchange and wholesale market can be arbitraged away.

b. If prices are set above actual wholesale price levels, this would trigger continuous decoupling, with congestion into Belgium. To maintain this price level, Electrabel would have to absorb the incoming flows from the Netherlands, paying the excess price difference (which would be a revenue for the transmission operator). The benefit of this strategy is however that the higher prices provide a barrier for non-asset-based suppliers to enter the Belgian market, as the market will be provided at the lower wholesale price levels. In this case, the price difference cannot be arbitraged by independent players (except by entry in generation). The gains for the incumbent are the larger market share, which should be weighed against the losses from the absorption of Dutch imports.

The fact that price differences between exchange and wholesale levels can only be arbitraged in one direction, therefore allows a strategy to sustain exchange prices above wholesale levels, and thus hampering competition in supplies in Belgium. The profitability of the strategy is related to the price difference between exchange and wholesale prices, and the extra revenues enjoyed by domination of the supply market,

\[ \text{Profit} = \text{extra mark-up} \times \text{load} - \text{interconnect capacity} \times \text{price difference} \]

This strategy would increase prices in both the Belgian and the Dutch market compared to the current scenario combined with retail market opening.
Appendix C: Comparison of electricity prices in Belgium and the Netherlands

Electricity prices in Belgium
To verify whether the lack of congestion between the Netherlands and Belgium is caused by the absence of price differences, we need independent evidence on electricity prices in Belgium. Since the wholesale market in Belgium is not well developed, determining the ‘market price’ in Belgium is not unambiguous, and in fact, through lack of arbitrage within Belgium, there may well be different prices for various groups of market participants. In this document we will use the term market price to indicate the effective commodity price that is implied by end user prices for the majority of end-users. We will try to gather information on this price by inspecting Electrabel’s quoted wholesale price, information on cost structures, end-user prices, information of price models and the Belgian balancing prices.

The Belgian Price Index
The only quoted price available in e.g. the European Power Daily is the price index BPI, quoted by Electrabel. This daily index consists of a “choice price” named by Electrabel at which it commits to either buy or sell base load power, in blocks of 25 MW, with a certain maximum (usually 100 MW). The Brattle Group compared this index to the APX base load prices and interconnector prices, and found that these prices did not relate to each other as expected. Arbitrage would suggest that interconnector capacity would on average be priced equal to the difference between market prices (possibly up to the CBT charge of 0.50 Eur/MWh for exports out of Belgium\(^{27}\)). In reality, such relations do not seem to hold. Suggestions for an explanation of this fact put forward by the Brattle Group are that not sufficient competition for exports from Belgium into the Netherlands might be present, keeping interconnector prices low even in case of positive price difference (similar to hypothesis 2 above); that Dutch generators find it difficult or costly to find consumers in Belgium (related to hypothesis 3 above); or that uncertainties due to the current timing of the various auctions (TSO and APX) may give rise to inefficient arbitrage.

A more likely explanation however is that the lack of arbitrage is due to choice of base load price in the Netherlands. Apart from the base load price generated by the 24 hourly auctions on the APX, also a day-ahead base load price is quoted in the Over-The-Counter trade. This price is the result of continuous trade in these standardised base load contracts. Although APX and OTC prices are on average similar, individual days may exhibit large price discrepancies between the two markets.

When comparing the Dutch OTC price with the Belgian index, a closer connection between these prices is found. Figure 8 shows a scatter diagram of BPI and Dutch OTC day-ahead prices, from the start of publication of the BPI until February 2003. Prices are corrected for base load day ahead interconnection prices, although these are generally zero or negligible. Clearly there is a close relation between both prices.

\(^{27}\) CBT = Cross Border Tariff. As from 1 January 2003 this tariff is lowered from 1 Eur/MWh to 0.5 Eur/MWh.
If we include the bid-ask spread for Dutch OTC contracts, we find that in 56% of all days the BPI is within this range, and for 71% of all cases, prices are within twice the spread.

Although possibly this indicates that there is good arbitrage between Belgian base load power prices and Dutch (OTC) day-ahead prices, it has to be borne in mind that the quoted price is not directly market based, but is determined by Electrabel. It is therefore conceivable that the BPI is in fact priced off the Dutch traded OTC base load price.

Some other indications of Belgian prices may be obtained, however. We will subsequently analyse evidence for prices based on computations of marginal production costs, on end-user price data, on prices following from strategic modelling, and on the charges for balancing power.

**Marginal costs**

Figure 9 below, by the Brattle Group, gives an indication of Belgian and German marginal production costs, compared to Dutch marginal costs.
Figure 9 marginal costs of power in Germany, Belgium and the Netherlands

![Graph showing marginal costs of power in Germany, Belgium, and the Netherlands.](image)

Source: The Brattle Group.

Although nuclear plants form a large part of the Belgian production park they do not generally set the margin. However, marginal production costs are in general somewhat lower in Belgium compared to the Netherlands.

Brattle also estimated the marginal system price for various parts of the day and various seasons in the Netherlands and Belgium based on least cost dispatch. In this analysis possible imports and exports between the two countries is taken into account. The estimated costs are shown in Table 4, and it shows that the price resulting from least cost dispatch in Belgium are on average 3 Eur/MWh lower than Dutch prices.

Table 4 marginal costs per season in Belgium and the Netherlands [Eur/MWh]

<table>
<thead>
<tr>
<th>Season</th>
<th>Belgium</th>
<th>Winter</th>
<th>Shoulder</th>
<th>Average</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Peak</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Peak</td>
<td>28.12</td>
<td>31.09</td>
<td>28.62</td>
<td>29.10</td>
</tr>
<tr>
<td></td>
<td>32.00</td>
<td>34.27</td>
<td>30.99</td>
<td>32.05</td>
</tr>
<tr>
<td><strong>Off-peak</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Off-peak</td>
<td>24.04</td>
<td>27.02</td>
<td>24.52</td>
<td>25.02</td>
</tr>
<tr>
<td></td>
<td>27.12</td>
<td>29.84</td>
<td>27.77</td>
<td>28.12</td>
</tr>
<tr>
<td><strong>Weekend</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Weekend</td>
<td>23.70</td>
<td>25.52</td>
<td>23.87</td>
<td>24.23</td>
</tr>
<tr>
<td></td>
<td>27.36</td>
<td>29.39</td>
<td>27.43</td>
<td>27.90</td>
</tr>
<tr>
<td><strong>Base load</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Base load</td>
<td>25.41</td>
<td>28.04</td>
<td>25.80</td>
<td>26.25</td>
</tr>
<tr>
<td></td>
<td>28.94</td>
<td>31.29</td>
<td>28.83</td>
<td>29.46</td>
</tr>
</tbody>
</table>

Source: The Brattle Group
**ECN competitive price simulations**

We also computed competitive prices for power production in Belgium (and the Netherlands) using ECN's model COMPETES of Northwest European electricity markets. We used the model to compute optimal dispatch for the Benelux, Germany and France, given marginal costs of the production parks in all countries, and interconnector constraints between the countries. This model gives different results than the Brattle Group model. Belgian and Dutch competitive price levels are estimated to be equal during most hours (i.e. the interconnector is not congested). In winter and shoulder peak and superpeak hours, Belgian prices are however estimated to be slightly higher than Dutch levels. Differences are presumably caused by differing assumptions for available interconnector capacity, and a focus on purely the central generation (Brattle) versus inclusion of decentral production (ECN).

**Table 5 Competitive prices in Belgium and the Netherlands [EUR/MWh]**

<table>
<thead>
<tr>
<th></th>
<th>Summer</th>
<th>Winter</th>
<th>Shoulder</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Superpeak</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Belgium</td>
<td>40.80</td>
<td>39.32</td>
<td>39.32</td>
</tr>
<tr>
<td>Netherlands</td>
<td>40.80</td>
<td>34.49</td>
<td>35.51</td>
</tr>
<tr>
<td><strong>Peak</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Belgium</td>
<td>32.32</td>
<td>39.32</td>
<td>34.24</td>
</tr>
<tr>
<td>Netherlands</td>
<td>32.32</td>
<td>31.56</td>
<td>32.32</td>
</tr>
<tr>
<td><strong>Middle</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Belgium</td>
<td>28.39</td>
<td>28.39</td>
<td>28.39</td>
</tr>
<tr>
<td>Netherlands</td>
<td>28.39</td>
<td>31.56</td>
<td>32.32</td>
</tr>
<tr>
<td><strong>off-peak</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Belgium</td>
<td>22.09</td>
<td>20.43</td>
<td>20.43</td>
</tr>
<tr>
<td>Netherlands</td>
<td>22.09</td>
<td>20.43</td>
<td>20.43</td>
</tr>
<tr>
<td><strong>base load</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Belgium</td>
<td>29.06</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Netherlands</td>
<td>27.96</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

*Source: ECN, modelling results using the electricity market model COMPETES.*

In the lower load hours, competitive interconnection usage is in the direction Belgium-Netherlands, whereas in the higher price hours, Belgium is a net importer from the Netherlands. In the hours of highest load, in winter and shoulder peaks, the interconnection capacity is congested (at 1150 MW), and prices in Belgium rise higher than Dutch prices. These results for (super)peak hours are in line with the observation that Belgian reserve margins are very low, so that Belgium relies on imports for the supply of peak power.

On the basis of marginal costs, one may conclude that competitive prices could be on average similar.

**End user prices**

To obtain insight in market prices, we may also compare end-user prices for Dutch and Belgian electricity consumers. These give an incomplete picture of wholesale prices, since they also include network charges and (energy) taxes. For large companies the charges for connection to the high voltage grid are known however, and therefore from price information for these end users, information about underlying commodity prices may be obtained. Energy Advice surveys the market for large users, and finds end user prices for large users (80 MW) as shown in Table 6. These industrial prices include all taxes except VAT, as industrial

---

28 Appendix A contains a short description of this model.
consumers are exempted from VAT. The table also shows the end-user prices for smaller industrial users (10 MW) and small businesses (500 kW).

Table 6 Electricity prices in Belgium and the Netherlands for different categories of end users for January 2003 [Eur/MWh]

<table>
<thead>
<tr>
<th></th>
<th>High</th>
<th>Low</th>
<th>Representative</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>500 kW</td>
<td>10 MW</td>
<td>80 MW</td>
</tr>
<tr>
<td>Belgium</td>
<td>92.5</td>
<td>67.2</td>
<td>51.3</td>
</tr>
<tr>
<td>Netherlands</td>
<td>75.2</td>
<td>61.1</td>
<td>55.8</td>
</tr>
<tr>
<td></td>
<td>500 kW</td>
<td>10 MW</td>
<td>80 MW</td>
</tr>
<tr>
<td>Belgium</td>
<td>68.4</td>
<td>43.2</td>
<td>36.4</td>
</tr>
<tr>
<td>Netherlands</td>
<td>59.3</td>
<td>43.4</td>
<td>37.6</td>
</tr>
<tr>
<td></td>
<td>500 kW</td>
<td>10 MW</td>
<td>80 MW</td>
</tr>
<tr>
<td>Belgium</td>
<td>82.3</td>
<td>56.8</td>
<td>41.9</td>
</tr>
<tr>
<td>Netherlands</td>
<td>67.0</td>
<td>53.7</td>
<td>46.9</td>
</tr>
</tbody>
</table>


Grid charges for large users were estimated by the Brattle Group as slightly higher in Belgium than in the Netherlands (6 Eur/MWh vs. 4 Eur/MWh), and taxes for Belgian users consist only of 21% VAT (as opposed to Dutch users who pay an additional energy tax). Judging from the prices shown in Table 6, base load contracts in Belgium should range around 36 Eur/MWh (41.9 minus 6 Eur/MWh), although lowest prices suggest somewhat lower base load energy price of around 30 Eur/MWh. Traditionally, large industry in Belgium is known to benefit from cheaper French power, via preferred import contracts on that border, which might give rise to these lower prices.

The data from Energy Advice indicate that for slightly smaller industrial users (10 MW), Belgian prices are slightly higher than Dutch prices, and for small businesses the differences are even larger. This suggests higher margins on these customers. This picture is confirmed by the data available in the EU study “Electricity liberalisation indicators in Europe”. Here Eurostat price data for various consumer groups are compared across European countries. In all cases, Belgian prices (excluding taxes) are among the highest in Europe, in general only to be exceeded by Italian prices. The price data for various consumer types for 2000 (the last available year in the report) are compared for Belgium and the Netherlands in the following table.

Table 7 End-user prices for electricity in Belgium and the Netherlands in 2000 based on Eurostat data

<table>
<thead>
<tr>
<th></th>
<th>Belgium (Eurct/kWh)</th>
<th>Netherlands (Eurct/kWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Industrial, 10 GWh/year</td>
<td>6.73</td>
<td>5.90 1</td>
</tr>
<tr>
<td>Industrial, 2 GWh/year</td>
<td>7.34</td>
<td>5.02</td>
</tr>
<tr>
<td>Business, 50 MWh/year</td>
<td>14.30</td>
<td>8.32</td>
</tr>
<tr>
<td>Domestic, 7.5 MWh/year</td>
<td>10.77</td>
<td>8.73</td>
</tr>
<tr>
<td>Domestic, 3.5 MWh/year</td>
<td>11.71</td>
<td>9.41</td>
</tr>
<tr>
<td>Domestic, 1.2 MWh/year</td>
<td>15.20</td>
<td>11.64</td>
</tr>
</tbody>
</table>

Note 1: price for July 1999
Source: Oxera report for Commission.

Judging from end user price information, it is likely that effective wholesale prices in Belgium are higher than in the Netherlands, except for the largest energy intensive industrial users.
This might be explained by the fact that electricity prices used to be set by Belgian CCEG, a board including representatives of government and unions, who may have acted in line with Belgian industrial policy to retain/promote energy intensive industry.

**Modelled prices**

While prices may be equal to marginal costs in competitive power markets, in markets with market imperfections and where a certain amount of market power is present prices may be significantly higher. Given the current concentration in the Belgian generation market, it is conceivable that electricity prices in Belgium may be raised above competitive levels. We assessed the impact of market power on Benelux prices using ECN’s strategic market model, simulating quantity (Cournot) competition on the Northwest European market, where generators dispatch plant in accordance with individual profit optimisation given the existing constraints on import and exports. ²⁹

<table>
<thead>
<tr>
<th></th>
<th>Summer</th>
<th>Winter</th>
<th>Shoulder</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Superpeak</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Belgium</td>
<td>55.73</td>
<td>57.52</td>
<td>56.78</td>
</tr>
<tr>
<td>Netherlands</td>
<td>47.45</td>
<td>43.58</td>
<td>45.26</td>
</tr>
<tr>
<td><strong>Peak</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Belgium</td>
<td>45.68</td>
<td>55.55</td>
<td>50.91</td>
</tr>
<tr>
<td>Netherlands</td>
<td>41.51</td>
<td>40.27</td>
<td>40.68</td>
</tr>
<tr>
<td><strong>Middle</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Belgium</td>
<td>39.53</td>
<td>44.07</td>
<td>42.59</td>
</tr>
<tr>
<td>Netherlands</td>
<td>34.00</td>
<td>32.65</td>
<td>33.21</td>
</tr>
<tr>
<td><strong>off-peak</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Belgium</td>
<td>30.72</td>
<td>34.24</td>
<td>32.74</td>
</tr>
<tr>
<td>Netherlands</td>
<td>28.80</td>
<td>26.10</td>
<td>25.90</td>
</tr>
<tr>
<td><strong>base load</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Belgium</td>
<td>43.05</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Netherlands</td>
<td>34.56</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Source: ECN, modelling results using the electricity market model COMPETES. ²⁹

Table 8 shows the theoretical prices that result from the model simulations. It shows that strategic behaviour affects prices in both countries, but market power is significantly larger in Belgium, given the fewer competitors. Comparing these prices with the prices in Table 5, shows that mark ups in Belgium and the Netherlands average 50 % and 18 % respectively. The model results indicate that prices in Belgium could be significantly higher than in the Netherlands. Moreover, according to the model results, the interconnector is always congested in both directions, which is not consistent with the observations in the current market. In chapter 4 we explained that although price differences might exist between Belgium and the Netherlands, hardly any congestion occurs on the interconnector. We have mentioned several possible reasons for the limited flows between Belgium and the Netherlands.

**Balancing prices**

Information on the possible scope of price behaviour may be obtained from the prices for imbalances in Belgium. In competitive markets, the balancing market, being a real time market, provides an indication of average feasible wholesale price levels. If average prices in

²⁹ Appendix A contains a short description of the model approach.
the day ahead or intra-day market were higher than prices paid on average for imbalances, market players would have an incentive to incur imbalances rather than contract for energy day ahead. Balancing prices therefore restrain prices in the rest of the wholesale market.

Elia sets Belgian balancing prices according to the mechanism described above in chapter 2. The price for dispatch up power is set to 1.75 times the hourly APX result, on peak hours (7-23 hour) capped at Eur 60/MWh or 50 Eur/MWh (in winter months respectively other months). At night, prices are capped at 30 resp. 25 Eur/MWh. These tariffs apply for small negative imbalances (<10%); at larger imbalances prices are higher.

We can compute the implied price for power by comparing to average hourly APX prices (averages for year 2002). This gives indicative implied base load prices (excluding weekends) of Eur 45/MWh in winter months, and Eur 40/MWh in other months (compared to a base load price of 35 Eur/MWh for the APX). This is based on the assumption that imbalance do not exceed the 10%-limit.

Conclusion on prices in Belgium
We see that on the one hand marginal cost data suggest that prices in Belgium should be similar to, or lower than prices in the Netherlands (except possibly in the peaks). The publication by Electrabel of its index also suggests wholesale prices in the Netherlands and Belgium are equal most of the time. The Belgian wholesale market however is not at all liquid, and it seems that the index is actually set according to Dutch day-ahead prices (see scatter plot in Figure 8). On the other hand, there seems to be a large mark-up to end-user prices in Belgium (except for the largest users). It is therefore likely that the market price for the bulk of electricity, deduced from the end-user tariffs, is significantly higher than published wholesale prices suggest. Under the assumption that access to the complete market is open, strategic modelling also demonstrates there is substantial incentive for raising market prices in Belgium above Dutch levels. We may expect that especially with the recent opening of the Belgian market in July 2003 there is increased likelihood of rising prices in the wholesale market.

Alternatively, high end-user prices in Belgium may be explained by high grid charges instead of high wholesale prices, and Electrabel may use its position in transmission and distribution to deter entry by cross subsidisation between energy and network charges.

From the price information we cannot uniquely determine which hypothesis is most likely. The lack of transparency and differences in sources makes it hard to conclude whether wholesale prices in Belgium or in Netherlands are higher. Nevertheless the information does give the impression that the lack of congestion on the Dutch-Belgian interconnector can not be ascribed to the lack of price difference between the countries. In the following paragraph we discuss whether the current balancing system in Belgium might cause this lack of cross border trade.
Appendix D: Analysis of balancing charges in Belgium

Apart from the (limited) market for base load power in Belgium, initiated by Electrabel, in the absence of an active hourly spot market, exports from the Netherlands will primarily occur if these can be directly sold to end users. In order to be able to serve power to end users, shape contracts have to be offered, as consumption and delivery will have to be balanced within each 15 minute period. Since trade over the interconnector is limited to hourly constant quantities, this will necessarily expose the supplier involved to the Belgian balancing system. Export to Belgium is therefore valuable only if combined with Belgian ancillary services.

Providing power to Belgian customers will therefore involve importing a profile consisting of hourly ‘blocks’ of power, and selling or purchasing the difference with the actual consumption (based on quarter-hourly values) from the Belgian system operator. Since buying Belgian balancing power is generally more expensive than buying Dutch wholesale power (see the analysis in appendix C), and since when selling to the system operator prices are lower, this procedure of balancing supply and demand will constitute a mark up to costs of providing power to Belgian end users. The magnitude of this mark up will determine the ability to compete with Belgian generators, who can use their own generation units to balance supply and demand. The size will be affected by, on the one hand, the degree of variability of the end users’ power consumption profile, and on the other hand by the difference in price of balancing and wholesale power.

While the largest industrial consumers will have relatively flat energy profiles, more general consumers will have a certain amount of swing in their energy use. As a proxy for a typical consumer’s load, we consider the aggregate load profile for the complete Belgian system. As two extremes we consider weekdays with very high and very low swing (in August respectively December 2002). Swing is here defined as the ratio of spread in daily demand to maximum daily demand. The resulting load profiles are plotted in Figure 10.

The largest imbalances will likely be incurred in the periods where the profile is steepest (mainly in the morning hours), as here the discrepancy between the flat hourly import values and actual load will be maximal.

We compute the impact of balancing charges on serving these load profiles using an average hourly APX price and assuming export capacity is not congested. The average APX values are calculated from all 2002 weekdays. The resulting price profile is demonstrated in Figure 11, together with the associated Belgian balancing charges for shortage and surplus.

---

30 Or a Belgian producer. These will however not have an incentive to offer at a lower price than the (fixed) balancing price.
31 Available from www.elia.be
Figure 10 Aggregated load profiles of the Belgian system based on weekdays in 2002

Figure 11 APX prices and the balancing prices in Belgium based on APX prices during weekdays in 2002
In the two hours that the APX averages above the 60 Eur/MWh cap, it is optimal to incur a shortage and selling electricity to the APX (this only applies up to 10% of load, as for higher imbalances prices rise quickly).

If we compute the optimal hourly profile (i.e. minimising total costs of serving energy) for the two sample load profiles, we find that the amount of imbalance, and the associated costs, are minimal. Figure 12 shows the optimal hourly profile for the example of the high swing day. Imbalances are rarely larger than 3%, for either profile. Total additional costs, compared to serving all energy at APX prices, is less than 0.30 Eur/MWh.

Figure 12 The realised load profile on quarter hourly basis and the computed optimal hourly profile as could be purchased on the APX

Ignoring the uncertainty over demand, the incompatibility between the hourly imports and the quarter-hourly balancing requirement therefore does not per se seem a large deterrence to serving Belgian customers.

In practice, however, uncertainty over load will always exist. Therefore a second way in which the Belgian balancing regime may deter Dutch suppliers is by this inevitable uncertainty regarding the load: imbalance cannot be completely avoided due to unpredictable fluctuations in demand. This argument might even be more relevant for new entrants in a market, who presumably have less access to historical customer profiles than the incumbent. We estimate the imbalance costs of a wrong load estimate as a function of the forecast error in Figure 13 for both the high and low swing profiles.

---

The Program Time Unit consists of 15 minutes.
The graph shows that the cost of imbalance rises sharply with the degree of imbalance, and is especially severe for shortages. This may in particular impact new entrants who lack the advantage from the diversification effects of larger portfolios, and will hence typically have larger average imbalances. Risk-averse suppliers will over-contract to avoid shortage prices. The size of forecast errors will probably be related to the relative daily fluctuations in demand. Visual inspection of Belgian demand data suggests fluctuations of the order of several hundred MW’s, or several percents, leading to an expected price increase of around 1 Eur/MWh.

Based on the above analysis we may conclude that the current Belgian balancing mechanism in combination with the lack of a day-ahead market in Belgium can be a serious barrier to suppliers to enter the Belgian market. This can explain the minimal cross border trade between Netherlands and Belgium.