# Market Monitor: Development of the Wholesale Electricity Market in 2006

The Netherlands Competition Authority - Office of Energy Regulation

The Hague, December 2007

Project number: 102641

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# Summary

Competition in the Dutch electricity market is stagnating. The market remains concentrated, with relatively high prices. The north-west European market must be further integrated by expanding the available interconnection capacity in order to achieve a structural improvement. That could cut consumers' annual energy bills by several dozen euros per household. Consumers would also benefit indirectly since electricity prices for business would also fall, putting downward pressure on prices of other products. In order to achieve these benefits for consumers, the TSO's must make headway with the expansion of the available interconnection capacity.

**Higher prices due to a concentrated market**

The high degree of concentration in the electricity market in the Netherlands remains a point of concern. A result of the high concentration is that in many hours one or more players are pivotal in meeting demand. They are not necessarily always the same players. Such pivotality enables players to increase prices.

The high degree of concentration and the regular pivotality of one or more players have an impact on market outcomes. Our statistical analysis of the Monitor data confirms the conclusion recently reached by the European Commission in its recent "sector enquiry" that a positive link exists between the degree of pivotality and the profitability of electricity production[1]: the greater the pivotality, the more the electricity price differs from the underlying costs of production.

The pivotality of certain players is greatest in the hours when demand is high: the peak and super-peak hours[2]. In the peak hours, the electricity price was on average 9% higher than the marginal costs of the most expensive plant in operation, and during super-peak hours it was as much as 21% higher. Although some plants realise negative profits during off-peak hours, the average annual gross profit is more than sufficient to cover the annual costs of new investments.

**Stagnating trend in liquidity due to limited integration with neighbouring countries**

The liquidity of the Dutch wholesale market hardly improved at all in 2006. The Netherlands still scores poorly in comparison with other countries: the Netherlands had more price peaks (APX) and a widening bid-offer spread (OTC). The APX has higher prices than the foreign exchanges EEX and Powernext. Prices of forward contracts in the Dutch OTC market in 2006 were also higher than in Germany and France. The relatively high prices are due to the large proportion of relatively expensive gas-fired plants used in electricity production, combined with congestion at the borders and limited domestic competition. The differences observed in comparison with neighbouring countries mean international convergence in liquidity is still far from being achieved.

**Market integration impeded by limited cross-border connections**

As a result of congestion in the cross-border connections, players in the Dutch wholesale market are only disciplined to a limited extent by foreign supplies and market development continues to be determined by the Dutch situation. As a result, Dutch prices remain relatively high. The congestion is caused partly by the limited physical capacity and partly by suboptimal capacity allocation, as a result of which capacity is not always optimally utilised.

[1] To be precise: between the degree of pivotality and the gross margin of the price-setting plant.

[2] Peak hours are the hours from 7am to 11pm and super-peak hours are the hours from 9am to 6pm, in both cases on weekdays.

Market integration is further limited by the fact that international trade is not yet fully developed. There are still no possibilities for trading electricity across borders on the delivery date, because transmission capacity is then no longer available. Consequently, no coupling is yet possible between the imbalance markets and the very short-term markets in the various countries in the region.

**North-west European integration is crucial for the Dutch market**

There are clear benefits of scale in electricity production: with a larger production portfolio, risks can be better controlled and covered, plant utilisation can be better optimised, operating costs can be reduced and crucial knowledge can be retained more effectively. These scale benefits can be achieved in a wider, north-west European, market while allowing effective competition at the same time, leading to lower electricity prices.

The direct benefit for households from an integrated north-west European market can amount to several hundred million euros per year, equivalent to several dozen euros per household per year. Consumers will also benefit indirectly, since electricity prices for business will be lower, leading (in part) to lower product prices.

An additional benefit of north-west European integration is the fact that prices in the countries around the Netherlands are often much lower than in the Netherlands due to a different fuel mix. Integration would make these cheaper generated power available also to Dutch electricity users.

**Steps towards a north-west European market**

Many steps have been taken in the past few years to create an integrated north-west European market. In 2005, the "Pentalateral Energy Forum" was formed, in which the ministers responsible for energy policy in the Netherlands, France, Belgium, Germany and Luxembourg are working together to bring about an integrated market. In the same year, the regulators in Belgium, France and the Netherlands began working to achieve market integration in consultation with all the stakeholders. A regional action plan has been agreed in 2007 between the regulators in the north-west European region (Germany, Belgium, Netherlands, Luxembourg and France)[3].

MARKET COUPLING

An important milestone in 2006 was the completion of market coupling between the Netherlands, Belgium and France, allowing better utilisation of the existing connections between the countries and the quotation of a single price in the day-ahead market as long as there is sufficient physical interconnection capacity. We therefore expect a strong improvement in utilisation on the Belgian border connection in 2007 as a result of the introduction of market coupling at the end of 2006. From January 2009, market coupling with Germany is set to lead to improved utilisation of the cross-border infrastructure with Germany.

EXPANSION OF THE INFRASTRUCTURE

Even if the existing infrastructure is optimally utilised, it will not be sufficient to achieve a genuinely integrated market. The market will have access to greater interconnection capacity in the next few years due to the clearance of identified physical bottlenecks in the north-west European system and the construction of additional connections. From the end of 2007, the Netherlands will have a connection with Norway (through the NorNed cable); the plans for a connection with Great Britain (BritNed) are at an advanced stage. As a result, the Netherlands will also be linked to the Nord Pool integrated Scandinavian marketplace and to the British market. The market will also have access to greater interconnection capacity with Germany in the next few years. In all these expansion projects it is still unclear what proportion of the new technical capacity will

[3] The Action Plan refers to the Central Western European region.

need to be withheld by the grid managers to control the flows inherent in interconnected grids[4] and which are also influenced by features such as wind turbines and the increase in connections.

### Cross-border trade

Electricity can be traded across borders for anything from one or more days ahead to several years ahead. However, cross-border trading on the delivery date itself[5] is not yet possible. The imbalance markets, which have been established by the grid managers to offset differences between planned production and delivery, are also national in nature. This means that fluctuations in supply and demand are still resolved domestically through trading or through the TenneT imbalance mechanism, except in the event of serious problems, when the grid managers intervene. According to the Action Plan, which has been aligned with European regulations, cross-border trading on the delivery date must be possible from 2008, and the imbalance markets will be connected from 2009.

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[4] Loop flows; transit flows.

[5] Cross-border intraday trade.

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# 1 Introduction

### Background and justification

In accordance with the Electricity Act and the Gas Act, the Office of Energy Regulation (DTe) is required to promote competition in the energy markets. DTe has the statutory duty to monitor these markets closely and to report to the Minister of Economic Affairs annually on the extent to which market forces operate and effective competition occurs in the various energy markets (Section 5(3) of the Electricity Act of 1998). In so doing, DTe is required to monitor whether the energy markets are transparent and non-discriminatory. In liberalised energy markets, characterised by actual competition and sufficient transparency, end users – including consumers – ultimately reap the benefits of competitive prices, a differentiated product range and high-quality services.

The purpose of this Monitor is to provide an insight into the development of the market and to provide a timely indication of any bottlenecks which impede further development.

### Approach

The Market Monitor uses indicators to track the development of the wholesale electricity market. These relate to the operation of the wholesale market as a whole. DTe reports not on individual companies but on an aggregate level. Indicators relating to competition and liquidity constitute the pillars of the Market Monitor.

The extent of competition between producers influences the prices at which suppliers purchase electricity and hence the price of electricity for the end user. The degree of liquidity in the market determines the transaction costs applying to contracts and parties' confidence in the market. Competition indicators concern market structure (e.g. the degree of concentration) and market outcomes (e.g. profitability). Liquidity indicators include trading volumes, price volatility and the spread between bid and offer prices.

DTe has used various sources to obtain the indicators. It requested producers to supply electricity production data and plant characteristics. TenneT was requested to provide data on available production capacity and available import capacity. A liquidity survey was sent to all important players in the Dutch electricity market. DTe has also made use of public sources such as Platts and TSO Auction for prices and volumes.

In order to reach judgments on the development of the wholesale market, results of indicators are compared with previous years (trend comparison), set against a standard or benchmark and/or compared to the situation abroad.

### Process

The Market Monitor has a consultative group consisting of producers, traders and interest organisations. A draft of the Monitor report was distributed to members of the consultative group. Subsequently the consultative group met to discuss the findings of the Monitor. Specific suggestions for improvement were adopted as far as possible. The final report was not discussed with the consultative group and is the sole responsibility of DTe.

### Reader's guide

There follows first a brief description of the main developments in 2006. Chapter 3 presents the Monitor results for competition and chapter 4 provides the results for liquidity. The final chapter deals with the current situation concerning the integration of electricity markets. With regard to both competition and liquidity, it makes a difference whether the Dutch electricity market stands alone or forms part of a larger whole. The summary and conclusions can be found at the front of the report.

# 2 Main developments in 2006

A number of developments took place in 2006 which have an influence on the operation of the Dutch wholesale electricity market:

1. Market coupling with Belgium and France (Trilateral Market Coupling) on 21 November 2006. The trading on the APX, Belpex and Powernext electricity exchanges is now connected, taking into account the available capacity at the various borders.
2. Spread annual auction for import capacity. Traders now have the possibility of acquiring capacity at the borders with Germany and Belgium twice a year (in addition to the existing monthly and daily auctions).
3. Start-up of the APX central intraday market. In addition to the day-ahead market, the APX introduced an intraday market in September 2006. In this market quarter hours of electricity are traded up to two hours before delivery.
4. EnergieNed and APX transparency initiative. Production data have been published since October 2006 on the initiative of EnergieNed and APX. They were published initially on the APX site, but from June 2007 they were published on the EnergieNed website because the quality of the data was still insufficient.
5. Launch of the Regional Initiative for better market integration. The regulators of the energy markets in Germany, France, Belgium, Luxembourg and the Netherlands published a list of priorities at the beginning of 2007 and formulated specific actions (Action Plan), including market coupling with Germany and cross-border intraday and balancing trade.
6. Loop flows through wind energy production. The production of electricity from wind parks in northern Germany provides increasing transit flows. TSOs are compelled to maintain larger reserves at the interconnectors, limiting the import capacity available to the market.
7. New plant construction projects. Producers announced further new investment plans in 2006, after the construction of new large-scale plants was announced for the first time in many years in 2005. The electricity producers' new plant construction projects currently amount to around 9 GW. These plants are scheduled to enter service from 2009 to 2013.

# 3 Competition in the Dutch wholesale market

The high degree of concentration in the Netherlands remains a matter of concern. A result of this high degree of concentration is that in many hours one or more players are pivotal in meeting demand. There are clear indications that in the hours when this occurs the margin earned on electricity generation is considerably higher than in the other hours when no single player has a pivotal position. Further integration in the north-west European market through an expansion of the available interconnection capacity can bring about a structural improvement. Consumers' annual energy bills may fall by several dozen euros per household as a result.

The degree of concentration of installed capacity (expressed in HHI) in 2006 is 1,995, which is comparable to the level in 2005. The degree of concentration of realised production in 2006 is an average of 1,984, almost 250 points lower than in 2005. This HHI value means that there is still a highly concentrated market. The concentration of supply manifests itself in the pivotality of one or more market players during individual hours. For 31% of all hours in 2006, one or more players were pivotal in meeting demand. During peak hours the figure was as high as 59% of hours. Pivotality gives players the possibility of influencing market outcomes.

The Monitor data show a clear connection between the pivotality of players and the mark-up (i.e. the difference between the electricity price and the marginal costs of the most expensive plant in operation): the more pivotal one or more players are, the higher is the mark-up. The pivotality of certain players is greatest during the hours when demand is high: the peak and super-peak hours[6]. In peak hours, the electricity price was on average 9% higher than the marginal costs of the most expensive plant in operation, and in super-peak hours it was as much as 21% higher.

The high mark-ups during peak and super-peak hours more than offset the negative mark-ups that mainly occur during off-peak hours. On an annual basis, the resulting gross profit is in many cases more than sufficient to cover the annual costs of new investments. Part of the profit can therefore be seen as supracompetitive. This indicates that the high degree of concentration and the regular pivotality of one or more players have an impact on market outcomes.

## 3.1 Introduction

This chapter focuses on the competition in the Dutch wholesale market. The Netherlands has over 21 GW of installed generating capacity. This is largely in the hands of a limited number of electricity producers. The production decisions and pricing by these producers to a large extent determine the market outcomes. A wholesale market with sufficient competition among producers benefits suppliers and ultimately end users. However, if producers exert insufficient discipline on each other, the result will be upward pressure on prices.

[6] Peak hours are the hours from 7am to 11pm and super-peak hours are the hours from 9am to 6pm, in both cases on weekdays.

## 3.2 Competition indicators

The following indicators have been used to monitor competition in the Dutch wholesale market:

- Market structure:
    - Degree of concentration: installed capacity and realised production
    - Pivotal supplier index and residual supply index
- Behaviour:
    - Dispatch of plants and utilisation of production capacity
- Market outcomes:
    - Spark spread and dark spread
    - Price-cost margin

Market structure

The degree of concentration shows whether there are many parties operating with low market shares or whether the market is characterised by a few large players. The construction of additional production capacity by a market participant or a merger between electricity producers changes the distribution of market shares and hence the degree of concentration in the wholesale market. A market participant with relatively large production capacity and a varied generating fleet may exert more liberty (in other words behave more independently) in the dispatch of plants and the price that is sought.

Whether this market participant is also able to push prices higher is dependent on the other players' ability to utilise flexible capacity in response. Electricity producers whose plants are already operating at full capacity can no longer react to any price increase. In the event that the other players' total capacity is insufficient to meet demand, this market participant is pivotal and in principle able to influence the market outcome. The pivotal supplier index (PSI) states whether and how often such situations occur. The extent to which a market player is pivotal is shown by the residual supply index (RSI).

Behaviour

If one or more market participants can behave more independently and are able to influence the market outcome, this may lead to a higher market price. In that case strategic behaviour on the part of producers gains in relevance.

For producers with large production capacity, the considerations surrounding the dispatch of plants may differ from those of smaller producers. Whereas a small producer will generate electricity with those plants for which generation is a profitable activity, for a large producer it may be more profitable to make no use or only limited use of an inherently profitable plant. Plants are utilised in principle in the order of their respective cost levels (merit order) up to the point at which the volume of electricity produced is sufficient to meet demand. The plant which produces at the highest marginal costs sets the market price. Other production units earn the difference between the market price and their own marginal costs, from which fixed costs can be covered. If a plant which would normally operate (at full capacity) is withheld (or used for limited production) from the market, the marginal plant moves up one or more positions in the merit order, leading to a higher market price. This producer may more than compensate for the missed revenues from the withheld plant with the higher margins on the plants which do operate. This practice of withholding can prove profitable particularly in the case of owned plants which are (relatively) low in the merit order.

As well as size, producers also differ in the composition of their generating fleet. Producers with several flexible gas-fired plants higher in the merit order may have other considerations when quoting the prices at which they are prepared to produce electricity than parties which mainly have combined heat-power plants or coal-fired units. After all, a flexible gas-fired unit can turn out to be the marginal plant at any time. A market participant can anticipate this by trying to increase the margin on this plant. However, by asking a price above the marginal cost level, this producer does run the risk of pricing himself out of the market. More expensive plants higher in the merit order, which stay closer to the marginal costs in terms of pricing, may then be called upon earlier. The more such plants a producer has available, the lower is the probability that this will occur. There are then only a limited number of other candidates to supply the marginal plant, so there is more opportunity to increase the mark-up.[7]

MARKET OUTCOMES

The profit achieved in the production of electricity may be an expression of scarcity in the market. Price peaks accompanied by high spreads give a positive signal for investment in new production capacity. High spreads or mark-ups can also reflect limited competition between electricity producers. In order to obtain a clearer view of this, the Monitor investigates connections between indicators of market structure (degree of concentration, *pivotal supplier* and *residual supply*), indicators of electricity companies behaviour (*dispatch inefficiency* and utilisation of production capacity) and indicators of profitability (price-cost margin or mark-up).

## 3.3 Structure of the market

### 3.3.1 Degree of concentration

The degree of concentration of installed capacity in 2006 is 1,995, which is comparable to the level in 2005. The degree of concentration of realised production in 2006 is an average of 1,984, almost 250 points lower than in 2005. In view of the continued high concentration in capacity, this must mean that the largest players are producing less. This HHI value indicates that the market is still highly concentrated.

Approximately 25 electricity producers are active in the Netherlands. In terms of the size of generating fleets, the Netherlands has seven large and 18 small electricity producers. The large coal- and gas-fired plants and the combined heat-power plants which provide the bulk of production in the Netherlands are owned by a few large producers. Three-quarters of the Dutch generating fleet belongs to four electricity producers.

The degree of concentration in the Dutch wholesale market is measured using the Herfindahl-Hirschman Index (HHI).[8] DTe calculates the following HHIs: installed capacity, capacity by cost segment, realised production and production by part day.[9]

HHI OF INSTALLED CAPACITY

The HHI of installed capacity is calculated on the maximum capacity of the production units.[10] The value of this HHI for 2006 amounts to 1,995. If import capacity is also included, the HHI is 1,719.[11] These values correspond more or less to those of 2005.

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[7] When demand is not totally inelastic a higher price means a lower utilisation of available capacity.

[8] To calculate the HHI, the producers' market shares are squared and then added together. The results range from 0 (full competition) to 10,000 (monopoly). If the value is higher than 1,800, there is a highly concentrated market; if the value is between 1,200 and 1,800, there is a moderately concentrated market.

[9] Information on plant characteristics and production data is obtained from electricity producers.

[10] The calculation includes all production units with a maximum electric power greater than 15 MW. This includes more than 80% of the available production capacity in the Netherlands.

The HHI of installed capacity is calculated on the total production capacity and makes no distinction in terms of the positions of plants in the merit order. However, decisions on the dispatch of plants and pricing by producers are closely related to the position of these plants in the Dutch generating fleet. For this reason, the Monitor also looks at the degree of concentration within the various segments of the merit order.

### HHI of installed capacity in segments of the merit order

In the merit order the production units are classed according to the level of marginal costs[12]. These comprise fuel costs, CO2 costs and operating and maintenance costs.[13] In order to show the degree of concentration through the merit order, this has been divided into four segments of approximately equal size. The results are shown in the table below.

| *Cost segment* | *Cumulative capacity* | *HHI* |
|---|---|---|
| 1 | 26% | 2,654 |
| 2 | 50% | 2,315 |
| 3 | 75% | 3,248 |
| 4 | 100% | 1,961 |

In the case of withholding, it is the plants that are low in the merit order, particularly segment 1 and to a lesser extent segment 2, that are relevant, because they can earn high margins relative to variable costs. The HHI value shows a high concentration for both segments. In the case of pricing, the segments concerned are those which contain the marginal plants: these are in particular segment 4 and to a lesser extent segment 3. Here too the HHI shows values typical of a highly concentrated market. Strategic considerations may therefore play a role in the dispatch and utilisation of plants.

### HHI of realised production

The degree of concentration of installed capacity concerns the potential to influence market outcomes. The degree of concentration in realised production is assessed in order to gain a view of the actual distribution of market shares at any time. The HHI of realised production is calculated separately for each hour.

The HHI of realised production in 2006 amounts to an average of 1,984. If imports are also included, the average is 1,643.[14] Compared to 2005, the HHI of realised production (excluding imports) is almost 250 points lower. If imports are included, it is almost unchanged.

### HHI of realised production by part day

Since market conditions can change in the course of a day, the HHI is broken down into part days. Market conditions also vary between weekdays and the weekend. The table below shows the HHI of realised production on weekdays divided into peak hours, off-peak hours, super-peak hours and shoulder hours.

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[11] Available import capacity is allocated in blocks of 400 MW to the five largest producers and the remainder in blocks of 400 MW to new parties. This 400 MW is the maximum capacity which a market participant can acquire.

[12] Average variable costs (costs of producing 1 MWh of electricity) when operating at full capacity.

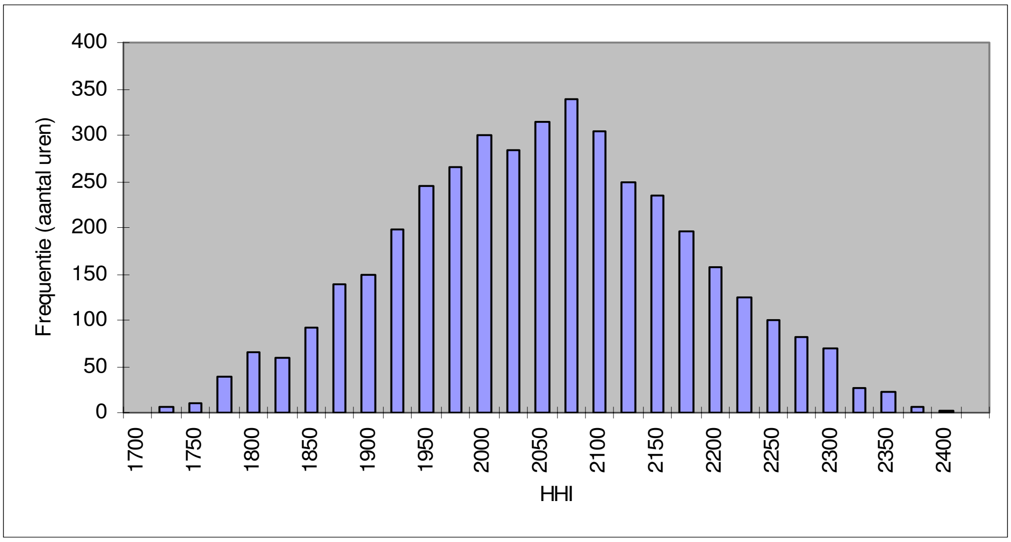
[13] Compared to HHI of installed capacity, plants for which no efficiency data were available were omitted from the calculation. This concerns a number of plants of small players.

[14] Actual imports are allocated to players on the basis of market shares, taking into account a maximum of 400 MW. The remaining volumes are allocated to new parties in blocks of 400 MW.

| Part days | HHI (excluding imports) |
|---|---|
| Peak hours: 07.00 – 23.00 | 2,039 |
| Super-peak hours: 09.00 – 18.00 | 2,062 |
| Shoulder hours: 07.00 – 09.00 and 18.00 – 20.00 | 2,034 |
| Off-peak hours: 23.00 – 07.00 | 1,931 |

Figure 1 shows the frequency of HHI values in peak hours. The number of hours in which the HHI of realised production is below the threshold value of 1,800 points for a highly concentrated market is very limited. Progress has been made compared to 2005, when all hours had an HHI higher than 1,800. The tail on the right of the distribution has also largely disappeared in 2006. By way of comparison, in 2005 a considerable number of hours were still in the range of 2,400 to 2,900 points. In short, the distribution of HHI values for realised production has shifted clearly to the left. That means the market has become less concentrated. With an average of 2,039 points in peak hours, the market is still highly concentrated.

*Figure 1: Histogram of HHI of realised production in peak hours in 2006*




*Source: electricity producers' production data*

## 3.3.2 Pivotality of individual producers

The pivotal supplier index for 2006 amounts to 31% over the whole day and 59% in peak hours. In almost half of cases, two players are *pivotal* simultaneously. One or more market players are therefore pivotal on a regular basis. The residual supply index averages 1.18 in 2006, and 0.99 in peak hours. The extent to which market players are pivotal also fluctuates widely: in almost one-fifth of peak hours, the RSI does not exceed 0.9, i.e. the joint capacity of the other players is a maximum of 90% of total market demand.

The analyses of the degree of concentration concern the distribution of market shares and any potential to exercise market power. The pivotal supplier and residual supply analyses make clear whether any actual potential to influence market outcomes has arisen. The pivotal supplier index shows whether and how often players have had an opportunity to do so. The residual supply index shows the extent to which market participants are pivotal.

### Pivotal supplier index

The pivotal supplier index (PSI) shows the percentage of hours in which an electricity producer's capacity is required in order to meet market demand having regard to the combined capacity of the other producers.

The calculation of the pivotal supplier index is based on available capacity: plants which market participants can utilise at any time to produce electricity (or which they can choose not to utilise or to utilise only to a limited extent).[15] Plants which are defective or undergoing maintenance or servicing at that time (outage) are not included. Due account has also been taken of any must-run character of plants. Industrial CHP units generally have extremely limited flexibility. For this reason, most of these units are not included in the PSI analysis. By contrast, CHP units for district heating are generally suitable for adjusting the production of electricity for supply to the public grid as required. Most district heating CHP plants are therefore included. A correction has been made to the must run portion in the analysis to take account of those district heating or industrial CHP units which can be partly utilised on a flexible basis.

The PSI is based on a so-called binary indicator. The value is 1 if there is a pivotal supplier in a given hour and 0 if that is not the case. This was analysed for each hour in 2006 for each individual player by deducting his capacity from the total available capacity and then comparing it to the market demand (by approximation total production by available units). If the joint capacity which all other players have available is insufficient to meet market demand, the respective player is a pivotal supplier. The PSI is calculated as the sum of all hours in which there is a pivotal supplier divided by the total number of hours in a year.

The PSI analysis gives the following results: in 2006, there is a pivotal supplier in 31% of hours. For peak hours the percentage is 59% and for super-peak hours 76%. In almost half of cases there are two simultaneous pivotal players.[16] At least one player was pivotal in one or more hours on 262 days in 2006.

### Residual supply index

The residual supply index shows the extent to which a player is pivotal. The more capacity that is required from a player to meet market demand, having regard to the capacity of the other producers, the greater possibility this player has to influence market outcomes.

The calculation of the residual supply index is based on the same basic data as the calculation of the PSI. It therefore takes account of outages and any must-run character of plants.

The RSI is expressed as a ratio. For each player, the market demand for each hour in 2006 is divided by the joint capacity of all the other players (i.e. total available capacity minus the available capacity of the respective player). If this produces a value of less than one, the joint capacity of the other players is insufficient to meet market demand and the respective market player is pivotal. The further below 1 the RSI value is, the more capacity is required from this player and the greater its pivotality. For each hour in 2006, it is then seen which player has the lowest RSI value. This lowest RSI per hour determines the RSI value for the sector as a whole.

The results of the RSI analysis are as follows: on average in 2006, the RSI is 1.18. In peak hours, the RSI averages 0.99 and in super-peak hours 0.95.

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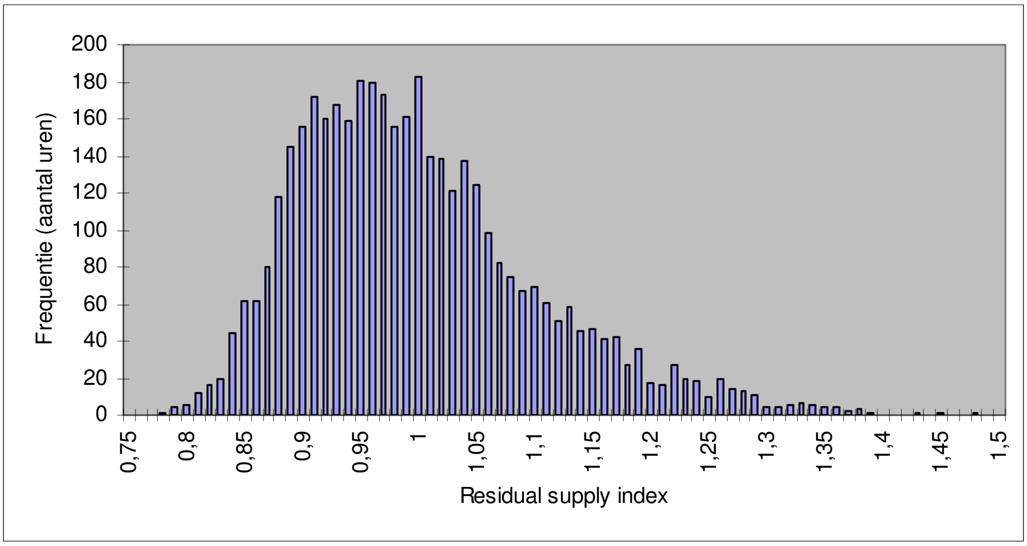
[15] Information concerning availability of plants is obtained from TenneT.

[16] This does not mean that the competition between these parties increases. Rather, the competition decreases, because there is one fewer market participant to exert discipline on a pivotal player. Several players now have the incentive to withhold capacity and the expenses are shared with other parties (loss of revenues). They jointly have more capacity, so the price can be pushed higher. Whether this actually happens is connected to the extent to which the respective players are pivotal (relative to the situation in which one player is pivotal) and the extent to which they influence such pivotality in each other.

Figure 2 shows the distribution of RSI in peak hours. The pivotal supplier analysis has already shown that one or more players were pivotal in 59% of peak hours (hence an RSI value of below 1). The histogram shows that in 18% of peak hours the residual supply index does not exceed 0.9. In these hours the pivotal supplier must meet at least 10% of market demand.

*Figure 2: Histogram of RSI in peak hours in 2006*




*Source: production data from electricity producers and availability data from TenneT*

## 3.4 Behaviour: dispatch and utilisation of plants

The (calculated) dispatch inefficiency in individual portfolios does not differ markedly from the (calculated) dispatch inefficiency at sector level. This means that the calculated average dispatch inefficiency at sector level (17% in peak hours) cannot be explained by the strategic dispatch of plants, but may be the result of other factors.

The degree of concentration, the pivotal supplier index and the residual supply index are indicators of the market structure. These indicators provide an insight into the potential which the market players have to influence market outcomes at any time. Market outcomes can be influenced by withholding plants.

### Dispatch inefficiency

Strategic behaviour can manifest itself in dispatch inefficiency. After all, if the withholding of (relatively cheap) plants leads to the utilisation of more expensive plants, the result is more inefficient dispatch (at sector level).

When a relatively expensive plant serves as the marginal plant in situations of low demand, that can indicate deliberate withholding of capacity in order to push prices higher. After all, in a competitive market the marginal plant will keep pace with demand, which means that when demand is low the marginal plant will have relatively low marginal costs and when demand is high the marginal costs of the marginal plant will be relatively high. In the event of withholding, the dispatch at sector level is less efficient than would otherwise be the case.

In order to gain a view of this mechanism, it is necessary to determine on the one hand the actual price-setting plant and on the other hand the marginal plant under fully competitive conditions. The actual price-setting plant is the most expensive plant which is online at any time. For each hour in 2006, it was ascertained which operating plant has the highest marginal costs. In order to determine the marginal plant at optimal dispatch, DTe commissioned KEMA Consulting to simulate the dispatch in 2006 using a dynamic dispatch model (Prosym).[17] This model took account of must-run characteristics, start-up costs and other dynamic characteristics which influence the optimal dispatch. The actual dispatch was then compared to the optimal dispatch.

The difference in costs between the actual marginal plant and the marginal plant at optimal dispatch is a dispatch inefficiency. This dispatch inefficiency shows how much more expensive the production of a unit of electricity by the actual marginal plant is compared to the marginal plant at optimal dispatch. This difference, expressed in the marginal costs at optimal dispatch, gives the dispatch inefficiency. In 2006, the dispatch inefficiency at sector level in peak hours is an average of 17%. This result shows nothing more (or less for that matter) that the actual dispatch at the margin is 17% more expensive than it could be according to the Prosym model.[18]

In order to determine whether the calculated dispatch inefficiency may be related to the strategic withholding of plants, we compare the dispatch inefficiency at sector level with that in individual portfolios. We can assume that strategic behaviour will not result in players making the dispatch more inefficient in their portfolio. If a player wishes to withhold capacity, such capacity will be at the margin, i.e. the most expensive capacity which could operate given the demand. If another player offers a more expensive plant in response, that will lead to higher marginal costs at sector level. To the extent that strategic behaviour manifests itself in dispatch inefficiency, it does so at sector level. We have therefore investigated the extent to which dispatch inefficiency at sector level differs from the dispatch inefficiency in individual portfolios.

The statistical analysis shows that the dispatch inefficiency of the sector is on average not significantly higher than the dispatch inefficiencies within the portfolios of the individual producers. The conclusion is therefore that the analysis of the dispatch inefficiency does not indicate any strategic behaviour in the dispatch of plants.

### Extent of utilisation of available capacity

Strategic behaviour may be indicated by the extent to which players utilise the available capacity. In competitive circumstances, an increase in demand for electricity leads to an increase in the utilisation of capacity. We can see from the data (with realised production data) that with higher total production the utilisation is logically also higher. With regard to individual players, we see that some players rarely utilise all or almost all of the available capacity, even when the total production in the sector is at a maximum level and the electricity price peaks. In the case of other players, by contrast, the available capacity is fully or almost fully utilised when the total production in the sector is high. The substantial non-utilisation of available production capacity when the total sector production (and the electricity price) is high, may indicate that capacity is being withheld for strategic reasons. This mechanism can arise when demand is not completely inelastic, as a result of which total demand decreases in response to the lower supply of electricity and the higher price. However, it is also possible that these differences in capacity utilisation among players are explained by differences in portfolios and specific circumstances. Further research is needed to show how pivotal players influence the market outcomes.

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[17] KEMA Consulting, Analysis of the dispatch efficiency of generators in the Netherlands in 2006, October 2007.

[18] Since it is not possible to incorporate in a model all the real factors which determine the actual dispatch from one hour to the next, no further conclusions can be drawn from this average figure. It is possible that the observed inefficiency is entirely due to special circumstances which are not related to any strategic behaviour, such as the precise extent of must-run obligations or the level of fuel prices in specific contracts.

## 3.5 Market outcomes: prices and profitability

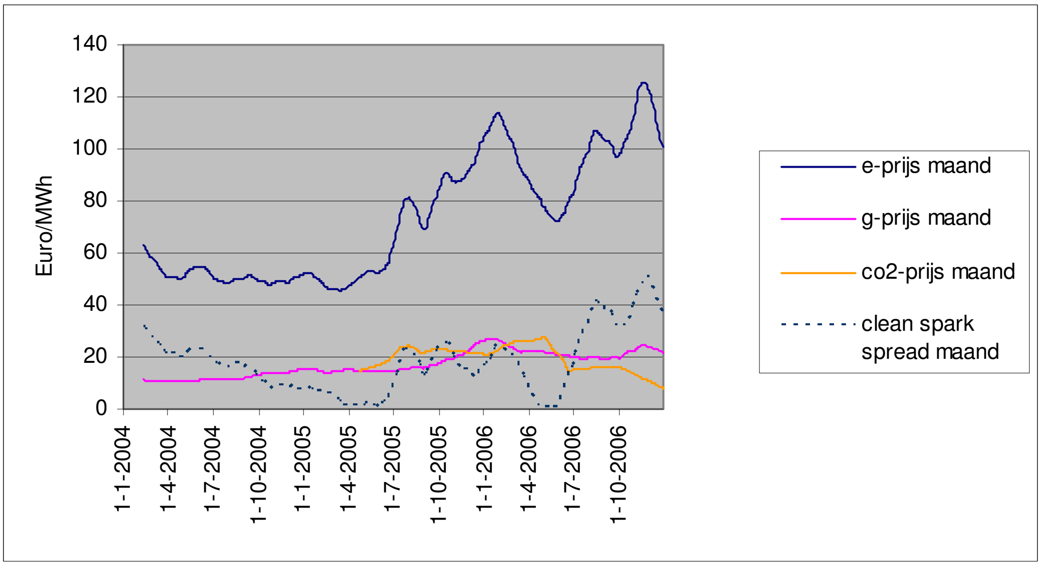
Prices for electricity are on a higher level in 2006 than they were in previous years. Compared to the relatively low spreads in 2004 and 2005, the spreads have increased in 2006. The higher electricity prices have led to higher mark-ups, i.e. higher margins between the electricity price and the marginal costs of the most expensive plant in operation. In peak hours, the mark-up averaged 9% and in super-peak hours 21%. These high mark-ups more than offset the negative mark-ups that mainly occur in off-peak hours. On an annual basis, the resulting gross profit is in many cases more than sufficient to cover the annual costs of new investments.

Indicators of profitability are the spark spread, dark spread and price-cost margin. The spark spread is the difference between the electricity price and the gas price and the dark spread is the difference between the electricity price and the coal price, taking efficiency of generation into account. The price-cost margin is the difference between the electricity price and the marginal costs of the most expensive plant in operation.[19]

### Spark spread and dark spread

The (clean) spark spread for monthly (peak load) contracts initially declined but then rose sharply in the second half of 2006.[20] In the final quarter the spark spread was more than €40/MWh, a level unseen in the previous two years. As in 2005, the electricity price also rose sharply in the second half of 2006. As a result of the rise in the gas price in 2005, the spark spread was then around €20/MWh. Thereafter the gas price fell back somewhat, and a sharp fall was observed in the CO2 price, as a result of which the spark spread increased further in 2006. This calculation of the spark spread is based on TTF gas prices. In Q4 2006, the (oil-indexed) gas prices of GasTerra were clearly above those of the monthly contracts on the TTF; this effect has not been included in this analysis.[21] Figure 4 shows the trend in the spark spread over the last three years.

*Figure 4: Clean spark spread for monthly contracts and underlying prices, peak hours in 2004-2006 (30-day moving average)*




*Source: Platts, European carbon index, Carbix*

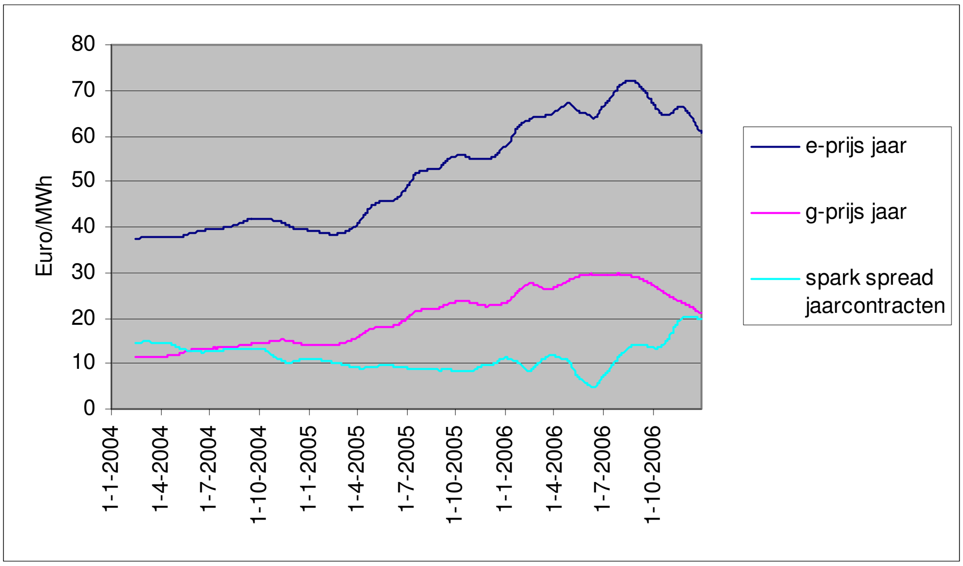
[19] The spark spread and dark spread are calculated using efficiencies of a hypothetical gas and coal plant. The price-cost margin is calculated using the efficiencies of the actual marginal (price-setting) units.

[20] The *clean spark spread* for monthly contracts is calculated according to the formula: Pe - Pg/R – Pco2*U/R (R=0.35; U=0.20196).

[21] A sensitivity analysis shows that even with higher gas prices in Q4 2006 the spark spread remains well above the 2005 level.

For annual base load contracts, both the spark spread and the dark spread are calculated.[22] The electricity price in annual contracts has moved in a clearly upward direction since the beginning of 2005. The spark spread remained around €10/MWh for a long time due to the similar rise in the gas price. Midway through 2006, the gas price reached a high of €30/MWh, after which it fell back within a few months to €20/MWh. Under the influence of a continued high electricity price, the spark spread, after dipping in the second quarter, rose to €20/MWh at the end of the year (see figure 5).

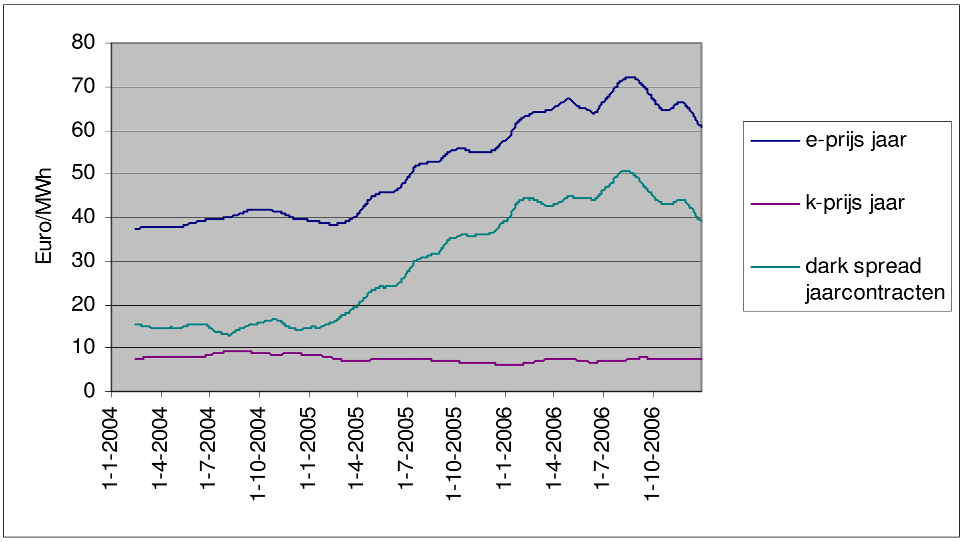
*Figure 5: Spark spread on annual contracts and underlying prices, base load 2004-2006 (30-day moving average)*




*Source: Platts*

When the electricity price began to rise, the dark spread moved in the same direction. The coal price remained below €10/MWh in both 2005 and 2006. Since the coal price hardly ever changes, the dark spread is determined by the electricity price. With a declining electricity price from August, the dark spread also declined in value, in contrast to the spark spread (see figure 6).

*Figure 6: Dark spread on annual contracts and underlying prices, base load 2004-2006 (30-day moving average)*




*Source: Platts*

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[22] The calculation for annual contracts takes no account of CO2 (emission allowances are obtained free of charge, not interpreted here as *opportunity costs*) and an efficiency of 50% is assumed for gas-fired plants and 34% for coal-fired plants.

### Price-cost margin

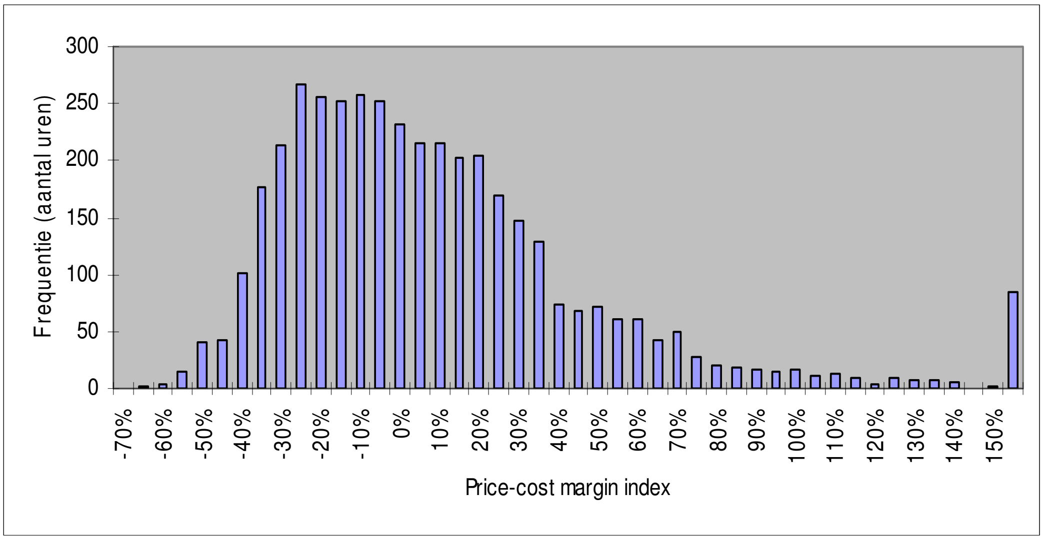
A market price which far exceeds the cost level of the marginal plant is conspicuous. If there is sufficient competition between producers, it can be expected that the market price will be in the region of the costs of the marginal producer. A limited mark-up for the marginal producer will also be necessary to cover the overheads and capital costs of a plant which is offline for a large part of the year. A high mark-up, by contrast, is an indication of limited competition.

In order to visualise this, a comparison was made for each hour in 2006 of the market price (APX) and the highest level of marginal costs of all the production units operating at that time.[23]

The difference between the market price and the marginal costs is the price-cost margin. This states the extent to which the market price for electricity exceeds the costs of producing electricity in the marginal (price-setting) plant. This difference, expressed in the marginal costs of the price-setting plant, gives the price-cost margin index (PCMI). For 2006, the price-cost margin index in peak hours amounts to an average of 9% and in super-peak hours 21%.

Figure 7 shows the frequency distribution of the price-cost margin index for peak hours in 2006. These are the mark-ups for the actual marginal plant in the hours in question. The histogram shows that the level of the mark-up may vary to quite some extent, with both high spikes and negative values.

*Figure 7: Histogram of PCMI in peak hours in 2006*




*Source: production data from electricity producers*

Over the year as a whole, the negative mark-ups in off-peak hours are more than offset by higher mark-ups in peak hours. With the exception of the odd plant which only goes online in the event of extreme peak load, the annual gross profit per plant is more than sufficient to cover the annual overheads of a new investment.

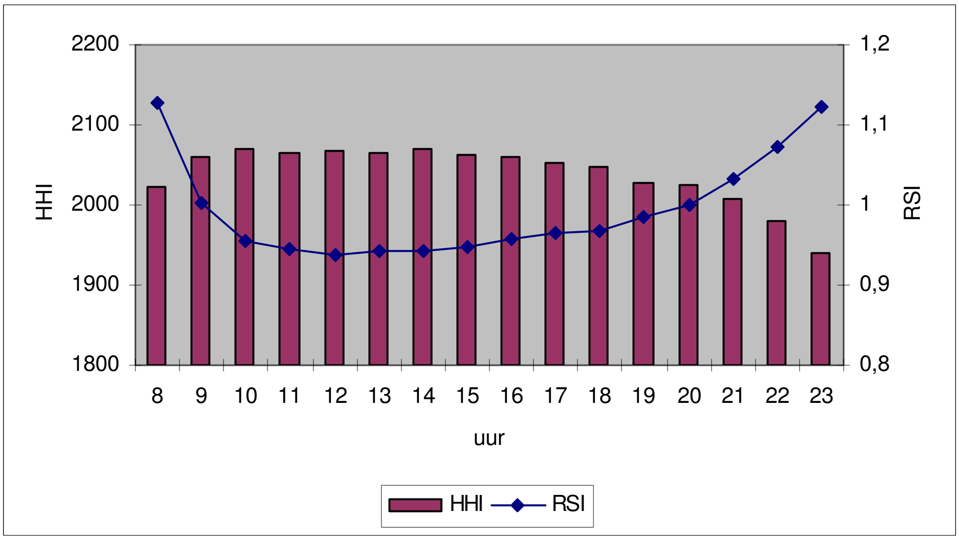
[23] This is the price-setting plant (the most expensive plant online in that hour) in the analysis of dispatch inefficiency.

## 3.6 Interpretation: connection between structure and market outcomes

The two indicators of market structure (HHI of realised production and the RSI) are closely connected: the higher the HHI (i.e. the more concentrated the production), the lower the RSI (i.e. the less pivotal some players are). Also indicators of market outcomes mark-up and price are closely related. This implies that costs of generation are only partly responsible for price movements. Finally the RSI is closely related to the mark-up: the lower the residual supply index, the higher the price-cost margin, and clearly higher mark-ups are seen as soon as there is a pivotal supplier (RSI below 1). This indicates that the high degree of concentration and the regular pivotality of one or more players affect market outcomes.

The structure indicators show that the wholesale electricity market is a highly concentrated market in which one or more players are regularly pivotal. Figure 8 shows the average values of the HHI and the RSI for each hour through the day. The chart shows that the market is most concentrated during super-peak hours (between hours 10 and 18) and that the extent to which one or more players are pivotal is greatest during these hours. The trend in the HHI and the RSI shows a clear pattern over the day. In the morning hours the concentration increases and the RSI declines rapidly. Both indicators then show a reasonably stable picture during the day, after which the concentration decreases and the RSI rises in the evening hours.

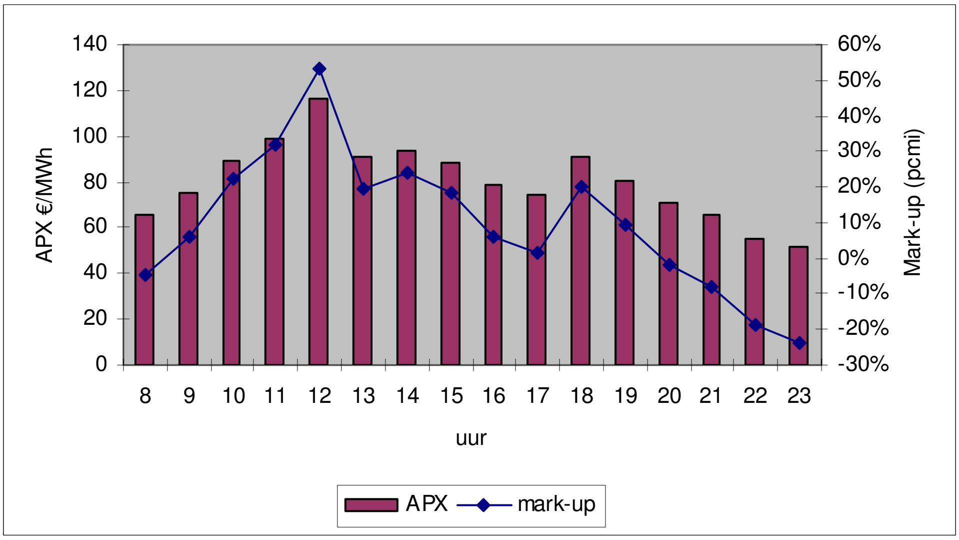
*Figure 8: HHI of realised production and RSI, average over the year for each peak hour*




*Source: production data from electricity producers and availability data from TenneT*

Indicators of market outcomes show that on average there is a positive mark-up in peak hours. Figure 9 shows the average mark-up (PCMI) and the average electricity price (APX) for each hour. It can be clearly seen that the mark-up and the electricity price follow an almost identical pattern. Variations in prices are therefore caused to a limited extent by higher generating costs and hence to a large extent lead to higher profit margins.

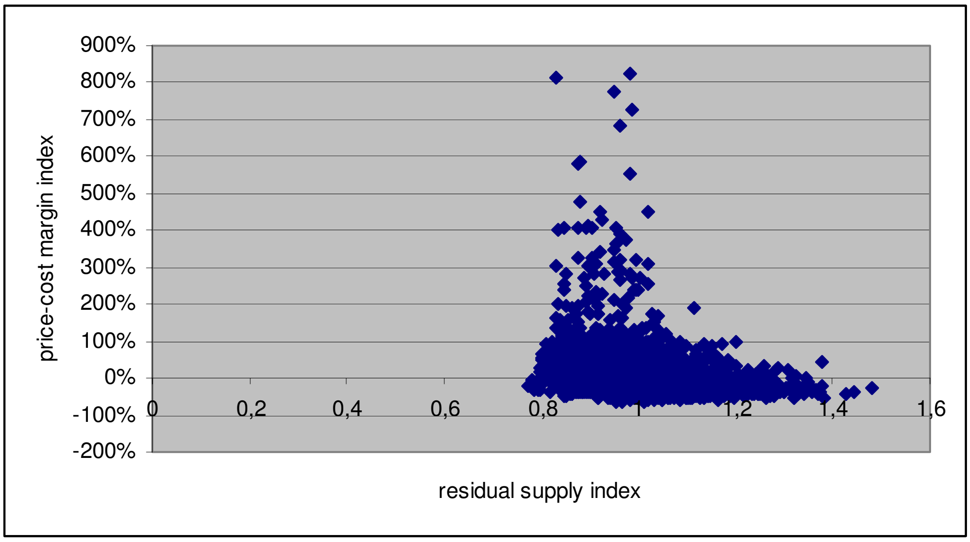
*Figure 9: APX price and mark-up, average over the year for each peak hour*




*Source: APX and production data from electricity producers*

A combination of figures 8 and 9 shows that the RSI and the mark-up are related. An RSI value lower than 1 (pivotal supplier) corresponds to a positive mark-up. When the RSI falls in the morning hours, the mark-up increases and reaches a peak in hour 12, when the RSI reaches its lowest value. The RSI then remains for a considerable time below 1 and the average mark-up for all these hours is positive. When the RSI moves back to the region of 1 and above, the mark-up becomes negative. Figure 10 illustrates directly the (negative) connection between the RSI and the mark-up. It also shows that clearly higher mark-ups arise with an RSI lower than 1, in other words when one or more players are pivotal.

*Figure 10: Distribution of RSI and mark-up during peak hours*




*Source: production data from electricity producers, availability data from TenneT and APX*

The statistical analysis, in which we have made a correction for the effect of actual scarcity [24], shows that the RSI has a significant negative effect on the level of the mark-up. The lower the residual supply index is, the higher is the price-cost margin. The high degree of concentration and the regular pivotality of one or more players thus affect the market outcomes. In other words, the high concentration in the electricity market in 2006 had the effect of pushing up prices.

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[24] Measured in terms of unutilised available capacity.

### 'Back-of-the-envelope' calculation of the effect of market integration

The statistical connection observed between the residual supply index and the price-cost margin makes it possible to estimate the effect of more market integration with neighbouring countries on the electricity price, for example for households. If the available interconnection capacity increases, prompting other providers to enter the wholesale market, the current players will be pivotal to a lesser extent or less frequently. As a result, the wholesale price (particularly during peak and super-peak hours) may decrease by 5% to 10%. Due to the competition in the end user market, this price benefit will be largely passed on to the consumer. The direct benefit of an integrated north-west European market for households could therefore amount to several hundred million euros per year, equivalent to several dozen euros per household per year. Consumers will also benefit indirectly, since electricity prices for business will also fall, which in turn will be partly reflected in lower product prices.

# 4 Liquidity in the various marketplaces

The liquidity of the Dutch wholesale market hardly improved at all in 2006. In previous years too, the Monitor has recorded a largely unchanged situation. The liquidity in the Netherlands is evidently at a level that can be expected given the current level of market integration.

On the APX (spot market) the trading volume rose 17% in 2006 to 19.2 TWh and there is greater market depth, as a result of which the price sensitivity of additional demand bids is lower than in previous years. On Endex (forward market), the total volume rose 25% in 2006 to 131.3 TWh. A shift can be seen from trading on the futures exchange (launched in 2005) to the OTC clearing: the trade in standardised OTC contracts has decreased by almost 40%.

The Netherlands still scores poorly in comparison with other countries: the Netherlands had more price peaks (APX) and a widening bid-offer spread (OTC). In the Dutch spot market, the number of times the APX exceeded €100/MWh increased by one-quarter. A particularly large number of price peaks were observed in Q1 2006. The average price level is also higher than in previous years. Compared to the foreign EEX and Powernext exchanges, the APX has a higher price level and shows the most price peaks. In the Dutch OTC market, the prices for forward contracts in 2006 are higher than in Germany and France. The bid-offer spread in 2006 (more than) doubled compared to 2005 for peak load forward contracts. Q2 2006 shows an exceptionally high spread. The bid-offer spread in the Netherlands is three times higher than in Germany and France (peak load forward contracts). The volatility in the Netherlands has remained roughly the same and is below that of Germany and France.

The differences observed in comparison with neighbouring countries mean that there is still no international convergence in liquidity. The rising volumes and increasing market depth on the APX were achieved in the Netherlands, which is a positive sign. However, in view of the differences in liquidity compared to neighbouring countries, particularly the bid-offer spread on the OTC, there is still much to be gained.

## 4.1 Introduction

This chapter focuses on the development of liquidity in the various marketplaces. In a liquid market, standard transactions can generally be conducted rapidly, i.e. a counterparty can be found rapidly for each transaction and a large volume can be traded in each transaction without any noticeable effect on the price ("the market has sufficient depth"). Liquidity minimises the transaction costs and generates confidence among market participants. This in turn attracts more parties, thereby further improving the liquidity.

## 4.2 Marketplaces

Before attention is devoted to the liquidity indicators, there follows first a brief description of the marketplaces. The various marketplaces in the wholesale electricity market are:

- Bilateral market (forward and spot)
- OTC (forward and spot)
- Endex (forward)
- APX (spot)
- TenneT (imbalance)

Producers and suppliers can agree contract specifications among themselves, including the size, duration and term of electricity supplies. It is mainly forward contracts that are traded in this bilateral market, but spot contracts (day-ahead, intraday) are also concluded.

Standardised contracts are available in the OTC (over the counter) market and on the APX and Endex exchanges. For standard volumes of electricity, contracts are available in these marketplaces with different durations and for multiple terms. In the OTC market, brokers match demand and supply for forward and spot electricity contracts. Parties can trade on the exchanges without the intermediation of brokers. Forward electricity contracts are traded on the Endex electronic trading platform (both physical and financial products). The APX electronic trading platform has been established for the spot electricity market.

In addition there is the imbalance market. This market is maintained by TenneT, the manager of the national high-voltage grid, in order to maintain the balance in the system.

Producers and suppliers are generally active in all marketplaces. Pure traders operate in all marketplaces with the exception of the imbalance market and the bilateral market. Large customers conclude contracts particularly in the bilateral market. The purchasing cycle which a supplier goes through is illustrative of the trading in various markets. In order to fulfil their delivery obligations, suppliers generally purchase in several phases, both at home and abroad (import). Purchases are made to meet the bulk of demand from two to three years to one month prior to delivery through bilateral contracts and standardised (long-term) forward contracts. The closer the delivery time, the more precisely demand can be estimated. Short-term forward contracts and day-ahead contracts are used to attune the rough procurement profile more closely to the actual profile to be supplied. On the delivery date itself, the profile is smoothed either by means of intraday contracts or, failing all else, through the imbalance market.

## 4.3 Liquidity indicators

The degree of liquidity in the market is measured using the following indicators:

- Trading volume
- Number of parties
- Available contracts
- Volatility of prices
- Sensitivity of prices (to additional demand)
- Spread between bid and offer prices

An increasing market volume and more participants trading in a wider range of contracts increase the possibilities for concluding a transaction, or for doing so rapidly. Less volatile prices, decreasing price sensitivity and a lower bid-offer spread show that demand and supply are more closely matched in terms of price and volume and that individual transactions can therefore be absorbed more effectively by the market.

The Monitor report thus assesses the development of liquidity in the wholesale electricity market. Attention is devoted in turn to the APX (spot), Endex/OTC (forward) and TenneT (imbalance) markets. There is no further examination of the bilateral market, due to a lack of comparability. Attention is then focused on arbitrage between marketplaces and the extent of information provision (transparency). This chapter ends with an international comparison of liquidity.

## 4.4 Trading on the APX spot market

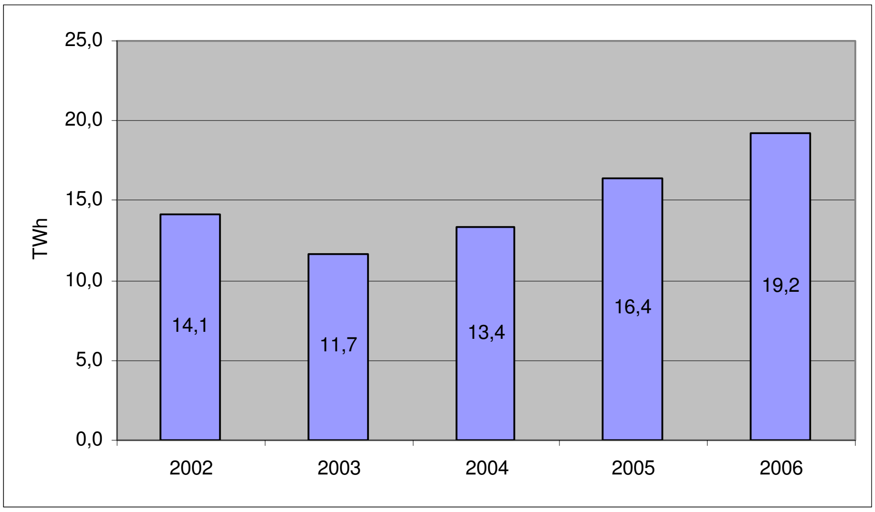
The trading volume on the APX rose 17% in 2006 to 19.2 TWh. More traders are active and the degree of concentration has decreased. With a price level that was higher on average in 2006, the number of price peaks (higher than €100/MWh) increased by one-quarter compared to 2005. A particularly large amount of price peaks were recorded in Q1 2006. At the same time there appears to be greater depth in the market, and the price sensitivity of additional demand bids is 2% lower than in 2005 and 10% lower than in 2004. The APX launched an intraday market in 2006.

The APX is a marketplace for trading in day-ahead contracts. For each individual hour, a price is arrived at on the basis of an auction. In order to gain a view of the liquidity on the APX, an analysis is made of the trading volumes, the number and market share of traders, available contracts, price peaks and price sensitivity.

### 4.4.1 Trading volume

The trading volume on the APX spot market rose for the third successive year in 2006 and now amounts to over 19 TWh, as can be seen from figure 11.

*Figure 11: Trading volume on the APX spot market in TWh*




*Source: APX*

### 4.4.2 Number and share of traders

Seven new traders joined the APX and one left in 2006. There were a total of 47 traders on the APX at the end of 2006. By comparison, there was a net addition of three new traders on the APX in both 2004 and 2005. The share of the three most active APX participants in any trading hour in 2006 amounts to 44.5%, and for the five most active participants 60.6%. These shares are roughly the same as in previous years. Compared to 2005, the number of hours in which the share of the three most active traders exceeded 50% decreased by around one-third, and the number of hours in which the five most active traders had a share of more than two-thirds of the trading volume decreased by over 40%.

## 4.4.3 Available contracts

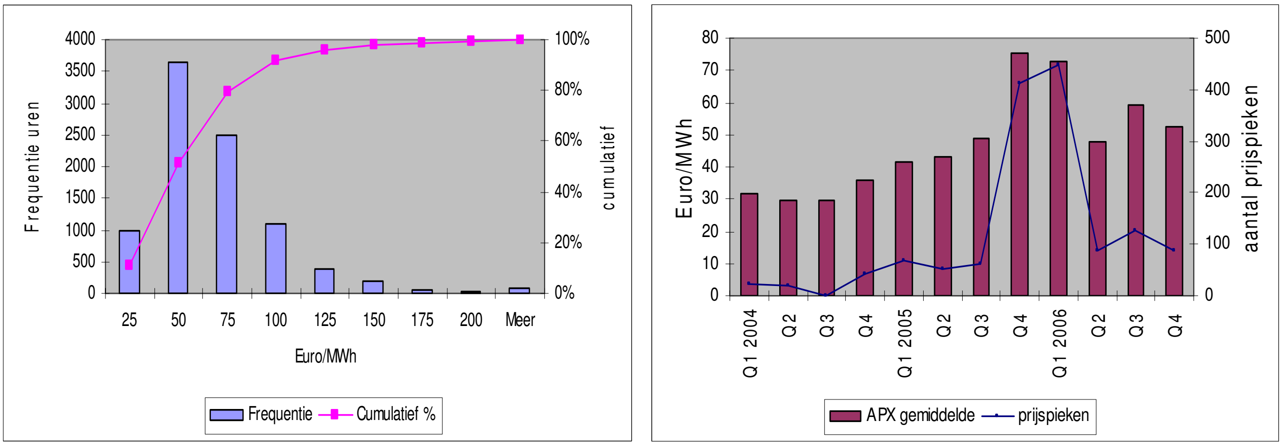
In addition to the day-ahead market, the APX launched an intraday market in September 2006. In this market, quarter hours of electricity can be traded up to two hours before delivery. The volume on the intraday market in 2006 amounted to 103 GWh.

## 4.4.4 Price peaks

For over 90% of the hours in 2006, the price level on the APX was less than €100/MWh (see figure 12a).

The number of times the APX peaked above €100/MWh increased in 2006 compared to previous years. The average price level of the APX also rose in 2006. It is striking to note the high price level and the associated large number of peaks (price higher than €100/MWh) in the first quarter. Figure 12b shows that this is a clear continuation of the price level and associated price peaks from the final quarter of the previous year. Prices appear to stabilise somewhat from the second quarter, but the average is higher than previously and there are also more price peaks.

*Figure 12: (a) APX prices in 2006 and (b) APX average/number of price peaks per quarter in 2004-2006*



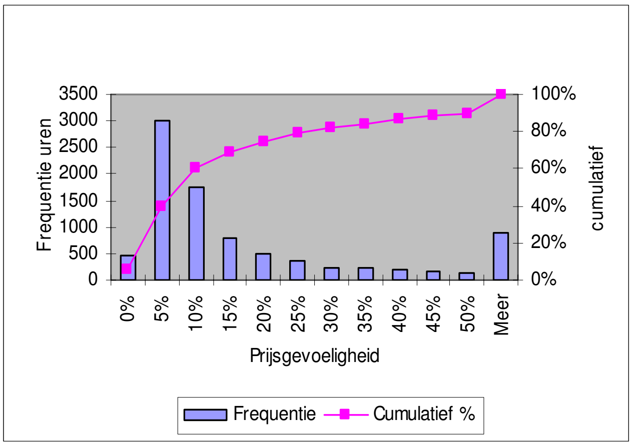

*Source: APX*

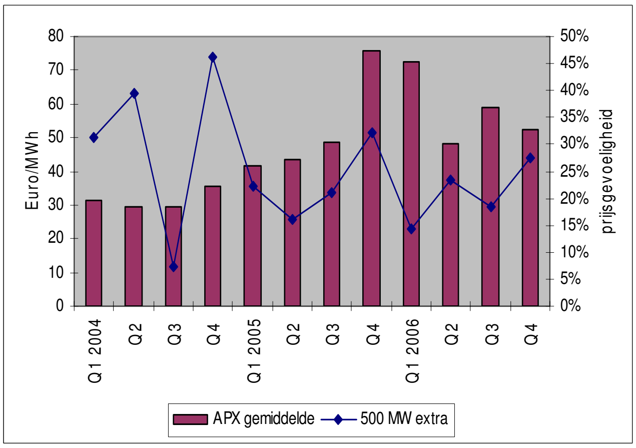
## 4.4.5 Price sensitivity

A simulation of additional demand bids provides an insight into the market depth of the APX. This is expressed in price sensitivity, the percentage price rise resulting from the additional demand. If there were an additional 500 MW of demand on the APX at maximum prices, the price rise in 60% of the hours would be less than 10% and in 80% of the hours less than 25% (see figure 13a).

Compared to 2005, the price sensitivity with 500 MW of additional demand has decreased somewhat with higher average prices. As can be seen in figure 8b, with the high price level of Q4 2005 and Q1 2006, the price sensitivity in the first quarter of 2006 is markedly lower than in the final quarter of 2005. Q1 2006 thus combines an exceptionally large number of price peaks with a remarkably low price sensitivity. Simulations for 5 MW and 50 MW of additional bids show comparable results for 2006 and for 2005. They are around 0.15% and 1.5% of price sensitivity respectively.

*Figure 13: (a) price sensitivity of the APX in 2006 and (b) APX average/price sensitivity per quarter in 2004-2006*




*Source: APX*

## 4.5 Trade in standardised OTC forward contracts

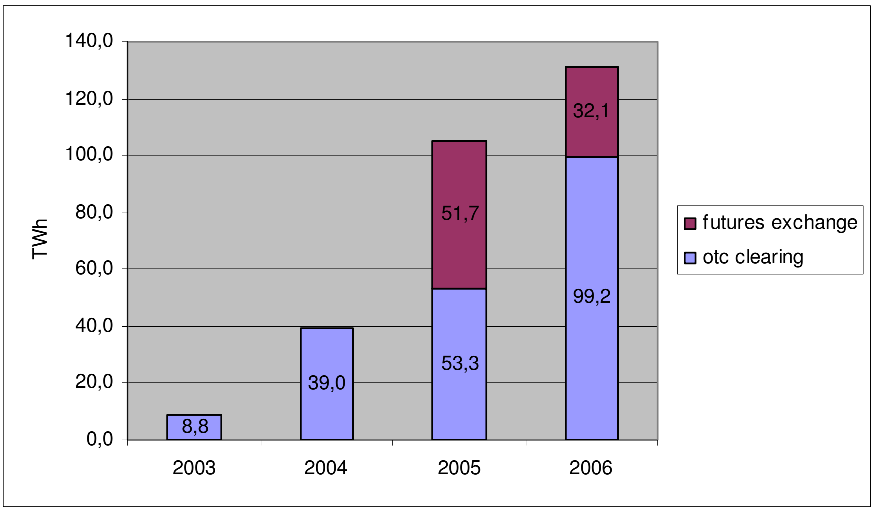
The total trading volume on Endex rose 25% in 2006 to 131.3 TWh. A shift can be seen from trading on the futures exchange (launched in 2005) to the OTC clearing: the trade in standardised OTC contracts has decreased by almost 40%. The number of participants on Endex has grown. In the OTC market the bid-offer spread on peak load forward contracts has (more than) doubled in 2006. Q2 2006 shows an exceptionally high spread. With OTC contracts at higher price levels, the volatility is comparable to previous years.

Standardised forward contracts are traded on Endex or through brokers (OTC). In order to gain an insight into the liquidity of the forward trade, reports are produced for Endex on trading volumes, the number of traders and available contracts; for OTC in general, an analysis has been made of the spread between bid and offer prices and daily price fluctuations (volatility).

### 4.5.1 Trading volume on Endex

As in 2005, the total volume on Endex has increased in 2006. The combined volume of the OTC clearing and futures exchange (trading and clearing) in 2006 amounts to 131.3 TWh, a rise of 25%. This growth is due entirely to the clearing activities. After a successful start in 2005, trading in standardised OTC contracts on Endex decreased by almost 40%, as can be seen in figure 14.

*Figure 14: Trading and clearing volumes on Endex in TWh*




*Source: Endex*

## 4.5.2 Number of traders on Endex

The number of traders on Endex has increased both for the OTC clearing and the futures exchange. The number of participants in OTC clearing (authorised to clear Dutch OTC contracts) have decreased by seven to 25 in 2006, and in the futures exchange the number of participants (authorised to trade in Dutch electricity contracts) has also increased by seven to 24.

A clearing member also joined in 2006. There are now a total of eight clearing members. A clearing member fulfils the role of service provider between the Endex participant and the clearing house.

## 4.5.3 Available contracts on Endex

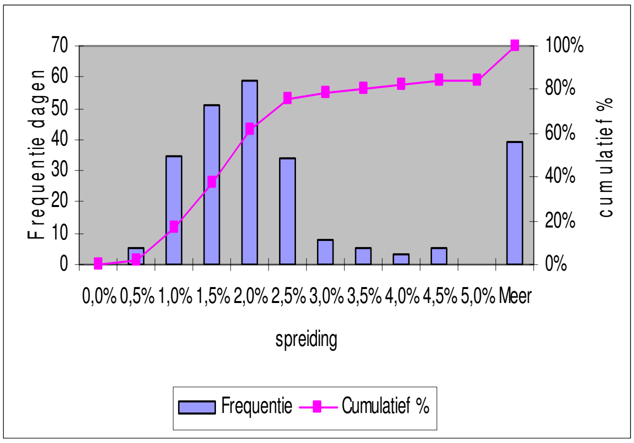
The number of available standard forward contracts on Endex remained the same in 2006 as in the final quarter of 2005. Three new monthly contracts, two new quarterly contracts and a new annual contract were introduced in that quarter, for both base load and peak load. A total of 30 standard forward contracts are therefore now available on Endex.

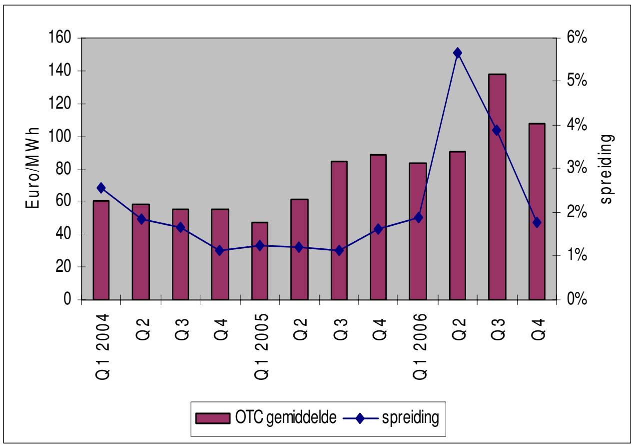
## 4.5.4 Spread between bid and offer prices

The bid-offer spread for quarterly contracts is at or below 2.5% for three-quarters of the days in 2006. On over 15% of days, the bid-offer spread exceeds 5% (see figure 15a).

For quarterly OTC contracts, the bid-offer spread has increased sharply in 2006 compared to previous years, as can be seen in figure 15b. This wider spread is accompanied by a higher price for quarterly contracts. It is striking that a considerably wider spread can already be seen in the second quarter, while the price of quarterly contracts only increases strongly in the third quarter. This pattern is also evident in monthly contracts, but there the spread in the third quarter is already below 2% again. Similarly in the annual contracts, the considerably higher spread is only evident in the second quarter, and the price increases more gradually over the quarters.

*Figure 15(a) bid-offer spread on OTC quarterly peak load contract in 2006 and (b) average OTC/spread per quarter in 2004-2006*



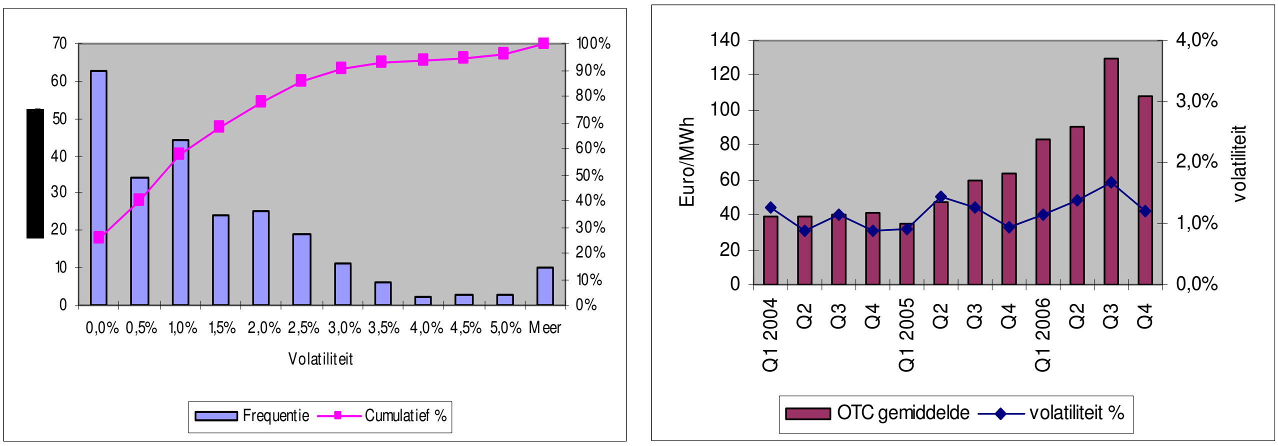

*Source: Platts*

### 4.5.5 Volatility of prices

For two-thirds of the days in 2006, the price of quarterly contracts changes by a maximum of 1.5% from day to day. On 15 days in 2006, the price of a quarterly contract differed from the previous day's price by more than 5% (see figure 16a).

The volatility of quarterly contracts in 2006 is therefore somewhat higher than in 2005, as can be seen from figure 16b. Hence, the considerably higher price level in 2006 has only been accompanied to a limited extent by greater volatility. The volatility does move with the price level, but this trend is more subdued. In the case of monthly contracts, the volatility in 2006 has clearly declined, while the price level shows a rising trend. For annual contracts, the volatility is comparable to previous years, except in the second quarter, when volatility increases sharply.

*Figure 16: (a) Volatility of OTC quarterly base load contract in 2006 and (b) average OTC/volatility per quarter in 2004-2006*




*Source: Platts*

## 4.6 Transactions on the TenneT imbalance market

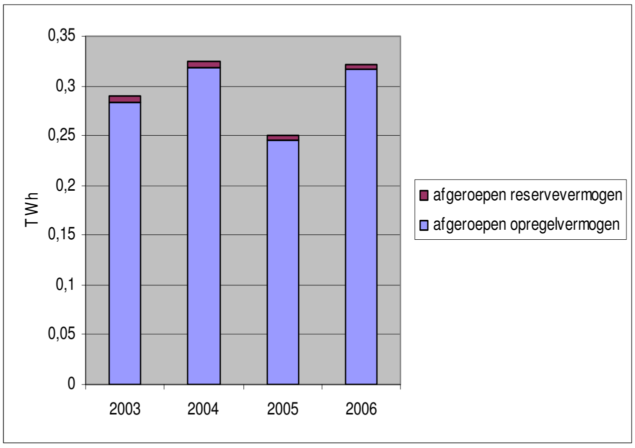
In the market for control and reserve power, 30% more volume was called upon in 2006 than in 2005. The number of time units in which TenneT had to call upon reserve power decreased further; it halved compared to 2003. In short: in time units when calls are made, much more is called upon. With a higher average price level in 2006, the number of price peaks in the imbalance market has decreased.

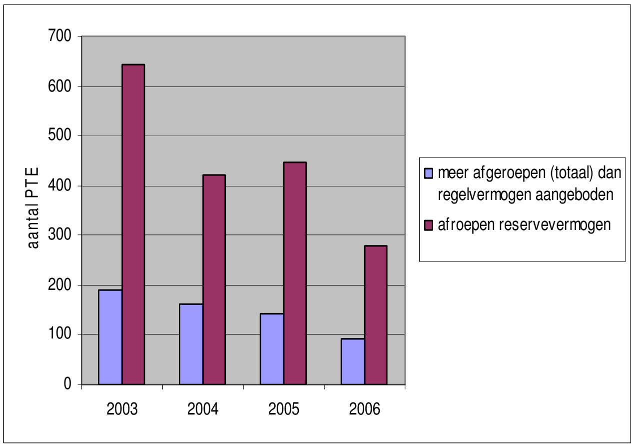
In the market for control and reserve power, the parties issue bids at which they are prepared to produce more or less than is stated in the programmes. The imbalance price is arrived at on the basis of a bidding ladder. This is the price at which TenneT offsets the imbalance among the market participants (caused by differences compared to programmes) for each quarter. The following are analysed in turn: volumes, excess/shortage in offered control and reserve power and the imbalance price peaks.

### 4.6.1 Volumes in the market for control and reserve power

In 2006, TenneT called upon almost 30% more control and reserve power than in 2005. The total control and reserve power called upon in 2006 is approximately 322 GWh (see figure 17a). Despite the fact that more was called upon in 2006, there was a decrease in the number of programme time units (PTUs) in which the offered control and reserve power was insufficient. The number of PTUs in which TenneT had to call upon reserve power also decreased in 2006 (see figure 17b). Both have (more than) halved since 2003.

*Figure 17: (a) volumes of regulation power and reserve power called upon in 2003-2006 and (b) number of PTUs in 2003-2006*



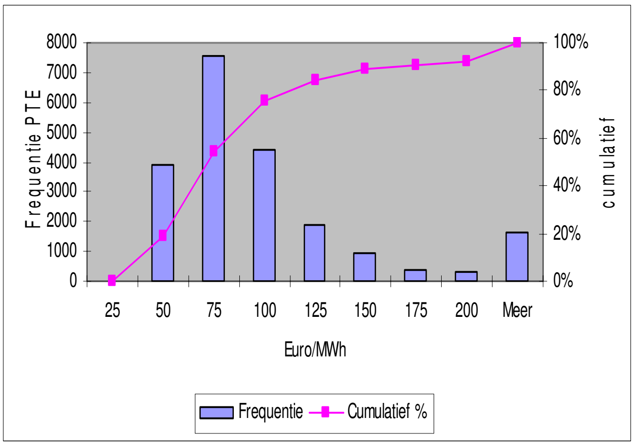

*Source: TenneT*

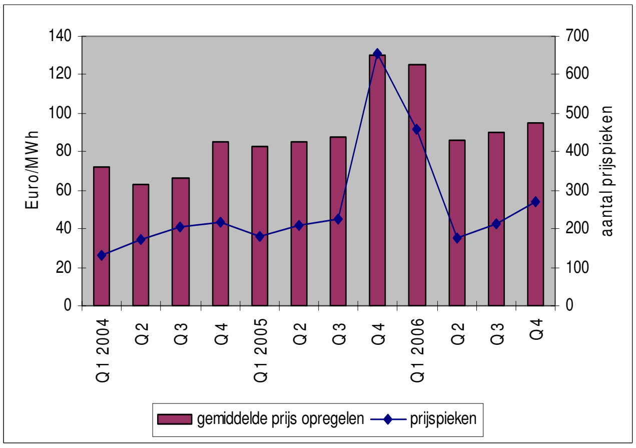
## 4.6.2 Price peaks in the market for control and reserve power

For three-quarters of the number of PTUs, the imbalance price remains below €100/MWh. In 8% of the time the price in the imbalance market has exceeded €200/MWh (see figure 18a).

The average price level in 2006 was somewhat higher than in 2005, while the number of PTUs with a price in excess of €250/MWh decreased. Figure 18b shows that the first quarter differs markedly from the remainder of the year. Compared to the final quarter of 2005, in which there is a comparable price level, the number of price peaks in the first quarter of 2006 is clearly lower. At the same time, the prices themselves show a rising trend, which corresponds to the price trend on the APX.

*Figure 18: (a) TenneT imbalance prices in 2006 and (b) average imbalance price/number of price peaks per quarter in 2004-2006*




*Source: TenneT*

## 4.7 Arbitrage and substitution

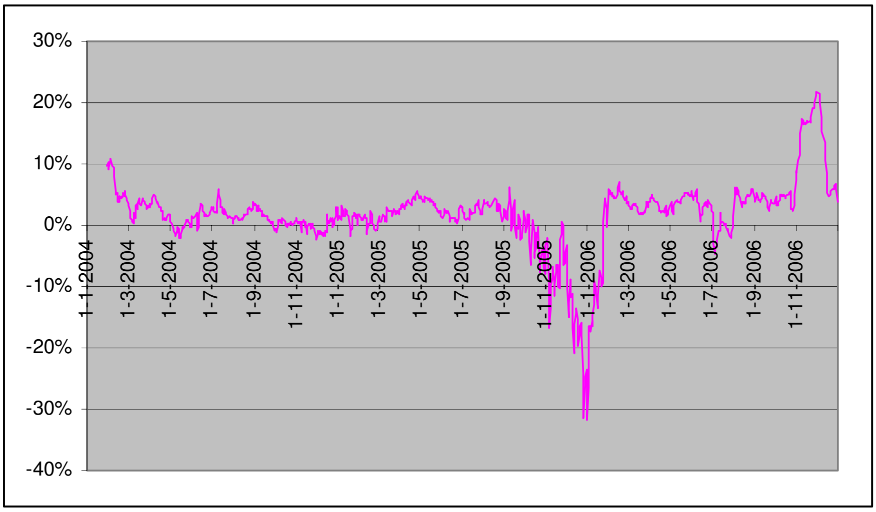
Prices on the day-ahead OTC market are generally higher than on the APX. This difference increased further in 2006. There is no clear picture of the price relationship between the TenneT imbalance market and the APX. Traders mostly state that they see day-ahead products on the OTC and the APX as substitutes; the possibilities for arbitrage are judged to be less good.

In a liquid market, price differences between comparable standardised contracts which are traded through various channels (exchange, through a broker and bilaterally) are arbitraged. If the prices for comparable contracts in the various marketplaces do not tend towards the same value, the possibilities for arbitrage are not being fully exploited. A difference in price can be caused by a difference in transaction costs, a lack of transparency (too little reliable information among traders) or congestion at the interconnectors.

Day-ahead OTC and APX

Figure 19 shows the trend in the price difference between day-ahead contracts on the OTC market and on the APX, expressed as a percentage of the OTC price. A positive value means that the price on the OTC market is higher than on the APX. The price difference between OTC and APX contracts appears to have been reasonably constant over the last few years. The large price rises on the APX (as on Powernext and the EEX) at the end of 2005 which only occurred in part on the OTC market, appear to be an exception in the pattern over the last few years. At the end of 2006, an opposite movement appears to occur for a short time, with a relatively sharp rise in the price of OTC contracts.

*Figure 19: Trend in the price difference between OTC and APX in 2004 – 2006, day contracts (30-day moving average)*



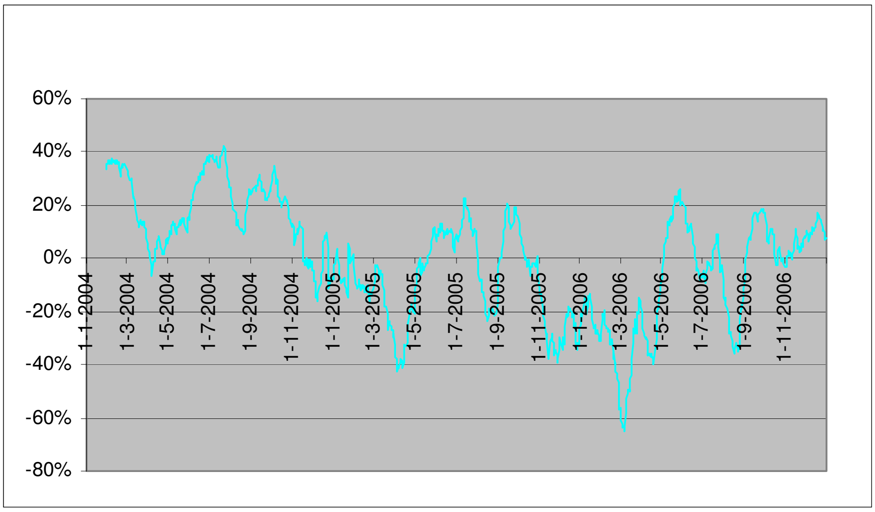

*Source: APX, Platts*

In the survey of traders, half of the respondents state that they consider day-ahead products on the OTC and the APX to be substitutes. Ten per cent state that they do not see them in that way. Respondents' views are divided on the possibilities for arbitrage between these two markets. One-third state that there are good possibilities and another one-third state that the possibilities are poor.

TenneT imbalance and APX

Figure 20 shows the trend in the price difference between the TenneT imbalance price and the APX price, expressed as a percentage of the TenneT imbalance price. A positive value means that the imbalance price is higher than the APX price.[25] As in 2005, the chart shows a volatile picture for 2006, with periods of substantially higher APX prices alternating with periods in which the TenneT imbalance price is higher. The pattern over the year as a whole is nevertheless comparable, with peaks and troughs around the same months. The 2004 picture, in which the TenneT imbalance price was structurally above the APX price, has not been repeated since that year.

*Figure 20: Price difference on the TenneT imbalance and APX 2004 – 2006 (30-day moving average)*




*Source: APX, TenneT*

## 4.8 Transparency

According to the traders surveyed, a great deal of improvement is still needed in market transparency concerning demand, production and transmission. With regard to trading, the transparency on the OTC market is considered to be too low. The transparency with regard to interconnection is generally considered to be satisfactory, except for transparency on the way in which available interconnection capacity is calculated and the available capacity itself. The Congestion Management Guidelines at the end of 2006 make it possible to enforce greater transparency.

A transparent wholesale electricity market makes a large contribution to ensuring that electricity demand and supply can be matched at the lowest possible cost. Transparency means that traders have access to accurate, relevant information on the wholesale electricity market so that they can buy and sell electricity at minimum transaction costs. The relevant market information includes the availability of production capacity, transmission capacity and interconnection capacity; information on the rules in force in exchanges and auctions (including calculation methods); and information on the results of trading: prices and volumes.

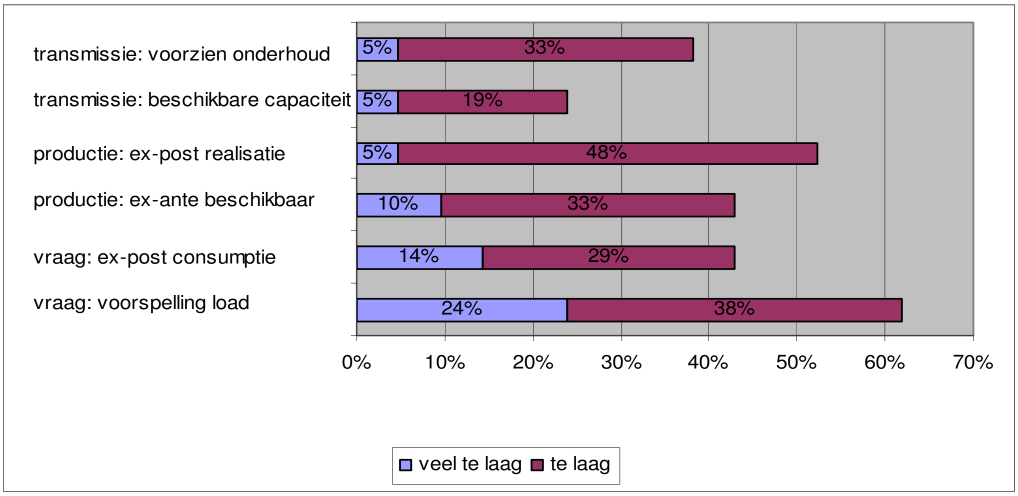
Attention is devoted in turn to transparency concerning demand, production and transmission, transparency with regard to interconnection; and transparency with regard to trading.

[25] Price formation takes place at different times in the APX and the imbalance market. Any price comparison must therefore be interpreted cautiously. A better insight would be obtained from a comparison between the APX day-ahead price and the APX intraday price on the one hand and the APX intraday and the TenneT imbalance price on the other hand. The APX intraday market has not been operating long enough to present an analysis for 2006.

### Demand, production and transmission

The survey of traders shows that the transparency relating to demand, production and transmission in the Netherlands still leaves something to be desired. Figure 21 shows the results for 2006.

*Figure 21: Traders' opinions on extent of information provision on demand, production and transmission in 2006*



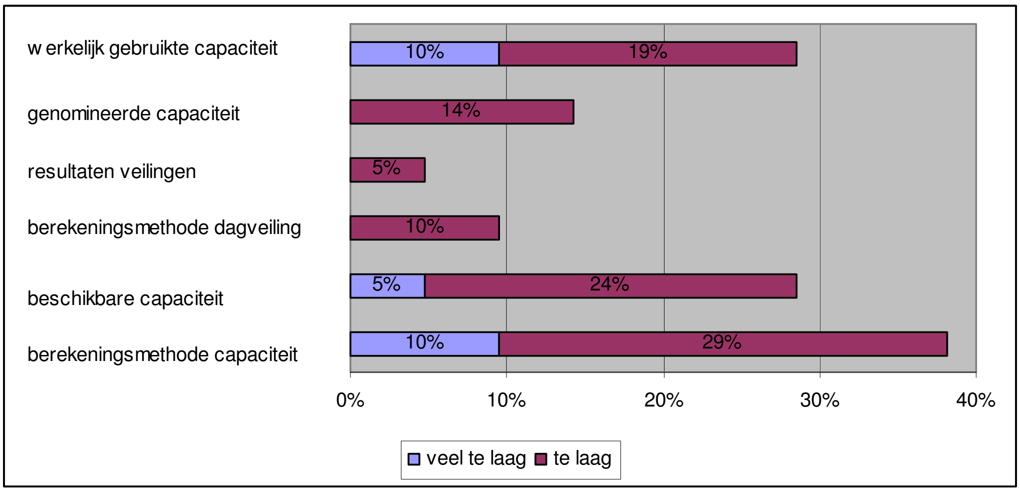

*Source: DTe survey*

Compared to the survey results for 2005, traders believe that transparency has increased across the board. Production data have been published since October 2006 on the initiative of EnergieNed and APX. They were published initially on the APX site, but from June 2007 publication they were published on the EnergieNed website because the quality of the data was still insufficient. In this case, the provision of incorrect information can be seen as worse than the situation in which no information was available.

### Interconnection

The survey of traders shows that transparency with regard to the interconnection is mostly viewed positively. Figure 22 shows the results of the survey.

*Figure 22: Traders' opinions on the extent of information provision on interconnection in 2006*



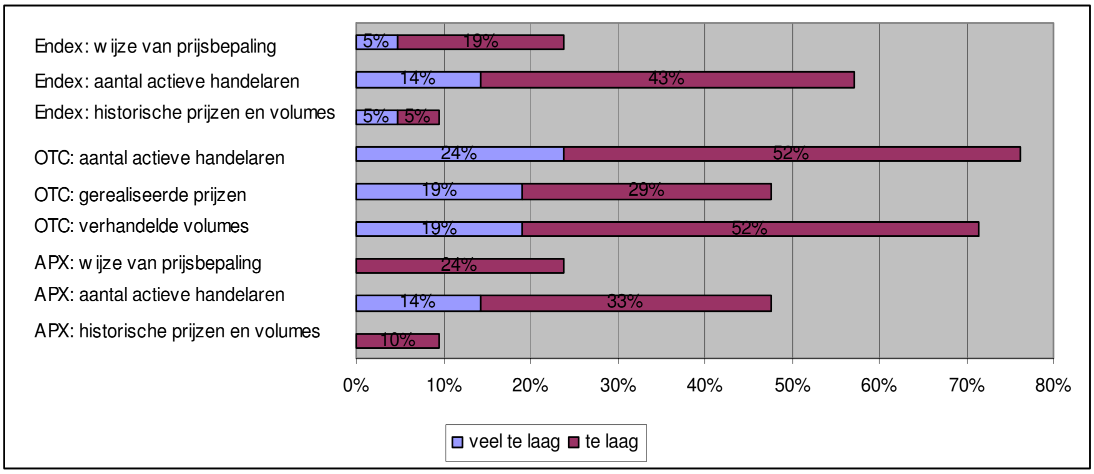

*Source: DTe survey*

Compared to the 2005 survey, traders' perception is that there is greater transparency relating to interconnection, although there appears to be no appreciable change in the information provision on the above components.

Trading

Respondents to the trader survey state in particular that transparency in the OTC market as a whole is too low. For the APX and Endex, this mainly concerns the number of active participants in the trading, as shown in figure 23.

*Figure 23: Traders' opinions on the extent of information provision on trading in 2006*




*Source: DTe survey*

Compared to the results of the 2005 survey, traders are less positive than in the previous year. There may be a different pattern of expectations, since there has been no change in the information provision on the above components.

These survey results largely correspond to the analysis of the current level of market transparency conducted as part of the Regional Initiative. The adoption of new European guidelines (the "Congestion Management Guidelines") at the end of 2006 has created a legal basis for the improvement of market transparency in relation to demand, production, transmission and interconnection. On a regional level, work is being carried out on a uniform interpretation of these new guidelines to prepare for their actual implementation. There is as yet no legal basis for the improvement of transparency in the OTC market. The degree of transparency in the OTC market currently depends on voluntary initiatives in the market.

## 4.9 International comparison

The differences between the Netherlands and the surrounding countries are clearly visible: the development of liquidity in the Netherlands evidently remains stuck at more less the same level. In the spot market, trading volumes on the exchanges continue to show a rising trend. The price level of the APX in 2006 is generally higher than that of the EEX (average of over 12%) and Powernext (average of over 15%). The APX also has the largest number of price peaks, which are particularly visible in Q1. The highest peaks, however, occur on the EEX and Powernext. In the forward market, Dutch prices are generally higher than in Germany and France. For monthly peak load contracts, the price is an average of 17% higher in 2006, and in the case of annual base load contracts an average of 15% higher. The bid-offer spread in the Netherlands is three times higher (forward peak load contracts), and the difference is particularly visible in Q2. By contrast, the volatility of prices in the Netherlands is somewhat lower than in Germany and France.

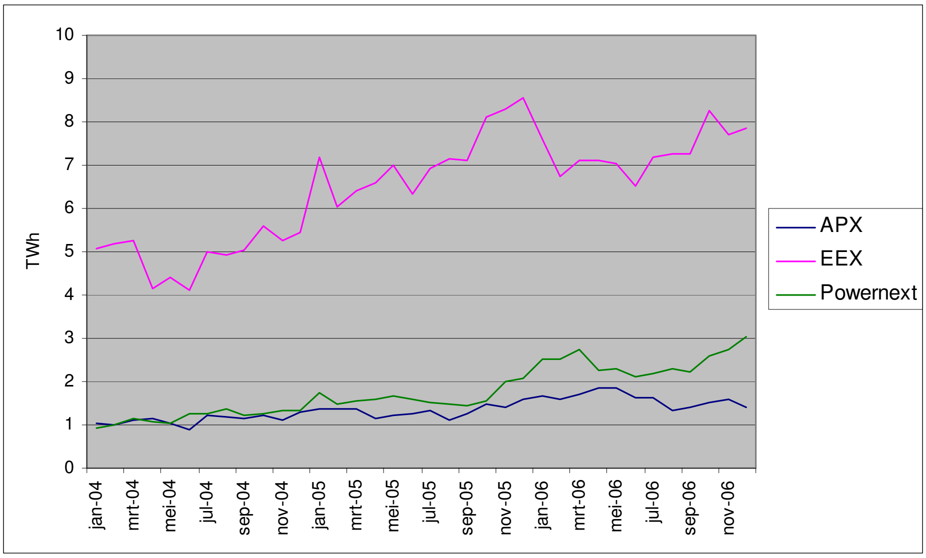
An international comparison shows whether developments in the Dutch wholesale market are also occurring in other countries or are specific to the Netherlands. The spot markets in the Netherlands (APX), Germany (EEX) and France (Powernext) are compared in terms of trading volumes, price trends and price peaks. For the forward markets in these countries, an analysis is made of the price trend, the spread between bid and offer prices and day-to-day price fluctuations (volatility).

### 4.9.1 Spot market

Trading volumes

Trading volumes on the exchanges still show a rising trend, despite the fact that periods of high trading activity sometimes alternate with substantially lower volumes (see figure 24). For the French and particularly the German exchanges, the first half of the year shows a decline compared to the volumes at the end of 2005. The APX saw a continued increase in trading volumes over this period, but marked time when volumes on the German and French exchanges picked up again in the second half of the year. In comparison with electricity consumption in those countries, the Dutch spot market is large relative to France, but comparable to the German situation.[26]

*Figure 24: Trading volumes on the APX, EEX and Powernext in TWh per month in 2004-2006*



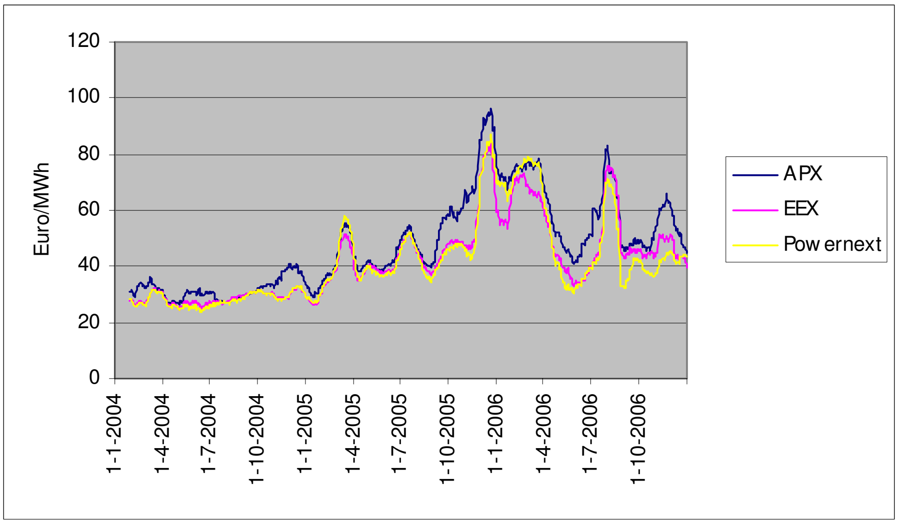

*Source: APX, Powernext, EEX*

Price trends

The price movements on the various exchanges are relatively similar in 2006, as can be seen in figure 25. As in previous years, the price level of the APX is generally higher than that of the EEX and Powernext. This is most clearly evident in the 'trough' of the second quarter and the 'peak' of the final quarter. The APX is the first to halt days of successive price falls, but it also allows days of price rises to continue for the longest period.

[26] Electricity consumption in 2005: Netherlands 104,507 GWh; France 422,323 GWh; Germany 517,504 GWh (Source: Eurostat).

*Figure 25: Price trends on the APX, EEX and Powernext 2004 – 2006 (30-day moving average)*

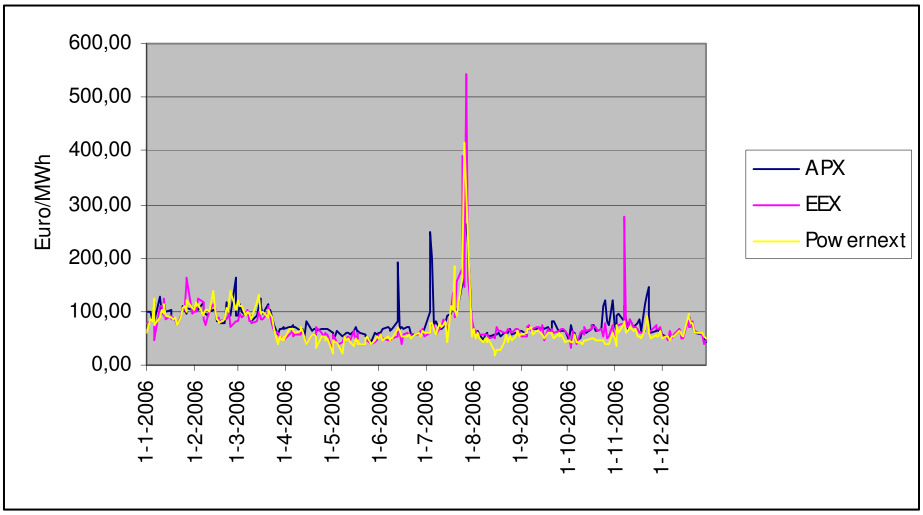



*Source: APX, EEX, Powernext*

PRICE PEAKS

The highest price peaks in 2006 are nevertheless found on the EEX and Powernext (see figure 26). In the final week of July, the highest daily average price on the EEX is €543.72/MWh and on Powernext €416.93/MWh. The highest daily average on the APX in the same week is €263.64/MWh. This is also the only period in which the exchanges all surged to high levels. The other large spikes in 2006 are caused by an individual exchange. On two occasions this was the APX and on one occasion the EEX.

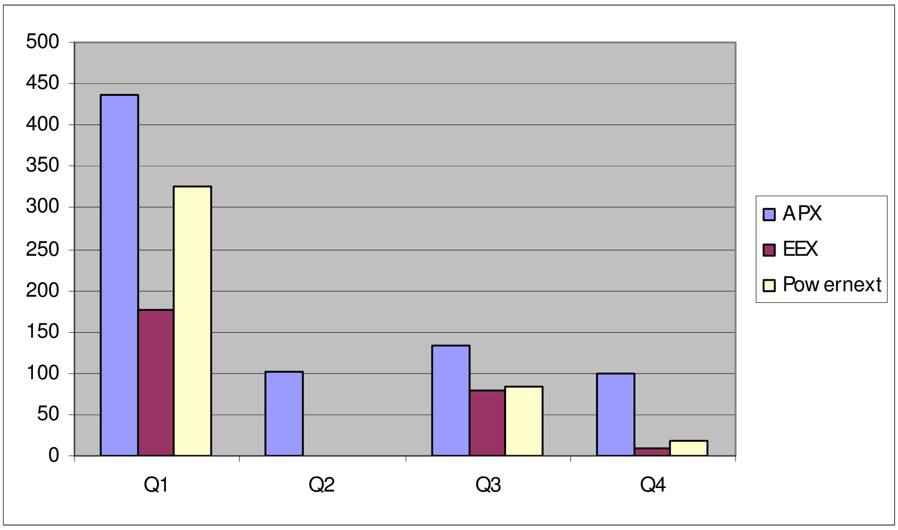
*Figure 26: Prices on the APX, EEX and Powernext 2006 (peak daily averages)*




*Source: APX, EEX, Powernext*

In terms of quantity, the APX has the largest number of price peaks. In the whole of 2006, there were 771 hours (8% of the time) when the APX price was above €100/MWh. These price peaks are concentrated mainly in the first quarter. The other exchanges also show the largest number of peaks in this quarter. In the remainder of the year, the EEX and Powernext only show a substantial number of peaks in the third quarter, while the APX shows at least 100 hours in the other quarters with prices above €100/MWh. Figure 27 presents an overview.

*Figure 27: Number of price peaks (hours P>100) on the APX, EEX and Powernext in 2006*




*Source: APX, EEX, Powernext*

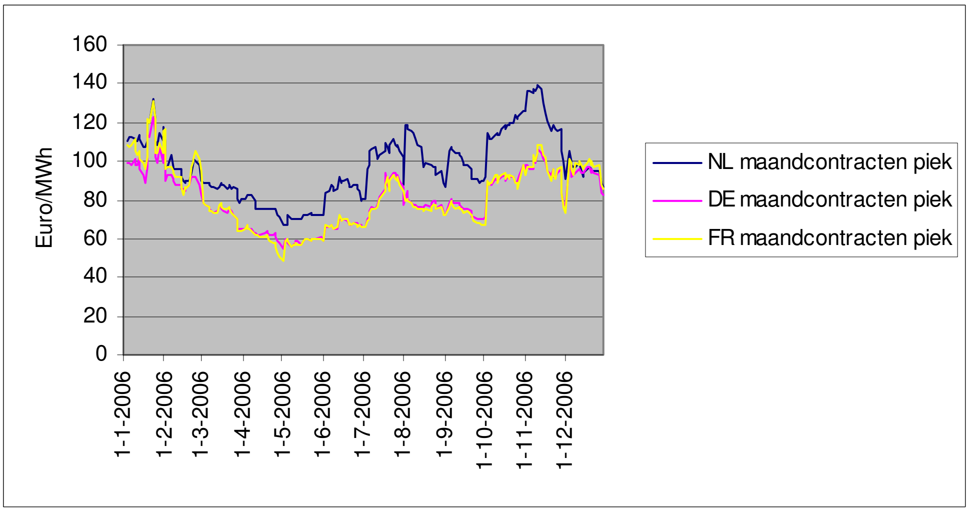
### 4.9.2 Forward market

Price trends

In the forward market it can be seen that the price level in the Netherlands is generally higher or much higher than in Germany and France. Prices also follow each other closely in Germany and France, while the Netherlands more often shows a different pattern.

Figure 28 shows the prices for monthly peak load contracts in 2006. In approximately three-quarters of the year (March to November inclusive), the prices in the Netherlands are considerably higher, with price movements remaining roughly similar. In January, February and December, the three countries are much closer to each other.

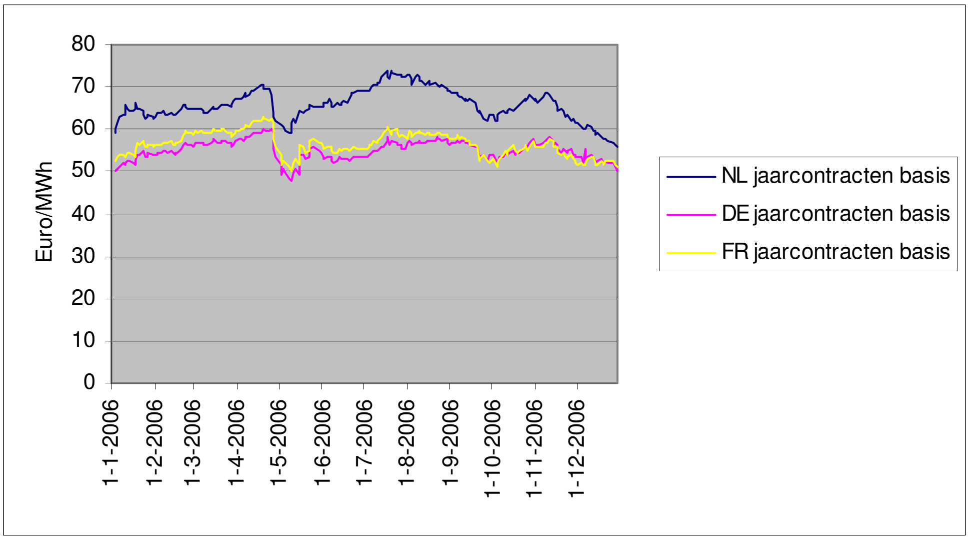
*Figure 28: Prices of monthly peak load contracts in the Netherlands, Germany and France*




*Source: Platts*

Figure 29 shows the prices for annual base load contracts. Over the year as a whole, prices in the Netherlands are much higher, with the exception of a few days at the end of April and the end of May. The price movements in the three countries are reasonably similar for large parts of the year. In other periods, such as June and August, the price trends are opposite.

*Figure 29: Prices of annual base load contracts in the Netherlands, Germany and France*

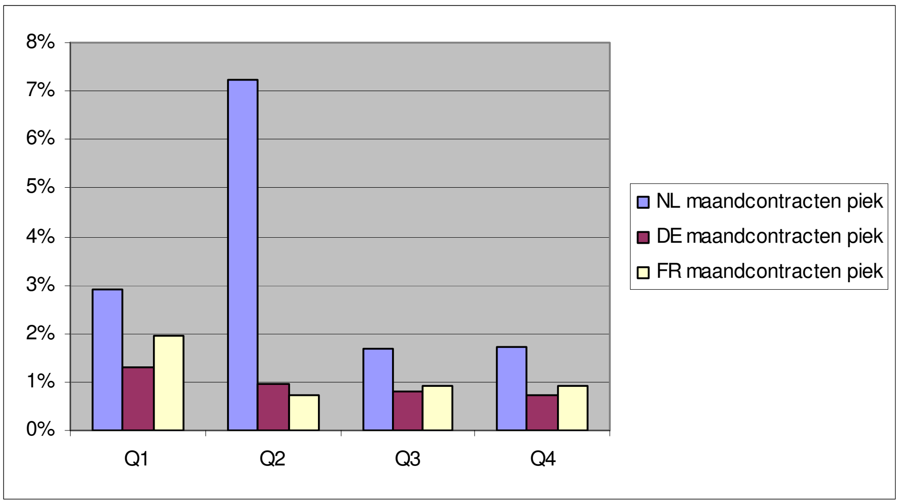



*Source: Platts*

### Spread between bid and offer prices

The spread between bid and offer prices for peak load contracts in 2006 is considerably higher in the Netherlands than in Germany and France. Figure 30 shows the average bid-offer spread for monthly peak load contracts for each quarter. Over the year as a whole, the average bid-offer spread in Germany and France is around 1%, while in the Netherlands it is 3.4%. The strikingly high spread in the Netherlands in the second quarter, averaging more than 7%, was clearly an isolated case. In the other quarters a pattern appears to emerge: the Netherlands has the highest spread, Germany the lowest, with France closer to Germany than the Netherlands. In the case of quarterly peak load contracts, a much higher spread can also be seen for the Netherlands in Q3, which is not matched in Germany or France. Annual peak load contracts also have a higher spread in Q2, but for Q1 there is a strikingly low spread comparable to that of Germany and France.

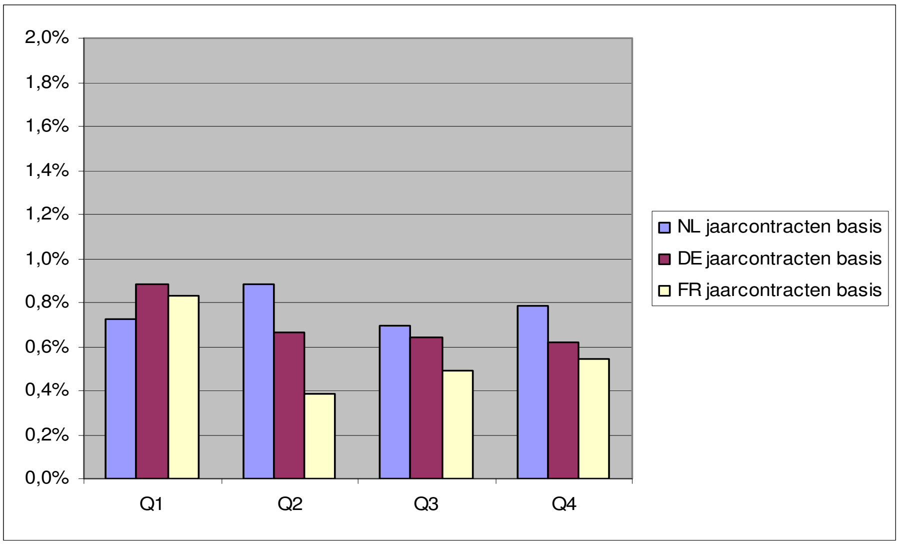
*Figure 30: Bid-offer spread on monthly peak load contracts in the Netherlands, Germany and France in 2006*




*Source: Platts*

For base load contracts, there is less difference between the bid-offer spread in the Netherlands and that of Germany and France. Figure 31 shows the average bid-offer spread for annual base load contracts in each quarter. The Netherlands even shows the lowest spread on annual base load contracts in the first quarter. A low spread can also be seen in monthly and quarterly base load contracts in the third quarter in the Netherlands.

*Figure 31: Bid-offer spread on annual base load contracts in the Netherlands, Germany and France in 2006*

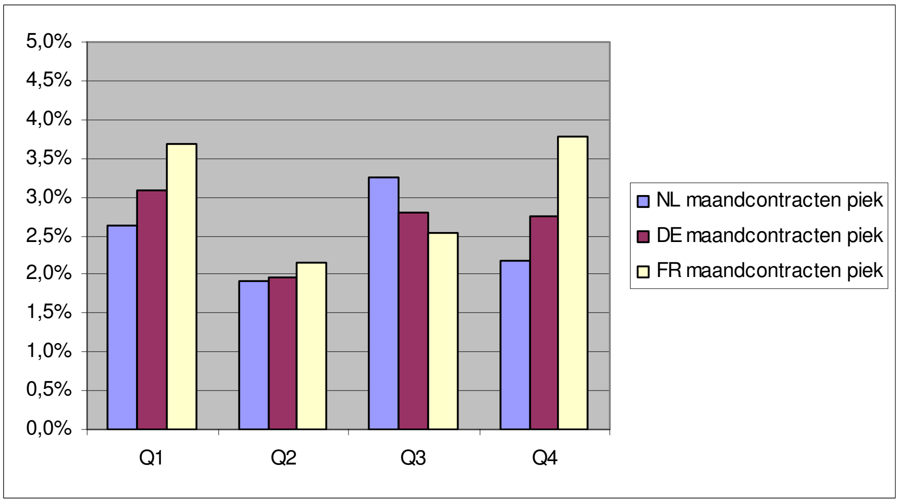



*Source: Platts*

## Volatility of prices

The volatility (extent to which the price varies from day to day) is lower for peak contracts in the Netherlands than in Germany and France in 2006. Figure 32 shows the volatility of monthly peak load contracts. The average daily change in the price of monthly contracts in the Netherlands is 2.5%, while in Germany and France it is 2.7% and 3% respectively. The volatility shows a fluctuating picture through the year in all countries. Generally, however, a pattern is evident, except in the third quarter: the Netherlands has the lowest volatility and France the highest, with Germany situated roughly in the middle. The volatility in all three countries is much closer in the quarterly and annual peak load contracts.

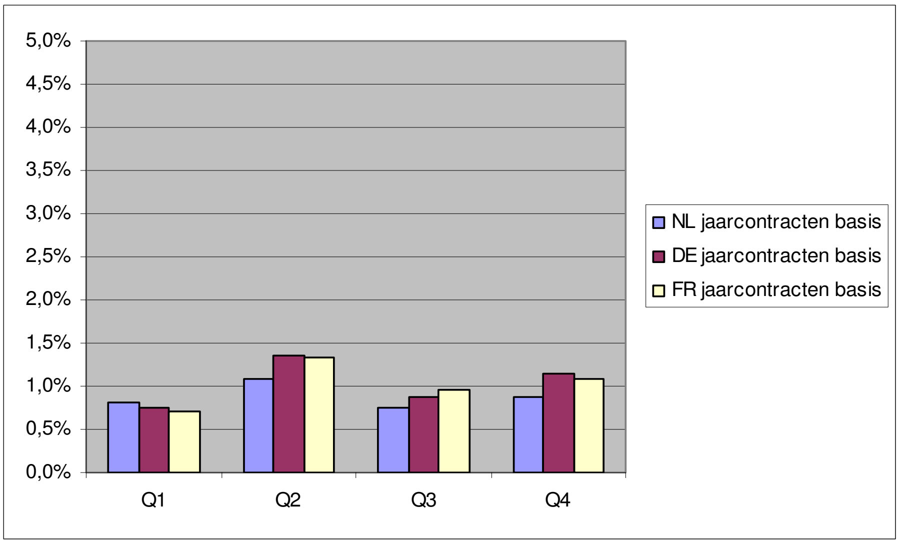
*Figure 32: Volatility of monthly peak load contracts in the Netherlands, Germany and France in 2006*




*Source: Platts*

For base load contracts, the volatility in the Netherlands is likewise low in comparison with Germany and France. Figure 33 shows the volatility for annual base load contracts. In the case of quarterly and monthly base load contracts, the volatility in the Netherlands and France is reasonably comparable, but Germany shows a markedly higher volatility.

*Figure 33: Volatility of annual base load contracts in the Netherlands, Germany and France in 2006*




*Source: Platts*

# 5 The Dutch market in a north-west European perspective

As a result of congestion in the cross-border connections, players in the Dutch wholesale market are only disciplined to a limited extent by foreign supplies and the development in liquidity continues to be determined by the Dutch situation. Market integration is further limited by the fact that there are still no possibilities for trading electricity across borders on the delivery date, because transmission capacity is then no longer available.

The interconnectors with Germany are fully utilised 20% of the time and interconnection capacity with Belgium 19% of the time. It is not possible to import more power during those hours. There is also unexploited potential. Available import capacity is not always fully utilised at times when electricity prices elsewhere are lower. For 50% of the hours in which the Dutch electricity price is higher than in Germany or France, there is underutilisation of interconnection capacity. Congestion is thus caused on the one hand by insufficient physical capacity, and on the other hand the current system of capacity allocation is not operating in an optimal way.

Market coupling with Belgium and France (2006) is allowing better utilisation of existing import capacity, and the construction of a connection with Norway (2007) means more physical capacity. These are steps in the right direction. The Action Plan for the Central West European Region includes major steps for further market integration. In particular, market coupling with Germany and the introduction of cross-border intraday trade will lead to better utilisation of interconnectors. Price convergence with the neighbouring countries will have a major effect on competition because it reduces the scarcity of import capacity. As long as this is not achieved by means of investments in new production capacity in the Netherlands and/or investments in interconnectors, the high degree of concentration in the Netherlands will remain a focus of attention.

## 5.1 Introduction

This chapter deals with the interaction between the Dutch wholesale market and the electricity markets in the surrounding countries. It focuses attention on the availability and utilisation of cross-border transmission capacity. Almost 95 TWh of electricity was generated in the Netherlands in 2006 (after deduction of production for own consumption) and over 21 TWh was imported from abroad for approximately 112 TWh of domestic consumption [27]. In comparison with 2005, almost 2 TWh less was produced and over 3 TWh more was imported, with an increase in domestic consumption.[28] The Netherlands is a net importer of electricity; this position has been reinforced in the past few years.

## 5.2 The Dutch generating fleet

The Dutch generating fleet is characterised by a large proportion of gas-fired plants. Germany has a relatively large number of coal-fired plants, while in Belgium and France the emphasis is on nuclear plants. The higher fuel costs for the generation of electricity by means of gas-fired plants in 2006 result in a price difference averaging over 12% compared to Germany and over 15% compared to France in the spot electricity market. Investments in new production capacity in the Netherlands may lead to more price convergence with the neighbouring countries.

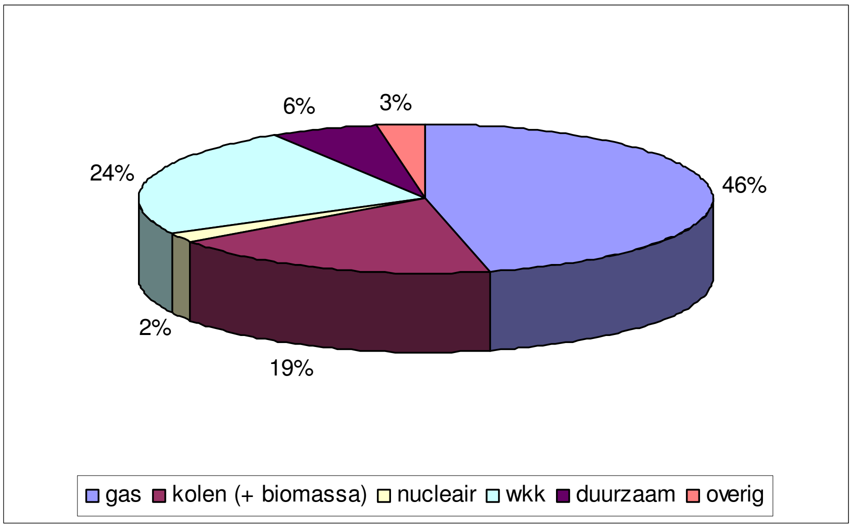
[27] The difference is due to grid losses.

[28] Source: CBS Elektriciteitsbalans (StatLine), provisional figures for 2006.

## 5.2.1 Composition of the generating fleet

The Netherlands has over 21 GW of generating capacity. Natural gas and coal- (plus biomass-) fired plants, together with the nuclear plant, provide almost 15 GW of generating capacity. Decentralised capacity, mainly combined heat-power plants, accounts for over 5 GW and sustainable generation accounts for approximately 1.5 GW. No new large-scale capacity entered service in 2006. Figure 34 shows the composition of the generating fleet in percentages.

*Figure 34: Composition of the Dutch generating fleet (installed capacity)*




*Source: ECN, CBS*

Electricity producers' new construction projects currently represent approximately 9 GW.[29] These plants are due to enter service from 2009 to 2013. They include over 3.5 GW of gas-fired plants (combined cycle), over 4 GW of coal- and biomass-fired plants and a 1.2 GW coal gasification plant. An expected 300 MW of total energy plants are expected to be completed in 2007. Coal-fired plants dominate the new construction projects, with the preferred locations being Eemshaven or the Maasvlakte. The EU ETS does not yet discourage parties from investing in production capacity with high $CO_2$ emissions. Due to transmission limitations in the high-voltage grid, it will not be possible to accommodate all the new construction projects in the short term. In addition, it remains to be seen how many GW of production capacity will actually be realised by the parties. The proportion of sustainable energy will increase further in the future (particularly wind) and there are currently no plans to build new nuclear plants.

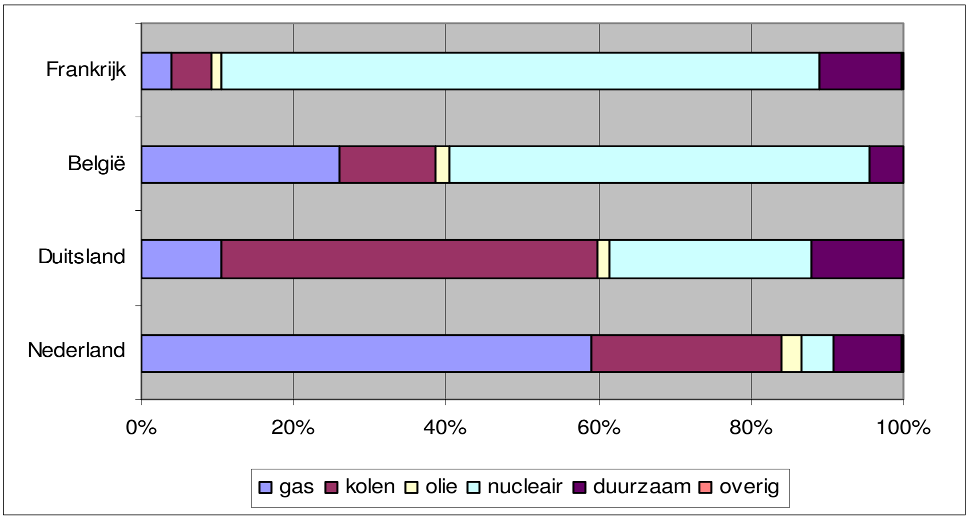
## 5.2.2 Comparison of the fuel mix for electricity production

Most of the electricity produced each year in the Netherlands comes from gas-fired plants. In comparison with the neighbouring countries too, the Netherlands also produces a relatively large proportion of electricity using natural gas as the fuel. In Germany the emphasis is on production from coal-fired plants and in Belgium and France from nuclear plants. Figure 35 shows the proportion of each type of fuel used in electricity production in the Netherlands and surrounding countries (figures for 2005).

In the Netherlands, this mix of fuel for electricity production shows a strong similarity to the respective shares of fuel for installed capacity. In Germany, the proportion of coal in electricity production is higher and that of gas lower than the fuel mix for installed capacity. In Belgium and France, the proportion of nuclear power in production is higher in comparison with the installed capacity.

[29] Source: ECN, Energeia, producers' websites.

*Figure 35: Differences in the fuel mix in the Netherlands and surrounding countries (electricity production)*



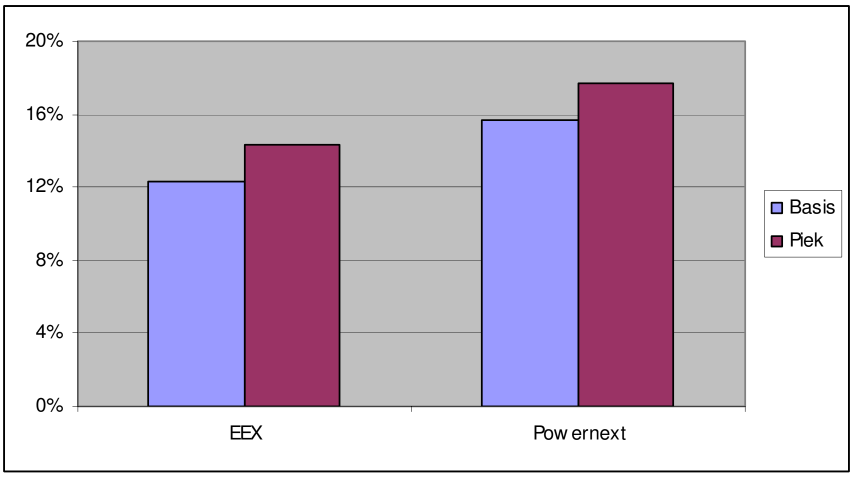

*Source: IAE*

Due to the relatively low price of coal, the fuel costs of coal-fired plants for electricity production are usually much lower than those of gas-fired plants, which generally have a higher fuel efficiency.[30] In 2006, the average coal price is one-third of the average gas price.[31] This relationship between fuel costs is unaltered by the price of CO2 emission allowances in 2006, having regard to the higher emissions of CO2 at coal-fired plants. In a country with a relatively large amount of coal-fired plants, it may be expected on the basis of the fuel costs and the low CO2 price that the electricity price will be lower than in a country in which a relatively large proportion of energy is produced from gas-fired plants.

### 5.2.3 Price differences compared to neighbouring countries

The prices in the Dutch spot electricity market (APX day-ahead) in 2006 are on average over 12% higher than on the German exchange (EEX) and over 15% higher than the French price (Powernext). Figure 36 shows that the average price difference compared to France is greater than the difference compared to Germany and that for both countries the price difference in peak hours (based on the Dutch definition: between 7am and 11pm) is 2% higher than the average over the whole day.

*Figure 36: Price difference in spot markets in the Netherlands and surrounding countries (as % of APX price)*




*Source: APX, EEX, Powernext*

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[30] Coal-fired and nuclear plants have higher overheads (depreciation charges, etc.).

[31] Coal price: CIF ARA 90-day; gas price: TTF monthly.

## 5.3 Cross-border connections

In the auctions of border capacity, market participants usually acquire all of the import capacity that is made available. Not all the acquired capacity is actually used to import electricity. On average, almost 3600 MW was available in 2006, of which an average of over 2900 MW was used. The available capacity is not always fully utilised, even when the Dutch electricity price is markedly higher than the German or French price.

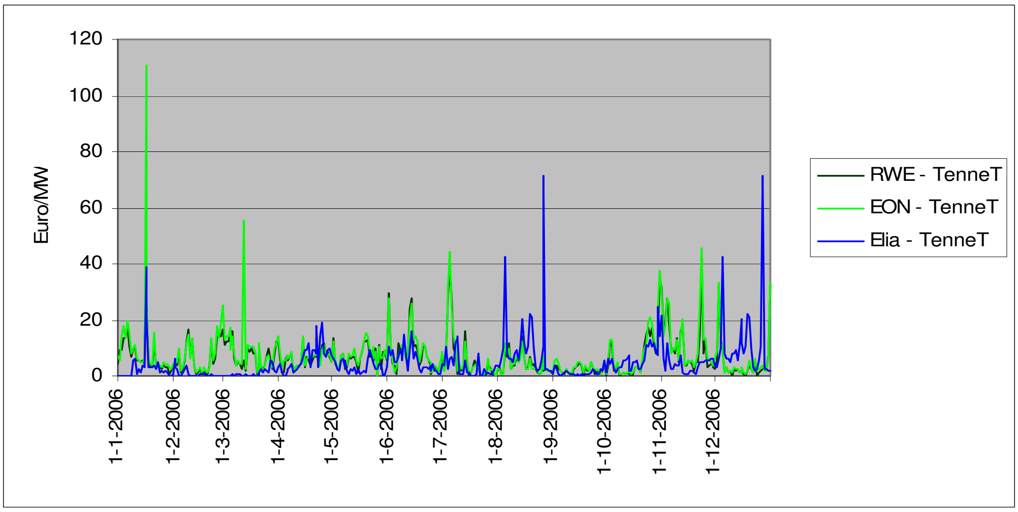
The Netherlands currently has cross-border connections with Germany and Belgium. Under normal circumstances there is 3,600 MW of interconnection capacity available to the market at these connections, rising under favourable conditions to 3,850 MW. Having regard to the physically available interconnection capacity, 4,700 MW could be available to the market. The TSOs hold reserves, in particular due to transit flows caused by wind energy production in northern Germany. This limits the securely available capacity.

### 5.3.1 Explicit auction of border capacity

Market players can acquire import capacity by bidding at the auctions held by the respective TSOs. In this system of explicit auctions, capacity is made available on an annual, monthly and daily basis. A spread annual auction (twice a year) took place for the first time in 2006. Players who do not nominate imports on capacity acquired in the annual or monthly auction lose this capacity in the daily auction (on the basis of the "use it or lose it" principle). The price in the border auction is set at the lowest bid at which capacity has been acquired. If the demand is lower than the available capacity, this capacity is free. TSOs are required to use the auction proceeds to eliminate restrictions in the transmission capacity for the cross-border grid.[32]

The average prices (on a daily basis) of the daily auctions of import capacity are shown in figure 37.

*Figure 37: Average prices at the daily auctions (daily averages, base load)*




*Source: TSO Auction*

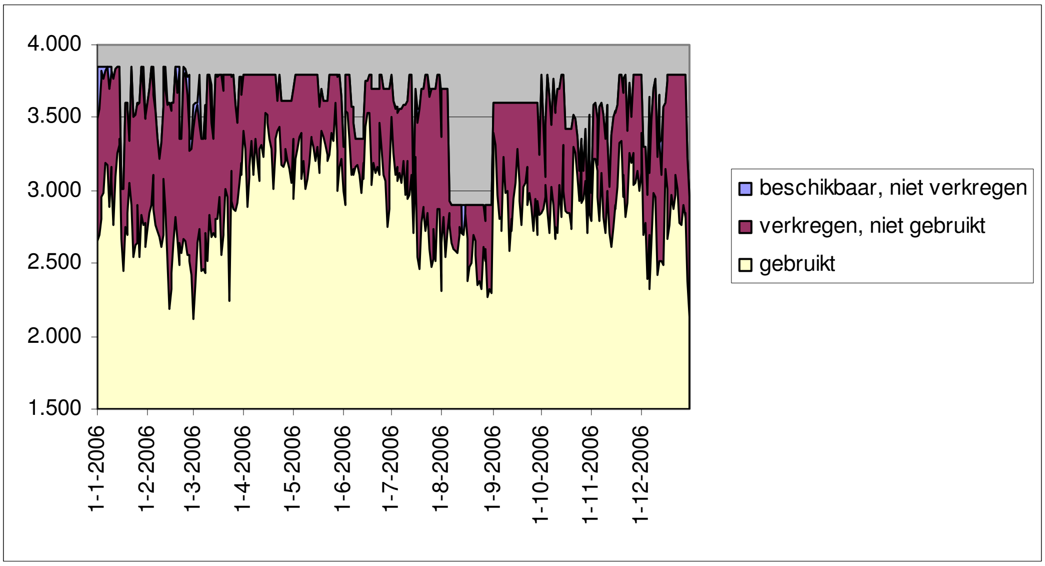
### 5.3.2 Import capacity: available, acquired and used

Figure 38 shows daily averages of available interconnection capacity, the capacity acquired by market players at the various auctions and the actual imports. It can be clearly seen that the market players acquire practically all of the available capacity. In 2006, the average difference between available and acquired capacity is only 15 MW. It can also be clearly seen that in general the acquired capacity is not fully used in

[32] Or for other purposes to be specified by the Executive Board of the competition authority (Section 31(6) of the Electricity Act 1998).

order to import power. In 2006 there is an average difference of 640 MW between acquired and used capacity.

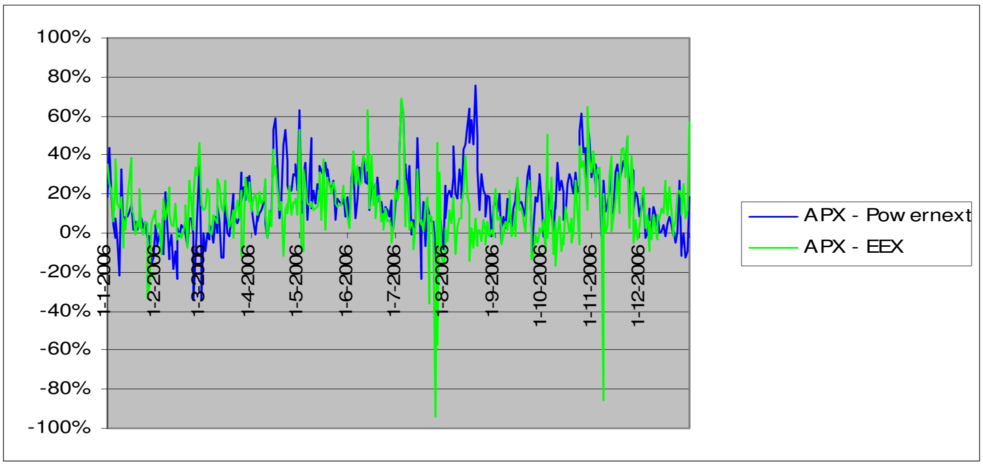
*Figure 38: Import capacity in the Netherlands and surrounding countries (daily averages, MW)*




*Source: TenneT, TSO Auction*

Figure 39 shows the daily average price difference between the APX and Powernext and the EEX, expressed as a percentage of the APX price in 2006. Rising price differences between countries generally correspond to an increase in cross-border traffic. For example, in February, when there are small price differences, relatively little is imported, but when price differences increase in March, imports also show a rising trend. Even when the difference between the APX price and the EEX and Powernext 'peaks' in April, it is still evident that players are not using all the capacity to import. Limited or volatile availability of interconnection capacity to some extent contributes to larger price differences between countries. For example, August is a period of limited availability in which the APX regularly 'peaks' compared to both Powernext and the EEX. It can also be seen that imports lag behind the available and acquired capacity on these days.

*Figure 39: Price difference between APX and EEX/Powernext (daily averages, base load)*




*Source: APX, EEX, Powernext*

## 5.4 Congestion at the interconnectors

Congestion occurs if the interconnection capacity is fully utilised, but also occurs virtually if the interconnectors are underutilised. The interconnectors with Germany are fully utilised 20% of the time and with Belgium 19% of the time. For 50% of the hours in which the Dutch electricity price is higher than the German or French price, the available import capacity is not fully utilised. Congestion thus results in part from a shortage of physical capacity and in part from an inefficient allocation of import capacity. Having regard to the extent of underutilisation, it is recommended that market coupling be introduced at all borders, together with cross-border intraday trading.

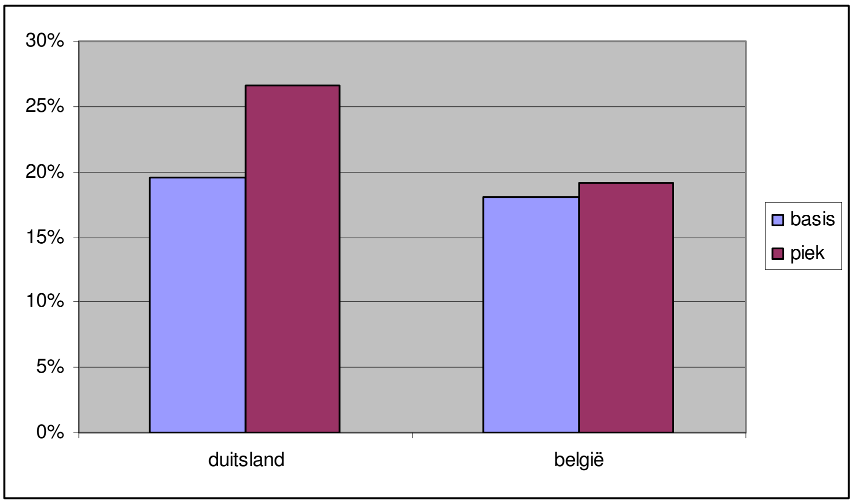
Cross-border connections enable an expensive country to import cheap electricity from abroad. Imports also boost the liquidity in the Dutch marketplaces. However, the interconnection capacity is bound by physical limits. If the interconnector is full, price differences can persist. From the competition perspective, domestic producers are then no longer subject to the disciplining effect of imports. The consequences of any congestion are therefore reflected in the levels of liquidity and competition in the Dutch wholesale market. For this reason, the Monitor looks at the extent of congestion at the interconnectors.

Congestion occurs if the interconnection capacity is fully utilised, but also occurs virtually if the interconnectors are underutilised. In the case of full utilisation, market players would want to import more, but are simply unable to do so due to physical restrictions in the connections. When individual market players do not use all the acquired capacity to import electricity, in spite of a price difference compared to neighbouring countries, there is underutilisation (unexploited potential).

### 5.4.1 Full utilisation

On the interconnectors with Germany, there is full utilisation 20% of the time (Germany to the Netherlands), and in the connections with Belgium the figure is 19% (Belgium to the Netherlands).[33] Figure 40 shows that full utilisation occurs relatively more often during peak hours than over the whole day. The interconnectors with Germany are fully utilised for more than one-quarter of peak hours.

*Figure 40: Percentage of hours of full utilisation of interconnectors with surrounding countries*



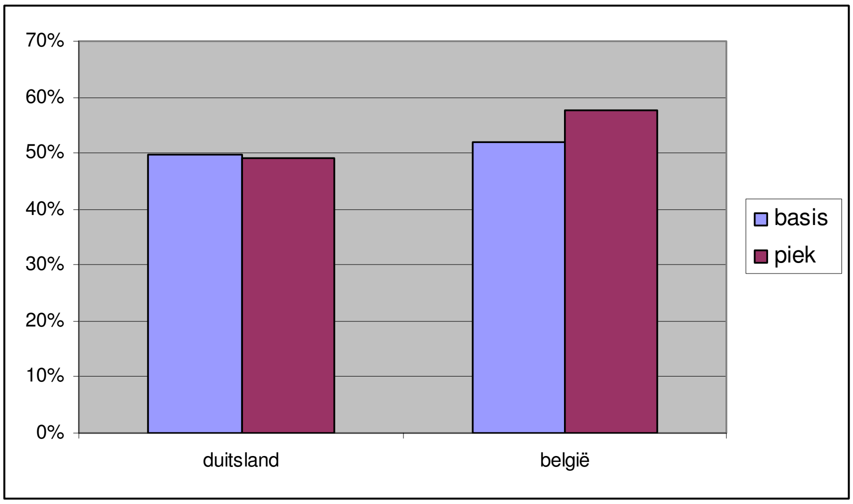

*Source: TenneT, TSO Auction, Elia*

[33] For the purposes of this Monitor, the interconnection capacity is considered to be fully utilised if the nominated imports exceed 97.5% of the available capacity.

### 5.4.2 Underutilisation

In the hours in which the Dutch electricity price is higher than in Germany and/or Belgium, the available import capacity is not fully utilised in 50% of the hours.[34] Figure 41 shows that in the connections with Belgium there is slightly more underutilisation of import capacity, which is most evident in peak hours.

*Figure 41: Percentage of hours of underutilisation of interconnectors with surrounding countries*




*Source: TenneT, TSO Auction, Elia*

If we consider figures 40 and 41 together, congestion is both a question of physical shortage of capacity and of inefficient allocation of the available capacity.[35] On the one hand, for approximately one-fifth of the hours in 2006, there would have been a need for greater import capacity. On the other hand, for half of the time, more could have been imported using the existing capacity. The degree of underutilisation observed shows that there is a need for more efficient use of the available capacity. This underutilisation could be brought to an end by the introduction of market coupling at all borders and the implementation of cross-border intraday trading.

## *5.5 Towards a north-west European market*

With market coupling between the Netherlands, Belgium and France, the border capacity for day-ahead trade is auctioned implicitly on the electricity exchanges. Underutilisation of interconnection capacity is no longer possible in the event of price differences between those countries. On the interconnectors with Belgium, there was congestion for 19% of the time during that period (22 November – 31 January).
The Action Plan for the Central West European Region includes major steps for further market integration. In particular, market coupling with Germany and the introduction of cross-border intraday trade will lead to better utilisation of interconnectors. The so-called flow-based approach is intended to lead to higher values for the available interconnection capacity. Price convergence with the neighbouring countries will have a major effect on the competition because it reduces the scarcity of import capacity. As long as this is not achieved by means of investments in new production capacity in the Netherlands and/or investments in interconnectors, the high degree of concentration in the Netherlands will remain a focus of attention.

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[34] For the purposes of this Monitor, there is underutilisation of interconnection capacity if, in spite of a price difference on the exchanges, the nominated imports amount to less than 97.5% of the acquired capacity.

[35] The analysis is based on a comparison of exchange prices. The trading times differ on the respective exchanges. In addition to exchange trading, imported power also comes from other types of contract (OTC, bilateral).

An important development in 2006 is the completion of market coupling with Belgium and France (Trilateral Market Coupling) on 21 November. Trading on the APX, Belpex and Powernext electricity exchanges is now connected, taking into account the available capacity at the various borders.[36] The interconnection capacity for day-ahead trade is thus auctioned implicitly on the electricity exchanges. Congestion now only occurs if the capacity is fully utilised. If the capacity is not fully utilised, electricity prices in the respective countries are the same. This new allocation method leads to the full utilisation of the available capacity for day-ahead trade. However, it is not yet possible to fulfil any requirements to trade intraday across borders.

The first results of day-ahead market coupling are now known. Between 22 November 2006 and 31 January 2007, prices on the APX, Belpex and Powernext were the same for 65% of the time. More specifically, electricity prices in the Netherlands and Belgium were identical for 81% of the time.[37] This means that for 19% of the time there was congestion as a result of full utilisation, comparable to the situation in 2006 before market coupling.

As a result of the laying of the NorNed cable, which is expected to enter service at the end of 2007, there will be additional cross-border physical import capacity (700 MW). The entire capacity of this connection between the Netherlands and Norway is intended to connect the APX to the Nord Pool Scandinavian electricity exchange. However, it is uncertain whether market coupling will be able to start when the NorNed cable is completed. The possible laying of the BritNed cable will also contribute to the further expansion of physical import capacity (approximately 1,000 MW). The plans provide for the cable to enter service at the end of 2010. The capacity on this cable will be auctioned partly implicitly (APX in both the Netherlands and Great Britain) and partly explicitly.

These developments bring the creation of a north-west European market a step closer. Market integration leads to more efficient cross-border trade and better utilisation of cross-border capacity. Further action needs to be taken to make this market a reality. Market coupling with Germany is currently under consideration. The Action Plan for the Central Western Region (Netherlands, Belgium, France, Germany, Luxembourg)[38] includes the implementation of day-ahead flow-based market coupling as one of the action points. It also covers the implementation of cross-border intraday and balancing trade. In particular the possibility of trading intraday across borders will lead to better utilisation of existing interconnectors. Other points in the Action Plan include harmonisation and improvement of the explicit auctions for the long term, joint calculation of cross-border capacity, maximisation of the volume and use of cross-border capacity and a regional plan for investments in capacity. It is very important that these action points are implemented to allow further market integration.

Price convergence with the neighbouring countries will have a major effect on the competition, because it will reduce the scarcity of import capacity. Such price convergence may arise due to investments in new production capacity with lower marginal costs (such as coal-fired plants) in the Netherlands. The plans for new plants are in place; the question is when and to what extent they will be implemented. An expansion of the cross-border transmission capacity may also promote competition to a large extent. Investment proposals for the expansion of interconnection capacity will only come to fruition if there is a positive cost-benefit analysis. With sustained price differences, however, it is likely that substantial benefits can be expected. Only after a considerable expansion of the interconnection capacity would there be a relevant geographic market that is wider than just the Netherlands (Vision Document: Mergers on the Energy

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[36] The Belgian electricity exchange Belpex began operating on 21 November 2006 at the same time as the introduction of TLC.

[37] For Belgium and France this percentage is 82%.

[38] Publication date 12 February 2007, drawn up by the five regulators BNetzA, CRE, CREG, ILR and DTe, in co-operation with the national grid managers.

Markets, NMa, November 2006). Until there is a truly integrated north-west European market, the high degree of concentration in the Netherlands will remain a focus of attention.